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REPORT

Reliability of Deepwater Subsea BOP Systems and Well Kicks

Unrestricted Version

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Title

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Summary

Deepwater BOP reliability and well kick data have systematically been collected for wells spudded in the period 2007 – 2009 in the US GoM OCS. The main source of information for the study has been the well activity reports (WARs) in the BSEE e-Well system.

A total of 259 wells (when regarding sidetracks and by-pass as separate wells) have been included in the study. All the wells are drilled in waters deeper than 2000 ft (610 meters).

Only the periods of the well when the BOPs are located on the wellhead have been included in the study, so shallow gas incidents or shallow water flows have not been considered.

Keywords English	Keywords Norwegian
Reliability	Pålitelighet
Offshore	Offshore
Blowout Preventer	Utblåsningssikring
Kick	Brønnspark

Preface

The evaluation, analysis and calculations performed are based on a number of assumptions, limitations, and definitions of system and environmental boundaries, all of which are stated further in the report or in its references. ExproSoft will accept no liability for conclusions being deduced by readers of the report. Caution should always be taken when using the results from this report further, such that decisions are not made on an erroneous basis.

Summary and Conclusions

Deepwater BOP reliability and well kick data have systematically been collected for wells spudded in the period 2007 – 2009 in the US GoM OCS. The main source of information for the study has been the well activity reports (WARs) in the BSEE e-Well system.

A total of 259 wells (when regarding sidetracks and by-pass as separate wells) have been included in the study. All the wells are drilled in waters deeper than 2000 ft (610 meters).

Only the periods of the well when the BOPs are located on the wellhead have been included in the study, so shallow gas incidents or shallow water flows have not been considered.

Table 1.1 shows an overview of wells and days in service for the various water depths.

Table 1.1 Overview of wells and days in service for the various water depths

Water depth grouped (ft) / (m)	Development well			Exploration wells			Total		
	Original	Sidetrack or by-pass	BOP-days in service	Original	Sidetrack or by-pass	BOP-days in service	Original	Sidetrack or by-pass	BOP-days in service
2000-3000 / 610-914	7	3	720	37	19	2541	44	22	3261
3000-4000 / 914-1219	10	3	810	31	16	2372	41	19	3182
4000-5000 / 1219-1524	8	3	688	19	13	1988	27	16	2676
5000-6000 / 1524-1829	5		337	17	11	1810	22	11	2147
6000-7000 / 1829-2134	5		371	20	9	1838	25	9	2209
7000-8000 / 2134-2438	2	1	87	9	5	1039	11	6	1126
8000-9000 / 2438-2743	3		125	4		223	7	0	348
9000-10141 / 2743-3091	2	1	85	2		22	4	1	107
Total	**42**	**11**	**3223**	**133**	**73**	**11833**	**175**	**84**	**15056**

BOP-days, is defined as the number of days from when the BOP was landed on the wellhead the first time until it was pulled from the wellhead the last time.

Overview of BOP failures

A total of 156 BOP related failures were observed during this study corresponding to a total time in service of 15056 BOP-days. A BOP failure does not mean that the complete BOP safety barrier function failed, but a component in the BOP or the BOP control system failed. For most of the BOP failures there are redundant or alternative components to ensure the overall safety and performance of the BOP.

An overview of key reliability parameters is provided in Table 1.2. The column "item days in service" represents individual BOP subsystem exposure time. When a failure and associated downtime was not possible to allocate to a specific BOP subsystem (due to lack of information), a dummy item was introduced in the BOP stack.

Table 1.2 Overview of failures

BOP Subsystem	BOP-days in Service	Item days in service	No of failures	Total lost time (hrs)	MTTF (Item days in service)	MTTF (BOP-days)	Avg. Downtime per failure (hrs)	Avg. Downtime per BOP day (hrs)
Annular preventer	15056	28150	24	2344,5	1173	627	98	0,156
Connector	15056	31142	8	638	3893	1882	80	0,042
Flexible joint	15056	15056	1	288	15056	15056	288	0,019
Ram preventer	15056	77264	23	1765,5	3359	655	77	0,117
Choke & kill valve	15056	160310	4	136	40078	3764	34	0,009
Choke & kill lines, all	15056	15056	17	1992	886	886	117	0,132
Main control system	15056	15056	72	4712	209	209	65	0,313
Dummy Item	15056	-	7	1572	-	2151	225	0,104
Total	15056	-	156	13448	-	97	86	0,893

In this study, a total of 156 failures are identified. Seventy-two of these failures, or 45%, are attributed to the control system. The control system is also found causing the highest downtime.

A total of 13448 hours (560 days) of downtime was caused by BOP failures. This corresponds to approximately 4% of the total time in service for the BOP.

Comparison with the previous BOP Deepwater (Phase I & II DW) studies

The previous Phase I DW (/3/) study included wells drilled in more shallow waters than 400 meters, (1312 ft.), and it has been decided only to use data from wells drilled in more than 400 meters for this comparison. The study represented wells drilled from 1992 – 1996. Further, many of the BOP stacks analyzed in Phase I DW included an acoustic backup system. The failures and downtime associated with this system have been disregarded in the comparison.

The Phase II study (/1/) focused on offshore wells drilled in waters deeper than 400 meters in US GoM. The study represented wells drilled in 1997 and 1998. The study was similar to the work carried out in this project.

Table 1.3 shows a comparison of some key results from Phase I & II DW and this study.

Table 1.3 Comparison of key figures, Phase I DW and Phase II DW

Study	BOP-days	Total lost time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hr.)	Avg. downtime per BOP-day (hrs)
Phase I DW	3191	3457,5	138	23,12	25,05	1,08
Phase II DW	4009	3637,5	117	34,26	31,09	0,91
Present Study	15056	13448,0	156	96,51	86,21	0,89

Table 1.3 shows that more BOP-days are covered in the present study than in the previous two studies. The Mean Time To Failure (MTTF) has improved significantly compared to the two previous studies, but the average downtime per BOP day is at the same level. When reading this table it is important to note that the main source of information for this study has been the well activity reports (WARs), while the previous studies were based on daily drilling reports. It can be assumed that many less critical failures are not described in the WARs. These less critical failures typically produce little downtime.

These wells are on the average drilled in deeper waters than in the previous studies. Deeper water increases the repair time for the individual failures because of the time needed to pull and run the BOP.

It is believed that the reliability of the BOPs in general has improved when comparing with the previous studies.

Water depth and BOP reliability

Table 1.4 gives an overview of the BOP reliability vs. water depths.

Table 1.4 Overview of BOP reliability indices for various water depths

	Water Depth range (ft)									
	2000 - 3000	3000 - 4000	4000 - 5000	5000 - 6000	6000 - 7000	7000 - 8000	8000 - 9000	9000 - 10000	>10000	Total
No. of failures	26	37	28	16	26	12	11			156
Total downtime (hrs.)	1720	2611	2483	1068	1978	1788	1800			13448
BOP-days in service	3261	2997	2861	2147	2209	1126	348	100	7	15056
MTTF (days)	125	81	102	134	85	94	32			97
Loss time per BOP day (hrs.)	0,53	0,87	0,87	0,50	0,90	1,59	5,17			0,89
Avg. Downtime per failure (hrs.)	66	71	89	67	76	149	164			86
Avg. Downtime per failure (hrs.) when BOP was on the wellhead	58	65	80	67	58	75	121			70

For water deeper than 8000 ft a limited time in service is represented. There is no clear trend related to water depth and BOP reliability based on this table.

The average lost time per BOP failure is strongly influenced by a few time-consuming failures.

Safety critical failures

All failures that occur in the BOP after the installation test are regarded as safety critical failures. This is the period the BOP acts as a well barrier. The criticality of each failure will of course depend on what part of the BOP system that fails and the failure mode.

The frequency of safety critical failures that occurred in this study is lower than the frequency observed in the Phase II DW and Phase I DW study. Severe BOP failures still occur.

In this study the most severe failure, leakage in the wellhead connector, occurred once. The failure was observed during BOP testing, and 20 bbls of mud were lost to the environment. If this failure occurs during a kick event the well fluid will leak to the surroundings, i.e. a blowout will occur. Further, a spurious disconnect of a LMRP connector occurred once. Such incidents have caused blowouts in the past, but not this time. Further, a BOP control system incident that caused total loss of the BOP control took place.

Table 1.5 lists a coarse ranking of the failures that were taking place in the safety critical period in this study. The same ranking from the previous studies, Phase II DW and Phase I DW, is presented alongside. It should be noted that the number of BOP-days in service in the present study is twice as high as the two other studies together.

Table 1.5 Coarse ranking of failures occurring in the safety critical period according to severity

<table>
<tr><th colspan="2">This study</th></tr>
<tr><td colspan="2">1. One failure causing wellhead connector external leakage
2. One spurious opening of the LMRP connector (Unknown cause, no autoshear in BOP)
3. One control system failure that caused total loss of the BOP control
4. One shear ram leakage in closed position
5. Upper and lower variable bore ram leaked at the same time
6. Two incidents, pipe ram failed to close
7. Nine incidents, loss of all functions one pod
8. Two incidents, pipe rams leaked in closed position
9. One flexible joint external leak
10. One failed to close annular incident
11. Four incidents, annular preventer leak
12. Six choke and kill line leaks
13. Five incidents with loss of one function both pods</td></tr>
<tr><th>Phase I DW BOP study (/3/)</th><th>Phase II DW BOP study (/1/)</th></tr>
<tr><td>1. One failure causing wellhead connector external leakage
2. One failure where they failed to shear the pipe during a disconnect situation
3. One external leakage in the connection between lower inner kill valve and the BOP stack
4. Five failures that caused total loss of the BOP control by the main control system
5. Two shear ram leakages in closed position
6. Two failures to disconnect the LMRP
7. Seven failures that caused loss of all functions one pod
8. One UPR leakage
9. One spurious closure of the shear ram
10. Three annular preventers that leaked in closed position
11. Six choke and kill line leakages</td><td>1. One control system failure that caused total loss of the BOP control
2. One spurious opening of the LMRP connector (control system failure)
3. One shear ram failed to close
4. One shear ram leak in closed position
5. Two failures to open pipe ram
6. Two failures where the pipe ram leaked in closed position
7. External leak in flexible joint
8. One failure to disconnect the LMRP
9. Four failures that caused loss of all functions one pod
10. Loss of one function both pods (annular close)
11. Four annular preventer leaks in closed position
12. One choke and kill line leak (jumper hose)</td></tr>
</table>

Kick Frequency
Table 1.6 shows the mean time between kicks (MTBK) related to number of BOP-days and number of wells drilled.

Table 1.6 Mean time between kicks (not incl. shallow kicks)

Phase*	No. of kicks	No. of wells			BOP-days in service	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
		Original	Sidetrack or by-pass	Total			
Development drilling	7	42	11	53	3223	7,57	460
Exploration drilling	74	133	73	206	11833	2,78	160
Total	81	175	84	259	15056	3,20	186

* Two of the development drilling well kicks and two of the exploration drilling well kicks actually occurred during completion activities

As expected there are more frequent kicks in exploration drilling than in development drilling. The main reason for this increased frequency is that they are drilling in less known formation.

Two of the 81 kicks observed were kick in the riser.

The well kicks occurred on all well depths. Thirty-seven, or 46% occurred deeper than 20 000 ft TVD. The deepest kick occurred at 27 860 ft TVD.

Comparison with previous kick study
The Deepwater Kicks and BOP performance study from 2001 (/2/) presented kick statistics. Table 1.7 shows the mean time between kicks (MTBK) related to the number of BOP-days and the number of wells drilled found in the 2001 study.

Table 1.7 Mean time between kicks (not incl. shallow kicks), US GoM wells spudded in 1997 and 1998 (/2/)

Phase	No. of kicks	No. of wells	BOP-days in service	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
Development drilling	9	25	1000	2.8	111.1
Exploration drilling	39	58	3009	1.5	77.2
Total	48	83	4009	1.7	83.5

When comparing the overall kick frequencies in Table 1.6 with the kick frequency found in the previous study (/2/), in Table 1.7, it is seen that the frequency of kicks is significantly lower in the present study, only approximately 50%.

Kick causes
The most significant contributors to the kick occurrence were:

- Too low mud weight (43 kicks)
- Gas cut mud (15 kicks)
- Swabbing (10 kicks)
- Unknown (5 kicks)
- Annular losses and gains (3 kicks)
- Annular losses (3 kicks)
- Drilling break (2 kicks)

- Leaking through cement (2 kicks)
- Trapped gas in BOP (1 kick)
- Temperature expansion, well open for a long time (1 kick)

The frequent occurrences of too low mud weight may to a large degree be explained by the relatively small difference between the fracture pressure and the pore pressure. Annulus friction during circulation is also likely affecting this problem.

Gas cut mud occurs when formation gas mixes with the mud as small gas bubbles. This effect reduces the mud density, and at a certain level it will cause that the hydrostatic control of the well is lost.

When drilling break is listed as a partial cause of the kick, a drilling break has been mentioned in the well activity report just prior to the incident. A drilling break may occur when drilling into gas bearing sands.

The ballooning effect is observed in association with annular losses. First annular losses are observed, thereafter the formation partly returns the losses. This effect has contributed to some kicks. It should be noted that this effect was observed several times when reviewing the well activity reports, but did normally not cause a kick.

Swabbing is typically a main contributor to kicks during tripping out of the hole. If the trip margin is low, the mud weight is cut by gas, or the well is improperly filled up, it is more likely that swabbing will cause a kick.

Killing duration
Table 1.8 shows the killing duration of the experienced kicks.

Table 1.8 Killing duration distribution of the 48 kicks

Killing duration grouped (days)	No. of kicks	Total days used
≤ 1	25	20,9
1 ≤ 2	36	57,3
2 ≤ 5	17	59,0
5 ≤ 10	0	0,0
10 ≤ 15	3	38,0
All	**81**	**175,2**
Average		**2,16**

Many of the kicks were time-consuming to control. Most of the kicks, 75% were controlled within two days. For three kicks they used more than ten days to control the kick. The average time spent to control a deepwater kick was 2,16 days.

BOP configuration
A BOP test ram will reduce the probability of a successful closure of the BOP because it will add potential leakage paths in the stack below the lowest pipe ram preventer.

A BOP test ram will also reduce the quality of the wellhead connector test

Two sealing shear rams would be the preferred option in any BOP stack. The importance of two rams will increase with the water depth, due to drilling margin issues and loss of position risk for dynamically positioned rigs. These blind shear rams should have the ability to shear any drillpipe in the well.

If a casing shear ram that is able to seal after cutting is available and proven, at least one of the shear rams should be such a ram.

Through the current study and the previous study (/2/) 130 kicks were identified. For none of these kicks a casing or liner was across the BOP when the kick occurred, indicating that the need for cutting the casing in an emergency is limited.

List of Abbreviations

AMF	-	Automatic Mode Function
BOEMRE	-	Bureau of Ocean Energy Management, Regulation and Enforcement (Now replaced by BSEE and BOEM)
BOP	-	Blowout Preventer
BS	-	Blind-Shear
BSR	-	Blind-Shear Ram
BSEE	-	Bureau of Safety and Environmental Enforcement
CARA	-	Computer Aided Reliability Analysis
CBU	-	Circulate bottoms up
C/K	-	Choke and Kill Valves
CR	-	Casing Ram
CSR	-	Casing Shear Ram
EDS	-	Emergency Disconnect System
EH	-	Electro Hydraulic
FTA	-	Fault Tree Analysis
HPHT	-	High Pressure High Temperature *(A well with an expected maximum shut-in pressure above 10 000 psi (690 bar) and/or formation temperatures above 238 F (150 centigrade) is regarded as a HPHT well)*
ID	-	Inner Diameter
IK	-	Inner Kill
ITT	-	Isolation Test Tool
JIP	-	Joint Industry Project
LA	-	Lower Annular
Lbs	-	Pounds
LCL	-	Lower Confidence Limit
LIC	-	Lower Inner Choke
LMRP	-	Lower Marine Riser Package
LOC	-	Lower Outer Choke
LOT		Leak Off Test
LPR	-	Lower Pipe Ram
MFDT	-	Mean Fractional Deadtime
MMS	-	Minerals Management Service (Now replaced by BSEE and BOEM)
MPR	-	Middle Pipe Ram
MTBK	-	Mean Time Between Kicks
MTTF	-	Mean Time To Failure
MPS	-	Multi Position Lock
MUX	-	Multiplex Control System
MW	-	Mud Weight
NCS	-	Norwegian Continental Shelf
NPD	-	Norwegian Petroleum Directorate
NTNU	-	Norwegian University of Science and Technology
OCS	-	Outer Continental Shelf
OD	-	Outer Diameter
OK	-	Outer Kill
Phase I DW	-	Phase I of the Deepwater BOP Study (/3/ and /4/)
Phase II DW	-	Phase II of the Deepwater BOP Study (/1/)

POOH	-	Pull out of hole
Ppg	-	Pounds per gallon
ROV	-	Remotely Operated Vehicle
SEM	-	Subsea Electronic Module
SICP	-	Shut-in Casing Pressure
SIDPP		Shut-in Drill Pipe Pressure
UA	-	Upper Annular
UCL	-	Upper Confidence Limit
UIC	-	Upper Inner Choke
UOC	-	Upper Outer Choke
UPR	-	Upper Pipe Ram
VBR	-	Variable Bore Ram
Vs.	-	Versus
WAR	-	Well Activity Report
WOW	-	Wait On Weather
WOSP	-	Wait On Spare Parts
WOO	-	Wait On Other

1 Introduction

1.1 Background

From 1983 to 2010, Sintef and ExproSoft have documented results from a number of detailed reliability studies of Blowout Preventer (BOP) systems. The majority of these studies are related to subsea BOP systems. Through these studies the reliability of subsea BOPs has been documented. A total of approximately 550 wells have been reviewed with respect to BOP reliability. The latest studies involving substantial collection of subsea BOP reliability and kick data were performed on behalf of MMS (now replaced by BSEE and BOEM). Both studies were initiated through Sintef, but the second study was completed by ExproSoft under subcontract of Sintef (both studies managed by Per Holand). The first study *Reliability of Subsea Blowout Preventer Systems for Deepwater Applications--Phase II* (BSEE TA&R project no. 319) was completed in 1999. The second study *Performance of Deepwater BOP Equipment During Well Control Events* (BSEE TA&R project no. 383) was completed in August 2001 (http://www.bsee.gov/).

The US GoM OCS deepwater drilling activity peaked in 2001, with a total of 225 wells in waters deeper than 2000 ft. The drilling in more shallow water, less than 2000 ft, still represents the majority of wells drilled. For the period 1996 through 2009, 81.2% of the wells were drilled in waters with depth less than 2000 ft (610 m). The two other major deepwater areas in the world are West Africa and Brazil. There is also deepwater activity as well Offshore India, and in Norwegian and UK waters. In Norway, a total of around 50 deepwater wells have been drilled, while in UK waters approximately 60 deepwater wells are drilled to date.

To meet the increased demand for deepwater drilling services, several new floating drilling rigs dedicated for deepwater drilling have been put into service since the last data collection. The newer generation of rigs include new technology both in terms of station keeping system, derrick located systems and subsea BOPs. The major new technology items related to the BOPs are the modern control system, locking system for rams, high capacity shear rams, more compact preventers and increased number of ram preventers. In addition the present subsea BOPs include more emergency shear and disconnect systems.

The Deepwater Horizon blowout and subsequent spill in the US Gulf of Mexico Outer Continental Shelf (OCS) deepwater in 2010 has served as an important reminder of the significance of reliability of BOP and controls when drilling for oil and gas, especially in deepwater drilling with long risers, lack of riser margin, and dynamically positioned rigs that may lose position.

The summer 2010, ExproSoft therefore proposed to perform a new study on deepwater BOP reliability and well kicks.

ExproSoft invited the whole Industry to participate in such a study, BSEE (former MMS and BOEMRE) and Eni was the only organisations that decided to support such a study. This caused the original scope of the study to be reduced.

During the study information has been requested from US Operators and Drilling contractors. Only one Operator and one drilling contractor supplied the requested information. The study has therefore mainly been based on the information BSEE has in the e-Well system, and not the operator and drilling contractor information.

1.2 Objective

The main objectives of this study are to:

- Establish an updated reliability overview of deepwater subsea BOPs
- Establish a quantified overview of the deepwater well kick frequencies and the important parameters contributing to the deepwater kick frequency

Sub-objectives are to:

- Ensure that the deepwater drilling business keep up the focus on the importance of BOP reliability and kick prevention
- Establish an overview of BOP stack layout for the various rigs, and further to highlight differences among the different areas
- Establish an overview of the various emergency control systems, (Emergency disconnect, autoshear, deadman and acoustic system)
- Present the deepwater BOP reliability time dependent trends by comparing with results from earlier studies
- Compare kick frequencies and parameters from the various areas and earlier studies
- Highlight the impact of "new" equipment on the BOP reliability

2 Data Collection Methodology

2.1 Data Sources

The initial idea was to get the data from operating companies in the form of daily drilling reports (DDR), but only one of the operators that were requested for DDR data submitted such data to the project. The main source of data has therefore been the e-Well system on BSEE website (www.bsee.gov).

The e-Well system includes well and operational data submitted by the operating companies to BSEE. A large proportion of the information in the e-Well system is public and can be accessed by anyone. It is possible to view the individual reports or download a series of reports as a Microsoft Access database file.

This study is mainly based on the applications for permit to drill (APD) and well activity report (WAR).

2.1.1 Application for Permit to Drill/modify

An APD typically contains information about how they are planning to drill a specific well.

Parts of the APDs are public on the BSEE webpage, but additional non-public information was made available for the study.

The information in the APDs is mainly used to find information about the BOP systems used and the rigs.

2.1.2 Well Activity Report (WAR)

The Well Activity Reports (WAR) was the key information source for the study. These reports are submitted by operator companies to BSEE on weekly basis and are available for public access on BSEE web page (www.bsee.gov). This report includes the information:

- *General information* as API well, no, operator, drilling rig, water depth
- *Wellbore information* as lease, area, block, spud , current depths, latest BOP test, mud weight
- *Wellbore historical information*
- *Casing and liner* in the well, with sizes, grade, setting depth
- *Well activity summary* that describes the activity carried out on the well the past week.

For this study the WAR database was downloaded from the BSEE web page. All well activity reports were reviewed for the relevant wells.

It should be noted that some of the wells (approximately 25%) did not include any Well activity summary. These wells were omitted from the study.

The well activity summary for all the relevant WAR reports was reviewed to identify BOP failures and well kicks. A total of 3100 weekly reports were reviewed.

The quality of the well activity summary varied from well to well. Some were very detailed while others were more of a short summary.

2.1.3 Daily Drilling Report

A daily drilling report (DDR) is a detailed description of the drilling activity on a certain well. This information is in far more detail than WAR however this information is not readily accessible to general public. It was only Operator AP among all the operators who provided DDRs. Therefore estimation of time consumption on testing BOP is only carried out for Operator AP.

2.2 Statistical Estimation Procedure and Assumptions

For data sets for which no trend is observed, the number of failures during a specific time period may be modelled by a homogeneous Poisson process, with failure rate λ (/3/). The failure rate may be estimated by:

$$\hat{\lambda} = \frac{Number\ of\ failures}{Accumulated\ operating\ time} = \frac{n}{s}$$

The number of BOP-days multiplied with the number of items is used as the *accumulated operating time* or *days in service for the* BOP failures.

The uncertainty in the estimate, $\hat{\lambda}$, may be measured by a 90% confidence interval:

- If the number of failures $n > 0$, a 90% confidence interval is calculated by:

Lower limit: $\lambda_L = \frac{1}{2s}\chi^2{}_{0.95,2n}$

Upper limit: $\lambda_H = \frac{1}{2s}\chi^2{}_{0.05,2(n+1)}$

- If the number of failures $n = 0$, a 90% (single sided) confidence interval is calculated by:

Lower limit: $\lambda_L = 0$

Upper limit: $\lambda_H = \frac{1}{2s}\chi^2{}_{0.1,2}$

where $\chi_{\varepsilon,z}$ denotes the upper 100ε % percentile of the Chi-square distribution with z degrees of freedom (/3/).

The meaning of the 90% confidence intervals is that the frequency is a member of the interval with probability 90%, i.e., the probability that the frequency is lying outside the interval is 10%.

MTTF (Mean Time To Failure) is the inverse value of the failure rate, λ, i.e.:

$$MTTF = \frac{1}{\lambda}$$

The uncertainty in the MTTF may also be measured by a 90% confidence interval, and can be expressed by λ_H and λ_L:

Lower limit: $MTTF_L = \frac{1}{\lambda_H}$

Upper limit: $MTTF_H = \frac{1}{\lambda_L}$L

Example:

Assume that we want to find the failure rate λ and the MTTF of the annular preventers in a specific BOP stack.

The BOP stack has been in service for 1000 BOP-days, and the stack has two annular preventers. A total of four failures have been observed during the time in operation. The accumulated operating time will then be 1000 BOP-days x 2 annular preventers = 2000 days in service. The failure rate will then be:

$$\hat{\lambda} = \frac{Number\ of\ failures}{Accumulated\ operating\ time} = \frac{n}{s} = \frac{4}{1000 \times 2}$$

$$= 0.002\ failures\ per\ day\ in\ service$$

The corresponding MTTF will then be:

$$MTTF = \frac{1}{\lambda} = \frac{1}{0.002} = 500\ days\ in\ service$$

3 Subsea BOPs

The wells forming the basis for this study were spudded in US GoM OCS during the period January 1st 2007 to January 1st 2010 in waters deeper than 1968 ft (600 meters).

3.1 System Description and Boundary Conditions

Figure 3.1 shows typical BOP configurations for a conventional and a modern BOP, respectively. Note that these are representative sketches of BOPs as configuration may vary from rig to rig. A modern subsea BOP for deepwater drilling typically has six ram preventers, while a conventional subsea BOP has four ram preventers.

The BOP equipment considered in this study which are:

1. Wellhead and LMRP connectors
2. Ram preventers
3. Annular preventers
4. Flexible joint
5. Choke and kill lines and valves
6. Main control system

The drilling riser is not a part of this study.

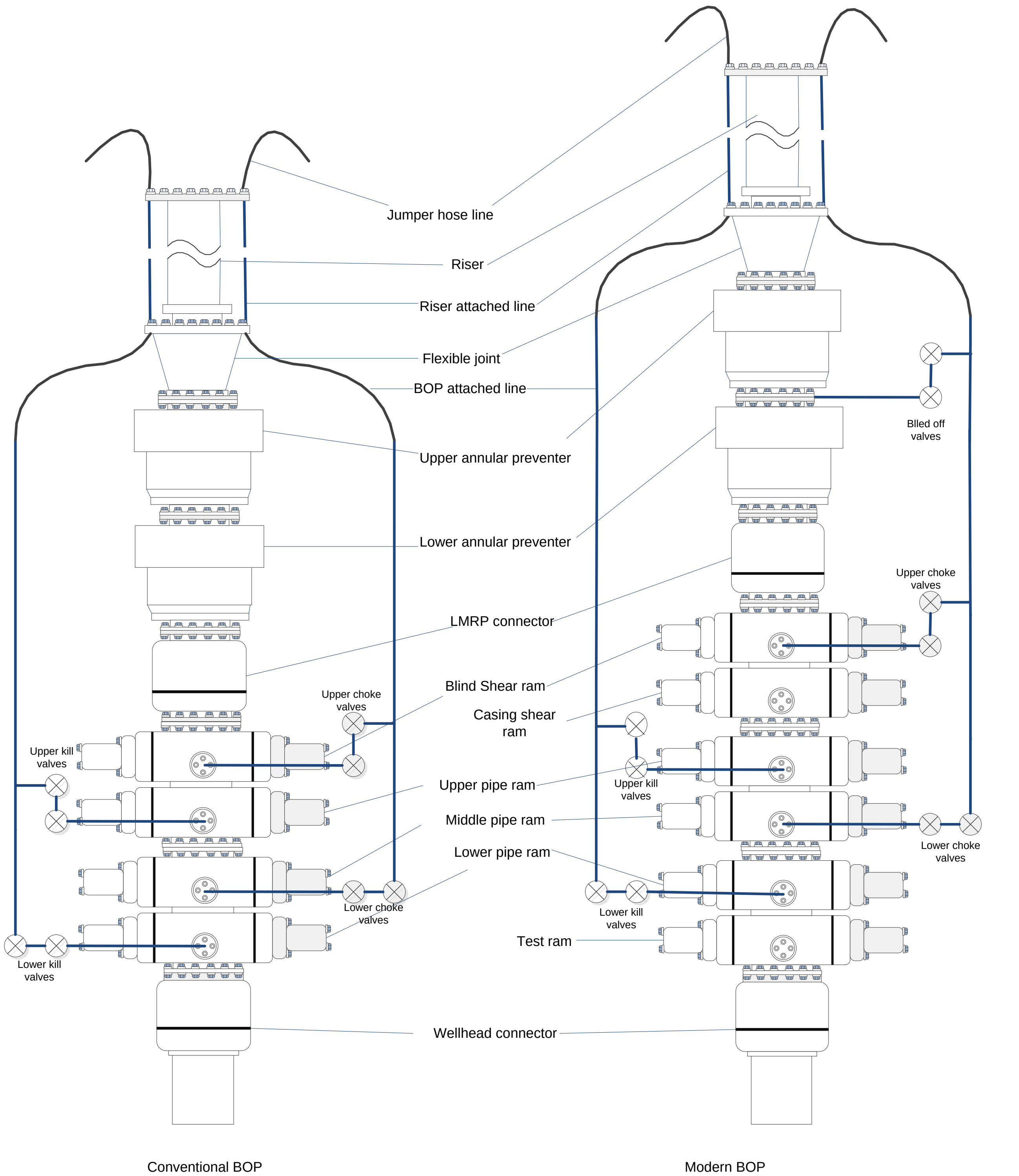


Figure 3.1 Typical BOP configuration

Table 3.1 shows an overview of the BOP configuration of rigs that are included in the study. The BOP stacks were all 18 ¾", mostly 15 000 psi rated and some few 10 000 psi rated. Seven of the drilling vessels were drill ships while 35 were semisubmersible rigs. All the drillships were dynamic positioning type and most of the semisubmersible rigs were anchored.

Table 3.1 BOP configuration of various rigs

RIGNAME	Rig type	Mooring	BOP manu-facturer (ram)	Control system	No. of Ann-ulars	No.of c/k valves	No. of ram Preventers						
							BS-ram	Cas-ing shear ram	Varia-ble pipe ram	Fixed pipe ram	Cas-ing ram	Test ram	Total
Rig AA	Ship	DP	Hydril	Multiplex	2	10	1	1	2			1	5
Rig AB	Semi	Anchored	Cameron	Pre-charged pilot hydraulic	2	12	1		2		1		4
Rig AC	Semi	Anchored	Hydril	Multiplex	2	8	1		2	1			4
Rig AD	Semi	Anchored	Cameron	Pilot hydraulic	2	8	1		1	1	1		4
Rig AE	Semi	DP	Shaffer	Multiplex	2	8	2		4				6
Rig AF	Semi	Anchored	Shaffer	Multiplex	2	8	1		3			1	5
Rig AG	Semi	Anchored	Hydril	Multiplex	2	10	1		3			1	5
Rig AH	Semi	Anchored	Hydril	Pilot hydraulic	2	10	1		2		1		4
Rig AI	Semi	Anchored	Cameron	Pilot hydraulic	2	10	1		2	1			4
Rig AJ	Semi	Anchored	Shaffer	Pilot hydraulic	2	10	1		2		1		4
Rig AK	Semi	Anchored	Cameron	Pre-charged pilot hydraulic	2	8	1		2		1		4
Rig AL	Semi	Anchored	Shaffer	Pre-charged pilot hydraulic	2	12	1		2		1		4
Rig AM	Semi	Anchored	Hydril	Pilot hydraulic, unknown if precharged	2	12	1		3				4
Rig AN	Semi	DP	Hydril	Multiplex	2	10	1	1	2	1		1	6
Rig AO	Semi	DP	Hydril	Multiplex	2	12	1	1	3			1	6
Rig AP	Semi	DP	Hydril	Multiplex	2	4	1	1	3			1	6
Rig AQ	Semi	Anchored	Cameron	Pilot hydraulic, unknown if precharged	2	12	1		2		1		4
Rig AR	Ship	DP	Cameron	Multiplex	2	12	2	1	3				6
Rig AS	Semi	Anchored	Cameron	Multiplex	2	10	1		2		1		4
Rig AU	Semi	Anchored	Shaffer	Multiplex	2	8	1		2		1		4
Rig AV	Semi	Anchored	Shaffer	Multiplex	2	12	1	1	2		1	1	6
Rig AW	Semi	Anchored	Shaffer	Multiplex	2	10	1		3			1	5
Rig AX	Semi	Anchored	Cameron	Pilot hydraulic, unknown if precharged	1	10	1		3				4
Rig AY	Semi	Anchored	Shaffer	Multiplex	2	12	1		2		1		4
Rig AZ	Semi	Anchored	Shaffer	Multiplex	2	12	1		3			1	5
Rig BB	Semi	DP	Cameron	Multiplex	2	12	1		2	1			4
Rig BH	Semi	DP	Cameron	Multiplex	2	10	1	1	3			1	6
Rig BI	Semi	DP	Cameron	Multiplex	2	12	1	1		2		1	5
Rig BK	Semi	Anchored	Cameron	Pilot hydraulic, unknown if precharged	2	8	1		2		1		4
Rig BL	Semi	DP	Cameron	Multiplex	1	8	1	1	2		1		5
Rig BM	Semi	DP	Cameron	Multiplex	2	14	1	1	3				5
Rig BN	Ship	DP	Cameron	Multiplex	2	12	2		2			1	5
Rig BO	Semi	Anchored	Cameron	Multiplex	1	10	1		3			1	5
Rig BP	Semi	DP	Hydril	Multiplex	2	12	2	1	3				6
Rig BQ	Semi	DP	Hydril	Multiplex	1	12	1	1	3			1	6
Rig BS	Ship	DP	Hydril	Multiplex	2	12	1	1	2		1	1	6
Rig BT	Ship	DP	Hydril	Multiplex	1	12	2		3			1	6
Rig BU	Ship	DP	Hydril	Multiplex	2	12	2	1	2		1		6
Rig BV	Ship	DP	Hydril	Multiplex	2	12	2		3			1	6
Rig BW	Semi	Anchored	Cameron	Pilot hydraulic, unknown if precharged	2	12	1		2	1			4
Rig BX	Semi	Anchored	Hydril	Pre-charged pilot hydraulic	1	12	1		2		1	1	5
Rig BY	Semi	Anchored	Hydril	Multiplex	2	12	1		3			1	5
Average					1,86	10,57	1,17	0,33	2,38	0,19	0,38	0,45	4,90

For most BOPs in this study the ram and annular preventers in a BOP stems from the same manufacturer. A BOP stack can however have components from different manufacturers. In this study a BOP is recognized from the manufacturer of ram preventer. As seen from Table 3.1 only the three major BOP manufacturers are represented in the study. Forty percent of

BOPs are manufactured by Hydril, 40% by Cameron and nearly 20% are manufactured by Shaffer.

The type of control system varies from rig to rig. Compared to the previous studies (/1/) and (/3/), a significant increase is seen in the use of multiplex control systems. This is mainly caused by the closing time requirements for BOPs that will be difficult to meet with pilot hydraulic systems in deep water. The fact that the multiplex technology has matured considerably over the past decade has also affected the increased use of such systems. Five of the rigs which had a pilot control system in the previous study have now changed to a multiplex system.

Most BOPs, conventional or modern, have two annular preventers except six rigs having only one annular preventer.

The number of choke & kill valves varies between eight and twelve except for one rig having only four.

The number of ram preventers varies between four and six. Apart from mandatory requirement of having at least one 'blind shear' in a BOP, seven BOPs have two blind shear rams. The casing shear ram, which was non-existing in the previous study, is found in fourteen rigs in this study**.** On the other hand, when it comes to variable and fixed pipe ram, the trend is to have variable pipe ram instead of fixed pipe rams. This is indicated by only eight fixed pipe rams in this study, which is significantly less compared to the previous study. Similarly, a new addition to the BOP stack configuration is a casing ram (9 5/8" or 7 5/8"), and a test ram compared to the last reliability study. In the current study, 16 BOPs had casing rams, and 19 BOPs had test rams.

3.2 Relevant Definitions

- **BOP-days in service** are defined as the number of days from when the BOP was landed on the wellhead the first time until it was pulled from the wellhead the last time. If the BOP is pulled during the operation due to a BOP failure, this is regarded as included in the BOP-days. If the well is temporarily abandoned and the rig is carrying out other operations before returning to the well, this is not included in the BOP-days.
- **Days in service** for a specific BOP component is the number of BOP-days multiplied with the number of this particular type of components in the BOP stack.
- **BOP failure** is an event when any component of the BOP system mentioned in Section 3.1 was not able to perform its intended function. The criticality of failure depends on the activity while the failure occurred and the severity of the failure.
- **BOP downtime** is the lost time in hours due to a failure on the BOP system without the distinction of whether the BOP was on the wellhead or not.

3.3 Operators and Wells

Table 3.2 shows the operators represented with drilling in this study. A total of 266 wells (when sidetracks and by-pass wells are counted as separate wells) are included, compared to 83 wells in the previous study (/1/).

It is also observed that far more exploration drilling is carried out than development drilling. In general there is a higher kick probability in exploration drilling than in development drilling due to unknown reservoir conditions during exploratory well drilling. A total of 15056 BOP-days is observed which is 3.76 times higher than in the previous study (/1/).

The highest number of wells is drilled by Operator AG and Operator AK, together representing 69 wells and 3485 BOP-days.

Table 3.2 Operators vs. Well types and BOP-days

Operator	Development				Exploration				Total no. of wells	Total BOP-days
	Origi-nal	Side-track or by-pass	Total	BOP-days	Origi-nal	Side-track or by-pass	Total	BOP-days		
Operator AD					2	2	4	331	4	331
Operator AK	2	1	3	123	19	12	31	1615	34	1738
Operator AO	1		1	46	6	5	11	431	12	477
Operator AP	6	4	10	459	13	2	15	992	25	1451
Operator AX	6		6	417	10	7	17	1144	23	1561
Operator BI	1		1	63					1	63
Operator AC	2		2	257	10	8	18	1114	20	1371
Operator BF					3	1	4	112	4	112
Operator AW					3		3	490	3	490
Operator BH					3	2	5	293	5	293
Operator BD					6	2	8	550	8	550
Operator AE	1		1	42	1		1	102	2	144
Operator AB					2	4	6	451	6	451
Operator AS	1		1	52	3	1	4	184	5	236
Operator AU					1		1	22	1	22
Operator AQ	1		1	40	7		7	243	8	283
Operator AH	2		2	207	4	7	11	479	13	686
Operator AJ					10	2	12	477	12	477
Operator BA					6	3	9	426	9	426
Operator AN					4	1	5	178	5	178
Operator AF	1	1	2	191	1		1	13	3	204
Operator AT	1		1	94	6	3	9	344	10	438
Operator AL					1	2	3	219	3	219
Operator BB					1		1	176	1	176
Operator BE					1		1	35	1	35
Operator AR	1		1	164					1	164
Operator AG	16	6	22	1068	8	5	13	679	35	1747
Operator BC					1	1	2	121	2	121
Operator AZ					1	1	2	49	2	49
Operator AA					3	1	4	365	4	365
Operator AM					1		1	68	1	68
Operator AI					1	1	2	73	2	73
Operator AV					1		1	57	1	57
Total	42	12	54	3223	139	73	212	11833	266	15056

** 7 wells were abandoned before running the BOP*

3.4 Rigs and Water Depths Evaluated

Table 3.3 shows rigs and their time in service for various water depths.

Table 3.3 Rigs and Water Depths

Rigs name	BOP-days in service for various water depth ranges (ft.)									
	2000 - 3000	3000 - 4000	4000 - 5000	5000 - 6000	6000 - 7000	7000 - 8000	8000 - 9000	9000 - 10000	>10000	Total
Rig AA			511							511
Rig AB	396	106	46		79					627
Rig AC	164	433			167					764
Rig AD	49									49
Rig AE			103	331	46		13	15	7	515
Rig AF					443		97			540
Rig AG		28			78					106
Rig AH	171	271								442
Rig AI	80									80
Rig AJ		345		82						427
Rig AK		216	212							428
Rig AL	183	85	222							490
Rig AM	153									153
Rig AN		199		109						308
Rig AO		57				12				69
Rig AP					32					32
Rig AQ		191								191
Rig AR		110	704		74					888
Rig AS	221	25								246
Rig AU		82		89	132	87				390
Rig AV						87	125	85		297
Rig AW		521		77						598
Rig AX	286	27								313
Rig AY	150			52						202
Rig AZ	334		47	244						625
Rig BB						211	70			281
Rig BH			26							26
Rig BI					133					133
Rig BK	494									494
Rig BL		43	76	49	162					330
Rig BM			256	169	174					599
Rig BN	39	33		121			43			236
Rig BO		130				370				500
Rig BP			353		163					516
Rig BQ					192					192
Rig BS			181							181
Rig BT				135	137	216				488
Rig BU				571						571
Rig BV	199		124	95	111	143				672
Rig BW	219									219
Rig BX	123	78								201
Rig BY		17		23	86					126
Total	3261	2997	2861	2147	2209	1126	348	100	7	15056

Most of the drilling is carried out in water depths less than 7000 ft. The deepest water drilling is observed in is 10141 ft (3091 meters).

The BOP-days in service for the various rigs varies highly. The rig with the most drilling time in this study is Rig AR with a service time of 888 BOP-days.

3.5 Overview of BOP Failures

A total of 156 BOP related failures occurred during this study corresponding to a total time in service of 15056 BOP-days. An overview of key reliability parameters is provided in Table 3.4 Overview of failures. The column "item days in service" represents individual BOP subsystem exposure time. When a failure and associated downtime was not possible to allocate to a specific BOP subsystem (due to lack of information), a dummy item was introduced in the BOP stack.

Table 3.4 Overview of failures

BOP Subsystem	BOP-days in Service	Item days in service	No of failures	Total lost time (hrs)	MTTF (Item days in service)	MTTF (BOP-days)	Avg. Downtime per failure (hrs)	Avg. Downtime per BOP day (hrs)
Annular preventer	15056	28150	24	2344,5	1173	627	98	0,156
Connector	15056	31142	8	638	3893	1882	80	0,042
Flexible joint	15056	15056	1	288	15056	15056	288	0,019
Ram preventer	15056	77264	23	1765,5	3359	655	77	0,117
Choke & kill valve	15056	160310	4	136	40078	3764	34	0,009
Choke & kill lines, all	15056	15056	17	1992	886	886	117	0,132
Main control system	15056	15056	72	4712	209	209	65	0,313
Dummy Item	15056	-	7	1572	-	2151	225	0,104
Total	15056	-	156	13448	-	97	86	0,893

Seventy-two of the 156 failures, or 45%, were attributed to components in the BOP control system that operates the various BOP functions. The control system is also causing the highest downtime of the BOP subsystems.

The total downtime caused by BOP failures was 13448 hours (560 days). This corresponds to approximately 4% of the total time in service for the BOP. It is important to note that 109 failures corresponding to 10978 hours of downtime occurred when the BOP was on the wellhead and 41 of these failures didn't cause any downtime, as shown in Table 3.5. Such failures represent instances where failures were accepted (in order to continue operation) due to low criticality or that the BOP was pulled due to another failure. For some failures, it was also difficult to assess downtime due to the lack of details in the WARs.

Table 3.5 Breakdown of failures based on BOP location

BOP location	No. of failures	Total lost time	Percentage of total failure	No. of failure with no associated downtime
BOP is on the wellhead	109	10978	70 %	41
BOP is on the rig	27	1312	17 %	9
While running/pulling BOP	20	1158	13 %	4
Total	156	13448	100%	54

Analysis of the downtime data shows that the downtime varied between 0 and 600 hours. For 54 failures no downtime was logged. A histogram of the lost time data is shown in Figure 3.2. It can be seen that underlying distribution is skewed to the positive or to the right. This means that most of lost times are on the left of distribution. In addition, note the downtimes at the far right of the histogram which characterize very high downtime (due to various reasons, such as bad weather or unavailability of spare parts). The data also reveals a mean lost time of 3.6 days with a standard deviation of 4.8 days. The high standard deviation shows that data is not tightly clustered around the mean and the uncertainty is high. The primary reason is the lack of information on exact downtimes since the WAR only provides a brief summary of the drilling activities and does not give any details of the activities. Also, note the median of the distribution which is a better representative of the data than the mean in this case.

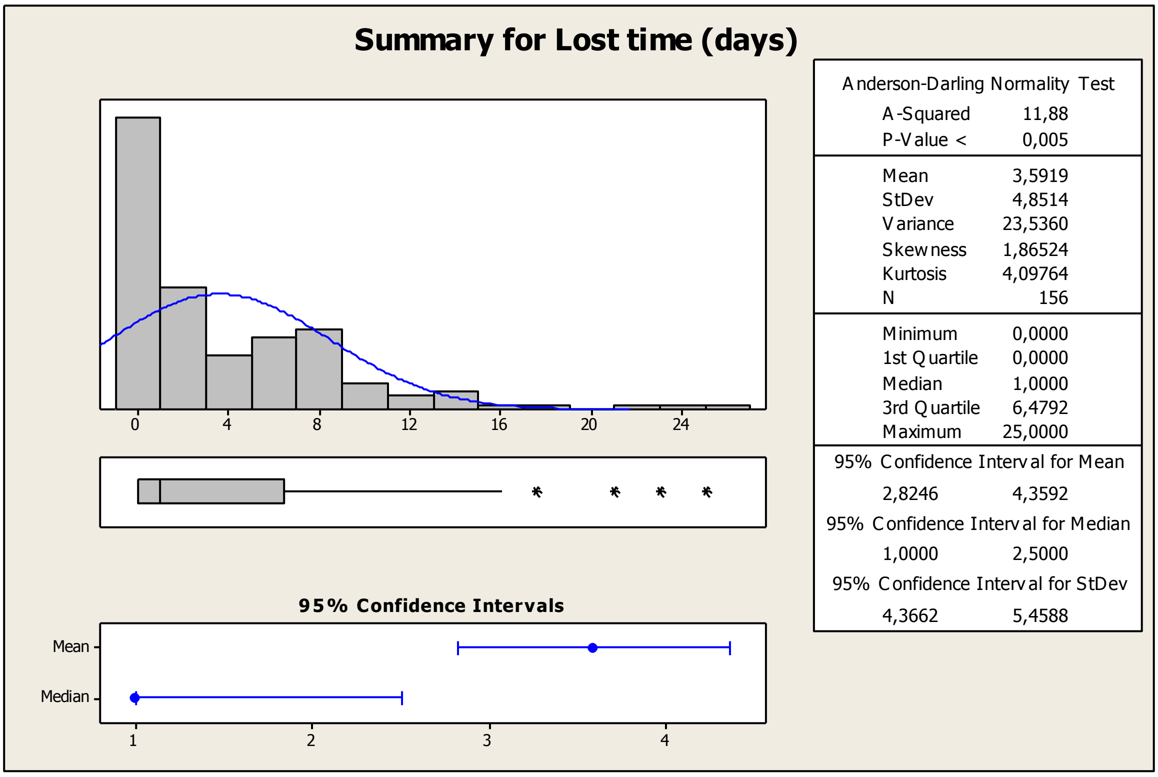


Figure 3.2 Summary of lost time (days)

In Figure 3.3 the failure rates for the BOP subsystems are shown. Although main control systems have the highest failure other BOP subsystems are also represented with many failures.

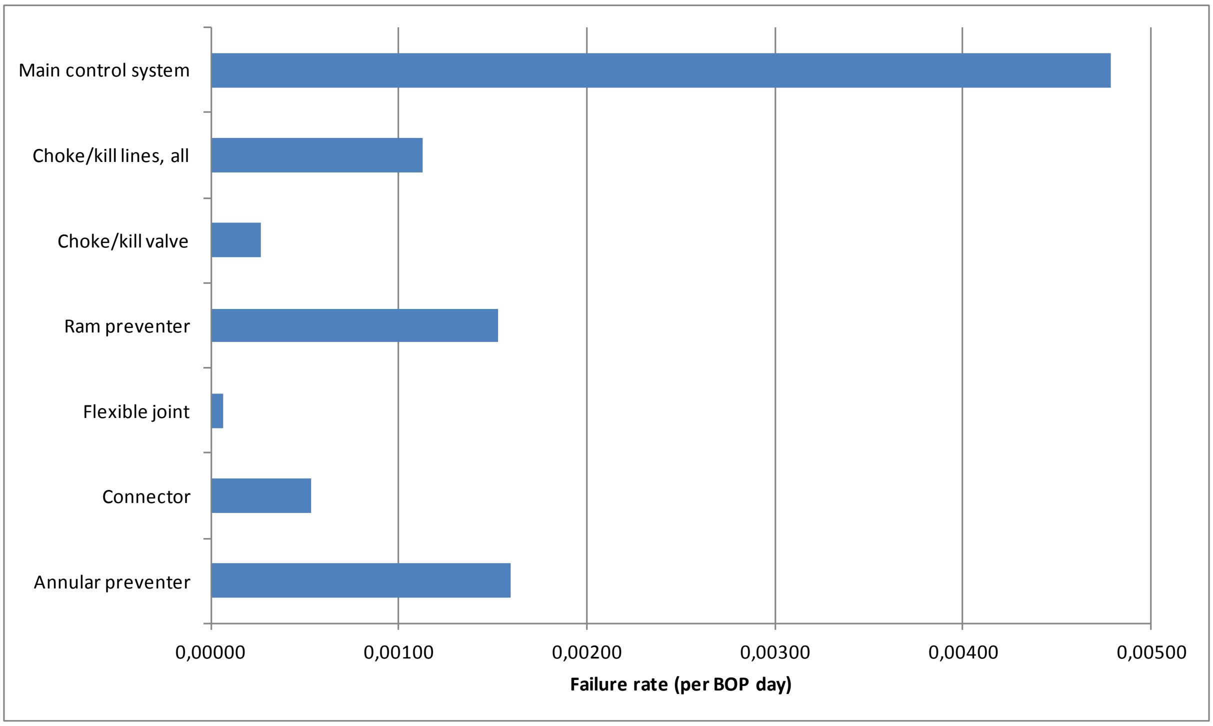


Figure 3.3 BOP subsystem failure rate

In Figure 3.4, BOP subsystem downtime per BOP-days is presented. Here again the main control system failures cause the highest downtime of the BOP subsystems. It is also observed that even though only one failure was reported for flexible joints the corresponding downtime was high, 12 days. It is for this reason flexible joint has highest average downtime per failure in hours. Further details on BOP subsystem fluctuations in reliability indices are discussed in Section 4.

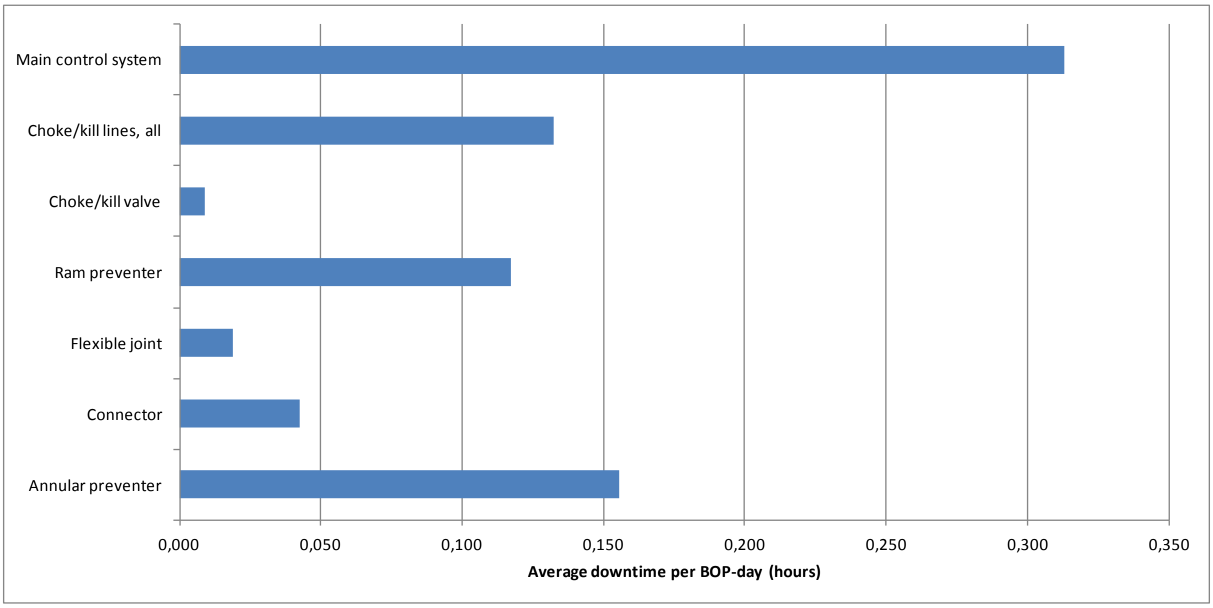


Figure 3.4 Average downtime per BOP-day

3.6 Comparison with the Previous BOP Deepwater (Phase I & II DW) studies

The previous Phase I DW (/3/) study included wells drilled in waters more shallow than 400 meters, (1312 ft.), it has been decided to only use data from wells drilled in more than 400 meters for this comparison. The study represented wells drilled from 1992 – 1996. Further, many of the BOP stacks analyzed in Phase I DW included an acoustic backup system. The failures and downtime associated with this system have been disregarded in the comparison.

The Phase II study (/1/) focused on offshore wells drilled in waters deeper than 400 meters in US GoM. The study represented wells drilled between 1997 and 1998. The study was similar to the work carried out in this project.

Table 3.6 shows a comparison of same key results from Phase I & II DW and this study.

Table 3.6 Comparison of key figures, Phase I DW and Phase II DW

Study	BOP-days	Total lost time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hr.)	Avg. downtime per BOP-day (hrs)
Phase I DW	3191	3457,5	138	23,12	25,05	1,08
Phase II DW	4009	3637,5	117	34,26	31,09	0,91
Present Study	15056	13448,0	156	96,51	86,21	0,89

Table 3.6 shows that more BOP-days are covered in the present study than in the previous two studies. The Mean Time To Failure (MTTF) has improved significantly compared to the two previous studies, but the average downtime per BOP day is at the same level. When

reading this table it is important to note that the main source of information for this study has been the well activity reports (WARs), while for the previous studies it was the daily drilling reports. It can be assumed that many less critical failures are not described in the WARs. These less critical failures typically produce little downtime.

Figure 3.5 shows a comparison of the BOP subsystem specific failure rates in the three studies. It can be observed that the failure rate is lower for all the subsystems in this study compared to the previous studies.

In this study, 29 out of 42 rigs have multiplex control system, while in the previous study most of the rigs had pilot hydraulic control systems.

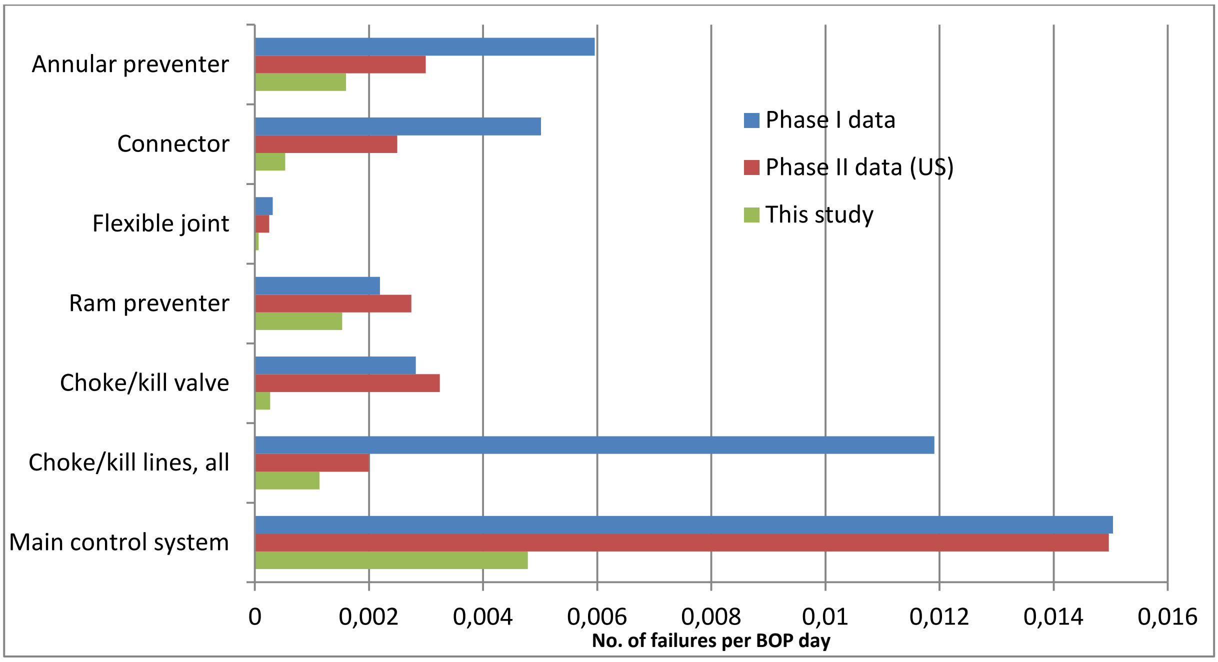


Figure 3.5 Comparison of BOP item specific failure rate with previous studies

When comparing the average downtime per BOP-day for the present study and the previous studies it is observed that the downtime is at the same level.

These wells are in average drilled in deeper water than in the previous studies. Deeper water increases the repair time for the individual failures because of the time needed to pull and run the BOP.

It seems that the reliability of the BOPs in general have improved when comparing with the previous studies.

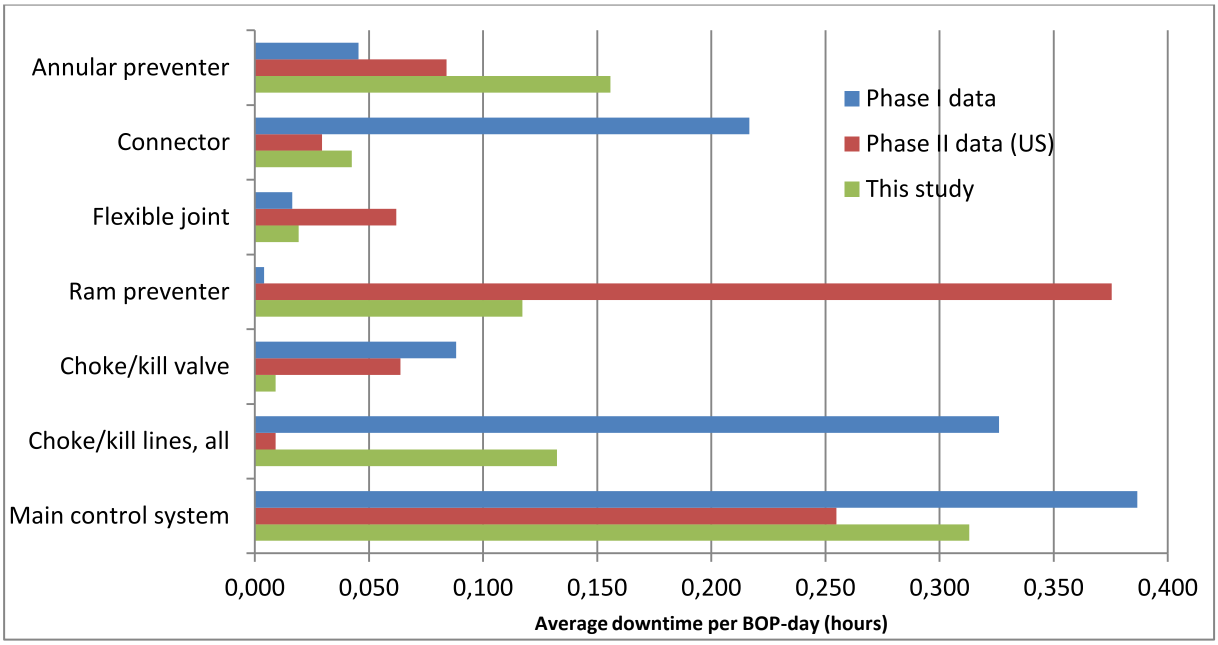


Figure 3.6 Comparison of BOP item specific downtime

3.7 Year to Year Trends in Failure Rates and Downtime

By combining the data from this study and the data from the previous BOP studies, an annual BOP failure rate since 1978 has been established. In Table 3.7 the overview data for each of the years is shown.

Table 3.7 Annual overview of BOP data

Year	BOP-days	Total Lost Time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hrs.)	Avg. downtime per BOP day (hrs.)
Before1978	162	26	4	40,5	6,5	0,16
1978	322	123,5	23	14	5,37	0,38
1979	528	637,7	45	11,7	14,17	1,21
1980	919	778	53	17,3	14,68	0,85
1981	1935	2298	129	15	17,81	1,19
1982	2346	2858	145	16,2	19,71	1,22
1983	1973	2146,7	115	17,2	18,67	1,09
1984	1338	1251	54	24,8	23,17	0,93
1985	1432	803	40	35,8	20,08	0,56
1986	969	592,8	34	28,5	17,44	0,61
1987	1165	1073	38	30,7	28,24	0,92
1988	1029	436,5	20	51,5	21,83	0,42
1989	442	632,5	16	27,6	39,53	1,43
1990 -1991	No data					
1992	962	1759	63	15,3	27,92	1,83
1993	1411	1293	48	29,4	26,94	0,92
1994	762	752	23	33,1	32,7	0,99
1995	801	154,5	13	61,6	11,88	0,19
1996	873	991	55	15,9	18,02	1,14
1997	1972	2529,75	61	32,3	41,47	1,28
1998	2074	1107,5	56	37	19,78	0,53
1999 - 2006	No data					
2007	4923	4546	53	92,9	85,77	0,92
2008	6253	4574,5	60	104,2	76,24	0,73
2009	3162	4178	38	83,2	109,95	1,32
Total	**37753**	**35691**	**1191**	**31,69**	**29,96**	**0,94**

The data in Table 3.7 has been used to create Figure 3.7. Figure 3.7 shows the annual failure rates, alongside 90 % confidence intervals, and linear and log linear trend lines for subsea BOP stacks. The years 1992 – 1996 represent the Phase I DW study and the years 1997 and 1998 represents the Phase II DW study. The current study is represented by the years 2007 – 2009. It has been decided to disregard the data from 1978 because this year has few data. Further, note that no data is available for the years 1990, 1991 and 1999 – 2006.

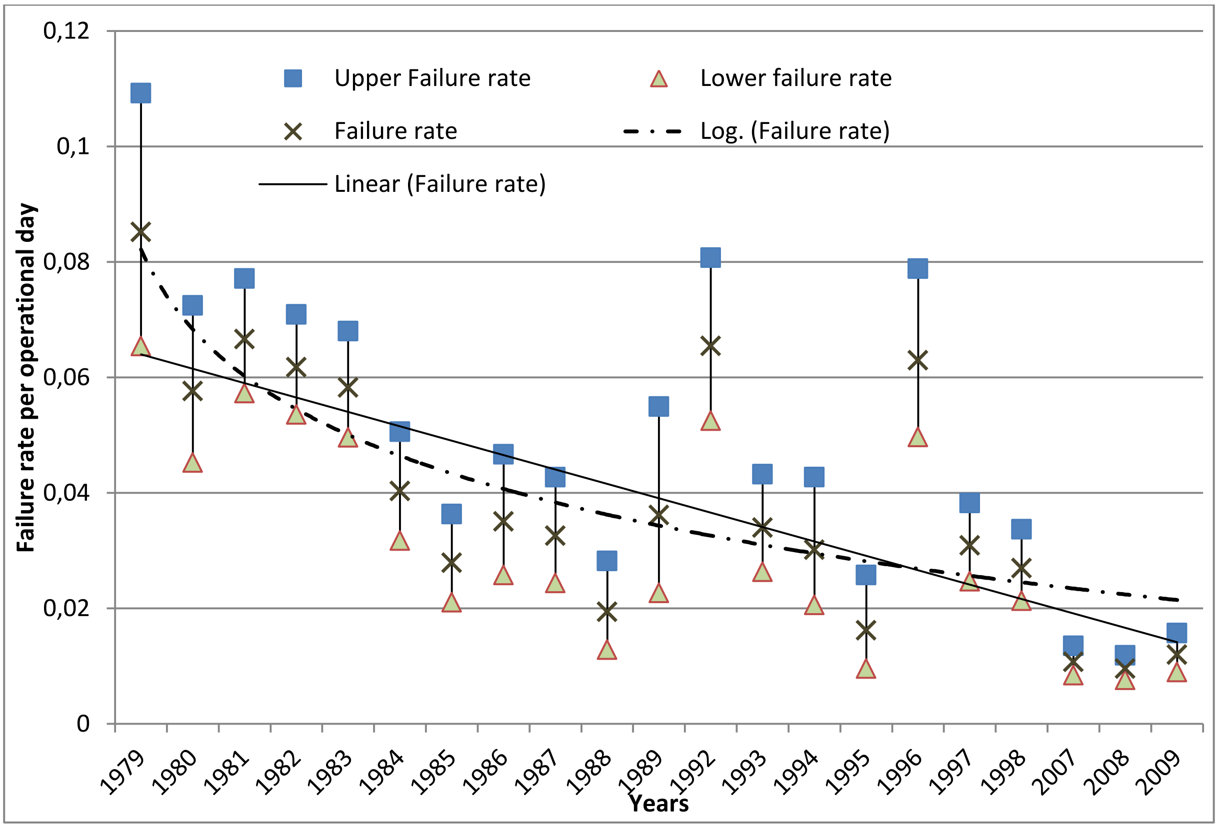


Figure 3.7 Annual failure rates, 90 % confidence intervals, linear and log linear trend lines for subsea BOP stacks for the period 1979 – 2009

The confidence band for the years 2007 – 2009 is very narrow due to the fact that in this study BOP service time is substantially higher than other studies. The negative trend line (correlation of -0.71) indicates a 99% probability that the trend is decreasing. It is important to note that the regression analysis is based on the average failure rate for each year. The total amount of experience within each year is thereby not considered. However, the plotted data in Figure 3.7 indicates that the failure rate was significantly reduced in the beginning of the 1980s. After 1984 – 1998, the failure rate seemed to be fairly stable. However the years represented by this study again depict an increase in reliability. The reasons for this are discussed in Section 3.6.

In Figure 3.8 the average downtime per year and the associated trend lines for the average downtime per day in service are shown.

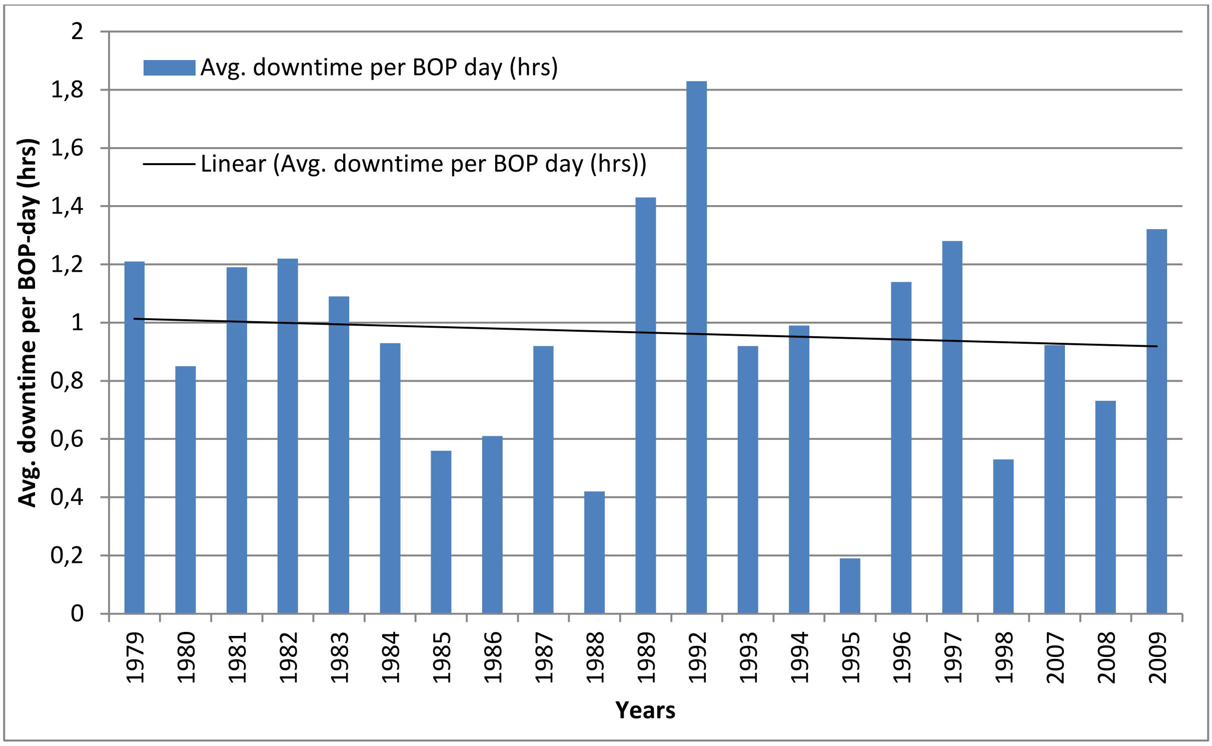


Figure 3.8 Average downtime per BOP-day and associated trend lines for the period 1979 – 2009

As seen from Figure 3.8, a slight reduction in the downtime per day in service is indicated by the trend lines. This is however, not a significant trend. If only regarding the period 1983 – 1996 and 2007 – 2009, a slight increase in downtime per day in service is observed. This is also to be expected since handling time increases with the water depth and large part of the most recent data is from deepwater wells.

3.8 Effect of Water depth on Reliability of BOP

In Table 3.8 overview of the BOP reliability against various water depths is presented. For the water depths deeper than 8000 ft a limited time in service is represented. There is no clear trend related to water depth and BOP reliability based on this table.

Table 3.8 Overview of BOP reliability indices for various water depths

	Water Depth range (ft)									
	2000 - 3000	3000 - 4000	4000 - 5000	5000 - 6000	6000 - 7000	7000 - 8000	8000 - 9000	9000 - 10000	>10000	Total
No. of failures	26	37	28	16	26	12	11			156
Total downtime (hrs.)	1720	2611	2483	1068	1978	1788	1800			13448
BOP-days in service	3261	2997	2861	2147	2209	1126	348	100	7	15056
MTTF (days)	125	81	102	134	85	94	32			97
Loss time per BOP day (hrs.)	0,53	0,87	0,87	0,50	0,90	1,59	5,17			0,89
Avg. Downtime per failure (hrs.)	66	71	89	67	76	149	164			86
Avg. Downtime per failure (hrs.) when BOP was on the wellhead	58	65	80	67	58	75	121			70

Figure 3.9 shows the average downtime per failure for all the failures and for failures when the BOP was on the wellhead. An increasing trend with water depth is observed in both cases as shown by fitted lines. Similar trend is also shown in Table 3.8 Overview of BOP reliability indices for various water depths based on BOP location.

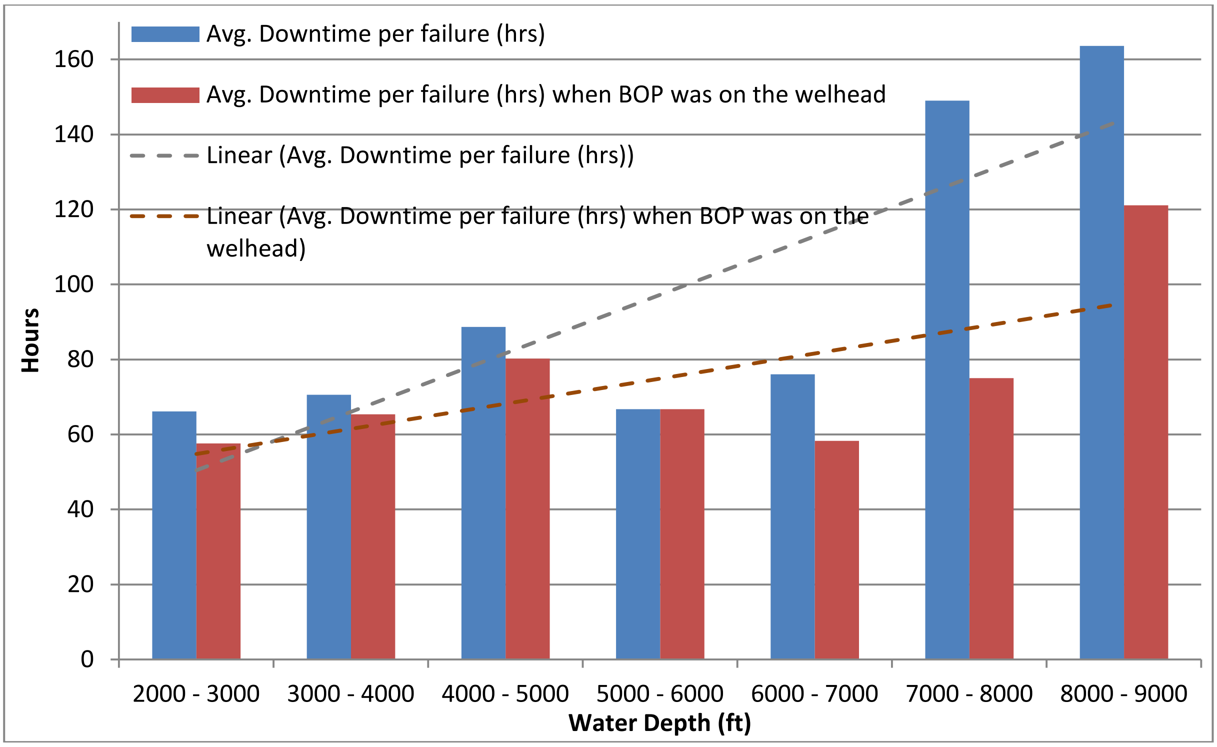


Figure 3.9 Average downtime of BOP failures for various water depth ranges

It should be noted that none of the trend lines represent a strong correlation.

3.9 Rig Specific Performance

The 42 rigs included in this study showed a highly varying failure rate and downtime per BOP day in service, as illustrated in Figure 3.11. The left and right vertical axes represent downtime and failure rate per BOP-days, respectively for each rig. The confidence band for the failure rate is also shown. Note that the dotted line marks the average failure rate which can be used to as a benchmark when comparing rigs. Also note that in Figure 3.11, rigs are sorted according to the failure rate.

There are eight rigs without any failure. Three of these rigs (Rig AS, Rig BW, and Rig BN) have more than 200 BOP-days in service.

Rig Rig AQ has the highest failure rate among all. This rig has seven failures corresponding to a lost time of 191 BOP-days. Similarly, rig Rig AO has the highest downtime per BOP-day, solely due to the fact that it has only 69 days of service but had 600 hrs downtime related to a BOP failure.

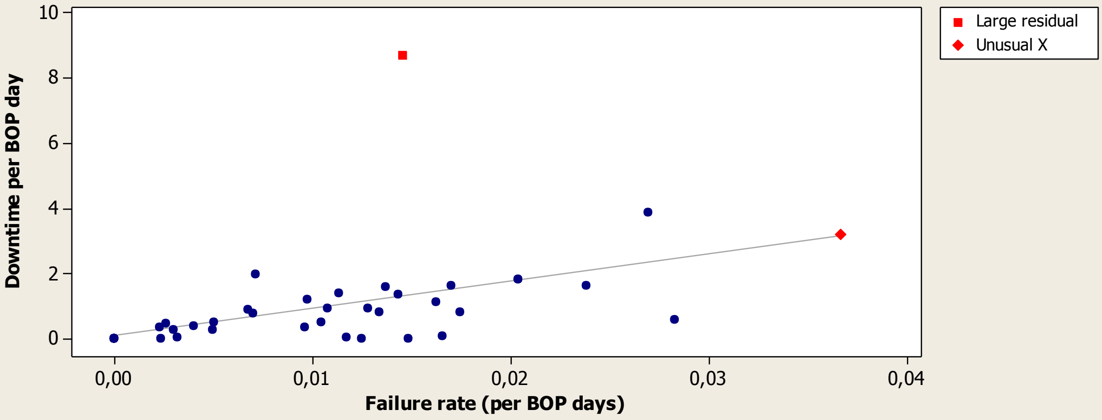
Intuitively downtime per BOP-day should increase with the increase in failure rate. Since it is argued above that downtime is highly influenced by relatively few failures of long duration, therefore an attempt is made in Figure 3.10 to investigate this correlation. The correlation is confirmed by regression analysis (positive correlation of 0.49) as shown in Figure 3.10. Note that the model only accounts for 22.07% of the variation. One of the reasons is that there is high uncertainty in lost time durations as discussed in Section 3.5. The downtime and the failure rate are also dependent on many other factors such as maintenance regime, operating and environmental conditions that are not accounted for here.

Regression for Downtime per BOP day vs Failure rate (per BOP days)
Model Selection Report

Y: Downtime per BOP day
X: Failure rate (per BOP days)

Fitted Line Plot for Linear Model

Y = 0,0906 + 83,41 X



Statistics

	Selected Model	Alternative Models	
	Linear	**Quadratic**	**Cubic**
R-squared (adjusted)	22,14%	20,45%	18,59%
P-value, model	0,001*	0,004*	0,013*
P-value, linear term	0,001*	0,096	0,297
P-value, quadratic term	-	0,700	0,695
P-value, cubic term	-	-	0,744
Residual standard deviation	1,329	1,343	1,359

* Statistically significant (p < 0,05)

Figure 3.10 Regression line for Downtime per BOP day vs. Failure rate per BOP day

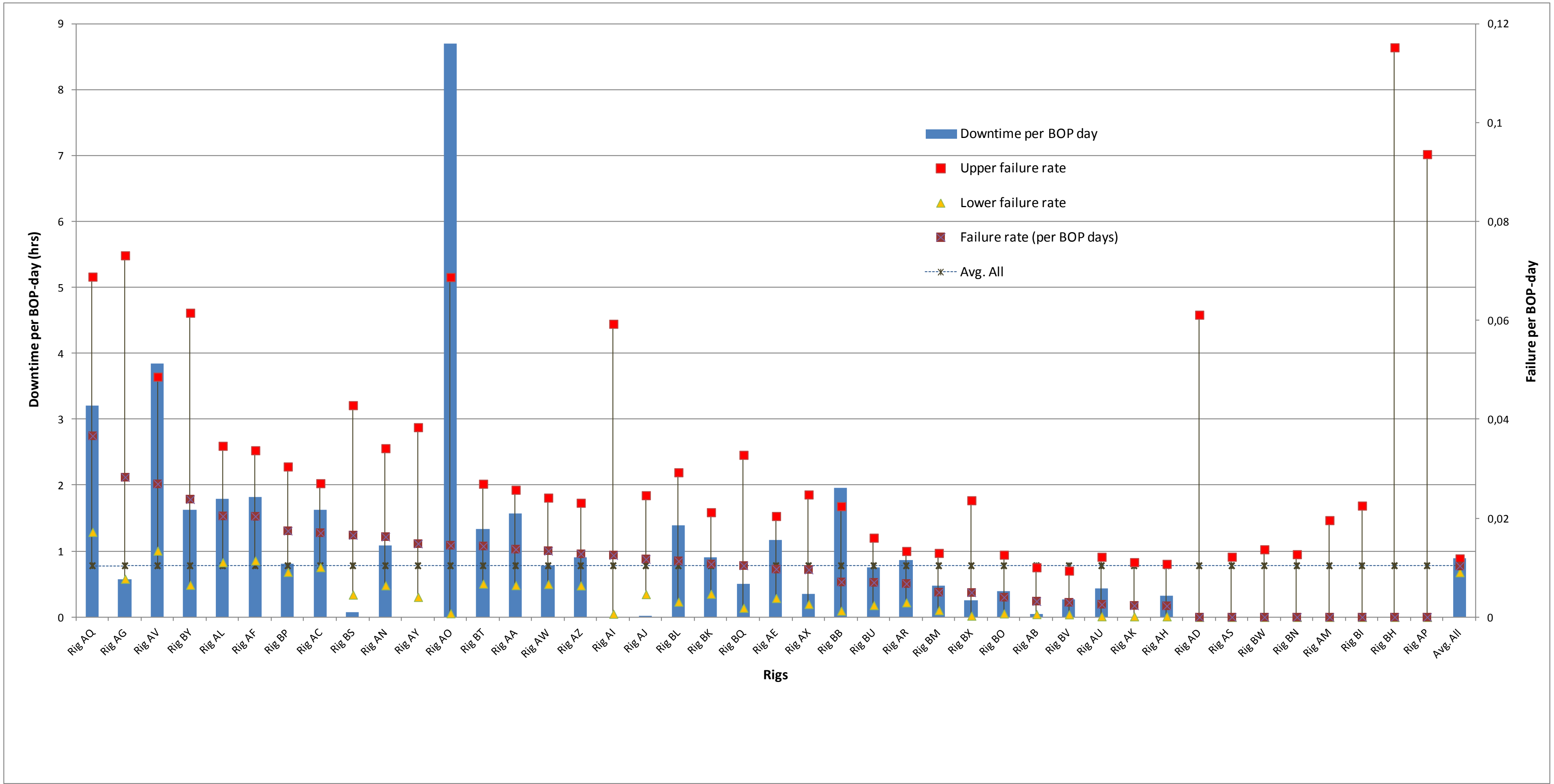


Figure 3.11 Rig specific performance for downtime and failure rate per BOP day with 90 % confidence interval

4 BOP System Specific Reliability

4.1 Flexible Joint

Today, most rigs have a flexible joint with a flexible element. The use of ball joint as a flexible joint is obsolete. This was also observed during the previous study. Different manufacturers have different models of flexible joints, but the UniFlex elastomer element is used by various manufacturers. A new model in this study is Annu-Flex by Hydril. The Annu-Flex combines a single or a dual subsea annular blowout preventer with a flexible underwater riser joint. It is noted that generally the information about flexible joint was missing.

Modern flexible joints are generally very reliable as indicated by only one failure in this study. In the Phase II DW study, only one failure occurred as well.

4.2 Description of Flexible Joint Failure

This failure resulted in a MMS district investigation report (/7/). The following text is copied from the investigation report *"The failure event was an external leakage which occurred while drilling at a water depth of 3400 ft. (1036 meters). The rig was drilling at a depth of approximately 22550 ft. On the morning of February 9, 2007 when a slight drilling break was taken and bit pas picked up off of bottom to check for flow and the well was not flowing. Tar was noted in mud returns when the well was circulated to clean the hole followed by a loss of SBM in pits as noticed by mud engineer. An ROV inspection revealed that 5 to 10 foot long stream of SBM flowing out of a weep hole in the LMRP at the riser flex joint. The leak was discovered around 10:30 and the well was immediately shut in at the BOPs using the annular. The level in the riser dropped 10 feet before stabilized and the leak stopped. The last time the riser and BOPs were inspected by the ROV was at 6:00 o'clock that morning and no pollution was noted.*

The drill pipe was then isolated by setting two cast iron bridge plugs (CIBPs) at approximately 21077 and 21072 ft. The drill pipe was hung off in the middle pipe rams. A back-off of the drill pipe was made at the BOP stack. At this time another release of SBM occurred from the fluid that was in the drill pipe above the BOP stack. The drill pipe that was above the BOP stack was pulled out of the hole. The riser was then displaced of remaining mud with seawater.

The riser was then pulled and Flex Joint was replaced. The LMRP was serviced and the riser package was re-run. The riser was then displaced back to mud. The drill pipe was screwed back in and the middle pipe rams were opened. The heavy-weight drill pipe was perforated above the CIBPs. The well was circulated clean from this depth. The drill pipe and BHA were pulled out of the hole for replacement of the perforated joint of heavy-weight drill pipe and then normal operations resumed.

The SBM loss was based on the loss in the pits on the rig. Some of the loss could have occurred down hole into the rubble zone just below the base of the salt which is normal for this depth and location. Approximately 862 bbl of 14.9 ppg 53% synthetic-based mud (SBM) *were lost to the GoM and SBM contained approximately 457 bbls of estimated synthetic based oil.*

The cause of the leak was the failure of the threaded plug that was installed into the test port by the manufacturer of the flex joint after it was tested in the shop. This design has been around for many years and this was the first known failure of this type. The tar in the fluid system could have created internal pressures in the flex joint that may have contributed to the failure of the threaded plug". The estimated time lost due to failure and repair was 12 days including running and pulling of plugs.

4.3 Annular Preventer Reliability

Table 4.1 shows the failure mode distribution and associated lost time for annular preventer failures. A total of 24 annular preventer failures occurred. The "failed to fully open" and "internal leakage (leakage through a closed annular)" were the dominant failure modes.

Table 4.1 Annular Preventer failure modes and associated number of failures

Failure mode description	No. of failures	Total lost time (hrs)	BOP-days in service	Item days in Service	MTTF (Item days in service)	Avg. down-time per failure (hrs)	Avg. downtime per BOP day (hrs)
Failed to close	1	268	15056	28150	28150	268,0	0,02
Failed to fully open	8	84			3519	10,5	0,01
Failed to open	0	0					
Internal hydraulic leakage (control fluid part)	2	66,5			14075	33,3	0,00
Internal leakage (leakage through a closed annular)	11	1902			2559	172,9	0,13
Other	1	24			28150	24,0	0,00
Unknown	1	0			28150		
All	24	2344,5			1173	97,7	0,16

A lower failure rate was observed for annular preventer in this study than in the previous studies, as shown in Figure 3.5. It may be suspected that this is because in this study some failures were not identifiable due to lack of details in the WAR remarks. In Phase II DW (/1/), only two failure modes were observed, i.e., internal leakage (leakage through closed annular) and failed to fully open.

Figure 4.1 shows the average downtime per failure vs. water depth. A general increasing trend can be observed. There were eight failures without any associated downtime. For these, the failures were accepted due to its low severity.

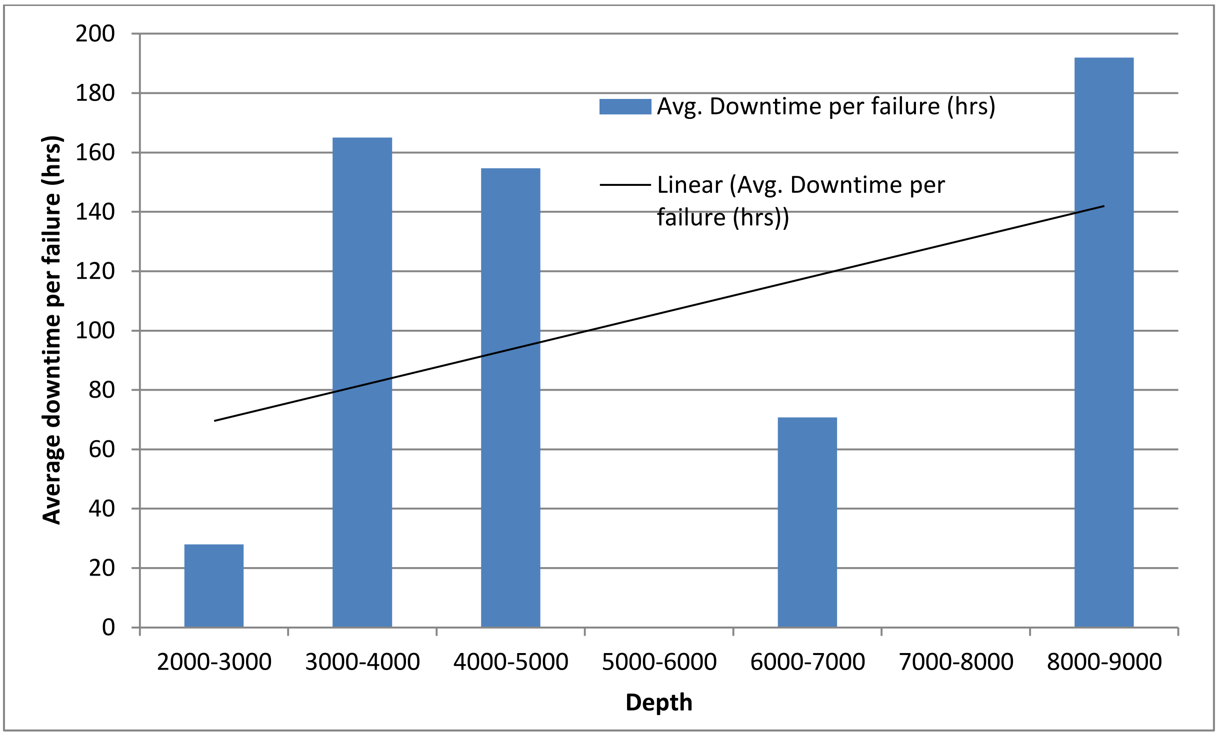


Figure 4.1 Annular preventer Avg. downtime per failure Vs. depth

4.3.1 Failed to Close Failures

One failure occurred in this study with the failure mode "failed to close". In the previous study no failure occurred with this failure mode.

This failure occurred when the BOP was on the wellhead. Due to ballooning and losses, they attempted to bullhead mud down the annulus and at that time the annular preventer failed to actuate. The annular preventer was then flushed from the kill line and they attempted to close the annular again by increasing the closing pressure, but in vain. Nevertheless they received verbal approval from MMS to continue to operate with the failed annular. Later during routine BOP tests, the annular preventer was also tested and found OK, but the BOP was pulled approximately a month later and repaired. It is uncertain what caused the failure, but the annular element was changed during the repair. The associated lost time was estimated to be 268 hours including running and pulling of packer and BOP.

4.3.2 Fail to Fully Open Failures

Such failures were normally overcome by using over-pull or increased weight below the tool that should pass the annular. The cause of the failure is normally slow relaxation of the annular rubber. It is also assumed that these failures occur more often than mentioned in the daily drilling reports or WAR remarks, because it is not regarded as a failure; rather a fairly frequent operational problem. Another contributing cause may be that the rig is not perfectly positioned above the well.

Eight "failed to fully open" failures occurred in this study compared to six such failures in the Phase II DW study. In addition this failure mode is normally not critical with respect to blowout hazard, but may produce some rig downtime. The average downtime per failure has increased in this study compared to previous study which may be because of increased water depths compared to the previous study.

Below a brief description of *Failed to fully open* failures are given:

1. First they were unable to get past the upper annular to change the bit. Circulated bottoms-up and got large amount of gumbo cuttings. Then, when testing the BOP, they washed the wellhead and worked the test plug through the upper annular with no restrictions.
2. Worked test plug through the BOPs. It is not known if it was the upper or lower annular preventer that had the problem.
3. Attempted to pass the annular preventer with the test assembly, no success. Pulled out of the hole and functioned the annulars. Attempted again to pass the annulars with the test assembly, this time successful. It is unknown if it was the upper or lower annular that had the problem.
4. While BOP testing, tested the annulars and functioned diverter. After several attempts to pull through the annulars, jumped a ROV to observe the slope indicators and decided to reposition the rig. Moved rig 37' @ 22 deg heading. Still unable to pass the annular. Rotate string 1/2 turn and slack through the annular.
5. While doing the completion activities attempted to pass through the lower annular with the ITC assembly, unsuccessful. Pumped 50 bbls of soap in the BOP to lubricate the lower annular. Landed out ITC. Closed the upper annular and pumped down kill line to test top of seal on ITC.
6. Worked test plug through the BOP. This may have been in the upper or lower annular. The same problem occurred earlier, when the BOP was on the rig due to a choke & kill line failure. The upper and lower annular were then changed out.
7. Pulled the wear bushing through the lower annular with no over-pull. Tagged the upper annular but were unable to work through.
8. Worked 10-3/4" brush/magnet assembly through the upper annular.

4.3.3 Internal Hydraulic Leakage (control fluid part)

No such failures occurred in the previous study. The two failures observed in the current study with “internal hydraulic leakage (control fluid part)” were discovered through BOP testing prior to running the BOP at the same rig. The first failure occurred on the upper annular which was unable to achieve close chamber pressure. They opened annular and installed new seals. Further, they installed the cap and functioned the annular 10 times to bed in new seals and achieved a close chamber pressure test. The failure of the seal appeared to be the cause of the failure. The associated lost time was estimated to be 30.5 hours.

The second failure occurred on the same rig after the upper annular was repaired and tested. On the lower annular they observed a leak at the weep hole. Broke out the cap on the lower annular and stripped down annular. Dressed body and piston, installed new seals and assembled annular. It appears that in this case the body and piston seal caused the failure. The associated downtime was estimated to be 36 hours.

4.3.4 Internal Leakage (leakage through a closed annular)

Internal leakage (leakage through a closed annular) is the most dominant failure mode, accounting for almost 50% of all the annular preventer failures. This is the same distribution as observed during the previous study. All except one failure occurred while the BOP was on the wellhead. A brief description of failures is provided below:

1. This failure was discovered during a BOP test scheduled by time. They made several attempts to test the upper annular without success and observed returns up the riser. LMRP was pulled and the upper annular element was replaced and retested to low pressure of 300 psi. Discovered a leak through the piston seal out to the weep hole. Subsequently changed inner seals. This time the annular passed the open and close die hydraulic test, but leaked between annular and drill pipe. A decision was made to function the element several times, but it leaked through weep hole. Decided to re-install the test joint and refill with water, functioned the upper annular six times and attempted to test. Installed new seals on test joint. Attempted to test 250 psi. The weep hole began leaking water. Removed annular cap and outer piston. Cleaned & inspected sealing areas for leaks and repaired. Pressure tested well bore side (no success). Leaked around riser connector AX ring gasket. Removed LMRP and changed out riser connector AX ring gasket. Attempted to pressure test wellbore side (no success). Removed annular cap and noticed top of the annular packer cut. Installed new annular packer. Installed annular cap and tightened. Functioned annular 3 times. Tested the upper annular to 250 low and 7000 psi high for 5 minutes each test (good test). Prepared RIH with LMRP on riser. The total lost time was 348 hours and water depth was 2670 ft (929 meters).
2. This failure was discovered during the installation test. The BOP was latched back after landing the X-mas tree. They attempted to retest the annular on 4.5 in Nu-tech tool with no success. They attempted to test again on 5.578 in. drill pipe and the test was good. However pulled riser and LMRP. Conducted annular element change out. In addition also changed out boost valve and solenoids valve on the LMRP. Ran and latched the LMRP. They had some problems with setting the Nu-tech test tool but managed and completed the installation test. The estimated total lost time was 154 hours and water depth was 6263 ft (1909 meters).
3. This failure was discovered during BOP test scheduled by time. The annular preventer failed the pressure test on 5 in test tool. They retested the annular preventer on 5.875 in test tool and test was successful. Made second attempt to test on 5 in tool however unsuccessful and decided to pull the LMRP. Changed out the annular rubber and serviced the LMRP. Ran and latched the LMRP back. The total lost time was 172 hours. Note that this time also includes the approximately 36 hours lost due to bad weather. The water depth was 4354 ft (1327 meters).
4. This failure was discovered during installation test after running the BOP. The upper annular failed the pressure test. They pulled the BOP and surface tested upper and lower annular individually (the lower annular failed also, recorded separately). Both annulars showed to be leaking at their respected upper vent ports. Repaired leaks in opening and closing chambers. Dismantled the upper annular and observed flaking in the upper cylinder head and buffed out same. In addition also observed a section of the upper annular element extruded into the wellbore. Change out the annular element. The total estimated lost time for these two failures was 552 hours. Note that this downtime also includes repairing of the lower annular. It was also noted that the spare

annular available on the rig was also in a failed state. The water depth was 8698 ft (2651 meters).

5. This failure was discovered during installation testing when the BOP was on the rig for repair of the upper annular, described above. They dismantled the lower annular. A slightly damaged seal and pitting corrosion was observed in the lower body. They buffed the corroded area in an effort to establish the effective seal area. Configured the BOP and ran and tested the BOP. The repair time is included in the lost time due to the upper annular failure (above).
6. This failure was discovered during the installation test after latching the BOP. Both the annulars failed the pressure test (the lower annular failure reported separately). Pulled the BOP for repair and changed the annular preventer. The estimated lost time was 160 hours. This lost time also includes the lower annular repair time. The water depth was 2949 ft (899 meters).
7. This failure was discovered during installation testing when the BOP was on the rig for upper annular repair, described above. Pulled the BOP and changed the annular preventer piston.
8. This failure occurred during normal operation when they had recently killed the well after a kick (probably caused by stripping). Pulled the LMRP. They changed out the annular element. The total estimated lost time was 192 hours and the water depth was 3399 ft (1036 meters).
9. While circulating a kick, the annular preventer was found leaking. Note that they were stripping out of the hole. The annular was functioning but was not positively holding pressure. It is believed that annular was repaired few days later when the LMRP was pulled due to Hurricane. No lost time assumed due to the failure.
10. This failure occurred during installation testing of the BOP. The lower annular preventer was leaking internally. They pulled the BOP and reinstalled the lower annular. In addition changed out the piston seals and installed the upper seals and assembled the lower annular. Also redressed test ram which was damaged because it was closed on a tool joint. The estimated lost time was 204 hours and the water depth was 6739 ft (2054 meters).
11. This failure occurred during installation testing of the BOP. The lower annular failed the test. They pulled the BOP and changed the lower annular element. The lost time was 120 hours. The water depth was 3999 ft (1219 meters).

4.3.5 Other and Unknown Failures

One failure each falls under this category. Below a brief description is provided for these failures:

1. The failure with the failure mode “other” was detected during testing prior to running the BOP. Little information is available. It is also not clear whether it is a failure on the upper or lower annular preventer. The WAR remarks states “*Waiting on replacement piston for BOP. Installed new piston. Test the annulars 250/7500*". The estimated lost time for this failure was 24 hours.

2. The failure with the failure mode “other” occurred during normal operation. It was reported several times that they recovered annular rubber. It was however not reported that the annular leaked. It is not known if it was the upper or the lower annular.

4.3.6 Manufacturers Included in the Study

Table 4.2 shows an overview of the manufacturer included in the study and the associated operational time.

Table 4.2 Overview of the manufacturers included and the associated operational time

Manufacturer & other parameters	Days in Service				
Dimension (inches)	18 3/4"			21 1/4"	Total
Pressure rating	5000 psi	10000 psi	Total	5000 psi	
Cameron D		2688	2688		2688
Cameron DL		2855	2855		2855
Cameron DL Dual		530	530		530
Cameron Unknown		438	438		438
Hydril Annu-Flex		1424	1424		1424
Hydril GL	313		313		313
Hydril GX		7005	7005		7005
Hydril GX Dual		616	616		616
NL Shaffer Bolted cover				160	160
NL Shaffer Dual	710	594	1304		1304
NL Shaffer SL		492	492		492
NL Shaffer Unknown	2446	4699	7145		7145
NL Shaffer Wedge cover	2060		2060	98	2158
Stewart and Stevenson QSA		1022	1022		1022
Total	5529	22363	27892	258	28150

4.4 Hydraulic Connector Reliability

All subsea BOPs are equipped with two hydraulic connectors. The wellhead connector connects the BOP stack to the wellhead. The Lower Marine Riser Package (LMRP) connector connects the riser to the BOP stack. These connectors are in principle identical, but usually the wellhead connector is rated to a higher pressure. Typically the wellhead connectors are rated to the same pressure as the ram preventers, and the LMRP connectors are rated to the same pressure as the annular preventers.

A total of eight failures occurred in this study corresponding to the total lost time of 638 hours. The distribution of failures for hydraulic connector is shown in Table 4.3. Six out of nine failures occurred when the BOP was on the wellhead. Of these six, three failures observed were *External leakage* (leakage to environment) and one each for *Failed to lock* and *Failed to unlock* and *Spurious unlock.*

Table 4.3 Hydraulic connector failure modes and associated number of failures

Failure mode description	No. of failures	Total lost time (hrs)	BOP-days in service	Item days in service	MTTF (Item days in service)	Avg. downtime per failure (hrs)	Avg. downtime per BOP day (hrs)
External leakage (leakage to environment)	3	252	15056	30112	10037	84	0,017
Failed to lock	1	168			30112	168	0,011
Failed to unlock (includes all incidents with problems unlocking connector)	1	96			30112	96	0,006
Spurious unlock	1	24			30112	24	0,002
Unknown	2	98			15056	49	0,007
All	8	638			3764	79,75	0,042

4.4.1 External Leakage Failures

This is one of the most critical failure modes in terms of controlling a well kick. Three failures are observed with external leakage to the environment corresponding to lost time of 252 hours. A brief description of these failures is provided below:

1. The following text is from MMS accident investigation report (/9/). "*This failure occurred when 13 5/8" casing was run, cemented in place, and the casing hanger was set. The annulus above the casing hanger packoff was pressured up to test the pack-off. The pressure held for approximately 15 seconds when the pressure began to decline. Two more attempts were made to apply pressure to the annulus, where the pressure declined on both attempts and 10 bbls of Synthetic Based Mud (SBM) was lost at an undetermined location. All pressure was then bled off the annulus and two more attempts were made to pressure up on the annulus where 3 more bbls of SBM was lost for a total of 13 bbls. The casing running tool was then pulled out of the hole, inspected and determined to be in good condition. It was then decided to test the wellhead connector while the ROV observed. In relation to this the blind/shear rams were closed and the wellhead connection was pressured up. With approximately 600 psi, the ROV observed 7 bbls of SBM discharging from the wellhead connector port for a total of 20 bbls. After setting a packer in the well, the Blowout Preventer (BOP) stack was pulled to surface for inspection. The BOP connector ring gasket seal area showed signs of wash in two places, as well as wash on two places of the ring gasket itself. The leak resulted from the hydrate seal interfering with the metal to metal seal area causing the wash out area on the BOP connector during the high pressure setting of the 13-5/8 inch casing pack-off. Another contributing cause could be hydrate seal laid across the ring during the initial BOP landing operation*". The estimated lost time was 96 hours and water depth was 6821 ft (2079 meters).
2. This failure occurred during installation test of the BOP. Pulled the riser and BOP. Change out the wellhead connector and re-ran the riser and BOP. The estimated lost time was 132 hours and the water depth was 2946 ft (898 meters).
3. This failure also occurred during installation testing of the BOP. Unlatched the BOP and installed new BX-VT gasket. The estimated lost time was 24 hours and the water depth was 4623 ft (1409 meters).

4.4.2 Failed to Lock Failures

Only one failure occurred with this failure mode. The LMRP had been on the rig for unknown reasons (may have been oceanographic conditions). When attempting to latch the LMRP to the stack they failed to do so. They pulled the LMRP to surface. Inspected the LMRP for damage and alignment and repaired the LMRP. The estimated lost time was 168 hours and the water depth was 6473 ft (1973 meters).

4.4.3 Failed to Unlock

Only one failure occurred with this failure mode. They attempted to unlatch the wellhead connector with no success. Pumped 20 gallons of glycol & 10 gallons of stack magic and injected methanol and let soak in the connector. Unlatched, pulled the riser and stored the BOP. The estimated lost time was 96 hours and the water depth was 4984 ft (1519 meters).

4.4.4 Spurious Unlock

This failure occurred while temporary abandoning the well. They had unlocked and pulled the diverter through the rotary table and made-up riser running tool to the landing joint. While holding PJSM (Pre Job Safety Meeting) on pulling the riser, LMRP was inadvertently unlatched. Landing joint was bent +/-18' above the rotary table. All the riser and LMRP weight was suspended on the tensioner ring. A ROV inspected and found the LMRP unlatched. The BOP was fully down on the subsea tree (SST). The BOP latch indicator rod was in the unlatched position. No other obvious damage was observed on the marine riser, LMRP, BOP stack, SST, or subsea architecture. Skid the rig to a safe zone and removed the damaged landing joint from the rig floor. Skid the rig over the BOP stack and prepare the ROV with hot stab to unlock H4 connector on the BOP stack. Dove the ROV and latched the LMRP to the BOP. ROV confirmed the latch and confirmed that the tree connector was unlatched. The failure cause is unknown and estimated lost time was 24 hours. The water depth was 3045 ft (928 meters).

A dropped BOP incident occurred in 2008, as mentioned in a MMS accident investigation report (/10/). Note that for this incident, there existed no WAR remarks, hence it is not a part of statistics in this report. The following text is from investigation report. “*The semi-submersible drilling rig was engaged in Marine Riser running operations. The riser running operations was being staged to coincide with the completion of mooring operations. Riser joint number 107 was landed in the spider gimble, which put the Blowout Preventer Stack (BOP) at a depth of 8400 feet Rotary Kelly Bushing (RKB). A satisfactory test of the Choke and Kill lines was conducted to a pressure of 7500 psi. The rigid conduit lines were left charged to 5000 psi to monitor pressures while waiting for the next stage of riser running. During this time frame there was a sporadic change in the pressures at the surface panel. The Remotely Operated Vehicle (ROV) was jumped to perform a stack supply pressure inspection of the manual gauges on the Lower Marine Riser Package (LMRP) and the following observations were made. At 21:15 hours, all pressures were observed to be normal on the LMRP manual gauges. At 21:22 hours the pressures on the Conduit, Supply Pressure, Pilot Pressure and Manifold Pressure fell to 0 psi. The ROV also observed a cloud of what was assumed to be BOP fluid developing around the LMRP. At 21:25 hours, the ROV visually confirmed that the BOP package had disconnected from the LMRP. A bottom survey utilizing the ROV confirmed that the BOP had fallen approximately 1400 feet to the seafloor. The BOP was found lying half submerged in the sea floor on a heading of 250°, approximately 180 feet from the Rig 1 Rotary Center. Probably combinations of events lead to the accidental release of the BOPs, however it is felt that the root cause was from a Leaking Pilot-Operator Check Valve (POCV) in the LMRP locking circuit, and a parted wire associated with the multi-pin connector for the lock mechanism on the riser connector. Contributing cause could have been* *that a Sub Plate Mounted (SPM) valve supplying hydraulic pressure to the LOCK side leaked, allowing the lock pressure to leak over to the UNLOCK side. Other possible contributing causes are the corrosion observed on two of the four multi-pin electrical connectors in the LMRP or the contaminated dielectric fluid that was discovered on the backside of the multi-pin connector. It is also possible that a combination of the above items may have contributed to the accidental release".*

4.4.5 Unknown Failure Modes of Connector

All of these failures occurred when the BOP was on the rig. The failures are described below:

1. The rig had temporary been on another location. When it came back, prior to running the BOP, they had problems with the wellhead connector. They repaired the wellhead connector and installed a new piston. The estimated lost time was 48 hours.
2. This failure occurred when the LMRP was on the rig for repair of control valves and solenoids for the casing shear ram. At that time they repaired failed seals on shuttle valve for LMRP connector. They repaired line for connector latch. No lost time was assumed for this failure.
3. This failure was detected through testing before running the BOP. Due to little information available it is only known that LMRP connector was repaired. In addition the wellhead connector was also replaced for unknown reasons. The estimated lost time was 50 hours.

4.4.6 Manufacturers Included in the Study

Table 4.4 shows an overview of the connector manufacturer included in the study and the associated operational time.

Table 4.4 Overview of the manufacturers included and the associated operational time

Function	Manu-facturer	Model	Time in service (days) vs. pressure rating 10000 psi	15000 psi	Total
LMRP connector	Cameron	Collet connector	803	627	1430
		H4 (High angle release) E		592	592
		H4 HD (Heavy Duty)		281	281
		HC-Collet	3578	884	4462
		M70- Collet	688		688
		HC Collet		888	888
		Total	5069	3272	8341
	Vetco	ExF HAR	516	192	708
		H4	153		153
		H4 E	442		442
		H4 EXF		201	201
		H4 HAR (High Angle Release)		181	181
		H4 HAR (High Angle Release) EXF	637		637
		H4 HD (Heavy Duty)		1950	1950
		Total	1748	2524	4272
	Unknown	H4 HD (Heavy Duty)		191	191
		Unknown	1362	890	2252
		Total	1362	1081	2443
	Total		8179	6877	15056
Wellhead connector	Cameron	Collet connector		764	764
		DWHC		1423	1423
		EVO		26	26
		M70- Collet	80		80
		SHD H4		500	500
		Total	80	2713	2793
	Vetco	DWHD		297	297
		DW-HD-H4		908	908
		H4	761	1970	2731
		H4 EXF		1868	1868
		H4 HD (Heavy Duty)		1791	1791
		H4 Super HD		2004	2004
		H4-EF		126	126
		HD (Heavy Duty)		390	390
		SHD H4		1644	1644
		Unknown	313		313
		Total	1074	10998	12072
	Unknown	H4 HD (Heavy Duty)		191	191
		Total		191	191
	Total		1154	13902	15056
Total			9333	20779	30112

4.5 Ram Preventer Reliability

The BOPs included in this study has from four to six ram preventers. The configuration of the rams is presented in Table 3.1. An overview of ram preventer reliability is shown in Table 4.5. The most dominant observed failure mode is *internal leakage*, accounting for 70% of all the ram preventer failure. Eighteen of 23 failures occurred when the BOP was on the wellhead and rest when the BOP was on the rig. Five of the 23 failures occurred on test rams, three on blind shear ram, and 15 failures occurred on pipe rams. Among pipe ram failures, two failures occurred on fixed pipe ram and the rest 13 on variable pipe ram.

Table 4.5 Ram preventer failure modes and associated number of failures

Failure mode description	No. of failures	Total lost time (hrs)	BOP-days in service	Item days in service	MTTF (Item days in service)	Avg. downtime per failure (hrs)	Avg. downtime per BOP day (hrs)
External leakage (bonnet/door seal or other external leakage paths)	2	720	15056	74174	37087	360	0,048
Failed to close	1	6			74174	6	0,000
Failed to fully open	1	24			74174	24	0,002
Failed to open	1	0			74174	0	0,000
Internal leakage (leakage through a closed ram)	16	1008			4636	63	0,067
Other	1	0			74174	0	0,000
Unknown	1	7,5			74174	8	0,000
All	23	1765,5			3225	77	0,117

When compared to Phase II DW study it seems that reliability has improved as shown in Figure 3.5. However it is worth noting that in the current study the average number of rams a rig has is 4.90 (Table 3.1) compared to 4.03 average rams of Phase II DW study (/1/).

A brief description of observed failure mode is provided below:

4.5.1 External Leakage

Two failures occurred with this failure mode corresponding to downtime of 720 hours. Only one failure occurred during the Phase II DW study. The failures in the current study are:

1. This failure occurred during installation testing of the BOP after landing the LMRP. When tested the upper annular, it was a good test. Then attempted to pressure up to 7,000 psi for the high pressure test, but the pressure bled off. They did some more attempts to test before an ROV observed a leak on the upper pipe ram bonnet seals. They sat a storm packer in the hole and pulled the BOP. Opened the bonnet doors on the BOP stack to inspect for damages and removed all bonnet seals, ram packers and top seals. Replaced the bonnet seals and the ram packing rubbers. Installed the ram rubbers in all ram blocks. Observed forward open/close cylinder seal leaking in the UPR. Replaced "ram change piston seat" and visually inspect, then changed seals, gaskets and springs as needed. Installed spare forward bonnet seal in the UPR and pressure tested "open and close side" hydraulics to 3000 psi. Configured the BOP and latched back onto the wellhead. The estimated downtime was 216 hours and the water depth was 3045 ft (928 meters).
2. This failure also occurred during the BOP installation testing when the LMRP was landed after Hurricane. The following text is from a MMS investigation report (/11/). *"While displacing the Blow Out Preventer (BOP) stack with Synthetic Base Mud (SBM) after returning to location from evacuating for Hurricane Ike, a seal on the Lower Bind Shear Rams (LBSR) failed. After latching up the Lower Marine Riser Package (LMRP) to the BOP stack, the kill line, boost line, drill pipe and riser were displaced to SBM. In preparation to displace the choke line from seawater to SBM, the UVBR was opened and the line displaced through the stack across the UVBR. After displacing the BOP and riser, the Emergency Drill Pipe Hang-Off Tool (EDPHOT) was retrieved. The BOP test tool was tripped in the hole and landed in the wellhead. Testing commenced on the BOP stack. While attempting to test the Annular, the pressure kept bleeding off. The Annular was tested good on the low pressure test of 250 psi but would not hold pressure on the high pressure test of 3500 psi. The ROV*

was sent down to visually observe the BOP stack and found a SBM leaking from the LBSR bonnet doors. The failure was due to an induced differential caused by functioning open the Upper Variable Bore Rams (UVBR) without opening a valve to allow for pressure equalization across the UVBR. The active mud pit volume was investigated and a total volume of 12.5 bbls was calculated missing from the pits. The SBM contained 51% synthetic fluid for 6.4 bbls of pollutant material that was discharged into GOM waters. The SBM was 14.1 ppg. The probable cause is that during the displacement procedure, the choke line and UVBR are opened to displace the BOP stack by taking returns up the choke line. The stack was shut-in around the EDPHOT with the Upper Blind Shear Rams (UBSR), LBSR, UVBR, Middle Variable Bore Rams (MVBR) and all the failsafe valves closed. After displacing the kill line through the annular bleed valve and the riser through the drill pipe, the choke line had to be displaced. The UVBR was opened with the Upper Inner Kill Valve (UIKV) and the Upper Inner Choke Valve (UICV) still closed. To displace the choke line, SBM was pumped down the kill line and across the stack to take returns up the choke line. When the UVBR were opened with the UIKV and UICV closed, a pressure drop was induced in the BOP. The pressure drop was induced by decreasing the volume in a closed system as a result of the ram being taken out of the system when the UVBR were opened. The seals on the bonnet doors for the LBSR were rated for a -660 psi negative differential. To collapse these seals, the pressure inside of the BOP would have to go 660 psi below the seawater hydrostatic pressure. With a water depth of 7,005 feet, the seawater hydrostatic pressure is equal to 3,133 psi. The pressure drop in the BOP from opening the UVBR was equal to approximately 6,900 psi. This results in a final pressure of approximately -3,767 psi. The pressure would only drop until the seal collapsed at 2,473 psi (660 psi below seawater hydrostatic) and then water would invade the BOP and equalize the pressure. Once the seals failed, the bonnet door and the BOP body washed out creating a leak path to the inside of the BOP". The lost time was estimated to 504 hours and the water depth was 7005 ft (2135 meters).

4.5.2 Failed to Close

One failure occurred with this failure mode. They were doing the function testing of the BOP when it was on the wellhead. The upper pipe ram did not close when attempted from the yellow pod. Then they repeated the test from the blue pod with the same result. However after that failure disappeared. The lost time was estimated to be 6 hours and the water depth was 4229 ft (1289 meters).

4.5.3 Failed to Fully Open

This failure occurred during a pressure test scheduled by time. The test ram failed to fully open. They cut the test ram hard piping and continued the operation. The downtime was estimated to 24 hours and the water depth was 7005 ft (2135 meters).

4.5.4 Failed to Open

This failure occurred while the BOP was on the rig due to an annular failure. During the pressure testing of the BOP, the pipe ram failed to close. It is unknown which ram it was, either the upper or the middle pipe ram. They attempted to test the BOP's with 6.625 in and plug would not seat. Drained the BOP's and found a ram had not retracted. They repaired damaged phenolic bearing. There was no lost time assumed because of this failure.

4.5.5 Internal Leakage (leakage through a closed ram)

Thirteen out of 16 failures occurred while the BOP was on the wellhead. A short description of these failures is provided below.

1. This failure occurred during installation testing of the BOP after landing of the LMRP. The lower VBR's did not test however; they continued the operation with two operating VBR's. No lost time was assumed for this failure.
2. This failure occurred during installation testing of the BOP after landing of the LMRP. The test ram was found leaking. No lost time was assumed for this failure.
3. This failure occurred during installation testing of the BOP after landing of the LMRP. The LMRP was on the rig due to Hurricane Ike. The test ram was found leaking. They went in the hole with a test plug and tested the BOP. No lost time was assumed for this failure.
4. This failure occurred when they were pressure testing the BOP after running the casing. The upper and lower variable pipe rams were found leaking. They pulled the BOP for repair. Changed out ram elements and measured ram blocks. Installed blocks and torqued doors on the BOP's. Stump tested the BOP's on 4-1/2" and was found satisfactory. The lost time was estimated to be 156 hours and the water depth was 4478 ft (1365 meters). *Note here that in the database this is included as two failures*.
5. This failure occurred when they were pressure testing the BOP after running the casing. They attempted to test the 9-3/8" casing against the BSR to 250 psi for 5 minutes (good) and 1862 psi for 24 minutes, at which point the leak developed in the BSR. They pulled the BOP for repair. Opened up the BSRs and find lateral t-seals missing from the upper block on both sides. The estimated lost time was 336 hours and the water depth was 3478 ft (1060 meters).
6. This failure occurred when the BOP was on the rig for repairing the upper pipe ram bonnets. Attempted to test MPR (9 5/8") but could not get above 300 psi. They repaired the MPR and tested. They opened the bonnet doors on the BOP stack to inspect for damage. Removed all bonnet seats, ram packers and top seats. In addition replaced bonnet seals and ram packing runners, and oiled bonnet faces and grease bonnets to prepare to close. There was no lost time assumed for this failure.
7. This failure is related to the above described failure. The BOP had been on the rig for repair of the upper pipe ram bonnet. During this repair they observed that the MPR was leaking. They repaired the MPR before the BOP was re-run. During the BOP test after the BOP was landed, they tested MPR's against the LOK and the UIK to 10,000 psi, it leaked. They again retested the MPR's against the LIK and the UOK to 10,000 psi however, it leaked. After this they tested MPR's down kill line against LIC and UOK for 10000 psi. The pressure dropped to 6000 psi in 15 minutes. Then they functioned the MPR's with higher closing pressure (2500 psi) and tested the MPR to 250 psi low and 10000 psi high pressure but MPR's didn't hold the pressure. The pressure was dropping with the rate of 220 psi/min. Nevertheless they did not repair the failure because the 9 5/8" already tested in the well. The estimated lost time for this failure was 24 hours and the water depth was 3045 ft (928 meters).
8. After cementing the 9 5/8 x 11 3/4" casing they attempted to test the BOP but the test ram was found leaking. No downtime was assumed for this failure.

9. This failure was detected during the installation test of the BOP. The BSR was found leaking. They pulled the BOP and repaired the BSR. The lost time was estimated to be 96 hours and the water depth was 3842 ft (1171 meters).
10. This failure is related to above described failure. After completing the BSR repair, while stump testing of the BOP middle pipe ram failed the test. They changed the MPR and ran the BOP. There was no lost time assumed with failure.
11. This failure occurred during the installation test of the BOP. While pulling the test plug from the well, they recovered pieces of the VBR. It is not known which pipe ram it was, however, it is believed that it was the middle pipe rams. The lost time and the water depth were 84 hours and 2011 ft (613 meters).
12. This failure occurred during BOP testing after circulating a kick. The VBR did not test, however, they got an approval not to test the middle pipe ram. The ram element was new, it had been replaced approximately 2 weeks earlier. No downtime was assumed for this failure.
13. This failure occurred during the BOP installation test. They attempted to test the BSR but the test failed. The BOP was then pulled to the rig and repaired. The estimated lost time was 144 hours and the water depth was 2949 ft (899 meters).
14. This failure occurred during BOP testing after running casing. The middle VBR did not test. They sat the packer in the well and pulled the BOP for repairs. The estimated lost time for the repair was 168 hours.
15. This failure occurred when the BOP was on the rig for annular repair. While testing the BOP before running, it was discovered that it was closed on tool joint. They dressed the ram. No lost time was assumed for this failure.

4.5.6 Other

Only one failure falls under this failure mode. It took several attempts and high closing pressure of 2300 psi to get the test on the VBR. No lost time was assumed for this failure.

4.5.7 Unknown

Only one failure falls under this failure mode. After reaching the well location, they repaired the VBR before running the BOP. The estimated lost time was 9.5 hours.

4.5.8 Manufacturers Included in the Study

Table 4.6 shows an overview of the ram preventer manufacturer included in the study and the associated operational time.

Table 4.6 Overview of the manufacturers included and the associated operational time

Manufacturer	Model	Time in service (days) vs. pressure rating 10000	15000	Unknown	Total
Cameron	Compact Dual		504		504
	Double/Dual		1202		1202
	Single		954		954
	T double		4220		4220
	TL Double Cavity		13370		13370
	TL single		2747		2747
	U double	4004			4004
	Total	4004	22997		27001
Hydril	Compact		201		201
	Compact Dual		6254		6254
	Compact Triple		1533		1533
	Double/Dual	612	7408	768	8788
	Single		3876		3876
	Unknown		9498		9498
	Total	612	28770	768	30150
NL Shaffer	NXT Tripple		1782		1782
	Single		598		598
	SL double		1960		1960
	SLX double		12683		12683
	Total		17023		17023
Total		4616	68790	768	74174

4.6 Choke and Kill Valve Reliability

Six of the 42 BOP stacks had 12 choke & kill valves, 24 rigs had 10, 11 rigs had eight and only one rig had four choke and kill valve. Deepwater rigs also have similar valves for choke and kill line isolation purposes, so the lines can be tested during running of the LMRP. These are not included as choke & kill and kill valves. If these valves leak to the surrounding during line testing when running the BOP or during regular operation or testing it has been regarded as a failure of the BOP mounted choke and kill line.

Table 3.1 gives an overview of the BOP stack configuration for the various rigs included. Only four failures are reported in the current study for choke & kill valves. The corresponding item days in service are 160310. This gives 40078 days to MTTF. A total of 136 hours of downtime is reported for the four failures. Note that the downtime comes from only one failure. This gives an average of 34 hours per failure for choke & kill valves. Similarly 0.0089 hours were lost per BOP-day in average.

All the experienced failures have failure mode “Internal leakage (leakage through a closed valve)”. Since these valves are in series, there will always be a backup if one of the valves leaks. Normally the BOP is not pulled from the seafloor to repair such failures as long as it is one valve leaking only. It is likely that some more of these failures have occurred, but they have not been mentioned in the well activity reports.

The far more severe failure mode *external leakage* was not observed in the current study.

In the Phase II DW study (/1/) the observed frequency of internal leaks was higher. Further, external leaks occurred four times in the Phase II DW study. Indicating that there has been an improvement in the choke and kill valve reliability.

Below a short description of the four choke and kill valve failures observed in this study is provided.

1. This failure occurred while running the BOP. They were testing the choke, kill and conduit lines when they observed a bad test on the kill line. It was the lower inner kill valve which was leaking internally. They pulled the BOP and repaired the valve and installed a new ring gasket. The estimated lost time was 136 hours and water depth was 2513 ft (766 meters).
2. This failure was detected during installation testing of the BOP. The upper inner choke valve was found to be leaking. They got verbal approval to continue forward with UIC slight leak from the wellbore side. The failure was repaired later when the BOP was on the rig due to a control system failure. No downtime was assumed for this failure.
3. While installation testing the BOP, the outer bleed valve did not test with seawater. They tested again with SBM two days later and found it in satisfactory condition. No lost time was assumed for this failure.
4. This failure was detected while testing the BOP after running casing. They got approval to continue ahead with drilling operations with a leak on the lower outer kill valve in closed position. No lost time was assumed for this failure.

4.7 Choke and Kill Line Reliability

The choke and kill line systems are divided in three main parts for the purpose of this study:

1. Flexible jumper hoses in the moon
2. Integral riser lines
3. BOP attached lines from the connection to the integral riser lines (flexible joint level) to the outer choke and kill valve outlets

Figure 3.1 shows a typical configuration of a BOP system. Table 4.7 shows a overview of failures of these lines.

Table 4.7 Choke and Kill line failure modes and associated number of failures

Failure mode distribution	No. of failures	Total lost time (hrs)	BOP-days in service	MTTF (BOP-days in service)	Avg. downtime per BOP-day (hrs)	Avg. downtime per failure (hrs)
BOP attached line						
External leakage (leakage to environment)	4	732		3764	0,049	183,00
Unknown	1	24		15056	0,002	24,00
Total	5	756	15056	3013	0,050	151,20
Jumper hose line						
External leakage (leakage to environment)	1	24	15056	15056	0,002	24,00
Riser attached line						
External leakage (leakage to environment)	11	1214	15056	1369	0,081	110,36
Total choke and kill line	17	1994	15056	886	0,132	117,29

Eleven out of 17 failures occurred in the riser attached lines. All except one failure were external leakage. In the Phase II DW study “plugged and bursted line” failure modes were also observed. A short description of the failures observed in this study is presented below.

1. This failure occurred on the BOP *attached line* while running the BOP. They were testing the choke & kill lines while running the BOP when they had a leak in the line.

They pulled the riser to identify the location of the leak and found the leak on the choke line Coflex hose on the BOP. They changed the hose and reran the riser and BOP. They lost 96 hours in the whole process. The water depth was 7415 ft (2260 meters).

2. This failure occurred on the BOP *attached line* while running the BOP. They were testing the choke & kill lines while running, when they experienced leak. They dive the ROV and discovered the leak on the coflex hose above the choke line test valve. Pulled the riser and stack and replaced the hose. They lost 96 hours in the whole process. The water depth was 6886 ft (2099 meters).
3. This failure occurred on the BOP *attached line* when the BOP was on the wellhead. They were doing the installation test after landing the LMRP. They found a leak (external) on the choke stab. Then they pulled the BOP and repaired the choke stabs and seals. The lost time was estimated to be 288 hours. The water depth was 5640 ft (1719 meters).
4. This failure occurred on the BOP *attached line* when the BOP was on the wellhead. After latching the BOP they tried to test against the casing but unsuccessful. They found a leak on the kill stab. Pulled the BOP and riser and installed a new kill stab and LMRP receptacle. They lost 252 hours in the whole process, however note that this time also includes time lost due to bad weather. The water depth was 8127 ft (2477 meters).
5. This failure occurred on the BOP *attached line* when the BOP was on the rig due to a hurricane. After the hurricane they repaired the kill line stabs which were identified having problems in damage assessment. The failure mode is unknown in this case. The lost time was estimated to 24 hours.
6. This failure occurred on *jumper hose line* while running the BOP. The kill line was leaking. They repaired the kill line and lost time was 24 hours.

The following failures occurred on riser attached lines:

7. The LMRP was on the rig due to a hurricane. While testing during running of the LMRP, the choke line was found leaking. They replaced the choke line seals and ran the riser. The estimated lost time was 24 hours.
8. This failure was detected during the choke & kill line testing while running the BOP. They pulled the riser and found leak on choke line. They repaired the leak and ran the BOP and riser. The lost time was estimated to 24 hours.
9. This failure occurred while running the BOP. They were testing the choke & kill line when they found a leak. Repaired the same. No downtime was assumed for this failure.
10. This failure was detected during the installation test of the BOP when it was landed on the wellhead after repair. They pulled the stack and changed seal sub from LMRP. They also inspected and cleaned marine riser. The lost time was estimated to 168 hours. The water depth was 8061 ft (2457 meters).
11. This failure occurred when the BOP was on the wellhead. A kill line leak was detected between 2nd and 3rd riser joint (2614’). They got the approval to take kill line out of service and continue operations (no drilling) to log the well, run production liner, displace well with completion fluid, prior to having to pull the riser and repair kill line.

They repaired the kill line three weeks later and also carried out rig maintenance. They had some problems in setting the test plug for installation testing of the BOP. The lost time was estimated to be 216 hours. The water depth was 2733 ft (833 meters).

12. This failure occurred while they were doing the repairs on the surface. They pumped through the kill line, observed 0 psi. The ROV inspection found leak between Jt.7 and #8 at 7449'. They displaced 11.2 ppg SBM with sea-water and sat the packer in the well in order to pull the riser and LMRP. They removed all packing and seals form each joint of choke, kill and boost line seals. After testing of these lines on surface they re-ran the riser. The lost time was estimated to 180 hours. The water depth was 7910 ft (2411 meters).
13. This failure was detected through testing of the BOP against casing. The kill line was found leaking but only on low pressure. They subsequently repaired with Seal-Tite and retested and continued the well operations. After 4 days when the BOP was latched back after bad weather. The BOP was tested and the leak was again recovered. The ROV located leak in kill line. They sat a packer in the well and pulled the riser to fix the leaks found. Replaced joints with leaks in the kill line and ran the riser. The lost time was estimated to 192 hours. The water depth was 8061 ft (2457 meters).
14. This failure occurred while they were circulating the well. A ROV inspection discovered that kill line seals between riser joints 7 and 8 were leaking. They tried to stop the leak with Seal-Tite but were not successful. Then they sat a packer in the well and pulled the riser for the kill line repair. After fixing the leak they re-ran the riser. The lost time was estimated to 240 hours. The water depth was 2713 ft (827 meters).
15. This failure was discovered when they were testing the choke & kill line while running the BOP. They pulled the riser and repaired the leak. The lost time was estimated to 72 hours. The water depth was 8061 ft (2457 meters).
16. This failure occurred when the BOP was on the wellhead. They were testing the BOP, which was scheduled by time, and found a leak in choke & kill line (leaking only on low pressure tests). They stopped the leakage with Seal-Tite and retested to 250/7500 psi. They lost 48 hours and the water depth was 3829 (1167 meters).
17. This failure occurred when the BOP was on the wellhead. The test was scheduled by time. They found the seals on the kill line between #7 and #8 riser joints leaking. They pumped Seal-Tite to fix the leak and tested the kill line, but failed. Pumped Seal- Tight for the second time and this time the Seal-Tite worked. They lost 48 hours and the water depth was 2713 ft (827 meters).

4.8 Main Control System Reliability

The two main BOP control system principles are:

- Multiplex control system (MUX)
- Pilot hydraulic control system

There are two versions of the pilot hydraulic system, one conventional and one pre-charged system. The pre-charged system reduces the activation time of the BOP components, and can thereby be used in deeper waters than the conventional. The conventional and the pre-charged pilot hydraulic systems are similar systems. A pilot hydraulic system can be modified to a pre-charged system

While in the previous study (/1/) the majority of the rigs were equipped with a pilot hydraulic or pre-charge pilot hydraulic system, in this study the majority of the rigs have a multiplex control system. Approximately 72% of service time in this study comes from multiplex systems. In this study many of the wells have been drilled in water depths where neither the pilot control system nor the pre-charge pilot control system can be used because the BOP closing times will not satisfy the closing time requirements.

Table 4.8 shows an overview of the different control system principles service times.

Table 4.8 Service time for Main Control System types

Control System Principle		Service time (BOP-days) for various water depth									
		2000-3000	3000-4000	4000-5000	5000-6000	6000-7000	7000-8000	8000-9000	9000-10000	>10000	Total
Multiplex electro hydraulic		1107	1678	2188	2258	1913	1343	305	128	22	10942
Pilot hydr-aulic	Conventional	300	616		82						998
	Pre-charged	702	485	480		79					1746
	Unknown if pre-charged	1152	218								1370
	Total	2154	1319	480	82	79					4114
Total		3261	2997	2668	2340	1992	1343	305	128	22	15056

A comparison of MTTFs for the different operating principles of the main control systems is shown in Figure 4.2. It can be seen that there is no significant difference between the MTTFs since the confidence bands are overlapping. This is the same observation as in Phase I & II DW studies (/1/ and /3/).

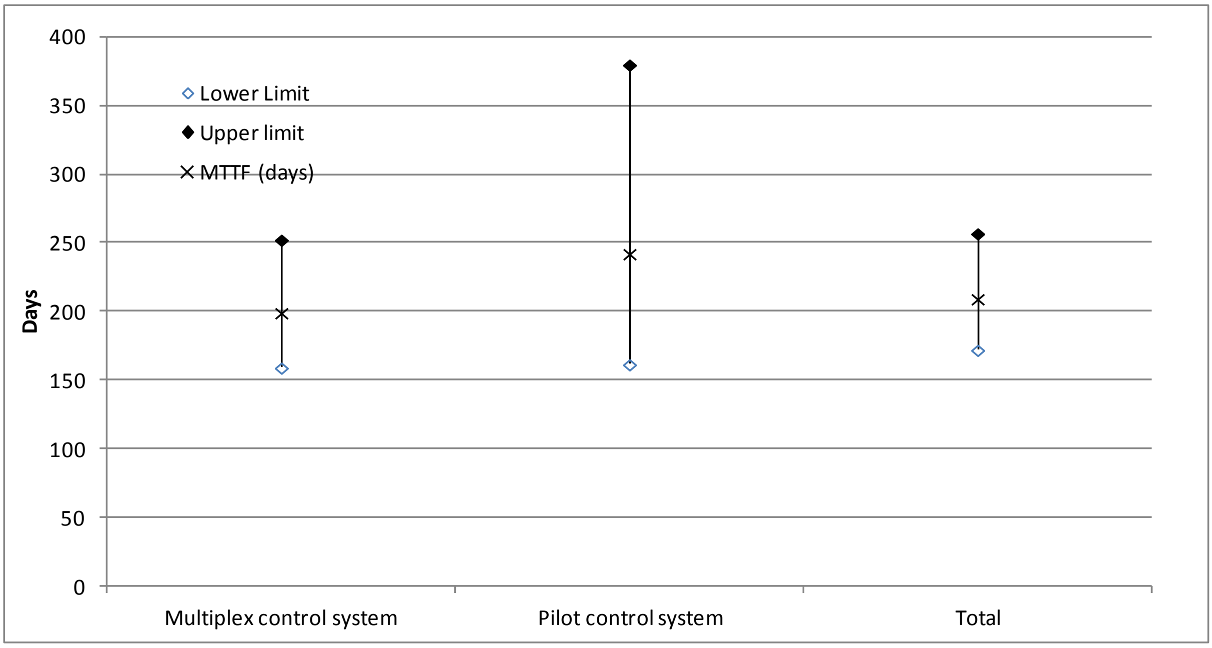


Figure 4.2 MTTF comparison, BOP control system principles with 90% confidence limits

A comparison of control system failures with previous studies (/1/ and /3/) is shown in Figure 4.3. It can be seen that the current study has significantly higher MTTF than the Phase I & II. The reasons for this are discussed in Section 3.6.

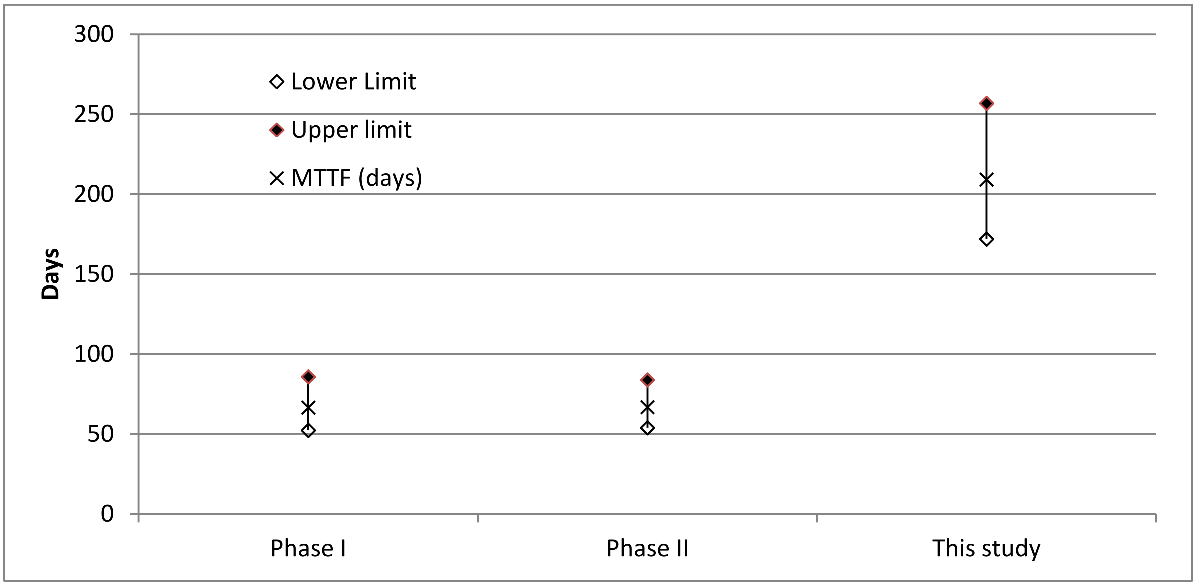


Figure 4.3 Comparison of Control System MTTF (average with 90% confidence limits) with Previous Studies

In terms of average downtime performance, the result for various control system types is shown in Figure 4.4. The multiplex system experienced the highest downtime. It should be noted that the multiplex system was also used for the largest water depths. Generally the downtime picture is dominated by few failures of long durations.

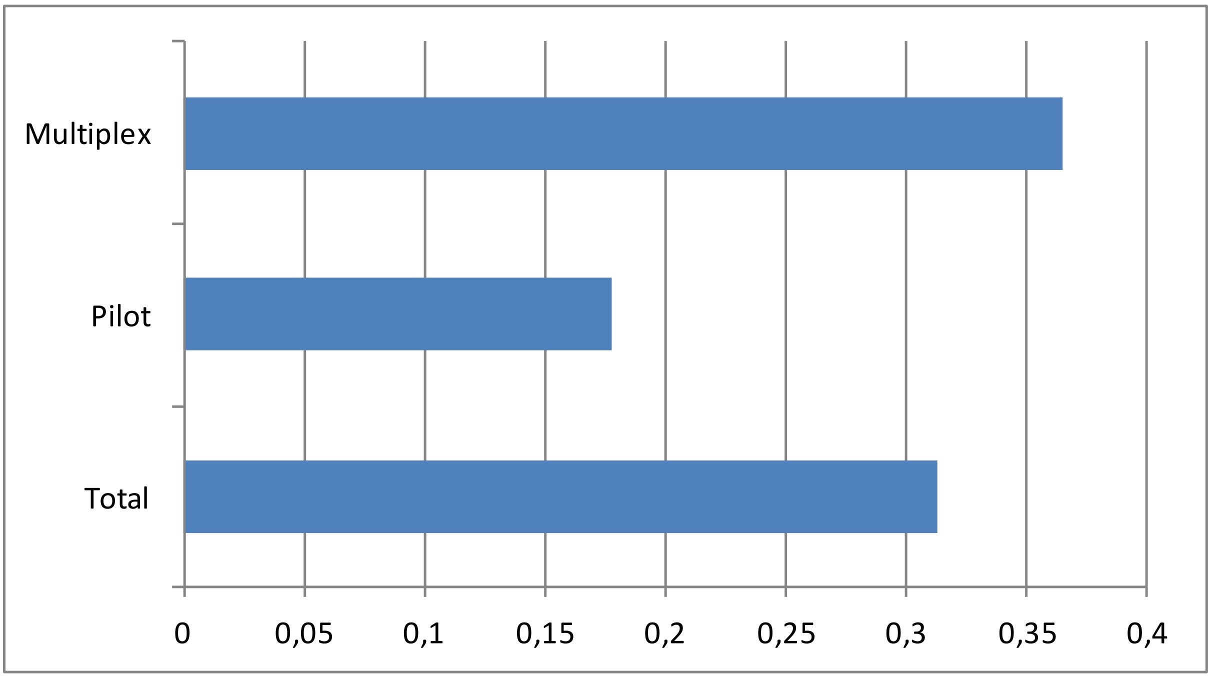


Figure 4.4 Average downtime per BOP-day caused by BOP main control system failures

The comparison of downtime figures with previous studies is presented in Section 3.6.

Table 4.9 shows an overview of the different control system failure modes, the associated number of failures and the lost time.

Table 4.9 Control system principle specific failure modes and associated number of failure

Failure Mode Distribution	No. of failures	Total lost time (hrs.)	Days in Service (BOP-days)	MTTF (days)	Avg. Downtime per BOP-day (hrs.)	Avg. Downtime-per failure
Multiplex electro hydraulic						
Loss of all functions both pods	1	192	10942	10877	0,018	192
Loss of all functions one pod	12	1592,5	10942	906	0,146	132,7
Loss of one function both pods	4	168	10942	2736	0,015	42,0
Loss of one function one pod	10	576	10942	1088	0,053	57,6
Loss of several functions one pod	1	0	10942	10877	0	0
Other	19	1108,5	10942	576	0,101	58,3
Unknown	8	330	10942	1360	0,03	41,3
Total	*55*	*3967*	*10942*	*198*	*0,365*	*72,1*
Pilot hydraulic						
Loss of all functions one pod	2	216	4114	2057	0,053	108,0
Loss of one function both pods	2	0	4114	2057	0,000	0
Loss of one function one pod	6	25	4114	686	0,006	4,2
Loss of several functions one pod	2	504	4114	2057	0,123	252,0
Other	4	0	4114	1029	0,000	0
Unknown	1	0	4114	4114	0,000	0
Total	*17*	*745*	*4114*	*242*	*0,181*	*43,8*
Total control system	**72**	**4712**	**15056**	**209**	**0,313**	**65,4**

4.8.1 Loss of all Functions Both Pods

In this study the *loss of all functions both pods* is only experienced for multiplex control system. This is a critical failure mode, because the BOP cannot be operated. This failure mode was also observed for multiplex systems and pre-charged pilot systems in Phase I DW and Phase II DW (/1/ and /3/). This failure mode was, however, not observed during the Phase IV and Phase V studies (/5/ and /6/). In the mentioned studies wells were drilled in "normal" water depths, pilot systems were utilized, indicating that such failures do not occur frequently in the pilot hydraulic control systems.

The only failure with this failure mode occurred when the BOP was on the wellhead. They ran the BOP test plug because the BOP test was due with time. The rig changed the top drive system during this time. Suddenly they lost the communication with the BOP stack for a time window of unknown length. They were only able to re-establish the communication with the blue pod SEM B and the blue pod SEM A, the yellow pod SEM A and B all failed. They then displaced the riser and choke & kill lines with sea water and attempted to pull the LMRP, but failed. The LMRP was then retrieved through ROV intervention. The unsuccessful unlatching of the LMRP is also assumed to be due to control system failure. The failure cause is unknown. After pulling the LMRP they repaired the control system and re-ran the riser and LMRP. The lost time for this failure was estimated to be 192 hours and water depth was 5282 ft (1610 meters).

4.8.2 Loss of all Functions One Pod

A total of fourteen failures with this failure mode are experienced, with 12 for multiplex system and one each for pre-charged and pilot hydraulic system. In the previous study, Phase II DW, six such failures occurred for a pilot hydraulic, one for a multiplex system and 2 for a pilot hydraulic, unknown if pre-charged system. On first look it's a completely different distribution, however, note that in this study most of the service time (72%) comes from multiplex system and in the Phase II DW study 64% of service time came from pilot hydraulic system. Below the experienced failures are discussed:

1. This failure occurred on *Pilot hydraulic system* when the BOP was tested after installation on the wellhead for the first time. The description in the WAR remarks is limited, but it seems the BOP was pulled twice to repair the failure. They pulled the riser and stack to repair blue pod. They also troubleshot the control fluid leak (location of the leak is unknown) and after function testing of the BOP, they ran the BOPs and marine riser. However, the blue pod was found leaking during the BOP installation test and subsequently they pulled the BOP again and fixed the leak. The lost time was estimated to 144 hours and the water depth was 2949 ft (899 meters).
2. This failure occurred on *Pre-charged pilot hydraulic system* when the BOP was on the wellhead. They were picking up the whip-stock assembly when they discovered a leak on the yellow pod. A SPM valve was leaking. After displacing choke, kill, boost line, and the riser with seawater, they pulled the LMRP and repaired the leak on the yellow pod (changed SPM valve). Then they re-ran the LMRP and riser and tested the BOP to 250/7500 psi for 5 minutes. The total lost time was estimated to 72 hours and the water depth was 2005 ft (611 meters).

The multiplex control system "loss of all functions one pod" failures are described below

3. This failure occurred when the BOP was latched on the wellhead after a choke line repair. During the installation test they encountered problems with the SPM valve on the yellow pod. In order to change the SPM valve they pulled the stack and changed out the failed SPM valve. Note here that this failure is a part of series of failures during which the BOP was pulled three times off the wellhead for BOP repair. The lost time for this failure was estimated to 144 hours and the water depth was 8061 ft (2457 meters).
4. This failure occurred when the BOP was on the wellhead. They found that the surface flow meter was running and started troubleshooting the leak. The BOP control system was causing surface flow meter to "runaway". The ROV inspection subsea found that 0.5 in stainless steel line connection on conduit going to the pod select valve had parted. They then pulled the LMRP and commenced inspection and removal and replacement of the broken yellow pod autoshear line. They also changed out a line on the blue pod autoshear sequence. After some other maintenance change outs on the BOP, they ran the riser and BOP. The lost time was estimated to be 137.5 hours. The water depth was 6214 ft (1894 meters).
5. This failure was detected through a function test when the BOP was on the wellhead. After the function test was complete on the blue pod, a leak developed on the pilot line for the yellow pod. They got verbal approval for a 48 hour extension to the 14 day BOP test requirement, the blind shear rams test, and to operate with only the blue pod functional on the BOP. Note here that they were preparing to run the completion when the failure occurred. No lost time was assumed for this failure.
6. This failure occurred while filling the string, when they observed loss of supply pressure on the blue pod. The ROV deployed to investigate the loss of pressure. Found check valve on the hot line parted. The RTTS packer and storm valve was set @ 4500' and conducted negative test for 30 min. Pulled the LMRP on the marine riser to surface and replaced the failed check valve in the blue pod. After this they ran

the LMRP on riser and lost time was estimated to be 216 hours. The water depth was 4144 ft (1263 meters).

7. This failure occurred while making up the lower gravel pack assemblies. When assemblies were run in hole, it was observed that the BOP yellow pod was not working correctly. They recovered the lower gravel pack assemblies to surface and sat 10.75 in RTTS packer at 4.905ft, and tested to 1.500 psi. Then, after pulling the LMRP, changed out the yellow pod umbilical and terminated ends. Function tested the yellow pod and ran the LMRP and the marine riser. They lost 171 hours and the water depth was 4354 ft (1327 meters).
8. This failure occurred while pulling the BOP off the wellhead. They lost the subsea accumulator pressure on the yellow pod. Then they switched to the blue pod and pressure was holding with a slow leak. The ROV noted a slow leak on shear accumulator supply line. No lost time was assumed for this failure.
9. This failure was detected through a function test of the BOP. The yellow pod would not function, even after several attempts. They sat the RTTS packer and bridge plug to pull the BOP. Some delay occurred due to problems in setting the plug. After pulling the BOP they evacuated the location due to Hurricane Ida and repaired the BOP off location. The cause of the failure is unknown. The lost time for this failure was estimated to 420 hours, including 120 hours lost due to bad weather. The water depth was 6421 ft (1957 meters).
10. This failure occurred when the LMRP was on the rig for repair of the solenoid and control valves for CSR on the yellow pod. While inspecting for failures, they discovered a failed seal on the blue pod LMRP stab. They subsequently repaired the packer seal for the blue pod stab. No lost time assumed for this failures.
11. Little is known about this failure. The BOP was on the rig and after a test prior to running the BOP, they changed out the mux cable for the blue pod. A lost time of 24 hours is estimated for this failure.
12. This failure was detected during BOP testing which was scheduled by time. They found the blue pod leaking. They sat the packer in the well and pulled the LMRP. During the repair they vacuum tested the blue pod, tested the annular preventers and replaced the blue pod EH section with a spare. After testing of the LMRP, they ran the LMRP and riser back to the well. The lost time was estimated to be 336 hours and the water depth was 6473 ft (1973 meters).
13. This failure was detected during installation testing of the BOP. While testing, they lost communication with the blue pod. They pulled the BOP and repaired the failure. The failure is unknown and the lost time was estimated to 120 hours. The water depth was 5814 ft (1772 meters).
14. This failure occurred while drilling a 16" casing hole. They discovered a mux line storm loop banana sheave and SDC control line junction box broke away from the termination joint due to weather conditions. They secured the well and suspended operations due to the necessity to perform repairs on the mux cables and hydraulic lines. Pulled the LMRP. Time lost in repair was estimated to 24 hours. The water depth was 7014 ft (2138 meters).
15. This failure occurred during drilling operation. The yellow pod failed. They sat the packer and closed the BSR in order to pull LMRP. After pulling the LMRP, they

repaired the yellow pod and ran the LMRP. The failure cause is unknown. The lost time was estimated to 168 hours. The water depth was 4144 ft (1263 meters).

4.8.3 Loss of One Function Both Pods

A total of five failures with this failure mode have occurred in this study. This failure mode is normally caused by a failure in the shuttle valve or the line from the shuttle valve to the BOP function. This part of the control system is in principle identical for the different control system types. Below a description of these failures is provided:

1. This failure occurred on a *Pilot hydraulic system* when the BOP was tested after running 11 7/8" liner. They put the lower outer kill line in close and blocked position due to small hydraulic leak. However, they got the approval to continue drilling. No lost time was assumed for this failure. The water depth was 3829 ft (1167 meters).
2. This failure occurred on a *multiplex control system* and was detected through a BOP test carried out after running casing. The lower choke line fail safe valves were malfunctioning. They got the approval to continue drilling operations and not attempt to function the lower choke failsafe valves. The failure was repaired three weeks later when the BOP was pulled due to another reason. The water depth was 5371 ft (1637 meters).
3. This failure occurred on a *multiplex control system* when they attempted to pull the LMRP. When disconnecting the LMRP, they were unable to retract the yellow pod. No lost time was assumed for this failure. The water depth was 5371 ft (1637 meters).
4. This failure occurred on a *multiplex control system* when they were reaming at 11534'. They pulled out of the hole due to a leak on the BOP control system. They put the upper annular in blocked position and got an approval to continue operations with the failure present. No lost time was assumed for this failure because the LMRP was pulled 4 to 5 weeks later to repair riser tensioners. They probably fixed the failure then. The water depth was 6398 ft (1950 meters).
5. This failure occurred on a *pre-charged pilot hydraulic control system*. Limited information is available on the failure. The BOP was on the wellhead when during normal operation they experienced a failed control function on the choke valve. They got the approval to continue operations.
6. This failure occurred on a *multiplex control system.* The BOP testing before sidetrack operations revealed that the upper VBR was unable to close due to a leaking shuttle valve. They got the approval to finish testing the BOPs and continue well operation of setting abandonment plug in well. After setting the plug they pulled the BOP and conducted the repair. The lost time was estimated to 168 hours.

4.8.4 Loss of One Function One Pod

This failure mode *Loss of one function one pod* occurred 12 times for multiplex control system, three times for a pilot hydraulic system, twice for pre-charged pilot hydraulic system and once for pilot hydraulic, unknown if pre-charged control system. In the Phase II study only one such failure occurred for a multiplex system, four for a pre-charged pilot hydraulic system, eight for a pilot hydraulic system, and one for a pilot system where it is unknown if it was pre-charged or not. Below a description of these failure is provided:

1. This failure for a *pre-charged pilot hydraulic system* was detected during installation testing of the BOP. After they had completed testing the BOP, they decided that the BOP had to be re-tested and the test assembly had to be re-run. Then they experienced opening and closing issues with the upper annular. It was determined that the RBQ plate was not seated properly. Corrected and function tested same. The downtime was estimated to 24 hours. The water depth was 2100 ft (640 meters).
2. This failure for a *pre-charged pilot hydraulic system* was detected during installation testing of the BOP. They function tested the yellow pod; all functioning. Then function tested the blue pod; all functioning except the upper annular was fine. They got the approval to continue since the lower annular was fully functional on both pods. The water depth was 2818 ft (859 meters).
3. This failure on a *pilot hydraulic, unknown if pre-charged control system* was detected when the LMRP was on the rig for repairs of the annulars. While function testing of the BOP they found a leak on the blue pod line 62 which is the rigid conduit flush close. No downtime assumed for this failure.
4. This failure on a *pilot hydraulic system* was detected through function testing of the BOP which was due by time. While functioning the yellow pod, noted leaking hose on upper inner choke; close side with a ROV. They got an approval to continue operating with the yellow pod control line leaking to the upper inner choke line valve. It is unknown when the failure was repaired. No downtime was assumed for this failure. The water depth was 3343 ft (1019 meters).
5. This failure on a *pilot hydraulic system* occurred during perforation operation. The lower inner kill valve on the yellow pod was inoperable. They got the approval to continue operations with the blue pod, but if the blue pod fails, shut down immediately until the BOP can be repaired. No downtime was assumed for this failure. The water depth was 3100 ft (945 meters).
6. This failure on a *pilot hydraulic system* was detected through function testing of the BOP which was due by time. They were unable to close the LPR from the blue pod from driller's panel. Then switched to the yellow pod and successfully closed the LPR. They got an approval to continue operations. No downtime assumed for this failure. The water depth was 3829 ft (1167 meters).

The multiplex control system failures are described below:

7. The WAR remarks have a very limited description of the failure. While running the BOP after repairing another control system failure, they troubleshot the blue pod open circuit on a ram (ram unknown). They pulled the riser and BOP and repaired the open circuit on the blue pod. It is believed that this was related to the hydraulic circuit, not electrical circuit. Note that this failure occurred when the BOP was pulled three times in a course of 4 weeks due to control system failures. They lost 144 hours while repairing the control system. The water depth was 8061 ft (2457 meters).
8. This failure was detected during installation testing of the BOP. The stack connector regulator failed on the blue pod. They pulled the BOP and rebuilt the leaking shear seal decrease function. After surface testing the BOP, they ran the riser and BOP. They lost 60 hours. The water depth was 2513 ft (766 meters).

9. This failure occurred during drilling operation. They got an approval to continue drilling ahead without the yellow pod lower annular open function. No lost time was assumed for this failure. The water depth was 3399 ft (1036 meters).
10. This failure was detected during installation testing of the BOP. They encountered opening problem on the annular preventer when using the blue pod. They got the approval to continue to operate with the failure. A few weeks later they retrieved the failed pod to surface and ran a new pod. It may be that a pilot valve of the blue was leaking. The lost time was estimated to 60 hours. The water depth was 4167 ft (1270 meters).
11. This failure was detected during BOP testing due by time. The lower inner choke was inoperable from the yellow pod only. However, they got an approval to continue operations with the failure. The failure cause is unknown. No downtime estimated for this failure. The water depth was 5712 ft (1741 meters).
12. This failure occurred while function testing of the casing shear rams due by time. They found that casing shear rams would not close on the yellow pod, however, rams would function on the blue pod. They got an approval to function the casing shear rams only on the blue pod. The failure could be caused by a solenoid or pilot valve failure. No lost time was assumed for this failure. The water depth was 5712 ft (1741 meters).
13. This failure occurred during well completion operation. They pulled the LMRP for maintenance and replaced open and close control valves and solenoids for CSR on the yellow pod; changed seals in riser adapter and flushed through control lines on the yellow pod. In addition they repaired failed seals on the shuttle valve and line for latching the LMRP connector. Further, the blue pod LMRP stab seals were also repaired but that is identified as a separate failure. The lost time because of all these activities was estimated to 144 hours. The water depth was 5637 ft (1718 meters).
14. This failure occurred during normal drilling operation. They were drilling approximately at 21000’ MD when the yellow pod navigation computer on the BOP stack stopped sending information. This information consists of electronic riser angle indicator, BOP stack temperature, BOP stack pressure, and accumulator pressure read-back. No downtime assumed for this failure. The water depth was 5230 (1594 meters).
15. This failure was detected through BOP testing after running 18” casing. They observed a failure in the yellow pod because the upper inner choke operator was leaking. They got the approval to continue drilling ahead. No downtime assumed for this failure. The water depth was 6283 ft (1915 meters).

4.8.5 Loss of Several Functions One Pod

These failures are normally caused by a leakage in the pod receptacle area affecting more than one line, or a leakage/failure in the pod located annular or ram pressure regulator. The two out of three failures observed with this failure mode in this study occurred for a pre-charged pilot hydraulic control system and one for multiplex control system. In the Phase II study no such failure occurred on a multiplex system.

1. This failure for a *pre-charged pilot hydraulic control system* occurred during a BOP test prior to running the tie-back casing. They observed that there were some problems with the yellow pod. They prepared for pulling the LMRP to repair the yellow pod. When they were ready to pull the LMRP the currents were too strong. After a while it

was decided to pull the complete BOP instead. They then had to set a cement plug in the well before the BOP could be pulled. After they got the BOP on the rig they observed that the yellow pod line had four damaged areas. Replaced the yellow pod line. It was not stated what caused the damages to the control line. It may be associated to the strong sea currents experienced. Tested and reran the BOP. During the running they had a leak in the conduit line and the BOP was pulled back for repair. Reran and landed the BOP. Tested the BOP. Pulled well plugs and drilled out cement plug. The lost time was estimated to 384 hours. The water depth was 4475 ft (1364 meters).

2. This failure occurred for a *pre-charged pilot hydraulic system* during BOP testing which was due by time. Prior to entering the BOP's with Frac Pack assembly, they opened the blind/shear rams and observed the accumulator pressure on the Koomey unit to drop to 2,000 psi and pumps running continuously. Switch from the blue pod to the yellow pod. Closed blind/shear rams and monitored the well on the mini trip tank while preparing to pull the riser and LMRP for repairs. Sat a packer in the well and pulled the LMRP. While troubleshooting pods found the connection on the 1" stainless steel tubing to manifold regulator supply on the blue pod that had separated from the compression fitting; replaced same. Also replaced kill line isolation valve operator and tested same to 250 psi low and 10,000 psi high. The lost time for this failure was estimated to 120 hours. The water depth was 2100 ft (640 meters).
3. This failure for a *multiplex control system* occurred when the BOP was on the wellhead.
4. They experienced a leak on the yellow 5K stab. Four to five weeks later, the LMRP was pulled to the rig due to a failure in the upper annular. They then located another leak on a weld at a flange for the blue pod 3 to 5K regulator. No downtime assumed for this failure. The water depth was 3399 ft (1036 meters).

4.8.6 Other Failures

In this study 24 failures are categorized as other failures corresponding to total lost time of 1276.5 hours. Among these 24 failures, 20 occurred for multiplex system, one each for a pilot hydraulic and a pre-charged pilot hydraulic system and 2 for pilot hydraulic, unknown if pre-charged system.

For the multiplex system, 10 failures occurred when the BOP was on the wellhead, six when the BOP was on the rig and four while running the BOP. A short description of these failures is provided below:

1. While running the BOP and riser, problems were encountered with the control system. It is suspected that this occurred after splashing the BOP, but before latching the BOP to the wellhead. After running to about 7500', they detected the first problem in the blue pod. Pulled the riser and BOP, and conducted repair on the LMRP electrical control system. The cause of the failure is unknown. Note that after repairing this failure the BOP was ran twice and pulled back for another failure. The lost time for this failure was estimated to be 228 hours. The water depth was 8061 ft (2457 meters).
2. The BOP was on the rig due to a leak through a choke line. While on the rig they replaced a hose and changed out the stack accumulator. The lost time was 24 hours.

3. After finishing the BOP test ROV inspected the riser, BOP, wellhead & mud line and ran current profile. It confirmed a leak on the blue pod. The leak was repaired 3 weeks later when the BOP was pulled.
4. After the tropical storm Fay the BOP was installation tested on 5” drill pipe. On the lower annular blue pod, they had an improper gallon count. ROV was deployed and confirmed a leak. The failure was also observed some ago but was not fixed. They repaired the leak a month later. No downtime is estimated for this failure.
5. The BOP was on the rig due to a riser leak. Prior to running the BOP they discovered a leak in the yellow pod. The BOP was ready to be run, but was pulled back. They found a leak in the filter housing. Replaced seals and moved back to well centre. The lost time was estimated to 16 hours.
6. While normal well operation, SEM-A on the yellow pod was not working. They got approval to continue with the operations. They lost 24 hours in troubleshooting the failure.
7. While the BOP was on the rig they repaired the BOP hot line. The lost time of 3 hours was assumed.
8. During the test before running the BOP they trouble shot and repaired leaks to the BOP pod.
9. While normal well operation the pilot valve pressure dropped when annular was opened and circulated well down string. Pressure dropped from 2.619 psi to 1.707 psi when closed LBSR. The LMRP was then unlatched and pulled, and problems in pods were identified. They repaired the LMRP, replaced filters on the blue pod, repaired leaking regulator on the blue pod and installed new yellow pod. Also topped off the blue pod with DC-200 and changed out seals on 2 shear valves. The lost time for the failure was estimated to 188.5 hours. The water depth was 4351 ft (1326 meters).
10. While BOP testing on the rig prior to running, they pressured up the system on the yellow pod but observed the shuttle valve leak on the upper annular open and the LPR open. Consequently they replaced the valves. On second attempt observed LBSR open leaking and repaired. On 3rd attempt observed a dielectric fluid and found a collapsed bladder on the yellow rigid conduit manual regulator (3k to 5k). They replaced the bladder and pressured up system and checked for leaks; this time the test was good. Lost time for this failure was 5 hours.
11. After landing the BOP on the wellhead, while testing they discovered a leak in the rigid conduit co-flex line on LMRP. They unlatched and pulled the riser and the BOP stack for repairs. Then replaced and tested the rigid conduit co-flex line on LMRP. Waited a few hours on weather and ran the riser and BOP. The lost time for this failure was 168 hours. The water depth was 4672 ft (1424 meters).
12. While completion activities were going on, the blue pod SEM B failed. They got the approval to continue operations with the blue pod SEM A and the yellow pod SEM A and B.
13. After completing the installation test of the BOP after latching, they had just drilled 10 ft. of new formation and were preparing for taking a FIT. At that time the ROV was inspecting the riser. The ROV found the conduit hot line leaking at 2173' RKB (18 joints below sea level). A decision was made to pull LMRP for repairs. Subsea hands repaired the leak on a Tri-Valve assembly. The lost time for this failure was estimated to 156 hours. The water depth was 6715 ft (1742 meters).

14. The information is limited for this failure. The LMRP was on the rig due to bad weather. Before running the LMRP again they repaired leaks on the LMRP and ran back to the wellhead. The lost time was 12 hours for this failure.
15. They had run 18 JTS of riser when they experienced a communication error with the BOP. Pulled the BOP. The failure was communication problems and ground fault on the blue pod SEM B; repaired same. Also troubleshot ground fault on the yellow pod. Started to run the BOP. The lost time was 72 hours for this failure.
16. The LMRP had been on the rig for repair. While running the LMRP they got a fluid leak alarm on the blue pod. They pulled the riser and LMRP. Repaired the blue pod and function tested. When running the LMRP again, a water intrusion alarm on the blue pod went off. Pulled the LMRP again, repaired and tested the blue pod. The lost time was 72 hours for this failure.
17. While running the BOP they experienced communication problems. The BOP was pulled and the problem was detected on the blue pod. They repaired a ground fault on the blue pod SEM B. Also troubleshot ground fault on the yellow pod and general communication problem with the BOP. The lost time was 60 hours for this failure.
18. The BOP had been on the rig due to a failure of the BOP choke coflexip. When running the stack they observed communication problems with the blue pod SEM B. Pulled the stack and troubleshot the pod problems. They repaired the blue pod and changed out OLM on the blue mux reel. The lost time was 80 hours for this failure.
19. While the BOP was on the wellhead, the BOP high pressure and high temp probe, LMRP high pressure and high temperature probe and subsea accumulator pressure probe failed and are currently not working with either the blue or the yellow pod. Besides these faults, the BOP stack was fully functional.

Only one failure occurred on a pilot hydraulic system.

20. While normal well operation the regulator leaked (probably a limited leak) on the BOP stack. They were instructed to maintain continuous observation of present regulator leak on the BOP stack with a ROV, with instructions to inform of any changes until the well is plugged and secured for abandonment. Later they received verbal approval from MMS to cease continuous BOP stack ROV observation, but maintain the ROV's readiness to deploy, and approval to classify the BOP test extension granted.

The two failures observed on a pilot hydraulic, unknown if pre-charged are briefly described below:

21. While running the BOP, the pod disconnected from the LMRP. Pulled the blue pod and inspected for damages. Re-run the blue pod.
22. While testing the rigid conduit and boost lines when running the BOP, a leak on the rigid conduit line occurred. It is unclear if the BOP was partly pulled or the failure was topside.

The only failure observed for a pre-charged pilot hydraulic system is described below:

23. During the BOP test after running the casing, noticed a leak on the pilot circuit line for the upper annular open function. They got approval to continue with operations. With

this condition, there was no loss of function to the upper annular. However, to prevent the leak from worsening, they requested to operate with the upper annular in the open/block position. The upper annular will close from this position and open without problems. Once opened, they will place the function in open/block position to control the leak in pilot circuit.

4.8.7 Failure Mode "Unknown"

Of nine failures observed with the failure mode "unknown", only one was experienced for a pilot hydraulic system and the rest occurred on multiplex systems. The pilot hydraulic system failure is described below:

1. During the installation testing of the BOP they troubleshot BOP control problems and found pod valve hydraulically locked.

The multiplex control system failures are described below:

2. This failure has a limited description. It is believed that the failure belongs to the control system, but it may also belong to the choke and kill lines. During the normal well operation they troubleshot leak on the BOP system. Then they sat packer in the well and pulled the LMRP. The WAR remarks further states *"Trouble shot leak & repaired same"*. The lost time was 168 hours for this failure and water depth was 3399 ft (1036 meters).
3. The BOP was on the rig for repair when a problem in the fiber optic was identified. WAR remarks states *"Terminate MUX cable on reel & yellow pod. Troubleshoot & repair fiber optic communication problems"*. No further detail available.
4. During the function testing of the BOP, the blue pod flow counter was found not working
5. It is uncertain what actually occurred however it is believed that the blue pod hot line reel was repaired. The effect on the BOP functionality was also unknown. This failure was detected during running of the BOP and they pulled the riser and repaired the blue pod hot line reel. While repairing the reel, they found ground faults in both pods. The lost time for this failure was 6 hours.
6. While running the BOP they experienced problems with the blue pod. Pulled the BOP after running to 122' and repaired the pod. The lost time for this failure was estimated to 12 hours.
7. The LMRP was on the rig due to Hurricane Ike. During "damage assessment" they tested the choke & kill lines, boost lines and repaired a blue pod electrical issue. In addition they repaired the BOP electrical problems and troubleshot electrical components on the yellow pod. The lost time for this failure was estimated to 120 hours.
8. Before running the BOP they repaired a pod and spent 24 hours as lost time. No other detail is known about failure.
9. While the BOP was on the wellhead they troubleshot the yellow pod SEM A and corrected problem.

4.8.8 Manufacturer Exposure and Rig Specific Failure Rates

Table 4.10 shows an overview of the different manufacturers and operating principles in the study.

Table 4.10 Overview of manufacturer exposure time

Manufacturer & Operating Principle	BOP-days
ABB	**511**
Multiplex electro hydraulic	511
Cameron	**4601**
Multiplex electro hydraulic	2938
Pilot hydraulic	49
Pilot hydraulic, unknown if pre-charged	559
Pre-charged pilot hydraulic	1055
Cameron - Payne	**80**
Pilot hydraulic	80
Honeywell/Valvecon	**571**
Multiplex electro hydraulic	571
Hydril	**3994**
Multiplex electro hydraulic	3994
Koomey	**595**
Pilot hydraulic	442
Pilot hydraulic, unknown if pre-charged	153
NL Shaffer	**1475**
Multiplex electro hydraulic	1048
Pilot hydraulic	427
Shaffer	**2446**
Multiplex electro hydraulic	1223
Pilot hydraulic, unknown if pre-charged	532
Pre-charged pilot hydraulic	691
Unknown	**783**
Multiplex electro hydraulic	592
Pilot hydraulic, unknown if pre-charged	191
All	**15056**

The control system performance for the 42 rigs included in the study showed a highly variable failure rate and downtime per BOP-day in service, as illustrated in Figure 4.5. The “dotted” line represents the average failure of all the rigs. Here, note that Figure 4.5 is sorted on rigs with highest failure rates. As it can be seen that confidence intervals re overlapping, hence no significant difference in performance is observed.

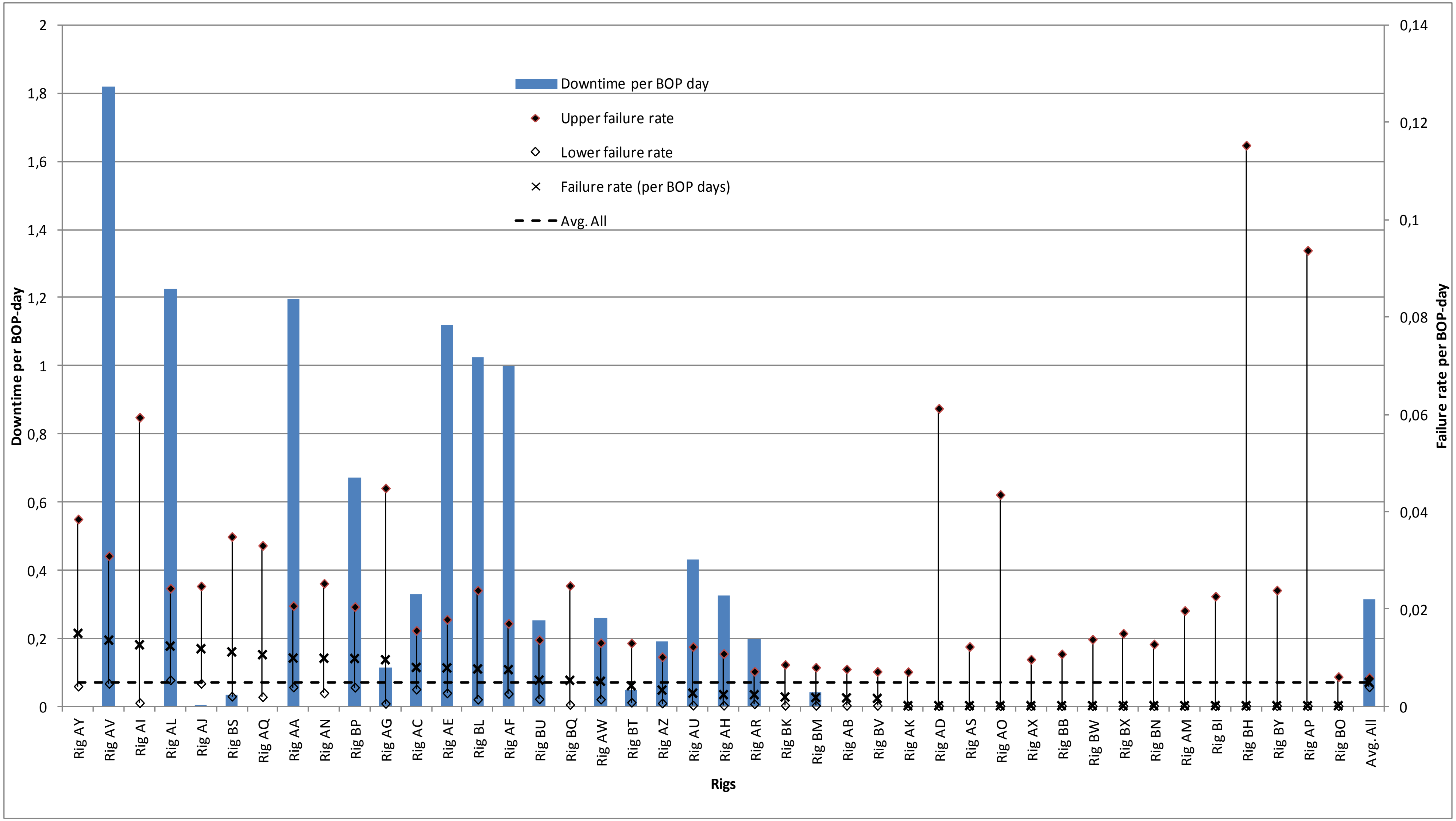


Figure 4.5 Rig specific control system performance

4.8.9 Age of Multiplex Control System vs. Reliability

It is a general assumption that new versions of equipment also will be more reliable. Therefore it can be assumed that the new generation of multiplex control systems are more reliable than older generations. In an attempt to investigate this, the Mux control systems of the BOPs of this study are categorized into three groups according to their age as shown in Table 4.11. The categorization is based on the rig built year or upgrade year, whichever comes latest. It is assumed here that whenever the rig was built or upgraded, the latest Mux control system is installed.

The MTTF figures in Table 4.11 indicate there is no specific trend within the Mux control system reliability. The MTTF of category "2007-2009" is lower than the other two but note that average water depth is also high compared to other two categories. Further, infant mortality may also be responsible for early life failures.

Table 4.11 Comparison of Mux control system

Parameter	Mux system category based on installation year			
	1998-2000	2001-2004	2007-2009	Total
BOP-days	6653	2840	1384	10877
No. of failures	29	15	11	55
MTTF (BOP-days)	229	189	126	198
Total lost time (hrs.)	2222	647	1098	3967
Lost time per BOP-days (hrs.)	0,334	0,228	0,793	0,365
Average Water depth (ft.)	4897	5498	6902	5276

Similarly the lost time per BOP-days for category 2007-2009 is fairly high than the other two. It is noted that 7 out of eleven failures under category 2007-2009 occurred during running of the BOP to wellhead. Strangely, all of these failures occurred on the blue pod.

In Table 4.12 failure modes observed for three different categories are presented. It appears that "loss of all function one pod" and "loss of one function one pod" has decreased after 1998-2000. However note the BOP-days in service for these is also less and on average no significant difference can be observed.

Table 4.12 Comparison of Mux control system Failure modes

Failure mode	Assumed Mux system category			
	1998-2000	2001-2004	2007-2009	Total
Loss of all functions both pods	1			1
Loss of all functions one pod	9	2	2	13
Loss of one function both pods	3	1		4
Loss of one function one pod	6	2	1	9
Loss of several functions one pod		1		1
Other	7	7	5	19
Unknown	3	2	3	8
Total no. of failures	29	15	11	55

In summary no significant difference between three categories is observed as shown in Figure 4.6 where confidence intervals of these groups are overlapping.

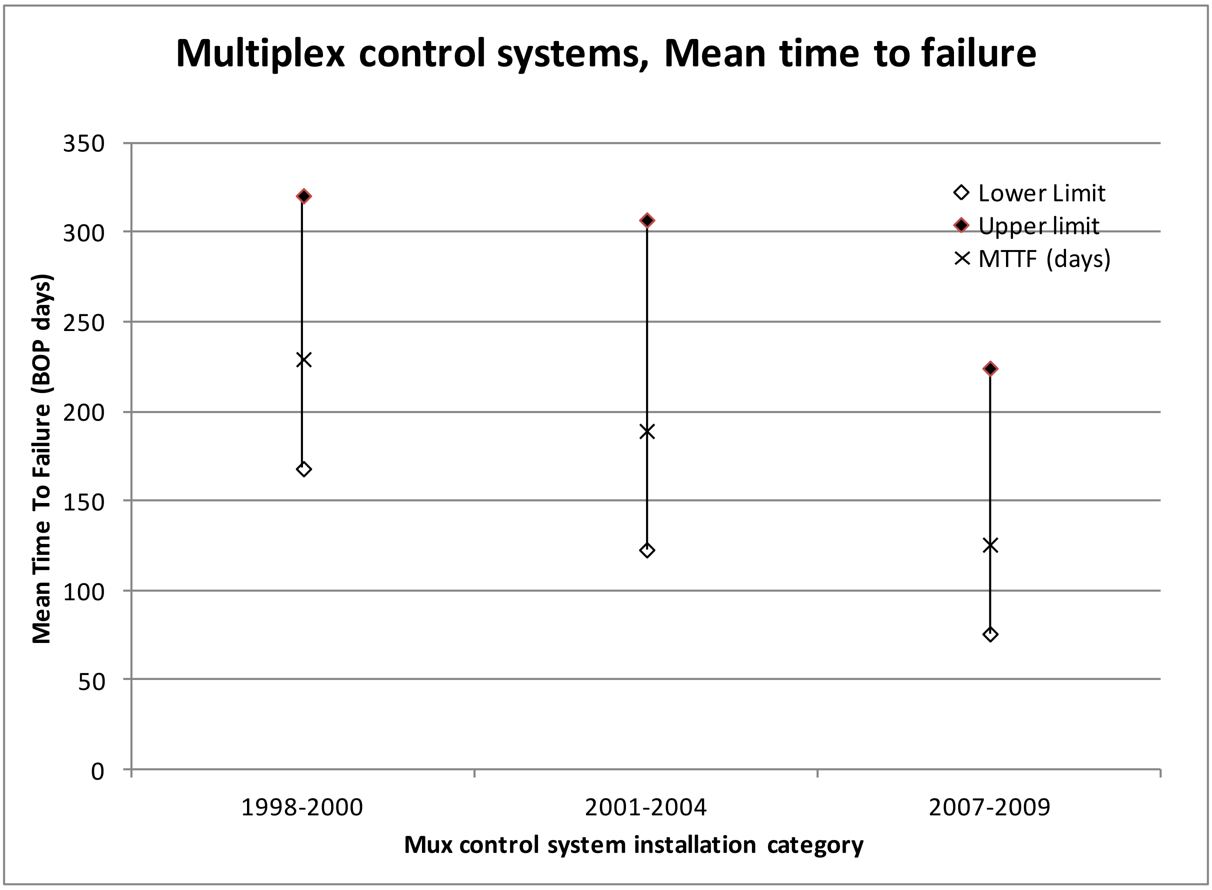


Figure 4.6 Mean Time to Failure comparison of Mux system with 90% confidence interval

5 Failure Criticality in Terms of Well Control

Failures that occur when the BOP is on the rig, during running of the BOP or during the installation testing are not regarded as critical failures in terms of well control. During these phases of the operation the BOP is not acting as a well barrier. After the installation testing is completed and accepted, the drilling starts and the BOP acts as a well barrier. All failures that occur in the BOP after the installation test are regarded as safety critical failures. The criticality of each failure will of course depend on what part of the BOP system that fails and the failure mode. This chapter discusses failure detection and failure criticality in terms of well control.

5.1 When are BOP Failures Observed?

Table 5.1 presents the location of the BOP and the tests during which the various BOP failures occurred.

Table 5.1 Observation of BOP failures

BOP subsystem	BOP is on the rig		While running (or pulling) BOP			BOP is on the wellhead					Total
	Test prior to running the BOP	Other/-unknown	Test while running BOP	Normal operation	Other/-unknown	Installation test	Test after running casing or liner	Test scheduled by time	Normal operation	Other/-Unknown	
	Safety non-critical failures						***Safety critical failures***				
Flexible joint									1		1
Annular preventer	3	1				6	2	5	7		24
Ram preventer	4	1				8	5	4		1	23
Connector, LMRP	1								2		3
Connector, WH	1					2	1		1		5
Choke & kill valve			1			2	1				4
BOP attached line		1	2			2					5
Riser attached line			4			1	1	2	3		11
Jumper hose line						1					1
Multiplex electro hydraulic	7	4	5	3	1	7	2	9	16	1	55
Pilot hydraulic control system	1			1	1	4	2	4	4		17
Dummy item	3				1	2	1				7
Total	20	7	12	4	3	35	15	24	34	2	156
	17%		12%			71%					

As seen from Table 5.1, 17% of the failures occurred when the BOP was on the rig prior to running the first time, or subsequent time. Approximately 12 % of the failures occurred during running of the BOP and the remaining 71% when the BOP was on the wellhead. Of the 110 failures that occurred when the BOP was on the wellhead, 35 occurred during installation testing and the remaining 75 during regular BOP tests or during normal operations.

An installation test is defined as the BOP test after landing the BOP the first time or during subsequent landings of the BOP or the LMRP.

5.2 Safety Critical Failures

This section discusses the safety critical failures shown in Table 5.1.

5.2.1 BOP Item, Safety Critical Failures

Table 5.2 shows the safety critical failures in flexible joints, annular preventers, ram preventers and hydraulic connectors.

Table 5.2 Safety critical failures in the flexible joints, annular preventers, the ram preventers and the hydraulic connectors

Failure mode distribution	No. of failures	Total lost time (hrs)	No of BOP-days	No. of items day	Average downtime pr BOP day (hrs)	MTTF (Item days in service)		
						Lower limit	Mean	Upper limit
Flexible joint								
External leakage	1	288	15056	15056	0,019	3174	15056	293528
All	**1**	**288**	**15056**	**15056**	**0,019**	3174	15056	293528
ANNULAR PREVENTER								
Failed to close	1	268	15056	28150	0,018	5934	28150	548805
Failed to fully open	8	84	15056	28150	0,006	1950	3519	7071
Internal leakage (leakage through a closed annular)	4	712	15056	28150	0,047	3075	7038	20603
Unknown	1	0	15056	28150	0,000	5934	28150	548805
All	**14**	**1064**	**60224**	**112600**	**0,071**	**5145**	**8043**	**13304**
RAM PREVENTER								
Failed to close	1	6	15056	77264	0,000	16287	77264	1506318
Failed to fully open	1	24	15056	77264	0,002	16287	77264	1506318
Internal leakage (leakage through a closed ram)	7	660	15056	77264	0,044	5876	11038	23518
Other	1	0	15056	77264	0,000	16287	77264	1506318
All	**10**	**690**	**60224**	**309056**	**0,046**	**18220**	**30906**	**56965**
CONNECTOR, LMRP								
Failed to lock	1	168	15056	15056	0,011	3174	15056	293528
Spurious unlock	1	24	15056	15056	0,002	3174	15056	293528
All	**2**	**192**	**30112**	**30112**	**0,013**	**4783**	**15056**	**84736**
CONNECTOR, Wellhead								
External leakage (leakage to environment)	1	96	15056	15056	0,006	3174	15056	293528
Failed to unlock (includes all incidents with problems unlocking connector)	1	96	15056	15056	0,006	3174	15056	293528
All	**2**	**192**	**30112**	**30112**	**0,013**	**4783**	**15056**	**84736**
DUMMY ITEM								
Unknown	1	192	-					
All	1	192	-					
BOP system total	**30**	**2618**	**15056**		**0,174**			

Flexible joint

Flexible joint failures are rare. One flexible joint external leakage failure occurred in the safety critical period. The flexible joint is not an element that shall be able to withstand the well pressure, only the differential hydrostatic pressure between the mud column and the seawater.

When a leak occurs in the flexible joint, mud in the riser will leak out until it has equalized with the hydrostatic pressure of the seawater. Many deepwater wells will then kick because they are drilling without a riser margin. In this case the well did not kick. In the previous study (/1/) a similar failure occurred. The well then immediately kicked. With the flexible joint leaking it was also a more difficult operation to control the kick. No safety critical flexible joint failure occurred in Phase I DW (/3/).

Annular preventers
One annular preventer failure with the failure mode “failed to close” occurred. This is a rather rare failure mode for annular preventers. In the previous study no failure occurred with this failure mode.

Due to ballooning and losses, they attempted to bullhead mud down the annulus and at that time, the annular preventer failed to actuate. The annular preventer was then flushed from kill line and attempted to close the annular again by increasing the closing pressure, but failed. The annular was repaired approximately one month later.

Four of the annular preventer failures were *Internal leakages.* For three of the four failures the LMRP was pulled to repair the annular preventer. For the forth failure the LMRP was pulled due to a hurricane just after the failure occurred. It was not stated in the WAR reports, but it is likely that the annular element was replaced then. This failure was not associated with any downtime in our report.

Eight out of the 14 annular preventer failures were observed as *Failed to fully open failures*. These failures are not regarded as failures that reduce the safety availability.

For the *Unknown* failure mode it was reported several times that they recovered annular rubber. It was not reported that the annular leaked.

Ram preventers
Ten ram preventer failures occurred in the safety critical period.

One *Failed to close* failure occurred. They were doing the function testing of the BOP when it was on the wellhead. The upper pipe ram did not close when attempted to close with the yellow pod. Then they repeated the test from the blue pod with the same result. However, after that the failure seemed to disappear. No more information about the failure was found.

One *Failed to fully open* failure occurred. The failure occurred during a pressure test scheduled by time. The test ram failed to fully open. They cut the test ram hard piping and continued the operation. This ram do not have a barrier function in the BOP.

Seven failures were *Internal leakage* through a closed ram. Two of the failures occurred on a BOP test ram, and were not repaired.

Two of the failures occurred at the same time, both the upper and the lower variable bore ram were leaking.

One of the failures occurred in a blind shear ram. They failed to test the casing against the blind shear ram. They found the lateral seal missing on both sides.

One variable bore ram failed on a test after circulating out a kick, and one variable bore ram failed during testing the BOP after running the casing.

One failure was in the *Other* category. For this failure it took several attempts and high closing pressure of 2300 psi to get the test on the VBR.

The failures in the critical period in the Phase II DW (/1/) study included two *failed to open failures* that were caused by locking system problems. This failure mode seems to have disappeared. The failing test ram failures have not been observed in the previous BOP studies, because test rams were not represented.

In the Phase I DW (/3/) study, a failed to shear pipe occurred during an emergency disconnect. For the two emergency disconnect situations observed in this study, the blind shear rams successfully cut the pipe and sealed off the well.

Hydraulic connectors

The most critical failure in a hydraulic wellhead connector is *External leakage* during normal drilling operations. It is not uncommon to see these failures on the installation test, but the installation test shall reveal such a failure. One external leakage incident occurred in this study. The failure occurred during a test after running the casing. A MMS district investigation was carried out after the incident (/9/). The incident caused a leakage of 10 bbls of mud to the sea. If a kick had occurred it is likely that the well fluid would have leaked out through this connector and a blowout would result.

This failure mode was not observed in the safety critical period in the Phase II DW study, but in the Phase I DW such a leakage occurred in the wellhead connector during a regular BOP test after running 13 5/8" casing.

One time they *failed to unlock* a wellhead connector. It is likely that this was caused by hydrates because they pumped methanol and glycol to be able to open the connector. This is not regarded as severe failure from a safety point of view when it occurs in a wellhead connector. If such a failure occurs in a LMRP connector it can be critical in association with an emergency disconnect. No failed to unlock LMRP connector failures occurred in the safety critical period.

Once they had problems with locking the LMRP connector. They had to pull the LMRP to rectify the problem.

Once they had a spurious disconnect of a LMRP connector. This failure occurred during temporary abandoning a well. When the incident occurred the well was secured, but if the failure had occurred during drilling it could have caused a blowout when the LMRP was inadvertently unlatched. The failure cause is unknown. It is not known if this was a human error, control system failure or a connector failure. It does not seem that the BOP had an autoshear system. The control of the BOP was lost when disconnecting. If this incident had occurred during drilling in well without a riser margin, the well would immediately blow out. A similar incident occurred in the US GoM OCS 28th of February 2000 that resulted in a blowout.

5.2.2 Choke and Kill Valves and Lines, Safety Critical Failures

Table 5.3 shows the safety critical failures of the choke and kill valves and choke and kill lines.

Table 5.3 Safety critical failures in the choke and kill valves and choke and kill lines

Failure mode distribution	No. of failures	Total lost time (hrs)	No of BOP-days	No. of items day	Average downtime pr BOP day (hrs)	MTTF (days in service)		
						Lower limit	Mean	Upper limit
CHOKE & KILL VALVE								
Internal leakage (leakage through a closed valve)	1	0	15056	160310	0,000	33793	160310	3125360
All	**1**	**0**	**15056**	**160310**	**0,000**	**33793**	**160310**	**3125360**
BOP attached line								
All	0	-	15056					
RISER ATTACHED LINE								
External leakage (leakage to environment)	6	924	15056	15056	0,061	1271	2509	5762
All	**6**	**924**	**15056**	**15056**	0,061	1271	2509	5762
Jumper hose line								
All	0	-	15056					
Choke & kill system total	**7**	**924**	**15056**	**15056**	**0,061**	**1145**	**2151**	**4583**

The frequency of safety critical failures was approximately the same in this study as in Phase II DW (/1/). The failures that occurred in the Phase I DW (/3/) were, however, more severe from a safety point of view.

Choke and kill valves

The only safety critical failure observed in a choke and kill valve was a leakage through a closed valve. This failure was detected while testing the BOP after running casing. They got approval to continue ahead with drilling operations with a leak in the lower outer kill valve in closed position. No lost time was assumed for this failure.

The failure mode *external leakage* in a choke and kill valve was not observed in this study or in the Phase II DW study (/1/) in the safety critical period. In Phase I DW (/3/) one *External leakage* in the connection between the lower inner kill valve and the BOP occurred when testing the BOP after running the 13 3/8" casing. This is a very critical failure when occurring in the outlet below the LPR.

Choke and kill lines

Six failures occurred in the choke and kill lines in the safety critical period. This is approximately the same frequency as observed in the Phase II DW study.

A kill line leak was detected between 2nd and 3rd riser joint (2614'). They took the kill line out of service and continued to log the well, run production liner, and displace the well with completion fluid, prior to pulling the riser and repair kill line.

One failure occurred while they were not drilling, but doing the repairs on the surface. The ROV inspection found leak between Jt.7 and #8 at 7449'.

Another failure was detected through testing of the BOP against casing. The kill line was found leaking but only on low pressure. They subsequently repaired with Seal-Tite and retested and continued the well operations. After 4 days, when the BOP was latched back after bad weather, and the BOP was tested a leak was again observed.

Further, a failure occurred while they were circulating the well. An ROV inspection discovered that kill line seals between riser joints 7 and 8 were leaking. They tried to stop the leak with Seal-Tite, but were not successful.

Another failure occurred when they were testing the BOP and found a leak in the choke & kill line (leaking only on low psi tests). They stopped the leakage with Seal-Tite and retested to 250/7500 psi.

The last safety critical failure of this type occurred during a BOP test. They found seals on kill line between riser joint #7 and #8 leaking. Pumped Seal-Tight two times before it worked.

All these failures reduce the BOP safety availability. However, the most important factor is that these failures will cause extra problems in case a kick has to be circulated out of the well.

5.2.3 Control System, Safety Critical Failures

Table 5.4 shows the safety critical failures that occurred in the BOP control systems during the study.

Table 5.4 Safety Critical Failures in the BOP Control Systems

Failure mode distribution	No. of failures	Total lost time (hrs)	No of BOP-days	Average downtime pr BOP day (hrs)	MTTF (days in service)		
					Lower limit	Mean	Upper limit
Multiplex electro hydraulic							
Loss of all functions both pods	1	192	10942	0,018	2307	10942	213322
Loss of all functions one pod	8	1472,5	10942	0,135	758	1368	2749
Loss of one function both pods	4	168	10942	0,015	1195	2736	8008
Loss of one function one pod	6	144	10942	0,013	924	1824	4188
Loss of several functions one pod	1	0	10942	0,000	2307	10942	213322
Other	6	368,5	10942	0,034	924	1824	4188
Unknown	2	168	10942	0,015	1738	5471	30791
All	**28**	**2513**	**10942**	**0,230**	**285**	**391**	**550**
Pilot hydraulic control system							
Loss of all functions one pod	1	72	4114	0,018	867	4114	80205
Loss of one function both pods	2	0	4114	0,000	653	2057	11577
Loss of one function one pod	3	1	4114	0,000	531	1371	5031
Loss of several functions one pod	2	504	4114	0,123	653	2057	11577
Other	2	0	4114	0,000	653	2057	11577
All	**10**	**577**	**4114**	**0,140**	**243**	**411**	**758**
BOP control system total	**38**	**3090**	**15056**	**0,205**	**302**	**396**	**529**

The overall MTTF for critical failures in control systems was significantly less in this study compared to the Phase II DW (/1/) and Phase I DW studies.

The critical failure mode *Loss of all functions both pods* was only observed one time in this study, one time in Phase II DW and five times in Phase I DW (/3/). When also considering the much higher number of days in service in this study compared to the previous studies, this is a significant improvement.

The majority of failures of this type in the Phase I study stemmed from multiplex systems. At that time (early 90-ties), the multiplex systems seemed to be more prone for this failure mode. With only one such failure it seems that today's multiplex systems are better with respect to this failure mode.

The failure mode *spurious operation of a BOP function* was not observed during the safety critical period. It should here be noted that once a LMRP connector opened spuriously, but the cause was not known, and the failure was regarded as a connector failure, but this may have been caused by a control system failure. In the Phase II DW study, two failures occurred were the LMRP connector opened spuriously.

Brief failure description

The ***Loss of all functions both pods*** failure occurred in a multiplex system. The rig changed top drive system during this time and suddenly they lost the communication with the BOP stack for a time window of unknown length. They were only able to re-establish the communication with the blue pod SEM B and the blue pod SEM A, the yellow pod SEM A and B all failed. They then displaced the riser and choke & kill lines with sea water and attempted to pull the LMRP, but failed. The LMRP was then retrieved through ROV intervention. The unsuccessful unlatching of LMRP is also assumed to be due to control system failure. The failure cause is unknown. After pulling the LMRP they repaired the control system and re-ran the riser and LMRP. The lost time for this failure was estimated to 192 hours and the water depth was 5282 ft (1610 meters).

Nine ***Loss of all functions one pod*** failures occurred in the safety critical period. Eight occurred on a multiplex control system and one in a pilot control system.

In the multiplex systems four of the *loss of all functions one pod* occurred due to hydraulic leaks in one of the pods. Two were caused by pod umbilical and terminations. For the two remaining failures, the cause of the failure was not described in the well activity reports.

The failure in the pilot hydraulic system was caused by a hydraulic leak.

The failure mode ***Loss of several functions one pod*** failure occurred three times in the safety critical period. Two of the failures were in a pilot control system, and one in a multiplex control system. Two of the failures were caused by faulty regulators, one in a multiplex system and one in a pilot system. For the third failure there were four damaged areas on the yellow pod line.

Six ***Loss of one function both pods*** failures occurred, three one a multiplex system and two on a pilot hydraulic system. Three of the failures were related to the operation of choke and kill valves. The function was typically blocked and they got a waiver to continue with the operation. The function of an annular preventer was also blocked due to a leak. One failure prevented the upper variable bore ram from closing due to a shuttle valve failure. The last failure was related to retraction of the yellow pod. They failed to retract the pod when pulling the LMRP.

The failure mode ***Loss of one function one pod*** occurred nine times in the safety critical period, six times for a multiplex control system and three times for a pilot hydraulic system. These failures cause fail to operate a valve or preventer on one pod, while it functions on the other pod. In many cases they got an approval to continue the operation with such a failure present, depending on what specific function is affected and the operations carried out.

Nine failures were listed with ***Other*** as the failure mode, seven in a multiplex system and two in a pilot control system.

Other failures:
Three times there were leaks in the system, but they could still operate the BOP functions.
For one leak in the rigid conduit line they pulled the LMRP to repair the leak. It seems that the BOP was still fully functional when pulling the LMRP. Two of these failures were related to a pilot control system and one to a multiplex control system.

The remaining *Other* failures all occurred in multiplex control systems.

Two of the other failures were related to a failure in one of the SEMs in the pod. The other SEM was still fully functioning.

One failure was related to failure of the BOP pressure and temperature signals, but otherwise the BOP was fully functioning.

For one failure the pilot pressure dropped strangely, but it was not identified as a failure of any function. They pulled the LMRP, identified and repaired the failure.

Two failures in a multiplex control system were listed with the failure mode ***unknown.***

5.3 Ranking of Failures with Respect to Safety Criticality

The frequency of safety critical failures that occurred in this study is less than the frequency observed in the Phase II DW and Phase I DW study, however, severe BOP failures still occur.

In this study the most severe failure - leakage in the wellhead connector occurred once.
Further, a spurious disconnect of a LMRP connector occurred and a control system incident that caused the total loss of the BOP occurred.

Table 5.5 lists a coarse ranking of the failures that occurred in the safety critical period in this study. The same ranking from the previous studies, Phase II DW and Phase I DW, is presented alongside. It should be noted that the number of BOP-days in service in the present study is twice as high as the two other studies together.

Table 5.5 Coarse ranking of failures occurring in the safety critical period according to severity

<table>
<tr><th colspan="2">This study</th></tr>
<tr><td colspan="2">1. One failure causing wellhead connector external leakage
2. One spurious opening of the LMRP connector (Unknown cause, no autoshear in BOP)
3. One control system failure that caused total loss of the BOP control
4. One shear ram leakage in closed position
5. Upper and lower variable bore ram leaked at the same time
6. Two incidents, pipe ram failed to close
7. Nine incidents, loss of all functions one pod
8. Two incidents, pipe rams leaked in closed position
9. One flexible joint external leak
10. One failed to close annular incident
11. Four incidents, annular preventer leak
12. Six choke and kill line leaks
13. Five incidents with loss of one function both pods</td></tr>
<tr><th>Phase I DW BOP study (/3/)</th><th>Phase II DW BOP study (/1/)</th></tr>
<tr><td>1. One failure causing wellhead connector external leakage
2. One failure where they failed to shear the pipe during a disconnect situation
3. One external leakage in the connection between lower inner kill valve and the BOP stack
4. Five failures that caused total loss of the BOP control by the main control system
5. Two shear ram leakages in closed position
6. Two failures to disconnect the LMRP
7. Seven failures that caused loss of all functions one pod
8. One UPR leakage
9. One spurious closure of the shear ram
10. Three annular preventers that leaked in closed position
11. Six choke and kill line leakages</td><td>1. One control system failure that caused total loss of the BOP control
2. One spurious opening of the LMRP connector (control system failure)
3. One shear ram failed to close
4. One shear ram leak in closed position
5. Two failures to open pipe ram
6. Two failures where the pipe ram leaked in closed position
7. External leak in flexible joint
8. One failure to disconnect the LMRP
9. Four failures that caused loss of all functions one pod
10. Loss of one function both pods (annular close)
11. Four annular preventer leaks in closed position
12. One choke and kill line leak (jumper hose)</td></tr>
</table>

6 BOP Testing Experience

In the original scope for this study, it was planned to collect data related to BOP testing. The primary source of information on BOP testing is the daily drilling report (DDR) system. In this study, only one of the operators provided DDRs. In Table 6.1 the number of pressure tests, average test time and time spent per BOP-day is presented for three rigs.

The average test time is estimated to be 13.06 hours per test in this study corresponding to average water depth of 4650 ft. The average test time figure is in the same range as was observed during the Phase II DW study (/1/) i.e. 13.9 hours per pressure test with 2947 average water depth.

Table 6.1 No. of BOP subsea tests and test time consumption

Rig	BOP-days in Service	Total no. of tests	Total time spent on pressure testing	Average test time (hrs)	Average Water Depth (ft)	Test time per BOP-Day
Rig BP	516	38	580	15,26	5052	1,12
Rig AR	888	68	804,5	11,83	4419	0,91
Rig AZ	625	3	39,5	13,17	4839	0,06
Total	2029	109	1424	13,06	4650	0,70

In addition to above listed pressure tests 67 function tests with a total test time of 54.25 hours were observed. This gives 0.81 hours per function test.

Rig AZ was equipped with a test ram, but unfortunately there was only one well this rig drilled for Operator AP. For the three tests carried out the test rams were not used.

Table 6.2 shows the average time spent on BOP testing with different test tools for this study.

Table 6.2 Test tools used for subsea BOP testing

BOP pressure test tool type	No. of tests	Total test time	Average test time
Casing pack off tool	14	95,5	6,82
Combined test tool	78	1084	13,89
Conventional test tool (requires wear-bushing)	14	234	16,71
Unknown	3	10,5	3,5
Total	109	1424	13,06

Due to the small sample size, rig specific performance and impact of depth on testing time are not evaluated.

7 Secondary Intervention Systems Installed on Subsea BOPs

7.1 What are the Requirements for a Subsea BOP System?

The "*Code of Federal Regulations, Title 30 CFR 250.442*" outlines the statutory requirements for a subsea BOP. These requirements changed October 14th 2010. Before then a requirement from 2003 was valid.

Below the present valid requirement and the requirement from 2003 are presented.

§ 250.442 What are the requirements for a subsea BOP system? (Valid October 2010)
When you drill with a subsea BOP system, you must install the BOP system before drilling below the surface casing. The District Manager may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need. The table in this paragraph outlines your requirements.

When drilling with a subsea BOP system, you must:	*Additional requirements*
(a) Have at least four remote-controlled, hydraulically operated BOPs.	*You must have at least one annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures.*
(b) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system.	
(c) Have an accumulator system to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface.	*The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). The District Manager may approve a suitable alternate method.*
(d) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability.	*At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind-shear rams and un-latching the LMRP.*
(e) Maintain an ROV and have a trained ROV crew on each floating drilling rig on a continuous basis. The crew must examine all ROV related well control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations.	*The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack.*
(f) Provide autoshear and deadman systems for dynamically positioned rigs.	*(1) Autoshear system means a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP. When the autoshear is armed, a disconnect of the LMRP closes the shear rams. This is considered a "rapid discharge" system.* *(2) Deadman System means a safety system that is designed to automatically close the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a "rapid discharge" system.* *(3) You may also have an acoustic system.*
(g) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions.	*Incorporate enable buttons on control panels to ensure two handed operation for all critical functions.*
(h) Clearly label all control panels for the subsea BOP system.	*Label other BOP control panels such as hydraulic control panel.*

When drilling with a subsea BOP system, you must:	Additional requirements
(i) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system.	*The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.*
(j) Establish minimum requirements for personnel authorized to operate critical BOP equipment.	*Personnel must have: (1) Training in deepwater well control theory and practice according to the requirements of 30 CFR 250, subpart O; and (2) A comprehensive knowledge of BOP hardware and control systems.*
(k) Before removing the marine riser, displace the fluid in the riser with seawater.	*You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition.*
(l) Install the BOP stack in a glory hole when in ice-scour area.	*Your glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.*

[75 FR 63373, Oct. 14, 2010]

§ 250.442 What are the requirements for a subsea BOP stack? (Valid 2003 -2010)

(a) When you drill with a subsea BOP stack, you must install the BOP system before drilling below surface casing. The District Supervisor may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need.

(b) Your subsea BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams.

(c) You must install an accumulator closing system to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). The District Supervisor may approve a suitable alternative method.

(d) The BOP system must include an operable dual-pod control system to ensure proper and independent operation of the BOP system.

(e) Before removing the marine riser, you must displace the riser with seawater. You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition.
[68 FR 8423, Feb. 20, 2003]

When comparing the regulation from 2010 with the regulation from 2003 it can be observed that the 2003 regulations did not include specific requirements related to ROV operability and autoshear and deadman systems for the BOP. Although this was not a specific requirement in the regulations many of the rigs had this capability.

7.2 Secondary Intervention Systems

The back-up systems utilized will vary among the different manufacturers and the rigs. The report (/12/) lists the following main BOP back-up control systems.

ROV; remotely operated vehicle (ROV) intervention capability. Can typically activate the BS ram, other ram and disconnect the LMRP connector

EDS (Emergency Disconnect System); Activates at least one shear ram to seal the well and disconnect the LMRP connector from the BOP stack. EDS is mostly used for loss off position incident for DP rigs.

Deadman; Initiates automatic if losing power signals and hydraulic supply to the BOP. Closes at least one blind shear ram and disconnect the LMRP from the BOP stack

AMF (Automatic Mode Function); similar to the Deadman system

Acoustic back-up controls; Separate control system for selected functions. Activates by sending acoustic signals from the rig, or alternatively another vessel. Powered by a dedicated accumulator bank. No automatic activation.

EH (Electro Hydraulic) Backup; Separate controls activated by electro hydraulic signals manually

Autoshear; automatic shear if LMRP disconnects spuriously

7.3 Emergency use of Secondary Intervention Systems in the Current Study

Secondary intervention systems are systems seldom used or tested when they are in service.

During this study, the EDS secondary intervention systems were used twice. One on Rig AR, 2nd of December 2007 and one on Rig BS 26th of April 2010. Both were initiated by loss of position due to problems with the DP systems. Both incidents resulted in an EDS. The pipe was cut and the LMRP connector was disconnected as it should on both occasions. For the first of these incidents a MMS District investigation report was issued.

Further, the ROV functions have been used at least two times in association with disconnecting a LMRP connector and disconnecting a wellhead connector.

Otherwise, no activation of emergency systems for BOPs was observed during the study.

7.4 Rigs and Secondary Intervention Systems

During the study we have reviewed the Application for permit to drill (APD) for the wells drilled in 2007 – 2009 and the “new” APDs for deepwater wells approved after the Deepwater Horizon accident in an attempt to identify the secondary intervention systems used on the rigs included in the study.

The data we found were incomplete for many of the rigs, and we therefore sent a request to all the drilling contractors represented with at least one rig in the study for additional information.

Only one of the drilling contractors answered the request. The rest of the drilling contractors did not answer at all, or promised to send an answer that never came.

In addition some information was found other places as in the drilling contractor's web pages and in investigation reports from the MMS.

The following pages present four tables related to secondary intervention systems for the various BOPs;

- Table 7.1 Secondary intervention systems 2007 – 2009 for anchored semisubs
- Table 7.2 Secondary intervention systems 2007 – 2009 for DP operated drillships with multiplex control systems
- Table 7.3 Secondary intervention systems 2007 – 2009 for DP operated semisubmersibles with multiplex control systems
- Table 7.4 Rigs where no info about backup systems were found or submitted

Table 7.1 shows an overview of the secondary intervention systems identified for anchored semisubmersible rigs. Seven of these rigs were equipped with a pilot hydraulic BOP control system. Of these seven rigs two did not have any ROV intervention possibilities, while the remaining five had. One of these rigs also had a hydraulic deadman/autoshear system, while the other five did not seem to have such a system. One of these rigs was equipped with an acoustic back-up system. There was no reference to testing of the acoustic back-up system in the well activity reports indicating that it was not in use for the current well. Acoustic backup systems have been required in Norway since 1981 and are tested regularly during operation to verify the function.

Eight of the anchored semisubmersibles were equipped with a multiplex control system. One of the anchored rigs with a multiplex control system did not seem to have ROV intervention possibilities in the period 2007 – 2009, while the remaining had. The new APDs, from after the Deepwater Horizon accident, indicates that ROV functions were implemented on the rig after this accident. This specific rig did however have both autoshear and a deadman. Three of the other anchored rigs with a multiplex control system had deadman and autoshear as well.

For the remaining anchored rigs with a multiplex control system, no deadman or autoshear was mentioned. So these rigs may or may not have had such a system.

Table 7.1 Secondary intervention systems 2007 – 2009 for anchored semisubs

Rigname	Rig build or upgraded	Control system type	Backup system description	Data source	Funtions for use 2007 - 2009				
					EDS	Dead-man	Auto-shear	ROV	Acou-stic
Rig AX	1974	Pilot hyd	ROV Intervention for; • Wellhead connector Unlock • Riser Connector Unlock • Shear rams close • One piperam close	Contrac-tor O				Yes	
Rig AQ	1983	Pilot hyd	During a spurious opening of the LMRP connector in this study, it seemed that the BOP was open, i.e. no autoshear included. They used ROV when normalizing the situation.	War			No	Yes	
Rig BX	1985	Pilot hyd	Deadman (Auto-Shear) functions (hydraulic). 12 ea. 40 gallon bottles, 4 for the main BOP control system and 8 dedicated to the dead-man/Auto-shear system. LMRP 1 ea. ROV Intervention Panel	Old APD		Yes	Yes	Yes	
Rig AH	1996	Pilot hyd	BOP equipped with ROV interface stabs to allow closure of the shear rams in the event of inadvertent release of the LMRP. (ROV system with pump and male stinger to be provided by Operator)	Old APD				Yes	
Rig AL	1997	Pilot hyd	Acoustic system seems not to have been used for the US GoM wells. Acoustic system removed in 2010 and replaced by ROV functions. Close BS ram close Lower pipe ram, Unlock LMRP and unlock WH connector). No deadman or autoshear	New APDs				No	Yes not in use
Rig BK	1997	Pilot hyd	ROV functions has been implemented in 2011, (i.e. no ROV functions in period 2007 - 2009:) • ROV shear rams close added • ROV Lower pipe rams close added • ROV secondary and primary • Wellhead connector unlock added • ROV secondary and primary riser connector unlock added	New APDs				No	
Rig AZ	1998	Mux	ROV Intervention for; • Wellhead connector Unlock • Riser Connector Unlock • Shear rams close One pipe ram close	Contrac-tor O				Yes	
Rig AU	1999	Mux	ROV Intervention for; • Wellhead connector Unlock • Riser Connector Unlock • Shear rams close • One pipe ram close	Contrac-tor O				Yes	
Rig AW	1999	Mux	Shaffer 4th generation Mux Have ROV access for • BS ram • One pipe ram • LMRP Unlock • WH connector unlock EHBS which functions as Both Deadman and autoshear	New APDs and Contrac-tor O		Yes	Yes	Yes	
Rig AY	1999	Mux	ROV Intervention for; • Wellhead connector Unlock • Riser Connector Unlock • Shear rams close One piperam close	Contrac-tor O				Yes	
Rig BO	2000	Mux	Autoshear and deadman No EDS anchored rig. ROV functions (seems to be implemented in 2011). • Blind Shear Rams “Open” • Blind Shear Rams “Close” • Middle Pipe Rams “Open” ST-Lock “Lock”	New APDs	No	Yes	Yes	No	
Rig AB	2004	Pilot hyd	BOP equipped with ROV interface stabs to allow closure of the shear rams in the event of inadvertent release of the LMRP. (ROV system with pump and male stinger to be provided by Operator).	Old APD				Yes	
Rig AF	2007	Mux	Autoshear activates: • Blind shear ram close • Choke and kill failsafe close EDS Implemented ROV functions • Riser connector lock • Riser connector unlock • Blind shear ram close and autoshear arm • Wellhead connector unlock	Old APD	Yes	Yes	Yes	Yes	
Rig AV	2007	Mux	ROV Intervention for; • Wellhead connector Unlock • Riser Connector Unlock • Shear rams close • One pipe ram close ROV flying leads from subsea accumulators EHBS which functions as Both Deadman and autoshear	Contrac-tor O		Yes	Yes	Yes	
Rig AG	2008	Mux	ROV interface for Closure of Blind shear ram in case of inadvertent opening of LMRP connector	Old APD				Yes	

Table 7.2 shows the secondary intervention systems 2007 – 2009 for DP operated drillships with multiplex control systems.

All these BOPs likely had EDS, deadman, autoshear and ROV intervention possibilities. For the Rig BU no information was found in the new APDs, but an old MMS district investigation report indicated that both a deadman and ROV was present at that rig.

Table 7.2 Secondary intervention systems 2007 – 2009 for DP operated drillships with multiplex control systems

Rigname	Rig build or upgraded	Rig type	Backup systems description	Data source	Funtions for use 2007 - 2009				
					EDS	Dead-man	Auto-shear	ROV	Acou-stic
Rig BU	1999	Drill-ship	The casing shear ram and the lower blind shear ram closed via the deadman sequence providing an effective seal on the wellbore. The drill string appeared to be intact from the rig floor down to and into the riser that penetrated the seafloor. The ROV was used to activate an upper set of blind shear rams.	MMS invest-igation from 2003		Yes		Yes	
Rig AR	2000	Drill-ship	Casing EDS: • Close casing shear ram • Close lower blind shear ram • Unlock LMRP • Close upper blind shear ram (through autoshear, using the deadman system supply) Drillpipe EDS: • Close lower blind shear ram • Unlock LMRP • Close upper blind shear ram (through autoshear, using the deadman system supply) Autoshear • Once LMRP lifts 4-1/4" off the BOP • Upper blind shear ram will close Autoshear system is powered by separate and independent subsea accumulators with sufficient capacity to close at least one set of blind shear rams. Deadman The deadman system will activate in the event of total loss of system hydraulics, power, and communication to the BOP at the same time • Close lower blind shear ram • Close upper blind shear ram ROV funtions: Connectors unlock and two blind shears close/lock	Oper-ator AP	Yes	Yes	Yes	Yes	
Rig BT	2001	Drill-ship	For this system the trigger to initiate the sequence relies on the loss of pilot supply to autoshear activate valve. A Deadman condition (loss of Hydraulic and Electrical power) OR an Autoshear condition (separation of LMRP) will result in the loss of the pilot supply to autoshear activate valve. EDS implemented 1. Closes all choke and kill valves and 2 . Closing the lower blind shear rams 3. Closing the upper blind shear rams 4. Unlatching the LMRP ROV functions 1. LMRP connector unlatch 2. WH connector unlatch 3. Close lower shear ram 4. Close upper pipe ram close 5. Close middle pipe ram close ELECTRO-HYDRAULIC (E/H) BACKUP A backup system is in place that will allow the stack to be disconnected from the wellhead without going through any of the Hydril Control System. The mux cables to both blue and yellow pods have separate dedicated lines for this independent system to work. The following functions are available: 1. Upper Shear Rams Close, 2. Pod Stabs Extend, 3. All Stabs Retract, 4. Riser Connector Unlock In the event that the Hydril Control System is inoperable, the stack can be disconnected from the wellhead using this system.	New APDs	Yes	Yes	Yes	Yes	
Rig BS	2009	Drill-ship	For this system the trigger to initiate the sequence relies on the loss of pilot supply to the autoshear activate valve. A Deadman condition (loss of Hydraulic and Electrical power) OR an Autoshear condition (separation of LMRP) will result in the loss of the pilot supply to autoshear activate valve. EDS implemented ROV functions not specified, but LMRP and WH connector disconnect, and BS ram close and one set of piperams close are included. If there are more pipe rams and BS rams is not stated.	New APDs	Yes	Yes	Yes	Yes	

Table 7.3 shows the secondary intervention systems from the period 2007 – 2009 for DP operated semisubmersible rigs with multiplex control systems. For some of the rigs some information is lacking. For two of the ten rigs only limited information related to the secondary intervention systems was found. Likely all of them had EDS, Autoshear, (and/or) Deadman and ROV access. The Rig BB also has an acoustic back-up system, but there was not mentioned in the well activity reports that this system had been tested, indicating that it may not have been in used.

Table 7.3 Secondary intervention systems 2007 – 2009 for DP operated semisubmersibles with multiplex control systems

Rigname	Rig build or upgraded	Rig type	Backup systems description	Data source	Funtions for use 2007 - 2009				
					EDS	Dead-man	Auto-shear	ROV	Acou-stic
Rig AE	1998	Semi-sub	BOP equipped with ROV interface stabs to allow closure of the shear rams in the event of inadvertent release of the LMRP. (ROV system with pump and male stinger to be provided by Operator).	Old APD				Yes	
Rig AN	2000	Semi-sub	Includes an EDS system, No other relevant info found in old APDs	Old APD	Yes				
Rig BL	2000	Semi-sub	EDS Sequence 1: • Closes blind shear • Unlatch LMRP EDS Sequence 2: • Closes super shear • Closes blind shear • Unlatch LMRP ROV • LMRP Disconnect • Upper blind shear ram, • More functions not mentioned Autoshear/deadman not mentioned	Old APD	Yes			Yes	
Rig BM	2001	Semi-sub	EDS drillpipe • Close blind shear rams • Unlock LMRP EDS Casing • Close casing Shear ram • Close blind shear rams • Unlock LMRP Deadman The system should activate when all three of the following conditions are met • loss of electrical power between the rig and BOP • loss of communication between the rig and the BOP • loss of hydraulic pressure from the rig to the BOP Autoshear • Close blind shear rams ROV capability	From investigation reports	Yes	Yes	Yes	Yes	
Rig BB	2002	Semi-sub	Rigowners Homepage states that a Kongsberg BOP acoustic control included. No tests of the acoustic system was mentioned in War remarks indicating this system was not in use for the US GoM wells	Rigowners Home page					Yes, but not in use

Rigname	Rig build or upgraded	Rig type	Backup systems description	Data source	Funtions for use 2007 - 2009				
					EDS	Dead-man	Auto-shear	ROV	Acou-stic
Rig BP	2004	Semi-sub	A deadman condition (loss of Hydraulic and Electrical power) OR an Autoshear condition (separation of LMRP) will result in the loss of the pilot supply to autoshear activate valve. Both functionalities (deadman & Autoshear) are tested simultaneously EDS Drill pipe 1 Lower blind/shear rams high pressure close, 2 Riser connector primary and secondary unlock, 3 Autoshear Function Closes Upper BSR EDS Casing 1 Super shear rams close, 2 Lower blind/shear rams high pressure close, 3 Riser connector primary and secondary unlock, 4 Autoshear Function Closes Upper BSR Autoshear (Stab Retract (or LMRP & STACK Separation) vents Hydraulic Pressure to Autoshear Valve and starts Autoshear Sequence) 1 Lower blind shear rams close, 2 Upper blind shear rams close Deadman Function, Loss of Electrical Supply to both Pods, Loss of Hydraulic Pressure from Both Rigid Conduits, and Loss of Hydraulic Pressure from Hot Line Hose will activate the Deadman Circuit. 1 Lower blind shear rams close, 2 Autoshear Function Closes Upper BSR ROV functions: LMRP connector unlatch, Upper pipe rams close, Upper shear blind rams close, Lower shear blind rams close and arm autoshear, Upper pipe rams close and lock, Wellhead connector unlatch. It seem some modifications of the ROV functions were carried out in 2010/2011	Oper-ator AP	Yes	Yes	Yes	Yes	
Rig BQ	2004	Semi-sub	A deadman condition (loss of Hydraulic and Electrical power) OR an Autoshear condition (separation of LMRP) will result in the loss of the pilot supply to autoshear activate valve. Both functionalities (deadman & Autoshear) are tested simultaneously. It seem some modifications of the ROV functions were carried out in 2010/2011 EDS implemented ROV functions: • LMRP connector unlatch • Upper pipe rams close • Bund shear blind rams close • Casing shear rams close and arm autoshear • Upper pipe rams close and lock • Wellhead connector unlatch	New APDs	Yes	Yes	Yes	Yes	
Rig AO	2008	Semi-sub	Autoshear/dead-man activates if: • Inadvertent disconnect of the LMRP • Loss of both hydraulic pressure and electrical supply from the surface BOP control system Autoshear is an integral part of the EDS sequence ROV functions: LMRP Connector unlock,blind shears close, casing shear ram close, Middle pipe ram close, WH connector unlock Seems to be no changes after 2010	New APDs	Yes	Yes	Yes	Yes	
Rig AP	2008	Semi-sub	Auto-shear requirements • Loss of electrical power to both Subsea Control POD's • Loss of hydraulic supply pressure to both Rigid Conduits. • Retracting both POD stabs while the Auto-shear Circuit is armed and the stack accumulators are charged. Autoshear is an integral part of the EDS sequence ROV functions: LMRP Connector unlock, blind shears close, casing shear ram close, Middle pipe ram close, WH connector unlock Seems to be no changes after after 2010	New APDs	Yes		Yes	Yes	
Rig BH	2008	Semi-sub	EDS function included seems to have three different modes • BS close • Casing shear close • BS plus Casing shear close ROV functions • Riser connector unlock • Blind shear ram close • Upper piperam close and lock • Wellhead connector unlock autoshear functions 1) blind / shear rams – close 2) choke and fail safes - close NEW APDS Indicates that there now is only one mode for EDS and Autoshear that closes both BS and CS.	Old APD	Yes		Yes	Yes	

Table 7.4 shows an overview of the semisubmersible rigs and drillship where no information related to the secondary intervention systems were identified. It is likely that all DP operated vessels were equipped with EDS, Autoshear, (and/or) Deadman and ROV access.

The majority of the anchored semisubmersibles with pilot hydraulic system probably had ROV intervention capabilities. Some few may also have had a hydraulic autoshear, and/or deadman. EDS is less likely.

The anchored semisubmersibles with a multiplex system likely had ROV intervention capabilities. They may also have had autoshear, deadman and EDS.

Table 7.4 Rigs where no info about backup systems were found or submitted

Rigname	Rig build or upgraded	Rig type	Mooring	Control system principle
Rig BW	1974	Semisub	Anchored	Pilot hyd
Rig AK	1988	Semisub	Anchored	Pilot hyd
Rig AM	1995	Semisub	Anchored	Pilot hyd
Rig AJ	1996	Semisub	Anchored	Pilot hyd
Rig AS	1998	Semisub	Anchored	Mux
Rig BY	1998	Semisub	Anchored	Mux
Rig AD	2000	Semisub	Anchored	Pilot hyd
Rig AI	2000	Semisub	Anchored	Pilot hyd
Rig AC	2001	Semisub	Anchored	Mux
Rig BN	1999	Drillship	DP	Mux
Rig AA	2000	Drillship	DP	Mux
Rig BV	2000	Drillship	DP	Mux
Rig BI	2008	Semisub	DP	Mux

8 Overview of Kick Data

8.1 Data Background and Data Sources

When collecting kick data, only the drilling period when the BOP is located on the wellhead has been considered. I.e. shallow gas or shallow water-flows are not considered. If the drilling covers a regular well test this is regarded as a part of the well drilling.

A total of 259 different wells, where a subsea BOP has been used, are included in the study when including side-tracks or by-passes as separate wells. Sidetracks and by-passes can be separated from the original wells by the well API number. For the wells were the well number ends with a zero, it is an original hole, the others are sidetracks or by-passes.

This represents 3.1 times more wells and 3.76 times more days in service with the BOP on the wellhead than the previous study (/1/).

The entry *BOP-days*, is defined as the number of days from the BOP was landed on the wellhead the first time until it is pulled from the wellhead the last time. If the BOP is pulled during the operation due to a BOP failure, this is regarded as included in the BOP-days. If the well is temporarily abandoned and the rig is carrying out other operations before returning to the well, this is not included in the BOP-days.

The main criteria for defining a well control incident as a kick is that the BOP was needed to control the situation. The meaning of "Control the situation" is to both close in the well with the BOP and to circulate the kick/let it be buoyed out (in case stripping failed) in a controlled way until the situation is normalized.

Table 8.1 presents an overview of wells and days in service for the various water depths.

Table 8.1 Overview of wells and days in service for the various water depths

Water depth grouped (ft) / (m)	Development well			Exploration wells			Total		
	Original	Sidetrack or by-pass	BOP-days in service	Original	Sidetrack or by-pass	BOP-days in service	Original	Sidetrack or by-pass	BOP-days in service
2000-3000 / 610-914	7	3	720	37	19	2541	44	22	3261
3000-4000 / 914-1219	10	3	810	31	16	2372	41	19	3182
4000-5000 / 1219-1524	8	3	688	19	13	1988	27	16	2676
5000-6000 / 1524-1829	5		337	17	11	1810	22	11	2147
6000-7000 / 1829-2134	5		371	20	9	1838	25	9	2209
7000-8000 / 2134-2438	2	1	87	9	5	1039	11	6	1126
8000-9000 / 2438-2743	3		125	4		223	7	0	348
9000-10141 / 2743-3091	2	1	85	2		22	4	1	107
Total	**42**	**11**	**3223**	**133**	**73**	**11833**	**175**	**84**	**15056**

These wells have been drilled with 42 different drilling vessels.

Table 8.2 presents an overview of drilling vessel type and BOP-days for the various water depths.

Table 8.2 Overview of drilling vessel types and BOP-days for the various water depths

Water depth grouped (ft) / (m)	BOP-days in service							
	Development well				Exploration wells			
	Anchored	Dynamic positioning		Total	Anchored	Dynamic positioning		Total
	Semisub	Drillship	Semisub		Semisub	Drillship	Semisub	
2000-3000 / 610-914	521	199		720	2482	59		2541
3000-4000 / 914-1219	767		43	810	1952	143	277	2372
4000-5000 / 1219-1524	105	345	238	688	263	1208	517	1988
5000-6000 / 1524-1829	129	208		337	438	714	658	1810
6000-7000 / 1829-2134		74	297	371	1050	241	547	1838
7000-8000 / 2134-2438	87			87	457	359	223	1039
8000-9000 / 2438-2743	125			125	97	43	83	223
9000-10141 / 2743-3091	85			85			22	22
Total	1819	826	578	3223	6739	2767	2327	11833

Table 8.2 shows that for more than 50% of the operational time the deepwater wells have been drilled with anchored semisubmersible rigs. Anchored rigs are now used for drilling in water depths as deep as 10 000 ft.

8.2 Kick Frequency and Type of Drilling

Table 8.3 shows the mean time between kicks (MTBK) related to number of BOP-days and number of wells drilled.

Table 8.3 Mean time between kicks (not incl. shallow kicks)

Phase*	No. of kicks	No. of wells			BOP-days in service	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
		Original	Sidetrack or by-pass	Total			
Development drilling	7	42	11	53	3223	7,57	460
Exploration drilling	74	133	73	206	11833	2,78	160
Total	81	175	84	259	15056	3,20	186

* Two of the development drilling well kicks and two of the exploration drilling well kicks actually occurred during completion activities

These kick frequencies are compared with kick frequencies identified in other studies in Section 8.3, page 96.

Various parameters affecting the kick frequency is discussed in Section 10, page 117.

The e-Well reporting system (Section 2.1, page 21) has a specific part that reports significant events. One of the possible significant events is well kicks. Approximately 50% of the identified kicks were reported as a significant event, while the remaining 50% were not.

As expected there are more frequent kicks in exploration drilling than in development drilling. The main reason for this increased frequency is that they are drilling in less known formation.

To check whether if the difference in the kick frequency between development and exploration drilling was statistically significant or not, 90% confidence limits were established for the kick frequencies. Figure 8.1 shows the kick frequencies for development and exploration drilling alongside the 90% confidence bands.

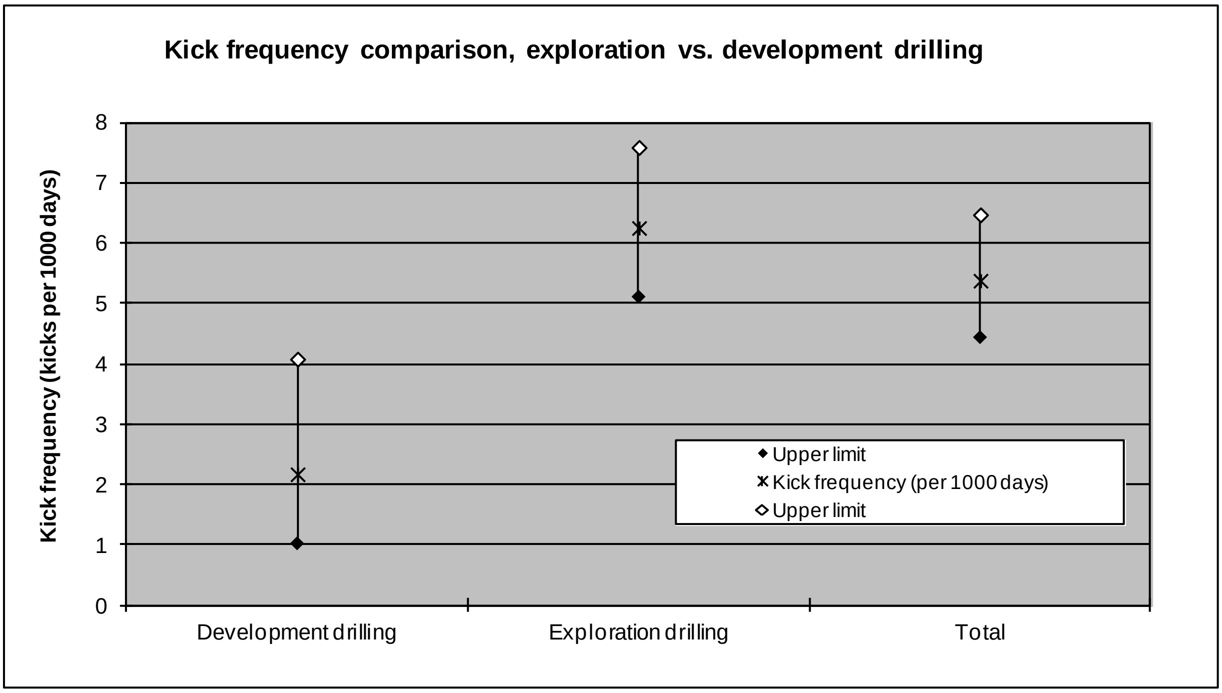


Figure 8.1 Kick frequency comparison, exploration vs. development drilling

Figure 8.1 confirms a statistical significant difference between the exploration and development drilling (the confidence bands do not overlap).

8.3 Comparison with Other Kick Statistics

The Deepwater Kicks and BOP performance study from 2001 (/2/) presented kick statistics.

Table 8.4 shows the mean time between kicks (MTBK) related to the number of BOP-days and the number of wells drilled found in the 2001 study.

Table 8.4 Mean time between kicks (not incl. shallow kicks), US GoM wells spudded in 1997 and 1988 (/2/)

Phase	No. of kicks	No. of wells	BOP-days in service	MTBK (wells between kicks)	MTBK (BOP-days between each kick)
Development drilling	9	25	1000	2.8	111.1
Exploration drilling	39	58	3009	1.5	77.2
Total	48	83	4009	1.7	83.5

When comparing the overall kick frequencies in Table 8.3 with the kick frequency found in the previous study in Table 8.4, it is seen that the frequency of kicks is significantly lower in the present study, only approximately 50%. There may be a number of causes for this reduction of kick frequency. Various parameters affecting the kick frequency is discussed in Section 10, page 117.

In 1998 a study was carried out concerning blowout probability of High Pressure High Temperature (HPHT) wells in the Norwegian Continental Shelf (NCS) (/2/). A well with an expected maximum shut-in pressure above 10 000 psi (690 bar) and/or formation temperatures above 238 F (150 centigrade) is regarded as a HPHT well.

In association with this study kick frequencies based on all wells drilled in the NCS in the period 1984 until 1997 were established. The shallow kicks were disregarded in the study, the results are therefore comparable with the kick frequencies established in this study.

Table 8.5 shows the NCS overall MTBK (mean time between kicks).

Table 8.5 NCS overall mean time between kicks (data from 1984 - 1997)

Type of drilling	No. of wells drilled	No. of kicks	MTBK (wells between kicks)
Exploration drilling	576	143	4.0
Development drilling	1428	272	5.3
Total	2580	558	4.6

When comparing the results shown in Table 8.3 and Table 8.5 it is seen that the overall frequency of kicks is approximately 50% higher in the US GoM deepwater wells drilled in 2007 – 2009 than in the rather old overall NCS experience. It should be noted that for NCS nearly all the exploration wells were drilled with floating rigs, while the majority of the production wells were drilled from fixed installations.

In Table 8.6 the NCS exploration wells have been divided in different categories to better explain the kick frequencies in different types of wells.

Table 8.6 NCS MTBK for different types of exploration wells

Type of exploration well	No. of wells	No. of kicks	MTBK (wells between kicks)
Normal (Well depth < 4000m = 13123 ft. TVD)	416	39	10.7
Deep (Well depth > 4000m = 13123 ft. TVD, not incl. HPHT)	111	36	3.1
HPHT wells	49	68	0.7
Total	576	143	4.0

From Table 8.6 it is seen that the NCS kicks in deep wells, and especially HPHT wells occurred at a frequent rate.

When observing the maximum theoretical shut-in pressures and depths for the US GoM wells, as presented in Figure 9.1 page 108, Figure 9.2, page 109, and Figure 9.3, page 110, it is seen that many of these wells are deep wells and HPHT wells.

The frequency of kicks found in the current study is a bit lower compared to the frequency of kicks of *comparable* NCS wells from 1986 - 1995. It should be noted that the NCS HPHT wells were normally drilled to a depth of 16 000 to 17 000 ft. in 150 to 1000 ft. of water.

8.4 Kick Frequency and Area

Table 8.7 shows an area specific overview of the time in operation and number of kicks.

Table 8.7 Area specific time in operation and mean time between kicks (MTBK)

Area	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
AC - Alaminos Canyon		297	-	1	70	70	1	367	367
AT - Atwater	1	133	133	6	558	93	7	691	99
DC -Desoto Canyon				2	211	106	2	211	106
EB - East Breaks		165	-	3	423	141	3	588	196
GB - Garden Banks	2	337	169	8	1108	139	10	1445	145
GC - Green Canyon	3	1265	422	16	3366	210	19	4631	244
KC - Keathley Canyon				3	700	233	3	700	233
LL - Lloyd					78	-		78	-
MC - Mississippi Canyon	1	1009	1009	26	3344	129	27	4353	161
VK - Viosca Knoll		17	-		46	-		63	-
WR- Walker Ridge				9	1929	214	9	1929	214
Total	7	3223	460	74	11833	160	81	15056	186

It is seen from Table 8.7 that the majority of deepwater drilling was carried out in the Green Canyon, Mississippi Canyon, Garden Banks and Walker Ridge. It seems that the kick frequency in the Garden Banks and Mississippi Canyon is a bit higher than in Green Canyon and the Walker Ridge. Even though Atwater is represented with a limited amount of drilling, the no. of kicks in this area has been high.

To check whether the differences in kick frequency between the different areas were statistically significant or not, 90% confidence limits are established for the kick frequencies. Figure 8.2 shows the area specific kick frequencies alongside the 90% confidence bands.

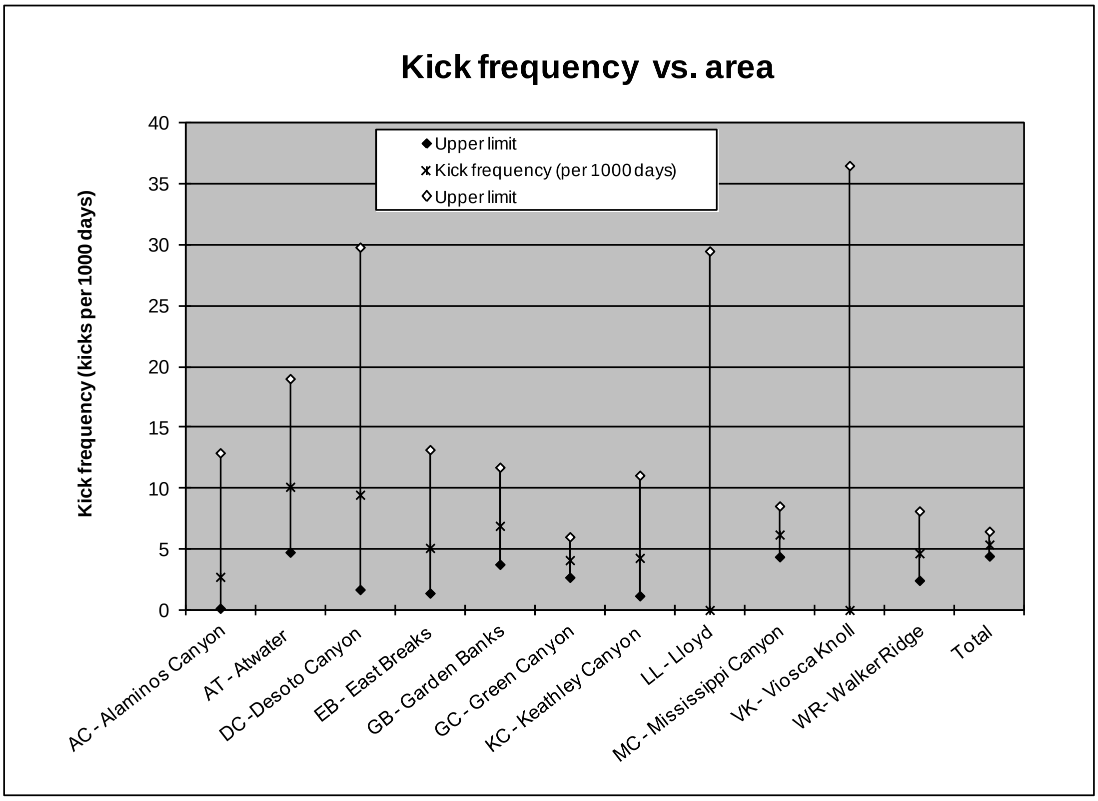


Figure 8.2 Kick frequency vs. area

Figure 8.2 cannot confirm a statistical significant difference between the areas.

8.5 Kick Frequency and Water Depth

Table 8.8 shows the water depth vs. the mean time between kicks.

Table 8.8 Water depth vs. mean time between kicks

Water depth grouped (ft) / (m)	Development well			Exploration wells			Total		
	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)
2000-3000 / 610-914	720	2	360	2541	24	106	3261	26	125
3000-4000 / 914-1219	810	1	810	2372	12	198	3182	13	245
4000-5000 / 1219-1524	688	2	344	1988	14	142	2676	16	167
5000-6000 / 1524-1829	337	1	337	1810	11	165	2147	12	179
6000-7000 / 1829-2134	371	1	371	1838	9	204	2209	10	221
7000-8000 / 2134-2438	87			1039	3	346	1126	3	375
8000-9000 / 2438-2743	125			223	1	223	348	1	348
9000-10141 / 2743-3091	85			22			107		
Total	3223	7	460	11833	74	160	15056	81	186

Table 8.8 shows that there are observed less frequent kicks in the deepest waters. Figure 8.3 shows the observed kick frequencies for the various water depth ranges alongside a trend line.

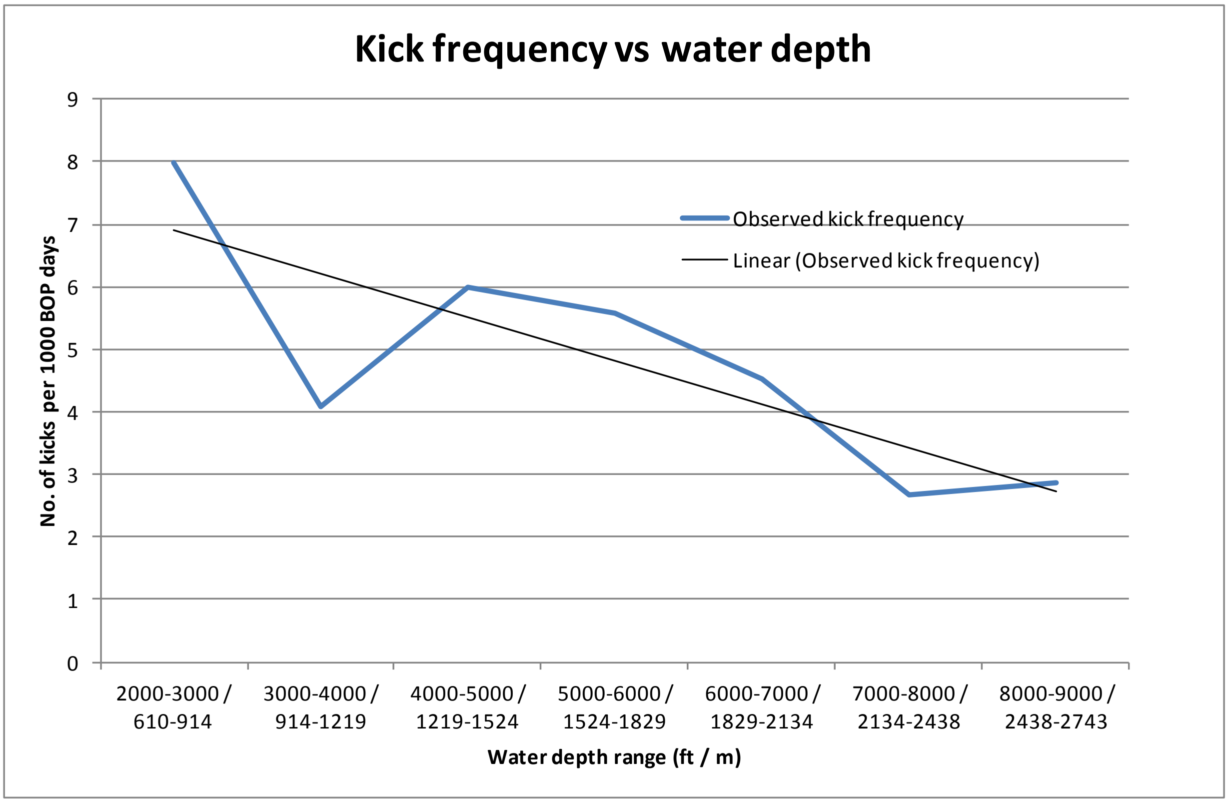


Figure 8.3 Kick frequency vs. water depth

The same trend as observed in Figure 8.3 was also observed in the previous report (/2/). The water depth influence is further discussed in Section 8.5, page 99.

8.6 Kick Frequency and Operator

Table 8.9 shows the operator vs. the mean time between kicks.

Table 8.9 Operator vs. the mean time between kicks

Operator	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Operator AD				2	331	166	2	331	166
Operator AK		123	-	2	1615	808	2	1738	869
Operator AO		46	-	8	431	54	8	477	60
Operator AP	2	459	229,5	5	992	198	7	1451	207
Operator AX		417	-	6	1144	191	6	1561	260
Operator BI		63	-					63	-
Operator AC	1	257	257	9	1114	124	10	1371	137
Operator BF				1	112	112	1	112	112
Operator AW				4	490	123	4	490	123
Operator BH				3	293	98	3	293	98
Operator BD				2	550	275	2	550	275
Operator AE		42	-	1	102	102	1	144	144
Operator AB				1	451	451	1	451	451
Operator AS		52	-	4	184	46	4	236	59
Operator AU					22	-		22	-
Operator AQ		40	-	4	243	61	4	283	71
Operator AH		207	-	3	479	160	3	686	229
Operator AJ				4	477	119	4	477	119
Operator BA				1	426	426	1	426	426
Operator AN				3	178	59	3	178	59
Operator AF	1	191	191		13	-	1	204	204
Operator AT		94	-	1	344	344	1	438	438
Operator AL				1	219	219	1	219	219
Operator BB					176	-		176	-
Operator BE				2	35	18	2	35	18
Operator AR	2	164	82				2	164	82
Operator AG	1	1068	1068	3	679	226	4	1747	437
Operator BC					121	-		121	-
Operator AZ				1	49	49	1	49	49
Operator AA				2	365	183	2	365	183
Operator AM					68	-		68	-
Operator AI					73	-		73	-
Operator AV				1	57	57	1	57	57
Total	7	3223	460	74	11833	160	81	15056	186

Many operators have been drilling deepwater wells in the US GoM OCS in 2007-2009. The average MTBK varies highly. It is here important to note that each of the companies is represented with relatively few days in service. Figure 8.4 shows the kick frequency vs. operator alongside the 90% confidence bands.

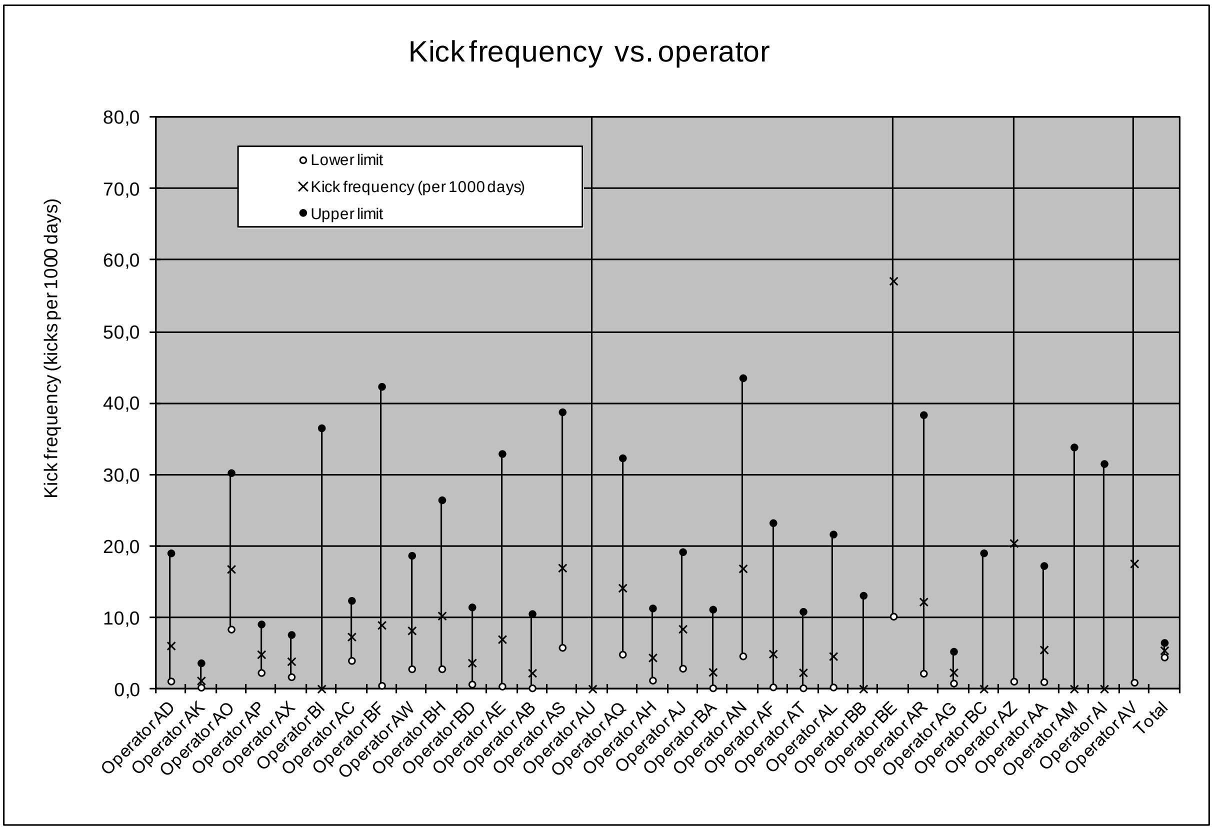


Figure 8.4 Kick frequency vs. operator

As seen from Figure 8.4, some operators have a significantly lower kick frequency than other. It is here also important to note that different wells have different difficulties when drilling, i.e. some wells kicks easier than others. The average MTBK should therefore not be used for ranking the operators.

Five operators have more than a 1000 BOP-days of experience in this dataset. These five operators have carried out approximately 50% of the drilling. Figure 8.5 shows the kick frequency vs. operator alongside the 90% confidence bands for the five operators represented with more than 1000 BOP-days in the study.

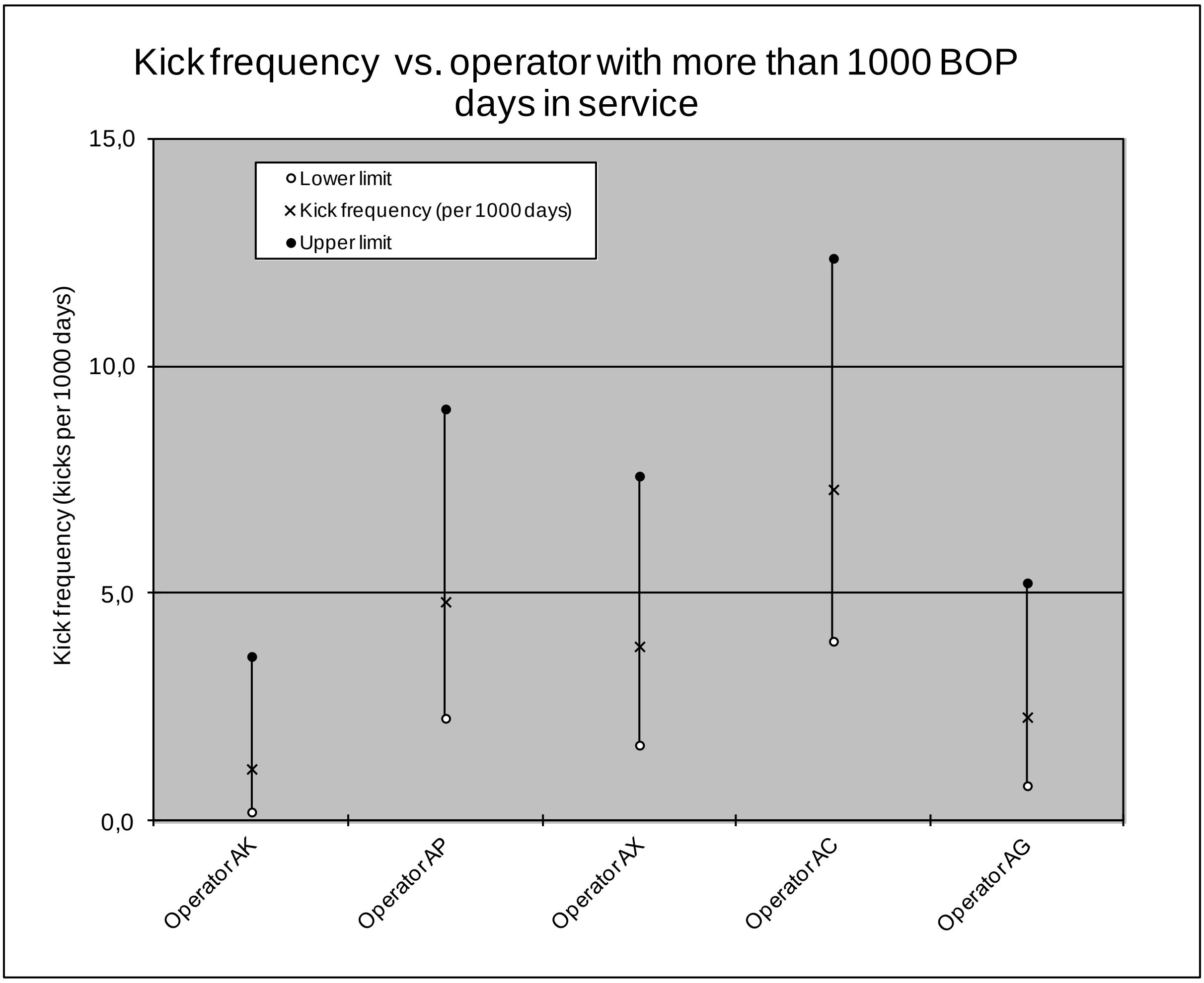


Figure 8.5 Kick frequency vs. operator for operators with more than 1000 BOP-days in service.

It is worth to note that Operator AK kick frequency is the lowest. This frequency is significantly lower than the Operator AC kick frequency. Most of the drilling Operator AK have been doing is exploration drilling. It has however not been investigated if there are specific reason for this low kick frequency.

8.7 Kick Frequency and Drilling Contractor

Table 8.10 shows the drilling contractor vs. the mean time between kicks.

Table 8.10 Drilling contractor vs. the mean time between kicks

Contractor name	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Contractor A	2	694	347	26	4126	159	28	4820	172
Contractor M			-	5	479	96	5	479	96
Contractor L			-		511	-		511	-
Contractor O	1	963	963	10	1466	147	11	2429	221
Contractor P			-	2	21	11	2	21	11
Contractor Q			-		133	-		133	-
Contractor C	4	1566	392	31	5097	164	35	6663	190
Total	7	3223	460	74	11833	160	81	15056	186

Contractor C, Contractor A, and Contractor O have carried out 93% of all the drilling. The remaining four contractors have drilled few wells.

The kick frequencies for the different contractors have been compared by using 90% confidence bands in Figure 8.6. It has been selected to group the drilling contractors with a short drilling period in one group.

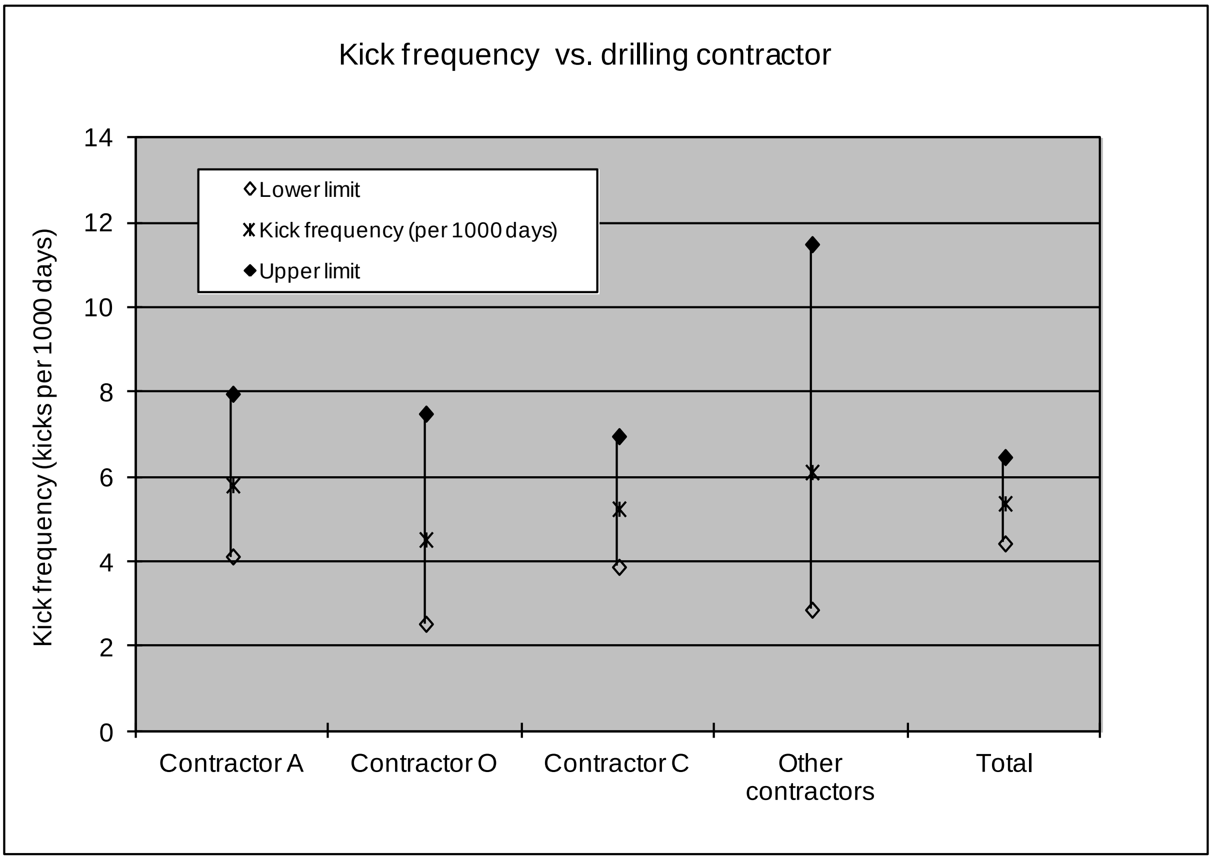


Figure 8.6 Kick frequency vs. drilling contractor

From Figure 8.6 it is seen that the difference in kick frequency between the various operators is relatively small.

Table 8.11 Kick occurrences, drilling contractors and water depth

Drilling Contractor	Water depth (ft) / (m)											
	2000-4000 / 610-1219			4000-6000 / 1219-1829			6000-10141 / 1829-3091			Total		
	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)	BOP-days in service	No. of kicks	MTBK (BOP-days)
Contractor A	2835	15	189	837	6	140	1148	7	164	4820	28	172
Contractor O	1404	6	234	509	5	102	516			2429	11	221
Contractor C	1927	13	148	2857	15	190	1879	7	268	6663	35	190
Other	277	5	55	620	2	310	247			1144	7	163
Total	6443	39	165	4823	28	172	3790	14	271	15056	81	186

As seen from Table 8.11, that Contractor A and Contractor C are well represented in all water depths. Contractor A's relative proportion of drilling in water depths less than 4000 ft is however larger than Contractor C's proportion. In deeper waters, Contractor C has carried out most drilling. While Contractor O and Contractor A has the lowest kick rate in water depths less than 4000 ft, Contractor C has a lower kick rate in the span between 4000 ft and 6000 ft, than in the more shallow waters. Both Contactor C and Contractor A have a lower kick rate in water depths above 6000 ft than in the span between 4000 ft and 6000 ft.

Table 8.12 shows the no. of kick occurrences and the drilling area for the drilling contractors.

Table 8.12 Kick occurrences, drilling contractors and area

Area	Contractor A		Contractor O		Contractor C		Other		All	
	BOP-days in service	No. of kicks	BOP-days in service	No. of kicks	BOP-days in service	No. of kicks	BOP-days in service	No. of kicks	Total	No. of kicks
AC - Alaminos Canyon	70	1	297						367	1
AT - Atwater	79	1			413	1	199	5	691	7
DC -Desoto Canyon	23				188	2			211	2
EB - East Breaks	404	1	170	2	14				588	3
GB - Garden Banks	738	4	93	1	614	5			1445	10
GC - Green Canyon	965	3	840	3	2258	13	568		4631	19
KC - Keathley Canyon	257	3			220		223		700	3
LL - Lloyd	35				43				78	
MC - Mississippi Canyon	1542	13	710	3	2056	9	45	2	4353	27
VK - Viosca Knoll	46				17				63	
WR- Walker Ridge	661	2	319	2	840	5	109		1929	9
Total	4820	28	2429	11	6663	35	1144	7	15056	81

8.8 Kick Frequency and Rig

The majority of deepwater drilling has been carried out by semisubmersibles, but some wells have been drilled with drill ships. Table 8.13 shows an overview of the rig type vs. the kick occurrences.

Table 8.13 Rig type and kick occurrences

Rig type and mooring	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
DP Drill ship	3	826	275	13	2767	213	16	3593	225
Anchored Semisubmersible	4	1819	455	44	6739	153	48	8558	178
DP Semisubmersible		578	-	17	2327	137	17	2905	171
Total	7	3223	460	74	11833	160	81	15056	186

Table 8.13 shows that dynamically positioned (DP) drill ships carried out approximately 24% of the drilling, and 20% of the kicks occurred when drilling these wells. Anchored semisubmersibles carried out 57% of the drilling, and 59% of the kicks occurred when drilling these wells. The remaining 19% of the drilling were carried out by dynamically positioned (DP) semisubmersibles, and 21% of the kicks occurred on these rigs.

Table 8.14 shows an overview of the kick occurrences and the number of BOP-days in service for the various rigs included in the study.

Table 8.14 Rig name and kick occurrences

Rig name	Development drilling			Exploration drilling			Total		
	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)	No. of kicks	BOP-days in service	MTBK (BOP-days)
Rig AA					511	-		511	-
Rig AB				2	627	314	2	627	314
Rig AC	2	164	82	3	600	200	5	764	153
Rig AD				1	49	49	1	49	49
Rig AE		46	-	2	469	235	2	515	258
Rig AF				2	540	270	2	540	270
Rig AG					106	-		106	-
Rig AH		94	-	3	348	116	3	442	147
Rig AI				3	80	27	3	80	27
Rig AJ		104	-	1	323	323	1	427	427
Rig AK		113	-	2	315	158	2	428	214
Rig AL		173	-	4	317	79	4	490	123
Rig AM				1	153	153	1	153	153
Rig AN				5	308	62	5	308	62
Rig AO					69	-		69	-
Rig AP					32	-		32	-
Rig AQ	1	191	191				1	191	191
Rig AR	2	238	119	5	650	130	7	888	127
Rig AS				1	246	246	1	246	246
Rig AU				1	390	390	1	390	390
Rig AV		297	-					297	-
Rig AW	1	419	419	1	179	179	2	598	299
Rig AX		40	-	3	273	91	3	313	104
Rig AY				3	202	67	3	202	67
Rig AZ		207	-	2	418	209	2	625	313
Rig BB				2	281	141	2	281	141
Rig BH				2	26	13	2	26	13
Rig BI					133	-		133	-
Rig BK				6	494	82	6	494	82
Rig BL		119	-	1	211	211	1	330	330
Rig BM				5	599	120	5	599	120
Rig BN				5	236	47	5	236	47
Rig BO				2	500	250	2	500	250
Rig BP		221	-		295	-		516	-
Rig BQ		192	-					192	-
Rig BS	1	181	181				1	181	181
Rig BT				3	488	163	3	488	163
Rig BU		208	-		363	-		571	-
Rig BV		199	-		473	-		672	-
Rig BW				1	219	219	1	219	219
Rig BX				2	201	101	2	201	101
Rig BY		17	-		109	-		126	-
Total	7	3223	460	74	11833	160	81	15056	186

Many different rigs have been drilling deepwater wells in the US GoM OCS in 2007-2009. The average MTBK varies highly. It is here important to note that many of the rigs are represented with relatively few days in service. Figure 8.7 shows the kick frequency vs. operator alongside the 90% confidence bands.

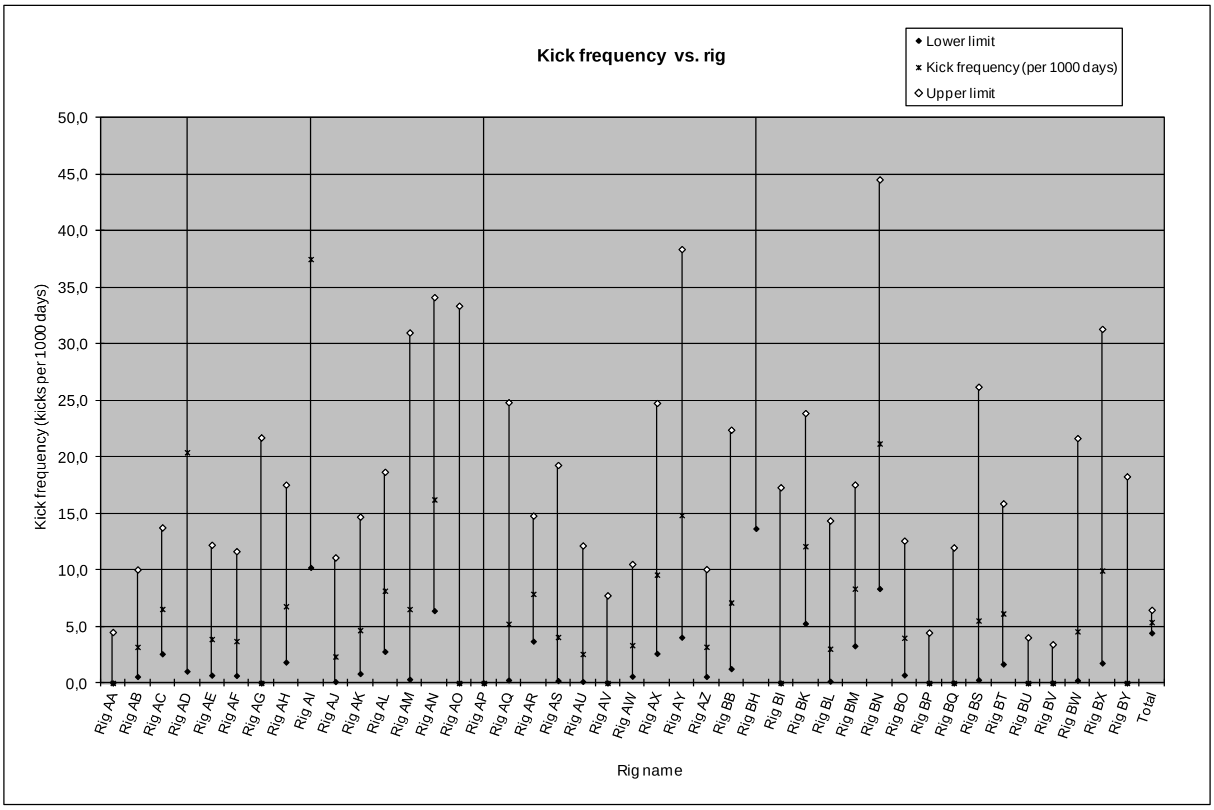


Figure 8.7 Kick frequency vs. rig

As seen from Figure 8.7 the confidence bands overlap for most of the rigs. It is here also important to note that different wells have different difficulties when drilling, i.e. some wells kicks easier than others. The average MTBK should therefore not be used for ranking the rigs.

9 Kick Characteristics

9.1 Theoretical and Measured Shut-in Wellhead Pressures

The maximum theoretical shut-in wellhead pressures for each kick have been estimated based on the following:

- The mud weight when the kick occurred (assumed to represent the pore pressure)
- The true vertical well depth when the kick occurred.
- Assuming the well was filled with methane gas

It was then estimated that the complete well bore was filled with methane with a density of 0.71 kg/m^3 at atmospheric pressure.

The formula used is as follows

$$P_{SI\text{-}Max} = P_{bottom} - \rho_{methane} * g * (D_{TVD} - D_W) * (P_{bottom} + P_{SI\text{-}Max}) / (2 * P_{ATM})$$

the solution for P_{SI} will then be:

$$P_{SI\text{-}Max} = P_{bottom} \ (1 - \rho_{methane} * g * (D_{TVD} - D_W) / 2 * P_{ATM}) / (1 + \rho_{methane} * g * (D_{TVD} - D_W) / 2 * P_{ATM})$$

For the calculations all English units were converted to Metric units. The results were then converted back to English units.

Where;

D_{TVD}	= True vertical well depth (m)
D_W	= Water depth (m)
P_{bottom}	= $\rho_{mud} * g * D_{TVD}$ (Pa)
$\rho_{methane}$	= density of methane at atmospheric pressure (= 0.71 kg/m^3)
ρ_{mud}	= density of mud (kg/m^3)
g	= gravity force (9.81 m/s^2)
$P_{SI\text{-}Max}$	= Shut-in wellhead pressure (Pa)
P_{ATM}	= Atmospheric pressure (100000 Pa)

Figure 9.1 shows the sorted well depths vs. the theoretical shut-in well pressures when the kicks occurred.

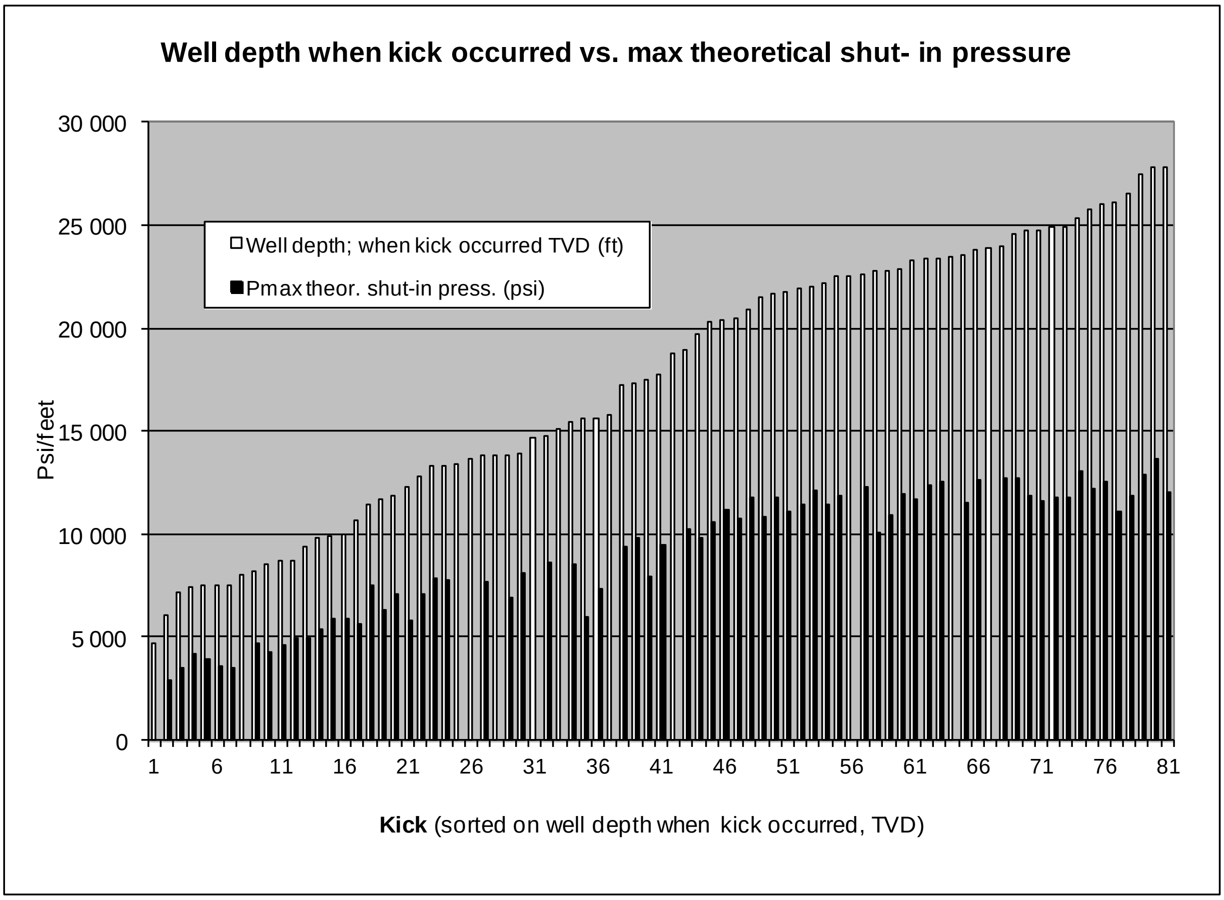


Figure 9.1 Sorted well depth and maximum theoretical shut-in well pressures

As seen from Figure 9.1 many of the wells that kicked were very deep and had high theoretic shut in pressures. Thirty-seven of the 81 kicks occurred when drilling deeper than 20 000 ft (6096 m). Eighth of these occurred when drilling deeper than 25 000 ft (7620m).

In the North Sea area wells with an expected maximum shut-in pressure above 10 000 psi (690 bar) and/or formation temperature above 238 F (150 centigrade) are regarded as HPHT wells. Nearly 50% of the observed kicks would be regarded as HPHT kicks when using the North Sea definition.

9.2 Well Depth when the Kick Occurred vs. the Casing Shoe Depth

Figure 9.2 shows the well depth when the kick occurred vs. the casing shoe depth (TVD).

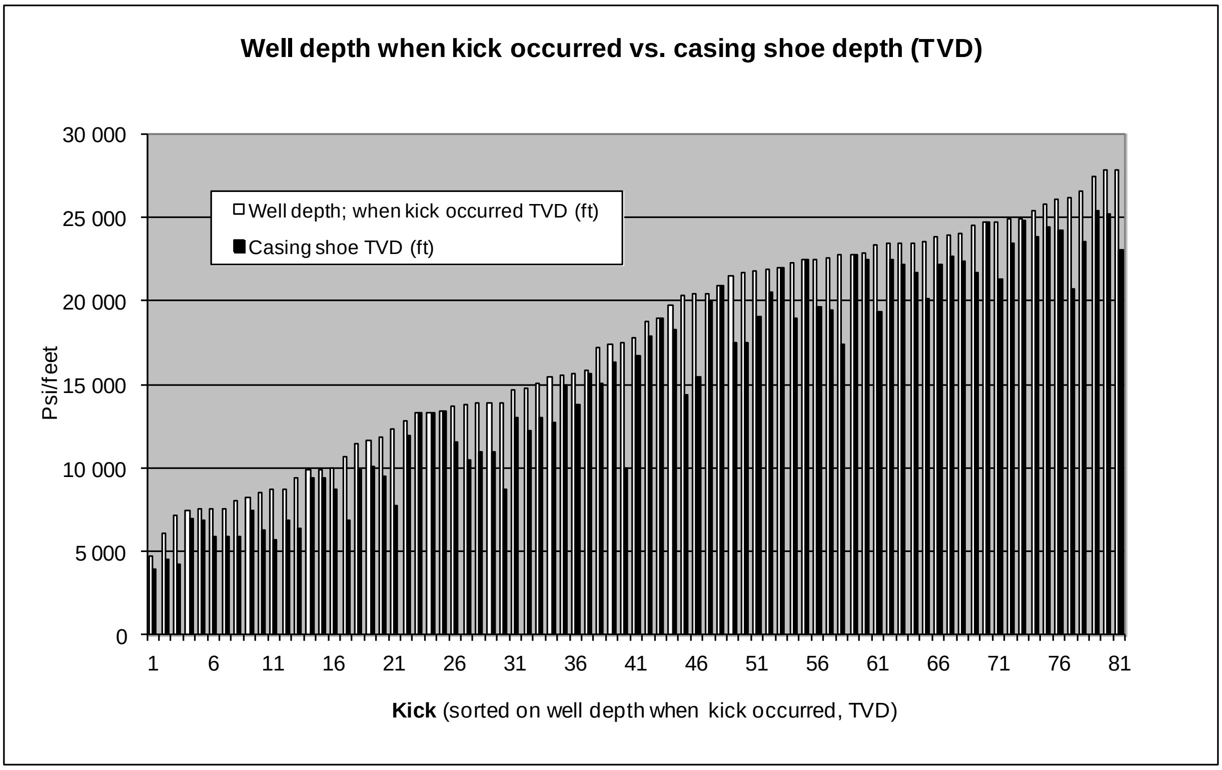


Figure 9.2 Well depth when the kick occurred vs. the casing shoe depth (TVD)

For eleven kicks the difference between the drilling depth and casing shoe depth was less than 150 ft /45 m (TVD). For 12 kicks it was between 150 – 1000 ft/305m, for 22 kicks it was between 1000 – 2000 ft / 610m, for 18 kicks it was between 2000 – 3000 ft /914 m, for 17 kicks it was between 3000 and 6000 ft / 1828 m. For one kick the difference was 7500 ft / 2286 m.

9.3 Well Depth when the Kick Occurred vs. the Total Well Depth

Figure 9.3 shows the well depth when the kick occurred vs. the total well depth.

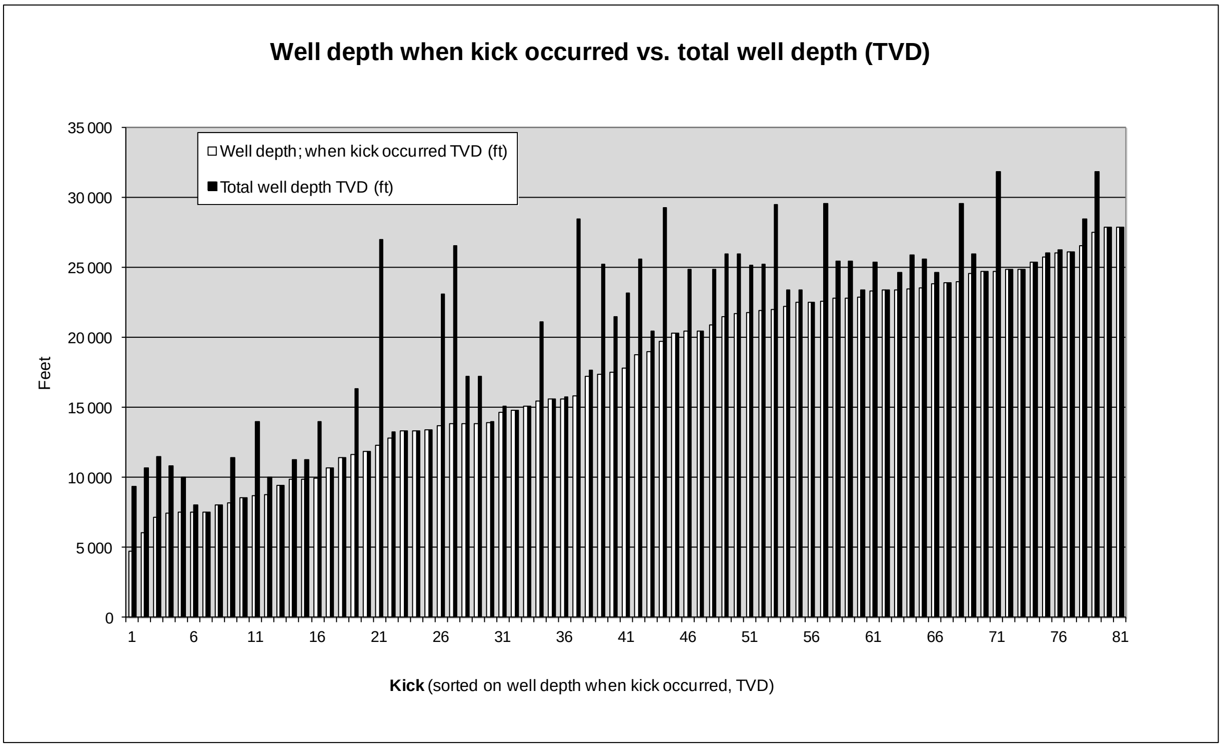


Figure 9.3 Well depth when the kick occurred vs. the total well depth (TVD)

As seen from Figure 9.3 some of the wells were not drilled any further after the kick was controlled. This is because the final well depth was reached, or that the well bore was side-tracked or abandoned as a result of complications associated to the well killing operations.

9.4 Leak off Test vs. Mud Weight when the Kicks Occurred

Figure 9.4 shows the leak off test (LOT) vs. mud weight (MW) when the kicks occurred.

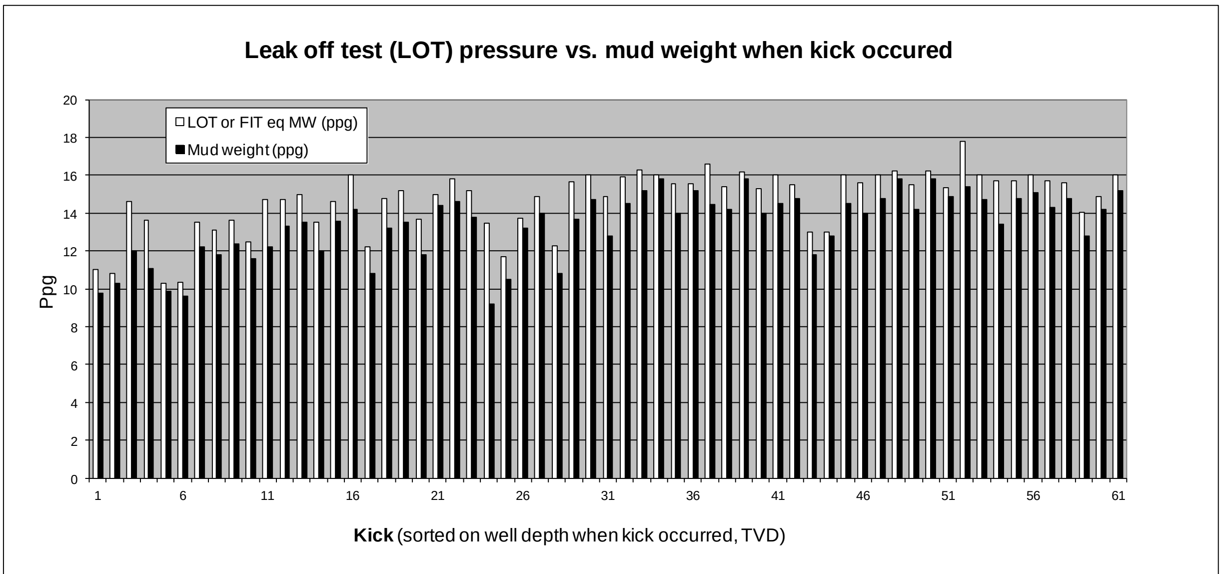


Figure 9.4 Leak off test (LOT) pressure vs. mud weight (MW) when kick occurred

For many of the kicks in Figure 9.4 a LOT or FIT and/or the mud weight used at the time could not be found in the data source. For three kicks both the LOT or FIT and mud weight was missing, for nine kicks the mud weight was missing, and for eight kicks LOT or FIT was missing. The 61 remaining kicks had both these values.

For nine (15%) of the kicks the difference between the LOT or FIT and the mud weight was below 0,5 ppg, for 12 (19%) it was between 0,5 ppg and 1ppg, for 32 (52%) it was between 1 ppg and 2 ppg and for 8 (13%) it was above 2 ppg.

A small margin between the MW and the LOT or FIT, indicates a small margin between the pore pressure and the fracture pressure, thus making the wells difficult to drill.

The difference between the LOT and the MW and the occurrence of kicks is further discussed in Section 10 on page 117.

9.5 Kick Sizes

Figure 9.5 shows the kick sizes recorded.

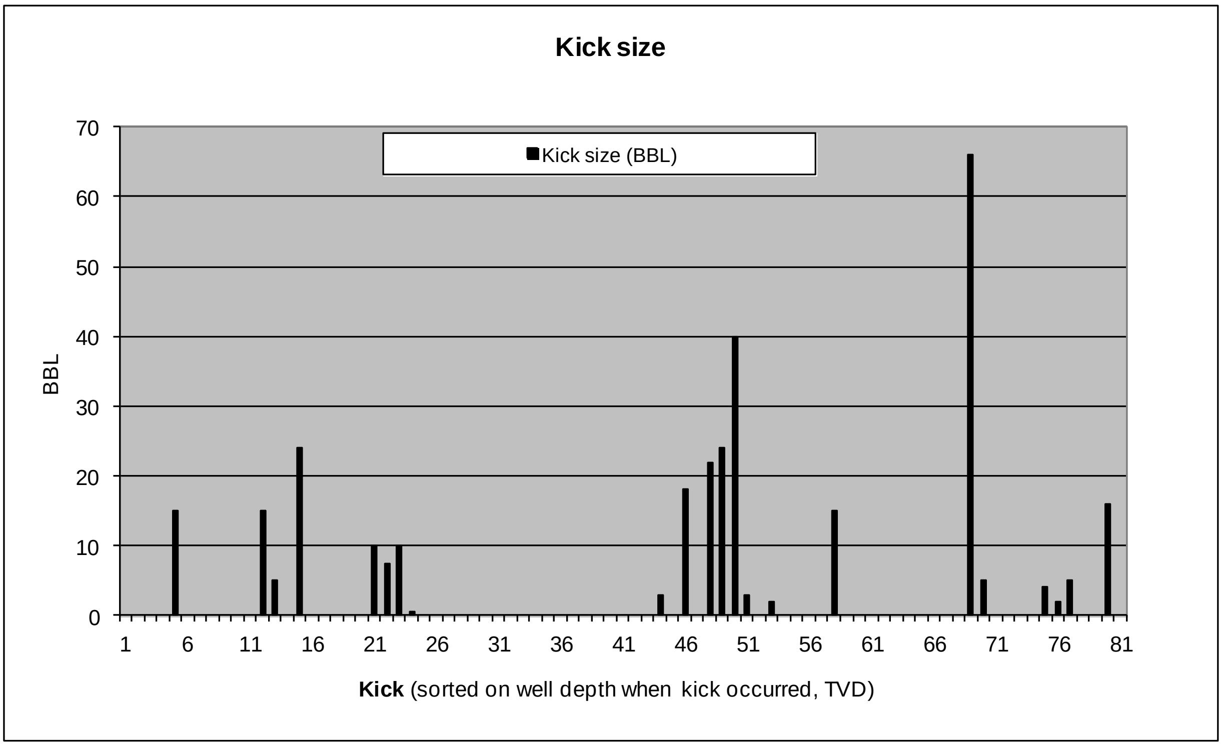


Figure 9.5 Kick size

The verbal information in e-Well mentioned kick size only for 22 of the 81 kicks. In the 2001 study (/2/) more kick sizes were captured. There it was concluded that it seems to be no correlation between the kick size and the well depth when the kick occurred. There was no obvious correlation between the kick size and the water depth.

9.6 Kick in the Riser

If a well influx is observed late, gas may have passed the BOP before it is closed. This gas will continue to rise and expand in the riser until released on the surface. In such cases the diverter system shall be activated to lead the gas away from the rig floor to avoid serious accidents.

A complicating factor during such an event is that when gas replaces the mud in the riser the riser may collapse due to the hydrostatic pressure from the seawater. Mud or seawater should therefore be pumped into the riser to avoid collapse.

Two of the 81 kicks are categorized as Kick in the riser kicks.

One of these incidents occurred on the semi-submersible Rig AX, April 19th, 2009. The incident occurred in 2013 ft (614 m) of water. A MMS district investigation report was issued after the incident (/13/). MMS categorized this event as a blowout.

February 6th, 2009 a similar incident occurred on Rig AJ. They were drilling in 3411 ft (1040 m) of water. This incident was not reported in a separate investigation report. In the e-Well report it was stated:

"Shut well in on upper Annular - well continued flowing - closed diverter & circ'd riser. Flushed across BOPs - rechecked press - well static. February 7th – Circulated bottom up-Checked flow - well static."

The amount of gas in the riser was not indicated.

For a third incident there was also gas in the riser, but for this incident the gas came through a leaking annular preventer during a kick circulation operation

There also was another similar incident August 4th, 2009. This well was not included in the material reviewed for this study, because no verbal description of the operations exists in the e-Well system. The incident was however investigated by the MMS, and a separate investigation report was issued (/14/). The well was drilled by Rig BP in 5641 ft (1719 m) of water.

After a kick was believed to be under control the following was stated in the investigation report:

When the fill from bottoms-up was approximately xxxx ft from surface, gas started to rapidly break out of the mud, the diverter was closed and returns were routed to the riser mud degasser. The surge from the gas breaking out of the mud pushed the mud up and out the mud degasser's vent line. The riser volume dropped approximately 68 feet (decrease of 180 barrels or 37 psi), with no additional open hole influx observed.

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9.7 Kick Killing Duration

Figure 9.6 shows the kick killing duration. The time from the kick occurred until the well was controlled and the operations could continue, is included in the killing duration.

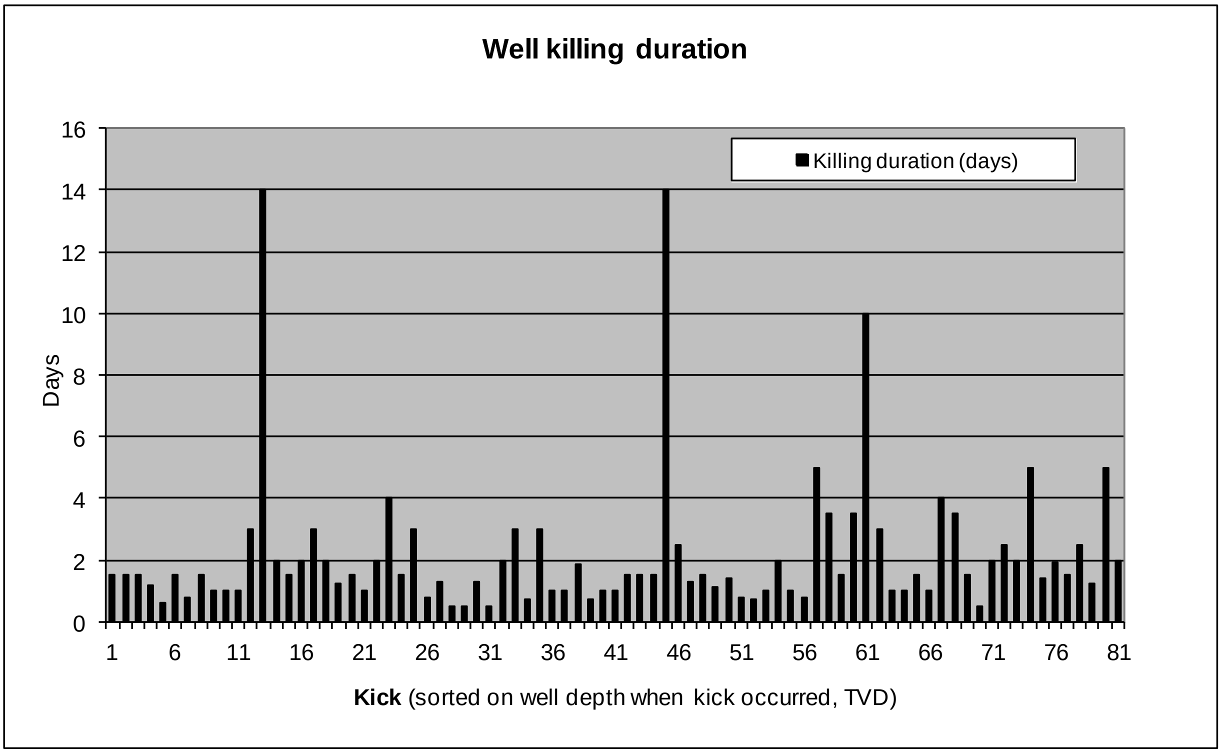

Figure 9.6 Killing duration

Thirty one percent of the kicks are controlled within one day, 44% are controlled in between one and two days, 21% are controlled in between two and five days, and 4% lasted more than 5 days.

Table 9.1 Average Kick Duration vs. Water Depth

Water depth grouped (ft)/(m)	Number of kicks	Sum of killing duration (days)	Average killing duration
2000-4000 / 610-1219	39	85,6	2,2
4000-6000 / 1219-1829	28	58,5	2,1
6000-10141 / 1829-3091	14	31,1	2,2
Total	81	175,2	2,2

There were found no correlation between water depth and well depth with the kick duration. It should be noted that when the kick caused problems with stuck pipe, or other that required the well to be abandoned or side-tracked, this is not included in the killing duration. This is discussed in Section 11.2.2, page 127. Factors affecting the killing duration are further discussed in Section11.3, page 128.

9.8 Mud Type vs. Casing Size

Table 9.2 shows the mud type used vs. casing size when the kick occurred.

Table 9.2 Mud type vs. casing size

Mud type	Casing OD (inch) grouped						Total
	20 - 22	16	13,375 - 13,625	10,576 - 11,875	9,375 - 9.875	7,625 - 7,75	
Water based mud	1		2	1	1	1	6
Synthetic based mud	2	2	12	9	4		29
Oil based mud			1		1		2
Unknown	6	8	13	8	5	1	41
Waterbased, workover, compl., drill-in mud						3	3
Total	9	10	28	18	11	5	81

Kicks may occur in any section of the well. Compared to the 2001 study (/2/) the distribution is similar.

The information about the mud types used is less fulfilled in this study, but it may seem that synthetic based muds are used more now than it was in the late 90-ties.

9.9 Kick Medium vs. Casing Size

Most kicks contain gas. Two kicks are listed with both oil and gas and one was kicking water. For 20 of the kicks the kick medium is listed as unknown, because it was not possible to find any reference to gas in the e-Well information.

Even though the oil is not mentioned in the text it is believed that for many of the kicks oil was also present, but the major issue in controlling the kicks is the gas and the gas expansion.

9.10 Tubular Running through the BOP when the Kick Occurred

For all the kicks the tubular running through the BOP when the kick occurred was recorded. Table 9.3 shows an overview of the tubular running through the BOP when the kick occurred

Table 9.3 Tubular running through the BOP when the kick occurred

Type of tubulars	Total
Coiled tubing	1
Drill pipe	76
Empty hole	2
Tubing	1
Wireline	1
Total	81

The majority of kicks occur when there is a normal drillpipe running through the BOP. For one of the two empty hole incidents they bullheaded 15.8 ppg synthetic based mud. They were in the process of running 9-5/8"liner when the incident occurred, but they had pulled the liner out of the hole due to some problems. For the second empty hole incident they had pulled out to 1061 ft (inside the riser) when observed a gain. Shut the well in and the gain stopped with no recorded pressure. Swept BOPs and pumped 50 bbls of 11.0 ppg down the kill line and spot same @ 2040'. Tripped in hole with cement stinger assembly to 6668'. Spotted 100 bbl 11.0 hi-vis pill.

For the wireline incident the well started flowing during logging when the wireline was at 17,850 ft. Pooh with the wireline. Monitored the well on the trip tank. Gained 66 bbls. Shut the well in with the lower blind shears and monitored on kill line. The initial shut in pressure was 100 psi that increased to 150psi. Started to bullhead 15.4 ppg down kill line. Failed to control the pressure. Displaced the riser with 16.2 ppg mud and then bullheaded 16.2 ppg mud down choke and kill line. Rih with 6.625 in drill pipe from 3,392 ft to 4,250 ft.

For the coiled tubing incident they had milled an obstruction with coil tubing. The coiled tubing became stuck and they had to cut the coiled tubing above injection head and rigged up wireline. Made three attempts to run free point assembly but unable to get down. RIH with cutter assembly to 6000. Noticed flow from coiled tubing annulus. Shut well in. Pumped down coil tubing with returns up landing string. Attempted to pull coil free. Killed well by bullheading 17.3 ppg fluid.

9.11 Well Depth vs. Fracture Strength and Mud Weight

In general the equivalent fracture strength (found through LOT or alternative FIT) increases with increasing formation depth. For 70 of the 81 kicks a LOT or FIT value was found in the source data. This has been visualized in Figure 9.7. For all the kicks the TVD of the casing shoe has been plotted against the LOT of the casing shoe.

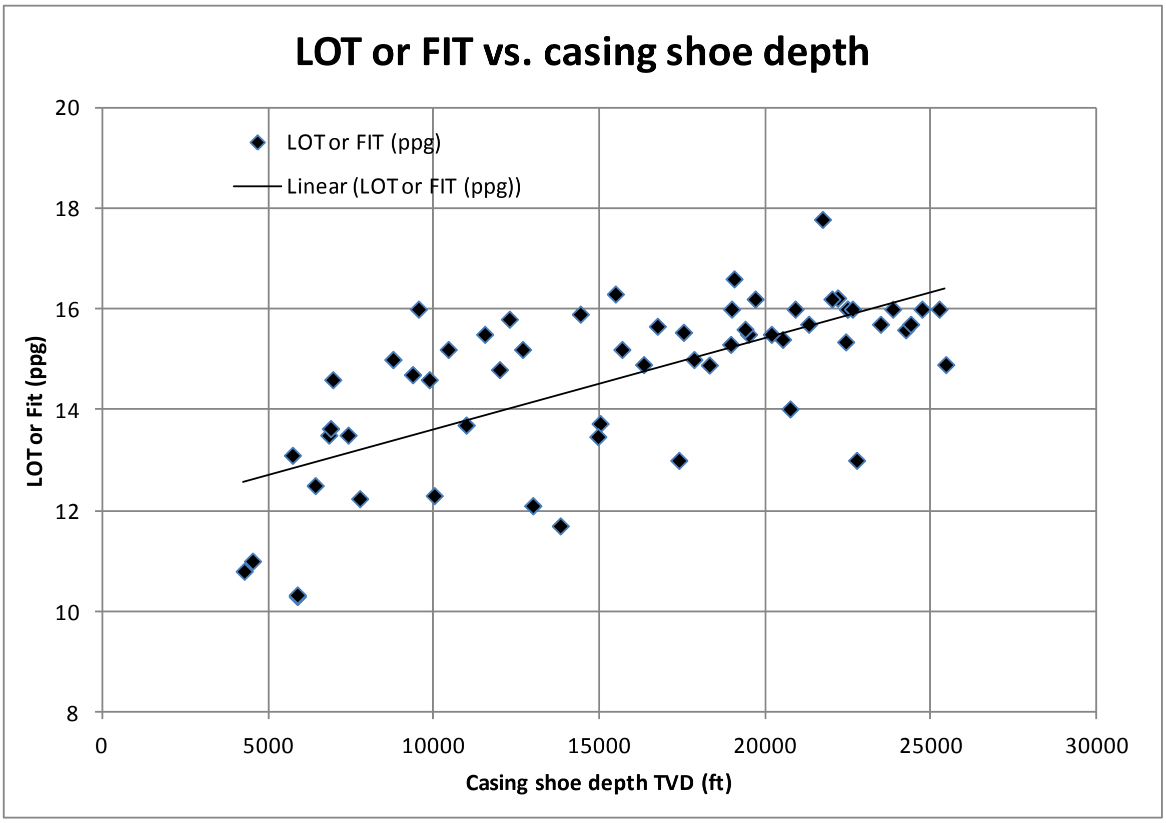

Figure 9.7 Fracture strength vs. casing shoe depth for all kicks

For 69 of the 81 kicks the mud weight was found in the source data. The same trend has been made for the mud weight (or pore pressure) as shown in Figure 9.8.

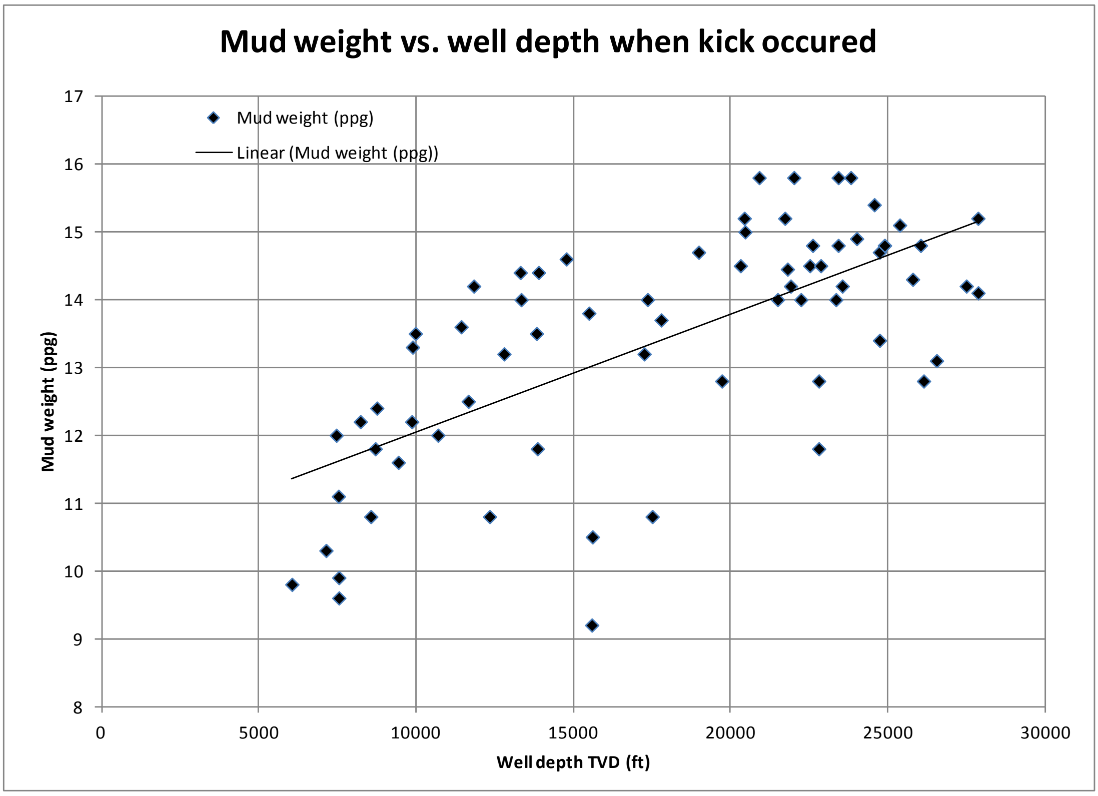

Figure 9.8 Mud weight (or pore pressure) vs. well depth when kick occurred

10 Kick Causes

The frequency of deepwater kicks is relatively high (Section 8.2 on page 95). This section focuses primarily on the operation and activities when the kick occurred and the direct reason for the loss of barriers.

The causes of the kicks have been included in the database when collecting the data. It should here be noted that specific causes were normally not stated in the data source. The kick causes listed have been assessed by evaluating the operations and observations listed prior to the kick.

10.1 Operation Activity when the Kick Occurred

Table 10.1 shows the operation and activity that were ongoing when the kick occurred.

Table 10.1 Operation activity when the kick occurred

Operation	Activity	Development drilling	Exploration drilling	Total
Abandon well	POOH before cementing		1	1
Running casing or liner	Wait on cement		2	2
	Circulating	1		1
	Cement liner, set liner hanger		1	1
Circulating	POOH		1	1
Coiled tubing	Stuck coil tubing		1	1
Drilling	Actual drilling	3	43	46
	Back reaming		1	1
	Circulating	1	8	9
	Curing losses		1	1
	Logging (Wireline)		1	1
	POOH		3	3
	POOH and circulate		1	1
	Reaming		1	1
	Repairing equipment		1	1
	RIH wash and ream		1	1
	Treating lost circulation		1	1
Logging	RIH		1	1
Perforating	Actual perforating	1		1
	Pulling string		1	1
	Reverse Circulating		1	1
Plug back well	Displaced riser		1	1
Running Gravel pack assembly	Trip in hole	1		1
Surveying	Circulating		1	1
	POOH		1	1
Total		7	74	81

As expected the majority of kicks occurred during drilling operations. Sixty-six of the incidents occurred during drilling operations, whereof 46 occurred while actual drilling new hole. Four of these incident occurred when drilling the shoe track.

Nine of the drilling incidents occurred during mud circulating, it is here however likely that the gas was already inside the well bore.

There were only four kicks that occurred during casing running operations.

10.2 Activity and Primary Cause of Kick

It has been selected not to separate the development and exploration wells for the remaining of this section.

Table 10.2 shows the ongoing activity and the assumed (by the project group) cause of the kick. The causes of the kick were for most cases not explicitly stated in the data source.

Table 10.2 Activity and primary cause of kick

Activity	Primary kick cause (Loss of barrier 1)	Total
Actual drilling	Annular losses and gains	1
	Drilling break	2
	Gas cut mud	5
	Swabbing	2
	Too low mud weight	33
	Unknown	3
Actual perforating	Too low mud weight	1
Back reaming	Swabbing	1
Circulating	Annular losses and gains	1
	Gas cut mud	4
	Too low mud weight	5
	Unknown	1
Curing losses	Annular losses	1
Displace riser	Gas cut mud	1
Logging (Wireline)	Annular losses and gains	1
Pull out of hole	Annular losses, swabbing	1
	Swabbing	2
	Swabbing, gas cut mud	1
	Unknown	1
POOH and circulate	Annular losses and gas cut mud	1
Pulling string	Trapped gas in BOP	1
Pump out of hole, monitor well	Too low mud weight	1
Reaming	Swabbing	1
Repairing equipment	Gas cut mud	1
Reverse Circulating	Too low mud weight	1
RIH	Gas cut mud, temp expansion, well open for a long time	1
RIH wash and ream	Swabbing	1
Set liner hanger	Gas migration thru cmt	1
Stuck coil tubing	Too low mud weight	1
Treating lost circulation	Gas cut mud	1
Trip in hole	Too low mud weight	1
Wait on cement	Leaking through cement	1
	Swabbing	1

When reading the results in Table 10.2 it is important to note Figure 9.4 on page 110 and

Table 10.3. The relatively narrow margin between the LOT and the MW indicates that it will be fairly easy to experience a kick or annular losses, because both the kick margin and the trip margin have to be kept within strict limits. The effect of a low LOT - MW for the deeper sections drilled is discussed in Section 10.4 on page 122.

It should further be noted that the category "Too low mud weight" also included incidents with an "Unexpected high well pressure". Kicks categorized with the kick cause "Too low mud weight" only, were typical kicks where no specific indication of kick cause was given in the well activity reports.

The most significant contributors to the kick occurrence were:

- Too low mud weight (43 kicks)
- Gas cut mud (15 kicks)
- Swabbing (10 kicks)
- Unknown (5 kicks)
- Annular losses and gains (3 kicks)
- Annular losses (3 kicks)
- Drilling break (2 kicks)
- Leaking through cement (2 kicks)
- Trapped gas in BOP (1 kicks)
- temperature expansion, well open for a long time (1 kicks)

The frequent occurrences of too low mud weight may to a large degree be explained by the relatively small difference between the fracture pressure and the pore pressure. Annulus friction during circulation is also likely affecting this problem.

Gas cut mud occurs when formation gas mixes with the mud. This effect reduces the mud density, and at a certain level it will cause that the hydrostatic control of the well is lost.

When drilling break is listed as a partial cause of the kick, a drilling break has been mentioned in the well activity report just prior to the incident. A drilling break may occur when drilling into gas bearing sands.

The ballooning effect is observed in association with annular losses. First annular losses are observed, thereafter the formation partly returns the losses. This effect has contributed to the kick occurrence for some kicks. It should be noted that this effect occurred several times when reviewing the well activity reports, but did normally not cause a kick.

Swabbing is typically a main contributor to kicks during tripping out of the hole. If the trip margin is low, the mud weight is cut by gas, or the well is improperly filled up, it is more likely that swabbing will cause a kick.

10.3 Drilling Margin and Kick Occurrence

A well must be designed to manage pore pressure and fracture gradients at different well depths. Pore pressure is the pressure exerted by fluids in the pore space of the formation being drilled. Fracture pressure is the point at which pressure exerted by the drilling fluid in the well would cause the surrounding formation to fracture.

The difference between pore pressure and the fracture gradient define the drilling margin.

The fracture pressure is normally determined by a leak-off test (LOT). This test is conducted immediately after drilling past the cemented casing shoe. Sometimes they do not test the formation until leak off but to a lower pressure that is regarded as high enough for the subsequent drilling. This is called a formation integrity test (FIT).

The mud weight (MW) needs to be higher than the pores pressure to avoid an influx into the well and lower than the LOT or FIT to avoid leakage of drilling mud to the formation.

The Code of Federal Regulations § 250.427(b) regulates the requirements for pressure integrity tests and drilling margin, but the regulation does not specify what a specific minimum requirement for a safe drilling margin.

In general, the narrower the drilling margin is, the more difficult it is to drill the well. Factors like gas cut mud and swabbing is more likely to occur. Killing the well is more difficult due to the increased risk of fracturing the well.

In Table 10.3 the primary kick causes vs. difference between the leak off test pressure (LOT) and the mud weight (MW) when the kick occurred, the kill mud weight, and the maximum mud weight used for the specific section where a kick occurred is shown.

Table 10.3 Primary kick causes vs. difference between LOT or FIT and mud weights

Primary kick cause	LOT/FIT – MW when kick occurred				LOT/FIT- kill MW to control the kick				LOT/FIT – max MW when drilling present section				Total
	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	
Annular losses and gains			2	1			2	1		1	1	1	3
Annular losses and gas cut mud	1				1				1				1
Annular losses, Swabbing				1				1				1	1
Drilling break		1			1				1				1
Gas cut mud	1	2	8	1	4	3	5		4	3	5		12
Leaking through cement				1			1	1		1		1	2
Swabbing	1	1	4	2	3	1	2	2	4		1	3	8
Swabbing, gas cut mud	1				1				1				1
Too low mud weight	1	6	24	11	13	14	10	5	19	13	5	5	42
Too low mud weight, drilling break	1				1				1				1
Too low mud weight, gas cut mud, temp expansion, well open for a long time			1				1				1		1
Too low mud weight, losses			1				1				1		1
Too low mud weight, unknown why				1				1				1	1
Trapped gas in BOP				1				1				1	1
Unknown	2	2		1	1	3		1	3	2			5
Total	8	12	40	21	25	21	22	13	34	20	14	13	81

It is difficult to identify any relation between the primary kick cause and the difference between the LOT or FIT and the mud weight.

If disregarding the kicks where the difference between the LOT/FIT and the mud weight were unknown, approximately one third of the kicks occurred where the margin was less than 1 ppg and two thirds in wells where the margin was above 1 ppg.

To control a kick the MW is normally increased. This can also be observed in Table 10.3. Then the margin between the LOT/FIT – mud weight will be further reduced.

As they are drilling the section further after a kick, the MW is often further increased to keep the mud weight above the pore pressure, further decreasing the margin between the LOT/FIT – mud weight.

Table 10.4 shows casing sizes when kick occurred vs. difference between LOT or FIT, and mud weights.

Table 10.4 Casing sizes when kick occurred vs. difference between LOT or FIT, and mud weights

Casing size group	LOT/FIT – MW when kick occurred				LOT/FIT- kill MW to control the kick				LOT/FIT – max MW when drilling present section				Total
	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	
16 and above	2	3	8	6	6	5	6	2	9	5	3	2	19
10,5 - 14"	6	6	27	7	15	13	12	6	22	11	8	5	46
9 3/8 - 10 1/4"		2	5	4	3	3	4	1	2	4	3	2	11
7" - 8 5/8"		1		4	1			4	1			4	5
Total	8	12	40	21	25	21	22	13	34	20	14	13	81

It may seem that low drilling margin is more common in large diameter wells than in for smaller diameter. This is also to expect, because the swabbing risk in this part of the well is less than in parts with smaller diameters.

Nineteen, or 23 % of the kicks, occurred when the casing or liner in the well was 16” or larger. The depth of the casing or liner shoe for these 19 kicks varied from 3949 ft to 19487 ft TVD, with an average of 10 320 ft TVD. The average depth when the kick occurred was 12 976 ft TVD.

Forty-six, or 57% of the kicks occurred when 10,5 - 14" casing or liner was in the well. This was typical 13 5/8” or 11 7/8” casing, and they were drilling the section for the 9 7/8” casing. The depth of the casing or liner shoe for these 46 kicks varied from 6250 ft to 25 438 ft TVD, with an average of 16 708 ft TVD. The average depth when the kick occurred was 18 805 ft TVD, so the majority of the kicks occurred in deep parts of the well.

Eleven, or 14 % of the kicks occurred when 9 3/8 – 10 1/4" casing or liner was in the well. The depth of the casing or liner shoe for these 11 kicks varied from 9875 ft to 23 465 ft TVD, with an average of 17 004 ft TVD. The average depth when the kick occurred was 18 828 ft TVD, so the majority of the kicks occurred in deep parts of the well.

Five, or 6% of the kicks occurred when 7 – 8 5/8” casing or liner was in the well. The depth of the casing or liner shoe for these 5 kicks varied from 13 305 ft to 25 238 ft TVD, with an average of 19 335 ft TVD. The average depth when the kick occurred was 19 966 ft TVD, so the majority of the kicks occurred in deep parts of the well.

Table 10.5 shows well depth when kick occurred (TVD ft) vs. difference between LOT or FIT, and mud weights

Table 10.5 Well depth when kick occurred (TVD ft) vs. difference between LOT or FIT, and mud weights

Well depth when kick occurred (TVD ft)	LOT/FIT – MW when kick occurred				LOT/FIT- kill MW to control the kick				LOT/FIT – max MW when drilling present section				Total
	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	
< 8000	2	1	3	1	2	2	2	1	4		1	2	7
8000 - 13000		2	10	3	3	6	3	3	8	2	3	2	15
13000 - 20000		3	9	10	6	7	5	4	6	11	2	3	22
> 20000	6	6	18	7	14	6	12	5	16	7	8	6	37
Total	8	12	40	21	25	21	22	13	34	20	14	13	81

The well kicks occur on all well depths. Thirty-seven, or 46% occurred deeper than 20 000 ft TVD. The deepest kick occurred at 27 860 ft TVD.

Table 10.6 Casing depth when kick occurred (TVD ft) vs. difference between LOT or FIT, and mud weights

Casing depth when kick occurred (TVD ft)	LOT/FIT – MW when kick occurred				LOT/FIT- kill MW to control the kick				LOT/FIT – max MW when drilling present section				Total
	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	< 0,5	0,5 < 1	> 1	Un-known	
< 8000	2	2	8	3	4	5	3	3	9	1	2	3	15
8000 - 13000		2	10	5	5	6	5	1	8	5	3	1	17
13000 - 20000	1	3	11	7	9	6	3	4	7	8	4	3	22
> 20000	5	5	11	6	7	4	11	5	10	6	5	6	27
Total	8	12	40	21	25	21	22	13	34	20	14	13	81

Twenty-seven, or 33% occurred when the casing shoe was deeper than 20 000 ft TVD. The deepest casing shoe when a kick occurred was 25 438 ft TVD. The deepest casing shoe of all the wells included was 31 498 ft TVD.

10.4 Leak Off Pressure vs. Maximum Mud Weight, all "Deep" Wells

To further investigate the possible effect on kick occurrences vs. the LOT/FIT – MW were closer examined. The idea was to identify if the LOT/FIT – MW were lower in the wells that experienced a kick with the wells that did not experience a kick.

To do so the LOT/FIT was identified for all the casing sections included in the study. Further, the maximum mud weights used when drilling for the next casing sections were identified. This information was mostly found directly from tables in the well activity reports (Section 2.1.2, page 21) and partly from the activity description in the well activity reports. Of the total of 714 different casing strings, this information was identified for 522 of the strings. It should be noted that there are some uncertainties related to the accuracy of these numbers.

When experiencing a kick, the mud weight is normally increased as a part of the kick controlling operations. When drilling deeper the mud weight is frequently increased further to keep the well under hydrostatic control. When doing the comparison of the well sections that experience the kicks with the wells that did not kick, it is the maximum mud weight of the section that has been compared.

Table 10.7 shows average LOT or FIT – mud weight when the kick occurred, while Table 10.8 shows the average LOT or FIT – Max mud weight for the sections that experienced a kick and the sections that did not experience a kick.

Table 10.7 Mud weight – LOT or FIT when the kicks occurred

Casing group(inch)	*MW-LOT/FIT < 0,5 ppg*		*MW-LOT/FIT > 0,5< 1 ppg*		*MW-LOT/FIT > 1 ppg*		*Unknown*	*Total*	
	No. of kicks	*Average of MW-LOT/FIT (ppg)*	*No. of kicks*	*Average of MW-LOT/FIT (ppg)*	*No. of kicks*	*Average of MW-LOT/FIT (ppg)*	*No. of kicks*	*No. of kicks*	*Average of MW-LOT/FIT (ppg)*
16 and above	2	0,45	3	0,78	8	1,56	6	19	1,21
10,5 - 14"	6	0,37	6	0,74	27	1,62	7	46	1,29
9 3/8 - 10 1/4"			2	0,95	5	1,64	4	11	1,80
7" - 8 5/8"			1	0,80			4	5	0,80
Total	8	0,39	12	0,79	40	1,61	21	81	1,33

Table 10.8 Max mud weight – LOT or FIT for all well sections, except the unknown

Kick or not	Casing group (inch)	*Max MW-LOT/FIT < 0,5 ppg*		*Max MW-LOT/FIT > 0,5< 1 ppg*		*Max MW-LOT/FIT > 1 ppg*		*Total*	
		No. Well sections	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*
Sections with kick	16 and above	5	0,08	7	0,69	3	1,51	15	0,65
	10,5 - 14"	14	0,19	11	0,74	8	1,55	33	0,70
	9 3/8 - 10 1/4"	2	0,15	4	0,74	3	1,20	9	0,76
	7" - 8 5/8"			1	0,50			1	0,50
	Total	21	0,16	23	0,71	14	1,47	58	0,69
Sections without kick	16 and above	62	0,25	115	0,72	46	1,47	223	0,74
	10,5 - 14"	21	0,21	88	0,76	68	1,59	177	1,01
	9 3/8 - 10 1/4"	6	0,14	23	0,75	27	1,59	56	1,09
	7" - 8 5/8"	1	0,30	3	0,97	4	1,58	8	1,19
	Total	90	0,23	229	0,74	145	1,55	464	0,90
Total		111	0,22	252	0,74	159	1,54	522	0,87

From Table 10.8 it can be observed that the Max mud weight – LOT or FIT are lower in the casing sections that experienced kicks than the sections that did not experience kicks. The overall average for the section that experienced a kick was 0,69 ppg while for the sections that did not experience a kick it was 0,90. This is a result that is expected in general. The lower the drilling margin is the higher the kick frequency is expected to be. It is however important to note that for many of the sections where no kicks were experienced the drilling margin was narrow.

Table 10.9 shows the same type of information as Table 10.8, but it is grouped in accordance with the depth of the casing shoe.

Table 10.9 Max mud weight – LOT or FIT for grouped well casing shoe depth depths, except the unknown

Kick or not	Well casing shoe depth grouped (ft TVD)	*Max MW-LOT/FIT < 0,5 ppg*		*Max MW-LOT/FIT > 0,5< 1 ppg*		*Max MW-LOT/FIT > 1 ppg*		*Total*	
		No. Well sections	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*	*No. Well sections*	*Average of Max MW-LOT/FIT (ppg)*
Sections with kick	< 8000	6	0,14	2	0,60	2	1,32	10	0,47
	8000 - 13000	2	0,40	7	0,73	3	1,50	12	0,87
	13000 - 20000	6	0,04	8	0,80	4	1,45	18	0,69
	> 20000	7	0,21	6	0,62	5	1,52	18	0,71
	Total	21	0,16	23	0,71	14	1,47	58	0,69
Sections without kick	< 8000	27	0,21	57	0,71	21	1,64	105	0,77
	8000 - 13000	31	0,24	79	0,73	53	1,43	163	0,86
	13000 - 20000	16	0,27	55	0,79	45	1,62	116	1,04
	> 20000	16	0,22	38	0,75	26	1,60	80	0,92
	Total	90	0,23	229	0,74	145	1,55	464	0,90
Total		111	0,22	252	0,74	159	1,54	522	0,87

10.5 Kick Frequencies per Casing Section

A total of 714 casing section have been included in the database. The kick frequency per section category is shown in Table 10.10.

Table 10.10 Kick frequency pr casing category

Casing Category	No. of kicks	No. of casing section with kicks	No. of casing section without kicks	Total no. of casing sections	Kick frequency pr. casing section
a 16 and above	19	17	293	310	0,061
b 10,5 - 14"	46	38	210	248	0,185
c 9 3/8 - 10 1/4"	11	11	102	113	0,097
d 7" - 8 5/8"	5	5	38	43	0,116
Total	81	71	643	714	0,113

The highest frequency of kick occurs when drilling after the casing of category 10,5 -14” is set. That is in most cases when drilling the hole for the 9 7/8” casing.

11 Analyses of Kick Killing Operations

This section focuses on the killing procedures, killing problems and killing duration for the 81 experienced kicks. Table 11.1 shows the killing duration of the experienced kicks.

Table 11.1 Killing duration distribution of the 48 kicks

Killing duration grouped (days)	No. of kicks	Total days used
≤ 1	25	20,9
$1 \leq 2$	36	57,3
$2 \leq 5$	17	59,0
$5 \leq 10$	0	0,0
$10 \leq 15$	3	38,0
All	**81**	**175,2**
Average		**2,16**

Many of the kicks were time-consuming to control. Most of the kicks, 75% were controlled within two days. For three kicks they used more than ten days control the kick. The average time spent to control a deepwater kick was 2,16 days.

The problems and relevant factors affecting the kick killing are discussed in the following subsections. Section 11.1 presents the killing methods in general, Section 11.2 discusses specific problem types observed during the killing of the various wells, and Section 11.3, page 128 attempts to identify correlations between the killing duration and well characteristics.

11.1 Killing Methods

The following killing methods categories were used;

- Drillers method
- Wait and Weight
- Bullheading
- Various
- Other
- Unknown

During a well kill operation various methods can be used. It is here attempted to identify the main method. For the kicks with very long duration a series of killing methods were used.

Table 11.2 shows the no. of the various killing methods used alongside the grouped killing duration time.

Table 11.2 Killing method vs. killing duration

Killing method (main)	Killing duration grouped (days)				Total
	≤ 1	1 ≤ 2	2 ≤ 5	10 ≤ 15	
Drillers method	10	17	9		36
Wait and Weight	12	14	7		33
Bullheading	2	3	1		6
Various				3	3
Other	1	1			2
Unknown		1			1
Total	25	36	17	3	81

.
Drillers method and Wait and Weight are the two most commonly used methods. Due to limited detail in many cases it is not always easy to distinguish these two methods from each other. For many kicks circulation alone could not control the kick and a combination of different methods was required. For the most time-consuming kicks, typically several methods were used before the kick was controlled.

Eight times it was specifically stated that both the choke and the kill lines were used for circulation. It may have been used more times. By using both lines, higher pumping rates can be used without increasing the bottom hole pressure above the formation fracture pressure. Fracturing the formation will complicate the kick killing operation. This is typically a deepwater problem. The friction depend on the choke and kill line lengths, diameters of lines, the velocity in the lines, and the fluid properties. Newer deepwater rigs may have 4, 5” lines while older rigs typically have 3” lines.

11.2 Factors investigated, Well Killing Operations

Some factors have been investigated to see if there are factors of importance for the kick killing. It should be noted that the description of the kicks in the well activity reports varies highly, and in many cases it is difficult to withdraw the specific information sought from the description.

11.2.1 Ballooning and Losses

Of the 81kicks evaluated problems related to ballooning or well losses were identified for 21 of these kicks. It is reasonable to assume that the ballooning and losses problems are related to the LOT/FIT observed and the MW margin. To check this assumption LOT/FIT - MW was investigated for the kicks that experienced ballooning and losses during the kick killing operation with the kicks that did not. Table 11.3 shows the results from a comparison between the LOT/FIT and the kill mud weight (KWM) and the max mud weight for the section drilled.

Table 11.3 Comparison between the LOT/FIT and the kill mud weight (KWM) and the max mud weight (Max MW) for the section drilled for wells with identified losses and ballooning

Kill Ballooning/losses	No. of kicks	Average of LOT/FIT – **Kill** MW	Unknown	No. of kicks	Average of LOT/FIT – **Max** MW	Unknown	Total
Ballooning or losses	20	0,75	3	21	0,61	2	23
Ballooning or losses not identified	48	0,84	10	47	0,73	11	58
Total	**68**	**0,81**	3	68	0,70	13	81

Table 11.3 shows that for the kicks identified with losses they in average had a lower difference between the LOT/FIT and the max mud weight. This difference does however

seem rather low. For two of the incidents the difference between the LOT/FIT and mud weight was around two. So, losses and ballooning may occur during killing for such wells as well.

11.2.2 Stuck Pipe

Stuck drill pipe occurred in connection with 11 of the 81 kicks, not including one incident where a coiled tubing became stuck.

When the drill pipe becomes stuck during a kick control operation it becomes more difficult to regain the well control and thereby increase the killing time. Further, after regaining the well control it is a likely that the well has to be abandoned or side-tracked.

This is clearly verified through the average time to control a kick with and without stuck pipe. The average time for controlling kicks with stuck pipe was 4,39 days, vs. 1,81days for kicks that did not experience stuck pipe. This time only includes the time until the well was controlled.

For five of the 11 stuck pipe incident they had to severe the pipe, cement the hole and sidetrack the well.

The total time used to severe the pipe, plug the bore, and drill sidetrack to the same depth as before the pipe became stuck for these five incidents was 44 days or in average 9 days per incident.

Table 11.4 shows the average length of open hole sections for wells that experienced stuck pipe vs. wells that did not experience stuck pipe alongside the LOT/FIT value and the kill mud weight.

Table 11.4 Open hole sections and LOT/FIT – kill mud weight for stuck pipe incidents

Pipe stuck during kick?	No. of kicks	Average of killing duration (days)	Average of Kick data LOT/FIT - KMW	Average of Open hole section ft TVD	Average of Open hole section ft MD
No	70	1,81	0,84	1904	2056
Yes	11	4,39	0,62	3074	3342
Total	81	2,16	0,81	2063	2231

Stuck drill pipe seems to be more likely during well kicks in wells with low drilling margin compared to wells with higher drilling margin. There also seem to be a correlation between the probability of becoming stuck during a kick killing operation and the length of the open hole section.

Table 11.5 shows the open hole sections for stuck pipe incidents and casing sizes during kick situations vs. the incidents that did not experience any stuck pipe.

Table 11.5 Open hole sections length, stuck pipe and casing size

Casing group (inch)	No stuck pipe incidents		Stuck pipe incidents		Total	
	No. of kicks	Average length of open hole section ft TVD	No. of kicks	Average length of open hole section ft TVD	No. of kicks	Average length of open hole section ft TVD
16 and above	16	2698	3	2439	19	2657
10,5 - 14"	40	1928	6	3221	46	2097
9 3/8 - 10 1/4"	9	1093	2	3585	11	1546
7" - 8 5/8"	5	631			5	631
Total	70	1904	11	3074	81	2063

Table 11.5 shows a narrow hole and a long open hole section further increases the probability of becoming stuck during a kick killing operation.

Table 11.6 shows the open hole sections for stuck pipe incidents and area during kick situations vs. the incidents that did not experience any stuck pipe.

Table 11.6 Open hole sections length, stuck pipe and area

Area	No stuck pipe incidents		Stuck pipe incidents		Total	
	No. of kicks	Average length of open hole section ft TVD	No. of kicks	Average length of open hole section ft TVD	No. of kicks	Average length of open hole section ft TVD
AC - Alaminos Canyon	1	1797			1	1797
AT - Atwater	7	1443			7	1443
DC -Desoto Canyon	1	48	1	5412	2	2730
EB - East Breaks	2	522	1	2300	3	1115
GB - Garden Banks	9	1198	1	3870	10	1465
GC - Green Canyon	17	2645	2	3585	19	2744
KC - Keathley Canyon	3	4065			3	4065
MC - Mississippi Canyon	22	1683	5	2356	27	1808
WR- Walker Ridge	8	1915	1	3280	9	2067
Total	70	1904	11	3074	81	2063

11.3 Relations between some Well Parameters and Prolonged Killing Time

Six different factors have been seen as potential reasons for the problems occurring during killing operations. In this subsection the kick duration vs. the following factors have been evaluated:

- Water depth (Section 11.3.1)
- Well depth (TVD) (Section 11.3.2)
- Maximum theoretical shut-in pressure (Section 0)
- Casing shoe depth (TVD) (Section 11.3.5)
- Open hole length (Section 11.3.6)
- Fracture strength (LOT) – mud weight (MW) (Section 11.3.7)

11.3.1 Water Depth vs. Killing Duration

Figure 11.1 shows an XY plot for the water depth vs. the killing duration.

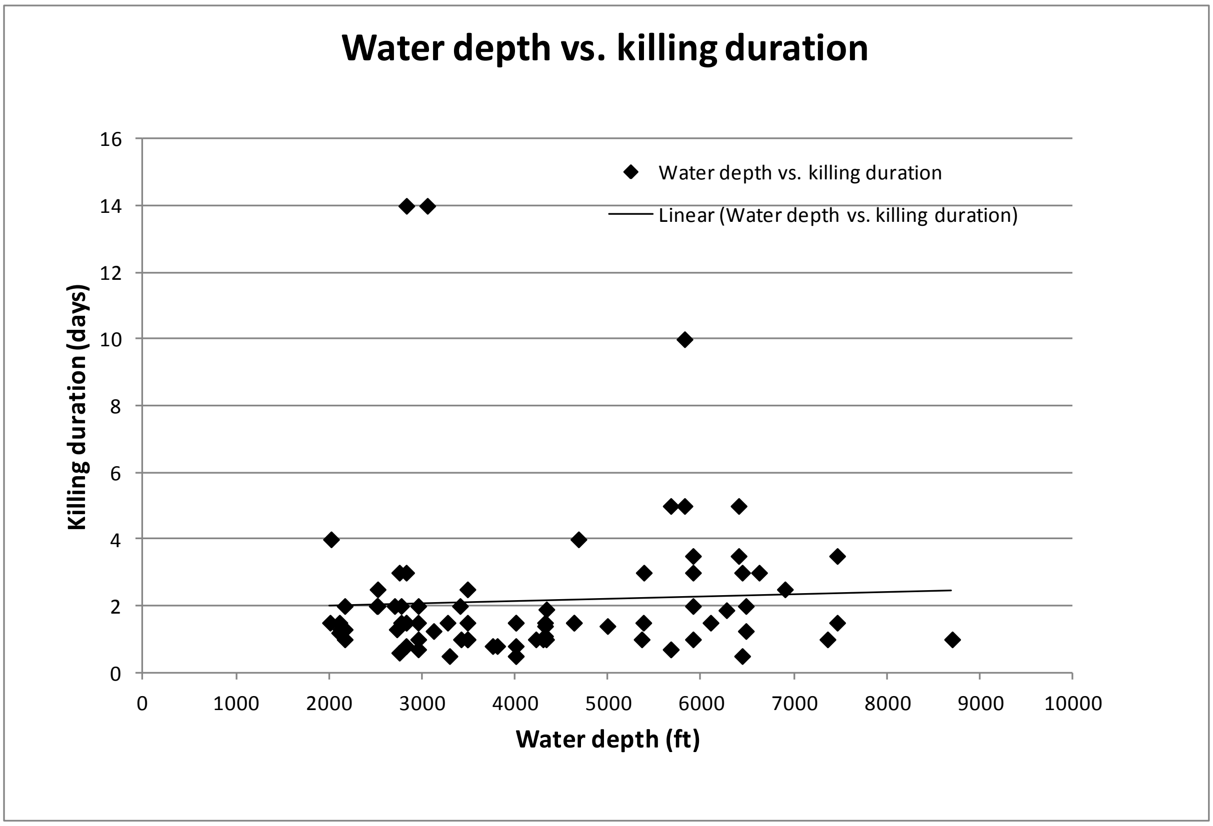

Figure 11.1 Water depth vs. killing duration

As seen from Figure 11.1 there cannot be observed any trend in the killing time vs. increased water depth.

The same data as in Figure 11.1 have been grouped in Table 11.7.

Table 11.7 Water depth grouped vs. killing duration

Water depth grouped (ft)	No. of kicks	Average of killing duration (days)
2000-4000	39	2,19
4000-6000	28	2,09
6000-10141	14	2,22
Total	81	2,16

There is little difference in the average killing duration for the three depth groups. The two most time-consuming kicks occurred in less than 4000 ft of water. One time long consuming kick occurred between 4000 and 6000 feet of water. These kicks will strongly affect the average killing times. If disregarding these three time-consuming kicks, there may seem to be a trend where the kick control time increases with the water depth.

11.3.2 Well Depth (TVD) vs. Killing Duration

Figure 11.2 shows an XY plot for the well depth when the kick occurred vs. the killing duration.

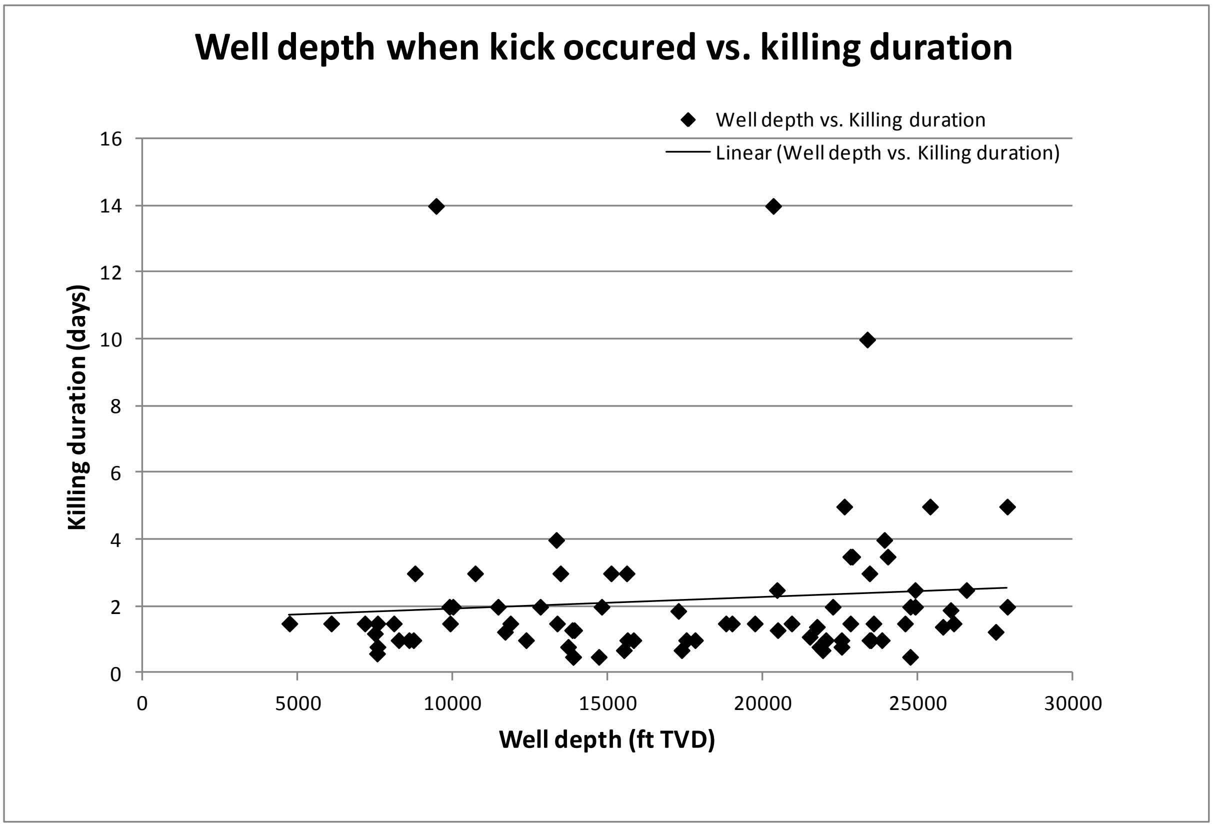

Figure 11.2 Well depth when the kick occurred (TVD) vs. killing duration

There is no significant trend in the killing duration with increasing well depth. If disregarding the three kicks with the 14, 14 and 10 days duration the correlation would be more evident. Kicks of long duration will have a large effect on such a trend line.

Table 11.8 shows the same data as in Figure 11.2, but now the depths have been grouped and the duration averaged.

Table 11.8 Well depth grouped (TVD) vs. killing duration

Well depth grouped; when kick occurred TVD (ft)	No. of kicks	Average of killing duration (days)
<8000	7	1,23
8000 - 13000	15	2,52
13000 - 20000	22	1,51
20000 - 27860	37	2,59
Total	81	2,16

The three kicks with 10, 14 and 14 days duration have large effect on the average durations and raises the average of the 8000-13 000 ft group with 0,82 days. For the group 20 000 to 27860 ft the average increase will be 0,54 days

11.3.3 Casing shoe depth (TVD) vs. killing duration

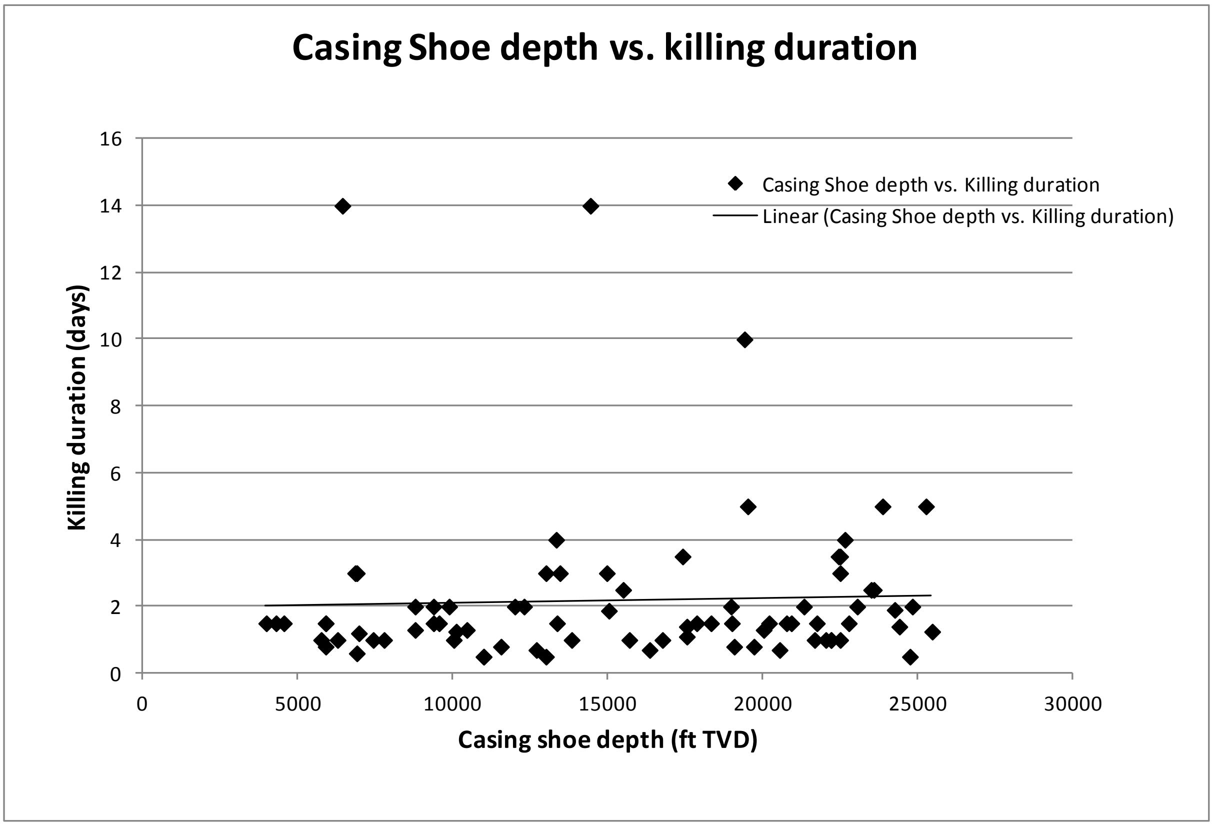

Figure 11.4 Casing shoe depth (TVD) vs. killing duration

There is no significant trend in the killing duration with increasing casing shoe depth. If disregarding the three kicks with the 14, 14 and 10 days duration it may seem to be a more evident correlation. Kicks of long duration will have a large effect on such a trend line.

11.3.4 Maximum Theoretical Shut-in Pressure vs. Killing Duration

Figure 11.3 shows a XY plot of the maximum theoretical shut-in pressure vs. killing duration.

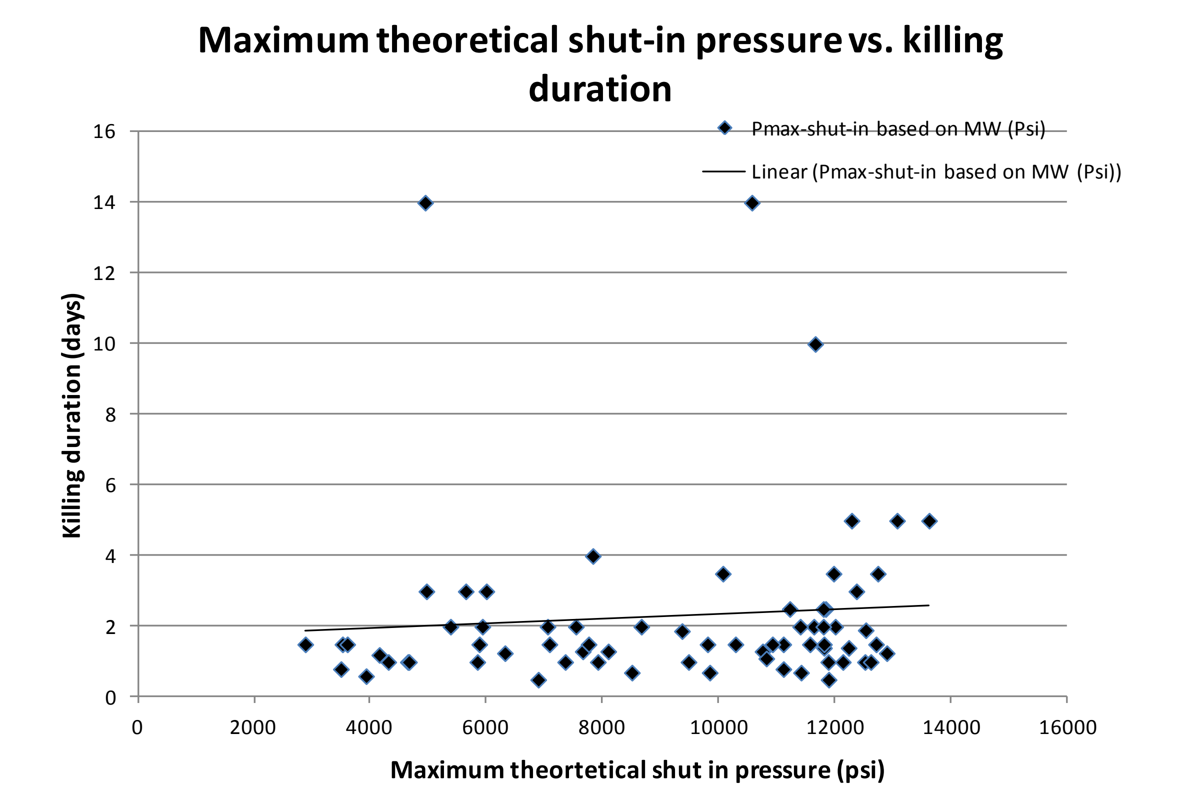

Figure 11.3 Maximum theoretical shut-in pressure vs. killing duration

There is no significant correlation between the maximum theoretical shut-in pressure and the killing duration. It should, however, be noted that the maximum theoretical shut-in pressure is partly a function of the well depth. The slope of the trend line for the well depth (Figure 11.2, page 130) is similar as for the maximum theoretical shut-in pressures. Whether or not the trend slope of the line is random or caused by an increased well depth or increased well pressure cannot be verified. As for the well depth, if disregarding the three most time-consuming kick control events there would be a more evident trend.

11.3.5 Casing Shoe Depth (TVD) vs. Killing Duration

Figure 11.4 shows an XY plot for the casing shoe depth vs. the killing duration.

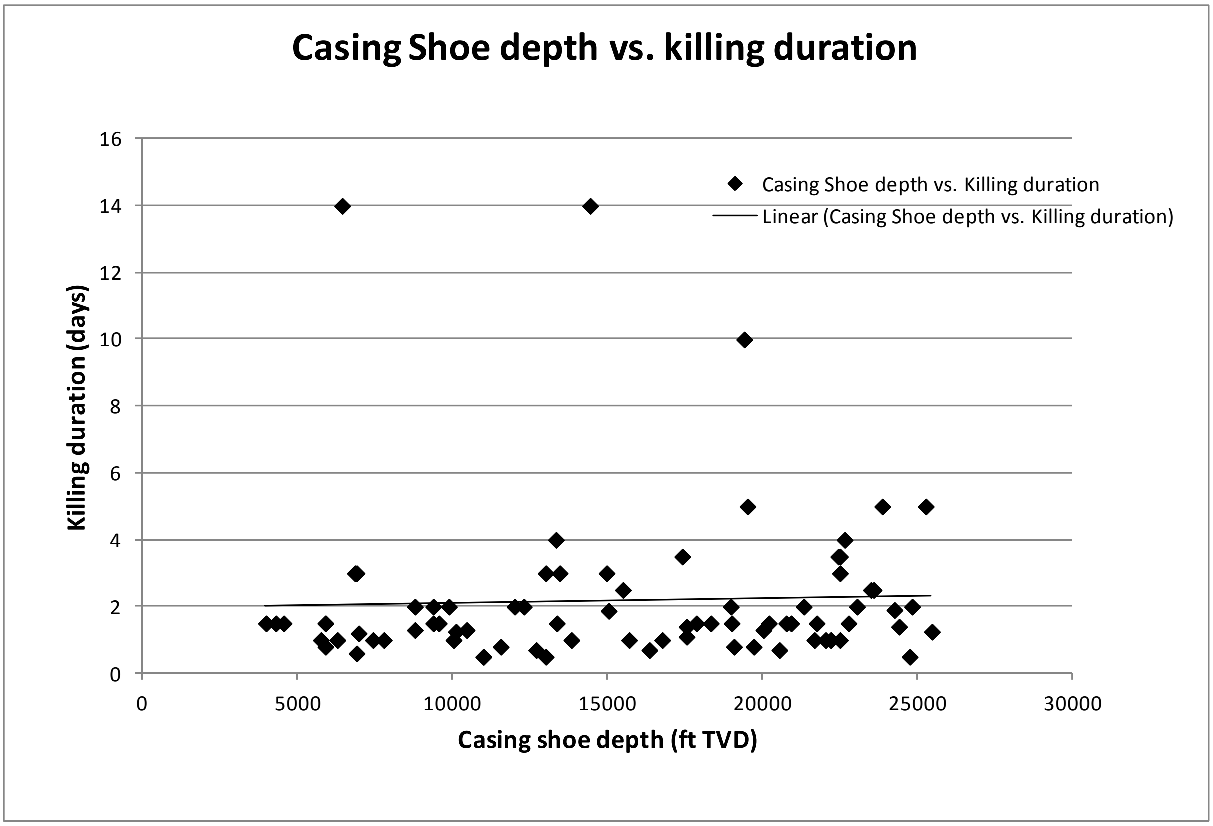

Figure 11.4 Casing shoe depth (TVD) vs. killing duration

There is no significant trend in the killing duration with increasing casing shoe depth. If disregarding the three kicks with the 14, 14 and 10 days duration it may seem to be a more evident correlation. Kicks of long duration will have a large effect on such a trend line.

Table 11.9 Casing shoe depth grouped (TVD) vs. killing duration

Casing shoe depth grouped; when kick occurred TVD (ft)	No. of kicks	Average of killing duration (days)
<8000	15	2,27
8000 - 13000	17	1,40
13000 - 20000	22	2,85
20000 - 25438	27	2,02
Total	81	2,16

The two kicks with a 14 days duration have large effect on the average durations and get the average of the < 8000 ft group to increase 0,84 days. For the group 13 000 to 20000 ft the average increase from the 10 and 14 days events will be 0,91 days

11.3.6 Open Hole Section vs. Killing Duration

The length of an open hole well section may influence the handling of a kick. To investigate this relationship an XY diagram was made based on the measured TVD length of the open hole section when the kick occurred. The diagram is presented in Figure 11.5.

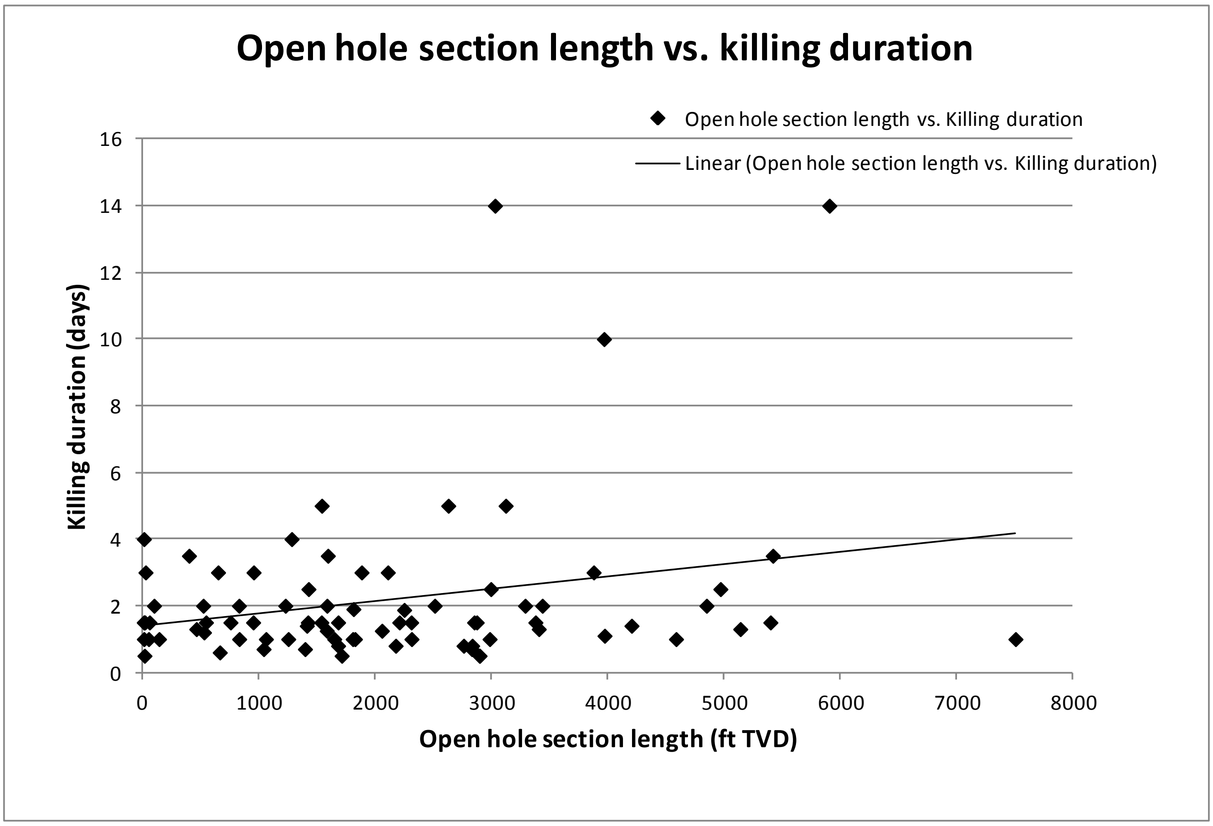

Figure 11.5 Open hole section length vs. killing duration, all kicks

From Figure 11.5 it may seem that there is a correlation between the length of the open hole section and the killing duration. All the three kicks with 10 days or more time consumption were experienced in open hole sections larger than 3000 ft TVD. However, if these three kicks are taken out of the dataset, there is no trend related to open hole section length and kick duration.

11.3.7 The Difference between Leak off Test (LOT) Strength and Mud Weight (MW)

The difference between the LOT/FIT strength and the actual MW used when killing is an indication of the difference between the pore pressure and the fracture strength of the formation. By experience, the drilling wells with a small difference between the LOT/FIT and MW are more difficult than wells with a large difference. In such wells kicks will occur more frequently due to losses or gains. This is also discussed in Section 10.4 on page 122.

It is likely to assume that a low margin between the LOT/FIT and the MW or KMW also will complicate the killing of the well and prolong the killing time. Figure 11.6 shows a XY plot of the killing duration vs. the LOT/FIT – MW and the LOT/FIT - KMW.

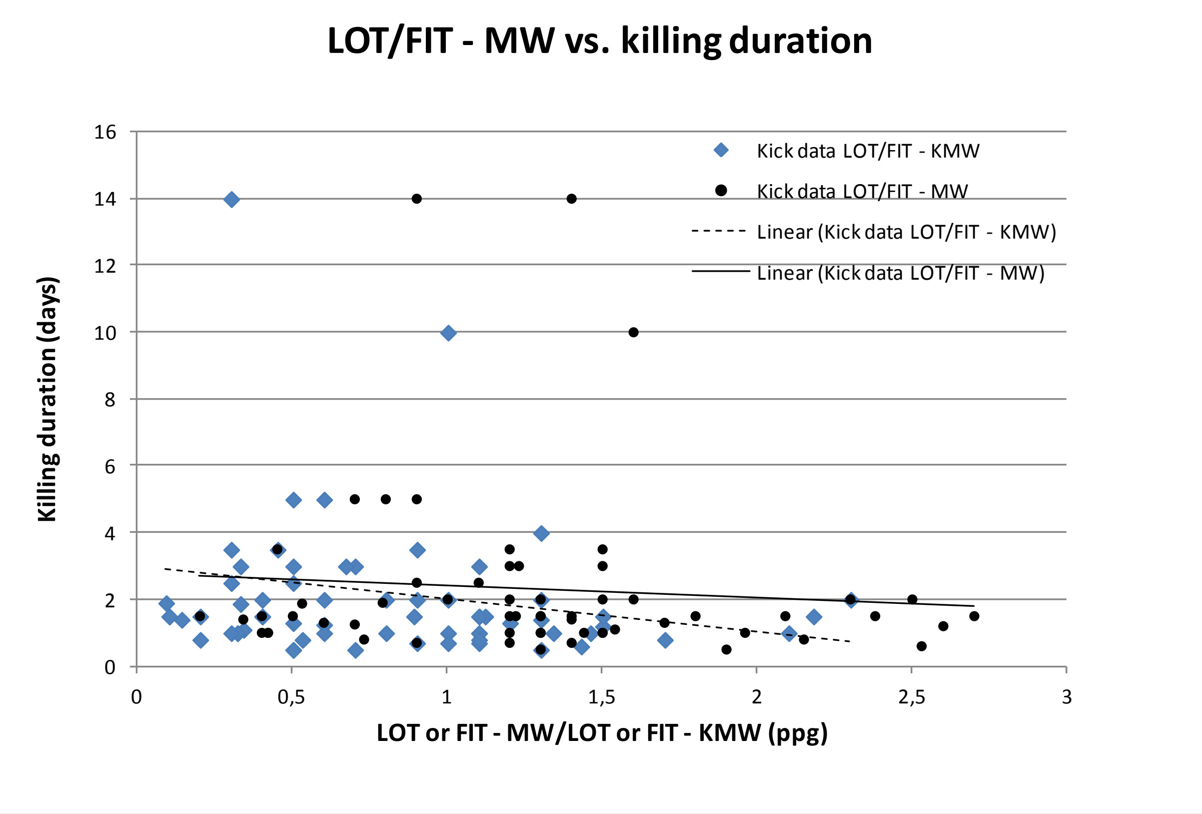

Figure 11.6 XY plot LOT - MW vs. killing duration

The XY-plot indicates a relation between the LOT/FIT-MW and the time it takes to control a kick. An in average longer kick control time can be expected with a reduced margin between the LOT/FIT and the mud weight. The results are affected by the few incidents with a very long duration. If taking out these kicks from the data set this correlation is more evident.

11.3.8 Summary Regarding Parameters and Killing Duration

Although none of the well parameters investigated showed very clear statistically significant trends, it seemed that there for some indications for weak correlations are observed. The most evident correlation was the correlation between LOT/FIT-MW and the killing duration.

For the other parameters it may seem to be a weak correlation.

There many other factors affecting the kick killing duration. Other factors may heavily affect the killing duration as well. Amongst such factors are; pressure transmission problems, formation of hydrates, ballooning/losses, stuck pipe, friction pressures during circulation, and competence of personnel.

12 Kick occurrences vs. BOP failure occurrences

There is a general opinion that when a BOP has been used for handling a well control operation this will increase the probability of experiencing a failure in BOP due to general wear and tear during the kick control operations.

In the previous parts of this report BOP failures and kick occurrences have been discussed separately. In this section we will investigate if we can find any evidence that kick circulation causes BOP wear and tear that causes the BOP to fail.

In Section 12.1 an overview of the BOP failures and kicks observed for the individual rigs is presented.

Section 12.2 focuses on the detailed kick and BOP failure experience.

12.1 Overview of BOP Failures and Kicks

Table 12.1 shows an overview of the rig specific BOP-days in service, BOP failures and kick occurrences observed during the study.

Some of the rigs are represented with little service time. For some rigs no BOP failures and/or kicks have been observed.

Table 12.1 Overview of rig specific days in service, BOP failures and kick occurrences

Rig name	No. of BOP-days	BOP Item		Choke & kill item		Control system		Dummy item		BOP failures total		Kicks	
		No. of failures	Lost time (hrs)	No. of failures	Lost time (hrs)	No. of failures	Lost time (hrs)	No. of failures	Lost time (hrs)	No. of failures	Lost time (hrs)	No. of kicks	Killing duration (days)
Rig AA	511	1	24			5	612	1	168	7	804		
Rig AB	627			1	24	1	0			2	24	2	3,8
Rig AC	764	4	516	2	136	6	252	1	336	13	1240	5	15,0
Rig AD	49											1	1,5
Rig AE	515	1	24			4	576			5	600	2	3,0
Rig AF	540	6	192	1	252	4	540			11	984	2	3,3
Rig AG	106	1	0	1	48	1	12			3	60		
Rig AH	442					1	144			1	144	3	4,3
Rig AI	80					1	0			1	0	3	4,3
Rig AJ	427					5	1			5	1	1	1,0
Rig AK	428	1	0							1	0	2	5,5
Rig AL	490	3	276	1	0	6	600			10	876	4	3,3
Rig AM	153											1	1,2
Rig AN	308	1	336	1	0	3	0			5	336	5	7,0
Rig AO	69							1	600	1	600		
Rig AP	32												
Rig AQ	191	5	612			2	0			7	612	1	14,0
Rig AR	888	4	594			2	174			6	768	7	9,6
Rig AS	246											1	0,7
Rig AU	390					1	168			1	168	1	1,0
Rig AV	297			3	432	4	540	1	168	8	1140		
Rig AW	598	3	96	1	24	3	156	1	192	8	468	2	3,8
Rig AX	313	3	108							3	108	3	7,5
Rig AY	202					3	0			3	0	3	4,8
Rig AZ	625	5	436			2	120	1	12	8	568	2	15,0
Rig BB	281	2	552							2	552	2	2,0
Rig BH	26											2	3,0
Rig BI	133												
Rig BK	494	2	0	3	504	1	0			6	504	6	11,6
Rig BL	330			1	96	2	272			3	368	1	2,5
Rig BM	599	2	264			1	24			3	288	5	7,4
Rig BN	236											5	23,5
Rig BO	500			1	96			1	96	2	192	2	5,0
Rig BP	516	4	72,5			5	347			9	419,5		
Rig BQ	192	1	96			1	0			2	96		
Rig BS	181	1	7,5			2	6			3	13,5	1	1,0
Rig BT	488	3	576	2	48	2	24			7	648	3	6,4
Rig BU	571			1	288	3	144			4	432		
Rig BV	672			1	180	1	0			2	180		
Rig BW	219											1	1,3
Rig BX	201	1	50							1	50	2	2,0
Rig BY	126	2	204	1	0					3	204		
Total	15056	56	5036	21	2128	72	4712	7	1572	156	13448	81	175,2

12.2 BOP Failures Caused by the Influence from Kick Killing Operations

12.2.1 Detailed Rig Specific BOP Failure Occurrence vs. Kick Occurrence Evaluation

In general no significant correlation between the occurrence of BOP failures and well control operations were revealed. However, after or during the kick control operation there have been observed BOP failures that likely were caused by the well control operation. In this section the drilling period, occurrence of kicks and occurrence of failures are followed by the calendar for each individual rig. It should be noted that for some of the rigs the data is collected for a limited period only.

To investigate this, kicks and the BOP failures for the individual rigs were sorted according to the calendar time. For all the kicks it was investigated if a BOP failure had occurred recently after or during the kick circulation on the same well.

Rig AC experienced a well kick 14th of December 2007. They spent approximately 2 days to control the kick. Four days after the kick occurred they pulled the LMRP and replaced the annular element. The well activity report did not describe the kick killing activity or the annular failure in detail. The annular may likely been used for stripping operations. The cause of the failure is very likely the kick killing operation.

Rig AC experienced a well kick 3rd of December 2009. They spent approximately 2,5 days to control the kick. Forty-five days later they were still on the same well, but the BOP had been on the rig for other reasons. When testing the choke and kill lines when running the BOP, the lower inner kill valve were found to be leaking. The BOP was pulled again for repair. This may be related to the kick killing operation carried out 45 days before.

Rig AK experienced a well kick 4th of January 2008. They spent approximately 1,5 days to control the kick. Thirteen days after the kick they experience problems with passing the annular preventer with the bit and thereafter the BOP test tool. This is a rather normal annular preventer problem and not believed to be related to the kick circulation.

Rig AL experienced a well kick 5th of June 2009. They spent approximately 0,8 days to control the kick. On the next well 52 days after the kick occurrence the annular preventer leaked on test. This failure can likely not be regarded as caused by the kick since the BOP had been on the rig and the annular, probably both inspected and approved before re-running the BOP.

Rig AN experienced a well kick 20th of June 2008. They spent approximately 1 day to control the kick. Four days later when attempting to test the 9 3/8" casing against the blind shear ram, the blind shear ram leaked after 24 minutes with 1862 psi. This failure may have been influenced by the kick control operation carried out.

Rig AR experienced two well kicks 12th and 13th of January 2007. They spent respectively 1,1 and 1,4 days to control these kicks. Eighteen days after the first kick they experience a problem with the annular preventer that failed to close. They attempted on both pods. It is unclear what the cause of this failure was. They had been stripping through the annulars during the kick killing operation. It does not seem likely that the failure was related to the kick circulation.

Rig AR experienced well kick 11th of October 2009. They spent approximately 1,9 days to control the kick. Thirty four days after the kick occurrence when working on the same well, the annular preventer failed. This may be related to the kick circulation carried out 34 days before.

Rig AX experienced two well kicks 19th and 22nd of June 2007. They spent respectively 2 and 1,5 days to control these kicks. Six days after the first kick they experience a problem with the upper annular preventer that failed to open fully. They were unable to work thru the upper annular. This is a rather normal annular preventer problem and not believed to be related to the kick circulation.

Rig AX experienced a well kicks 19th of April 2009. They spent approximately 4 days to control the kick. Six days after the kick occurred the middle variable bore ram leaked when it was tested. The cause of the failure is very likely the kick killing operation.

Rig AZ experienced a well kicks 27th of July 2008. They spent approximately 10 days to control the kick. The upper annular preventer developed a leak during the kick control operations. The annular was used for stripping during the well control operation. The well control operation definitively caused the annular preventer to fail.

Many of the above discussed failures are likely to be caused by the kick killing operations. It should be noted that for some kicks the history with respect to BOP failures after the kick is unknown. Some of these kicks may have contributed to failures.

Stripping operations cause annular preventer wear. Stripping operations during well killing operations is likely to cause an annular preventer to fail.

Only once the kick killing operation is likely to blame for choke or kill valve failure, indicating that the wear and tear from kick circulation is not a large problem for these valves, when considering the high number of kicks that were taken. The failure mechanism is unknown.

13 BOP Configurations vs. the Blowout Probability

13.1 Introduction

The primary barrier against blowouts during drilling is the hydrostatic pressure imposed by the mud column. The BOP is a secondary barrier against blowouts alongside the casing, the formation, the cement outside casing etc. If the hydrostatic pressure from the mud column becomes too low, a kick has occurred. Then if one of the secondary barriers fails a blowout will result.

During the previous subsea BOP reliability studies (/1/ to /5/) fault tree models were established to assess the probability of the BOP's ability to close in a well kick. These fault tree models have been revised to reflect the BOP configurations analyzed in the current study.

Based on an updated fault tree model, the BOP reliability data, and the kick data various BOP configurations have been analyzed with respect to the ability to close in a well kick.

All the input reliability data in the fault tree model stems from experience during deepwater drilling. The input reliability data are mainly based on the current study, but for some of the failure types data established in /1/ and /3/ have also been considered.

The relevant kick information from this study comprises:

- experienced kick frequencies (Table 8.3, page 95)
- tubulars running through the BOP when the kick occurred (Table 9.3, page 114)
- ram type and size inside the various BOPs during the kick situation (Table 3.1 page 26)

The estimated blowout frequency found from the analysis is not regarded as the important parameter in this study. The historic experienced blowout frequency will likely be a better indication of the blowout frequency. However, with a blowout probability model it will be possible to better analyze how the various BOP configurations affect the BOP's total ability to close in the types of kicks that can be expected.

It is important to note that the model only consider kicks that may be confined by the BOP. The following typical blowouts are not included in the model:

- Shallow gas blowouts (before the BOP is landed)
- Blowouts outside the casing
- Blowouts through the drillpipe
- Underground blowouts
- Blowouts caused by spurious disconnect of the riser connector and lack of riser margin (also disabling the BOP control)

The main fault tree utilized for the analysis is shown in Appendix 1, Subsea BOP Fault Tree. For the various BOP configurations analyzed minor alternations in the main fault tree have been done. These alternations have been both related to the fault tree itself or to the input reliability data used.

Fault tree analysis and symbols are briefly described in Appendix 1 to this report. Several textbooks related to fault tree construction and analyses exist, among them /15/.

13.2 Parameters Affecting the BOP's Ability to Close in a Well

The BOP stack is tested to verify that the BOP will be able to act as a well barrier in case of a well kick.

In general, it can be stated that the more frequently the BOP stack is tested, the higher the availability the BOP as a safety barrier will be. It is, however, important to note that some parts of a BOP stack are not as important as other parts with respect to testing.

When pressure testing the BOP, both the ability to operate the BOP function and the ability to seal off a pressure are tested. When function testing a BOP, only the ability to carry out the function is tested, and not the ability to close in a pressure.

The effect of the component testing on the BOP's total ability to close in a well kick will depend on:

- The BOP stack design/configuration
- The drillpipe or tubular that runs through the BOP
- The reliability of the various BOP functions
- The test frequency of the BOP function (both function and pressure test)

13.3 Operational Assumptions

13.3.1 The BOP Stack Design

The fault tree analyses are based on the BOP stack designs shown in Figure 3.1, page 25. One of the BOP stacks represents a conventional design with three pipe rams, one blind shear ram, and two annulars, while the other represents a more modern design with a casing shear ram and a test ram in addition to the preventers included in the conventional BOP. It has been assumed that all the pipe rams are variable pipe rams. The real variation of BOP configuration is shown in Table 3.1, page 26.

The BOP is equipped with a main control system only. The control system is a multiplex system.

Various variations of these two designs have also been evaluated during the analyses.

- Modern stack without test ram
- Effect of including an acoustic backup system
- Using two blind shear rams

The control system principle chosen does not have a significant effect on the evaluations related to the BOP test practices and BOP configuration.

13.3.2 Input Kick Frequencies

The input kick frequencies used for the fault tree calculation are based on the kick frequencies found in this study (Table 8.3, page 95).

- Kick frequency per 1000 BOP-days: 5.4 kicks/1000 BOP-days
- Kick frequency per well: 0.313 kicks/well drilled

These frequencies do not include shallow kicks, i.e. kicks occurring before the BOP is landed on the wellhead.

13.3.3 Tubulars Running through the BOP when the Well Kicks

There are very few fixed pipe rams in use on deepwater rigs. Only 7% of the pipe rams were fixed, and the remaining 93% were variable. The analyses assume that all the pipe rams are variable pipe rams, and may seal around any drillpipe in the well.

Table 13.1 Geometric sealing capability during initial kick situation (from Table 9.3, page 114)

Available preventers	Distribution
Only the blind-shear ram could be used (empty hole)	4,0 %
All preventers could be used	96,0 %
Total	100,0 %

The results shown in Table 13.1 are used as input for the fault tree calculation.

It is assumed that when a wireline is in the hole when the well kicks it can be regarded as an empty hole. The wireline, however, have to be pulled before the BOP blind-shear ram can be closed, alternatively cut at surface and dropped. (Many BS rams cannot shear wireline).

It is further assumed that a pipe ram preventer will never close on a tool joint by mistake during a kick situation.

13.3.4 Confined BOP Pressure Limitation

During none of the observed kicks the confined pressures exceeded the pressure rating of the annular preventers, i.e. the annular preventers were available for closing in a kick for all kicks that occurred when there was a tubular in the well.

13.3.5 BOP Unavailability Calculation

The mean fractional deadtime (MFDT) of a component is the mean proportion of the time where the component is in a failed state. Consider a component with failure rate λ. Failures are only assumed to be discovered at tests, which are performed after fixed intervals of length τ. Failed components are repaired or replaced immediately after discovery.

The mean fractional deadtime of such a component is

$$MFDT = (\lambda * \tau)/2 \quad (/15/),$$

provided that $\lambda * \tau \ll 1$

The availability (A) of such a component can be expressed by:

$$A = 1 - MFDT = 1 - (\lambda * \tau)/2$$

The expressions above assume that the test interval is fixed. In practical situations the test interval may vary. If a variation in the test interval exists and the τ value represents an average test interval, the formula will give too optimistic results. When collecting the BOP reliability data in Phase II DW (/1/) the real average time between pressure tests was found to be lower than two weeks, 11,5 days. In the current study this type of BOP test data was not collected, but it is likely that approximately the same average time between tests would have been found if doing so. It has been selected not to utilize the average time between tests in these calculations. If using the average time between tests a correction factor should have been applied. The typical correction factor would be approximately 1,1-1,2 (/5/), that should bring the input data to approximately 13 days between tests. For the purpose of these analyses this approximation will have no effect.

Further, when this formula is used for each single component in a redundant system (like a subsea BOP) that is tested at the same time the results will be too optimistic.

For the purpose of these analyses it is assumed that the BOP failures relevant for the fault tree analysis are observed during BOP testing only. This is not correct because some of the failures in the control system are observed when they occur. From a safety point of view this is beneficial, i.e., the calculated results will be conservative.

It is further assumed that the failure rate is constant, i.e., independent of time, and that all components are independent.

13.3.6 BOP Test Interval Assumption

The following BOP test strategies are followed:

It has been presupposed that a complete BOP installation test always is carried out, including pressure test of all equipment on one pod and function test on the other pod.

- Complete BOP installation test (pressure and function test)
- The BOP preventers and choke and kill valves are pressure tested every two weeks (pressure test one pod, function test one pod)
- BOP is function tested every two weeks (both pods)
- well duration is 60 days
- blind-shear ram is tested every 20 days in association with casing running

For a BOP with a test ram it is assumed;

- Wellhead connector seal are pressure tested every 20 days in association with casing running (not every 14 days as for test plug testing)

13.3.7 Initial Situation

The situation when the well kicks and the response of the BOP is required is as follows:

- There are no known failures in the BOP stack or the control system
- The BOP was completely pressure and function tested after it was landed on the wellhead last time
- All choke and kill valves are closed
- Hard shut in, i.e., an annular preventer will be closed without opening the choke line first

13.3.8 Failure Input Data

The input reliability data in the fault tree model are mainly based on the current study, but for some of the failure types data established in /1/ and /3/ have also been considered. The failure frequencies used are based on the failure frequencies for failures that occurred in the safety critical period only (see Section 5, page 75). This means that failures that were observed when the BOP was on the rig, during running of the BOP and during the installation test have been disregarded.

For the blind shear rams it has been assumed that it will be able to cut the pipe in 9 out of 10 attempts. This is based on some coarse evaluations and some data observed in other studies.

It is assumed that the casing shear ram can cut the normal drillpipe in 19 out of 20 attempts.

The detailed failure data used can be read out off the fault tree in Appendix 1, Subsea BOP Fault Tree.

13.3.9 Repair Strategies

For the purpose of the calculations presented, it has been assumed that whenever a BOP failure is observed, the failure is repaired before the operation continues.

From the collected data it was noted that MMS from time to time granted a waiver that postponed the repair. These waivers will to some extent reduce the BOP safety availability. The waivers granted were, however, only given for BOP components/functions where a redundancy was present in the stack or the well was nearly completed i.e. the well was safe.

13.3.10 Failure Observation

In the calculations it has been assumed that the BOP failures are observed during tests only. This is not correct, because many failures are observed during normal operations as well. Failures observed during normal operations are typically failures observed because the BOP is operated for other reasons than testing, and that pressurized control system equipment starts to leak.

The effect of this assumption is that the results will be conservative.

13.3.11 Other Assumptions

- The model only considers the probability for a successful control of the initial kick situation. This is a non-conservative assumption. Failures of BOP components during kick circulation are discussed in Section 12, page 136.

- Further, another simplification, adding conservatism to the result, is that when a kick occurs when there is no drillpipe in the well, only the blind-shear rams can be used for sealing off the kick. The annulars are assumed not to be able to close on an open hole. The BOP manufacturers claim that an annular can be used for closing on an open hole. During all the SINTEF/ExproSoft BOP reliability studies (experience from 750 wells) it has not been observed that they have tested this function once, so the success probability of such an operation is unknown.

- It is assumed that the well kicks are observed in reasonable time so normal well control procedures can be initiated.

- The reliability models used is based on a multiplex control system. The previous studies (/3/ and /1/) indicated that a multiplex systems had lower success probability than the pilot hydraulic systems. The problem then was lack of redundancy issues between the yellow and blue pod hydraulics. These problems were not identified in the current study. A reliability model with a pilot hydraulic study would produce more or less the same results as for the current model based on a multiplex system.

13.4 BOP Configuration vs. the Blowout Frequency

The estimates of the blowout frequency presented in this chapter should be used with care. The important aspect to focus on is the relative difference between the different BOP configurations for the experienced kick situations observed.

Appendix 1, Subsea BOP Fault Tree, presents the fault tree used for the calculation. The relevant collected kick data parameters and the BOP reliability data have been fed into the fault tree model. The expected blowout frequencies have been calculated for various BOP configurations. Table 13.2 shows the results from the calculations. It should be noted that when the frequency of an incident is low, the frequency and the probability are equal. This will apply for the blowout frequencies found in this study.

Table 13.2 Main results, blowout frequency

BOP Configuration	Average probability of failing to close in a kick (%)			Ratio vs. modern BOP	Blowout frequency pr well	No. of wells per blowout	No. of BOP days between each blowout
	With DP through BOP	Empty hole	Total*				
Modern BOP (see Figure 3.1)	0,124 %	0,264 %	0,130 %	1,00	0,041 %	2465	142901
Modern BOP w acoustic back-up control	0,092 %	0,232 %	0,097 %	0,75	0,030 %	3287	190527
Modern BOP without test ram	0,097 %	0,238 %	0,103 %	0,79	0,032 %	3103	179844
Modern BOP without test ram w acoustic back-up control	0,065 %	0,205 %	0,071 %	0,54	0,022 %	4528	262429
Conventional BOP (see Figure 3.1)	0,097 %	0,233 %	0,103 %	0,79	0,032 %	3109	180195
Conventional BOP w acoustic back-up control	0,065 %	0,200 %	0,070 %	0,54	0,022 %	4540	263177
Two BS ram in modern BOP	0,124 %	0,169 %	0,126 %	0,97	0,039 %	2540	147232
Two BS ram in modern BOP w acoustic back-up control	0,092 %	0,136 %	0,093 %	0,72	0,029 %	3421	198316

*Assuming 4% of kicks are empty hole kicks, and 96% with drillpipe running through the BOP

As seen from Table 13.2, a modern BOP including a test ram will have the highest average probability of failing to close in a kick. This result is to be expected, mainly because the test ram will represent additional potential leakage paths to the sea in the lower part of the BOP stack that cannot be sealed off by a ram preventer. Further, when testing the BOP against the test ram the wellhead seal will get less frequent testing than if testing the BOP against a test plug that is located in the wellhead. The test of the wellhead will be performed against a newly cemented casing or liner, to a lower pressure compared to using a test plug in the wellhead. Taking out the test ram from the BOP will have a significant positive effect on the blowout frequency. The main reason is that the potential leak paths are eliminated.

One the other hand a test ram will save valuable rig time because there will be less need for running a test plug in the wellhead.

Acoustic back-up systems have been mandatory in Norway since 1981, and are mandatory in some other areas as well. They are not frequently used in the US GoM OCS. These systems use independent accumulators and are fairly independent of the regular controls in an emergency situation. In the BOP studies carried out by SINTEF in the 80-ties and early 90-ties (/3/ - /6/) reliability data for acoustic systems were systematically collected. It was then observed that from time to time it could be difficult to communicate with the acoustic signals through the water column due to temperature layers that could be present in the water column. According to the manufacturers of these systems the acoustic communication has been significantly improved since then. Today such systems can be delivered for operation in 13000 ft (4000 m) of water. For the purpose of this study it has conservatively been assumed that the acoustic system will function as required in nine out of ten attempts. It has further been assumed that the acoustic system can close the lower and middle pipe rams, and the blind shear ram. In principle the acoustic system can operate any of the BOP functions.

The use of an acoustic back-up system will have a significantly positive effect with respect to the ability to close in a BOP for all the selected BOP configurations.

A conventional BOP configuration will have approximately the same probability for a successful closure of a kick as a modern BOP without a test ram. The reason why there is no difference is that the analyses assume that the kicks are observed in reasonable time, so normal well control procedures will control the majority of kicks. Cutting of pipe will very rarely be required. The analysis does not consider emergency disconnects caused by loss of position or blowouts through the drillpipe. For both these incident types an extra casing shear ram will increase the success probability of cutting the pipe before sealing with the conventional blind shear ram.

When comparing the average probability of failing to close in a kick for the conventional BOP with the results from the previous study (/2/), an improvement of 20-25% is observed. This is mainly caused by an improved reliability of the BOP components.

When also taking the reduced kick frequency observed in the current study into account, the blowout frequency per well based on the data in the current study is estimated to be less than 50% of the blowout frequency estimated in the previous study.

There are a large variety of combinations of shear rams in a BOP stack (Table 3.1, page 26.) Of the 41 rigs reviewed in this study 22 had on BS ram only, five had two BS rams, 12 had one BS ram and one casing shear ram, while two rigs had two BS rams and one casing shear ram.

Two BS rams will be the best with respect to sealing an empty hole, but the casing shear ram will likely have a higher success probability with respect to cutting the pipe. The calculations shows the use of two BS rams in a modern BOP will be slightly better than a blind shear and a casing shear ram for the situations analyzed in this section, but again this does not consider emergency disconnects caused by loss of position or blowouts through the drillpipe.

One of the BOP manufacturers now claims that blind shear rams that can cut a 6 5/8”drillpipe tool joints and seal afterword is available.

13.5 Conclusion

A BOP test ram will reduce the probability of a successful closure of the BOP because it will add potential leakage paths in the stack below the lowest pipe ram preventer.

A BOP test ram will also reduce the quality of the wellhead connector test.

Two sealing shear rams would be the preferred option in any deepwater subsea BOP stack. The importance of two rams will increase with the water depth, due to drilling margin issues and loss of position risk for dynamically positioned rigs. These blind shear rams should have the ability to shear any drillpipe in the well.

If a blind shear ram that is able to seal after cutting 6 5/8” tool joint is available and proven, at least one of the shear rams should preferably be such a ram.

Trough the current study and the previous study (/2/) 130 kicks were identified. For none of these kicks a casing or liner was across the BOP when the kick occurred, indicating that the need for cutting the casing in an emergency is limited.

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2. Holand, P.: "Deepwater Kicks and BOP Performance" Sintef Report STF38 AA01419, (Unrestricted version)
3. Holand, P., Reliability of Subsea BOP Systems for Deepwater Application, Sintef Report STF38 F97417, Trondheim, Norway, 1997. (Restricted)
4. Holand, P., Reliability of Subsea BOP Systems, Fault Tree Analysis, Sintef Report STF38 F97425, Trondheim, Norway, 1997. (Restricted)
5. Holand, P., Subsea BOP Systems, Reliability and Testing Phase V, revision 1 (this revision 1 is based on a report with the same title published in 1990), Sintef report STF 75 A89054, Trondheim, Norway, 1995.
6. Holand, P.: "Reliability of Subsea BOP Systems – Phase IV". Sintef Report STF75 F87007, Trondheim, Norway, 1987. (Restricted)
7. MMS GoM accident investigation report on incident occurred on 09-Feb-2007 (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/2007/070209.pdf)
8. Code of federal regulations, Title 30, revised as of March 26, 2012 (http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=e844b61e2a5ae94d1ad904cf76428f0d&rgn=div8&view=text&node=30:2.0.1.2.2.4.68.36&idno=30)
9. MMS GoM accident investigation report on incident occurred on 31-Jul-2007

   (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/2007/070731.pdf)
10. MMS GoM accident investigation report on incident occurred on 14-Jun-2008

    (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/2008/080614.pdf)
11. MMS GoM accident investigation report on incident occurred on 20-Sep-2008 (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/2008/080920.pdf)
12. West Engineering, Evaluation of Secondary Intervention Methods in Well Control, TAR Report 431, MMS, 2003
13. MMS GoM accident investigation report on incident occurred on 19-April-2009 (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/districtreports.html)
14. MMS GoM accident investigation report on incident occurred on 4-August- 2009 (http://www.gomr.boemre.gov/homepg/offshore/safety/acc_repo/districtreports.html)
15. Høyland, A., and Rausand, M., System Reliability Theory; Models and Statistical Methods, Second Edition, John Wileys Sons, New York, USA, 2004.

Appendix 1, Subsea BOP Fault Tree

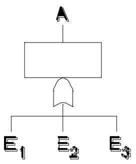
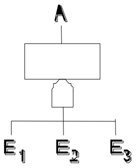
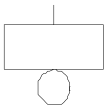
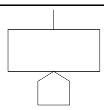
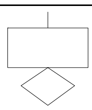
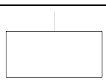
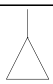
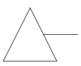
Fault Tree Construction

Fault Tree Symbols

A fault tree is a logic diagram that displays the connections between a potential system failure (TOP event) and the causes for this event. The causes (Basic events) may be environmental conditions, human errors, normal events and component failures. The graphical symbols used to illustrate these connections are called "logic gates". The output from a logic gate is determined by the input events.

The graphical layout of the fault tree symbols is dependent on what standard we choose to follow. Table A.1 shows the most commonly used fault tree symbols together with a brief description of their interpretation.

Table A.1 Fault tree symbols

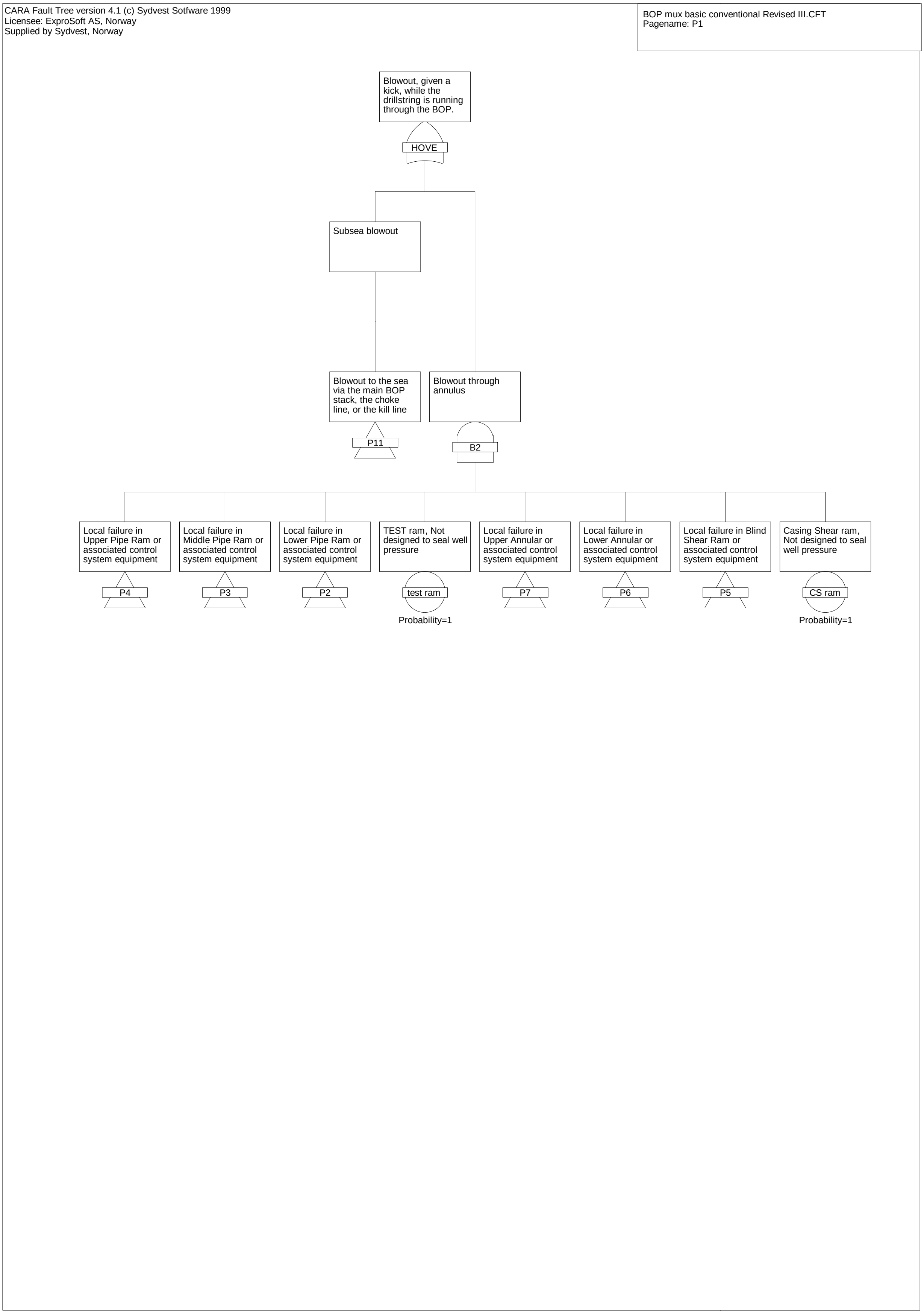
	Symbol		Description
Logic Gates	"OR" gate		The OR-gate indicates that the output event A occurs if any of the input events E_i occurs.
	"AND" gate		The AND-gate indicates that the output event A occurs only when all the input events E_i occur simultaneously.
Input Events	"BASIC" event		The Basic event represents a basic equipment fault or failure that requires no further development into more basic faults or failures.
	"HOUSE" event		The House event represents a condition or an event, which is TRUE (ON) or FALSE (OFF) (not true).
	"UNDEVELOPED" event		The Undeveloped event represents a fault event that is not examined further because information is unavailable or because its consequence is insignificant.
Description of State	"COMMENT" rectangle		The Comment rectangle is for supplementary information.
Transfer Symbols	"TRANSFER" out "TRANSFER" in	 	The Transfer **out** symbol indicates that the fault tree is developed further at the occurrence of the corresponding Transfer **in** symbol.

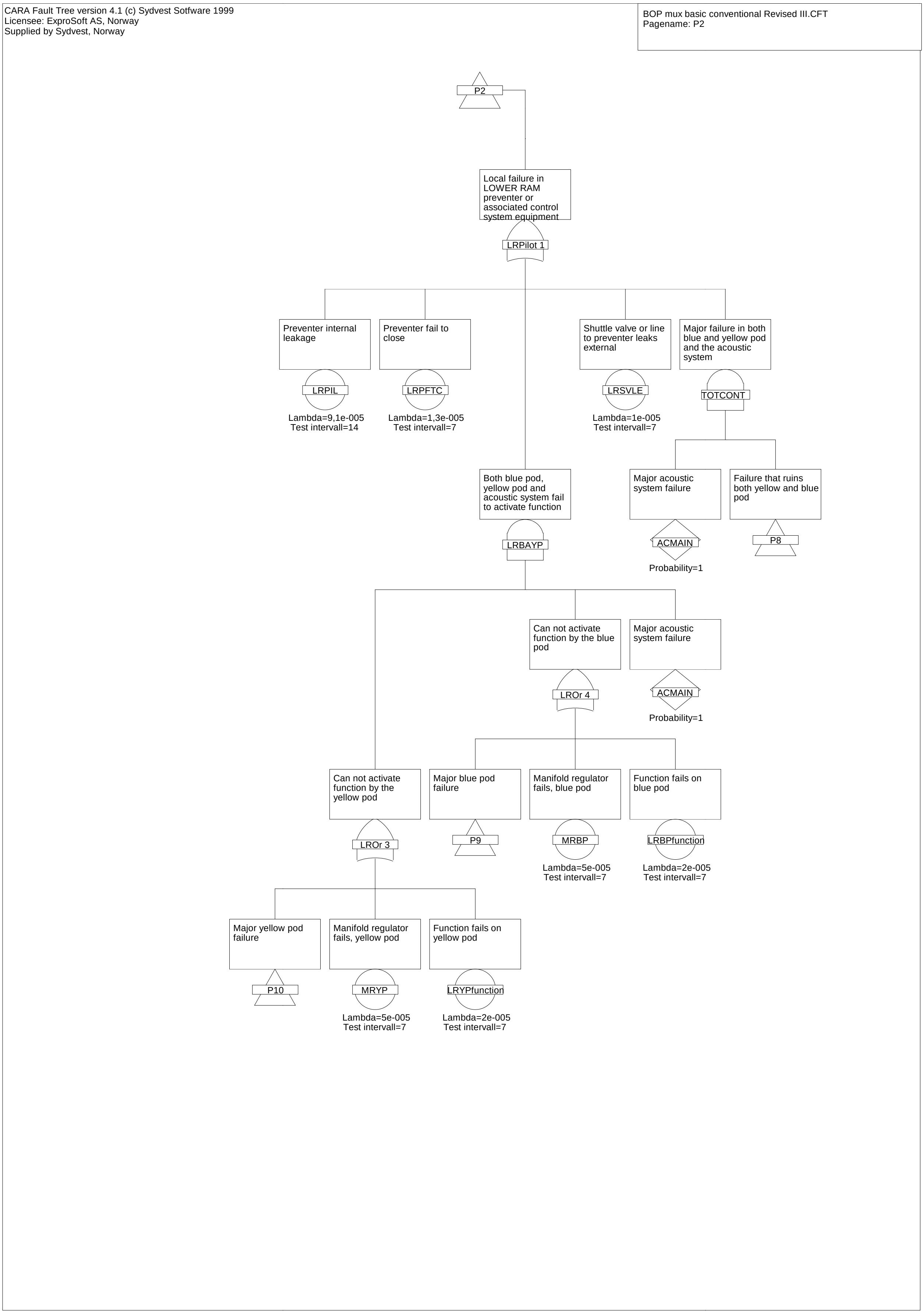
The logic events the basic events and the transfer symbol are the fault tree symbols mainly used in the Fault Trees constructed and analysed in this report. Fault Tree construction and analyses are described in many textbooks, among them /15/.

The CARA Fault Tree (www.exprosoft.com) has been used for constructing and analyzing the fault trees.

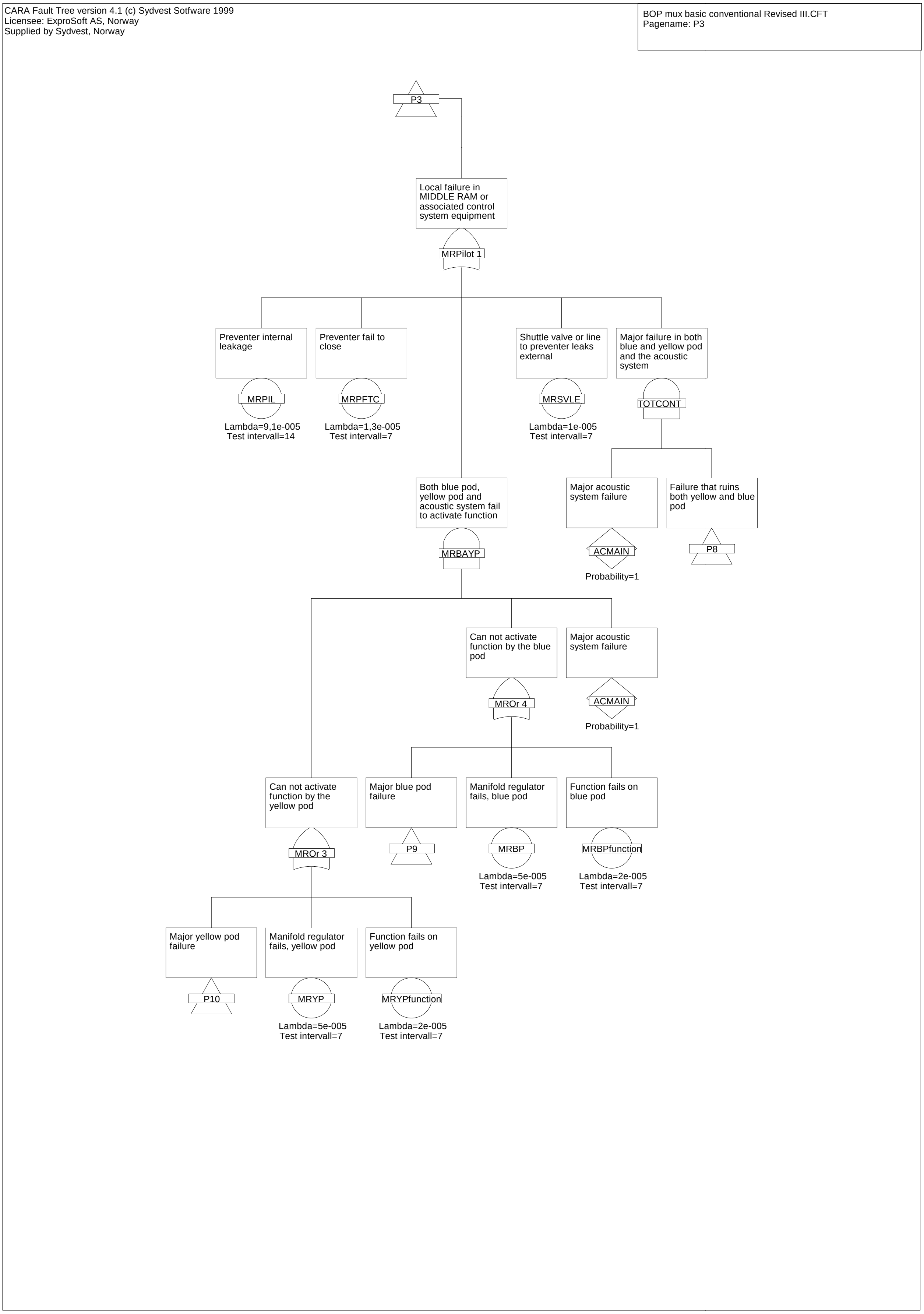
BOP Fault Tree

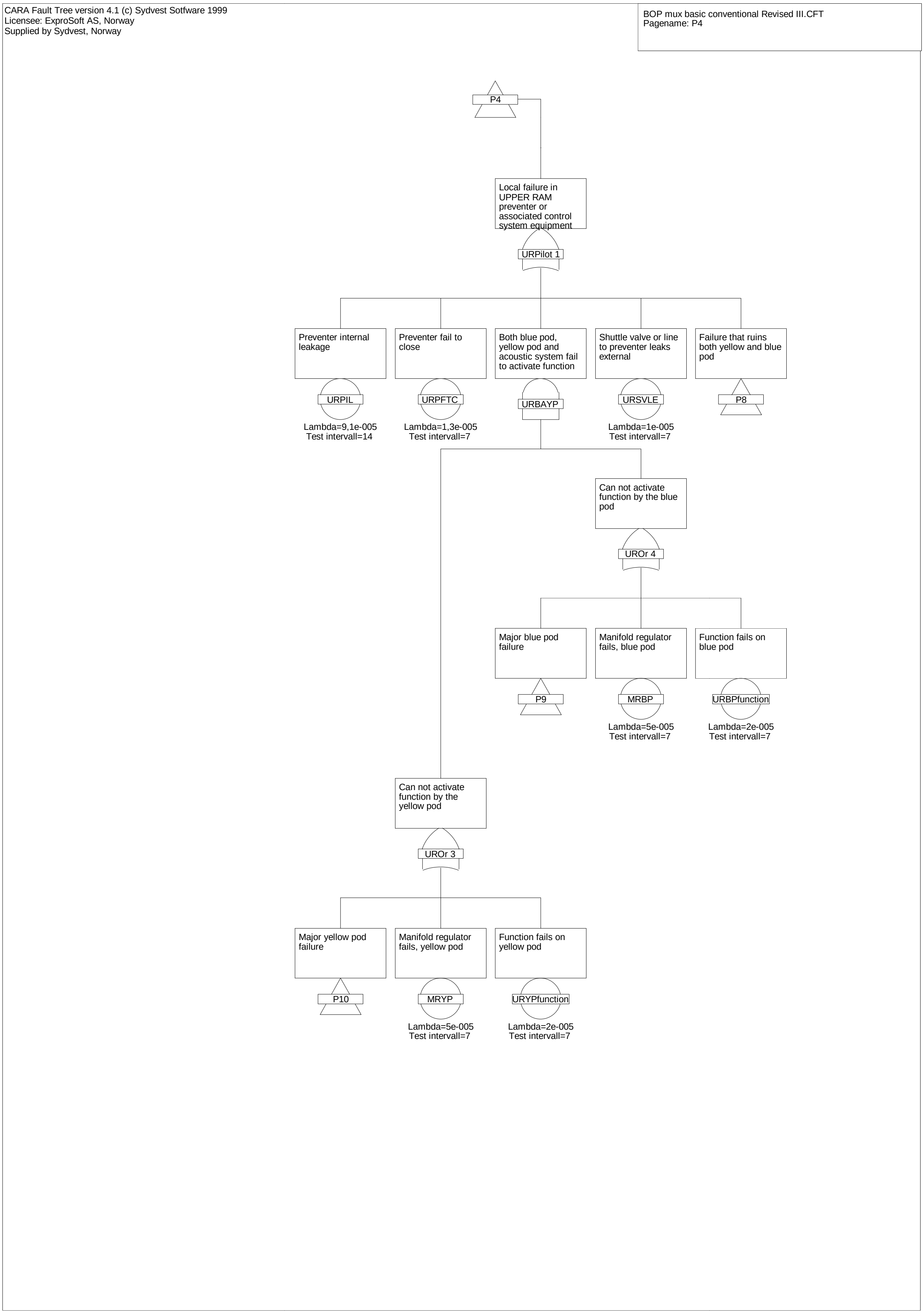
The fault tree utilized in the analyzes are presented on the following pages. The input data shown represents the Modern BOP with a drillpipe running through the BOP.


CARA Fault Tree version 4.1 (c) Sydvest Sotfware 1999
Licensee: ExproSoft AS, Norway
Supplied by Sydvest, Norway
BOP mux basic conventional Revised III.CFT
Pagename: P1
Blowout, given a kick, while the drillstring is running through the BOP.
HOVE
Subsea blowout
Blowout to the sea via the main BOP stack, the choke line, or the kill line
P11
Blowout through annulus
B2
Local failure in Upper Pipe Ram or associated control system equipment
P4
Local failure in Middle Pipe Ram or associated control system equipment
P3
Local failure in Lower Pipe Ram or associated control system equipment
P2
TEST ram, Not designed to seal well pressure
test ram
Probability=1
Local failure in Upper Annular or associated control system equipment
P7
Local failure in Lower Annular or associated control system equipment
P6
Local failure in Blind Shear Ram or associated control system equipment
P5
Casing Shear ram, Not designed to seal well pressure
CS ram
Probability=1

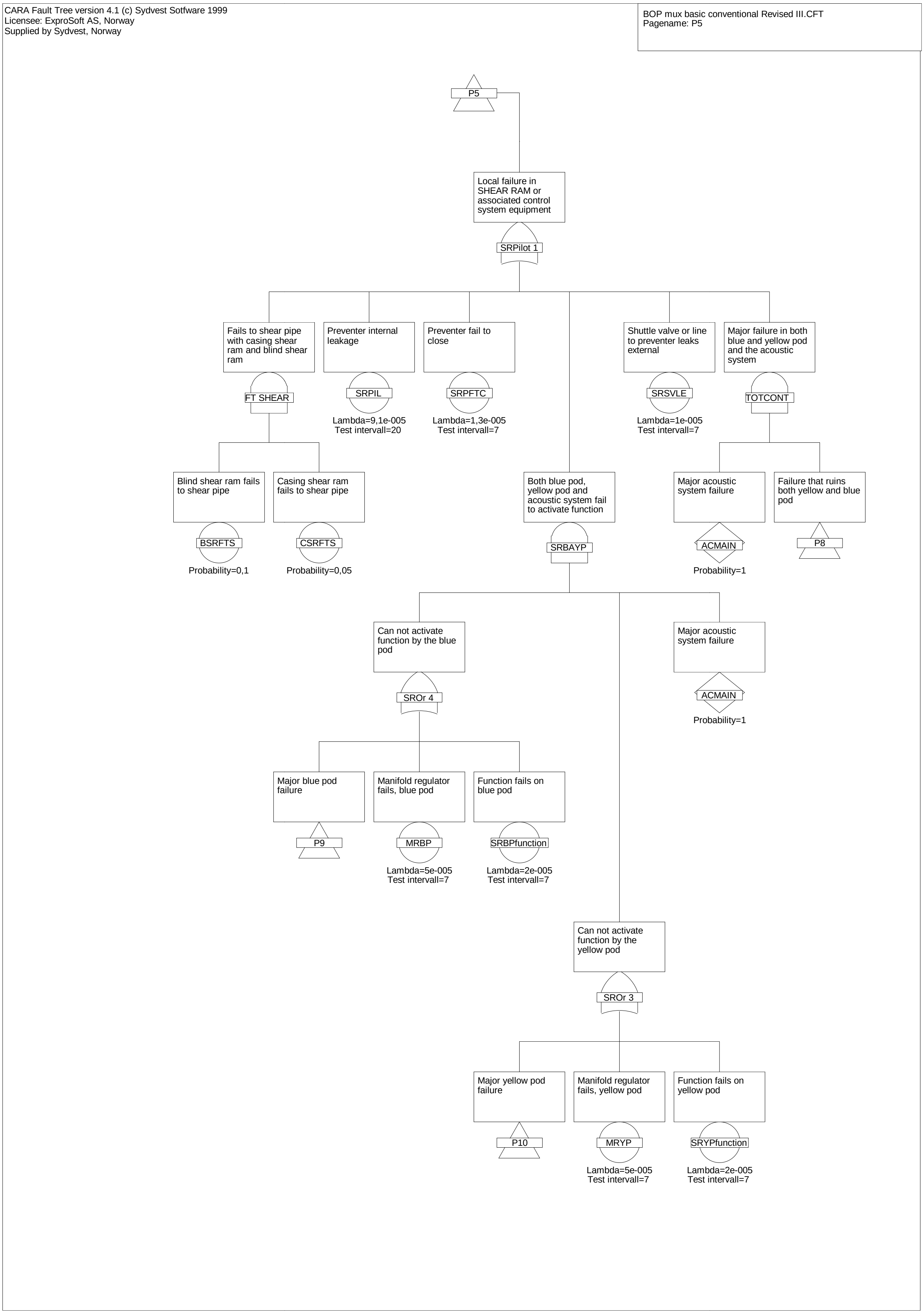


CARA Fault Tree version 4.1 (c) Sydvest Sotfware 1999
Licensee: ExproSoft AS, Norway
Supplied by Sydvest, Norway
BOP mux basic conventional Revised III.CFT
Pagename: P2
P2
Local failure in LOWER RAM preventer or associated control system equipment
LRPilot 1
Preventer internal leakage
LRPIL
Lambda=9,1e-005
Test intervall=14
Preventer fail to close
LRPFTC
Lambda=1,3e-005
Test intervall=7
Shuttle valve or line to preventer leaks external
LRSVLE
Lambda=1e-005
Test intervall=7
Major failure in both blue and yellow pod and the acoustic system
TOTCONT
Both blue pod, yellow pod and acoustic system fail to activate function
LRBAYP
Major acoustic system failure
ACMAIN
Probability=1
Failure that ruins both yellow and blue pod
P8
Can not activate function by the blue pod
LROr 4
Major acoustic system failure
ACMAIN
Probability=1
Can not activate function by the yellow pod
LROr 3
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Lambda=5e-005
Test intervall=7
Function fails on blue pod
LRBPfunction
Lambda=2e-005
Test intervall=7
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Lambda=5e-005
Test intervall=7
Function fails on yellow pod
LRYPfunction
Lambda=2e-005
Test intervall=7


CARA Fault Tree version 4.1 (c) Sydvest Sotfware 1999
Licensee: ExproSoft AS, Norway
Supplied by Sydvest, Norway
BOP mux basic conventional Revised III.CFT
Pagename: P3
P3
Local failure in MIDDLE RAM or associated control system equipment
MRPilot 1
Preventer internal leakage
MRPIL
Lambda=9,1e-005
Test intervall=14
Preventer fail to close
MRPFTC
Lambda=1,3e-005
Test intervall=7
Shuttle valve or line to preventer leaks external
MRSVLE
Lambda=1e-005
Test intervall=7
Major failure in both blue and yellow pod and the acoustic system
TOTCONT
Both blue pod, yellow pod and acoustic system fail to activate function
MRBAYP
Major acoustic system failure
ACMAIN
Probability=1
Failure that ruins both yellow and blue pod
P8
Can not activate function by the blue pod
MROr 4
Major acoustic system failure
ACMAIN
Probability=1
Can not activate function by the yellow pod
MROr 3
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Lambda=5e-005
Test intervall=7
Function fails on blue pod
MRBPfunction
Lambda=2e-005
Test intervall=7
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Lambda=5e-005
Test intervall=7
Function fails on yellow pod
MRYPfunction
Lambda=2e-005
Test intervall=7



CARA Fault Tree version 4.1 (c) Sydvest Sotfware 1999
Licensee: ExproSoft AS, Norway
Supplied by Sydvest, Norway
BOP mux basic conventional Revised III.CFT
Pagename: P4
P4
Local failure in UPPER RAM preventer or associated control system equipment
URPilot 1
Preventer internal leakage
URPIL
Lambda=9,1e-005
Test intervall=14
Preventer fail to close
URPFTC
Lambda=1,3e-005
Test intervall=7
Both blue pod, yellow pod and acoustic system fail to activate function
URBAYP
Shuttle valve or line to preventer leaks external
URSVLE
Lambda=1e-005
Test intervall=7
Failure that ruins both yellow and blue pod
P8
Can not activate function by the blue pod
UROr 4
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Lambda=5e-005
Test intervall=7
Function fails on blue pod
URBPfunction
Lambda=2e-005
Test intervall=7
Can not activate function by the yellow pod
UROr 3
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Lambda=5e-005
Test intervall=7
Function fails on yellow pod
URYPfunction
Lambda=2e-005
Test intervall=7


CARA Fault Tree version 4.1 (c) Sydvest Sotfware 1999
Licensee: ExproSoft AS, Norway
Supplied by Sydvest, Norway
BOP mux basic conventional Revised III.CFT
Pagename: P5
P5
Local failure in SHEAR RAM or associated control system equipment
SRPilot 1
Fails to shear pipe with casing shear ram and blind shear ram
FT SHEAR
Preventer internal leakage
SRPIL
Lambda=9,1e-005
Test intervall=20
Preventer fail to close
SRPFTC
Lambda=1,3e-005
Test intervall=7
Shuttle valve or line to preventer leaks external
SRSVLE
Lambda=1e-005
Test intervall=7
Major failure in both blue and yellow pod and the acoustic system
TOTCONT
Blind shear ram fails to shear pipe
BSRFTS
Probability=0,1
Casing shear ram fails to shear pipe
CSRFTS
Probability=0,05
Both blue pod, yellow pod and acoustic system fail to activate function
SRBAYP
Major acoustic system failure
ACMAIN
Probability=1
Failure that ruins both yellow and blue pod
P8
Can not activate function by the blue pod
SROr 4
Major acoustic system failure
ACMAIN
Probability=1
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Lambda=5e-005
Test intervall=7
Function fails on blue pod
SRBPfunction
Lambda=2e-005
Test intervall=7
Can not activate function by the yellow pod
SROr 3
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Lambda=5e-005
Test intervall=7
Function fails on yellow pod
SRYPfunction
Lambda=2e-005
Test intervall=7

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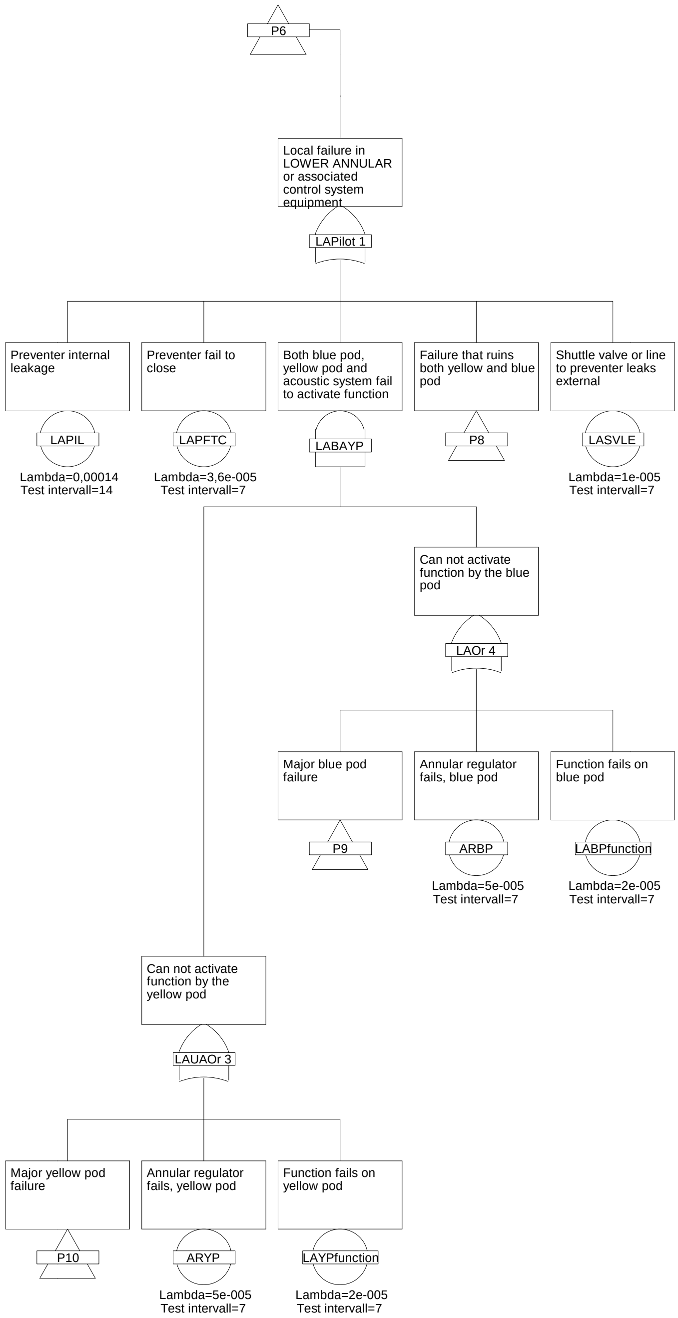
BOP mux basic conventional Revised III.CFT
Pagename: P6



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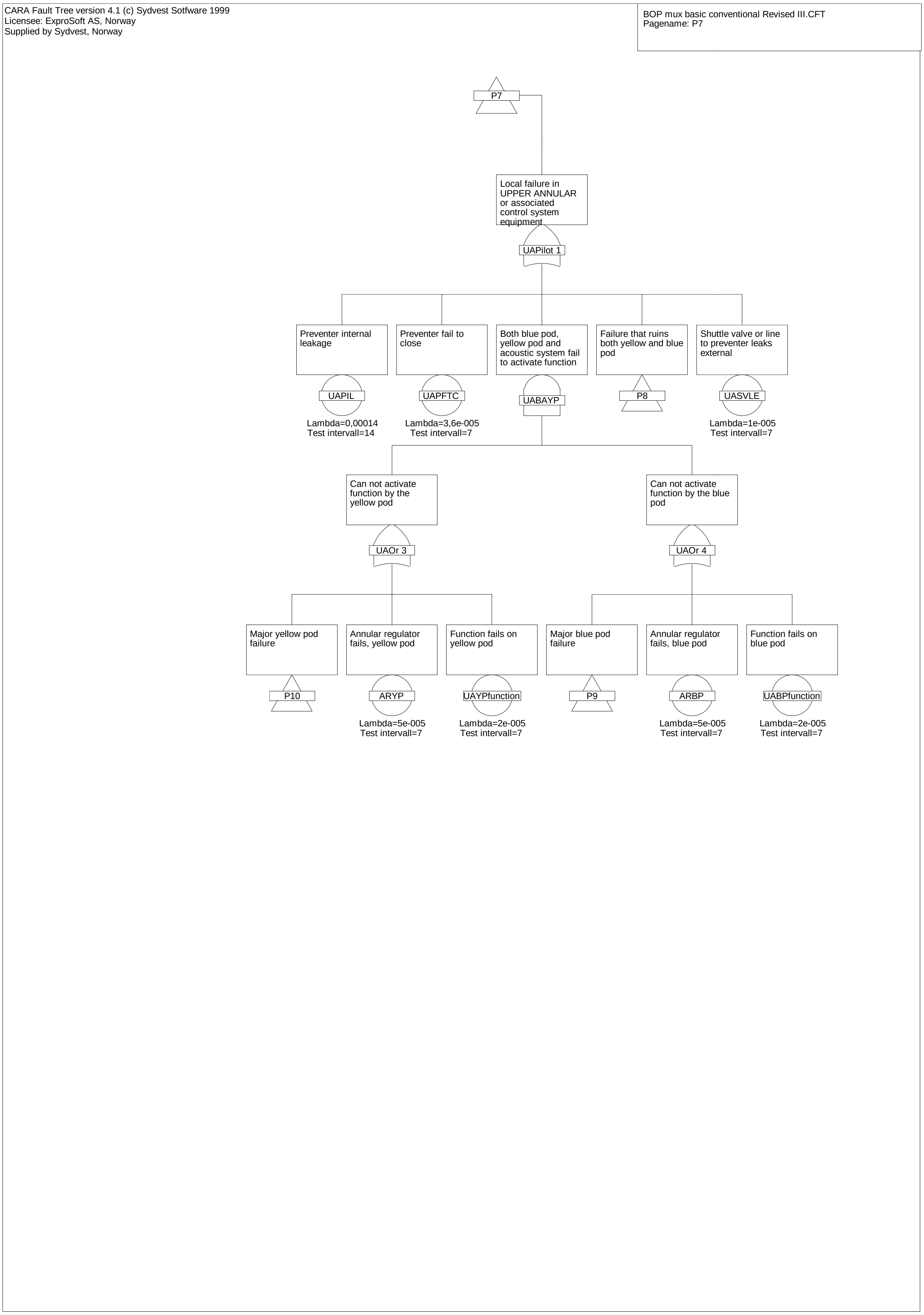
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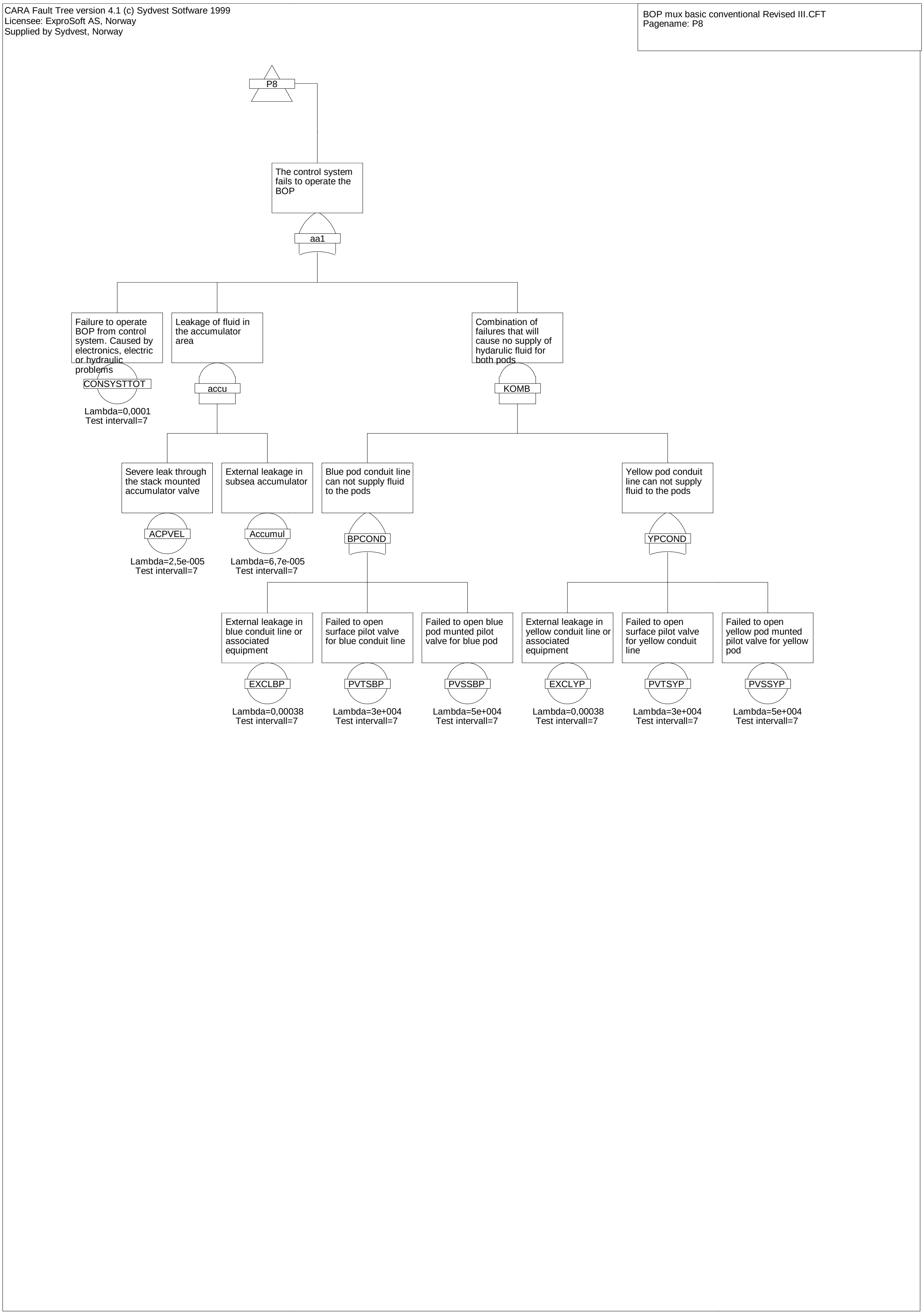
BOP mux basic conventional Revised III.CFT
Pagename: P7
P7
Local failure in UPPER ANNULAR or associated control system equipment
UAPilot 1
Preventer internal leakage
UAPIL
Lambda=0,00014
Test intervall=14
Preventer fail to close
UAPFTC
Lambda=3,6e-005
Test intervall=7
Both blue pod, yellow pod and acoustic system fail to activate function
UABAYP
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
UASVLE
Lambda=1e-005
Test intervall=7
Can not activate function by the yellow pod
UAOr 3
Can not activate function by the blue pod
UAOr 4
Major yellow pod failure
P10
Annular regulator fails, yellow pod
ARYP
Lambda=5e-005
Test intervall=7
Function fails on yellow pod
UAYPfunction
Lambda=2e-005
Test intervall=7
Major blue pod failure
P9
Annular regulator fails, blue pod
ARBP
Lambda=5e-005
Test intervall=7
Function fails on blue pod
UABPfunction
Lambda=2e-005
Test intervall=7



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BOP mux basic conventional Revised III.CFT
Pagename: P8
P8
The control system fails to operate the BOP
aa1
Failure to operate BOP from control system. Caused by electronics, electric or hydraulic problems
CONSYSTTOT
Lambda=0,0001
Test interval=7
Leakage of fluid in the accumulator area
accu
Combination of failures that will cause no supply of hydarulic fluid for both pods
KOMB
Severe leak through the stack mounted accumulator valve
ACPVEL
Lambda=2,5e-005
Test intervall=7
External leakage in subsea accumulator
Accumul
Lambda=6,7e-005
Test intervall=7
Blue pod conduit line can not supply fluid to the pods
BPCOND
Yellow pod conduit line can not supply fluid to the pods
YPCOND
External leakage in blue conduit line or associated equipment
EXCLBP
Lambda=0,00038
Test intervall=7
Failed to open surface pilot valve for blue conduit line
PVTSBP
Lambda=3e+004
Test intervall=7
Failed to open blue pod munted pilot valve for blue pod
PVSSBP
Lambda=5e+004
Test intervall=7
External leakage in yellow conduit line or associated equipment
EXCLYP
Lambda=0,00038
Test intervall=7
Failed to open surface pilot valve for yellow conduit line
PVTSYP
Lambda=3e+004
Test intervall=7
Failed to open yellow pod munted pilot valve for yellow pod
PVSSYP
Lambda=5e+004
Test intervall=7

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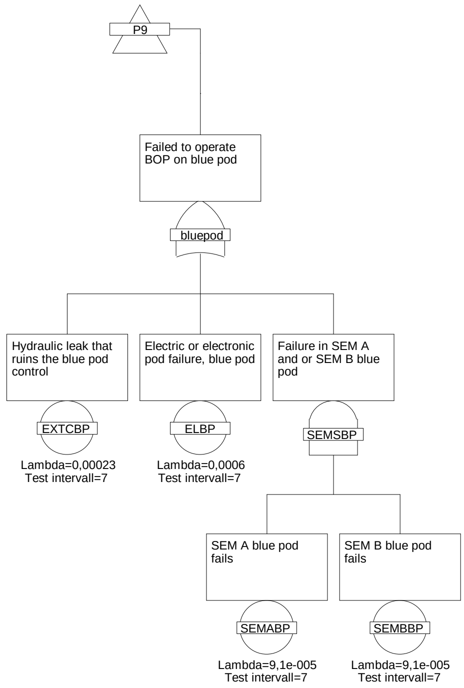
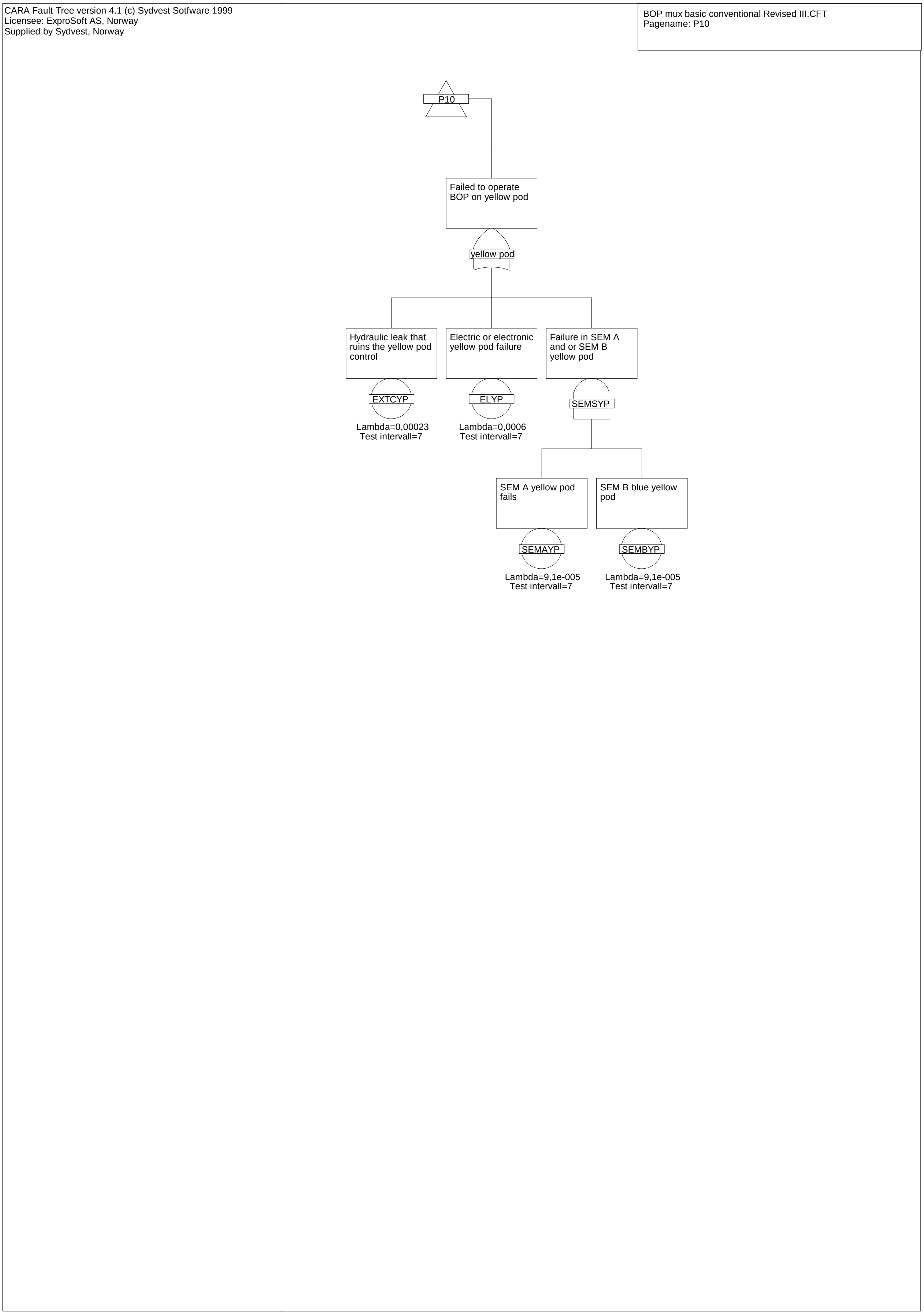
BOP mux basic conventional Revised III.CFT
Pagename: P9

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BOP mux basic conventional Revised III.CFT
Pagename: P10
P10
Failed to operate BOP on yellow pod
yellow pod
Hydraulic leak that ruins the yellow pod control
EXTCYP
Lambda=0,00023
Test intervall=7
Electric or electronic yellow pod failure
ELYP
Lambda=0,0006
Test intervall=7
Failure in SEM A and or SEM B yellow pod
SEMSYP
SEM A yellow pod fails
SEMAYP
Lambda=9,1e-005
Test intervall=7
SEM B blue yellow pod
SEMBYP
Lambda=9,1e-005
Test intervall=7

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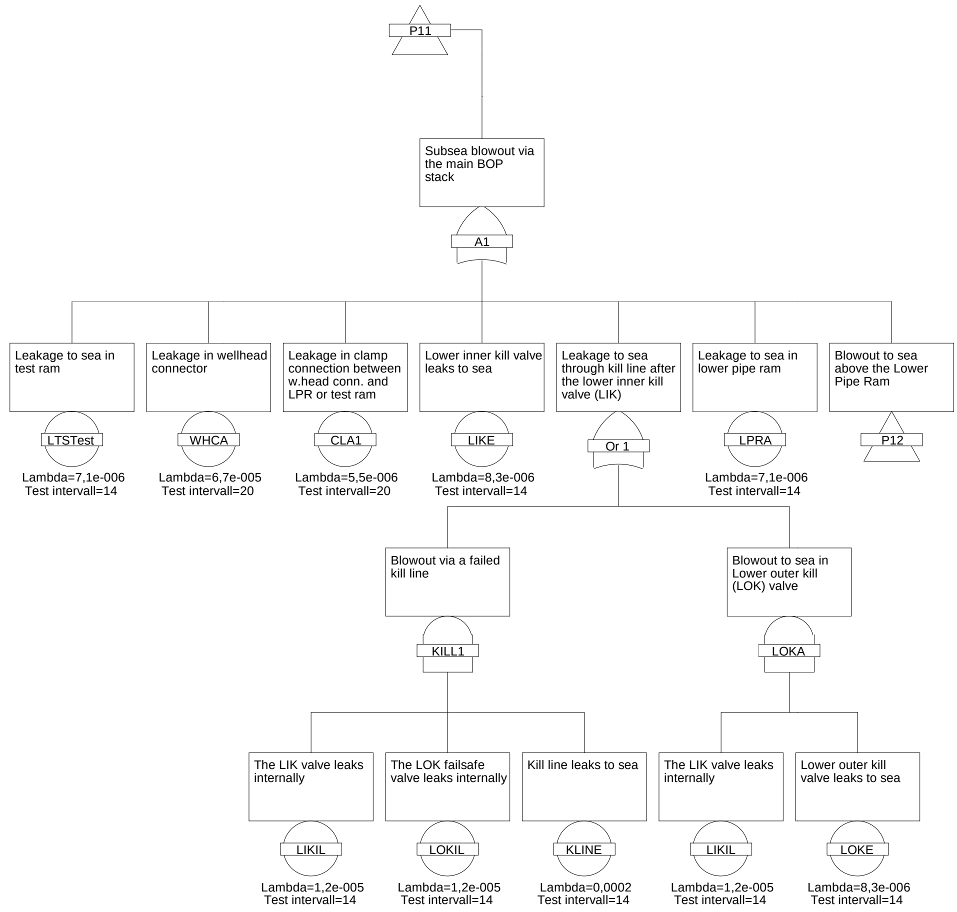
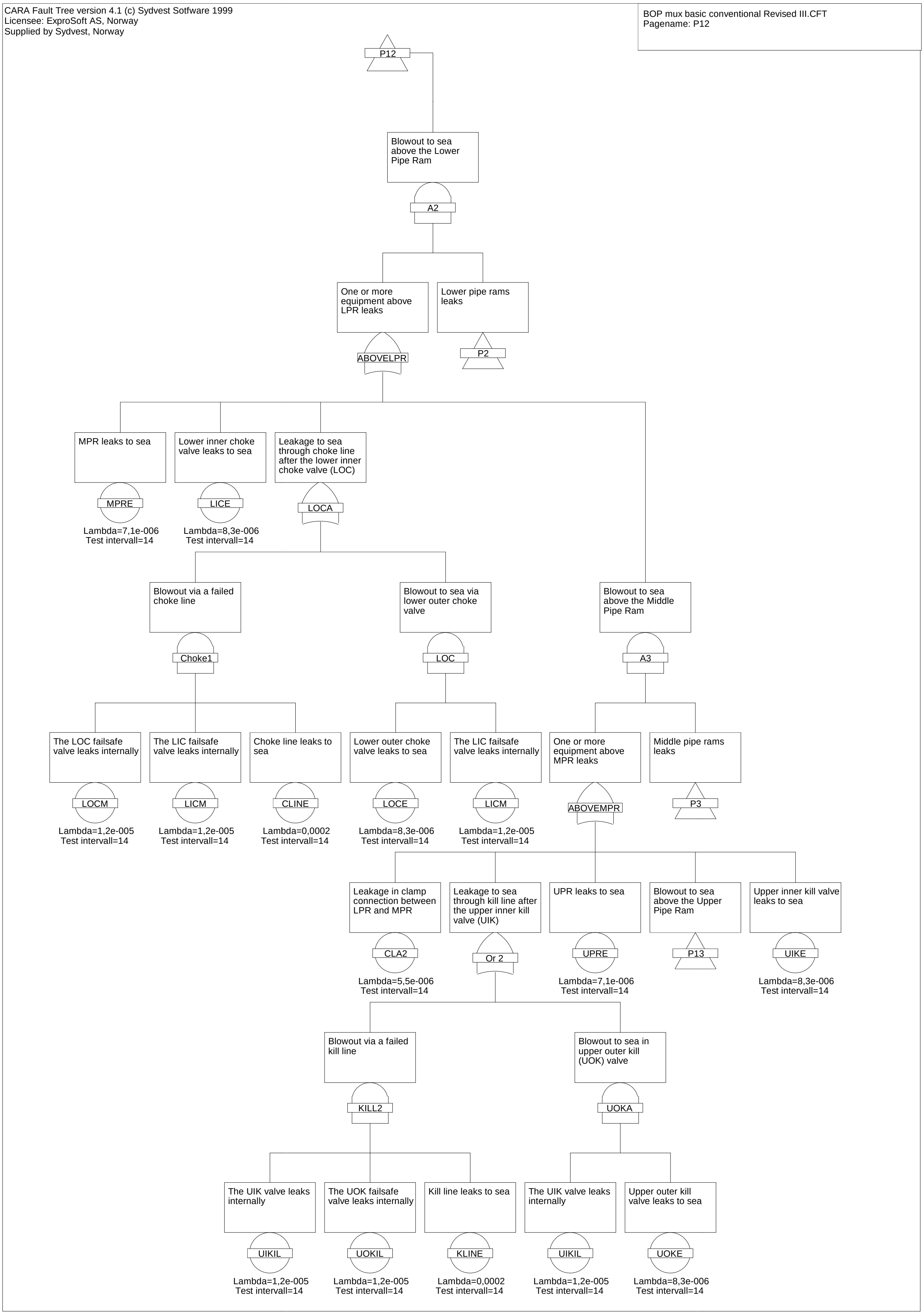
BOP mux basic conventional Revised III.CFT
Pagename: P11

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BOP mux basic conventional Revised III.CFT
Pagename: P12
P12
Blowout to sea above the Lower Pipe Ram
A2
One or more equipment above LPR leaks
Lower pipe rams leaks
ABOVELPR
P2
MPR leaks to sea
Lower inner choke valve leaks to sea
Leakage to sea through choke line after the lower inner choke valve (LOC)
MPRE
LICE
LOCA
Lambda=7,1e-006
Test intervall=14
Lambda=8,3e-006
Test intervall=14
Blowout via a failed choke line
Blowout to sea via lower outer choke valve
Blowout to sea above the Middle Pipe Ram
Choke1
LOC
A3
The LOC failsafe valve leaks internally
The LIC failsafe valve leaks internally
Choke line leaks to sea
Lower outer choke valve leaks to sea
The LIC failsafe valve leaks internally
One or more equipment above MPR leaks
Middle pipe rams leaks
LOCM
LICM
CLINE
LOCE
LICM
ABOVEMPR
P3
Lambda=1,2e-005
Test interval=14
Lambda=1,2e-005
Test interval=14
Lambda=0,0002
Test interval=14
Lambda=8,3e-006
Test interval=14
Lambda=1,2e-005
Test interval=14
Leakage in clamp connection between LPR and MPR
Leakage to sea through kill line after the upper inner kill valve (UIK)
UPR leaks to sea
Blowout to sea above the Upper Pipe Ram
Upper inner kill valve leaks to sea
CLA2
Or 2
UPRE
P13
UIKE
Lambda=5,5e-006
Test intervall=14
Lambda=7,1e-006
Test intervall=14
Lambda=8,3e-006
Test intervall=14
Blowout via a failed kill line
Blowout to sea in upper outer kill (UOK) valve
KILL2
UOKA
The UIK valve leaks internally
The UOK failsafe valve leaks internally
Kill line leaks to sea
The UIK valve leaks internally
Upper outer kill valve leaks to sea
UIKIL
UOKIL
KLINE
UIKIL
UOKE
Lambda=1,2e-005
Test interval=14
Lambda=1,2e-005
Test interval=14
Lambda=0,0002
Test interval=14
Lambda=1,2e-005
Test interval=14
Lambda=8,3e-006
Test interval=14

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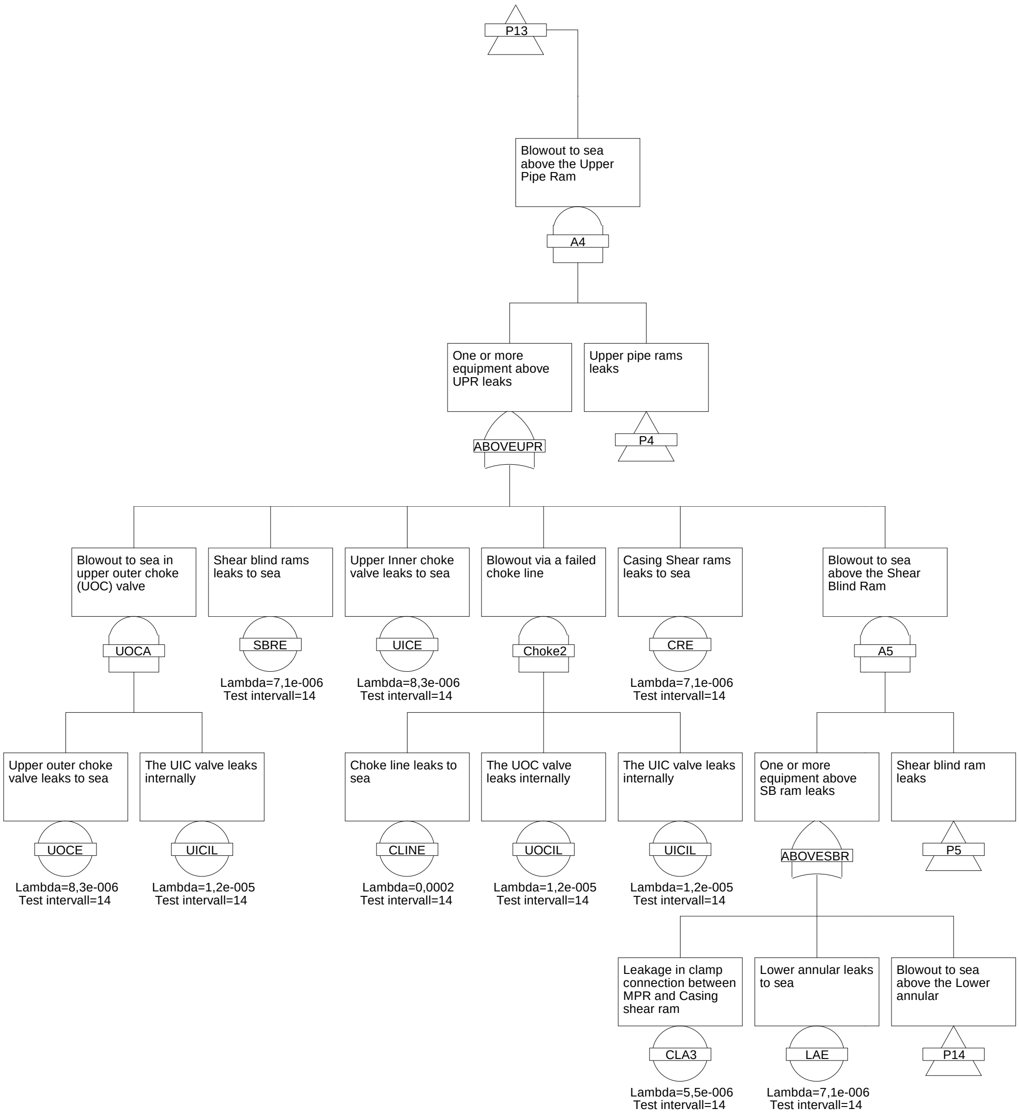
BOP mux basic conventional Revised III.CFT
Pagename: P13



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BOP mux basic conventional Revised III.CFT
Pagename: P14