SINTEF REPORT

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TITLE

Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW
Unrestricted version

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ABSTRACT

A reliability study of subsea BOPs has been performed. The study is based on information from 83 wells drilled in water depths ranging from 400 meters (1312 feet) to more than 2000 meters (6562 feet) in the US GoM OCS. These wells have been drilled with 26 different rigs in the years 1997 and 1998.

The main information source from the study has been the daily drilling reports. The collected data have been fed into a tailor made database system.

Detailed failure statistics for the various BOP systems are presented. Both the downtime aspect and the safety aspect of the failures have been evaluated. Further, BOP test time consumption has been investigated. The results from the study have been compared with the results from another deepwater BOP reliability study carried out for wells drilled in other parts of the world.

KEYWORDS	ENGLISH	NORWEGIAN
GROUP 1	Reliability	Pålitelighet
GROUP 2	Offshore	Offshore
SELECTED BY AUTHOR	Blowout Preventer	Utblåsningssikring
	Risk	Risiko

LIST OF CONTENT

LIST OF ABBRIVATIONS

API	-	American Petroleum Institute
BHA	-	Bottom Hole Assembley
BOP	-	Blowout Preventer
BSR	-	Blind-Shear Ram
CARA	-	Computer Aided Reliability Analysis
C/K	-	Choke and Kill Valves
FTA	-	Fault Tree Analysis
HW DC	-	Heavy Weight Drill Collar
HW DP	-	Heavy Weight Drill Pipe
ID	-	Inner Diameter
IK	-	Inner Kill
I/O	-	Input/Output
ITT	-	Isolation Test Tool
JIP	-	Joint Industry Project
KLB's	-	Kilo pounds
LA	-	Lower Annular
LCL	-	Lower Confidence Limit
LIC	-	Lower Inner Choke
LMRP	-	Lower Marine Riser Package
LOC	-	Lower Outer Choke
LPR	-	Lower Pipe Ram
MFDT	-	Mean Fractional Deadtime
MPR	-	Middle Pipe Ram
MTTF	-	Mean Time To Failure
MPS	-	Multi Position Lock
NPD	-	Norwegian Petroleum Directorate
OCS	-	Outer Continental Shelf
OD	-	Outer Diameter
OK	-	Outer Kill
Phase I DW	-	Phase I of the Deepwater BOP Study (/1/)
Phase II DW		Phase II of the Deepwater BOP Study (the present study)
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
V	-	Volt
VBR	-	Variable Bore Ram
Vs.	-	Versus
WOW	-	Wait On Weather
WOSP	-	Wait On Spare Parts
WOO	-	Wait On Other

PREFACE

The original report from this study has been classified as restricted. This report is based on the original report, but detailed statistics related to manufacturer and models have been taken out.

The report documents the study Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW.

The report is based on reliability experience from subsea deepwater BOPs that have been used in the US GoM OCS in 1997 and 1998. A similar report was issued in 1997, referred to as Phase I DW, based on BOP reliability experience from wells drilled in Brazil, Norway, Italy and Albania in the period 1992-1996.

The Mineral Management Service (MMS) has financed the project. William Hauser has been the MMS contact person. He has provided SINTEF with the necessary raw data requested from the oil companies.

Per Holand has been the project leader. The report has been written by Per Holand. Marvin Rausand, Professor at the Norwegian University of Science and Technology (NTNU), has reviewed, and commented on the report.

A kick-off meeting was arranged in November 1998. From January 1999 until the end of June 1999 the main activities were reviewing drilling reports to identify the relevant BOP information, and further to fill this information into an appropriate computer system. The draft report was mainly written in the period from July 15th until August 31st 1999. Two additional sections of the report were added after the first draft report was issued. The comments to the draft report received from MMS have been implemented in the final report.

Trondheim, November 7, 1999

Per Holand

DISCLAIMER

The overall results in this report are based on the average reliability results. The average reliability estimates presented for some components/systems are strongly influenced by particular problems experienced on one rig.

The term "manufacturer specific results" is only used to state which manufacturer the failures have been attributed to. Several factors besides the manufacturer specific design have influence on the component/subsystem reliability. These factors comprise preventive maintenance, well operations performed, skill of personnel etc. These factors have scarcely been considered in the statistics. Therefore the manufacturer specific performance should not be used as the only criterion when evaluating design specific performance.

SUMMARY AND CONCLUSIONS

BOP data have been collected from wells drilled in the US GoM OCS. All wells are categorized as deepwater wells. Deepwater is in this report defined as waters deeper than 400 meters (1312 ft.). The actual water depth for the wells is ranging from 407 m to 2050 m (1335 ft. to 6725 ft.). The majority of wells included were spudded in the period from July 1 1997 until May 1 1998. The BOP data have been fed into a database system designed for the purpose. The study is referred to as Phase II DW. Another study, completed in 1997, which the results from Phase II is compared with is referred to as Phase I DW.

When collecting the BOP reliability data only the drilling period has been considered. In total 83 different wells have been included. Table 1.1 presents an overview of wells, operational days and drilling vessels for the various water depths.

Table 1.1 Overview of wells, operational days and drilling vessels for the various water depths (Phase II DW)

Water depth m /(ft) (MSL)	No. of wells	No. of BOP-days	Dyn. Pos. drill ships	Dyn. Pos. semisubs	Anchored semisubs
400 – 600 / 1312 – 1969	30	1350			30
600-800 / 1969-2625	10	573			10
800-1000 / 2625-3281	10	521			10
1000-1200 / 3281-3937	18	644			18
1200-1400 / 3937-4593	6	475			6
1400-1600 / 4593-5249	2	140	2		
1600-1800 / 5249-5906	4	169	3		1
1800-2100 / 5906-6890	3	137	3		
Total	83	4009	8		75

It is seen from Table 1.1 that most of the wells have been drilled from anchored semisubmersibles. Only eight wells have been drilled from dynamic positioned vessels. In the previous Phase I of the deepwater study (Phase I DW) (/1/), a larger proportion of the drilling vessels were dynamically positioned (DP) drilling units.

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.

Days in service, for a specific BOP component is defined as the number of BOP-days multiplied with the number of components in the BOP stack

Overview of all Failures

A total of 117 failures were observed during the present study. These 117 failures produced 3637,5 hours lost time, or 0,907 hours per BOP-day. This represents 3,78 % of the drilling time related to the BOP-days in service. Table 1.2 shows an overview of the no. of BOP failures, total downtime and Mean Time To Failure (MTTF).

Table 1.2 Overview of the no. of BOP failures

BOP subsystem	BOP-days in service	Days in service	Total lost time (hrs)	No. of failures	MTTF (days in service)	MTTF (BOP-days)	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
Annular preventer	4009	7449	336,5	12	621	334	28,0	0,08
Connector*	4009	8018	117,75	10	802	401	11,8	0,03
Flexible joint **	4009	4009	248,5	1	4009	4009	248,5	0,06
Ram preventer	4009	16193	1505,25	11	1472	364	136,8	0,38
Choke/kill valve	4009	31410	255,5	13	2416	308	19,7	0,06
Choke/kill lines, all	4009	4009	36,5	8	501	501	4,6	0,01
Main control system	4009	4009	1021,5	60	67	67	17,0	0,25
Dummy item***	4009		116	2	-	2005	58,0	0,03
Total	**4009**		**3637,5**	**117**	**-**	**34**	**31,1**	**0,91**

* For one LMRP connector failure the lost time was not available because the daily drilling reports were missing. Two to three days were lost.

** For the flexible joint failure 250 hours more time was used to work on stuck pipe/fishing problems after the flex joint failure was repaired. This work was most likely a result of the flexible joint failure .

*** The Dummy item in Table 1.2 is used to include two BOP failures that were impossible to link to a specific BOP item. Both these failures occurred when preparing to run the BOP and were poorly described.

The main contributors to rig downtime caused by BOP failures are the ram preventers and the main control system. The annular preventers, the choke and kill valves, the choke and kill lines and the connectors caused less downtime than the above systems. The flexible joint failed only once, but this failure caused a long downtime. No failures were observed in the BOP flanges.

For the ram preventers it was found that two ram preventer types of relatively new design, failed far more frequent than older types of ram preventers. The failure mode *Failed to open* has not been observed in ram preventers in earlier BOP studies, but was observed three times in fairly new types of ram preventers.

Comparison with the Previous BOP deepwater Study

Table 3.2 shows a comparison of the same key results from Phase I DW and Phase II DW studies.

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 (hrs)	Avg. downtime per BOP-day (hrs)
Phase I DW	3191*	3457,5	138	23.1	25,1	1,08
Phase II DW	4009	3637,5**	117	34.3	31,1	0,91*

* Including only the BOP days from wells drilled in deeper waters than 400 m (1312 ft). In addition 1655 BOP-days stemmed from wells drilled in more shallow water.

** Note the comments below Table 1.2

Table 3.2 shows that the Mean Time To Failure (MTTF) was longer in the Phase II DW study than in the Phase I DW study. Further, that the average downtime caused by BOP failures was a little lower in the Phase II DW study than in the Phase I DW study. It is important to note the comments below Table 1.2. If the lost time mentioned had been regarded as downtime caused by BOP failures, the Phase II DW average would be approximately 10% higher. It should also be noted that for many of the failures observed in Phase II DW it was decided not to pull the BOP to repair the failure after MMS had granted a waiver. The failures in question were typically failures in components that were backed up by another component in the BOP stack. These types of decisions were also taken in Phase I DW, but not as frequent as in Phase II DW.

The most notable differences between the two data sets are the differences in the downtimes of the ram preventers and the choke and kill lines. In Phase II DW, some very time-consuming ram preventer failures occurred, while only minor ram preventer failures were observed in Phase I DW. Further, choke and kill line leakages seem to be a minor problem in the US GoM deepwater wells. These lines caused substantial problems in the Phase I DW study, and have also caused severe problems in earlier BOP studies for "normal" water depths.

The failure rate distribution is similar to the downtime distribution. The most distinct difference in failure rates between Phase I DW and Phase II DW is for the choke and kill lines. Otherwise, both the annulars and connectors experienced a lower failure rate in Phase II DW compared to Phase I DW.

Year to Year Trends in Failure Rates and Downtime

By combining the data from this study and data from the previous BOP studies, the annual BOP failure rates from 1978 were established. The failure rate was significantly reduced in the beginning of the 1980s. After 1984, the failure rate seems to have been fairly stable

The downtime per BOP day in service shows no significant trend.

Failure Rate and Downtime vs. Water Depth

Table 3.5 shows an overview of the BOP failures and downtimes for the various depth intervals.

Table 1.4 Overview of the BOP failures and downtimes for the various depth intervals (Phase II DW)

Water depth m /ft. (MSL)	No. of BOP-days	Total lost time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hrs)	Avg. downtime per BOP-day (hrs)
400 – 600 / 1312 – 1969	1350	1097	28	48,2	39,2	0,81
600-800 / 1969-2625	573	689	21	27,3	32,8	1,20
800-1000 / 2625-3281	521	603,5	12	43,4	50,3	1,16
1000-1200 / 3281-3937	644	424,75	27	23,9	15,7	0,66
1200-1400 / 3937-4593	475	290,5	11	43,2	26,4	0,61
1400-2100 / 4593-6890	446	532,75	18	24,8	29,6	1,19
Total all depths	4009	3637,5	117	34,3	31,1	0,91

An obvious trend regarding MTTF and average downtime per BOP-day related to the water depth can not be observed from Table 3.5. It seems that there is no correlation at all between the failure rate and the downtime related to the water depth. It is important to note that all the BOP failures are included, both the failures that occurred when the BOP was on the rig and the failures that occurred when the BOP was on the wellhead. Most failures that occurred when the BOP was on the wellhead did not cause the BOP to be pulled. The failures were frequently accepted or they were in the control system and could be repaired by pulling a pod.

The average lost time per BOP-day in operation is strongly influenced by a few time-consuming BOP failures. This is the same conclusion as in earlier BOP studies.

The water depth related downtime is not clear based on Table 3.5, and was therefore investigated closer. Regression analysis showed that the water depth influences the downtime related to BOP failures. The main explanation is that BOP running and pulling times increases with the water depth.

Safety Critical Failures

Safety critical failures are failures that occur in the BOP after the installation test is completed. In this period the BOP may have to act as a barrier. Failures observed on the rig, during running of the BOP, and during the installation test are not regarded as safety critical failures.

The frequency of safety critical failures that occurred in this study was similar to the frequency observed in Phase I DW.

In this study the most severe failures as leakage in the wellhead connector and leakage in the choke and kill valve to stack connection below the LPR, were not observed.

Rams and annulars have, however, failed at a higher rate in the safety critical period in this study than the previous study.

The severe failure mode loss of all functions both pods occurred more frequently in Phase I DW than in this study. It should, however, be noted that many of the BOPs in the previous study were equipped with an acoustic backup control system as well.

Based on this study and the previous Phase I DW study, it can be stated that the yellow and blue control pods have become less redundant in “new” BOP control systems. The main problem is related to common hydraulic supply parts. A single leakage can jeopardize the complete BOP control.

Below a coarse ranking of the failures that were observed in the safety critical period in Phase II DW is presented alongside the same ranking for Phase I DW. It should be noted that Phase I DW is represented with an approximately 20% longer time in service. Note that all the Phase I DW data is included so some of the failures stems from wells drilled in more shallow water than 400 m (1312 ft).

Phase I DW BOP study	Phase II DW BOP study
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 BOP control by the main control system 5. Two shear ram leakages in closed position 6. Two failed to disconnect the LMRP failures 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	1. One control system failure that caused total loss of 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 failed to open pipe ram failures 6. Two failures where the pipe ram leaked in closed position 7. External leak in flexible joint 8. One failed to disconnect the LMRP failure 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)

BOP Testing Experience

The average test time consumption was 13,9 hours. The total test time consumption for BOP subsea tests was 4761 hours. These 4761 hours represent 5% of the total no. of BOP-days, or in average 1,19 hours/BOP-day.

When looking at the data from Phase I DW, the average test time was 8,3 hours. If disregarding the tests performed in water depths shallower than 400m (1312 ft.), the average test time for the 225 tests was 9,6 hours, or 4,3 hours shorter than the average test time for the Phase II DW study.

The major contributor to the extra time consumption is that MMS requires that the variable bore rams (VBRs) shall be pressure tested against all sizes of pipe in use. If the VBRs only are tested against one size pipe (compared to two) this will have an insignificant effect on the BOP safety. This would, however, cause significant timesavings.

1. INTRODUCTION

1.1 SINTEF's BOP Reliability Experience

From 1981 to 1997, SINTEF has documented results from a number of detailed reliability studies of Subsea Blowout Preventer (BOP) systems (/1/, /2/, /4/ and /6-17/) on behalf of various oil companies operating in the Norwegian sector of the North Sea and the Norwegian Petroleum Directorate (NPD). The following studies have been carried out:

Phase I: Analysis of failure data from 61 exploration/appraisal wells drilled from semisubmersible rigs and BOP system analysis.

Phase II: Analysis of failure data from 99 exploration/appraisal wells from semisubmersible rigs and mechanical evaluation of BOP components. Separate report on reliability of control systems.

Phase III: Evaluation of operation and maintenance of subsea BOP components. Evaluation of test procedures and operational control.

Phase IV: Analysis of 58 exploration/appraisal wells, drilled in the period 1982 - 1986. The availability of the BOP as a safety barrier against blowout was assessed by fault tree analysis. Time consumptions for weekly BOP testing and associated problems were recorded and discussed.

Phase V: Analysis of 47 exploration/appraisal wells, drilled in the period 1987 - 1989. BOP failures were recorded and analyzed. Recommendations with respect to BOP test intervals were given. Time consumption for weekly BOP testing was recorded and discussed.

Phase I DW: Analysis of 140 wells drilled in four different countries in the period 1992 -1997. The report presents the data collected and further highlights deepwater specific problems. The three control system principles; conventional pilot hydraulic systems, pre-charged pilot hydraulic system, and multiplexed systems were compared by fault tree analysis with respect to the ability to close in a well given a kick.

In addition SINTEF has carried out a reliability study related to platform located BOPs used for development drilling (/5/). The analysis was based on failure data from 48 development wells drilled from three North Sea platforms in the period 1986 - 1990. The study was completed in 1992.

1.2 Background for this Project

In December 1997 SINTEF was requested by MMS to submit a proposal for a subsea reliability project to follow up the Phase I DW project. MMS approached the oil industry in the US GoM OCS and asked them to partly finance the study. The oil industry, however, showed little interest. In the autumn 1998 MMS decided to go for the project without the financial support from the oil industry.

The project kick-off meeting was arranged in New Orleans in November 1998.

1.3 Objective

The main objective of this study (Phase II DW) has been to investigate and present deepwater subsea BOP reliability for US GoM OCS rigs. Further, to compare the results with the reliability of deepwater subsea BOP from other areas and also subsea BOPs used at conventional depths. (For the purpose of this study deepwater is defined as waters deeper than 400 meters (1312ft).

Another objective of this study has been to propose a more effective way of testing the BOPs and at the same time from a safety point of view, to keep up the BOP safety availability.

2. DATA BACKGROUND AND DATA SOURCES

BOP data have been collected from wells drilled in the US GoM OCS. All wells are categorized as deepwater wells. Deepwater in this report is defined as waters deeper than 400 meters (1312 ft.). The actual water depth for the wells ranges from 407 m to 2050 m (1335 ft. to 6725 ft.). The majority of wells included were spudded in the period from July 1 1997 until May 1 1998. Four wells were spudded before this period and one well after this period. Approximately 85% of the deepwater wells spudded in this period are included. The goal was to cover 100% of the deepwater wells, but some operators did not supply the requested data. When referring to data collected in this study the study is called Phase II DW. In 1997 another study concerning deepwater BOP reliability was completed. This study is referred as Phase I DW in this report.

When collecting BOP reliability data, only the drilling period has been considered. The drilling period is the time from spud-in until leaving location. If the drilling covers a regular well test this is regarded as a part of the well drilling. Completion activities and workovers are not included.

A total of 83 different wells, where a subsea BOP has been used, are included in the study. Side tracks have been treated as separate wells. Some of the wells were abandoned for a period of time before re-entering and continuing operations.

Table 2.1 presents an overview of wells, operational days and drilling vessels for the various water depths.

Table 2.1 Overview of wells, operational days and drilling vessels for the various water depths

Water depth m /(ft) (MSL)	No. of wells	No. of BOP-days	Dyn. Pos. drill ships	Dyn. Pos. semisubs	Anchored semisubs
400 – 600 / 1312 – 1969	30	1350			30
600-800 / 1969-2625	10	573			10
800-1000 / 2625-3281	10	521			10
1000-1200 / 3281-3937	18	644			18
1200-1400 / 3937-4593	6	475			6
1400-1600 / 4593-5249	2	140	2		
1600-1800 / 5249-5906	4	169	3		1
1800-2100 / 5906-6890	3	137	3		
Total	83	4009	8		75

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 entry *Days in service,* for a specific BOP component is defined as the number of BOP-days multiplied with the number of components in the BOP stack

This study focuses the BOP-days and days in service when presenting failure rates and downtimes.

Mooring
It is seen from Table 2.1 that most of the wells have been drilled from anchored semisubmersibles. Only eight wells have been drilled from dynamic positioned vessels. In the previous Phase I of the deepwater study (Phase I DW) (/1/), a larger proportion of the drilling vessels were dynamically positioned (DP) drilling units.

2.1 BOP Data Collected

The type of operational data collected during the study is shown in Table 2.3 alongside the data sources used.

Table 2.2 Operational data collected and the data sources used

Type of data	Main data source
BOP failure data	Daily drilling reports
BOP subsea test data	Daily drilling reports/BOP test sheets
Well casing information	Well casing reports/Daily drilling reports
BOP stack configuration	BOP information from the operators/ information from contractors/ information from public sources
BOP key maintenance procedure	Information supplied from the drilling contractors
General rig information	Public sources

Data based on the daily drilling reports
The main data source for this study has been the daily drilling reports from the wells included in the study. These reports have mostly been sent to SINTEF as E-mail attachments in various formats, as Microsoft Excel, Microsoft Access, and plain test dump from the daily drilling reporting system. For some wells, hard copies of the daily drilling reports have been used as data source.

The chronological description of the activities in the daily drilling reports has been the main input, but also the observation fields have in many cases given additional information about the failure.

Data based on public sources
Information regarding rigs and BOPs has also been compiled from *The Guide to Mobile Drilling Units* (/17/) and *World Oils* December Issue for several years (/18/), including an overview of Marine drilling rigs. Some information has also been collected from the drilling contractors' homepages on the Internet.

2.2 Configuration of the BOP Stacks Included

Figure 2.1 shows a sketch of a "typical" subsea BOP system. All subsea BOP stacks are in principle similar.

The BOP stacks investigated in this study were all 18 ¾” 10 000 or 15 000 psi stacks. In Phase I DW most of the BOP stacks were 18 ¾” 10 000 or 15 000 psi stacks, except for the BOP stacks for the drill-ships. They were all 16 ¾” 10 000 psi stacks.

Table 2.3 shows the stack configuration for the various drilling vessels. It has been selected to give the rigs numbers from 50 to 75 to separate them from the rigs included in earlier BOP reliability studies.

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

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

As seen from Table 2.3 there are some differences between the various BOP stacks.

Six out of the 26 stacks have only one annular preventer. One of the stacks have two shear rams.

Most stacks have a combination of fixed and variable bore rams (VBR). Two rigs have only VBRs, while one has only fixed rams. It should be noted that the location of the VBRs varies. Some prefer to have a VBR as the lower pipe ram (LPR), while most prefer to have a fixed ram as the LPR.

The number of choke and kill valves varies significantly. For half of the BOP stacks eight valves are utilized. As many as five rigs have ten valves, while two rigs have only four valves.

Only two of the 26 BOP stacks included in the study have the lower choke and kill line outlet above the LPR, while the remaing 24 BOP stacks have the lower outlet below the LPR.

In addition, some rigs have so-called kill and choke isolation valves located in the LMRP choke and kill lines. These valves are in principle identical to the choke and kill valves, except that they are normally open. The main purpose of these valves is to be able to test the kill and choke lines when running only the LMRP. These valves are not included in the study as separate items. They are regarded as part of the choke and kill lines.

None of the rigs included in the study have an acoustic backup BOP control system. These systems are mandatory in Norway, and preferred in deepwater drilling in Brazil. The acoustic backup system is used to close the BOP in case the riser is disconnected from the BOP by an accident.

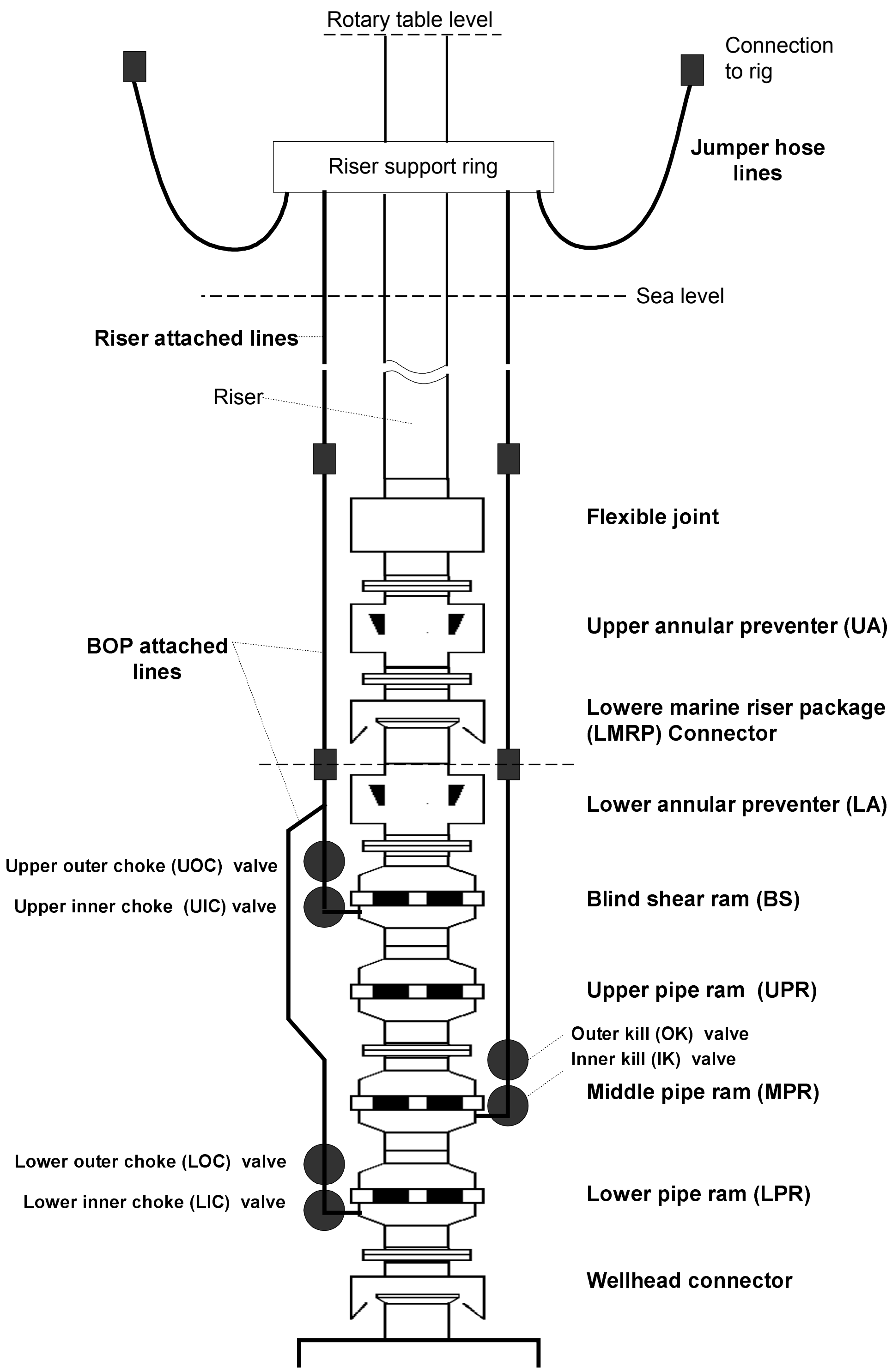

Figure 2.1 Typical configuration of a subsea BOP system

2.3 Deepwater Subsea BOP Preventive Maintenance

The intention with this section is to briefly describe the key subsea BOP maintenance actions carried out for deepwater BOP stacks utilized in the US GoM OCS. The section is based on information received from the rig contractors. It should be noted that the rig contractors were reluctant to provide the information. Further that the different rig contractors and rigs have given answers on a different levels.

The BOP preventive maintenance activities carried out in the US GoM OCS is on the same level as the preventive maintenance carried out on subsea BOPs in Brazil and in Norway. This was to be expected since oil drilling is an international business. The drilling contractors operating in the US GoM OCS also frequently operate in the North Sea and Brazilian waters. It should, however, be noted that there are differences in the maintenance between the various rigs and the various drilling contractors. These differences may be caused by:

- manufacturer specific recommendation will vary from manufacturer to manufacturer
- equipment performance will vary from rig to rig causing variation in maintenance need
- contractor/rig maintenance strategy may vary
- maintenance facilities and maintainability

2.3.1 Overview of BOP Maintenance Actions

The main BOP maintenance actions carried out between wells comprise inspection and testing of the BOP and the control system. Whenever severe wear, a failure or another problem is encountered, the actual failed or worn part is repaired or replaced.

For specific components/parts some rigs have a periodic replacement program, while other do not. These components/parts are the:

- control system pods
- choke and kill valves
- hydraulic lines on the BOP
- choke and kill line seals

In addition, major overhauls of BOP components are carried out at specific intervals. These intervals may vary from rig to rig. Some rigs reported that the main BOP component (for instance an annular preventer) was overhauled every 36 months, while for other rigs the interval could be 48 or 60 months. The typical interval in Norway is 48 months.

One of the rigs also noted that they carried out non-destructive testing (NDT) on load carrying components once a year, while none of the other rigs mentioned this type of testing for load carrying components. Third party NDT testing of specific components/parts are likely carried out for all/most of the BOPs at certain intervals.

None of the rigs reported that they replaced the main packers of the BOP on a periodic basis. The packers are replaced when the inspection indicates wear, or the preventer fails during a test according to the manufacturers recommendation.

In the following an overview of the key maintenance activities related to the various subsea BOP components is presented.

2.3.2 BOP Component Specific Key Preventive Maintenance

The information presented in this section is based on input from the contractors. It has been attempted to highlight the important issues. Since the level of information submitted to the project varied from rig to rig and contractor to contractor, this should not be regarded as an exact overview of the BOP preventive maintenance, but more as an indication of the level of preventive maintenance carried out.

BOP general (no specific component)
Maintenance between wells
The BOPs are always cleaned and inspected externally and internally for wear and key seat damage between wells.

All BOP actuators are pressure tested to the recommended operating pressure and the BOP stacks are pressure tested to full rated working pressure (or a lower pressure related to the maximum pressure expected in the next well to be drilled).

Flexible joint
Maintenance between wells
The flexible joints are cleaned and visually inspected for damage or abnormal wear. such as key seating. Further, they typically inspect that screws on flanges are properly installed and made up.

Maintenance every 12 months
One rig mentioned that they were carrying out NDT for load carrying components.

Total overhaul/replacement
One rig reported that they replaced the joint after 36 months. Another reported that they totally overhauled the joint after 60 months.

Annular preventer
Maintenance between wells
The annulars are cleaned and inspected internally and externally for damage or wear. If the elements are worn, they will be replaced as required. The actuators are typically tested to the recommended working pressure. A drift test was also mentioned by one of the contractors.

The annulars are typically pressure tested to 70% of the working pressure.

Maintenance every 12 months
One rig reported that they were carrying out NDT for load-carrying components. Another rig mentioned that they removed the upper housing and sealing element, inspected visually, and repaired as needed.

Total overhaul/replacement
Most rigs stated that they carried out a total overhaul of the annular after 36 months. One rig stated that they carried out a total overhaul when required, but maximum after 48 months.

Ram preventers

Maintenance between wells

Typically they clean and inspect the inside of the well bore for the condition of face seals, and the outer ram cavity for damage or wear between each well. Components are replaced/repaired as required. The rams are tested to the rated working pressure or to 75% of the rated working pressure. The ram locking systems are tested as well.

One rig did also open all the ram bonnets between wells and replaced the rubber parts when required. Thereafter they tested the rams to full rated working pressure.

Maintenance every 12 months

One rig executes NDT of load carrying components and measure ram and cavities test operating system and shuttle valves

Another rig carries out magnetic particle testing (MPI) of ram blocks and rods.

Total overhaul/replacement

The total ram preventer is overhauled or replacement with a factory rebuilt preventer every 36, 48 month or 60 month. This procedure varies from rig to rig.

Connectors (LMRP and wellhead)

Maintenance between wells

The connectors are inspected internally and externally for damage or wear. The sealing surface is also inspected. The connectors are then greased and locking mechanism/dogs inspected. Some rigs do also record the unlocking pressure and use this pressure as an indication of wear.

The connectors are tested when testing the BOP to typically the wellhead/annular rated working pressure.

(If a rig does not split the BOP stack between wells, the LMRP connector is subjected to the above maintenance typically every 6 months).

Maintenance every 12 months

One rig carries out NDT of load carrying components, and tests the operating system and the pilot check valve.

Total overhaul/replacement

The total hydraulic connector is overhauled or replaced with a factory rebuild preventer every 36, 48 month or 60 month. This procedure varies from rig to rig.

Choke and Kill valves

Maintenance between wells

The choke and kill valves are inspected and replaced with overhauled valves when needed. They are always cleaned, greased and pressure tested, normally to the working pressure, between wells.

Some rigs also utilize a periodic replacement strategy for the valves. If so typically two valves are replaced after each well.

Choke and Kill lines
Maintenance between wells
The seals are normally inspected for damage or wear and replaced as required. During running of the BOP the lines are pressure tested every 5 or 10 joints.

Other
One rig replaced all seals every second well
One rig stated that they replaced all seals every 12 months
Two rigs stated that they carried out NDT every 12 and 18 months

Control system
Maintenance between wells
All the hoses and pipe-work are inspected and checked for leaks between wells. The pods including the male body and female receptacle are typically also inspected. Any leaks or malfunctions found are repaired. Some rigs do, however, have one spare pod that is installed after each well. The pod taken out will then be overhauled and ready to be re-installed after the next well.

Some rigs also purged all pilot lines between wells. Others did it more seldom (every 6 months).

Otherwise, testing of pressure vessels, changing filter elements, inspect cables were among the activities mentioned.

The control system and the BOP stack are function tested between each well.

Every 24 months
Typically each pod is replaced or totally overhauled every second year. Several rigs have spare pods that are rotated. One rig reported that they rebuilt all SPM valves and regulators.

Every 48 – 60 months
Typically all control hoses on the BOP stack are replaced and thereafter tested to the working pressure or higher.

2.4 Downtime Calculation

The downtime (or lost time) associated to a failure includes all the time lost related to the specific failure. This means that the downtime recorded is the calendar time from the failure is observed until the drilling can proceed from the same position as when the failure was observed. If for instance a BOP failure that requires the BOP to be pulled occurs, the total time for plugging the well, pulling the BOP, repairing the BOP, rerunning the BOP and drilling the well plug is regarded as downtime associated to this failure. Also the BOP test where the failure was observed is regarded as downtime, but not the test after landing the BOP, since one BOP test was scheduled.

If, during the repair on the rig, another BOP failure, not linked to the original failure, is observed, this is regarded as a new failure. The downtime related to this failure is only the actual repair time, while the time for running the BOP is still linked to the original failure.

If, during the repair on the rig, some maintenance activities not linked directly to a failure are carried out, this is not considered as a separate BOP failure.

2.5 Failure Rate and MTTF Calculations

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:

$$\lambda = \frac{\text{Number of failures}}{\text{Accumulated Operating Time}} = \frac{n}{s}$$

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, λ, may be measured by a 90% confidence interval:

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

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

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

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

Lower limit: $\lambda_L = 0$

Upper limit: $\lambda_H = \frac{1}{2s}\chi_{0.10,\ 2}$

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.:

$$MTTF = 1/\lambda$$

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: $MTTF_L = 1/\lambda_H$

Upper limit: $MTTF_H = 1/\lambda_L$

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 * 2 annular preventers = 2000 days in service. The failure rate will then be:

$\hat{\lambda} = \frac{\text{Number of failures}}{\text{Accumulated operating time}} = \frac{n}{s}$ = 4/(1000 days*2) = 0,002 failures per day in service

The corresponding MTTF will then be:

MTTF = 1/λ = 1/(0,002 failures per day in service) = 500 days in service

2.6 What is Regarded as a BOP Failure?

In this study the BOP failures considered are only the failures that are observed:

- during the BOP stump test prior to running the BOP
- during running of the BOP, and
- when the BOP is on the wellhead

Other BOP failures observed between wells are not regarded as BOP failures, but as BOP maintenance.

2.7 Handling of BOP Failure and BOP Test Data

During the study the following main types of information have been collected:

- Key rig information
- Well information (water depth, well depth, spud date, BOP run date etc.)
- Casing information (mainly size and depth)
- BOP test information (described in Section 2.8)
- BOP equipment information
- BOP failure information (described in Section 2.7.2)
- Key BOP equipment information

2.7.1 Storing of Collected BOP data

During Phase I DW (/1/) a tailor-made computer program for handling BOP reliability information and BOP preventive maintenance information was developed. An overview of the database program's main parts is shown in Figure 2.2.

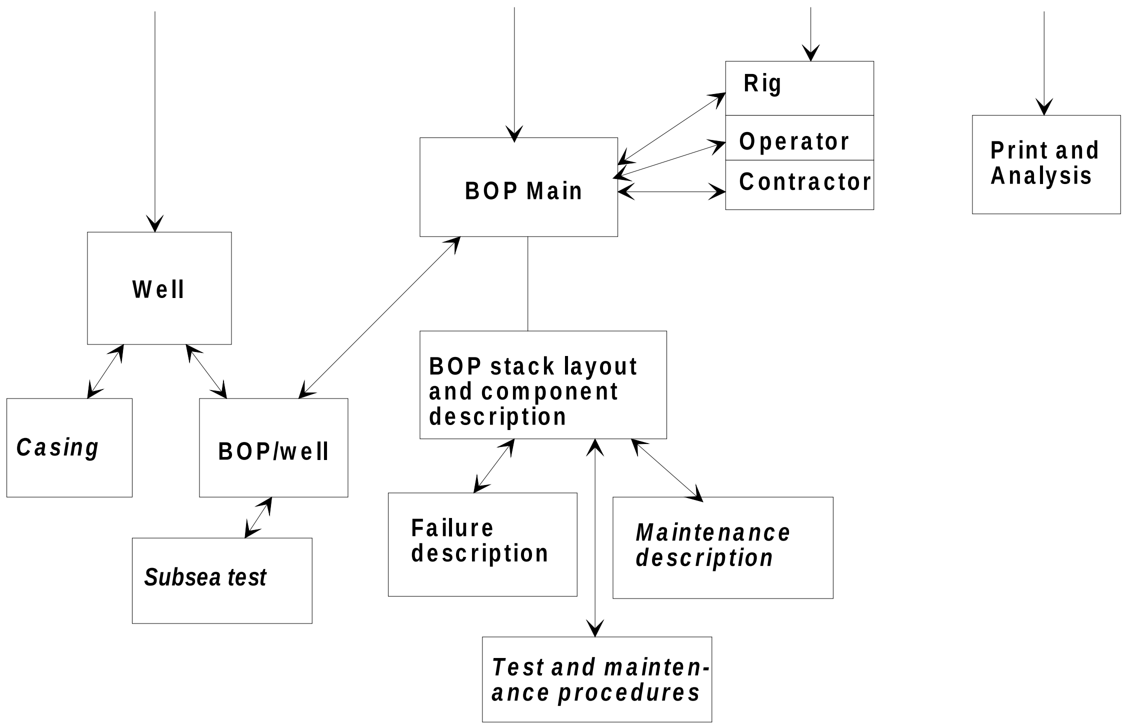

Figure 2.2 Overview of the database program main parts

For the purpose of this study the parts of the program related to preventive maintenance activities and procedures were not utilized. Otherwise all of parts the program were utilized to hold all the necessary information.

The BOP database resides in a Microsoft Access 97 data file. The main programming tools used are Microsoft Visual Basic. The Seagate Crystal Reports version 5.0 is used for making all the reports from the program.

The BOP database Program is described in /19/.

2.7.2 Categorizing BOP Failure Data

All the BOP failures observed have been categorized according to certain parameters. The most important parameters are listed below.

Part of the BOP that failed:

- Flexible joint
- Annular preventer
- Ram preventer
- Connectors
- Choke and kill valves
- Choke and kill lines
    - BOP mounted
    - Riser attached
    - Moonpool jumper hose
- Main control system
- Backup control system

Failure mode (only some examples included).
- Failed to fully open
- Internal leakage (leakage through a closed annular)
- Internal leakage (leakage through a closed ram)
- External leakage (leakage to environment)
- Failed to unlock (include all incidents with problems unlocking a connector)
- Internal hydraulic leakage (control fluid part)
- External leakage (bonnet/door seal or other external leakage paths)
- Failed to shear pipe

Location of the BOP when the failure is observed
- On the rig
- During running
- On the wellhead

How the BOP failure was detected
- Normal operation
- Pressure test
- Function test
- Other

Test type when the failure was observed (where relevant)
- Test prior to running the BOP
- Choke and kill line test when running the BOP
- Installation test
- Test after running casing or liner
- Test scheduled by time (periodic test)
- Test before well testing
- Other test
- Not relevant (if the failure was observed during normal operation)

Otherwise, for each failure a description of the incident, the date of the incident and detailed downtime is included.

2.8 Categorizing BOP Test data

For all the wells drilled information related to BOP subsea tests has been collected and categorized. The following categories of subsea BOP tests have been used:

- Installation test
- Test after running casing or liner
- Test scheduled by time
- Function test scheduled by time
- Other tests

Test pressures, test time consumption, and a description of the tests have been included for each of the BOP tests.

3. OVERVIEW OF BOP FAILURES

This chapter presents an overview of the observed BOP failures. The results from this study are also compared with results from previous BOP studies carried out by SINTEF (/1/, /4/, /9/, /12/, /13/, and /16/). The comparison focuses on the previous Phase I DW (/1/). The Phase I DW study also included some data from wells drilled in more shallow water than 400 meters (1312 ft.) The BOP reliability data from these wells have been disregarded for the overall comparisons between Phase I DW and Phase II DW.

3.1 Overview of all Failures in Phase II DW

A total of 117 failures were observed during the present study. These 117 failures produced 3637,5 hours lost time, or 0,907 hours per BOP-day. This represents 3,78 % of the drilling time related to the BOP-days in service. Figure 3.1 shows an overview of the contribution to this downtime from the various BOP subsystems.

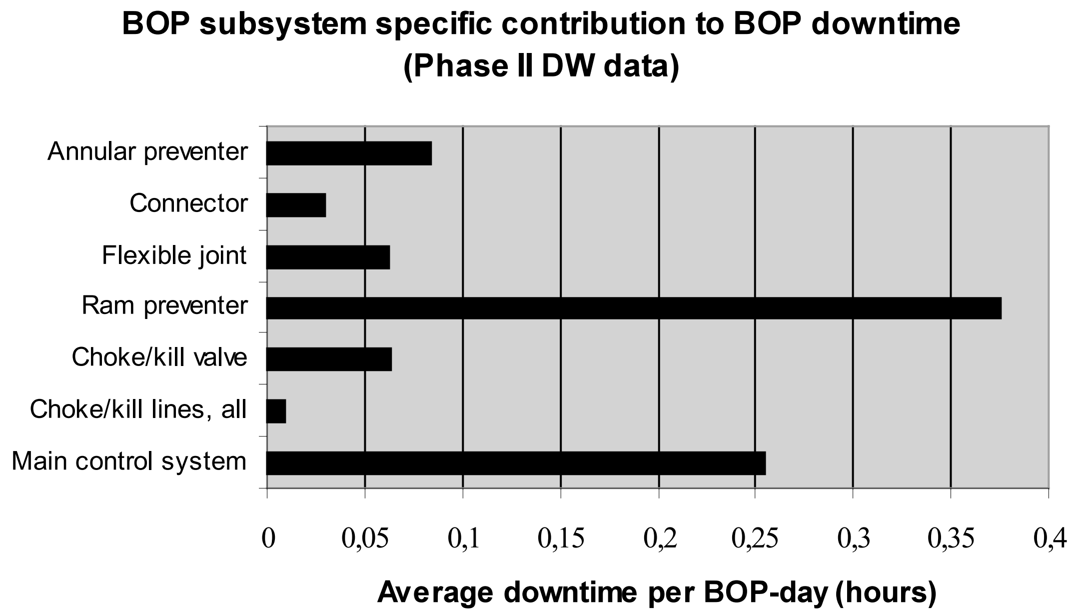

Figure 3.1 Overview of the contributors to rig downtime per BOP-day

As seen from Figure 3.1, the main contributors to rig downtime caused by BOP failures are the ram preventers and the main control system. The annular preventers, the choke and kill valves, the choke and kill lines and the connectors caused less downtime than the above systems. The flexible joint failed only once, but this failure caused a long downtime. No failures were observed in the BOP flanges.

Figure 3.2 shows the failure rates for the different BOP equipment.

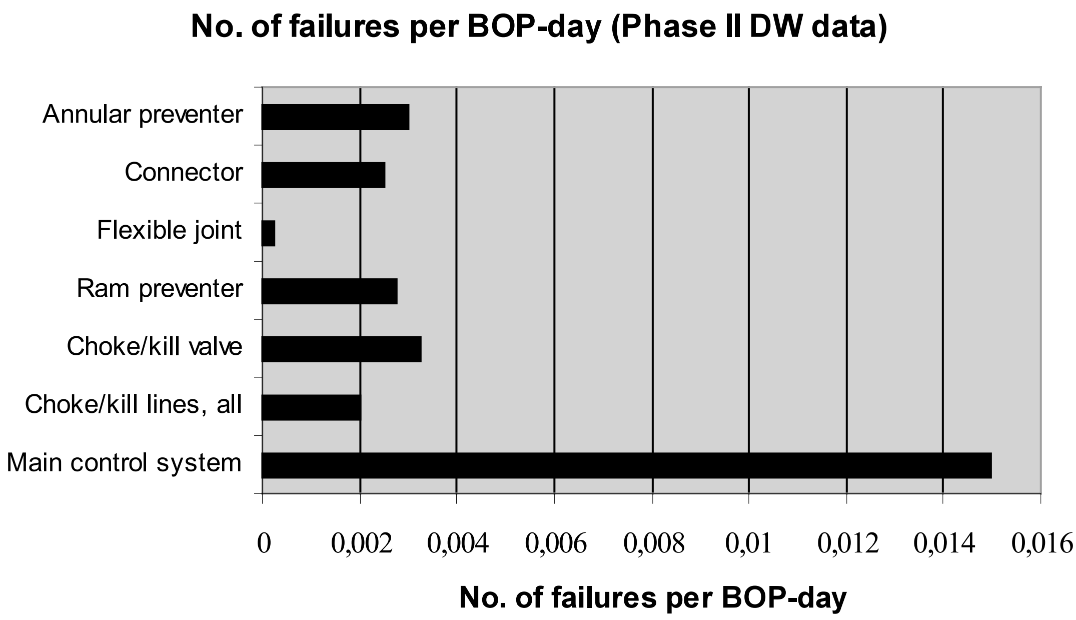

Figure 3.2 Failure rate for the different BOP equipment

From Figure 3.2 it is seen that the control system has a far higher failure rate than the other BOP main components. The failure rate have more or less the same distribution as the downtimes except for the ram preventers. For the ram preventers two very time-consuming failures were observed (618 hours and 475 hours), therefore the average downtime per day in service became so high.

Table 3.1 shows an overview of the no. of BOP failures, total downtime and Mean Time To Failure (MTTF).

Table 3.1 Overview of the no. of BOP failures

BOP subsystem	BOP-days in service	Days in Service	Total Lost Time (hrs)	No. of failures	MTTF (days in service)	MTTF (BOP-days)	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
Annular preventer	4009	7449	336,5	12	621	334	28,0	0,08
Connector*	4009	8018	117,75	10	802	401	11,8	0,03
Flexible joint **	4009	4009	248,5	1	4009	4009	248,5	0,06
Ram preventer	4009	16193	1505,25	11	1472	364	136,8	0,38
Choke/kill valve	4009	31410	255,5	13	2416	308	19,7	0,06
Choke/kill lines, all	4009	4009	36,5	8	501	501	4,6	0,01
Main control system	4009	4009	1021,5	60	67	67	17,0	0,25
Dummy item***	4009		116	2	-	2005	58,0	0,03
Total	**4009**		**3637,5**	**117**	**-**	**34**	**31,1**	**0,91**

* For one LMRP connector failure the lost time was not available because the daily drilling reports were missing (Described on page 59). Two to three days were lost.

** For the flexible joint failure 250 hours more time was used to work on stuck pipe/fishing problems after the flex joint failure was repaired. This work was most likely a result of the flexible joint failure (Described on page 49).

*** The Dummy item in Table 3.1 is used to include two BOP failures that were impossible to link to a specific BOP item. Both these failures occurred when preparing to run the BOP and were poorly described.

3.2 Comparison with the Previous BOP Deepwater (Phase I DW) study

Since the previous Phase I DW study included wells drilled in more shallow water than 400 m (1312 ft.), it has been decided only to use data from wells drilled in more than 400 meters for this comparison.

Further, many of the BOP stacks analyzed in Phase I DW included an acoustic backup system. The failures and downtime associated to this system have been disregarded in the comparison.

Table 3.2 shows a comparison of same key results from Phase I DW and Phase II DW studies.

Table 3.2 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 (hrs)	Avg. downtime per BOP-day (hrs)
Phase I DW *	3191	3457,5	138	23.1	25,1	1,08
Phase II DW	4009	3637,5*	117	34.3	31,1	0,91*

* Note the comments below Table 3.1.

Table 3.2 shows that the Mean Time To Failure (MTTF) was longer in the Phase II DW study than in the Phase I DW study. Further, that the average downtime caused by BOP failures was a little lower in the Phase II DW study than in the Phase I DW study. It is important to note the comments below Table 3.1. If the lost time mentioned had been regarded as downtime caused by BOP failures the Phase II DW average would be approximately 10% higher. It should further also be noted that for many of the failures observed in Phase II DW study it was decided not pull the BOP to repair the failure after MMS had granted a waiver (MMS granted twelve such waivers). The failures in question were typically failures in components that were backed up by another component in the BOP stack. These type of decisions were also taken in Phase I DW.

Figure 3.3 shows a comparison of the BOP item specific average downtime in Phase II DW and Phase I DW.

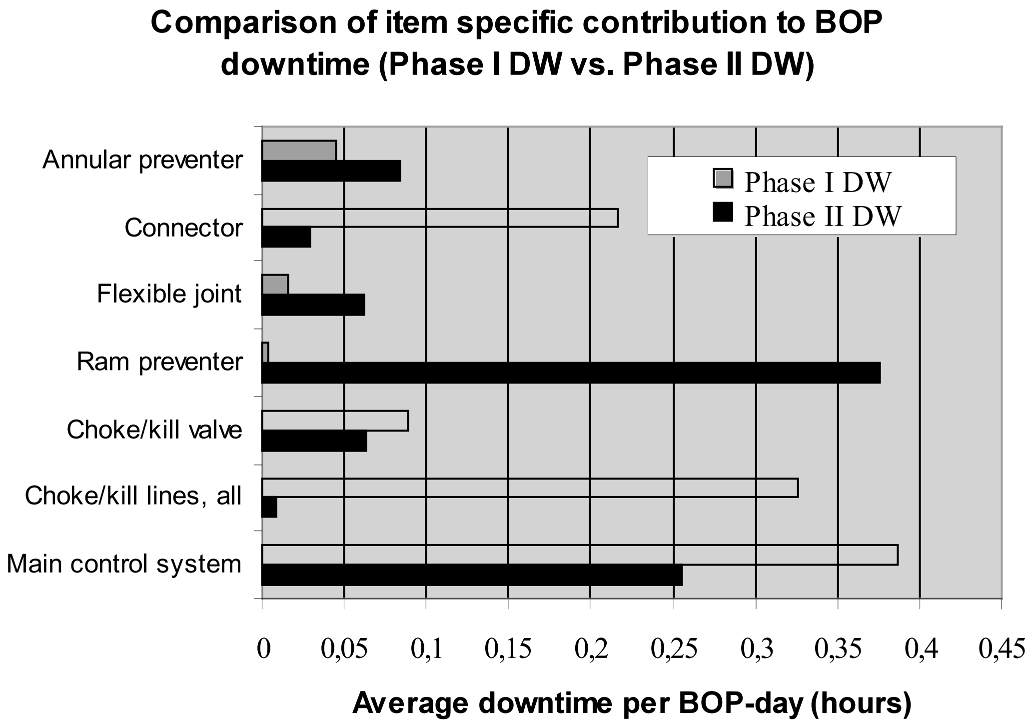

Figure 3.3 Comparison of BOP Item specific downtime

The most notable differences between the two data sets are the differences in the downtimes of the ram preventers and the choke and kill lines. In Phase II DW study, some very time-consuming ram preventer failures occurred, while only minor ram preventer failures were observed in Phase I DW.

Choke and kill line leakages seem to be a minor problem in the US GoM deepwater wells. These lines caused substantial problems in Phase I DW study, and have also caused severe problems in earlier BOP studies for “normal” water depths. It is worth noteing that in the previous studies some rigs had several problems with these lines while other rigs had no problems. In the Phase II DW no rigs had severe problems.

The connector average downtime per day in service was higher in Phase I DW than in Phase II DW. This was caused by an average longer downtime for each failure and a higher failure frequency.

Figure 3.4 shows a comparison of the BOP item specific failure rates in Phase II DW Phase I DW.

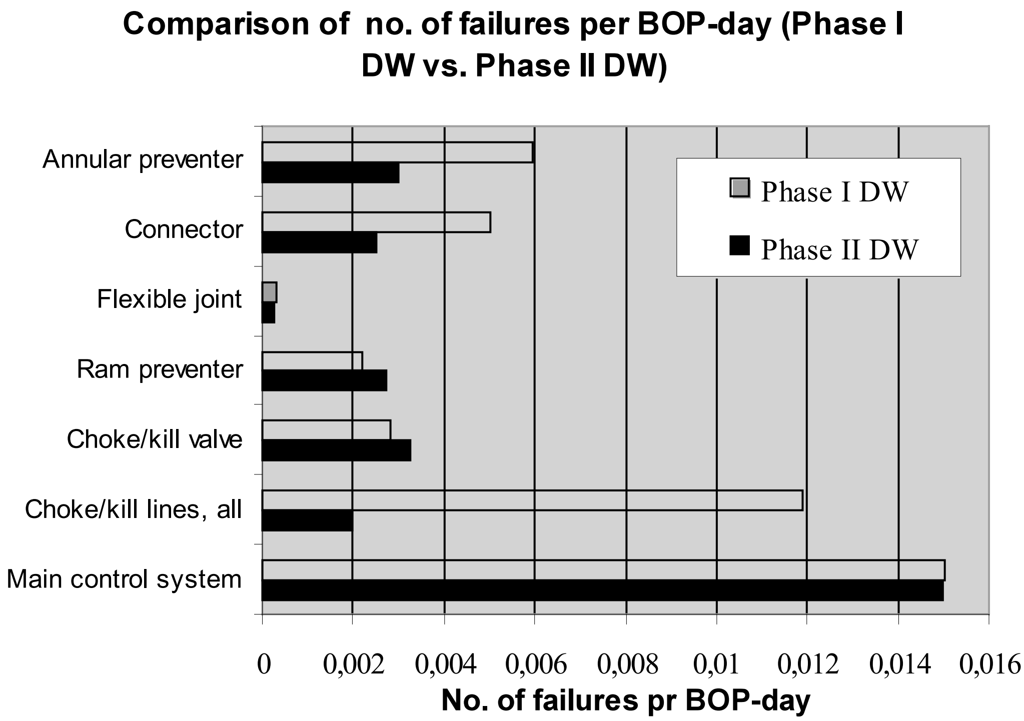

Figure 3.4 Comparison of BOP item specific failure rates

The most distinct difference in failure rates is for the choke and kill lines.

There is also a significant difference in the failure rates of the annular preventers and the connectors. For the annular preventers the failures that occurred in Phase I DW had minor impact on the downtime. Many of these failures were small leakages during testing. The leakages were overcome by increasing the annular closing pressure. The reason why the frequency of these "small" failures was much higher in the Phase I DW study may be due to different practices when writing the daily drilling reports.

Otherwise the failure rates are at the same level.

In Table 3.2 the overall failure data from Phase II DW are compared with data from previous BOP reliability studies.

Table 3.3 Comparison of key data for different BOP studies carried out in the period 1982 – 1999

Study*	BOP-days	Total Lost Time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hrs)	Avg. downtime per BOP-day (hrs)
Phase II **	8115	8779.9	503	16.1	17.5	1.08
Phase IV	3809	2734.8	139	27.4	19.7	0.72
Phase V	2636	2142	74	35.6	29.0	0.81
Phase I DW ***	4846	4949.5	202	24.0	24.5	1.02
Phase II DW	*4009*	*3637.5*	*117*	*34.3*	*31.1*	*0.91*
TOTAL	23415	22243.7	1035	22.6	21.5	1.08

* See introduction for brief explanation of the different studies
** Includes one failure not linked to any specific BOP system, causing 864 hours downtime
*** Includes all data (both "shallow" water wells and acoustic control system failures)

3.3 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 from 1978 has been established. In Table 3.4 the overview data for each of the years is shown.

Table 3.4 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	No data					
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	37.0	19.78	0.53
Total	23415	22243.45	1035	22.6	21.49	0.95

The data in Table 3.4 have been used to create Figure 3.5 that shows the annual failure rates, alongside 90% confidence intervals, linear, and log linear trendlines for subsea BOP stacks. The years from 1992 – 1996 represent Phase I DW study. The years 1997 and 1998 mainly represent Phase II DW study. It has been decided to disregard the data from 1978 because this year is represented with few data. Further, note that no data is available for the years 1990 and 1991.

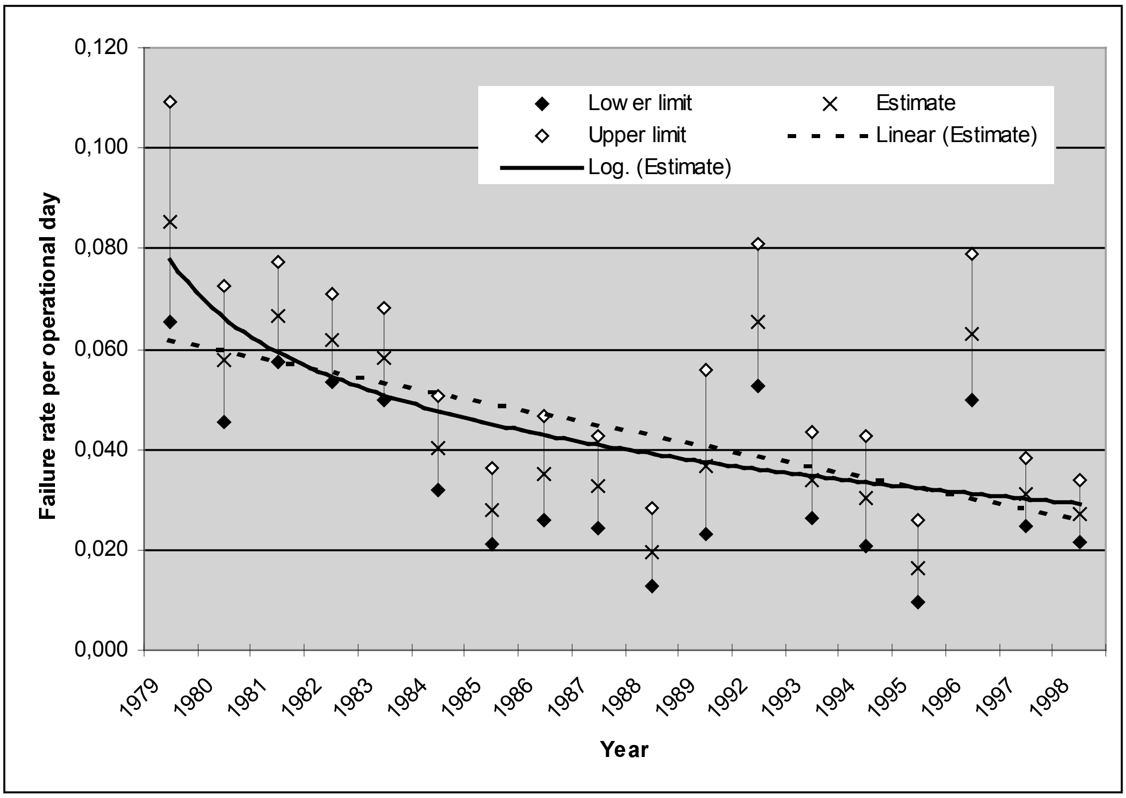

Figure 3.5 Annual failure rates, 90 % confidence intervals, linear and log linear trendlines for subsea BOP stacks for the period 1979 – 1998

The trendlines indicate a decreasing failure rate over the period. Linear regression analysis indicated a 99% probability that the trend has decreased. It is here 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 3.5 indicate that the failure rate was significantly reduced in the beginning of the 1980s. After 1984, the failure rate seems to be fairly stable. A similar plot as in Figure 3.5 has been dawn for the period 1984 – 1996. This plot is shown in Figure 3.6.

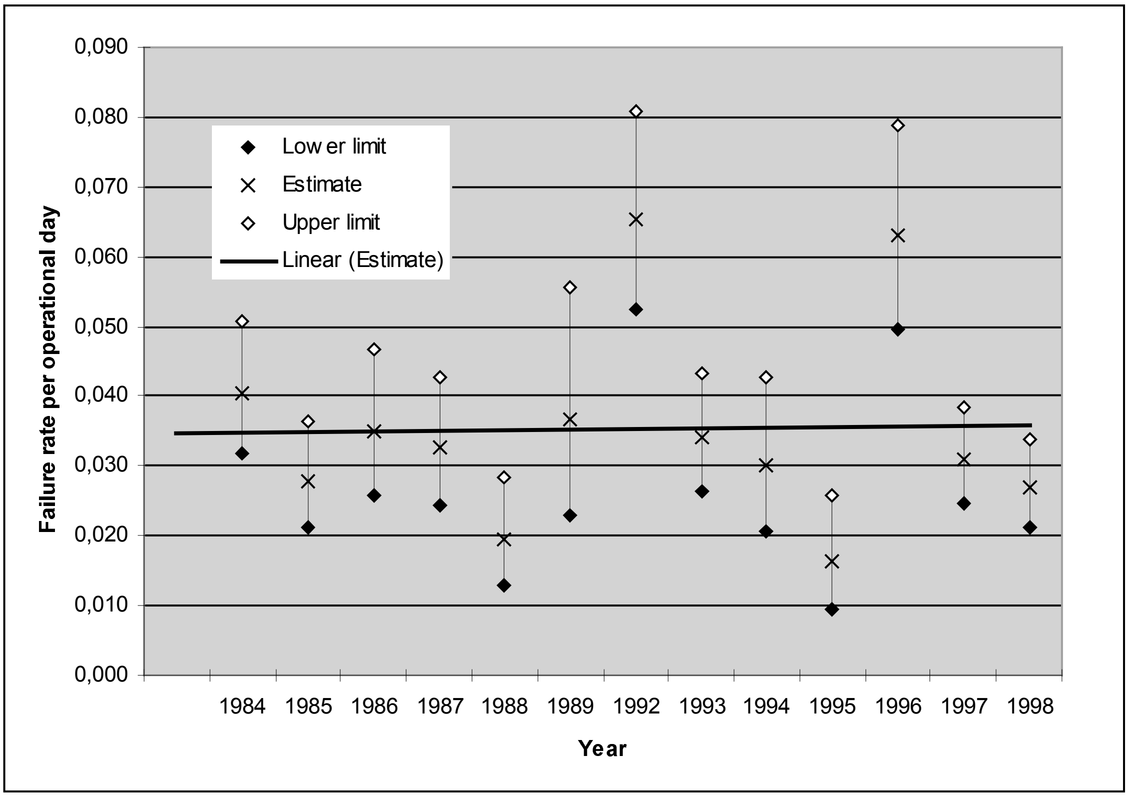

Figure 3.6 Annual failure rates, 90 % confidence intervals, linear and log linear trendlines for subsea BOP stacks for the period 1983 – 1998

As seen from the trendlines in Figure 3.6, there is no decreasing trend in the failure rate for the period 1984 – 1996. The reduction in failure rate was in the beginning of the 80s.

In Figure 3.7 the average downtime per year and the associated trendlines for the average downtime per day in service are shown.

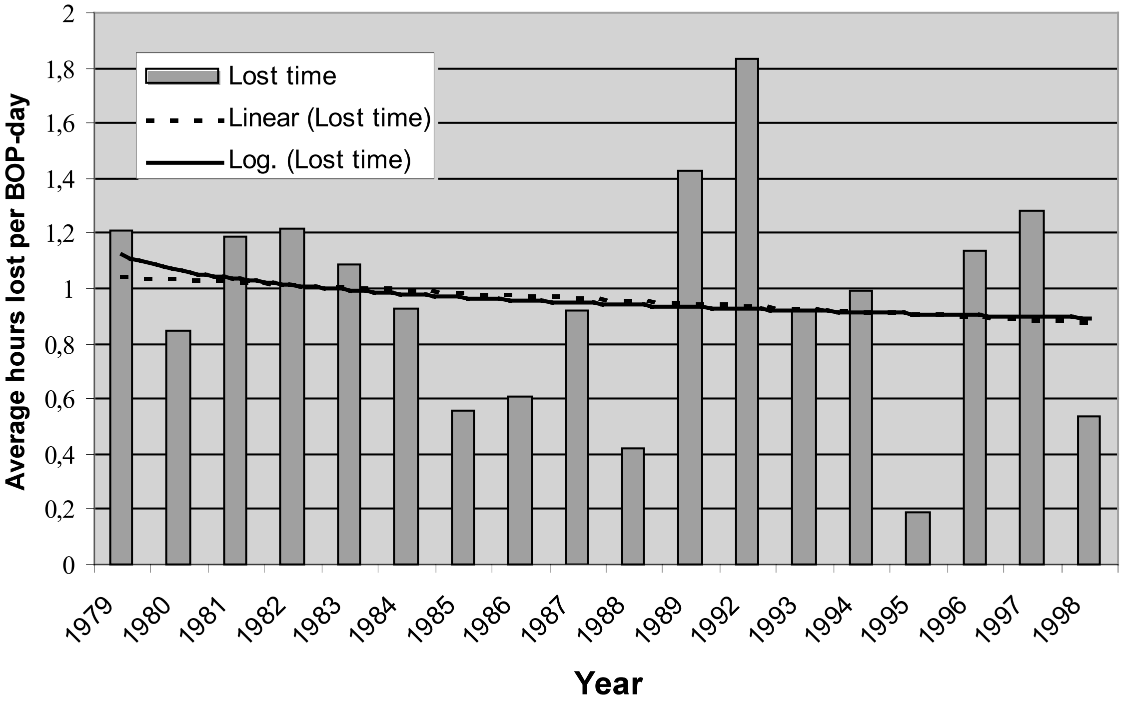

Figure 3.7 The average downtime per year and the associated trendlines for the average downtime per day in service for the period 1979 – 1998.

As seen from Figure 3.7, a slight decrease 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, 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 a large part of the most recent data is from deepwater wells.

3.4 Failure Rates and Downtimes vs. Water Depth

Table 3.5 shows an overview of the BOP failures and downtimes for the various depth intervals.

Table 3.5 Overview of the BOP failures and downtimes for the various depth intervals.

Water depth m /ft. (MSL)	No. of BOP-days	Total Lost Time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hrs)	Avg. downtime per BOP-day (hrs)
400 – 600 / 1312 – 1969	1350	1097	28	48,2	39,2	0,81
600-800 / 1969-2625	573	689	21	27,3	32,8	1,20
800-1000 / 2625-3281	521	603,5	12	43,4	50,3	1,16
1000-1200 / 3281-3937	644	424,75	27	23,9	15,7	0,66
1200-1400 / 3937-4593	475	290,5	11	43,2	26,4	0,61
1400-2100 / 4593-6890	446	532,75	18	24,8	29,6	1,19
Total all depths	4009	3637,5	117	34,3	31,1	0,91

An obvious trend regarding MTTF and average downtime per BOP-day related to the water depth can not be observed from Table 3.5. It seems that there is no correlation at all between the failure rate and the downtime related to the water depth. It is here important to note that all the BOP failures are included, both the failures that occurred when the BOP is on the rig and the failures that occurred when the BOP was on the wellhead. Most failures that occurred when the BOP was on the wellhead did not cause the BOP to be pulled. The failures were frequently accepted or they were in the control system and could be repaired by pulling a pod. The main difference in downtime between shallow and deepwater is believed to be caused by the BOP handling time itself.

The average lost time per BOP-day in operation is strongly influenced by a few time-consuming BOP failures. This is the same conclusion as in earlier BOP studies.

In Figure 3.8 and Figure 3.9 the average lost time per BOP-day in service and the failure rate per BOP-day in service for the different BOP subsystems are presented.

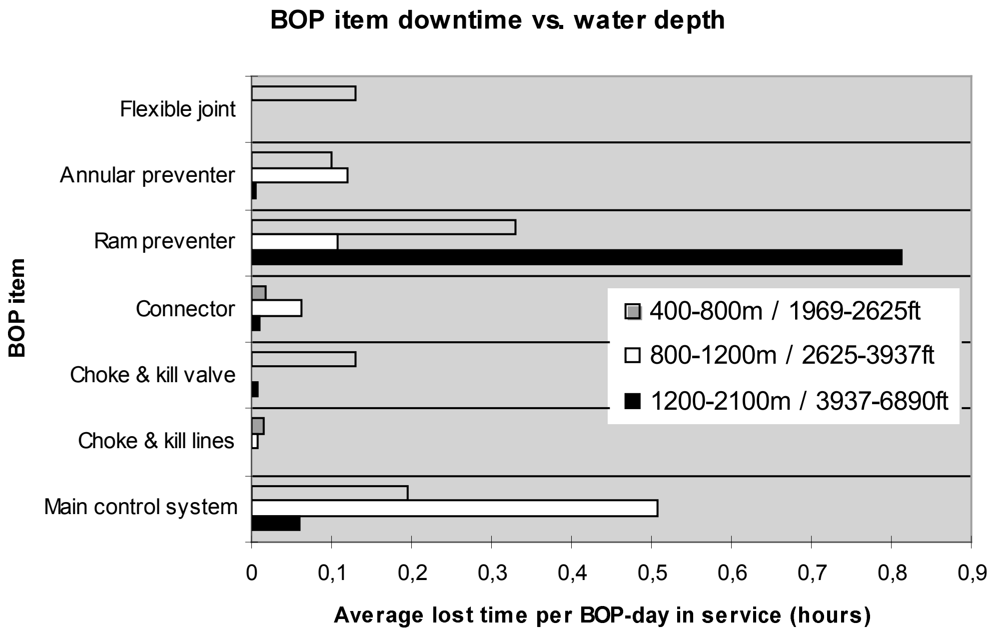

Figure 3.8 Average lost hours per BOP-day in service for different water depth and BOP equipment

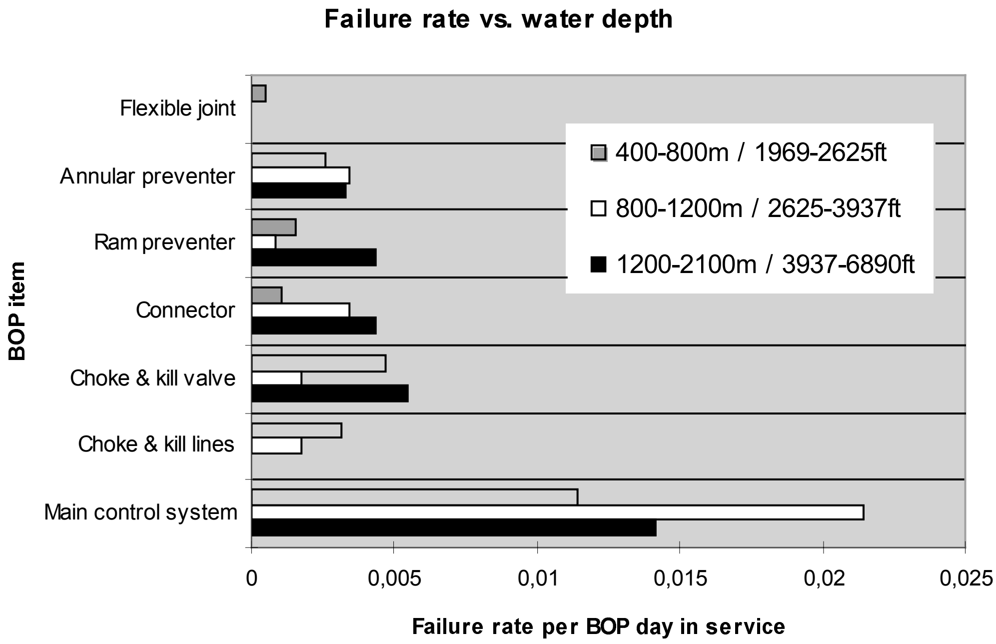

Figure 3.9 Failure rate per BOP-day in service for different water depth and BOP equipment

Both for the average downtime and for the failure rate it is impossible to observe any BOP component specific correlation with the water depth.

3.5 Water Depth Related Downtime

The correlation between downtime and the water depth is not at all clear based on the table and charts presented in Section 3.4. This is because the occurrence of failures is random and few failures with long duration confuse the picture. Also all the failures recorded are included. Of the 117 failures, 42 were observed when the BOP was on the rig prior to running the first time, or the failure was observed when the BOP was on the rig for repair of another BOP component. These failures resulted in a total lost time of 670,75. Ten failures resulting in 235,5 hours lost time were observed during running the BOP. The remaining 65 failures were observed when the BOP was on the wellhead, causing a total lost time of 2731,25 hours lost time.

In this section the correlation between the downtime and the water depth is investigated closer for the failures where the BOP was on the wellhead when the failure was observed. The failure rate is not considered.

In Figure 3.10 regression lines for lost time vs. water depth is shown.

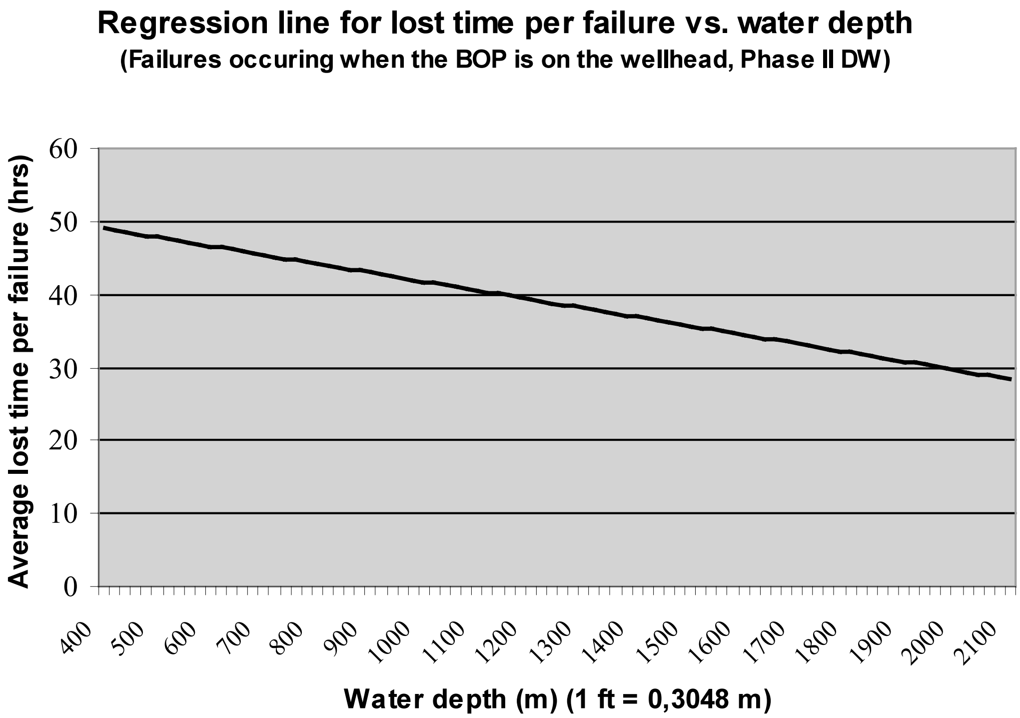

Figure 3.10 Regression line for lost time vs. water depth for failures that occurred when the BOP was on the wellhead.

The regression line in Figure 3.10 indicates a reduction in the average downtime with increasing water depth, a result that is *not* what should be expected. It should be expected that the regression line should increase with increasing water depth. Once again the results are influenced by single failures with long duration. This unexpected result is caused by one ram preventer failure in 442 meters (1450 ft.) of water. The failure caused 618 hours lost time. If removing this failure from the data set, the result in Figure 3.10 would be completely opposite.

It is to be expected that in the long run the average downtime for failures that occur when the BOP is on the wellhead should be higher for failures occurring in deep waters than in shallow waters.

To increase the dataset, the failures that occurred in Phase I DW study were combined with the Phase II DW data. The regression line for this combined data set is presented in Figure 3.11.

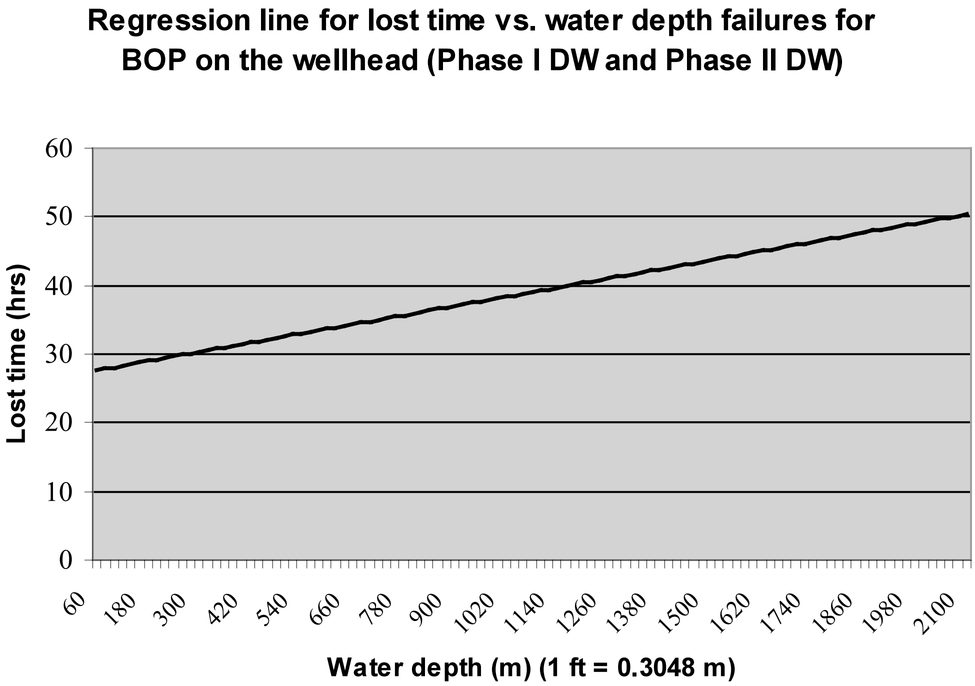

Figure 3.11 Regression line for lost time vs. water depth for failures that occurred when the BOP was on the wellhead (Phase I DW and Phase II DW data)

The regression line in Figure 3.11 is according to what should be expected when a large data set is available. The influence of single failures causing severe time losses will then be reduced. The main explanation for this slope of the regression line is the increased BOP running and pulling times.

For most of the BOP failures causing the BOP or the LMRP to be pulled from the wellhead, the pulling and running times have been recorded in the database. Figure 3.12 shows the BOP/LMRP running and pulling times sorted on water depth for both Phase I DW and Phase II DW data. Figure 3.13 shows the regression line for BOP/LMRP running + pulling times vs. water depth for both Phase I DW and Phase II DW data.

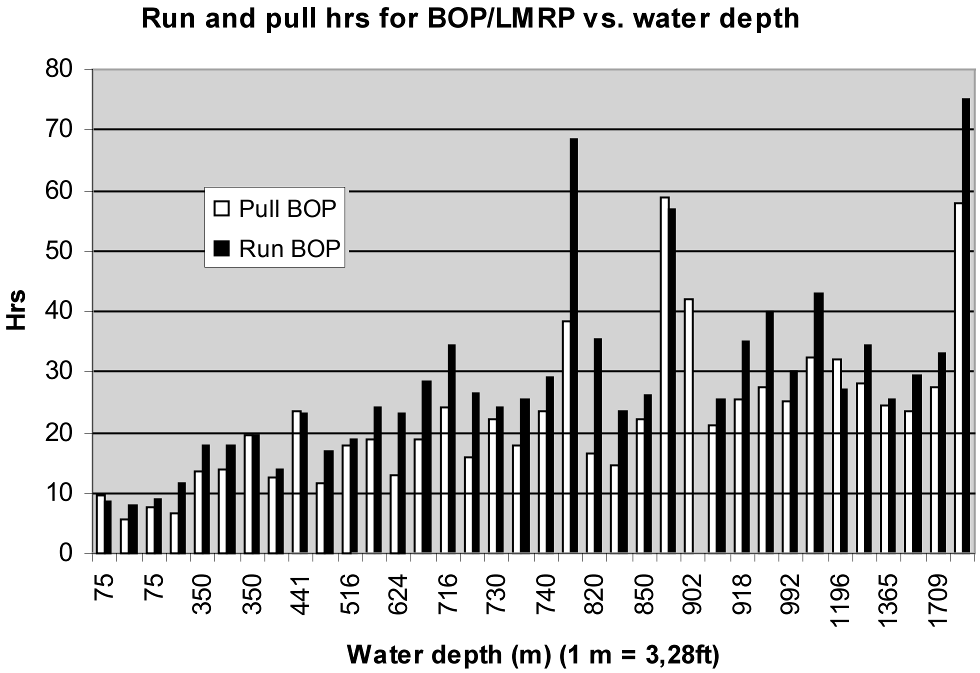

Figure 3.12 BOP/LMRP running and pulling times sorted on water depth for both Phase I DW and Phase II DW data

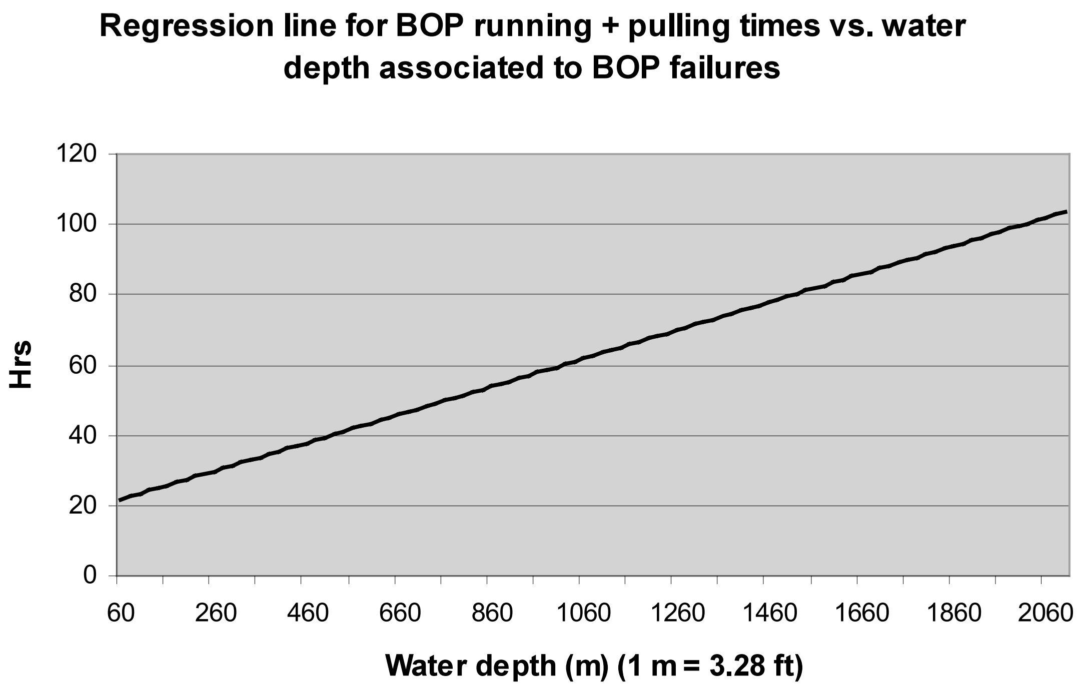

Figure 3.13 Regression line for BOP/LMRP running + pulling times vs. water depth for both Phase I DW and Phase II DW data

It is seen from Figure 3.12 and Figure 3.13 that the water depth has a significant influence on the BOP handling time, as expected. For a BOP in 60 meters of water it can be expected 10 hours for pulling and 10 hours for running the BOP. For a well in

2000 meters of water it can be expected 50 hours for running and 50 hours for pulling the BOP.

3.6 Waiting for Repair of BOP

The repair of the BOP is from time to time delayed because they have to wait on weather (WOW), wait on spare parts (WOSP) or wait on other (WOO). In Phase II DW they in total waited for 247 hours, representing 6.8% of the lost time caused by BOP failures.

There were five WOW incidents. In total they implied 140,5 hours waiting time. Typically they waited for wind and waves to calm down, but also once for the sea current to decrease.

There were six WOSP incidents. In total they implied 85 hours waiting time. Approximately 50 hours were lost when waiting for parts to a MUX system. Parts came partly from California. Once they were waiting for parts for an annular preventer, once a ram bonnet, twice parts for a choke/kill valve, and once a flexible hose for the BOP.

There were two WOO incidents. In total they waited for 21,5 hours In one occasion they waited personnel for 18,5 hours, and in another occasion they waited for orders related to quality acceptance of many replaced BOP control hoses.

3.7 Overview of Rig Specific Performance

The 26 rigs included in the study showed a highly varying failure rate and downtime per BOP-day in service, as illustrated in the Figure 3.14 and Figure 3.15.

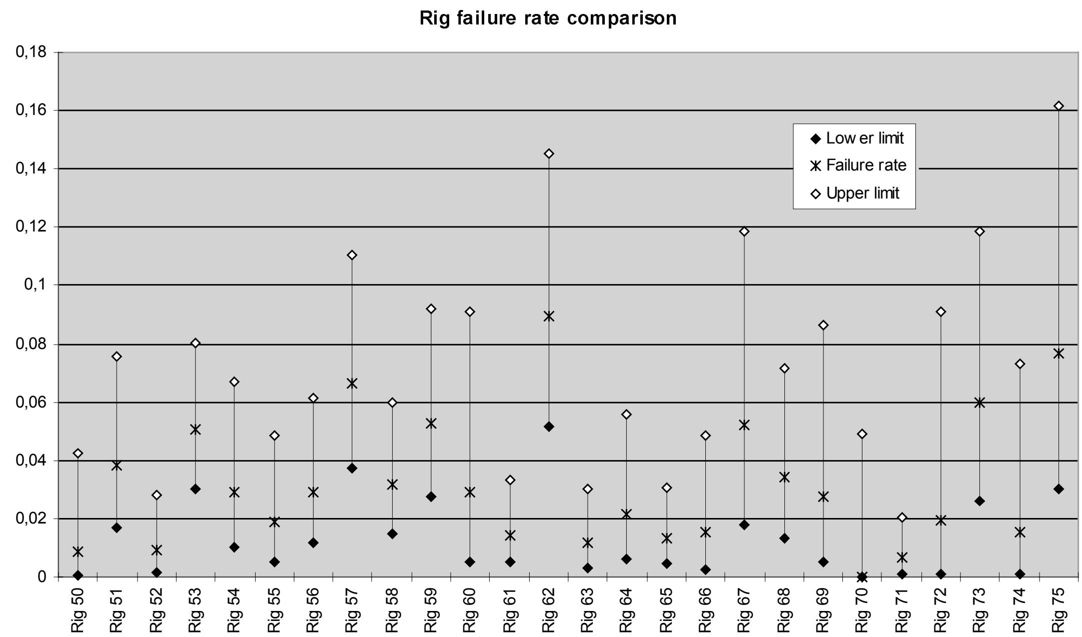

Figure 3.14 Rig specific failure rate per BOP-day in service with 90% confidence interval

Rig 62, 75 and 57 had the highest failure rates. The majority of failures for rig 62 were related to the main control system. Rig 75 was represented with few BOP-days in service. Five failures gave this high average. Rig 57 had also fairly many control system failures, and also failures in some other BOP components.

No failures were observed on rig no. 70. This rig was only represented with 47 BOP-days in service. Otherwise rig 71, 50, and 52 had low failure rates. These three rigs were all represented with a fair amount of BOP-days.

With the relatively few BOP-days in service for all the rigs included in the study it is to expect that the failure rate will vary from rig to rig. To get a better rig comparison each rig should have been represented with more days in operation.

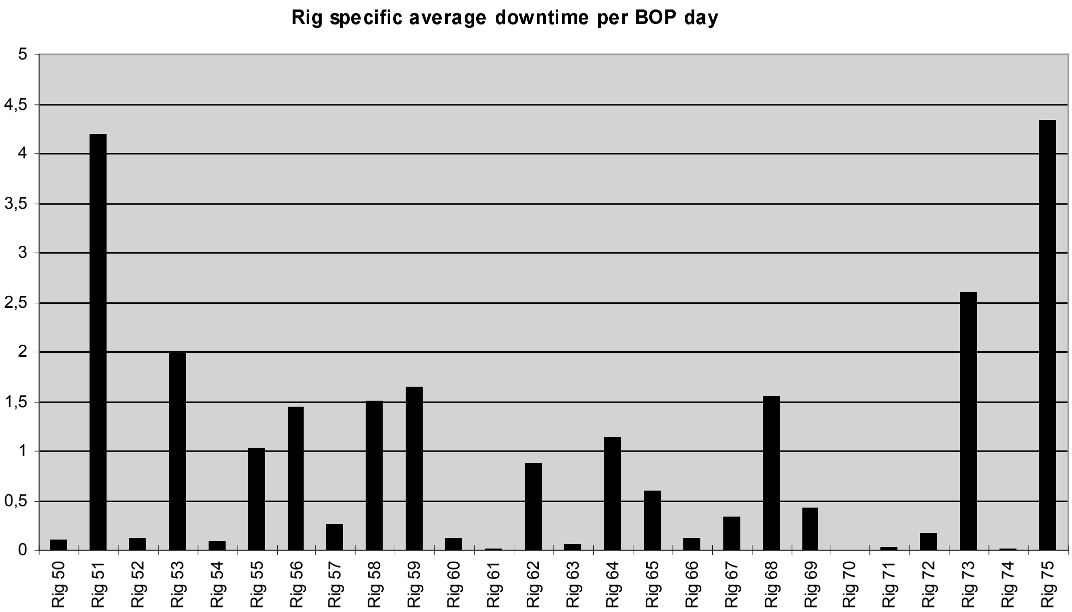

Figure 3.15 Rig specific average downtime per BOP-day in service

As seen from Figure 3.15 there are large differences in the average downtime per day in service as well. If comparing the average downtime per BOP-day in service with the rig specific failure rate in Figure 3.15 it is seen that there is no direct link between the highest failure rate and the average downtime. The downtime picture is dominated by relatively few failures of long duration.

4. BOP System Specific Reliability

4.1 Flexible Joint Reliability

Today most rigs have a flexible joint with a flexible element. Some do, however, still have a flexible joint based on the ball joint principle. Failures in the flexible joints are rare. This is the same experience as from previous subsea BOP studies. In the beginning of the 80-ies, when ball joint type flexible joints were frequently used, several failures were observed in the North Sea.

From earlier BOP studies, it can be concluded that the flexible joint principle is superior to the ball joint principle in terms of reliability.

In this study five of the 26 rigs utilized a ball joint type flexible joint. These represented 18.5% of the BOP-days in service.

The manufacturers of flexible joints included in the study are; Cameron, National, Oil-States and Vetco. Cameron has both flexible element and ball joints.

Description of flexible joint failure
One flexible joint failure was observed in the study. This failure was in a ball joint type flexible joint. The flexing principle was, however, not the cause of the failure.

The failure was an external leakage. The reason for the failure was, most probably, a welding error due to bad heat treatment. It was observed a vertical leak on the flex joint (30” x ¼” wide at the top & 2 ½” wide at the bottom) between two welds that were added in for the booster line inlet.

The water depth was approximately 650 meters (2130 feet). They were drilling at 5260 meters (17258 feet) when the failure was observed. The failure caused the fluid in the riser to be lost to the seafloor. The loss of fluid immediately caused that the hydrostatic control of the well was lost and the well kicked. The well was shut in with the lower annular, SICP = 800 psi and SIDPP = 0 psi. Then they attempted to work the pipe, but the pipe had become stuck.

They performed well control and stuck pipe operations for 80,5 hours before they could start repairing the LMRP. When they pulled the LMRP they had shot off the drill string at 10700 feet and ran a storm packer in the well. The fish remained in the well. They also had indications that the lower annular would not seal properly after stripping operations (this is reported as a separate failure record).

They repaired and ran the LMRP. After verifying that the BOP was OK, they pulled the storm plug assembly.

Up to this point they had lost 248,5 hours due to the flexible joint failure. They worked on the stuck pipe and fishing for another 250 hours before they plugged and abandoned the well (these 250 hours are not recorded as downtime related to the flexible joint failure).

4.2 Annular Preventer Reliability

Six of the 26 BOP stacks included in the study were equipped with one annular preventer, otherwise the rigs were equipped with two.

4.2.1 Annular Preventer Failure Modes, Downtimes and Frequencies

Table 4.1 shows an overview of annular preventer failure modes, the associated number of failures and lost time. The days in service refer to the BOP-days multiplied with the number of annulars in the stack.

Table 4.1 Annular preventer failure modes and associated number of failures

Days in Service	Failure Mode Distribution	Total Lost Time (hrs)	No. of failures	MTTF (days in service) Lower limit	Mean	Upper limit	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
	Internal leakage (leakage through a closed annular)	317,00	6	629	1 242	2851	52,83	0,079
	External leakage (leakage to environment)	0,00	0	3235	>7 449	-		0,000
	Failed to fully open	19,50	6	629	1 242	2851	3,25	0,005
	Failed to open	0,00	0	3235	>7 449	-		0,000
	Failed to close	0,00	0	3235	>7 449	-		0,000
	Internal hydraulic leakage (control fluid part)	0,00	0	3235	>7 449	-		0,000
	Unknown	0,00	0	3235	>7 449	-		0,000
	Other	0,00	0	3235	>7 449	-		0,000
7449	**All**	**336,50**	**12**	**346**	**621**	**1 076**	**28,04**	0,084

As seen from Table 4.1, six of the 12 annular preventer failures were *Internal leakage (leakage through a closed annular)* failures. Six of the 12 annular preventer failures were *Failed to fully open* failures. No other failure modes were observed. Two of the annular preventer failures caused the BOP or LMRP to be pulled.

Internal leakage failures

The failure mode *Internal leakage (leakage through a closed annular)* was observed at a slightly higher failure rate in Phase I DW than in Phase II DW.

On the rig failure

One of the six internal leakage failures was observed when the BOP was tested prior to running.

They were preparing to run the BOP on the well for the first time. During testing of the BOP they discovered the cap seal on the annular to be leaking. They replaced the cut cap seal and tested, the cap seal leaked again. Then they disassembled, cleaned and buffed the piston before reinstalling and testing. *Total lost time was* 21,5 hours.

On the wellhead failure

Five such failures occurred when the BOP was on the wellhead. For three of the failures they decided not to repair. Typically MMS was informed of the occurring failure.

The *first* failure occurred during a BOP test scheduled by time. When attempting to pressure test the lower annular they observed a small leak. The opened the annular and reset the test tool. Then the attempted to re-close the lower annular on both yellow and blue pods - unsuccessfully, the closing side fluid pumped away. With a ROV monitoring the stack, they tried to operate the lower annular open, close, and block a number of times with different sequences with the same results as above. The external control lines to the lower annular were not leaking and it was impossible to determine the source of the leak with the ROV due to pod enclosures. The source of leak was likely within the annular body. Fluid was likely passing by the seal on the closing side of the piston, going into the open side chamber, then venting to sea through the SPM valve. MMS approved continued operations with the non-functioning lower annular without repairing since the upper annular was tested OK. *Total lost time was* 2,5 hours. The water depth was 1410 m (4625 ft.).

The *second* failure occurred during a BOP test after running casing or liner. The lower annular low pressure test at 250 psi increased to 450 psi f/m hyd. Operating pressure differential on closing side. They did not repair this failure at once, but waited until the end of the well three weeks later. The water depth was more than 2000 m (6562 ft.).

Prior to the *third* failure they had been using the lower annular for stripping during well control operations. At first they had to increase the closing pressure to get a proper seal. Then the LMRP was on the rig for a flexible joint repair. Afterwards they observed that pieces of annular rubber came as well when pulling the wearbushing running tool. On the subsequent BOP test the lower annular failed to hold the test pressure. The annular leaked at 2400 psi with 2000 psi operating pressure. When increasing the operating pressure to 2400 psi the preventer leaked at 2000 psi. The failure was not repaired before the stack was pulled to abandon the well 16 days later. MMS was made aware of the annular failure. The water depth was approximately 650 m (2133 ft.).

Also prior to the *fourth* internal leakage failure they had been performing well control operations for three days. Among the operations carried out were stripping into the well. It was not stated which annular they used for the stripping operations. During the well control operations a leakage in the upper annular was observed. Likely the stripping operation caused the annular to fail. After the well was stabilized the BOP repair action started. They ran well packer and cement plug before pulling the BOP stack. It is not known why they decided to pull the complete stack and not the LMRP only. When the BOP was on the rig it was thoroughly inspected, and many parts not related to the failure replaced. It was observed excessive wear in the lower annular as well. *Total lost time was* 169,0 hours. The water depth was approximately 510 m (1673 ft.).

The *fifth* internal leakage failure was observed during the BOP installation test. They were unable to test the upper annular. After they pulled the LMRP they pressure tested the open and close chamber to 1500 psi (good test). Then they attempted a well bore test to 3500 psi (no test). Replaced annular element and tested to 250/3500 psi, 5 minutes each test. Annular tested, but improper gallon count to close annular. It took 61 gallons to close, but should only take 38 gallons. Disassembled the annular and found piston seal damaged. Replaced the seal, tested and ran the LMRP. *Total lost time was* 124,0 hours. The water depth was approximately 900 m (2953 ft.).

Failed to fully open failures

The *Failed to fully open* failures were normally overcome by using overpull or increased weight below the tool that should pass the annular. The cause of the failure is normally slow relaxation of annular rubber. It is also assumed that these failures occur more often than mentioned in the daily drilling reports, but it is not regarded as a failure, -rather a fairly frequent occurring operational problem. Another contributing cause may be that the rig is not perfectly positioned above the well.

Six such failures were observed. The total lost time was 19,5 hours.

The *Failed to fully open* failures are well-known annular problems. However, the problem has been reduced compared to the earlier subsea BOP studies. In the 80s the majority of these problems were related to Cameron D preventers. Cameron D preventers are represented with 13% of operational time in this study and one such failure was observed on that type preventer. I.e. the frequency of this type of failure on the Cameron D preventer is the same as the average for other types.

The *Failed to fully open* failure mode is normally not critical with respect to blowout hazard, but may produce some rig downtime.

Below brief descriptions of the six *Failed to fully open failures* are given

1. Had to work the running tool through the upper & lower annulars after a BOP test.

2. Unseat test plug – attempt to POOH. Test plug hanging up on the upper annular. Worked same but would not come free. Moved rig 15’ north – Plug worked free.

3. Had to work wearbushing through annulars after a BOP test

4. RIH with BOP isolation test tool and tag up on top of upper annular. They were unable to work through the upper annular. POOH with the test tool, washed and reran the tool. Had a little trouble to get through both annulars.

5. Worked through the annulars with the test tool. They observed the same problem with a wear bushing one week later.

6. Had problems to pass the annular with the wear bushing. Had to work through with 50k.

4.2.2 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	Dimension	Press. rate (psi)	Days In service
Cameron D	18 ¾"	10000	472
Cameron DL	18 ¾"	10000	424
Hydril GL	18 ¾"	5000	902
Hydril GX	18 ¾"	10000	775
NL Shaffer	18 ¾"	5000	330
NL Shaffer	18 ¾"	10000	3228
NL Shaffer	21 ¼"	5000	1318
Total			7449

There were no statistically significant differences in the failure rate between the manufacturers.

The 12 annular preventer failures were observed on nine different rigs. Three rigs experienced two failures each.

4.3 Ram Preventer Reliability

One of the 26 BOP stacks was equipped with five ram preventers. This BOP had one blind-shear ram (BSR) and four pipe rams. One of the BOP stacks was equipped with two BSRs and two pipe rams. The remaining 24 BOPs were equipped with one BSR and three pipe rams. Table 2.3 on page 21 gives an overview of the ram configuration for the various rigs included.

4.3.1 Ram Preventer Failure Modes, Downtimes and Frequencies

Table 4.3 shows an overview of the experienced ram preventer failure modes, the associated number of failures, and the lost time.

Table 4.3 Ram preventer failure modes and associated number of failures.

Days in Service	Failure Mode Distribution	Total Lost Time (hrs)	No. of failures	MTTF (days in service) Lower limit	Mean	Upper limit	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
	Premature closure	2,50	1	3413	16193	315695	2,50	0,001
	Failed to close	475,50	1	3413	16193	315695	475,50	0,119
	Failed to keep closed	10,00	1	3413	16193	315695	10,00	0,002
	Failed to shear pipe	0,00	0	7033	>16193	-	-	0,000
	Internal hydraulic leakage (control fluid part)	0,00	0	7033	>16193	-	-	0,000
	External leakage (bonnet/door seal or other external leakage paths)	24,50	1	3413	16193	315695	24,50	0,006
	Internal leakage (leakage through a closed ram)	140,50	4	1769	4048	11852	35,13	0,035
	Failed to open	852,25	3	2088	5398	19803	284,1	0,213
	Unknown	0,00	0	7033	>16193	-	-	0,000
	Other	0,00	0	7033	>16193	-	-	0,000
16 193	**All**	**1 505,25**	**11**	**889**	**1472**	**2625**	**136,84**	**0,375**

Seven of the 11 failures occurred when the BOP was on the wellhead, three when the BOP was on the rig, and one during running of the BOP. Six of the failures occurred in BSRs and five occurred in pipe rams. The failure rate for rams is slightly higher than in the Phase I DW study. The lost time due to ram preventer failures is very high in this study compared to the Phase I DW study.

Premature closure
As seen from Table 4.3, one of the 11 failures were *Premature closure* of a ram. The BSR closed unintentionally during running of the BOP. It was observed because the riser did not fill up with water. They tested the functions on the ram, and everything seemed OK. Two weeks later they got a *Failed to close* problem with the same BSR. It is likely that the two different failure modes had the same cause, but for the second failure the failure cause had developed. The failed to close failure is described below. *Total lost time was* 2,5 hours. The water depth was nearly 1800 m (5906 ft.).

Failed to close
The BOP failed to test after running the13 3/8" casing. They got a leakage on the BSR hardpipe from the shuttle valve to the ram body. It was indication of cracked socket weld to flange.

After pulling the BOP they observed problems with the ram hinges in general. They did work on all ram hinges. During the first attempt to run the BOP the blind-shear closed unintentionally again (see above failure). They pulled back and observed hinge problems. They also had problems with a BSR shuttle valve for the autoshear system. *Total lost time was* 475,5 hours. The water depth was nearly 1800 m (5906 ft.).

Failed to keep closed
During the BOP test on the rig prior to running, it was observed that the BSRs pos-locks did not hold properly. Replaced ram packers and re-adjusted pos-locks. *Total lost time was* 10,0 hours.

External leakage (bonnet/door seal)
When testing the BOP stack to 15,000 psi prior to running, the BSR bonnets started leaking. They retightened all bonnet bolts and ram housing flange. They also blew seals in piston bolt tension system on UPR's. They had to work and test for a while to get the BOP leak proof. On the last (and good) pressure test of the BOP body they held 15 000 psi pressure one hour with no pressure drop. *Total lost time was* 24,5 hours.

Internal leakage (leakage through a closed ram)
The first *internal leakage* failure was observed during a test scheduled by time. They were in the process of abandoning the well when they attempted to test the cement plug and casing to 1500 psi against the blind –shear ram. The pressure dropped to 235 psi in 10 minutes with returns in the riser. The failure was in the BSR sealing area. They then ran drill pipe to test the casing against the annular. They got verbal approval from MMS to proceed with the plug and abandon process with the failure. *Total lost time was* 3,5 hours. The water depth was nearly 1800 m (5906 ft.).

The second *Internal leakage* failure was observed during a test after running casing or liner. The LPR failed during the test. They functioned the LPR several times on both pods but could not pressure up below it. When opening the LPR after pulling it, they found that one VBR flexpacker was missing. Both pins on the top seal were sheared which allowed the flexpacker to fall out. The pins on the top seal of the other ram were deformed. *Total lost time was* 124,0 hours. The water depth was nearly 1800 m (5906 ft.).

The third *internal leakage* failure was observed during the installation test. They attempted to test the wellhead connector against the LPR. The test failed and they suspected a leakage in the wellhead connector. An ROV was used to inspect the wellhead and BOP. They pumped dye to stack, but could not see anything. Performed test once more and everything was OK. *Total lost time was* 5,0 hours. The water depth was approximately 600 m (1969 ft.).

The fourth *internal leakage* failure was observed during a test performed after running casing or liner. They attempted to test the BOP on 3 ½" drill pipe, but were unable to test the LPR (3 ½" x 5 ½" VBR). They pulled the test plug and replaced the 3 ½" pipe with 4 ½" pipe and tested. OK. They did not repair the LPR because the MPR also has 3 ½" sealing capability. The operator felt they needed MMS approval to continue operations with only one ram tested against 3 ½" drill pipe, but got the answer that they did need no BOP waiver. *Total lost time was* 8,0 hours. The water depth was approximately 1300 m (4265 ft.).

Failed to open

The failure mode *Failed to open* has been a rare failure mode in all the previous BOP reliability studies performed. In this study, however, three such failures have been observed. The three failures occurred on fairly new designed preventer/locking systems from two different manufacturers. In addition experience from Norway shows that fail to open is also a problem with the locking system from the third major BOP supplier. No failures in that specific system were, however, identified in this study.

It is important that ram locking systems function as intended, both when regarding the lost time caused by the failures and the safety. Stuck locking systems may create dangerous situations because the access to the well will be restricted. Mud may settle and kicks occur.

For the first *Failed to open* failure they were testing the BOP prior to running. They found that the UPR lock would not disengage fully. They stripped the lock and found a broken spring and some torn pieces. After repairing the failure, they found that they still had sequencing problem between the lock and the ram on both pods. A new lock assembly was ordered.

They flushed through the fluid lines and the pod and installed a new lock assembly. They operated the UPR only with hot line, to flush operating cavities, and activated the lock with hot line to clean & flush the operating cavities.

Finally they performed a thorough test of the locks and UPR. *Total lost time was* 69,5 hours.

The second *Failed to open* failure occurred on the same BOP stack as above, but it was the MPR that failed, and not the UPR. They had been running casing and tested the BOP against the seal assembly running tool. After releasing the seal assembly running tool, they attempted to pull it to lay down the cementing head. The running tool would, however, not pass through the MPR, that was a VBR. The locks were operated in an attempt to free up it. They continued to function the rams open and close and troubleshoot, but no progress was made. They closed the BSR and cut the drill pipe and pulled out of hole with the 5" drill pipe landing string (The BSR was inspected and found OK after the cutting operation). They pulled the BOP and attempted to open the MPR, unsuccessful. When opening the MPR bonnets they found that one side of the ram would not retract. Changed out both bonnet assemblies. *Total lost time was* 164,75 hours. The water depth was approximately 1300 m (4265 ft.).

The third *Failed to open* failure was observed during a BOP test after running casing was just finished. When attempting to pull the BOP test plug, it hung up in the BSR. The failure was caused by a failure in the shear ram locking system. It was a variable position locking system and not a fixed position locking system. It seemed that the BSR at first was partly closed, but during troubleshooting it became completely locked in closed position. A brief description of the activities to restore the failure follows:

They were troubleshooting and attempted to work the BOP test tool free, but failed. Sheared free and left the test plug and some pipe in the BOP.

The well was not stable. They had some gains, gained 3.5 bbls in 3.5 hours and therefore the well was shut in with the BSRs. Then they made reference points on the BSRs. When attempting to slack off further into cavity they could not get any deeper. It was discovered that the shear rams were locked closed.

They continued to monitor the well and fill the hole until the well was static. Then the LMRP was pulled and a rental shear ram installed between the LMRP connector and the annular. Thereafter they reran the LMRP.

A ROV was used to break disconnect the locks from the ram. They had some problems with this operation. Thereafter the BSR was functioned to the open position.

They sat a RTTS packer with difficulties and pulled and repaired the BOP. Ran and landed the BOP again. *Total Lost time was* 618,0 hours. The water depth was approximately 450 m (1476 ft.).

4.3.2 Manufacturers Included in the Study

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

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

Manufacturer	Size	Pressure rate	Days in service
Cameron T	18 ¾”	15000	944
Cameron U	18 ¾”	10000	5976
Cameron UII	18 ¾”	15000	1248
Hydril, Ligth weight	18 ¾”	15000	1185
Hydril	18 ¾”	15000	3368
Shaffer	18 ¾”	10000	308
Shaffer SL	18 ¾”	15000	1948
Shaffer SLX	18 ¾”	15000	1216
Total			16193

The fairly new type of preventers experienced a poorer performance than preventers that have been in use for many years.

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 LMRP to the rest of 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.

4.4.1 Hydraulic Connector Failure Modes, Downtimes and Frequencies

Table 4.5 shows an overview of the hydraulic connector failure modes, the associated number of failures, and the lost time.

Table 4.5 Hydraulic connector failure modes and associated number of failures for all the hydraulic connector failures

Days in Service	Failure Mode Distribution	Total lost time (hrs)	No. of failures	MTTF (days in service) Lower limit	Mean	Upper limit	Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
	External leakage (leakage to environment)	81,00	4	876	2005	5868	20,25	0,020
	Failed to unlock (includes all incidents with problems unlocking connector)	36,75	6	677	1336	3068	6,13	0,009
	Internal hydraulic leakage (control fluid part)	0,00	0	3482	>8018	-	-	0,000
	Failed to lock	0,00	0	3482	>8018	-	-	0,000
	Unknown	0,00	0	3482	>8018	-	-	0,000
	Other	0,00	0	3482	>8018	-	-	0,000
8 018	**All**	**117,75**	**10**	**473**	**802**	**1478**	**11,78**	**0,029**

Ten failures were observed in the connectors. They produced 117,75 hours lost time or in average 0,029 hours per BOP-day. The MTTF is 802 days. This MTTF is lower than for the Phase I DW, but at the same level as the failure rates observed in previous studies (/4/ and /9/). If comparing the results from Phase I DW study and this study, it is observed that the largest difference is for the failure mode *External leakage*. The

MTTF for the *External leakage* failures is nearly three times as high in this study compared to Phase I DW. The *Failed to unlock failure rate* is at the same level in the two studies.

Six of the 10 failures were observed when the BOP was on the wellhead. Of these six failures three *Failed to unlock* failures occurred in the wellhead connector in association with abandoning a well. One *Failed to unlock* occurred in the LMRP connector when attempting to disconnect due to a storm warning. The two *External leakage* failures were observed during the BOP installation test.

Failed to unlock LMRP connectors is a more important failure mode when drilling with DP vessels than for anchored vessels. Black-out on DP vessels will cause a drift off situation. Such incidents were observed in Phase I DW study. If the LMRP connector does not disconnect in a drift off (or drive off) situation, major damages to the riser and very costly rig downtime will likely be the result.

External leakage in the wellhead connector is one of the most critical failures in terms of controlling a well kick. Failure criticality will be discussed in Section 5 *Failure Criticality in Terms of Well Control* on page 85.

Below the various connector failures are described.

Failed to unlock failures
The first *Failed to unlock failure* occurred when attempting to unlatch the LMRP connector when the BOP was on the rig. There was no hydraulic response. They troubleshooted the system, hooked up the jumper hose, and unlatched the connector. Then they re-latched the connector and verified correct unlatch. Serviced the connector and installed a new VX gasket. The failure cause is unknown, it may have been a stuck connector or a hydraulic system failure. *Total lost time was* 1,75 hours

The second *Failed to unlock failure* occurred while preparing to run the BOP. They failed to remove the BOP from the stump. They changed the connector and tested the same using the BSR from 250 to 10000 psi. Replumbed lines on the connector, welded plates on the connector housing, and bolted the same to the connector. *Total lost time was* 23,5 hours.

For the third *Failed to unlock failure* they were going to disconnect the BOP to abandon the well when they had problems to unlatch the stack. They attempted to unlatch the stack on the yellow pod. They had to use the secondary unlatch to unlatch the stack (14.5 gal and 1450 psi.) *The lost time was negligible*. The water depth was nearly 1800 m (5906 ft.).

The fourth *Failed to unlock failure* was very similar to the third. The failure occurred on the same rig approximately four months later. They were going to abandon the well when they had problems to unlatch the BOP stack. Functioned open the primary BOP stack connector, but the stack did not release. Functioned open the secondary unlatch and the stack released. *The lost time was negligible*. The water depth was approximately 1400 m (4593 ft.).

The fifth *Failed to unlock* failure was also related to a BOP disconnect to abandon a well. They failed to unlatch the wellhead connector. They dumped the accumulator fluid through the connector to flush hydrates/debris. Spotted CA CL 2 fluid across the wellhead. Functioned latch with 2500 psi and 250 K overpull while attempting to unlatch from 18 ¾" wellhead. Closed shear ram and bullheaded seawater at 10 barrels per minute w/1800 psi down kill line. Unlatched. *Total lost time was* 11,5 hours. The water depth was approximately 1100 m (3609 ft.).

The sixth *Failed to unlock* failure occurred in a LMRP connector when they were getting ready for a storm. When attempting to unlatch the LMRP connector they failed. The wellhead connector was unlatched instead. It was stated that they pulled the LMRP two days later to service the LMRP connector. The daily drilling reports for these days were missing (total 6 days missing) The failure report was listed as a BOP test note. They had bad weather, but they also lost time due to the LMRP connector failure (how much is unknown) *Total Lost Time* was probably in the range of 2 –3 days. The water depth was approximately 1150 m (3773 ft.).

External leakage failures

The first *External leakage* failure was observed when testing the BOP prior to running. The wellhead gasket leaked. They found damage to two hydraulic operated VX ring retainer pins in the wellhead connector (one sheared off, one bent) and observed two areas of trash damage in wellhead connector VX profile due to use of SS gasket. Each damage area was less than 1/3 rd length of sealing area. Installed SS VX ring gasket in wellhead connector. *Total Lost time was* 7,0 hours.

The second *External leakage* failure was also observed when the BOP was on the rig. Before running the BOP they tested the LMRP connector, it leaked. Picked up the LMRP connector, inspected and troubleshooted. Changed AX-ring and tested connector to 10000 psi. *Total lost time was* 7,0 hours.

The third *External leakage* was observed after they had been moving the BOP stack from one well to another. They could not observe if the seal ring fell out of the connector during the operation due to bad visibility. There was no seal ring on the wellhead they left. Observed inside subsea connector what seemed to be the ring gasket and removed the ring gasket from the well. It was impossible with the ROV & camera on port arm to identify if the ring gasket was inside the connector. Searched sea floor for the ring gasket, but could not see any. Landed and latched the connector, and made a 50 k overpull with the compensator to insure a good latch. Attempted to test the connector, but a turbulence near the connector was observed with the ROV. Hot stabbed the ring gasket function to unlock position. With ROV monitoring, they unlatch of the connector. The ROV did verify that the ring gasket was *not* in connector. The latch segment & ring gasket retaining mechanism is what they thought was the ring gasket due to poor visibility inside connector. Installed ring, landed and tested the connector. *Total lost time was 38*,0 hours. The water depth was approximately 1000 m (3281 ft.).

The fourth external leakage was also observed after they had been moving the BOP stack from one well to another. After landing the BOP with a new seal ring and made 80k overpull they attempted to test casing, blind rams, and connector. Had a slow leak at 3000 psi. The connector did not appear to be leaking. They overpulled 80k and attempted to test casing, BSR, and connector once more. Pressed up to 3000 psi. The pressure bled off immediately. It leaked out of the connector weep hole. They verified the leakage with a BOP test tool and dye. Prepared to and unlatched the BOP stack. Installed a new VX-ring and landed the BOP again. Tested the BOP. *Total lost time was* 29,0 hours. The water depth was approximately 550 m (1804 ft.).

4.4.2 Manufacturers Included in the Study

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

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

LMRP connectors		Days in service
Cameron	All types and sizes	1864
National	All types and sizes	420
Vetco	All types and sizes	1725
All LMRP connectors		4009
Wellhead connectors		
Cameron	All types and sizes	775
Drill-Quip	All types and sizes	598
Vetco	All types and sizes	2636
All wellhead connectors		4009

The ten failures occurred on seven different rigs. Six of the rigs experienced one failure each, while the seventh rig experienced four failures; three in the wellhead connector and one in the LMRP connector. In this study all 26 rigs are represented with relatively short drilling time. In the Phase I DW all rigs, except one experienced hydraulic connector failures. The last rig was represented with a short drilling period.

The frequency of failures was less in this study than in Phase I DW. It is important to note that in Phase I DW the wells were in average drilled faster, which means that the BOP landed more often. Leaks in connectors are typically observed after a BOP landing. It should also be noted that in the previous BOP study they had frequent choke and kill lines failures that caused the LMRP to be pulled. Typically, leakages in LMRPs are also observed after landings. The number of landings is probably a better exposure measure for connectors than the days in service.

After a connector is locked to the wellhead and pressure tested, it is unlikely that it will develop a leak.

4.5 Flange Reliability

Subsea BOPs have normally five or four flanges in the mainline connection. Most BOP flanges are clamped, but some are also studded. In this study no leakage in BOP flanges has been observed. The total flange time in service has been 21 124 days.

No flange leakages were observed in Phase I DW either. Leakages in subsea BOP flanges are rare. Such failures have not been observed since the early 80s.

4.6 Choke and Kill Valve Reliability

Five of the 26 BOP stacks had 10 choke and kill valves, 13 rigs had eight choke and kill valves, six rigs had six valves, while the remaining two had four choke and kill valves. Some deepwater rigs did also have similar valves for choke and kill line isolation purposes, so the lines can be tested during running of the LMRP. These valves are not included as choke and kill valves. If these valves leak to the surrounding during line testing when running the BOP or during regular testing it has been regarded as a failure of the BOP mounted choke and kill line.

Table 2.3 on page 21 gives an overview of the BOP stack configuration for the various rigs included.

4.6.1 Choke and Kill Valve Failure Modes, Downtimes and Frequencies

Table 4.7 shows an overview of choke and kill valve failure modes, the associated number of failures and the lost time.

Table 4.7 Choke and kill valve failure modes and associated number of failures.

Days in Service	Failure Mode Distribution	Total lost time (hrs)	No. of failures	MTTF (days in service)			Avg. down-time per failure (hrs)	Avg. down-time per BOP-day (hrs)
				Lower limit	Mean	Upper limit		
	External leakage (leakage to environment in main valve or valve connectors)	189,50	4	3431	7853	22989	47,38	0,047
	Unknown leakage (not specified external or internal leakage)	0,00	0	13641	>3140	-	-	0,000
	Internal leakage (leakage through a closed valve)	62,50	6	2652	5235	12021	10,42	0,016
	Failed to open	0,00	1	6621	31410	612363	-	0,000
	Failed to close	2,50	1	6621	31410	612363	2,50	0,001
	Unknown	1,00	1	6621	31410	612363	1,00	0,000
	Other	0,00	0	13641	>3140	-	-	0,000
31 410	**All**	**255,50**	**13**	1520	2416	4085	**19,65**	0,064

When comparing the results with the results from Phase I DW, the MTTF is slightly lower in this study. The distribution of failure modes is similar in the two studies.

External leakage failure

The most severe failure mode in a choke and kill valve is *External leakage*. If such a leakage occurs in the lower inner valve below the LPR, the BOP will leak if attempting to close in a well kick. In general, more external leakages occur in the connection between the inner valve and the BOP body, than in the connection between the two valves in series. The two valves are also frequently located in a common valve block.

Four *External leakage* failures in the choke and kill valves were observed in this study. Three of them were observed when the BOP was on the rig prior to running. The fourth failure was observed during the BOP installation test.

The first *External leakage* failure was observed when attempting to test the choke and kill lines prior to running the BOP. A leak was discovered at the ring gasket for the upper kill valve. Repaired same. *Total lost time was* 1,0 hour.

The second *External leakage* failure was observed during a test prior to running the BOP. An external leakage was observed. Replaced the ring gaskets between the failsafe valve and BOP body. Repaired. *Total lost time was* 4,0 hours.

For the third *External leakage* failure, they also attempted to test the BOP prior to running. The flange between the BSR body to the choke valve was leaking around the ring gasket. Replaced the leaking ring gasket and tested. *Total lost time was* 10,5 hours.

The fourth *External leakage* failure was observed when the BOP just had been landed on the wellhead and they were performing the BOP installation test. The inner choke valve failed to test due to a leakage in the connection between the BOP stack and the kill line. The failure was observed with the SSTV and ROV. Prepared to and pulled the BOP. They inspected, welded and re-cut ring grooves in kill line failsafe valve flanges and the BOP outlet flange. (Had to wait for personnel to repair the BOP). Tested, ran and landed BOP. *Total lost time was* 174 hours. The water depth was approximately 700 meters (2297 ft.).

Internal leakage

The failure mode *internal leakage* is not as critical as an external leakage. Choke and kill valves are always in series of two. Even though two valves fail you need another leakage before the well fluid can reach the surroundings. It has, however, been observed in earlier BOP studies that both valves in series have failed.

Six failures were *Internal leakage (leakage through a closed valve)* failures. Four of these six failures were observed when the BOP was on the rig, and two were observed when the BOP was on the wellhead.

The two first *internal leakage* choke and kill valve failures occurred at the same time on the same BOP. When testing the BOP prior to running, both the inner and outer choke valve was found to be leaking. Flushed and greased the valves, but they still leaked. After having disassembled the lower outer and lower inner choke valves, the seat & gate were found scored in both valves. Waited for parts before repairing both the valves. *Total lost time was* 34,5 hours

The third *Internal leakage* was observed when testing failsafe valves from top side before running the BOP. The Upper Outer Choke (UOC) valve would not hold low-pressure test (250 psi). Disassembled, cleaned and inspected the valve. They had to wait for a new failsafe valve to be night-flighted to the rig, but the helicopter arrived with the wrong parts. Rebuilt UOC with parts on hand. *Total lost time was* 16,0 hours.

The fourth *Internal leakage* was observed when testing failsafe valves from top side before running the BOP. Detected a leak in lower outer choke valve. Repaired the lower outer choke valve and stump tested. *Total lost time was* 12,0 hours.

The fifth *Internal leakage* was observed during a BOP test scheduled by time. It was observed that the inner lower choke would not test. They received a waiver from the MMS on same. No repair was carried out before the BOP was pulled six weeks later. *No time was lost*. The water depth was approximately 1100 meters (3609 ft.)

The sixth *Internal leakage* failure was observed on a BOP test after running casing or liner. They failed to get a good test on the upper inner kill valve. They got a verbal approval from the MMS to continue without repairing until after completing the well. It was repaired four weeks later, when the BOP was pulled. *No time was lost*. The water depth was approximately 600 meters (1969 ft.).

Other observed failure modes

The *Failed to open* failure mode was observed during a BOP test scheduled by time. When attempting to pump through the choke & kill lines the lower kill line was plugged. After troubleshooting, they found the lower inner kill failsafe valve inoperable. They received verbal approval from MMS to continue drilling with the lower kill line plugged. The actual BOP has four choke and kill line outlets, whereof one was plugged. *No time was lost*. The water depth was approximately 630 meters (2067 ft.).

The *Failed to close* failure mode was observed during a BOP test prior to running the BOP. They troubleshooted the closing problem on the lower outer kill valve. *Total lost time was* 2,5 hours.

The *Unknown* failure mode was observed during a BOP test prior to running the BOP. It was only stated that they tested the choke & kill lines to 250/10000 psi. Rebuilt tail rod cartridge on the upper inner choke valve. *Total lost time was* 1,0 hours.

4.6.2 Manufacturers Included in the Study

Table 4.8 shows an overview of the manufacturer included in the study and the associated operational time.

Table 4.8 Overview of the manufacturers and models included and the associated operational time.

Manufacturer	Pressure rate	Days in service
Cameron, AF/DF	10000	3168
Cameron, DF	10000	2176
Cameron, DF	15000	441
Cameron, F	10000	5319
Cameron, MCS	15000	2570
Cameron, MCX	15000	1888
Cameron, Unknown	10000	1260
Flow Control, DW	15000	5480
Flow Control, Unknown	15000	650
Flow Control, Unknown	10000	278
McEvoy, DS	15000	1256
McEvoy, EDU	10000	1370
NL Shaffer, CB	10000	462
NL Shaffer, HB	15000	3732
NL Shaffer, Unknown	10000	414
VKM, Straigth &Target	10000	626
WOM, Magnum	10000	320
All valves		**31410**

As seen from Table 4.8 there is a large number of valve models, and it is not possible to identify any significant differences in failure rates between the different valve types. When comparing the manufacturers only there was no significant difference in failure rate between the various manufacturers.

Five of the rigs experienced two choke and kill valve failures, while three rigs experienced one failure. The remaining 18 rigs did not experience any failure on the choke and kill valves during the study.

4.7 Choke and Kill Lines Reliability

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

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

Figure 2.1 on page 23 shows a typical configuration of a BOP system.

4.7.1 Choke and Kill Line Failure Modes, Downtimes and Frequencies

Table 4.9 shows an overview of choke and kill line failure modes, the associated number of failures and lost time.

Table 4.9 Choke and kill line failure modes and associated number of failures

BOP-days	Failure mode distribution	Total lost time(hrs)	No. of failures	MTTF (days) Lower limit	Mean	Upper limit	Avg. down-time per BOP-day (hrs)	Avg. down-time per failure (hrs)
JUMPER HOSE LINE								
4 009	Bursted line	4,00	1	845	4009	78159	0,0010	4,00
4 009	External leakage (leakage to environment)	5,50	1	845	4009	78159	0,0014	5,50
4 009	All	9,50	2	637	2005	11281	0,0024	4,75
RISER ATTACHED LINE								
4 009	Plugged line	0,50	1	845	4009	78159	0,0001	0,50
4 009	External leakage (leakage to environment)	10,50	3	517	1336	4903	0,0026	3,50
4 009	All	11,00	4	438	1002	2934	0,0027	2,75
BOP ATTACHED LINE								
4 009	External leakage (leakage to environment)	16,00	2	637	2005	11281	0,0040	8,00
4 009	All	16,00	2	637	2005	11281	0,0040	8,00
TOTAL CHOKE AND KILL LINE								
4 009		36,50	8	278	501	1007	0,0091	4,56

The choke and kill lines were not a significant contributor to BOP downtime in this study. The experienced failure rate in Phase I DW was 5,5 times higher than Phase II DW. The riser attached lines were the major problem in Phase I DW, but the BOP attached lines were also a significant contributor to downtime. Since the no. of riser joints is higher in a deepwater riser than a shallow water riser, it should be expected that deepwater risers are more failure prone. But the failure rate and downtime in this study is also far lower than the results from reliability studies carried out in the 80ties for BOPs in "normal" water depths.

It is not known why so few failures have occurred in these lines in this study. One fact is that in the previous studies some few rigs have given the bad average results, while most rigs performed satisfactory. Maintenance of the choke and kill line pin and box ends and thorough inspection and care when running the BOP are likely important factors. Also in the previous studies it has been observed a relation between the riser age and the frequency of failures. Another aspect is that for some rigs the pin ends corrode while for most rigs they do not.

Of the few failures observed *External leakage* is of course the dominant failure mode. Six out of eight failures were external leakages. *Plugged line* was observed once and *Bursted line* was observed once.

The *Plugged line* failure occurred in the riser attached line. After cementing they observed that the choke line plugged off. The line was unplugged by applying 5300 psi pressure.

The *Bursted line* failure occurred in the jumper hose in the moonpool during a BOP test after running casing and liner. The line was replaced in four hours.

The remaining six choke and kill line failures were all *external leakages*.

The first *External leakage* failure was in the jumper hose line. Just before landing the BOP, the choke and kill lines were installed. When attempting to test the choke jumper hose line it was leaking at 3500 psi. They pulled the line and replaced the packing seals, re-installed and pressure tested the choke and kill lines to 250/7500 psi. *Total lost time was* 5,5 hours.

The second *External leakage* failure was in the riser attached line. While running the BOP the choke and kill lines were tested. A choke line leak was observed. They pulled two riser joints and changed the seal in the choke line joint. *Total lost time was* 3,5 hours.

The third *External leakage* failure was in the riser attached line. They were testing the BOP prior to running when they observed the hub on kill line leaking. They replaced the ring gasket on the kill line. *Total lost time was* 2,0 hours.

The fourth *External leakage* failure was in the riser attached line. While testing riser joint no. 50, while running the BOP, the choke line would not hold the pressure. They pulled a 10 feet pup joint and three riser joints, replaced the choke line seal and reran three joints *Total lost time was* 5,0 hours.

The fifth *External leakage* failure was in the BOP attached line. They had ran two joints of riser when they attempted to test the choke & kill lines to 250/7500 psi. The kill line leaked. They pulled the BOP stack back to the spider beams, re-torqued the clamp on the kill fail-safe valve and began running riser, *Total lost time was* 3,0 hours.

The sixth *External leakage* failure was in the BOP attached line. The BOP was on the rig. They were performing a test prior to running BOP when the flexible hose on the BOP blew. They had to wait for parts for the kill line hose (4,5 hours) before they repaired the kill line hose and tested to 12500 psi. *Total lost time was* 13,0 hours.

4.7.2 Riser Manufacturers Included in the Study

Table 4.22 shows an overview of the riser manufacturer and models and the associated exposure data.

Table 4.10 Overview of the days in service for each riser type

Riser manufacturer and model	BOP-days in service
Cameron, RCKH	509
Cameron, RD	171
Cameron, RF	236
Hughes Offshore, H.M.F	134
National, Unknown	420
Regan, FC-7	77
Regan, FD-8	69
Shaffer, DT-1	165
Shaffer, FT	434
Unknown, Unknown	65
Vetco, H.M.F	606
Vetco, MR-6B	220
Vetco, MR-6C	903
Total all	4009

With the few experienced failures in the riser attached lines a comparison of the experienced failures rates is of no interest. Earlier studies indicate that the failure frequencies of riser attached lines are more rig specific than manufacturer and model specific.

4.8 Main Control System Reliability

The three main BOP control system principles are all represented in this study. These three systems are:

- Multiplex control system (MUX)
- Pre-charged pilot hydraulic control system
- Pilot hydraulic control system

The main differences between the three control system principles are related to how the pilot signals are transmitted from the rig to the pilot valves in the subsea control pod. For a pilot hydraulic control system it is a plain pilot signal activating the pilot valves. For a pre-charged (or biased) pilot hydraulic system, the pilot signal is given a pre-charge pressure to reduce the BOP function response time. For a multiplex system a multiplexed pilot signal is transmitted to the pods, that gives an almost immediate function of the subsea pilot valve.

Recommended maximum closing times for preventers are based on the API recommended practice, but some countries have stricter regulations. For a pilot hydraulic system (pre-charged or not), the preventer closing time is increasing with increasing water depth due to the signal transmission time. The response time of a multiplex system is independent of the water depth.

The pilot valves, the stack piping, and the shuttle valves are identical for all the three control system principles. The different control system manufacturers do, however, have different valve types.

The supply of control fluid for operating the BOP functions is similar for the three system principles.

For redundancy purposes all subsea BOP control systems include two pods; the so-called yellow and blue pod. The BOP can be fully controlled by each of these pods. They are relatively independent of each other. The pod selector valve on the rig is common for the pods. Further the shuttle valves located on the preventers, connectors and valves are common. Otherwise there are some communication possibilities between the control fluid supply in the pods.

Pilot hydraulic control systems are the systems mostly used when drilling at water depths up to 500 – 600 meters. Pre-charge pilot hydraulic control systems are a modified version of the conventional pilot hydraulic control systems, and can be used in waters up to 1000-1500 meters. The multiplex control systems can be used in water depths of more than 2000 meters.

The multiplex systems included in this study have been used in water depths from 900 – 2020 meters (2953 – 6627 ft.). The pre-charged pilot hydraulic control systems have been used in water depths from 900 – 1600 meters (2953 –5249 ft.). The pilot hydraulic control systems have been used in water depths from 400 – 1300 (1312 – 4265 ft.).

4.8.1 Overall Reliability Comparison of the Different Control System Principles

Figure 4.1 shows a MTTF comparison of the different control system principles included in Phase II DW.

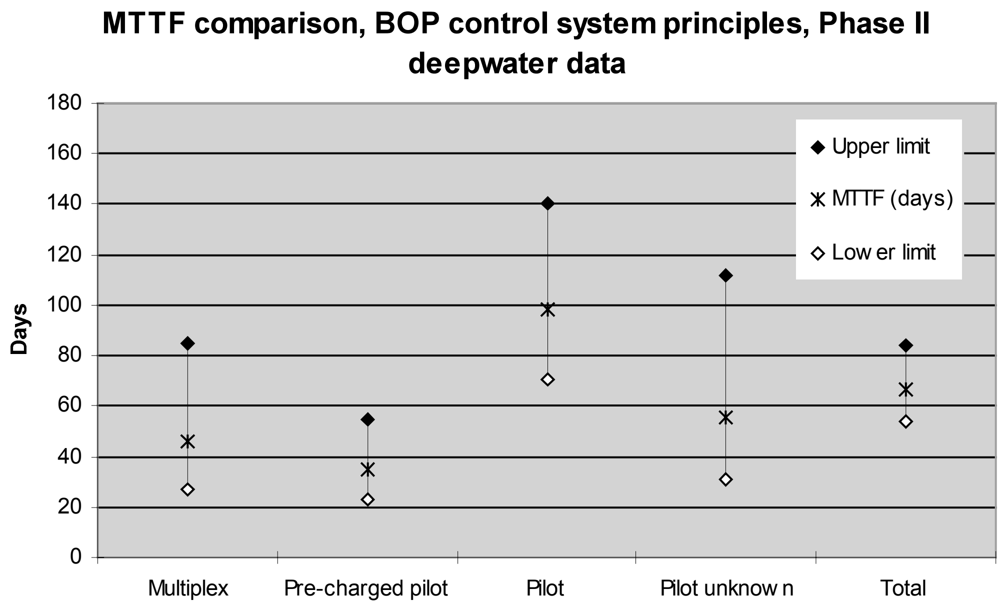

Figure 4.1 MTTF for the different control system principles with 90% confidence limits (Phase II DW)

As seen from Figure 4.1, there is a significant difference between the MTTFs for a conventional pilot control system and the pre-charged pilot control system. This significant difference was not confirmed in Phase I DW, as shown in Figure 4.2. Because the technical differences between the conventional pilot and the pre-charged pilot control system are small, this was not expected. None of the 16 failures observed in this system type could be linked to the pre-charge components included in the control system. When looking closer at the experienced failures, 10, or 62,5% of the failures of the pre-charged pilot control system were observed on one rig only. This rig represented 134 BOP-days, 24% of the BOP-days for pre-charged hydraulic control systems. The conclusion is that the total average was strongly influenced by a control system with low performance.

Otherwise, there are no significant differences, because there are overlaps of the confidence bands.

The pilot unknown is either a pre-charged system or a conventional pilot system. The rig contractor did not provide the information requested.

Figure 4.2 shows a MTTF comparison of the different control system principles included in the Phase I DW study and the results from the Phase V study (/4/). (Phase

V included pilot hydraulic control systems only and was drilled in normal water depths).

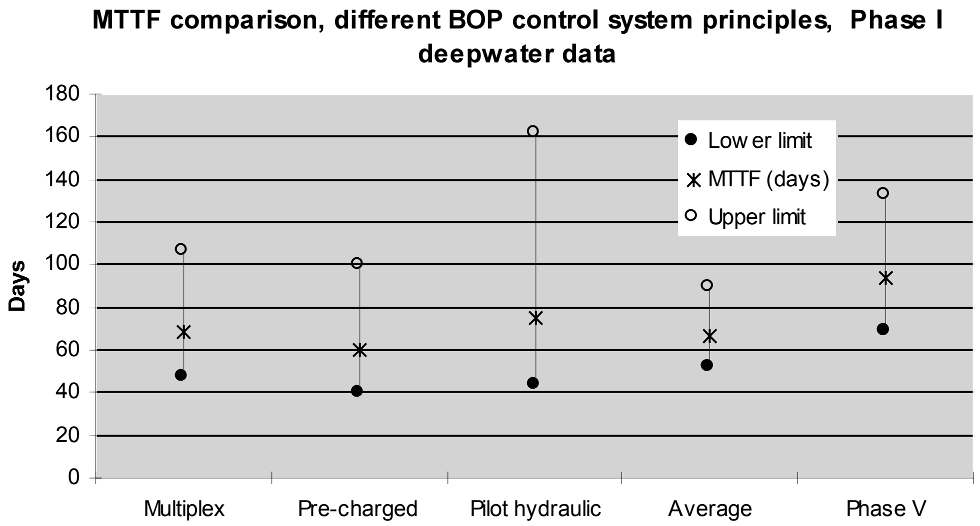

Figure 4.2 MTTF for the different control system principles with 90% confidence limits (Phase I DW)

As can be seen from Figure 4.2, there were not observed significant differences in MTTFs for the different control system principles in Phase I DW. The MTTFs for the three principles were fairly similar. The MTTF in the Phase V study (/4/) is, however, a little larger, but the difference is not statistically significant within 90% confidence limits (Phase V included pilot hydraulic control systems only and was drilled in normal water depths). It should be noted that in Phase I DW the data from the pilot control systems stemmed from one rig only. For the Phase V study the data stem from several rigs.

It should also be noted that the average MTTFs for Phase I DW and Phase II DW study are identical.

Figure 4.3 shows the average downtime per BOP-day caused by BOP main control systems for the different control system principles included in the study.

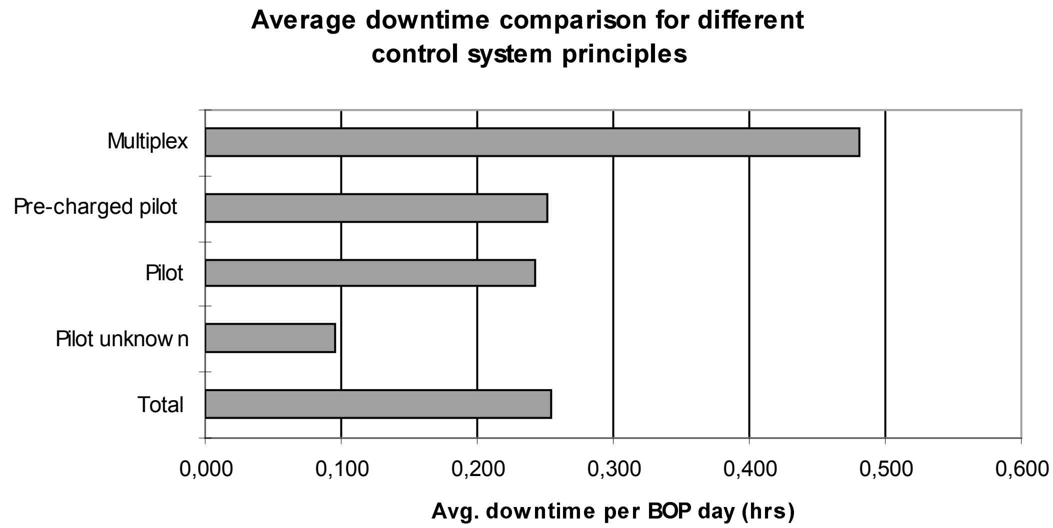

Figure 4.3 Average downtime per BOP-day caused by BOP main control systems

As seen from Figure 4.3 the Multiplex system experienced the highest downtime. It should be noted that the multiplex system also was used for the largest water depths. The high average was caused by one failure only. The subsea electronic module (SEM) failed and the BOP had to be pulled. This failure caused 190 hours of downtime.

The total average downtime per day in service caused by control system failures was lower in this study than in the Phase I DW.

In this study the ram preventer was the largest contributor to rig downtime, but in the long run the main control system is the largest contributor to BOP downtime. This has been confirmed through all the subsea reliability studies carried out by SINTEF (/1/, /4/, /9/, /12/, /13/ and /16/).

4.8.2 Control System Failure Modes, Downtimes and Frequencies

Table 4.11 shows an overview of the different control system failure modes, the associated number of failures and the lost time.

Table 4.11 Control system principle specific failure modes, associated number of failures

BOP-days in Service	Failure Mode Distribution	Total lost time (hrs)	No. of failures	MTTF (days)			Avg. down-time per BOP-day (hrs)	Avg. down-time per failure (hrs)
				Lower limit	Mean	Upper limit		
	Multiplex							
	Loss of all functions both pods	2,50	1	97	459	8949	2,5	0,005
	Loss of all functions one pod	189,50	1	97	459	8949	189,5	0,413
	Loss of one function one pod	1,00	1	97	459	8949	1,0	0,002
	Unknown	17,50	4	50	115	336	4,4	0,038
	Other	10,00	3	59	153	561	3,3	0,022
459	**All**	**220,50**	**10**	**27**	**46**	**85**	**22,1**	**0,480**
	Pre-charged pilot hydraulic							
	Loss of all functions both pods	42,50	1	116	552	10762	42,5	0,077
	Spurious operation of BOP function(s)	1,75	1	116	552	10762	1,8	0,003
	Loss of several functions one pod	54,50	4	60	138	404	13,6	0,099
	Loss of one function one pod	14,00	4	60	138	404	3,5	0,025
	Unknown	7,50	2	88	276	1553	3,8	0,014
	Other	18,50	4	60	138	404	4,6	0,034
552	**All**	**138,75**	**16**	**23**	**35**	**55**	**8,7**	**0,251**
	Pilot hydraulic							
	Spurious operation of BOP function(s)	57,50	2	406	1277	7184	28,8	0,023
	Loss of all functions one pod	173,50	6	216	426	977	28,9	0,068
	Loss of several functions one pod	135,00	1	538	2553	49773	135,0	0,053
	Loss of one function both pods	121,50	1	538	2553	49773	121,5	0,048
	Loss of one function one pod	33,50	8	177	319	641	4,2	0,013
	Loss of control of one topside panel	2,00	1	538	2553	49773	2,0	0,001
	Unknown	81,00	3	329	851	3122	27,0	0,032
	Other	16,00	4	279	638	1869	4,0	0,006
2 553	**All**	**620,00**	**26**	**71**	**98**	**140**	**23,8**	**0,243**
	Pilot hydraulic, unknown if pre-charged or not							
	Loss of all functions one pod	3,50	2	71	223	1252	1,8	0,008
	Loss of several functions both pods	0,00	1	94	445	8676	0,0	0,000
	Loss of several functions one pod	35,50	1	94	445	8676	35,5	0,080
	Loss of one function one pod	1,00	2	71	223	1252	0,5	0,002
	Unknown	2,25	2	71	223	1252	1,1	0,005
445	**All**	**42,25**	**8**	**31**	**56**	**112**	**5,3**	**0,095**
4 009	***All control system principles***	**1 021,50**	**60**	**54**	**67**	**84**	**17,0**	**0,255**

Below the various failures are discussed.

Loss of all functions both pods

The failure mode *Loss of all functions both pods,* occurred once for a multiplexed system and once for a pre-charged system, but was not observed for the pilot hydraulic control system. This is a very critical failure mode, because the BOP can not be operated. This failure mode was also observed for multiplexed systems and pre-charged pilot system in Phase I DW. This failure mode was, however, not observed during the Phase IV and Phase V studies (/4/ and /9/). These 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 first *Loss of all functions both pods* failure occurred in a multiplex system while the BOP was on the wellhead. They observed that the accumulator fluid was running away on rigid conduit and 1" supply line during normal operation. The failure was obviously related to the yellow pod, because they retrieved the yellow pod to repair the failure. It was not stated what component failed. It was only stated that they were troubleshooting and repaired the yellow pod for approximately 10 hours. Thereafter the work they did was more specified. This work is likely not directly related to the original failure. This work was:

- Remove annular SPM valves. Function the upper and lower SPM valves, inspect, reseat and lube same. Bled pilot lines. Functioned pod.
- Replaced regulator (for annular or ram?).
- Rebuild open and closed side SPM valves on annular (note that the Y. pod was pulled to repair these SPM valves 10 days before as well). Bleed annular pilot lines.

Ran yellow pod with assistance from ROV. *Total lost time* 42,5 hours. The water depth was approximately 1150 meters (3773 ft.).

For the second *Loss of all functions both pods* failure the BOP had been on the rig for repair. During the subsequent BOP testing they revealed a failure in the supply piping for the yellow and blue pod. A seal for the upper annular open valve was also replaced. *Total lost time was* 2,5 hours.

In Phase I DW the main hydraulic supply seemed to be the major problem, and not the electric/electronics regarding this failure mode. The same seems to be the main problem for the multiplex system here.

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

Loss of all functions one pod
The failure mode *Loss of all functions one pod* was observed once in the multiplex system, six times in the conventional pilot control system and twice in the systems where it is not known if the system is pre-charged or not. It was not observed in the pre-charge pilot hydraulic system.

The *Loss of all functions one pod* failure in the multiplex system was observed while running the BOP. The choke and kill lines were tested after running 7 joints of risers. They observed that the solenoid for selecting the blue pod was out and POOH to replace the solenoid. They removed the subsea electronic module (SEM) and troubleshooted. The "A" selection female plug of the blue pod was shorted and leaking. They had to wait for a part from California (waiting time was not specified, but it was likely 8 – 12 hours). Then they replaced the female plug, purged the system, and attempted to function test, but found that other functions also were shorting out. Removed the SEM from the pod and replaced two plugs with the only spares. Then they had to wait for plugs for the SEM for approximately 24 hours. Replaced plug for the SEM. Inspected the yellow pod and observed trace of moisture inside the SEM there as well. Performed electronic tests of the blue pod SEM. They had some low voltage problems for four solenoids. They needed some lubricant as well as parts for the yellow pod SEM. Changed out the SEM plugs on yellow pod and injected gel type sealant. To overcome the low voltage problem in the blue pod they took 6 electronic cards from the yellow pod and installed in the blue pod. Installed blue pod on the BOP and tested. The middle pipe ram (MPR) and the BSR failed. Found that one SEM plug was in the wrong direction. Corrected and tested. OK. Received the I/O cards for the yellow pod and installed them. Tested the yellow pod on the computer. Installed the yellow pod and tested the BOP. Prepared to and ran 7 joints of riser. *Total lost time was* 189,5 hours.

The first pilot control system *Loss of all functions one pod* failure was observed during the BOP installation test when closing the 3-1/2" x 5" VBR's ON 3-1/2" tube the 1" supply line on blue pod failed near pod. MMS approved continued testing on the yellow pod. Pulled the blue pod while POOH w/ test plug. Repaired the X-over manifold for the blue pod. Tested the blue pod on stump before running to stack & function the BOP'S. After the function test the complete pod started to leak. Pulled the blue pod again. It was the same leak on the X-over manifold. Changed O-rings on X-over manifold on blue pod & function tested pod on stump. Ran, latched and function tested the BOP. The majority of repair was done while doing other operations so the *total lost time was* 5,5 hours. The water depth was approximately 450 meters (1476 ft.).

The second pilot control system *Loss of all functions one pod* failure was observed during a test after running casing or liner. When attempting to switch to the blue pod after a function test on yellow pod, they failed to switch due to a failure in the pod selector valve. Replaced the pod selector valve, then functioned again. *No lost time* was reported. The water depth was nearly 550 meters (1804 ft.) (Note: the pod selector valve is located on the rig).

The third pilot control system *Loss of all functions one pod* failure was observed when function testing the BOP on rig prior to running. They found a leak in the yellow pod stinger area. Changed out the complete stinger assembly. Re-tested the yellow pod. *Total lost time was* 7,0 hours.

The fourth pilot control system *Loss of all functions one pod* failure was observed during a test scheduled by time. Just after they had finished the BOP test it was stated that they had to pull the yellow pod and repair the pod hose line. The pod was pulled and the pod hose repaired. They had to wait some time to repair the ROV before landing the pod. When attempting to land, the pod they damaged the shuttle valve for the upper kill valve (the line inlet is below the upper annular). They failed to stab the pod and pulled it back. They were planning to plug the well with cement prior to pulling the LMRP to repair the pod and the shuttle valve. They TIH w/ mule shoe to above the shear ram and displaced the riser with 9.7 ppg mud (mud cut 8.9 ppg). Then the BSR was opened. The well immediately kicked. Closed the BSR again and displaced the riser with 10.1 ppg, no mud cut. The well became stable. Tripped in the hole to the casing shoe (3016 ft.). Ran the cement plug. Waited on weather before pulling the LMRP and repairing the shuttle valve. Re-ran and landed the LMRP. *Total lost time was* 155,0 hours. The water depth was approximately 620 meters (2034 ft.)

The fifth pilot control system *Loss of all functions one pod* failure was observed during logging operations, not BOP testing. The yellow pod hose failed. MMS approved that they could complete the wireline operations before repairing the pod hose. The pod hose was pulled, repaired and rerun the day after the failure occurred. On the subsequent test they did not get a proper fluid count for several functions. They were then allowed to continue the casing operation before repairing the pod. Three days after the failure occurred they attempted to test the UPR and MPR on the yellow pod, but they did not get a proper fluid count. The drill pipe was sheared leaving 353 feet of fish in the hole. It is not stated how it was sheared. Two days were spent for fishing (not incl. In this downtime). They then got approval from MMS to continue operations prior to completion work while working on the yellow pod. The yellow pod was not mentioned any more before it was tested after running casing 12 days after it failed. The *total lost time* was only 4,0 hours because they were allowed to continue operations with a failed pod. The water depth was approximately 620 meters (2034 ft.).

The sixth pilot control system *Loss of all functions one pod* failure occurred during a tropical storm. When performing well abandon operations the rig was evacuated for the tropical storm “Earl”. The LMRP was disconnected from the stack. When they returned to the rig they found the blue pod hose with excess amount of slack. They made a visual inspection of riser & BOP by ROV, checked for leak on blue pod hose and found leak on 1” supply line from stack to surface. They reconnected the LMRP and disconnected the stack to abandon the well some few hours later. *Total lost time* 2,0 hours. The water depth was more than 1200 meters (3937 ft.).

The first of the two *Loss of all functions one pod* failures in the unknown pilot type control system was observed during the BOP installation test. They were having problems with a leak in the blue pod. The problem was found in the Koomey room. *Total lost time was* 1,5 hours.

The second of the two *Loss of all functions one pod* failures in the unknown pilot type control system was observed during function testing of the BOP prior to running. A leak in the 1” control line on yellow pod line occurred. *Total lost time was* 2,0 hours.

Spurious operation of BOP function(s)

The failure mode *Spurious operation of BOP function(s) occurred* twice in the pilot hydraulic control system and once in the pre-charged pilot control system. In Phase I DW this failure mode was not observed in the pilot hydraulic control system, but once in the multiplex system and once in the pre-charge hydraulic system. This failure mode may occur in all control system principles.

All the three spurious operations were related to unintended disconnect of the LMRP connector. In deepwater drilling this is a very critical incident, because at the same time the control of the BOP is lost the well will kick if drilling without a riser margin.

The first of these *Spurious operation of BOP function(s)* failure was observed when they were preparing to pull the BOP and abandon the well. They changed the quick disconnect plate on the pod reel to install the running plate. During this operation the LMRP disconnected for some reason. It was reconnected at two hours later. It is unknown why the connector disconnected, but in one way or another it seems that pressure has been applied on the LMRP unlock pilot line. (Note: BOPs have been lost during pulling of the BOP because running plates that ventilates all pilot lines have not been utilized). *Total lost time was* 5,5 hours. The water depth was approximately 1100 meters (3609 ft.).

The second *Spurious operation of BOP function(s)* failure was observed when they swapped from the yellow to the blue pod to function test the BOP after pressure testing. The LMRP connector then disconnected.

A ROV was utilized to observe the wellhead and BOP. The LMRP appeared to be 20' feet off location. They started repositioning the LMRP over the BOP when the no. 5 anchor winch gearbox failed. Approximately 40 hours were spent to get new parts and repair the gearbox. This is not regarded as downtime associated to the LMRP disconnect. They continued troubleshooting the control system while repairing the anchor winch and started to re-position the LMRP over the BOP. Them they attempted to pull the drill pipe, but it parted 20 feet above the BOP. The drill pipe was probably damaged during the disconnect due to the positioning failure. They failed to recover the drill pipe with slings, and installed a cutter device on the ROV and cut the bent drill pipe on top of BOP.

They landed the LMRP, but there was no indication of locking. Therefore they attempted several times, took 80 k overpull and the LMRP came loose. The LMRP was landed again, they had indications of latching, and took 100 k overpull.

They ran overshot latched onto fish and pulled out of hole. Thereafter the BOP was tested (test time not incl in downtime, a BOP test was scheduled).

After pulling the BOP one month later they started to inspect the connector and the associated controls. The findings from this inspection was not mentioned in the daily drilling report. The cause of the disconnect is unknown. It seems likely that it was caused by a failure in the control system, but it may also have been caused by a failure in the connector itself. *Total lost time was* 52,0 hours. The water depth was approximately 700 meters (2297 ft.).

The third *Spurious operation of BOP function(s)* failure was observed when they tested the BOP prior to running. When the riser connector on the LMRP was placed in the block position, the connector unlatched. When troubleshooting the problem pressure was found trapped in the unlatch function pilot line. They pulled the junction box from the yellow hose reel and inspected the check valves. They then reconnected the junction box and functioned the riser connector. *Total lost time was* 1,75 hours.

Loss of several functions both pods
Loss of several functions both pods is a rare failure mode for BOPs. One such failure occurred. During a BOP test scheduled by time it was noted that the lower inner & outer kill line valves were inoperative. It is not known whether this was a valve problem or a control system problem, or a combination. The valves remained closed for the rest of the well. No repair was carried out. The actual BOP has four kill/choke outlets. *No lost time.* The water depth was approximately 500 meters (1640 ft.).

Loss of one function both pods
Loss of one function both pods failure occurred once in this study in a pilot hydraulic system. 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. In the Phase I DW this failure mode occurred twice, once in a multiplex system and once in a pre-charge control system.

The *Loss of one function both pods* failure was observed during a BOP test after running casing. It was revealed that the hose connecting the shuttle valve to the opening side of the lower annular had failed. (This hose is common for both pods). The BOP already had a leaking hose for the MPR opening on the yellow pod (listed as a separate failure). It was then decided to pull the BOP. They ran a RTTS plug in the well and pulled the BOP.

At surface they removed and replaced the two failed hoses, and visually inspected the BOP stack for other suspect hoses. It was decided that all hoses of the same make and type designation as those two that failed should be replaced. Also, those hoses should be replaced which had paint on them from when the stack was painted. (Note: the stack was last painted several years ago). After replacing all suspect hoses on the BOP stack they ran and tested the BOP, and pulled the RTTS plug. *Total lost time was* 121,5 hours. The water depth was approximately 500 meters (1640 ft.).

Loss of several functions one pod
Six failures with the failure mode *Loss of several functions one pod* were observed. None of the failures were observed in a multiplex control system. Three of the failures were observed on the same rig. 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. Three such failures were observed in the Phase I DW.

The first *Loss of several functions one pod* failure was observed during normal operation. While inspecting the riser and the BOP with an ROV during drilling it was observed that the annular regulator on the blue pod was leaking. They attempted to stop the leak by functioning the regulator and switching the pods, but it was impossible. The ran a RTTS packer in the well and pulled the blue pod. Replaced a SPM valve and the annular regulator. Ran the pod, tested, and pulled the RTTS packer. *Total lost time was* 35,5 hours. The water depth was approximately 1100 meters (3609 ft.).

The second *Loss of several functions one pod* failure was observed during the BOP installation test. When testing the BOP they got a leakage in the blue pod manifold regulator. Pulled the blue pod and repaired the leak. After relatching the pod they found that it still leaked. This time it was a SPM valve that leaked. They pulled the pod again and replaced the valve. They also found a leakage in the pilot line. They ran, landed and function tested the pod. *Total lost time was* 11,5 hours. The water depth was approximately 1150 meters (3773 ft.).

The third *Loss of several functions one pod* failure was observed during a BOP test after running casing or liner. The annulars could not be function tested on the yellow pod. They pulled the pod, replaced the annular regulator, and reran the pod. It should be noted that the same regulator was changed six months earlier. *There was no lost time* because other operations were carried out. The water depth was approximately 1150 meters (3773 ft.).

The fourth *Loss of several functions one pod* failure was observed during the BOP installation test. They could not get a function test on the annulars on yellow pod. They pulled the yellow pod and replaced the annular regulator, reran and tested the pod (the flow meter was not working). *Total lost time was* 34,0 hours. The water depth was approximately 1150 meters (3773 ft.).

The fifth *Loss of several functions one pod* failure was observed during the BOP installation test. The pressure test was OK. After running the pipe to 4859' it was stated that they were troubleshooting the annular regulator on the yellow pod. It seems that the annular regulator was not the problem, but the annular supply piping. They pulled the BOP and repaired three O-rings in the annular supply piping. They did some other control system maintenance as well (- Rebuilt SPM valve for the UPR, - Replaced shuttle valve for the UPR, - Checked torque on the pod manifold bolts, - changed out 1 SPM for the upper annular). *Total lost time was* 135,0 hours. The water depth was approximately 1100 meters (3609 ft.).

The sixth *Loss of several functions one pod* failure was observed during normal operation. There was no read-back pressure on the yellow pod. It took five minutes to function the annulars and one minute to function the rams. They troubleshooted the yellow pod, unlatched and re-latched the yellow pod. Then they function tested all BOP components on the yellow pod. Everything seemed OK. The day after the BOP was function tested on both pods and the pod was still OK. The failure cause is not known, but it seems to have been in the pod stinger area. *Total lost time was* 9,0 hours. The water depth was approximately 1600 meters (5249 ft.).

Loss of one function one pod

The failure mode *Loss of one function one pod* occurred once in a multiplex control system, four times in a pre-charge pilot hydraulic system, eight times in a pilot hydraulic system, and once in a pilot system where it is unknown if it was pre-charge type or not.

<u>*Multiplex control system*</u>

The multiplex *Loss of one function one pod* occurred when the BOP was function tested prior to running. It was only stated that they replaced one shear seal valve for the LPR open function. *Total lost time was* 1,0 hr.

Pre-charged pilot control system

Three of the four *Loss of one function one pod* failures in the pre-charged pilot control system occurred on the same rig.

The first *Loss of one function one pod* failure was observed during a function test prior to running the BOP. A pilot line leak in the yellow hose bundle occurred. After a period of time the leak was located to a pilot line for the upper outer choke failsafe valve. Switched function to spare line. *Total lost time was* 6,0 hours.

The second *Loss of one function one pod* failure was observed during a BOP pressure test scheduled by time. The upper annular close function on the blue pod failed. They pulled the blue pod and replaced the SPM valve for the upper annular close. They had problems with this BOP function on the BOP test 14 days before as well. Then they reran latched and function tested the blue pod. *Total lost time was* 6,5 hours. The water depth was approximately 1150 meters (3773 ft.).

The third *Loss of one function one pod* failure was observed just after the BOP was landed on the wellhead. The BOP installation test was yet not performed. It was stated that they pulled and repaired the yellow pod. They obviously had a leakage because they replaced one pilot line with a spare. *Total lost time was* 1,5 hours (they were repairing the topdrive at the same time). The water depth was approximately 1150 meters (3773 ft.).

The fourth *Loss of one function one pod* failure was observed on a test after running casing or liner. They failed to open the upper annular on the yellow pod. The SPM valve had failed. The failure was repaired one week later. *No Lost Time* because normal operations were carried on. The water depth was approximately 1150 meters (3773 ft.).

Pilot control system

Loss of one function one pod failure was observed eight times in a conventional pilot control system.

The first *Loss of one function one pod* failure was observed during a BOP test scheduled by time. The upper annular preventer failed to close/open properly on the yellow pod during a function test. Then activated the upper annular close function with the yellow pod in 70 seconds, metered 148 gallons. Repeated a second time, it took 58 seconds, and metered 148 gallons. They had to open the annular with the blue pod. Normally, the annular will close with 52 gallons of fluid. They did not repair the failure, but got a MMS waiver. The failure was repaired nearly 2 months later when the LMRP was on the rig for other reasons. The failure was in an SPM valve for the upper annular in the yellow pod to. *No lost time*.

The second *Loss of one function one pod* failure was observed during a test prior to running the BOP. A leak in the MPR package on the blue pod was discovered during the function test. They retracted the stingers and replaced 6 quick connect gaskets on the “J-box”. They pulled the blue pod, extended the stingers and changed a packing for the MPR closure. *Total lost time was* 7,5 hours.

The third *Loss of one function one pod* failure was observed during a BOP test scheduled by time. The yellow pod opening line for the MPR ram had developed a leak. The ram closed and tested properly. When it was opened, the opening fluid pumped away. The yellow pod opening hose for the MPR ram likely had a broken hose between the yellow pod receptacle and the shuttle valve. The failure was not repaired. A MMS waiver was given. The failure was repaired when another failure was observed ten days later. *No lost time*. The water depth was approximately 500 meters (1640 ft.).

The fourth *Loss of one function one pod* failure was observed during a BOP installation test. The upper annular would not close on the yellow pod. They pulled the yellow pod to surface, but could not find any failure. After they re-ran and tested the yellow pod, the failure was still there. Verbal approval was received from MMS to proceed with drilling operations with one annular working and tested. It is not known how long they continued operations with this failure. The last test the failure was mentioned was two days after the failure was observed the first time. The MMS waiver was, however, mentioned the last time 11 days after the failure was observed. Possibly the failure was present through the whole well. The BOP was pulled more than two months after the failure was observed. *No lost time*. The water depth was approximately 1100 meters (3609 ft.).

The fifth *Loss of one function one pod* failure was observed during normal operations with the BOP on the wellhead. A guideline cable had rubbed a hole on blue pod hose, cutting the lower inner choke pilot line on rig level. They circulated and conditioned mud and pulled back into the casing shoe before they repaired the blue pod pilot line. Then they tested the blue pod hose and function tested the BOP on the yellow pod. *Total lost time* 5,5 hours. The water depth was approximately 600 meters (1969 ft.).

The sixth *Loss of one function one pod* failure was observed during a BOP test prior to running the BOP. They found one bad stinger on the blue pod. Picked up the pod and repaired same. Function tested BOP on both pods. *No lost time.*

The seventh *Loss of one function one pod* failure was observed during a BOP installation test. The upper annular failed to close on the blue pod. They retrieved the blue pod and changed the SPM valve on open – close side of the upper annular. Ran and tested the blue pod. *Total lost time was* 20,5 hours. The water depth was approximately 1000 meters (3281 ft.).

The eight *Loss of one function one pod* failure was observed during normal operation with the BOP on the wellhead. It was only stated that while repairing the drawwork, they located and isolated a leak on the yellow pod. *No lost time*. The water depth was approximately 1000 meters (3281 ft.).

<u>Pilot hydraulic, unknown if pre-charged or not</u>

The *Loss of one function one pod* failure was observed two times in a pilot hydraulic system, where it is unknown if it was of the pre-charge type or not.

The first *Loss of one function one pod* failure was observed during a test prior to running the BOP. It was only stated repair no. 7 SPM valve on the blue pod. *Total lost time was* 1,0 hr.

The second *Loss of one function one pod* failure was observed during normal operation with the BOP on the wellhead. They had to pull and re-run the blue pod due to malfunction in upper outer choke valve SPM. The failure was noted 20 hours after a BOP test. It seems the failure was not observed during the BOP test but during circulation. *No lost time*. The water depth was approximately 500 meters (1640 ft.).

Other failures
One failure was categorized with the failure mode *Loss of control of one topside panel*. *Total lost time was* 1,0 hr.

Eleven failures were categorized with the failure modes *Other*.

Of the 11 failures with the failure mode *Other* three failures were observed for the multiplex type system. All failures occurred when the BOP was on the wellhead.

1. The flow meter failed on the accumulator unit, and they got no flow readings during the BOP test. *No lost time.* The water depth was approximately 900 m (2953 ft.).

2. A malfunction was noticed on the BOP control panel. Lights indicated that the BSR was closed and all readbacks on the blue pod were lost. They picked up on string, but observed no weight lost. They pulled above the BOP stack to troubleshoot the problems. They found that a leaking backup battery had created shorts in the system that they repaired. Then they TIH to below the BOP stack and function tested the annulars and pipe rams from the drill floor on both pods. The control system now seemed to be functioning properly. *Total lost time was* 10 hours. The water depth was approximately 2000 m (6562 ft.).

3. They observed sluggish closing of lower annular on blue pod. The closing time was 60-70 seconds. The typical closing time should be 35-40 seconds. The lower annular performance on the yellow pod was fine. *No lost time*. The water depth was approximately 1400 m (4593 ft.).

Four of the 11 *Other* failures were observed for the pre-charged pilot type system. Two failures were observed when the BOP was on the wellhead, and two while running the BOP.

4. They failed to unlatch the BOP from the wellhead with the Reel Panel. Reinstalled the RBQ plate on the blue pod reel and unlatched the wellhead connector. *Total lost time* 1,5 hours.

5. The flow meter was out of order so they got now flow readings during BOP testing. *No lost time*.

6. They troubleshooted a leak on the rigid conduit line while running the BOP. *Total lost time* 1,5 hours.

7. They had just started to run the BOP. They failed to test the rigid conduit lines. First they pulled one riser joint (no. 2) and attempted to retest. Then they pulled riser joint no.1 and the BOP to surface. Un-flanged the riser and attempted to test the rigid conduit line on the BOP. The blue pod select SPM valve was leaking. They rebuilt two SPM valves on the blue and yellow pod and re-tested. Also replaced pocket seals on the blue pod. *Total lost time was* 15,5 hours

Four of the 11 *Other* failures were observed for the conventional pilot type control system. One failure was observed when the BOP was on the wellhead, two while running the BOP, and one when the BOP was on the rig.

8. During an installation test of the BOP (the BOP had been on the rig due to a BSR failure) they discovered a leak on the lower outer kill valve on the close side. They functioned the lower outer choke & pumped through same to confirm that the valve would open & failsafe close. *Total lost time was* 1,5 hours. The water depth was approximately 450 m (1476 ft.).

9. When they had run one riser joint it was observed that they failed to fill the hydraulic line. Pulled back to the spider beam. Troubleshooted the problem. Repaired TRI-valve to yellow pod. *Total lost time was* 3 hours.

10. Failed to test the rigid conduit line on joint no. 17. Laid down five joints looking for leak. ROV verified that it was the flush valve leaking on the rigid conduit line. Reran 5 joints. *Total lost time was* 6,5 hours.

11. The BOP was on the rig when a leaking dump valve was observed. *Total lost time was* 5 hours.

Failure mode unknown

Of the 11 failures with the failure mode *Unknown*, four failures were observed for the multiplex type system. All failures occurred when the BOP was on the rig. Three of the failures were related to the multiplex electronic/electric system and one to an accumulator bladder. *Total lost time* for the three failures was 17,5 hours.

Two *Unknown* failures were observed in the pre-charged pilot control system. One failure occurred when the BOP was on the wellhead. The failure was related to surface components. *Total lost time was*1,5 hours. The failure that occurred when the BOP was on the rig was related to a regulator for the yellow pod. *Total lost time was* 6,0 hours.

Three *Unknown* failures were observed in the pilot hydraulic control system. One failure occurred when the BOP was on the wellhead. When starting to test the BOP they got some trouble with the subsea accumulator system. It was not specified what type of problem they had. They spent 2 hours to sort it out. The water depth was approximately 700 m (2297 ft.).

Two *Unknown* failures occurred when the BOP was on the rig. One caused severe time losses. This was a very poorly described failure. They were working on the BOP prior to running for nearly three days. The only specific problems and operations described were replacing an SPM for the accumulator and testing the BOP on the yellow and blue pod. *Total lost timewas* 69 hours. For the second *Unknown* failure that occurred on the rig they had problems with the pre-charge of nitrogen bottles on BOP'S. *Total lost time was* 10,0 hours.

For the pilot hydraulic control systems which are not known to be pre-charged or not, two minor failures were observed when the BOP was on the rig. *Total lost time was* 2,25 hours.

4.8.3 Manufacturer Exposure and Rig Specific Failure Rates

Table 4.12 shows an overview of the different manufacturers and operating principles included in the study. It should be noted that Shaffer bought Koomey in the 80ties and Koomey systems are therefore listed as Shaffer. Cameron-Payne systems are listed as Cameron.

Table 4.12 Overview of the manufacturer exposure time.

Manu-facturer	Operating principle	BOP days
Cameron	Multiplex electro hydraulic	65
Cameron	Pilot hydraulic	729
Cameron	Pilot hydraulic, unknown if pre-charged	280
Cameron	Pre-charged pilot hydraulic	236
Hydril	Multiplex electro hydraulic	257
Hydril	Pilot hydraulic	157
Shaffer	Pilot hydraulic	1520
Shaffer	Pilot hydraulic, unknown if pre-charged	165
Shaffer	Pre-charged pilot hydraulic	316
Unknown	Multiplex electro hydraulic	137
Unknown	Pilot hydraulic	147
Cameron	*All principles*	*1310*
Hydril	*All principles*	*414*
Shaffer	*All principles*	*2001*
Unknown	*All principles*	*284*
All	**Total**	**4009**

The control system performance for the 26 rigs included in the study showed a highly variable failure rate and downtime per BOP-day in service, as illustrated in Figure 4.4 and Figure 4.5.

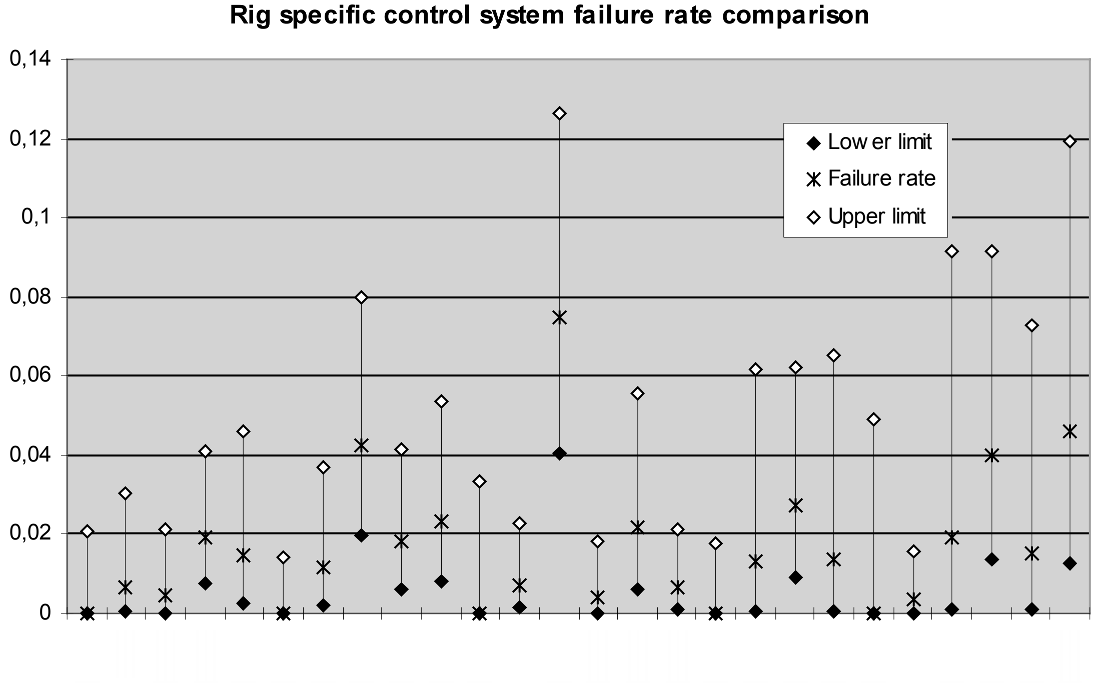

Figure 4.4 Rig specific control system failure rate per BOPday in service with 90% confidence interval

The average MTTFs are very influenced by “bad” performance specific rigs. Other rigs with the same control system have performed well. Rig 62 has the highest failure rate, while Rig 57, 73 and 75 also have fairly high failure rates.

With the large number of rigs each rig is represented with a relatively short period of operation in the study. Therefore the confidence bands become fairly wide. Even though it is seen that for many rigs the confidence bands do not overlap, i.e. there are significant differences in failure rates between many of the rigs.

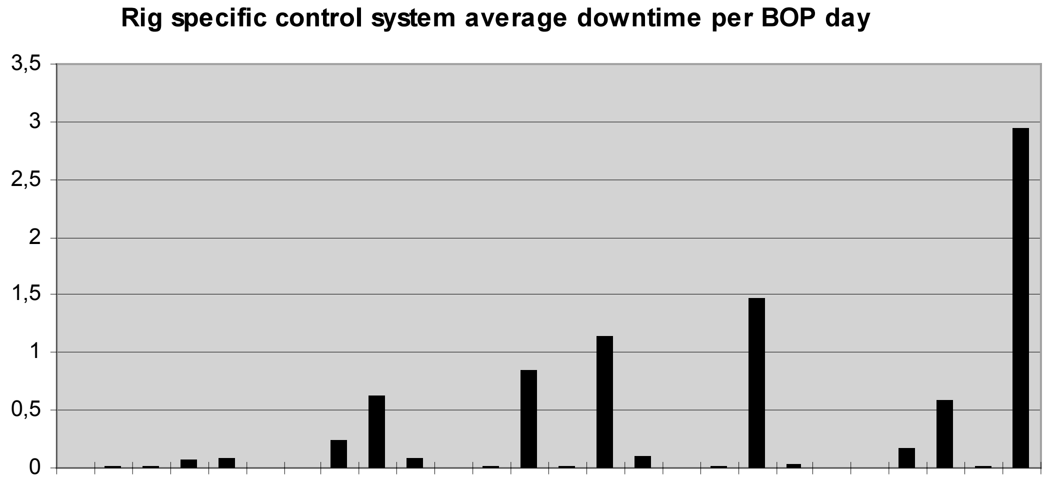

Figure 4.5 Rig specific control system average downtime per BOP-day in service

As seen from Figure 4.5 there are large differences in the average downtime per day in service for the different rigs. This is explained by the fact that single time-consuming failures dominate the picture, and in addition each rig is represented with a relatively short time in operations.

4.9 Backup Control Systems

There were no back-up control systems included in this study. In Norway back-up control systems have been required for subsea BOPs since early in the 80s. In countries like Brazil and Italy, back-up control systems have not been mandatory. All back-up control systems use an acoustic signal transmission, and the systems are frequently referred to as the acoustic system. Six out of 10 rigs in the Phase I DW had backup systems.

5. Failure Criticality in Terms of Well Control

Failures that occur when the BOP is on the rig, during running of the BOP and 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 is acting 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 coarse 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 were observed.

Table 5.1 Observation of BOP failures

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

As seen from Table 5.1, 34% of the failures were observed when the BOP was on the rig prior to running the first time, or subsequent time. Approximately 9% of the failures were observed during running of the BOP and the remaining 57% were observed when the BOP was on the wellhead. Of the 67 failures that were observed when the BOP was on the wellhead, 15 were observed during installation testing and the remaining 52 were observed during regular BOP tests or during normal operations.

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

Table 5.2 shows the number of BOP failures observed during the different types of tests alongside the total no. of tests.

Table 5.2 The probability of experiencing a failure during different subsea test types based on the collected data.

Subsea test type	Total no. of tests	No. of failed tests	No of failures	Failure probability per test (%)
Installation test	83	13	15	15,6
Test after running casing or liner	163	17	17	10,4
Test scheduled by time (function & pressure tests)*	319	12	13	3,8
Other tests	10	0		
Not relevant (Normal operation)	-	-	22	
Total subsea	576	42	67	

1. 103 pressure tests, 217 function tets

As seen from Table 5.2, for every 6,4-installation test and every 9,6 test after running casing or liner a BOP failure was observed. If comparing with the results from the Phase I DW it is observed that fewer installation tests failed in Phase II DW. In the Phase I DW a failure was observed in every fourth installation test. The no. of failures observed on tests after running casing were also a little lower in this study. It is here important to note that far more tests scheduled by time were performed in this study, so some of the failures observed after running casing in the previous study would in this study be observed during the test scheduled by time. The frequency of failures observed during normal operation is at the same level for the two studies.

Failures in the BOP and choke and kill items are typically observed because the BOPs are pressurized. The failures observed in the control systems are typically observed because the BOP is functioned.

5.2 Safety Critical Failures

From a well control point of view, the important failures are the failures observed during *Test after running casing or liner*, *Test scheduled by time, Other test (not incl. Installation testing),* or during *drilling/testing operations*. This section discusses the safety critical failures observed during the study.

BOP item, safety critical failures

Table 5.3 shows the safety critical failures in the flexible joints, annular preventers, the ram preventers and the hydraulic connectors.

Table 5.3 Safety critical failures in the flexible joints, annular preventers, the ram preventers and the hydraulic connectors

Days in Service	Failure Mode Distribution	Total Lost Time (hrs)	No. of failures	MTTF (days)			Avg. downtime per BOP-day (hrs)	Avg. downtime per failure (hrs)
				Lower limit	Mean	Upper Limit		
	FLEXIBLE JOINT							
	External leakage	248,50	1	845	4 009	80 180	0,06	248,50
4 009	**All**	**248,50**	**1**	**845**	**4 009**	**80 180**	**0,06**	**248,50**
	ANNULAR PREVENTER							
	Failed to fully open	19,50	6	629	1 242	2 849	0,00	3,25
	Internal leakage (leakage through a closed annular)	171,50	4	814	1 862	5 457	0,04	42,88
7 449	**All**	**191,00**	**10**	**439**	**745**	**1 373**	**0,05**	**19,10**
	RAM PREVENTER							
	Internal leakage (leakage through a closed ram)	135,50	3	2 088	5 398	19 748	0,03	45,17
	Failed to open	782,75	2	2 572	8 097	45 614	0,20	391,38
	Failed to close	475,50	1	3 413	16 193	323 860	0,12	475,50
16 193	**All**	**1 393,75**	**6**	**1 368**	**2 699**	**6 192**	**0,35**	**232,29**
	CONNECTOR							
	Failed to unlock (includes all incidents with problems unlocking connector)	11,50	4	876	2 005	5 874	0,00	2,88
8 018	**All**	**11,50**	**4**	**876**	**2 005**	**5 874**	**0,00**	**2,88**

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. The flexible joint failure that occurred was, however, critical in terms of safety because it caused the well to go into a critical situation. When the mud was leaking out of the joint the hydrostatic well control pressure was lost and the well immediately kicked. Further, the pipe became stuck. With the flexible joint leaking it was also a more difficult operation to control the kick (the failure is further described in Section 4.1 on page 49).

No safety critical flexible joint failure was observed in Phase I DW.

Annular preventers

Six out of ten annular preventer failures were observed as *Failed to fully open failures*. These failures are not regarded as failures that reduce the safety availability. Four of the ten annular preventer failures were *Internal leakages* .

Three of these four failures were not repaired before the BOP was pulled for other reasons. For the fourth failure they pulled the stack and repaired the annular before continuing operations. All the four actual BOPs had two annular preventers.

Two of the failures were caused by excessive wear during stripping operations, one was caused by an internal hydraulic leak in the annular. The fourth failure had no indication of the failure cause.

The failure rate of internal leakage problems in the safety critical period was more than twice as high in this study compared to the results from Phase I DW. It should here also be noted that during Phase I DW they experienced internal leakages during installation tests that were accepted, and the operation continued.

For BOPs with two annulars, an internal leakage failure in one of the annulars has little effect on the safety due to the location of the annulars on the top of the BOP and the in-built redundancy in the BOP.

Ram preventers
Six ram preventer failures were observed in the safety critical period. Three failures were *Internal leakage* through a closed ram.

All the *Internal leakage* failures were observed during BOP pressure testing. One of the failures was in a BSR and the two others in variable pipe rams. The BSR failure was observed when preparing to abandon the well. For one of the pipe rams the sealing element on one side was completely gone, the BOP was pulled and the ram repaired. For the other, the VBR failure, the ram would not test on 3 ½" pipe, but tested on 4 ½" pipe. Since they had a tested backup ram for the 3 ½" pipe sealing capability it was not regarded necessary to pull the BOP for repairing the failure.

One failure was a *Failed to close* failure. The BSR did not close because the ram located hydraulic piping ruptured during the test. The BOP was pulled for repair.

Two failures where the rams could not be opened caused excessive downtime because they were not able to pull the tools out of the BOP. This also limits the access to the wellbore, and can cause severe well control problems if the mud settles.

During Phase I DW six failures were observed in the safety critical period. Four of these failures were critical failures in terms of ram function in a well control situation. The ram preventer leaked during test three times. Two of these failures were in a shear ram, and one was in the UPR. They also *Failed to shear pipe* once during an emergency disconnect situation.

Hydraulic connectors
The most critical failure in a hydraulic wellhead connector is *External leakage*. This failure mode was not observed in the safety critical period in this study. In Phase I DW such a leakage was observed in the wellhead connector during a regular BOP test after running 13 5/8" casing.

The failure mode *Failed to disconnect* was observed four times in this study during the safety critical period. Three of these failures were observed in the wellhead connector in association with abandoning wells. These failures are not critical in terms of well control. The fourth failure occurred in the LMRP in association with a storm warning. The same number of *Failed to disconnect* failures was observed in Phase I DW. This failure mode is not a critical failure mode if the disconnect situation is controlled. If an emergency LMRP disconnect is required (for instance caused by a dynamic positioning problem), this may be a critical failure in terms of well control presupposed that the riser pull provides so much stress on the BOP that the flanges separate. Even if the BOP flanges do not separate, this failure in an emergency disconnect situation may cause severe damages to the riser and the topside compensating system, and thereby severe time losses.

Another failure mode that was not caused by a connector failure, but by control system failure was *spurious disconnect* of the LMRP connector. When drilling without a riser margin, the well will kick at the same time as the control of the BOP is lost if the LMRP discinnects. The LMRP spurious disconnect will be discussed in association with the safety critical failures for the control system.

Choke and kill valves and lines, safety critical failures

Table 5.4 shows the safety critical failures of the choke and kill valves and choke and kill lines.

Table 5.4 Safety critical failures in the choke and kill valves and choke and kill lines

Days in service	Failure Mode Distribution	Total lost time (hrs)	No. of failures	MTTF (days in service) Lower limit	Mean	Upper limit	Avg. downtime per failure (hrs)	Avg. downtime per BOP-day (hrs)
	Choke and kill valve							
	Internal leakage (leakage through a closed valve)	0,00	2	4 990	15 705	88 479	0,0000	-
	Failed to open	0,00	1	6 620	31 410	628 200	0,0000	-
31 410	**All**	**0,00**	**3**	**4 050**	**10 470**	**38 305**	0,0000	-
	BOP attached line							
4009	No failures	-	0	1 741	4 009	-	-	-
	Jumper hose line							
4009	Bursted line	4,00	1	845	4 009	80 180	0,0010	4,00
	Riser attached line							
4009	Plugged line	0,50	1	845	4 009	80 180	0,0001	0,50

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

Choke and kill valves

In this study internal leakages in two valves plus one failed to open were observed. Since there always are two valves in series and there are several choke and kill line outlets on the BOP, these failures will only cause operational problems. None of the failures were repaired.

In Phase I DW one *External leakage* in the connection between the lower inner kill valve and the BOP was observed 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

There were only two failures in the choke and kill lines in the safety critical period. One of them was a plugged line that was overcome by applying a high pump pressure. The other failure was a blown jumper hose in the moon pool. In Phase I DW, six external leakages were observed in these lines. 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.

Control system, safety critical failures

Table 5.5 shows the safety critical failures that were observed in the BOP control systems during Phase II DW.

Table 5.5 Safety Critical Failures in the BOP Control Systems (Phase II DW)

Days in service	Failure mode distribution	Total lost time (hrs)	No. of failures	MTTF (days)			Avg. down-time per BOP-day (hrs)	Avg. down-time per failure (hrs)
				Lower limit	Mean	Upper limit		
	Loss of all functions both pods	42,50	1	845	4 009	80 180	0,011	42,50
	Spurious operation of BOP function(s)	57,50	2	637	2 005	11 293	0,014	28,75
	Loss of all functions one pod	161,00	4	438	1 002	2 937	0,040	40,25
	Loss of several functions both pods	0,00	1	845	4 009	80 180	0,00	-
	Loss of several functions one pod	44,50	3	517	1 336	4 889	0,011	14,83
	Loss of one function both pods	121,50	1	845	4 009	80 180	0,030	121,50
	Loss of one function one pod	12,00	7	305	573	1 220	0,003	1,71
	Unknown	3,50	2	637	2 005	11 293	0,001	1,75
	Other	11,50	4	438	1 002	2 937	0,003	2,88
4 009	Total	**454,00**	**25**	**101**	**160**	**270**	**0,113**	**18,16**

The overall MTTF for critical failures in control systems was at the same level as for the MTTF revealed in Phase I DW. The distribution of failure modes were, however, a little different. The main difference is that the critical failure mode *Loss of all functions both pods* occurred five times in Phase I DW and only once in Phase II DW. The main reason for this difference is that that multiplex systems are more prone to this failure mode than conventional pilot control systems. In Phase II DW, relatively little exposure time from multiplex systems have been included. Otherwise, there were not large difference between the two studies.

Brief failure description

The ***Loss of all functions both pods*** failure occurred in a multiplex system. They observed that the accumulator fluid was running away on rigid conduit and 1" supply line during normal operation.

Two ***Spurious operation of BOP function(s)*** failures were observed in the safety critical period. Both the failures were related to unintended disconnect of the LMRP connector. In deepwater drilling this may be a very critical incident, because at the same time the hydrostatic control of the well is lost (if drilling without a riser margin) the control of the BOP is lost.

The first of these *Spurious operation of BOP function(s)* failures was observed when they were preparing to pull the BOP to abandon the well. They changed the quick disconnect plate on the pod reel to install the running plate. During this operation the LMRP disconnected for some reason. Since they were abandoning the well, well plugs were in place, so this incident did not represent a threat to safety.

The second *Spurious operation of BOP function(s)* failure was observed when they swapped from the yellow to blue pod to function test the BOP after pressure testing. The LMRP connector then disconnected.

Four ***Loss of all functions one pod*** failures were observed in the safety critical period. All occurred in a conventional pilot control system. One failure was observed during a test after running casing or liner. When attempting to switch to the blue pod after a function test on yellow pod they failed to switch due to a failure in the pod selector valve.

The second *Loss of all functions one pod* failure was observed during a test scheduled by time. Just after they had finished the BOP test it was stated that they had to pull the yellow pod and repair the pod hose line.

The third pilot control system *Loss of all functions one pod* failure was observed during logging operations, not BOP testing. The yellow pod hose failed. MMS approved that they could complete the wireline operations before repairing the pod hose. The pod hose was pulled, repaired, and rerun the day after the failure occurred.

The fourth pilot control system *Loss of all functions one pod* occurred during a tropical storm. When performing well abandon operations the rig was evacuated for the tropical storm “Earl”. The LMRP was disconnected from the stack. When arrived on the rig they found leak on 1” supply line from stack to surface.

The ***Loss of several functions both pods*** is a rare failure mode for BOPs. One such failure occurred. During a BOP test scheduled by time it was noted that the lower inner & outer kill line valves were inoperative. It is not known whether this was a valve problem or a control system problem, or a combination. The valves remained closed for the rest of the well.

The failure mode ***Loss of several functions one pod*** failure was observed three times in the safety critical period. Two of the failures were caused by faulty annular regulators. For the third failure it took five minutes to function the annulars and one minute to function the rams. The cause of this failure is unknown.

The ***Loss of one function both pods*** failure occurred because the hose that connects the shuttle valve to the opening side of the lower annular had failed. (The hose is common for both pods).

The failure mode ***Loss of one function one pod*** was observed seven times in the safety critical period. Failed SPM valves caused four of these failures. One failure was caused by a guideline cable that had rubbed a hole the blue pod hose, cutting the lower inner choke pilot line on rig level. For one failure the yellow pod opening line for the MPR ram had developed a leak. The ram closed and tested properly. When it was opened, the opening fluid pumped away. For the last failure it was only stated that they located and isolated a leak on the yellow pod.

Four failures were listed with ***Other*** as failure mode and two were listed with ***Unknown*** as failure mode.

Other failures:

1. They observed a sluggish closing of lower annular on blue pod. Annular closing time 60-70 seconds, typical closing time 35-40 seconds. Lower annular performance on yellow pod was fine.
2. A malfunction on the BOP control panel was noticed. Lights indicated that the BSR was closed and all readbacks on the blue pod were lost. Found that a leaking backup battery had created shorts in the system.
3. Attempted to unlatch the wellhead connector with the reel panel. Reinstalled the RBQ plate on blue pod reel and unlatched wellhead connector.
4. Flow meter was out of order so they got no flow readings during testing.

Unknown failures

2. It was only stated that they repaired the rig manifold (regulator on blue pod). It seems from the test report that they had problems to unlatch the wellhead connector from the hose reel.
3. When starting to test the BOP they got some trouble with the subsea accumulator system. It was not specified what type of problem they had.

5.3 Ranking of Failures with Respect to Safety Criticality

The frequency of safety critical failures that occurred in this study was similar to the frequency observed in Phase I DW.

In this study the most severe failures as leakage in the wellhead connector and leakage in the choke and kill valve to stack connection below the LPR, were not observed.

Rams and annulars have, however, failed at a higher rate in the safety critical period in this study than the previous study.

The severe failure mode loss of all functions both pods occurred more frequently in Phase I DW than in this study. It should, however, be noted that many of the BOPs in the previous study were equipped with an acoustic backup control system as well.

Below a coarse ranking of the failures that were observed in the safety critical period in Phase II DW is presented alongside the same ranking for Phase I DW. It should be noted that Phase I DW is represented with an approximately 20% longer time in service.

Phase I DW BOP study	Phase II DW BOP study
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 BOP control by the main control system 5. Two shear ram leakages in closed position 6. Two failed to disconnect the LMRP failures 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	1. One control system failure that caused total loss of 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 failed to open pipe ram failures 6. Two failures where the pipe ram leaked in closed position 7. External leak in flexible joint 8. One failed to disconnect the LMRP failure 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)

6. BOP TESTING EXPERIENCE

Subsea BOP testing is important both with respect to the BOP's ability to act as a safety barrier and time consumption.

A variety of different test tools are commonly used. Each rig is equipped with several devices that may be used for BOP testing. The different tools are designed to seal against the different wellheads used. Normally the manufacturer of the wellhead also supplies the test tools for the wellheads.

When testing the BOP, some test tools require the wear bushing to be pulled prior to testing (conventional test tools) and some do not (combined test tools). The BOPs are also frequently tested against the seal assembly running and retrieving (R/R) tools (also called casing pack-off tool).

The most common practices in equipment handling during subsea BOP testing are listed below.

BOP test after landing BOP on wellhead:

Alternative 1	**Alternative 2**
1. Run test plug	4. Run combined test tool
2. Test BOP	5. Test BOP
3. Pull test plug	3. Pull combined test tool
4. Run wear bushing	

BOP test after running and cementing casing:

Alternative 1	**Alternative 2**	**Alternative 3**
1. Run test plug	1. Test BOP against seal assembly R/R tool	1. Run wear bushing
2. Test BOP		2. Run combined test tool
3. Pull test plug	2. Pull seal ass. R/R tool.	3. Test BOP
4. Run wear bushing	3. Run wear bushing	4. Pull combined test tool

Periodic BOP pressure tests:

Alternative 1	**Alternative 2**	**Alternative 3**
1. Pull wear bushing	1. Run combined test tool	1. Pull wear bushing inspect
2. Run test plug	2. Test BOP	2. Run wear bushing
3. Test BOP	3. Pull combined test tool	3. Run combined test tool
4. Pull test plug		4. Test BOP
5. Run wear bushing		5. Pull combined test tool

The various rigs most frequently use one of the alternatives within the actual test category. However, if test problems are experienced, other alternatives may be chosen. Other alternatives may also be chosen for single tests without experiencing test problems.

6.1 BOP Testing Regulations

Some countries have governmental BOP testing regulations while others have not. In Norway and in the US there are such regulations. In Brazil there were, up to recently (approximately 1998), no governmental BOP testing regulations. Petrobras procedures were followed. Now there exist governmental regulations. In Italy and the UK there are no such regulations.

Norwegian and US regulations are similar in terms of test frequencies. The following BOP tests are scheduled in these regulations:

- Test prior to running the BOP (only US requirement)
- Installation tests
- Test after running casing
- Pressure test scheduled by time (Never more than 14 days since last test)
- Function test scheduled by time (Never more than 7 days since last pressure test)

Prior to all pressure tests there shall be carried out a low-pressure test to 200 – 500 psi.

In the US the test prior to running the BOP and the installation test shall be performed to the rated working pressure for the complete BOP except the annulars that shall be tested to 70 % of the rated working pressure.

Blind-shear rams shall be actuated once a week and pressure tested at least once every 30 days.

Variable rams shall be pressure tested against all sizes of pipe in use.

In Norway the BOPs shall be tested to the maximum expected working pressures at least every six months. During the initial and subsequent installation the BOP shall be tested to the maximum design pressure for the casing string that is designed to withstand the highest pressure.

The installation test may be limited to the wellhead connection and the kill choke lines, in addition to all functions, presupposed the BOP has been tested to the design pressure of the above mentioned casing string before being lowered to the seabed.

Before drilling out of casing the BOP shall be tested to the maximum design pressure for the relevant section.

The pressure holding times in Norway are 10 minutes for high-pressure tests and 5 minutes for low-pressure tests.

Blind-shear rams shall be pressure tested prior to drilling out of casing. The BOP function test scheduled by time does also include a pressure test of the choke and kill line. The acoustic system shall be function tested during all BOP tests when the BOP is subsea.

6.2 BOP Test Time Consumption

In Table 6.1 the number of pressure tests, the average BOP test time consumption and the mean time between pressure tests for the various rigs included in the study are listed. Pressure tests includes;

- Installation tests
- Tests after running casing
- Pressure tests scheduled by time.

It should be noted that time used/lost in connection with BOP failures are not recorded as a part of the BOP test time. Only the test time itself, time for running/pulling of tools and time lost in connection with tool problems are included in the BOP test time.

In general it can be stated that the operators are carrying out the BOP test as often as stated in the MMS regulations. When a BOP test has been postponed due to specific operations/problems, it has been stated that MMS has given the permission.

Table 6.1 No. of BOP subsea tests, test time consumption and time between tests for pressure tests

Rig	BOP-days in service	Total no. of tests	No. of tests listed with no test time *)	Average test time (hrs)	Average water depth (m)	Average water depth (feet)	Average time between pressure tests (days)
Rig 50	112	11	1	8,8	619	2032	10,2
Rig 51	157	12	1	20,7	446	1464	13,1
Rig 52	223	20		8,2	508	1668	11,2
Rig 53	257	21	1	16,5	1591	5221	12,2
Rig 54	137	13	1	14,0	1992	6537	10,5
Rig 55	160	15	1	12,9	988	3240	10,7
Rig 56	171	14	1	19,1	598	1962	12,2
Rig 57	165	14	0	14,6	790	2592	11,8
Rig 58	220	19	1	12,1	516	1693	11,6
Rig 59	171	15	1	13,6	1303	4274	11,4
Rig 60	69	6	0	16,3	565	1853	11,5
Rig 61	276	24	1	14,3	850	2788	11,5
Rig 62	134	13	0	10,1	1158	3800	10,3
Rig 63	258	23	0	11,7	517	1697	11,2
Rig 64	139	13	1	13,2	576	1889	10,7
Rig 65	300	26	1	14,6	945	3101	11,5
Rig 66	130	12	0	20,5	1001	3283	10,8
Rig 67	77	10	0	10,4	485	1590	7,7
Rig 68	147	11	0	18,0	1112	3649	13,4
Rig 69	73	7	0	9,4	534	1751	10,4
Rig 70	47	3	0	10,0	593	1945	15,7
Rig 71	304	21	0	16,4	1260	4135	14,5
Rig 72	52	5	1	12,4	1613	5292	10,4
Rig 73	100	9	2	16,0	716	2350	11,1
Rig 74	65	6	1	10,2	903	2963	10,8
Rig 75	65	6	1	12,9	885	2902	10,8
Total	***4009***	***349***	***16***	***13,9***	***898***	2947	***11,5***

*) Some of the BOP subsea tests carried out were not listed with test time consumption because this time was included as downtime caused by a BOP failure, or it was impossible to identify the specific BOP test time from the description in the daily drilling reports.

In addition to the above listed pressure tests 216 function tests with a total test time of 118 hours, and 10 other tests with a total test time of 12 hours were listed.

As seen from Table 6.1 the average BOP pressure test time varies from rig to rig. In addition large variations in BOP test time within each rig exist.

The average test time consumption was 13,9 hours. The total test time consumption for BOP subsea tests were thereby 4761 hours. These 4761 hours represent 5% of the total no. of BOP-days, or in average 1,19 hours/BOP-day.

When looking at the data from Phase I DW the average test time was 8,3 hours. If disregarding the tests performed in water depths shallower than 400m (1312 ft.), the average test time for the 225 tests was 9,6 hours, or 4,3 hours shorter than the average test time for the Phase II DW study.

The testing of the subsea BOPs is very important in terms of safety and time consumption. BOP testing should be focused to keep up the present safety level, but efforts should be made to reduce the time consumption.

Why is the difference in the average test time compared to the Phase I DW study so large?
When testing the BOP, some test tools require the wear bushing to be pulled prior to testing (conventional test tools) and some do not (combined test tools). The BOP's are also frequently tested against the seal assembly running and retrieving (R/R) tools (also called casing pack-off tool).

Table 6.2 presents an overview of the distribution of the main test tools utilized alongside the average decomposed BOP test time in Phase I DW and Phase II DW.

It should be noted that the information in Table 6.2 is approximate information. For some BOP tests they have utilized test tools of different types due to test problems, the tests have then normally been categorized according to the first test tool utilized. Further, the type of test tool utilized is frequently not stated in the daily drilling reports, so the categorizing has been done according to what type of runs that have been carried out. The decomposing of test times has for many tests been difficult, and therefore an undefined time column exist.

Table 6.2 Test tool principles vs. decomposed BOP test times for the Phase I DW and Phase II DW studies

Type of BOP test tool	No of BOP tests	Average decomposed BOP test time (hrs)							Avg. water depth	
		Pull wear bushing	Run test plug	Run test	Pull test plug	Run wear bushing	Undefined time	Total test time	(m)	(ft.)
Phase II DW data										
Casing pack off tool	24	0,0	0,0	4,5	3,3	4,3	0,1	12,2	1237	4058
Conventional test tool (requires wearbush)	59	1,3	3,0	5,3	2,2	3,3	1,6	16,8	672	2206
Combined test tool	244	0,1	3,9	5,2	2,6	0,1	1,3	13,1	917	3008
Other/unknown	6	2,1	6,3	7,3	3,6	1,7	2,6	23,5	1002	3289
Total	**333**	**0,3**	**3,5**	**5,2**	**2,6**	**1,0**	**1,3**	**13,9**	**898**	**2947**
Phase I DW data										
Casing pack off tool	91	0,0	0,0	2,7	1,5	3,4	0,1	7,7	881	2890
Conventional test tool (requires wearbush)	97	0,8	2,8	3,3	1,8	2,5	0,4	11,6	992	3255
Combined test tool	35	0,0	2,7	3,2	2,1	0,1	0,7	8,8	833	2734
Other/unknown	2	0,0	5,5	4,0	1,5	0,0	0,0	11,0	871	2856
Total	**225**	**0,3**	**1,7**	**3,0**	**1,7**	**2,5**	**0,3**	**9,6**	**920**	**3019**

It is seen from Table 6.2 that the average time for running and pulling tools, and the testing time itself was higher in Phase II DW than Phase I DW study. The average water depth for each test was 924 m (3031 ft.) in the Phase I DW study, compared to 898 m (2947 feet) in this study. The water depth should then have insignificant effect on the average BOP test time difference between the two Phases

The main reasons for the differences are believed to be:
1. In Phase II DW variable bore rams (VBRs) normally were tested on two diameters, thus increasing the number of tests. Normally a telescopic type test joint was used for this testing. Due to problems with a dart for this type of test joint for some rigs they frequently made two test plug runs with different joint diameter.
2. In Phase I DW relatively more tests where performed after running casing (periodic tests were seldom performed) and the casing pack-off tool was then

used. The average test time when utilizing the casing pack-off tool for BOP testing is lower than utilizing the other tools. In Phase II DW only 4-5 rigs tested the BOP against the casing pack-off tool regularly. Table 6.2 shows an overview of the average test time consumption for the two studies and the different BOP test tool principles.

3. In Phase II DW the blind-shear ram test pressures were held for 30 minutes, while in Phase I DW they were held for 3 – 10 minutes
4. If the casing leaked in Phase II DW, frequently an extra trip was performed to test the shear ram against the plug (this was normally not done in Phase I DW)
5. One rig was frequently testing the shear ram with a separate plug.

6.3 Rig Specific Evaluation of Test Time Consumption

As seen from Table 6.1 there are differences in the average test time from rig to rig. The influence from the water depth is discussed in Section 6.4. This section highlights specific problems, procedures or tools for the rigs with the highest average test time. (BOPs with an average test time below 15 hours are not commented).

Figure 6.1 shows the BOP test times sorted on rig and test time for the successful BOP pressure tests.

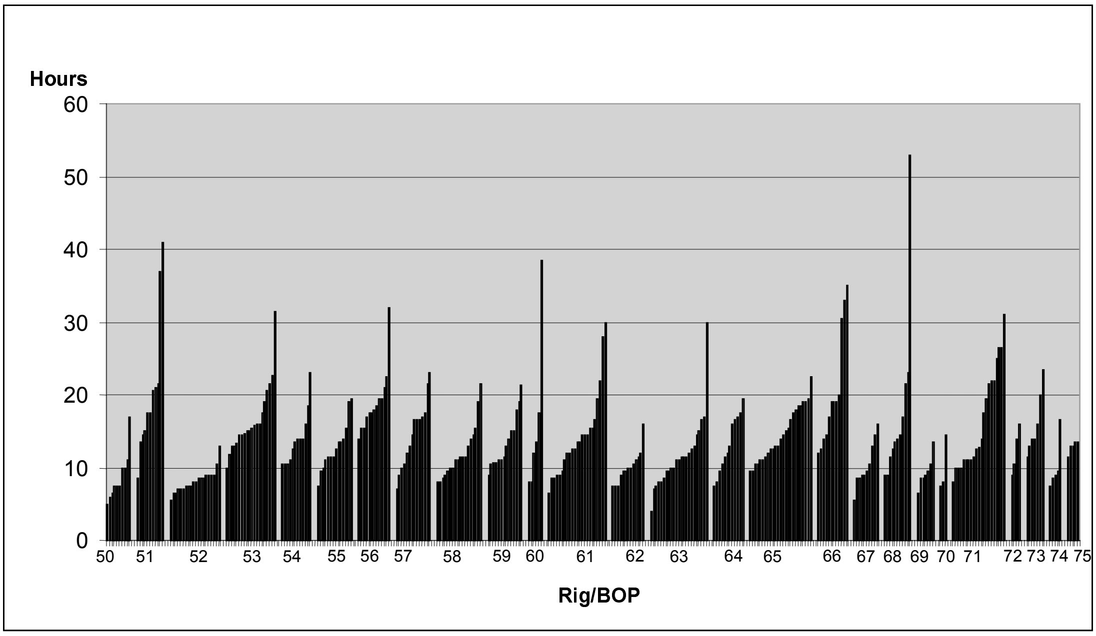

Figure 6.1 BOP test times sorted on rig and test time for the BOP pressure tests

The average BOP test time for each rig was between 8,2 and 20,7 hours. The highest average test time was experienced on rig no. 51 that had the lowest average water depth. The lowest test time was experienced on a rig drilling at approximately the same water depth.

Rig 51 The average test time for the 12 BOP tests was 20,7 hours. The main reasons for this high average test time were:

- They pulled and ran the flexible joint wear bushing (not wellhead wear bushing) in association with each test.
- After running casing they were normally testing the shear ram against a separate plug. This was time consuming.

Rig 53 The average test time for the 21 BOP tests was 16,5 hours.
- Specific problems with test plug sealing and gumbo in riser for the most time-consuming tests

Rig 56 The average test time for the 14 BOP tests was 19,1 hours.
- Two leaking test plugs, one severe.
- No tests with duration less than 14 hours.

Rig 60 The average test time for the 6 BOP tests was 16,3 hours.
- One test where they had problems with gumbo in the riser, leaking test tool lasted 38,5 hours. This test dominated the average. In addition they had problems with a leaking tool during another test as well.

Rig 66 The average test time for the 12 BOP tests was 20,5 hours.
- They had problems with the dart in the test plug during 3 tests
- For three tests they performed two test plug runs with different pipe diameter.
- No tests with duration less than 12 hours.

Rig 68 The average test time for the 11 BOP tests was 18,0 hours.
- For two tests they had to reset the tool several times. One test lasted for 53 hours.
- For one test they ran the test plug twice on different diameter pipe.

Rig 71 The average test time for the 21 BOP tests was 16,4 hours.
- For four tests they ran the test plug twice on different diameter pipe.
- They had problems with the dart in the test plug during two tests
- Made a separate run to test the BSR against a plug when the casing failed.
- For one test they had to rerun because they used the wrong tests assembly, thereafter they got problems with the dart in the test plug and had to make an extra run with 4” test assembly.

Rig 73 The average test time for the 9 BOP tests was 16,4 hours
- They experienced problems with setting the wear bushing for one test
- The test tool leaked on one test.

6.4 BOP Pressure Test Time Consumption vs. Water Depth

It is likely to assume that the time to pressure test a BOP will increase with an increasing water depth due to the additional time required to trip tools in and out. This can not directly be confirmed by reviewing the average test times vs. water depth in Table 6.1. The average test times vs. the average water depths as presented in Table 6.1 have been sorted and are presented in Figure 6.2.

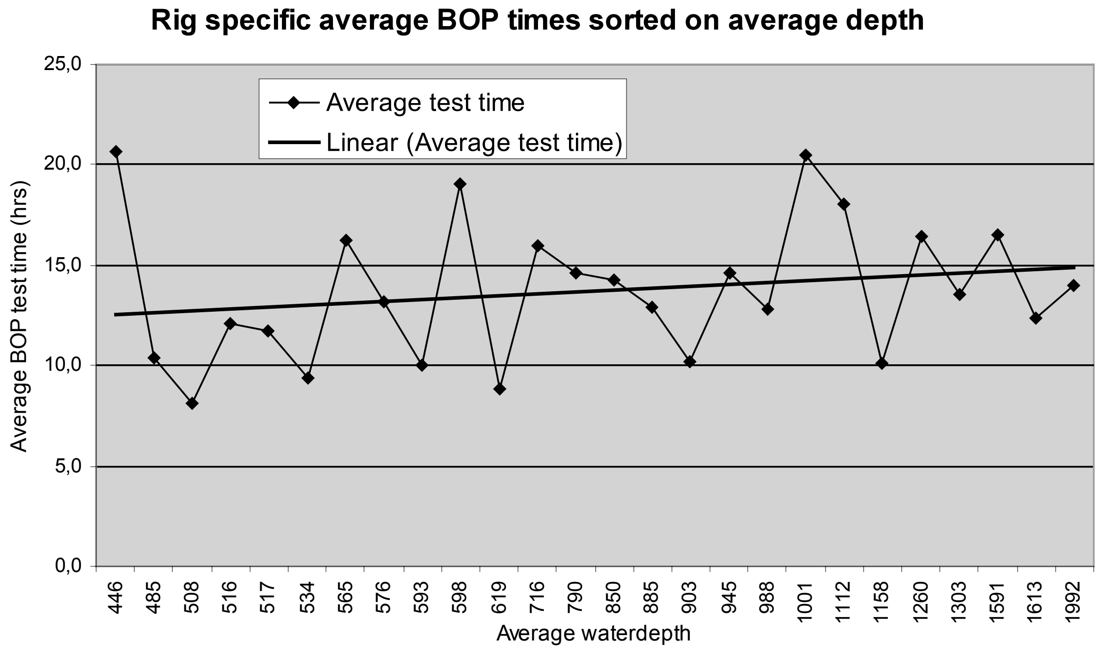

Figure 6.2 Rig specific average BOP test times sorted on average water depth.

As seen from Figure 6.2 there is a trend in the test time vs. the average water depth. However, the variation is relatively large from rig to rig independent of the water depth. Especially the average test time for the rig drilling in the most shallow water depths disturbs the picture.

Figure 6.3 shows the BOP test time vs. the water depth for all the BOP pressure tests.

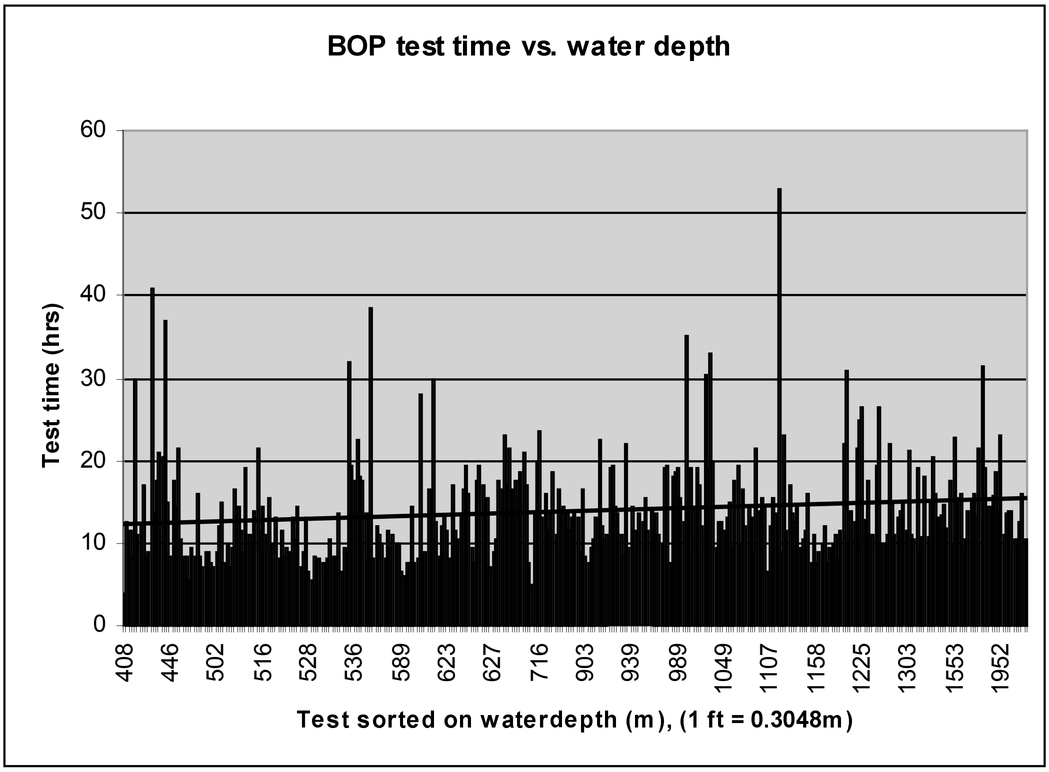

Figure 6.3 Water depth vs. BOP test time for BOP tests

Figure 6.3 shows the same relation between the water depth and the BOP test time, as observed Figure 6.2. However, the BOP test time varies a lot from test to test at the same water depth.

In Figure 6.4 a linear regression line for the BOP test time vs. the water depth is shown alongside a linear regression line for the BOP test tool handling time.

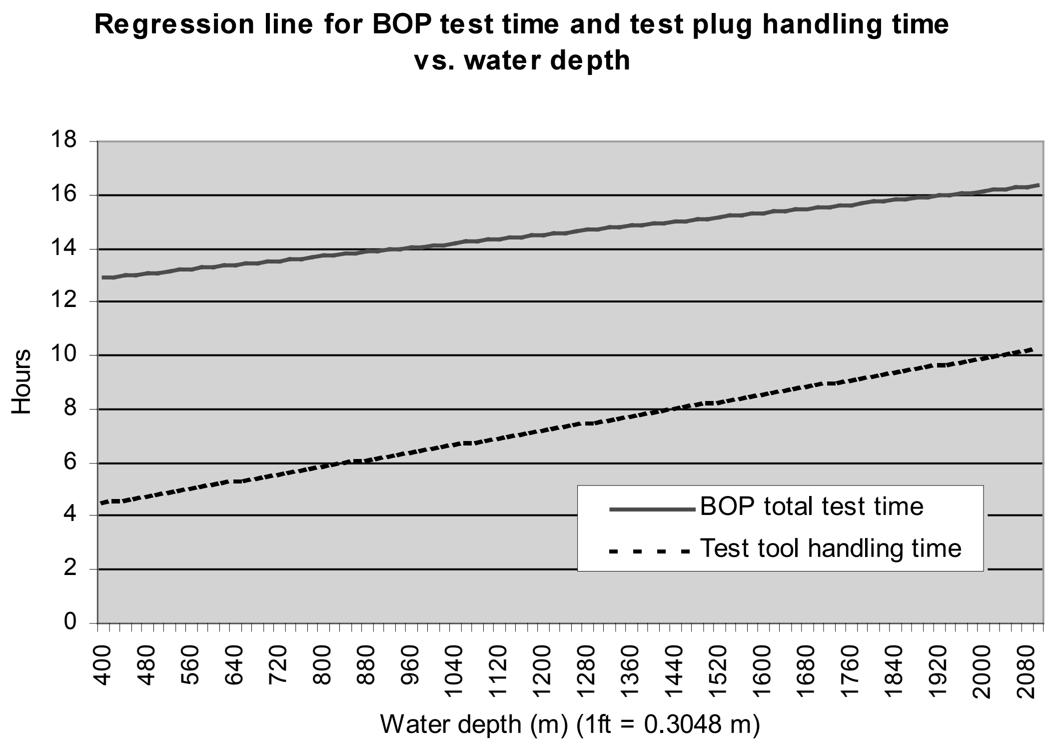

Figure 6.4 Linear regression lines for the total BOP test time and the BOP test tool handling time vs. water depth

When looking at the regression line for the BOP test time, it increases with the increased water depth. It is seen that a test at 400 m (1312 ft.) can be expected to last approximately 13 hours, while a test in 2000 m (6562 ft.) can be expected to last for approximately 16 hours, i.e. a three hours difference. When looking at the same depth interval for Phase I DW this difference was more than five hours. Since some of the BOP tests at relatively shallow water in Phase II DW had a long duration the total picture is disturbed.

The main difference in the BOP test time from shallow to deep water is the handling time for the BOP test tool. The regression line for the running plus the pulling times of the test tools is steeper than the time for the complete test. The difference between 400 and 2000 meter of water is approximately 5,5 hours. It is believed that this is a more realistic time difference vs. water depth than the complete test time for the test sample in Phase II DW.

7. BOP Testing Efficiency

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 is not as important as other with respect to testing.

The objective with this section is not to maximize the probability that a BOP will be able to close in a kick, but to propose alternative ways of testing the BOP that will keep the safety availability at the same level as today with a less time consumption.

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 total ability to close in a well kick will depend on:

- The BOP stack design/configuration
- The drill string 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)

In this section a fault tree model established in Phase I DW for a pilot BOP control system has been used as basis for the calculations.

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 /3/. A more thorough description of how the fault tree was constructed is presented in /2/.

This section focuses more on the operational assumptions than the fault tree analyses itself.

7.1 Operational Assumptions

7.1.1 The BOP Stack Design

The fault tree analyses are based on the BOP stack design shown in Figure 5.

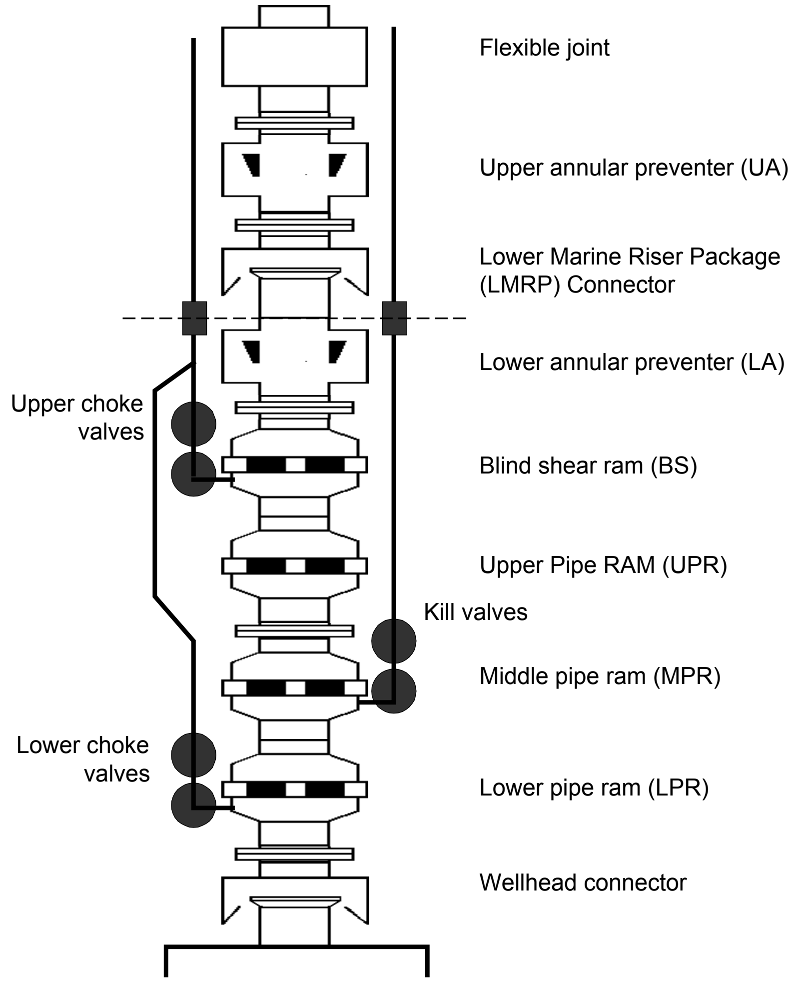

Figure 5 BOP stack design used for the fault tree analyses

The base case BOP stack design includes the following:

- Two annular preventers, one above the LMRP connector (upper annular) and one below (lower annular)
- One shear ram preventer and three pipe ram preventers located in two dual blocks
- Six choke and kill valves (lower choke outlet below LPR, kill outlet below MPR, and upper choke outlet below shear ram)
- Two hydraulic connectors (one LMRP connector and one wellhead connector)
- The stack is joined together with five clamped flanges

The BOP is equipped with a main control system only. No acoustic backup control system that can operate the shear ram, middle pipe ram, and the lower pipe ram is included.

Assumptions regarding the subsea BOP control systems design and function are presented in /2/ and will not be explained in detail in this report. The fault tree is, however, based on a Shaffer (Koomey) pilot control system from the early 80ties. In principle this control system is similar to other pilot control systems. One important aspect to note is that some newer BOP control systems have less redundancy caused by subsea communication between the pods. The effect of this reduced redundancy on the safety availability is discussed in /2/.

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

7.1.2 BOP Unavailability Calculation and Test Frequencies

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

$$MFDT = (\lambda * \tau)/2 \quad (/3/),$$

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.

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.

7.1.3 BOP Test Interval

The following BOP test intervals have been chosen for the purposes of the fault tree analyses in this report unless other test intervals are specifically stated.

- The BOP preventers and choke and kill valves are pressure tested every two weeks (pressure test one pod, function tested one pod)
- Theh BOP is function tested every two weeks (both pods)

This means that every relevant BOP function will be operated once a week, and that every component will be pressure tested once every two weeks.

The real average time between pressure tests are lower than two weeks, 11,5 days (see Table 6.1 on page 98). It has been selected not to utilize the average time between tests in these calculations. If utilizing the average time between tests a correction factor also should have been utilized. The typical correction factor would be approximately 1,1-1,2 (/9/) that should bring the input data to approximately 13 days between tests.

For the comparison of the different test practices this will have no effect.

7.1.4 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.

7.1.5 Failure Input Data

The failure data used as input for the fault tree analyses are based on the reliability data collected during both the Phase I DW and Phase II DW projects. The failure frequencies used as input for the fault tree analysis are based on the failure frequencies for failures that occurred in the safety critical period in Phase I DW and Phase II DW. 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.

The major differences between the detailed input data used in Phase I DW compared to the data used in the Phase II fault tree analyses are:

- Reduced probability of choke and kill line leakage
- Reduced probability of wellhead connector leakage
- Reduced probability of flange leakage between inner choke and kill valve and the BOP body
- Increased probability of annular preventer internal leakage
- Increased probability of pipe ram preventer internal leakage
- Increased manifold and annular regulator failure rate
- Reduced probability of pilot line leakage

- Reduced probability of leakage in the main supply line

From a total BOP safety availability point of view the data utilized for the Phase II DW study are better then the data utilized for the Phase I DW study. The main cause for this improvement is the improvement in the wellhead connector and the choke and kill valve to BOP body connection.

7.1.6 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 extend 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. For the purpose of these calculations the MMS waivers as practiced today will have an insignificant effect on the results.

7.1.7 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.

7.2 Evaluation of the Effects of Different BOP Tests Strategies

It should be noted that this analysis only considers the initial closure of the BOP. When circulating out a well kick the preventers and valves will be subjected to wear, increasing the chance of equipment failure. It has been impossible to quantify this effect within the scope of the present study. For some kicks, circulating out the kick is very easy and causes hardly any wear, for other kicks the wear may be substantial.

The estimates of the BOP safety availability presented in this chapter should be used with care. The important aspect to focus on is the relative difference between the different estimates related to the test practice utilized.

The calculations have been carried out for some different test strategies and assumptions related to the BOP configuration vs. the drillpipe/tubular running through the BOP.

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.

The following six situations where the BOP has to act as a well barrier have been investigated;

1. All the pipe rams and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well (Table 7.2).

2. Only the UPR and MPR and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well (LPR not available) (Table 7.3).

3. Only the LPR and UPR can seal around the drill pipe/tubular in the hole (The annulars can not be used due to the well pressure, the BSR can not be used due to large pipe diameter, the MPR can not be used due to the large pipe diameter) (Table 7.4).

4. Only the MPR can seal off the hole (Large diameter pipe, well pressure exceeds annular pressure rating, pipe diameter/material exceeds BSR shear capacity) (Table 7.5).

5. Only the UAP and LAP can seal around the casing in the hole (no rams available) (Table 7.6).

6. One pod is pulled for repair, all the pipe rams and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well (Table 7.7).

For each of the above situations four different test strategies have been evaluated. The test strategies are presented in Table 7.1.

Table 7.1 BOP test strategies evaluated

Short test strategy description	BOP test strategy
Base test case (similar to present regulations)	- 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)
Body test* every two weeks, in-between function test	- Complete BOP installation test (pressure and function test) - Body test the BOP every two weeks against UPR. Function test on both pods - Function test both pods every two weeks
Body test* only (no in-between function test)	- Complete BOP installation test (pressure and function test) - Body test the BOP every two weeks against UPR. Function test on both pods - No additional function test
Body test* every week incl. function test	- Complete BOP installation test (pressure and function test) - Body test the BOP every week against UPR. Function test on both pods

*	For the body test strategies it has been assumed that the well duration is 50 days

The results from the calculations are presented in Table 7.2 to Table 7.7, followed by a brief discussion.

Table 7.2 BOP safety availability when *all the pipe rams and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well.*

Scenario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
1a	Base test case (similar to present regulations)	0,10511	1,000
1b	Body test every two weeks, in-between function test	0,10515	1,000
1c	Body test only (no in-between function test)	0,10840	1,031
1d	Body test every week incl. function test	0,05372	0,511

For the situation described in Table 7.2 a blowout through the BOP bore is highly unlikely. There is so much redundancy in the stack, both with respect to preventers and controls. The most likely blowout path is through the wellhead seal to the surroundings or in the other components in or below the LPR.

Due to the redundancy and the high reliability of each BOP component excluding the testing of the single preventers will have no effect on the total safety availability. The only important pressure test to carry out will be the test of the BOP body to ensure that there are no external leaks.

The effect of the bi-weekly function test of the BOP will also be fairly low for this situation.

From a safety availability point of view it is much better to perform a BOP body test including a full function test on both pods every week, rather than a detailed testing of the BOP every two weeks and an in-between function test (as carried out today).

Table 7.3 BOP safety availability when only *the UPR and MPR and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well (LPR not available)*

Scenario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
2a	Base test case (similar to present regulations)	0,12678	1,000
2b	Body test every two weeks, in-between function test	0,12682	1,000
2c	Body test only (no in-between function test)	0,13007	1,026
2d	Body test every week incl. function test	0,06456	0,509

The situation in Table 7.3 is similar to the situation in Table 7.2 except that now the LRP can *not* be used for closing in the well because the ram blocks have a different diameter from the pipe in the hole.

The probability of failing to close in the well has increased with approximately 20% compared to the situation in Table 7.2. Otherwise, the relative difference between test scenarios 2a to 2d in Table 7.3 are very similar to the relative differences between the test scenarios in Table 7.2.

The reason why the total probability of failing to close in a kick is reduced is that more possible leakage paths in lower parts of the BOP stack have been exposed to the well pressure. A blowout through the BOP bore is still highly unlikely due to the redundancy.

If performing the same calculations as in Table 7.3 under the assumption that the LPR and the UPR, but not the MPR can seal around the drillpipe, the total probability of failing to close in a kick will be nearly identical with the results in Table 7.2. This is explained by the LPR that will be an extra barrier before additional leakage paths in the lower parts of the BOP stack can be exposed to well pressure. From the probability of failing to close in a kick point of view, a large diameter range VBR should be utilized in the lower pipe ram. Most rigs included in this study preferred to have a fixed ram as the LPR (see page 21). It should be noted that the hang-off capacity is also a criterion when selecting the LPR blocks.

Table 7.4 BOP safety availability when only *the LPR and UPR can seal around the drill pipe/tubular in the hole (The annulars can not be used due to the well pressure, the BSR can not be used due to large pipe diameter, the MPR can not be used due to the large pipe diameter)*

Scenario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
3a	Base test case (similar to present regulations)	0,10537	1,000
3b	Body test every two weeks, in-between function test	0,10562	1,002
3c	Body test only (no in-between function test)	0,10941	1,038
3d	Body test every week incl. function test	0,05405	0,513

For the situation analyzed in Table 7.4 the average probability of failing to close in a kick is similar to the results presented in Table 7.2. It may now be observed a small effect of excluding the detailed testing of each ram on the average probability of closing in a kick. The reason why the difference is only 0,2% is the high reliability of each pipe ram with associated control.

Table 7.5 BOP safety availability when only *the MPR can seal off the hole (Large diameter pipe, well pressure exceeds annular pressure rating, pipe diameter/material exceeds BSR shear capacity)*

Scenario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
4a	Base test case (similar to present regulations)	0,21473	1,000
4b	Body test every two weeks, in-between function test	0,41296	1,923
4c	Body test only (no in-between function test)	0,42756	1,991
4d	Body test every week incl. function test	0,35088	1,634

For the situation analyzed in Table 7.5 only one ram is available for closing in the well in a kick situation. It is now observed a significant effect of the detailed pressure test.

Table 7.6 BOP safety availability when *only the UAP and LAP can seal around the casing in the hole (no rams available)*

Scen-ario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
5a	Base test case (similar to present regulations)	0,18093	1,000
5b	Body test every two weeks, in-between function test	0,29000	1,603
5c	Body test only (no in-between function test)	0,29481	1,629
5d	Body test every week incl. function test	0,22006	1,216

The situation in Table 7.6 is similar to the situation in Table 7.4, but this time it is the two annulars only that can be used for closing in the well. It is observed that the average probability of failing to close in a kick is much higher than in Table 7.4. The main reason is the increased number of possible leakage paths from the stack to the sea below the annulars.

The relative effect of the detailed pressure test is much larger in Table 7.6 than in Table 7.4. The reason why is the rather low reliability of the annular preventer with respect to internal leakage in closed position. The probability of an annular preventer to experience a leak in closed position is four times higher than the probability that a pipe ram should leak.

Table 7.7 BOP safety availability when one pod is pulled for repair, *all the pipe rams and the annulars can seal around the drill pipe/tubular in the hole, in addition the BSR can cut the pipe and seal off the well.*

Scenario no.	Short test strategy description	Average probability of failing to close in a kick (%)	Ratio vs. base case
6a	Base test case (similar to present regulations)	0,32812	1,000
6b	Body test every two weeks, in-between function test	0,32821	1,000
6c	Body test only (no in-between function test)	0,55291	1,685
6d	Body test every week incl. function test	0,27687	0,844

The situation analyzed in Table 7.7 is related to situations that occur from time to time. There has been observed a failure in one pod and the pod has been pulled for repair while the drilling operation proceeds. It is observed that the average probability of failing to close in a kick is three times higher than for a situation where both pods are operative (Table 7.2). The effect of the detailed pressure testing of the BOP is still insignificant. Now the effect of function testing the BOP becomes higher. This is also to be expected since only one pod is operative.

7.3 Discussion Related to Testing Practices and Safety Availability

The BOP stack is primarily used for closing in and circulating out kicks. The discussion in this section is related to “normal kicks” and “not normal kicks”.

“Normal kicks”
For most well kicks a normal drill-pipe will be running through the BOP stack and there will be redundancy in the BOP for kicks through the well annulus.

For these situations there is no need for a detailed pressure testing of the BOP stack during regular operations.

The most important tests are:
- A detailed installation test to ensure that all the BOP functions are satisfactory.
- A bi-weekly BOP body test against for instance the UPR and a complete function test

The in-between bi-weekly BOP function test will only have a small effect on the average probability of being able to close in a kick. This test does not require high time consumption (0,5 – 1,0 hours)

“*Not* normal kicks”
For specific operations a kick can occur when there is less redundancy in the stack. Examples of such situations are:

- Pulling and running bottom hole assemblies (BHA) through the BOP (depending on diameters)
- Running casing
- Empty hole
- Kick through the drillstring

The BHA is running through the BOP a limited proportion of the total tripping time. In addition, a flowcheck should always be performed before the BHA is pulled through the BOP. The probability of experiencing a kick when a BHA is inside the BOP should thereby be fairly low.

For the empty hole situation the BSR would be the primary preventer to use to seal off the well. In addition the annulars are claimed to have the capacity to seal off the well. Field experience shows that the annular preventer can be used for sealing off an empty hole. The success probability of such an operation is unknown. The annulars are never tested against an empty hole, therefore no such reliability data exists.

If a kick occurs during casing running only the annulars can be used to seal off the annulus. A BSR can normally not shear the casing.

For a kick through the drillstring the only subsea BOP measure will be the BSR. For these incidents both stabbing valves (if occurring during tripping) and a remotely operated safety valve in the topdrive are available as well. Experience, however, show that the shear ram from time to time is very useful.

For all the above situations a kick may occur, even though the probability of a kick is low compared to the situation when a drillstring is running through the BOP.

For these situations there is not much redundancy in the BOP stack and a detailed pressure and function testing of the BOP stack is important in addition to the body test. Some of the components are, however, more important than other.

- A regular pressure test of the BSR will always be important.
- If the stack has only one annular this will always be an important item to test.
- If the stack is equipped with three wide range variable rams the importance of the rams will be less than if the rig is equipped with three fixed rams
- The detailed testing of the choke and kill valves located above the LPR wrt. internal leakage is less important.

The ranking of the different BOP components with respect to the need for pressure testing is possible. Such a ranking will, however, need to be based on the specific BOP stacks in use and the tubulars that run through the BOP for each well to be drilled.

Further, field experience related to occurrence of well kicks would be important. If such kick experience existed it would be possible to quantify when the kicks are occurring and the type of tubulars are present inside the BOP.

Testing regulation related to VBRs
In the US GoM OCS regulations it is stated "*Variable rams shall be pressure tested against all sizes of pipe in use"*.

This regulation causes that rather complex test tools are used. Several times the drilling crew experienced problems with this test tool and thereby lost operational time. If a VBR leaks on test for one diameter it will most likely fail when utilizing another diameter as well. It has only been observed one failure where the VBR failed to seal on 3 ½" pipe, but was OK on 4 ½" pipe. For that particular failure it was decided to continue operation without repairing because there was redundancy in the stack. It should also be mentioned that for none of the other BOP studies carried out such testing practice was followed, and the probability of observing such a failure would be small.

From a safety point of view the testing of VBR on both diameters in a subsea BOP adds very little to increased safety availability in the BOP stack due to the redundancy in the BOP stack and that most failures will be revealed during the pressure test anyway.

One effect of such a regulation is that the operators may prefer only fixed rams instead of VBRs to save time during BOP testing. This will in general reduce the redundancy in the stack and thereby the safety availability.

It is therefore recommended to remove the regulation related to testing of VBRs on both diameters and instead to include a requirement that the test joint for testing the rams shall include diameters reflecting all the sizes of pipe in use.

Conclusion relating BOP testing practices.

The most important BOP test is the BOP body test that verifies that there are no external leakages in the lower part of the BOP stack.

For most kicks a BOP body test and function testing would keep the safety availability at the same level as the test practices used today.

For some kicks the level of redundancy in the stack will, however, be lower and utilizing body tests and function tests only will reduce the probability of a successful closure of the well.

By investigating experienced kick occurrences, the actual BOP stack configurations, and the tubulars utilized in a well, it will be possible to further analyze the BOP safety availability vs. test practices with the aim to reduce the BOP test time, but to keep the safety availability at the same level as today.

It is recommended to remove the regulation related to testing of VBRs on both diameters and instead to include a requirement that the test joint for testing the rams shall include diameters reflecting all the sizes of pipe in use.

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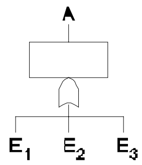
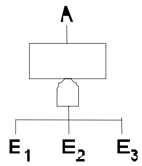
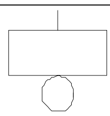
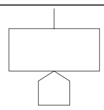
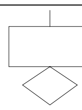
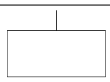
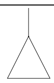
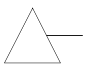
Appendix 1 FAULT TREE CONSTRUCTION

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

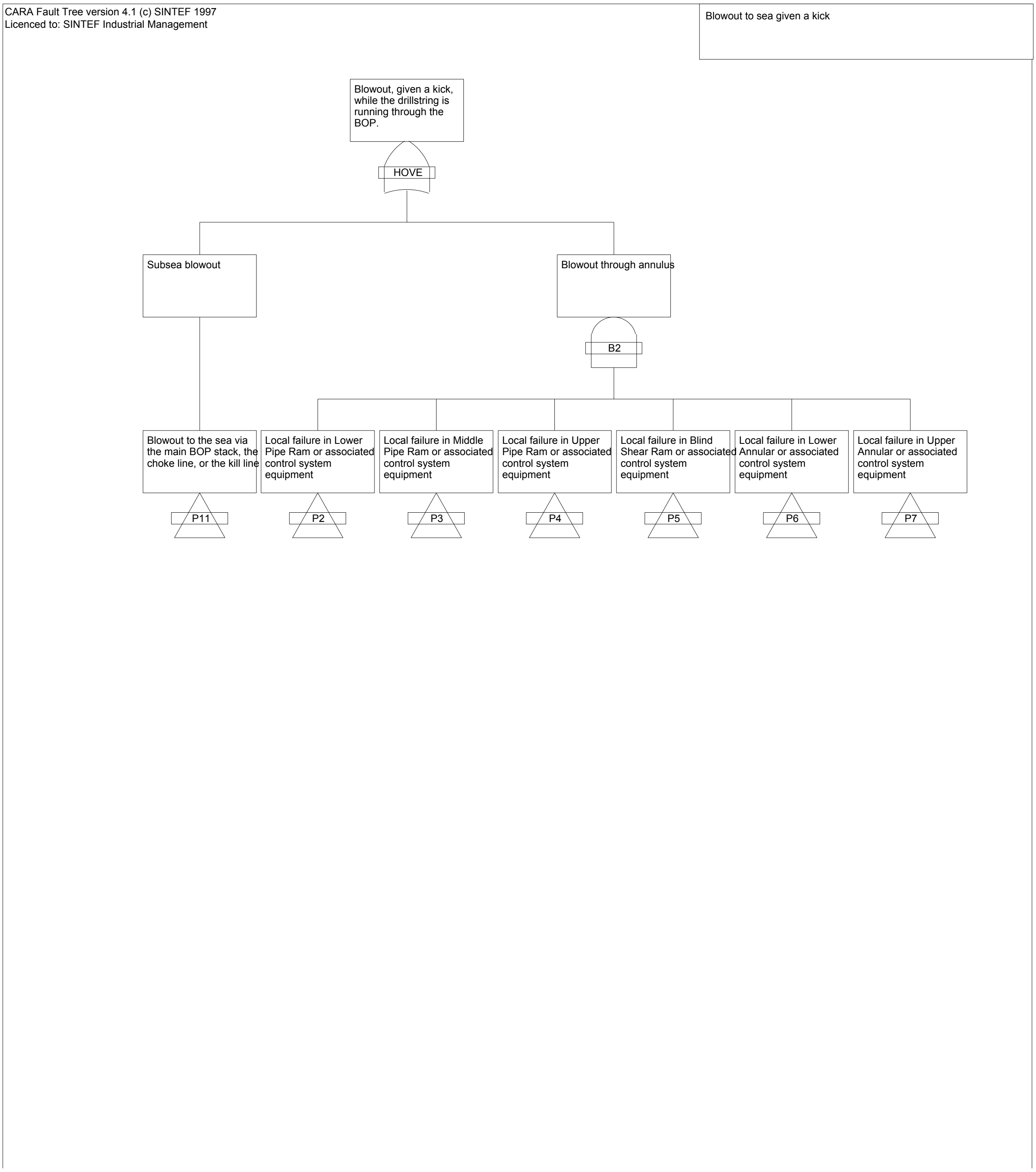
Symbol			Description
Logic Gates	"OR" gate		The OR-gate indicates that the output event A occurs if any of the input events E_i occurs.
	"AND" gate		The AND-gate indicates that the output event A occurs only when all the input events E_i occur simultaneously.
Input Events	"BASIC" event		The Basic event 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		The Transfer **out** symbol indicates that the fault tree is developed further at the occurrence of the corresponding Transfer **in** symbol.
	"TRANSFER" in		

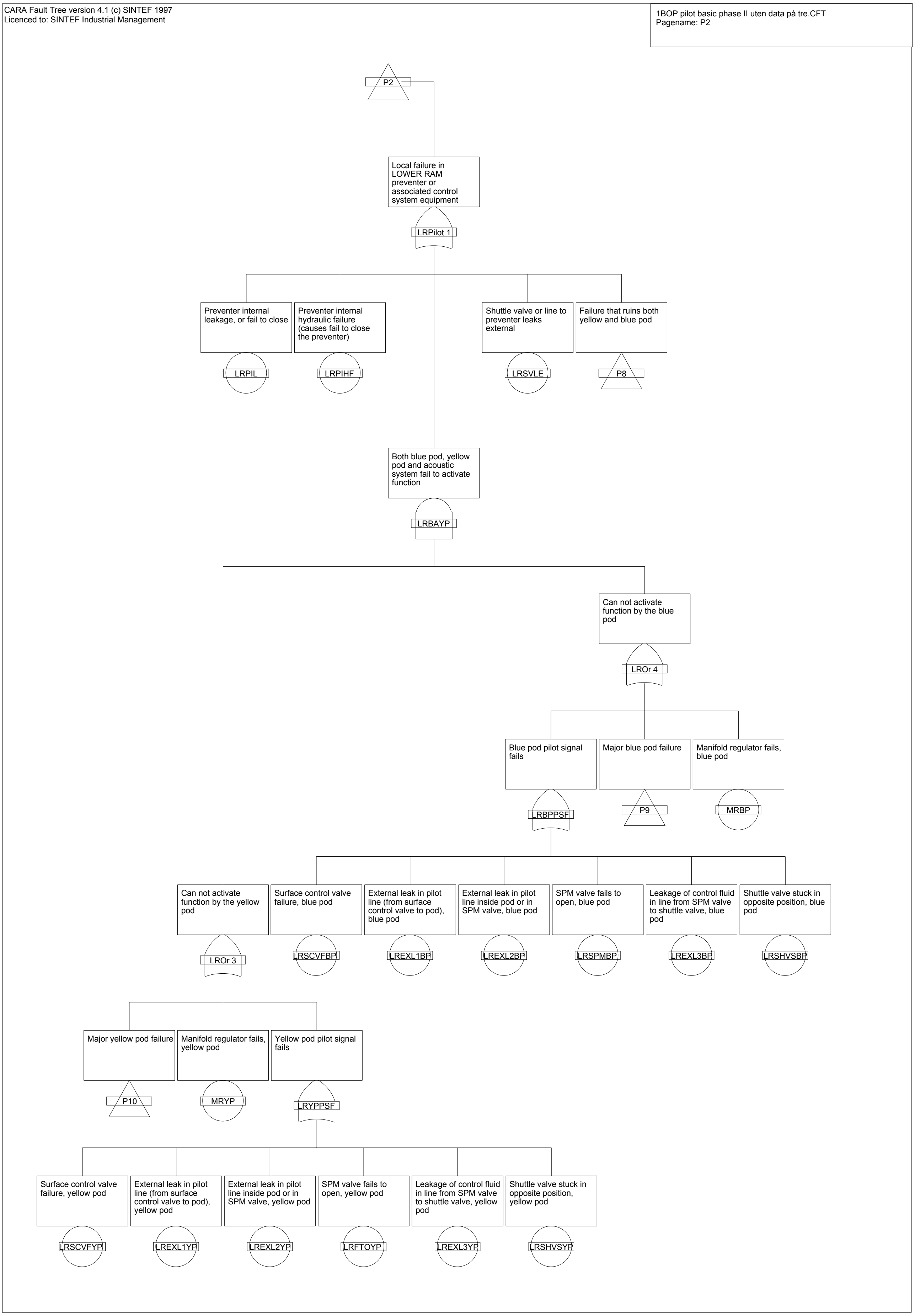
The logic events the basic events and the transfer symbol are the fault tree symbols mainly used in the Fault Trees constructed and analysed in this report. Fault Tree construction and analyses are described in many textbooks, among them /3/.

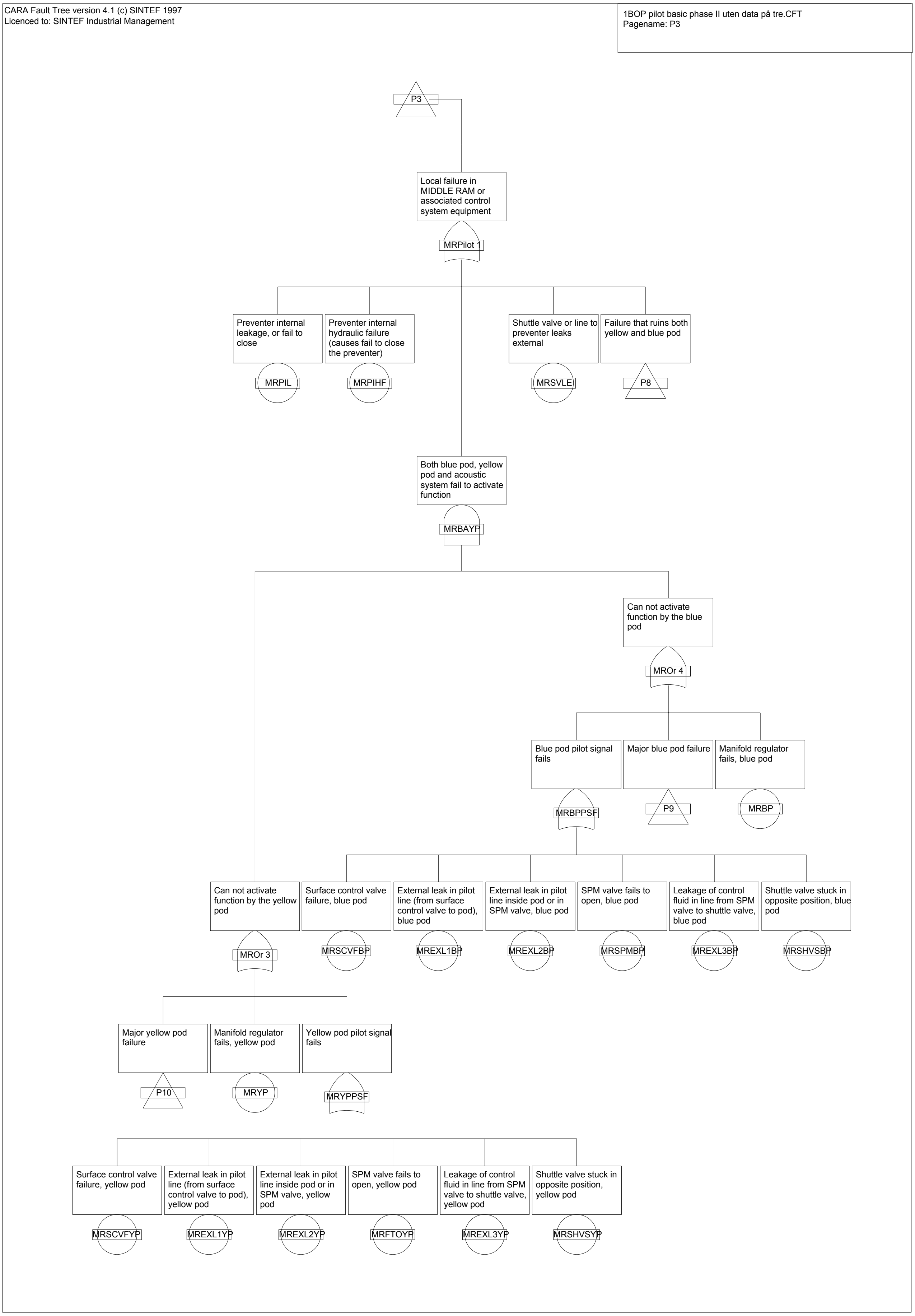
The SINTEF developed program CARA Fault Tree has been used for constructing and analyzing the fault trees (/20/).

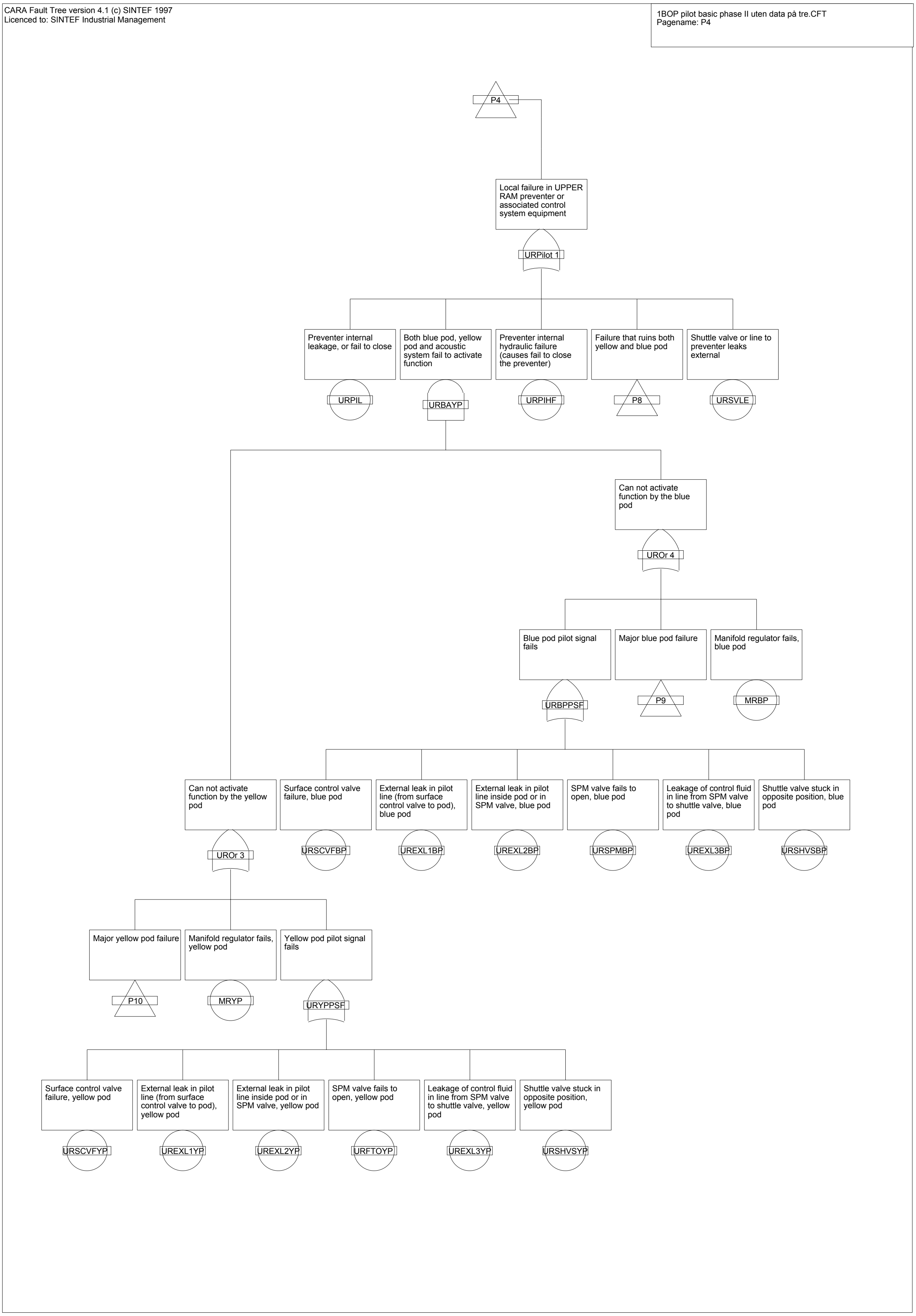
The fault tree utilized for the analyzes are presented on the following pages.

Fault tree utilized for the analyzes with input data




CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P2
P2
Local failure in LOWER RAM preventer or associated control system equipment
LRPilot 1
Preventer internal leakage, or fail to close
LRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
LRPIHF
Shuttle valve or line to preventer leaks external
LRSVLE
Failure that ruins both yellow and blue pod
P8
Both blue pod, yellow pod and acoustic system fail to activate function
LRBAYP
Can not activate function by the blue pod
LROr 4
Blue pod pilot signal fails
LRBPPSF
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Can not activate function by the yellow pod
LROr 3
Surface control valve failure, blue pod
LRSCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
LREXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
LREXL2BP
SPM valve fails to open, blue pod
LRSPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
LREXL3BP
Shuttle valve stuck in opposite position, blue pod
LRSHVSBP
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Yellow pod pilot signal fails
LRYPPSF
Surface control valve failure, yellow pod
LRSCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
LREXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
LREXL2YP
SPM valve fails to open, yellow pod
LRFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
LREXL3YP
Shuttle valve stuck in opposite position, yellow pod
LRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P3
P3
Local failure in MIDDLE RAM or associated control system equipment
MRPilot 1
Preventer internal leakage, or fail to close
MRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
MRPIHF
Shuttle valve or line to preventer leaks external
MRSVLE
Failure that ruins both yellow and blue pod
P8
Both blue pod, yellow pod and acoustic system fail to activate function
MRBAYP
Can not activate function by the blue pod
MROr 4
Blue pod pilot signal fails
MRBPPSF
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Can not activate function by the yellow pod
MROr 3
Surface control valve failure, blue pod
MRSCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
MREXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
MREXL2BP
SPM valve fails to open, blue pod
MRSPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
MREXL3BP
Shuttle valve stuck in opposite position, blue pod
MRSHVSBP
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Yellow pod pilot signal fails
MRYPPSF
Surface control valve failure, yellow pod
MRSCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
MREXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
MREXL2YP
SPM valve fails to open, yellow pod
MRFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
MREXL3YP
Shuttle valve stuck in opposite position, yellow pod
MRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic phase II uten data på tre.CFT
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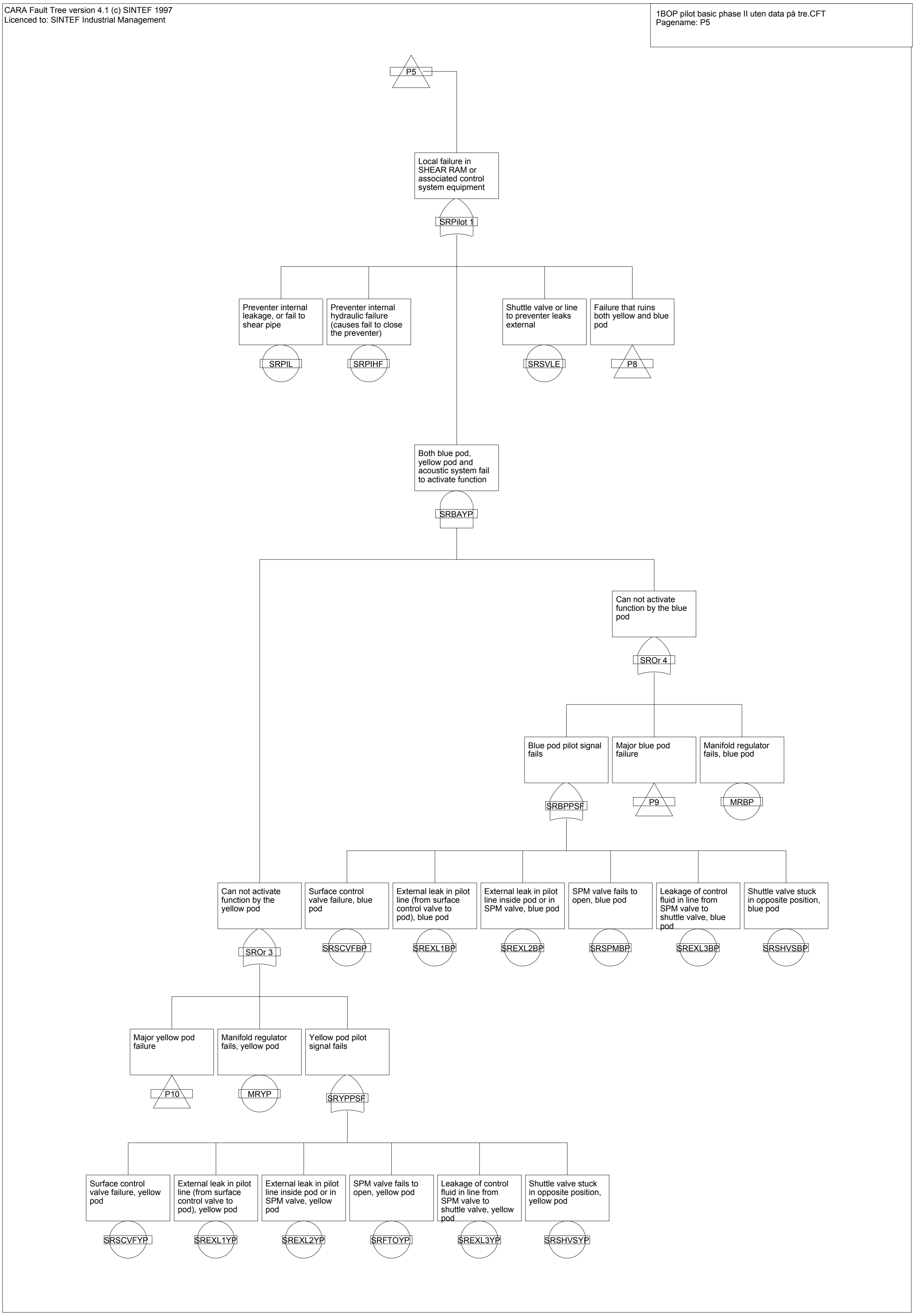
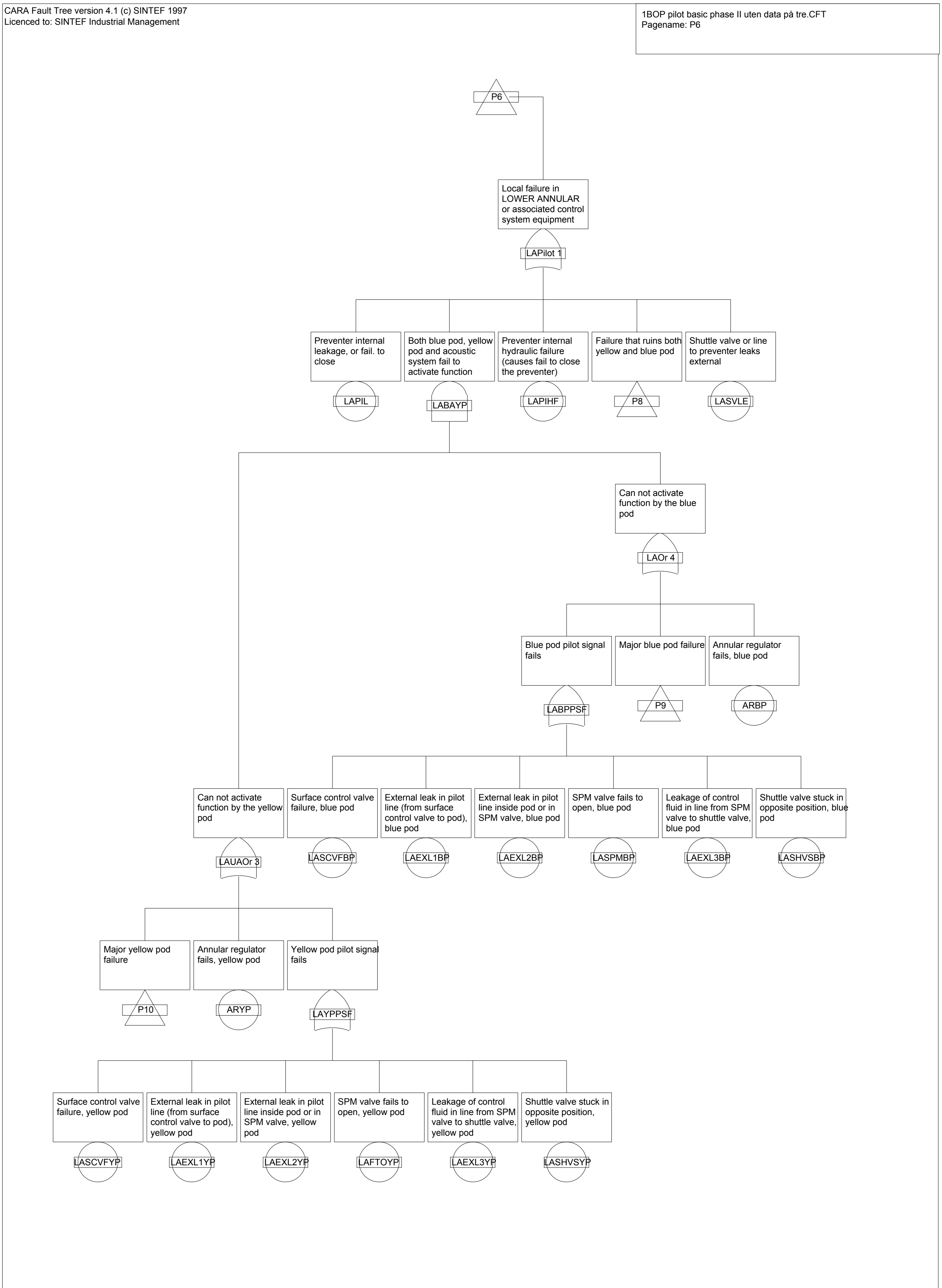
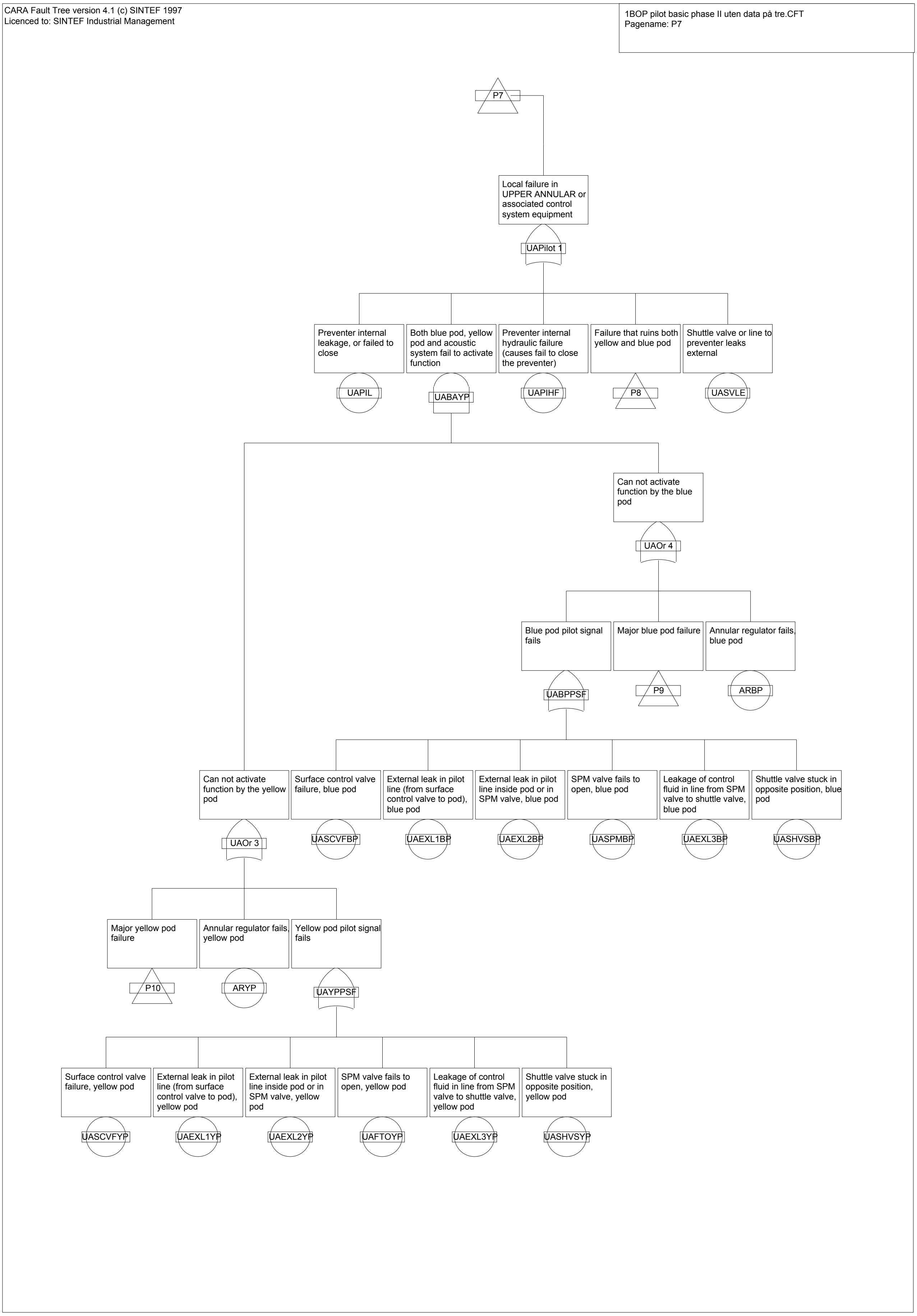
P4
Local failure in UPPER RAM preventer or associated control system equipment
URPilot 1
Preventer internal leakage, or fail to close
URPIL
Both blue pod, yellow pod and acoustic system fail to activate function
URBAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
URPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
URSVLE
Can not activate function by the blue pod
UROr 4
Blue pod pilot signal fails
URBPPSF
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Can not activate function by the yellow pod
UROr 3
Surface control valve failure, blue pod
URSCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
UREXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
UREXL2BP
SPM valve fails to open, blue pod
URSPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
UREXL3BP
Shuttle valve stuck in opposite position, blue pod
URSHVSBP
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Yellow pod pilot signal fails
URYPPSF
Surface control valve failure, yellow pod
URSCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
UREXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
UREXL2YP
SPM valve fails to open, yellow pod
URFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
UREXL3YP
Shuttle valve stuck in opposite position, yellow pod
URSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P5
P5
Local failure in SHEAR RAM or associated control system equipment
SRPilot 1
Preventer internal leakage, or fail to shear pipe
SRPIL
Preventer internal hydraulic failure (causes fail to close the preventer)
SRPIHF
Shuttle valve or line to preventer leaks external
SRSVLE
Failure that ruins both yellow and blue pod
P8
Both blue pod, yellow pod and acoustic system fail to activate function
SRBAYP
Can not activate function by the blue pod
SROr 4
Blue pod pilot signal fails
SRBPPSF
Major blue pod failure
P9
Manifold regulator fails, blue pod
MRBP
Can not activate function by the yellow pod
SROr 3
Surface control valve failure, blue pod
SRSCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
SREXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
SREXL2BP
SPM valve fails to open, blue pod
SRSPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
SREXL3BP
Shuttle valve stuck in opposite position, blue pod
SRSHVSBP
Major yellow pod failure
P10
Manifold regulator fails, yellow pod
MRYP
Yellow pod pilot signal fails
SRYPPSF
Surface control valve failure, yellow pod
SRSCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
SREXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
SREXL2YP
SPM valve fails to open, yellow pod
SRFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
SREXL3YP
Shuttle valve stuck in opposite position, yellow pod
SRSHVSYP


CARA Fault Tree version 4.1 (c) SINTEF 1997
Licenced to: SINTEF Industrial Management
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P6
P6
Local failure in LOWER ANNULAR or associated control system equipment
LAPilot 1
Preventer internal leakage, or fail. to close
LAPIL
Both blue pod, yellow pod and acoustic system fail to activate function
LABAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
LAPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
LASVLE
Can not activate function by the blue pod
LAOr 4
Blue pod pilot signal fails
LABPPSF
Major blue pod failure
P9
Annular regulator fails, blue pod
ARBP
Can not activate function by the yellow pod
LAUAOr 3
Surface control valve failure, blue pod
LASCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
LAEXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
LAEXL2BP
SPM valve fails to open, blue pod
LASPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
LAEXL3BP
Shuttle valve stuck in opposite position, blue pod
LASHVSBP
Major yellow pod failure
P10
Annular regulator fails, yellow pod
ARYP
Yellow pod pilot signal fails
LAYPPSF
Surface control valve failure, yellow pod
LASCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
LAEXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
LAEXL2YP
SPM valve fails to open, yellow pod
LAFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
LAEXL3YP
Shuttle valve stuck in opposite position, yellow pod
LASHVSYP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1BOP pilot basic phase II uten data på tre.CFT
Pagename: P7
P7
Local failure in UPPER ANNULAR or associated control system equipment
UAPilot 1
Preventer internal leakage, or failed to close
UAPIL
Both blue pod, yellow pod and acoustic system fail to activate function
UABAYP
Preventer internal hydraulic failure (causes fail to close the preventer)
UAPIHF
Failure that ruins both yellow and blue pod
P8
Shuttle valve or line to preventer leaks external
UASVLE
Can not activate function by the blue pod
UAOr 4
Blue pod pilot signal fails
UABPPSF
Major blue pod failure
P9
Annular regulator fails, blue pod
ARBP
Can not activate function by the yellow pod
UAOr 3
Surface control valve failure, blue pod
UASCVFBP
External leak in pilot line (from surface control valve to pod), blue pod
UAEXL1BP
External leak in pilot line inside pod or in SPM valve, blue pod
UAEXL2BP
SPM valve fails to open, blue pod
UASPMBP
Leakage of control fluid in line from SPM valve to shuttle valve, blue pod
UAEXL3BP
Shuttle valve stuck in opposite position, blue pod
UASHVSBP
Major yellow pod failure
P10
Annular regulator fails, yellow pod
ARYP
Yellow pod pilot signal fails
UAYPPSF
Surface control valve failure, yellow pod
UASCVFYP
External leak in pilot line (from surface control valve to pod), yellow pod
UAEXL1YP
External leak in pilot line inside pod or in SPM valve, yellow pod
UAEXL2YP
SPM valve fails to open, yellow pod
UAFTOYP
Leakage of control fluid in line from SPM valve to shuttle valve, yellow pod
UAEXL3YP
Shuttle valve stuck in opposite position, yellow pod
UASHVSYP

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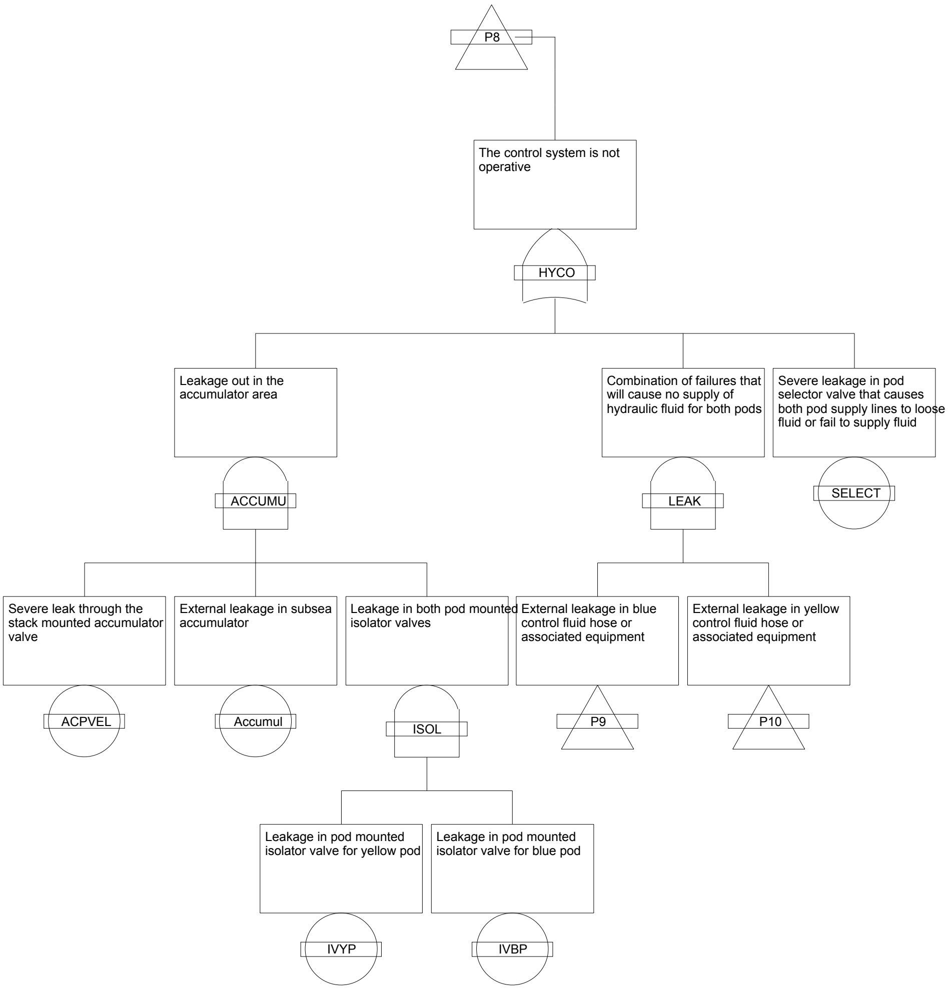
Pagename: P8



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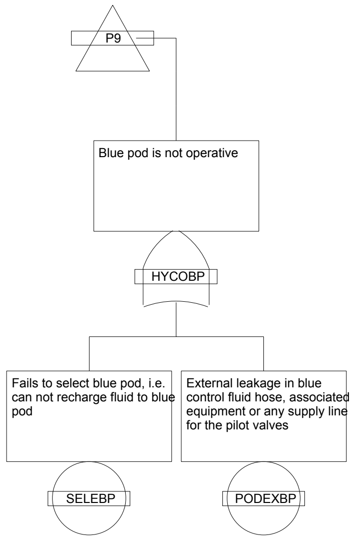
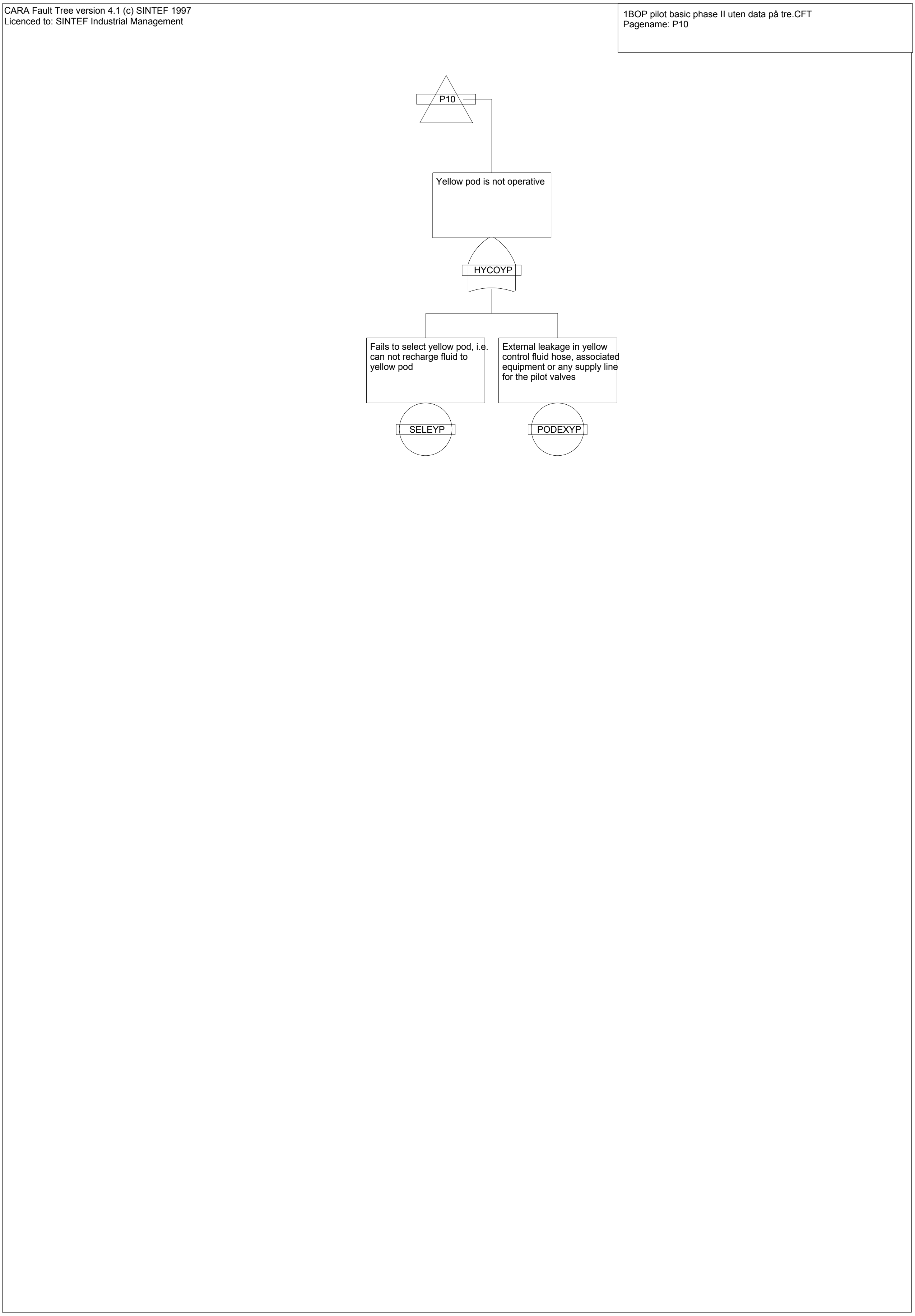
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P9

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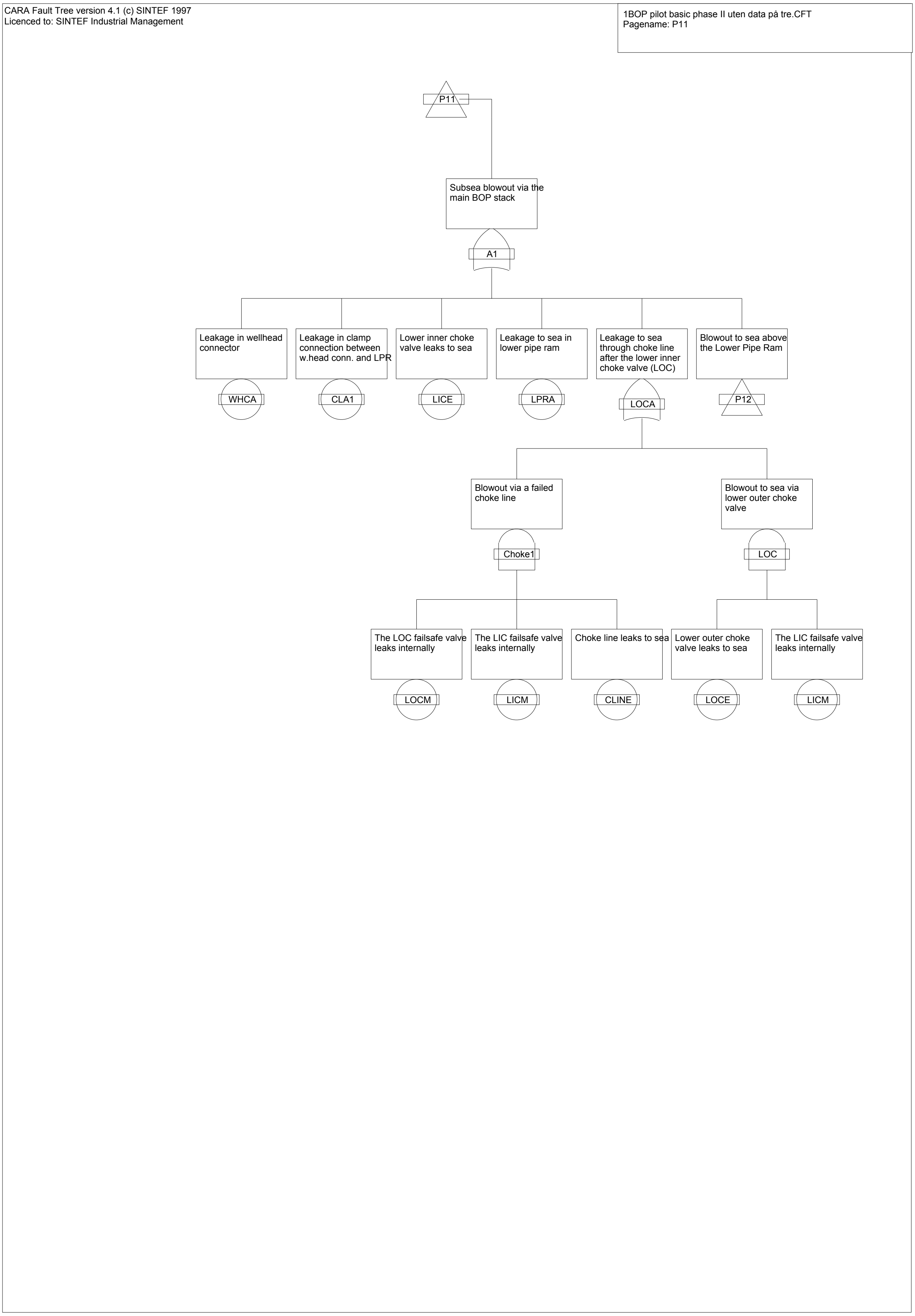
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P10
P10
Yellow pod is not operative
HYCOYP
Fails to select yellow pod, i.e. can not recharge fluid to yellow pod
External leakage in yellow control fluid hose, associated equipment or any supply line for the pilot valves
SELEYP
PODEXYP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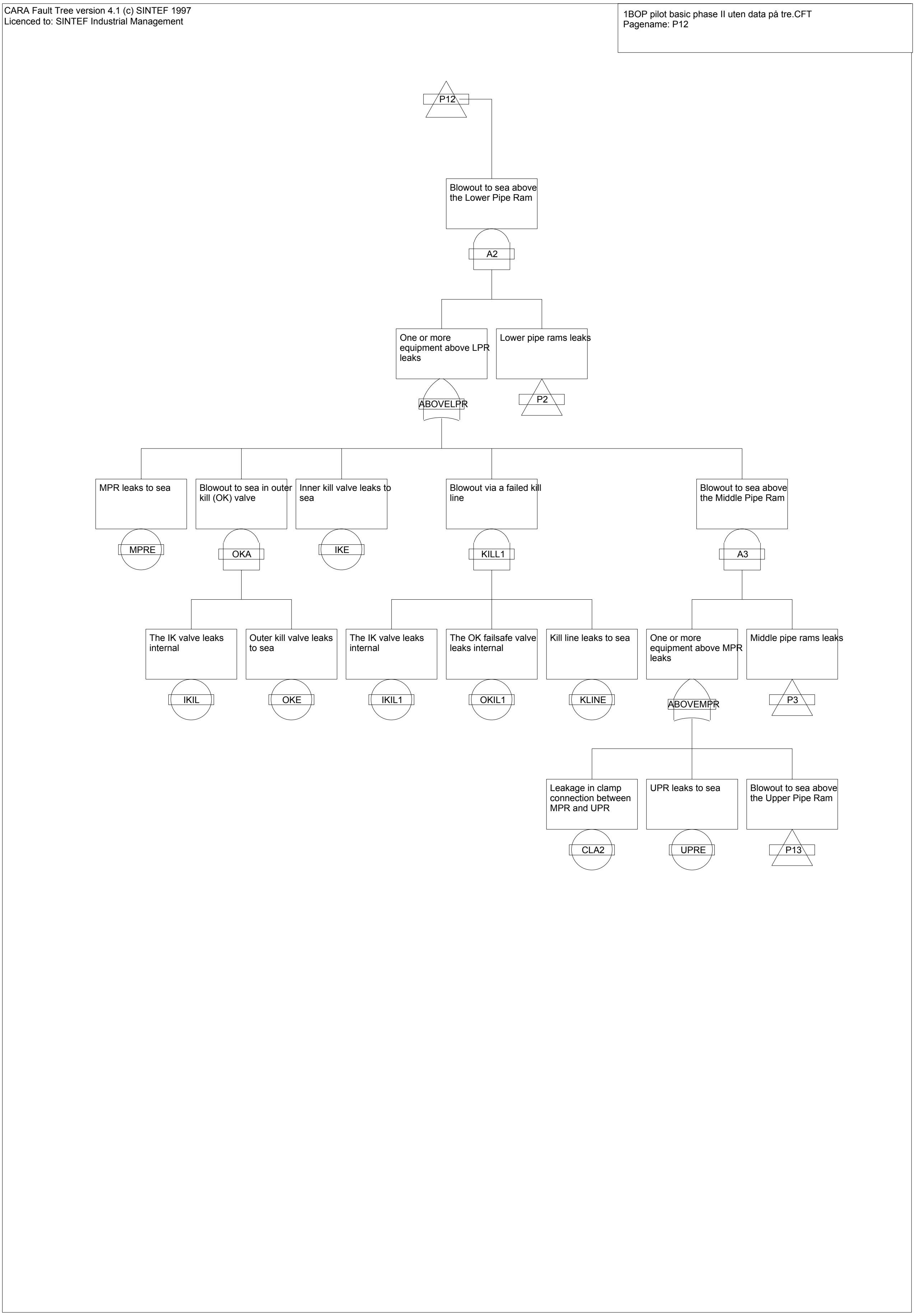
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P11
P11
Subsea blowout via the main BOP stack
A1
Leakage in wellhead connector
WHCA
Leakage in clamp connection between w.head conn. and LPR
CLA1
Lower inner choke valve leaks to sea
LICE
Leakage to sea in lower pipe ram
LPRA
Leakage to sea through choke line after the lower inner choke valve (LOC)
LOCA
Blowout to sea above the Lower Pipe Ram
P12
Blowout via a failed choke line
Choke1
Blowout to sea via lower outer choke valve
LOC
The LOC failsafe valve leaks internally
LOCM
The LIC failsafe valve leaks internally
LICM
Choke line leaks to sea
CLINE
Lower outer choke valve leaks to sea
LOCE
The LIC failsafe valve leaks internally
LICM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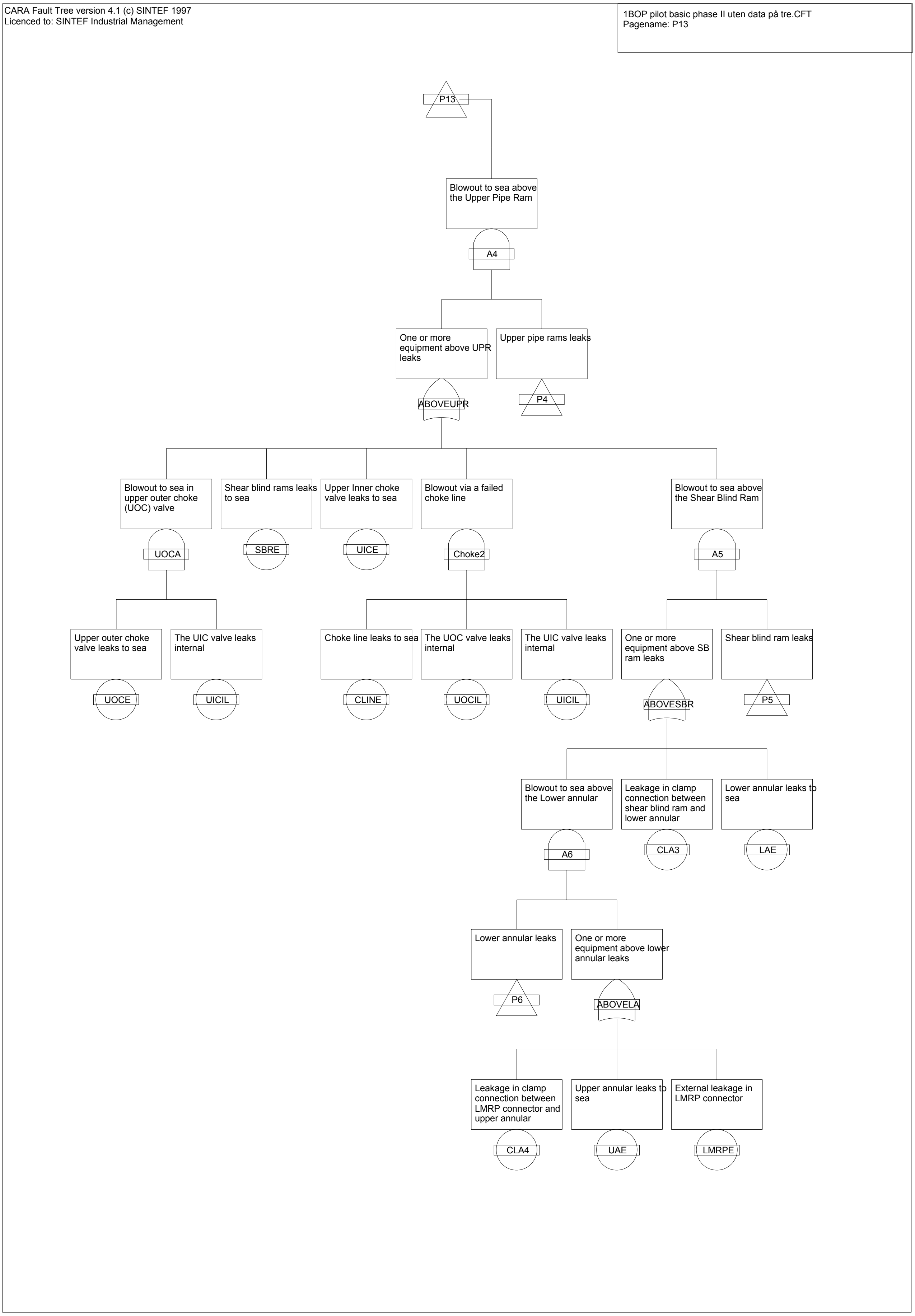
1BOP pilot basic phase II uten data på tre.CFT
Pagename: P12
P12
Blowout to sea above the Lower Pipe Ram
A2
One or more equipment above LPR leaks
ABOVELPR
Lower pipe rams leaks
P2
MPR leaks to sea
MPRE
Blowout to sea in outer kill (OK) valve
OKA
Inner kill valve leaks to sea
IKE
Blowout via a failed kill line
KILL1
Blowout to sea above the Middle Pipe Ram
A3
The IK valve leaks internal
IKIL
Outer kill valve leaks to sea
OKE
The IK valve leaks internal
IKIL1
The OK failsafe valve leaks internal
OKIL1
Kill line leaks to sea
KLINE
One or more equipment above MPR leaks
ABOVEMPR
Middle pipe rams leaks
P3
Leakage in clamp connection between MPR and UPR
CLA2
UPR leaks to sea
UPRE
Blowout to sea above the Upper Pipe Ram
P13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1BOP pilot basic phase II uten data på tre.CFT
Pagename: P13
P13
Blowout to sea above the Upper Pipe Ram
A4
One or more equipment above UPR leaks
Upper pipe rams leaks
ABOVEUPR
P4
Blowout to sea in upper outer choke (UOC) valve
Shear blind rams leaks to sea
Upper Inner choke valve leaks to sea
Blowout via a failed choke line
Blowout to sea above the Shear Blind Ram
UOCA
SBRE
UICE
Choke2
A5
Upper outer choke valve leaks to sea
The UIC valve leaks internal
Choke line leaks to sea
The UOC valve leaks internal
The UIC valve leaks internal
One or more equipment above SB ram leaks
Shear blind ram leaks
UOCE
UICIL
CLINE
UOCIL
UICIL
ABOVESBR
P5
Blowout to sea above the Lower annular
Leakage in clamp connection between shear blind ram and lower annular
Lower annular leaks to sea
A6
CLA3
LAE
Lower annular leaks
One or more equipment above lower annular leaks
P6
ABOVELA
Leakage in clamp connection between LMRP connector and upper annular
Upper annular leaks to sea
External leakage in LMRP connector
CLA4
UAE
LMRPE