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EXECUTIVE SUMMARY

The Bureau of Safety Environment & Enforcement (BSEE) has contracted MCS Kenny to execute a Technology Assessment and Research Project (TA&R) in the areas of Blowout Preventer (BOP) stack sequencing, monitoring and kick detection. The project has been developed to assess three key areas of a BOP, including:

Topic 1 - Ram Sequencing and Shearing Performance

Topic 2 - BOP Monitoring and Acoustic Technology

Topic 3 - Kick Detection and Associated Technologies

This report addresses Topic 2 and covers the following areas:

- State-of-the-art industry practices for monitoring of subsea BOPs.
- BOP and BOP control system issues/failures and an investigation of the underlying root cause to assess what sort of condition monitoring is required/available.
- Detailed description of existing acoustic technologies for subsea well control.

A comprehensive review of available literature on BOP reliability has been performed, including key reports from Sintef, DNV, West Engineering and more. Comparing the results from these reliability studies the trend shows that the Mean Time to Failure (MTTF) on BOP components is getting significantly longer while the time to fix the failed component is also getting longer. This is an indication of increasing reliability of BOP components but may also be an indication of the increasing complexity of BOP equipment, which takes more time to fix. Over the years 1992 through 2009 covered in multiple reports the average downtime per failure increased from 25.05 hrs to 86.21 hrs.

Control system failures are the most likely category of failure on BOP equipment. In all studies reviewed, the control system failures accounted for more than 45% of all failures. This is followed by annular preventer and ram preventer failure.

As the control system is the lifeline of the BOP and the conduit for diagnostics and monitoring of the BOP's health, the control system is the primary focus of this study.

Based on a review of available BOP control system reliability data it is observed that the MTTF has improved significantly in recent years. This is due in part to technology maturity. There is no significant difference between the MTTF for MUX and conventional control systems however there is a significant increase in the downtime to repair MUX systems.

MUX systems are relatively new and so the reliability data available on this type of system is not extensive. MUX systems have more subsea components and are more complex than conventional systems. A MUX system consists of electrical and electronic components in the water so any leaks could cause significant damage. In a conventional system the hydraulic side leakages could cause leak of fluid into the sea whereas any leaks in MUX electrical systems can result in complete failure [50].

The majority of control system failures were due to malfunctioning of the different components on the control pods on the LMRP. Some of the failures were due to leakages in the control pods, Subsea Plate Mounted (SPM) valves, solenoids, malfunctions of the choke line fail safe valves on the stack connector regulator. In some instances *Loss of all functions on both pods* was observed but these instances are in the minority compared to *Loss of partial/complete function of one pod*.

A significant number of the BOP failures occurred during BOP operation subsea. To improve the reliability of the BOPs when subsea, more rigorous BOP maintenance and testing requirements, as per API 53, shall be implemented [35]. In addition, numerous diagnostic software products are available in the market to eliminate some of the inaccuracy and human error associated with traditional chart recorder techniques.

SureTec is a data acquisition software specifically used for testing the BOP on the stump and subsea. The software allows for remote BOP pressure testing which provides an independent means of witnessing a BOP pressure test on the rig from onshore. Approximately 25 rigs are presently using SureTec [54].

Archers Greenlight is a pressure test verification system utilized in pressure testing of wells, well systems and well components. The system approves or rejects pressure tests against predetermined test criteria, removing the subjective element, and generates a detailed pressure test chart. Some of the clients using this system are Shell, Seadrill, North Atlantic Drilling and Halliburton [43].

In addition to these enhanced diagnostic tools there are many technologies being developed to continuously monitor BOP operations from onshore. Multiple companies including BP and Talisman Energy have created Real Time Monitoring Centers (RTOC) to enable 24/7 monitoring of well parameters to enhance the safety of deepwater operations.

Real time monitoring systems like Ashford Technology's Rigwatcher, NOV's BOP dashboard system and GE's drilling iBox system collect raw BOP data from pressure switches, solenoids, pressure transducers and flow meters to allow cycle based maintenance of the control systems sub components.

This practice of Condition Monitoring (CM)/ Condition Based Maintenance (CBM) is a known practice proven in the aerospace and nuclear industries and can help to eliminate the root cause of failures and anticipate the needs of the equipment. Repairs can be planned before they turn into major failures which could lead to catastrophic results. Removing or eliminating unnecessary repairs/replacements from the work schedule also allows for more efficient and cost effective maintenance. In one example provided by a deepwater operator a faulty SPM valve resulted in an inability to test the shear/blind ram which required the BOP to be pulled out of water which took 14 days round trip and cost $10.1 million. The total BOP downtime loss for this drilling contractor was $80 million in 2011 and $60 million in 2012 [52]. If the drilling contractor had known the cycles the SPM valve had undergone, the part could have been replaced before it failed.

Moving to a condition based maintenance and monitoring program will require more collaboration between the Original Equipment Manufacturers (OEM), drilling contractors and the operators. Drilling contractors and OEMs should work together to review inspection protocols and develop long term integrity management plans. Rig watcher is presently installed on one Diamond Offshore rig and has operated in the Gulf of Mexico (GOM). It is planned to implement Rig watcher on three additional Diamond Offshore rigs this year. BP has been piloting the BOP dashboard system on the Ensco DS-4 drillship in Brazil with NOV and Ensco [57]. As the industry invests in more offshore rigs, there is a dearth of experienced crew. So the real time monitoring of the BOP subsea from onshore will help overseeing the drilling and safety of the offshore operations. The Subject Matter Expert (SME) can be located onshore monitoring multiple rigs at one time and providing the expertise which could be lacking on the rigs.

In addition to advances in monitoring technology, there have been some advancements in the control systems themselves. Acoustic control systems are generally considered as optional secondary systems for BOP control. However they have found primary use on some applications, particularly Subsea Isolation Devices (SID). In 2009, Murphy Oil installed an acoustic controlled SID system on the Azurite FDPSO. The system performed reliably during these operations and the decision to omit the umbilical as primary control conduit and use only acoustical control was made [27]. A similar decision was made on the Environmental Safe Guard (ESG) deployment offshore Brazil for Shell for the well drilled in 2003. Once the reliability of the acoustic control system was proven the MUX cable backup was no longer specified [32]. Much of the available reliability data surrounding acoustic control systems is on older analog systems. A review of analog acoustic data between 1977 and 1998 shows no trend in Mean Time to Failure (MTTF) of analog acoustic control systems. The primary sources of failure were mechanical, electric/electronic and signal transmission failures. From 602 acoustic tests, 4 failures were due to signal transmission (0.66%) or a signal transmission success of 99.34% [61]. Comparing this to data made available on digital acoustic systems the Nautronix Nasbop system had an average signal transmission success of 99.3% (98.3-100%) based on short duration deployments. This is consistent with the digital acoustic performance on the Shell ESG deployment where it was recommended to assume that 1 out of 100 attempts to transmit signals fails, i.e. 1% [32]. As stated earlier there is no obvious trend in analog acoustic system MTTF. The MTTF data ranged from 16,000 to 65,000 hrs. Indications from digital acoustic system supplier Sonardyne is that Mean Time Between Failures (MTBF) ranges from 164,000 to 39.4 x 10^9 hrs depending on how the system is configured and how much redundancy is built in [21]. Indications are that acoustic systems are in general becoming more reliable but more time in the water is still required. In addition acoustic systems have not been used to function the BOP during a well control event.

Acoustic systems are also being considered for capping stacks, vessel of opportunity and to replace the MUX system. If the rig has an emergency situation and the portable acoustic control unit on the rig cannot be accessed then the acoustic system from the neighbouring rig could be programmed to function the BOP acoustic control system. The capping stack system will use an acoustic BOP control system to monitor pressure and temperature in real-time inside the well. The capping stack used on the Macondo well had transponders attached to it to monitor pressure and temperature. The signals were interrogated by transceivers attached to the ROVs. Live data was provided by the acoustic system for many days during this incident.

Since 2008 Cameron and Nautronix have been developing the NASMUX acoustic system as the primary communication link to the subsea BOP which would remove the umbilical system. DNV has granted “Feasibility of Technology” in accordance with DNV-RP-A203. In 2014, a NASMUX production unit will be launched [12].

Modularization of control systems offers advantages in subsea replacement of failed components leading to reduced MTBF and reduced downtime cost. DTC's Modular Subsea Control System (MODSYS) permits an ROV equipped with a tooling kit to descend with a replacement control system module. This can significantly reduce the BOP control system downtime from up to 7 days to around 4 to 8 hours depending on the water depth. The MODSYS is lighter weight compared to traditional control system which results in ease of control systems retrieval to the surface by an ROV.

As drilling continues in deep and ultra-deep water, the time and expense to fix the control system failures will increase substantially. The industry has to innovate and embrace new technologies which are simpler, lighter, modular and highly reliable which can replace the traditional control system.

1.0 INTRODUCTION

1.1 General

This report is written in response to Objective 2 of the Bureau of Safety and Environmental Enforcement (BSEE) Broad Agency Announcement Number E12PS00004 regarding Assessment of Subsea BOP Well Control Technology.

The project has been developed to assess three key areas of a Blowout Preventer (BOP), including:

- Topic 1 - Ram Sequencing and Shear Performance
- Topic 2 - BOP Monitoring and Acoustic Technology
- Topic 3 - Kick Detection and Associated Technologies

1.2 Objective of this Report

This report addresses Topic 2 and covers the following areas:

- State-of-the-art industry practices for monitoring of subsea BOPs.
- BOP and BOP control system issues/failures and an investigation of the underlying root cause to assess what sort of condition monitoring or required/available.
- Detailed description of existing acoustic technologies for subsea well control.

1.3 Abbreviations

ACU	Accumulator Control Unit
API	American Petroleum Institute
BAST	Best Available and Safest Technology
BSEE	Bureau of Safety and Environmental Enforcement
BOP	Blowout Preventer
BSR	Blind Shear Ram
CCU	Central Control Unit
CFR	Code of Federal Regulations
CHIRP	Compressed High Intensity Radar Pulse
DAQ	Data Acquisition
DART	Deep-Rated Acoustic Remote Transceiver
DTC	Deepwater Technology Company

DP	Dynamic Positioning
DPO	Dynamic Positioning Operator
DGPS	Differential Global Positioning System
DNV	Det Norske Veritas
DW	Deepwater
EDS	Emergency Disconnect Sequence
ESG	Environmental Safe Guard
EWS	Engineering Work Station
Ft	Feet
FDPSO	Floating Drilling Production Storage and Offloading
FMA	Failure Mode Assessment
FMECA	Failure Mode Effect and Criticality Analysis
GE	General Electric
GOMR	Gulf of Mexico Regional
GOM	Gulf of Mexico
GPS	Global Positioning System
HPHT	High Temperature High Pressure
HSE	Health Safety Environmental
HVP	Hydraulic Valve Package
IADC	International Association of Drilling Contractors
JIP	Joint Industry Project
Lbs	Pounds
IFR	Interim Final Rule
kHz	Kilo Hertz
Ksi	Kilo pound per square inch
LMRP	Lower Marine Riser Package
M	Meter
MAWHP	Maximum Anticipated Well Head Pressure
MFDT	Mean Fractional Dead time
MODSYS	Modular Subsea Control System
MOC	Management of Change
MTTF	Mean Time to Failure

MTBF	Mean Time Between Failure
MTBK	Mean Time Between Kicks
MMS	Mineral Management Service
MUX	Multiplex Control System
NOV	National Oilwell Varco
OCS	Outer Continental Shelf
OEM	Original Equipment Manufacturer
OTC	Offshore Technology Conference
PM	Preventative Maintenance
PQS	Product Qualification Sheet
ROV	Remote operated vehicle
SBOP	Surface Blow out Preventer
SCU	Subsea Control Unit
SDS	Surface Disconnect System
SSOD	Subsea Shut-Off Device
SEM	Subsea Electronic Module
SID	Subsea Isolation Device
SONAR	Sound Navigation And Ranging
SPE	Society of Petroleum Engineers
SPM	Subsea Plate Mounted
TA&R	Technology Assessment and Research
TCLD	Thermally Compensated Leak Detection
TRL	Technology Readiness Level
VPN	Virtual Private Network

2.0 BOP CONTROL SYSTEMS

2.1 INTRODUCTION

The BOP control system is considered the heart of a BOP stack which drives the annulars and rams to open and close with or without using primary rig power. So this report discusses the control system in detail.

The two most common control systems are the Conventional control system and the Multiplex (MUX) control system. The major difference between these systems is how the signal is transmitted from the surface to control the subsea BOP stack.

Conventional hydraulic control systems operation is limited to 5,000 ft. The time taken for the hydraulic signals from the rig to reach the control pods after 5,000 ft water depth is very long. Therefore, hydraulic systems are not recommended for deep water (water depth above 1,000 ft) as it will require more hydraulic fluid, higher working pressures and pressure drop will increase (due to hose friction) and longer activation time will be required to close the BOPs. So MUX control systems are used in water depth above 5,000 ft.

The BOP is complex equipment and had lot of reliability issues. The BOP reliability is significantly affected by the number of cycles the various valves actuate in the BOP Control system [40]. BOP monitoring is done to measure and interpret the data to determine the condition and proper functioning of the BOP. Some of the current procedures used to monitor the BOP are discussed below.

There are two fully redundant control stations on the rig to monitor and function the BOP. One of the control stations is in the drillers shack, the other is placed in the tool pushers office or on the bridge. The information displayed on the control stations can quickly guide personnel to the problem which is being encountered.

The Engineering Work Station (EWS) also called the event logger is the only place where the BOP control system data on a MUX system can be accessed. The event logger is designed to be used by personnel (such as subsea engineer) proficient in BOP control systems for performing maintenance and troubleshooting system problems. The event logger records all the BOP functions that were operated from the control panel. The event logger data is not sent onshore.

The MUX BOP system can be connected to a VPN through the internet. This helps the onshore technician to access the control system from a remote place to help the offshore crew to trouble shoot. The updates on the software can also be performed through this network. The diagnostic files can be also downloaded at the remote location for office analysis.

Some of the regular methods by which the BOP is monitored periodically are as follows:

- The blind shear ram is pressure tested during stump tests on the rig surface and at all casing points subsea (the point where the section of casing is cemented in the well).
- The well control components on the BOP stack are function tested once a week from one BOP control station and one pod to make sure they are functioning properly.
- Function test done on ram BOP every seven days between pressure tests.
- The BOP is tested once every 14 days or when the integrity of the BOP stack has been compromised due to changing rams, seals, or lifting the stack.
- A Remotely Operated Vehicle (ROV) is used to do inspection and monitoring on and around the BOP.

2.2 Conventional Control System

The components on the BOP stack in a conventional control system operate hydraulically and require three components to work effectively [2]:

- Control fluid which is pressurized and regulated to operate components on the LMRP and BOP
- Pilot signal which is pressurized to activate a subsea pod control valve
- A process to "vent" depressurized fluid. Venting is necessary from one side of the component to allow the other side to function. If the equipment is not vented properly, there will be a "hydraulic lock" in the equipment.

The control system provides:

- Hydraulic control fluid to the BOP stack.
- A means of guiding the control fluid via a pilot signal to the control pod.
- Connection through a hose from the hydraulic power unit (HPU) on the rig surface to send a hydraulic signal to open and close the control pod.

Some of the primary components of the conventional control system (Figure 2.1) are:

- Accumulators to store pressurized hydraulic fluid to help in closing the BOP.
- Reserve tank to store mixture of hydraulic mixed fluid and fluid concentrate which are supplied to the components on the BOP stack.

- Hydraulic Power Unit (HPU) used to pressurize the hydraulic fluid and with the help of solenoids, control valves and regulators direct the fluid to perform the different functions.
- Control pods (Figure 2.1) house the multiple regulators and valves and receive fluid from the HPU to help perform the different functions on the BOP.
- Hoses are connected from the HPU to the control pods.
- Hose reels are used for spooling the hose when running the BOP.
- Remote panels are used to control the BOP from multiple locations other than the HPU.

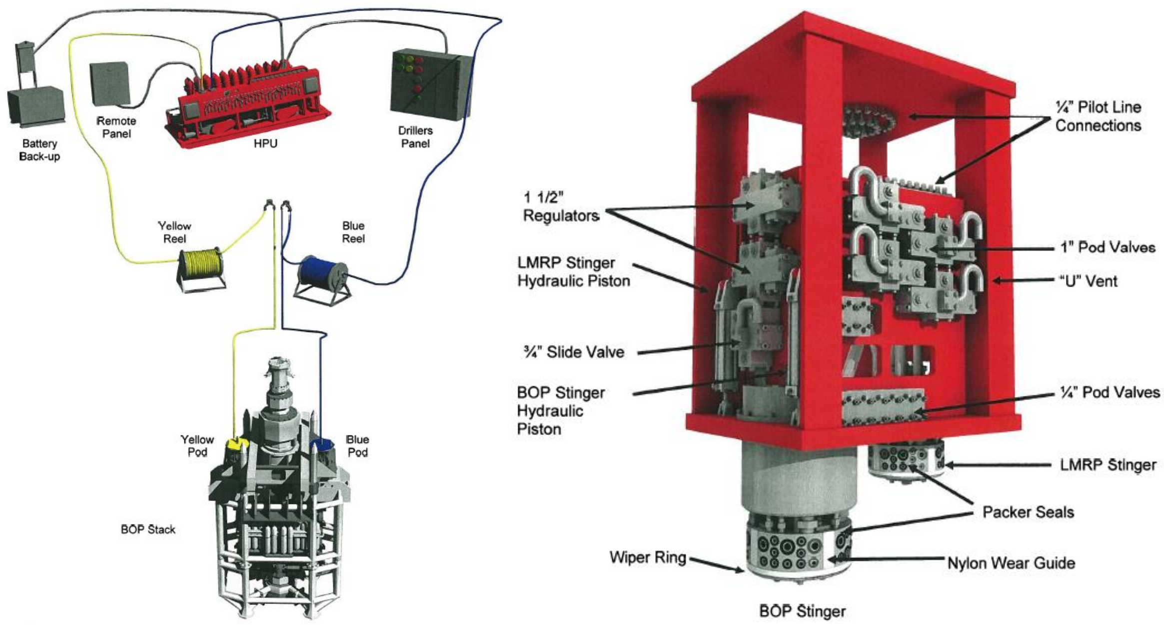

Figure 2.1: Conventional BOP Control System and Cameron Mark I Conventional Pod [2]

2.3 MULTIPLEX CONTROL SYSTEM

MUX control systems (Figure 2.2) work similar to a conventional system except that the electrical command signals are sent from the rig surface to MUX control pods on the LMRP. The electrical signal operates the solenoid which in turn activates the pilot signals on the MUX control pods. This results in very instantaneous response at depths of 10,000’ or more.

A MUX system has an event logger which is used to perform maintenance and troubleshooting in the system to help with operational decision making. The conventional hydraulic system does not have an event logger.

Some of the primary components on the MUX Control systems (Figure 2.2) are:

- Accumulators to store pressurized hydraulic fluid to help in closing the BOP rams.

- Fluid tanks to store a mixture of mixed fluid and fluid concentrate which are supplied to the components on the BOP stack.
- Hydraulic Power Unit (HPU) used to pressurize the hydraulic fluid and with the help of solenoids, control valves and regulators directs the fluid to perform the different functions.
- Control pods are located on the LMRP and house the multiple regulators and valves whilst receiving fluid from the HPU to help perform the different functions of the BOP.
- Remote panels are used to control the BOP from different locations other than the Central Control Unit (CCU).
- CCU processes and sends electric signals to the MUX control pods.
- MUX cables with either the local area network (LAN) or fiber optic lines are used to connect between remote panels and CCU to the MUX control pods.
- MUX reels are used for spooling the MUX cables when running the BOP.
- Riser fill line delivers the operating fluid at 5,000 psi to the control pods.
- Hydraulic line provides high pressure fluid to the control pods.

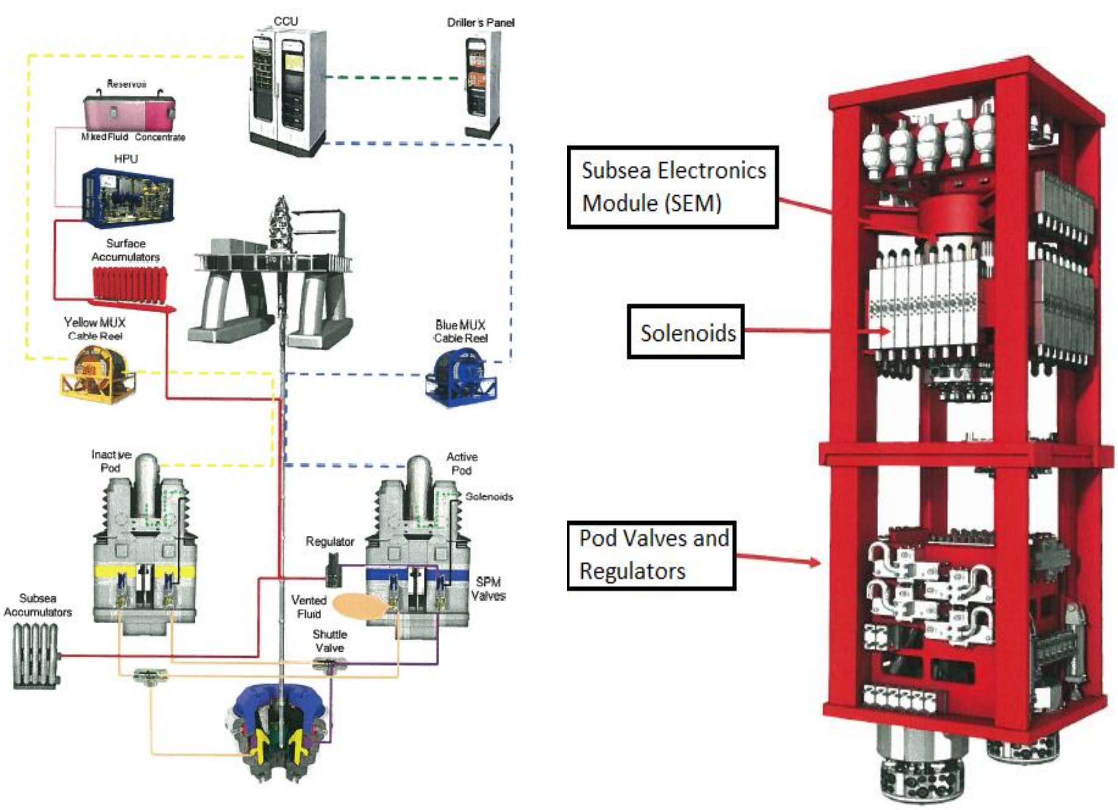

Figure 2.2: MUX BOP Control System and Cameron Mark 1 MUX Control Pod [2]

2.4 EMERGENCY SHUTDOWN SYSTEMS [23]

2.4.1 Deadman System

Deadman system is designed to automatically shut in the wellbore and disconnect the riser when hydraulic, electrical supply and the communication with the rig are lost. It is installed on the lower BOP stack and is independently operated with no input from the pods i.e. fail - function.

The Deadman system has three status modes such as armed, disarmed and activated. When armed, the Deadman system activates during the loss of communication and hydraulic supply to close the shear ram and disconnect the riser. The system can be designed to operate shear ram and riser connector or annular or choke and kill valves. Depending on the customer requirements different functions could be added.

The major limitation of the system is that it will not activate in an emergency when only one of the two communication links has failed. This could be serious when the rig loses power and could lose control over the shearing process and disconnecting the riser.

2.4.2 Automatic Mode Function (AMF)

The functioning of the AMF is similar to the Deadman system where the failure of the hydraulic supply and communication activates the shutdown sequence. The AMF system is controlled by the Subsea Electronic Module (SEM) located on the control pod. For the AMF to operate it needs at least one functional electronic module on the pod.

2.4.3 Autoshear System

The system is designed to keep the well sealed in the event of accidental unlatching of the LMRP which could be due to human error or malfunctioning of the control system. It will close the shear rams automatically and lock the wellhead connector in the event the LMRP is disconnected from the BOP.

2.4.4 Automatic Disconnect System

This system is designed to disconnect the riser in case of failure of both the riser disconnect function and the rig losing station keeping ability. The riser only gets disconnected with this system so the Autoshear function has to be coupled to this system to secure the well. The riser angle sensor determines the activation of this system.

2.5 Comparison of Different Emergency Shutdown / Back-Up Systems [3]

Comparing the various emergency shutdown and backup systems in use qualifies the dead man system as a completely redundant emergency shutdown system which can function under most of the expected adverse conditions [3] (Table 2.1). The Electro Hydraulic, Acoustic and ROV backup system are mentioned in Section 6.0.

Table 2.1: Comparison of Different Emergency Shutdown and Backup Systems [3]

CONDITION	AMF	DEAD MAN	EDS	AUTO Disconnect	AUTO SHEAR	Electro-Hydraulic Back Up	Acoustic Backup	ROV Back Up
Quick Response	YES	YES	YES	YES	YES	YES	YES	NO
Adverse Environmental Conditions	YES	YES	YES	YES	YES	YES	YES	NO
Independency	NO (SEM & POD VALVES)	YES	NO (MUX SYSTEM)	YES	YES	NO (MUX CABLE)	YES	YES
In case of Riser and Cable Parting	YES	YES	NO	NO	NO	NO	NO	NO
Loss of surface electrical + hydraulic supply	YES	YES	NO	NO	NO	NO	NO	NO
Subsea Noise	YES	YES	YES	YES (IN COMBINATION WITH AUTOSHEAR)	YES	YES	DEPENDS ON SYSTEM CONFIG	YES
LMRP accidental disconnection	NO	YES	NO	YES (IN COMBINATION WITH AUTOSHEAR)	YES	NO	YES	YES (IF WELL FLOW IS WITHIN LIMIT)

3.0 BOP AND BOP CONTROL SYSTEM RELIABILITY

3.1 Introduction

Reliability is defined as the probability that an item will continue to function satisfactorily for a period of time. This section summarizes the findings from a review of multiple studies of BOP and BOP control system reliability. The purpose of this review is to highlight critical BOP issues and to identify any reliability trends. Monitoring technology development should focus on these critical issues.

Some of the key references in this review include:

- Study 1 - Phase I DW [24, 31]
- Study 2 - Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW [24]
- Study 3 - Reliability of Deepwater Subsea BOP Systems and Well Kicks [24, 31]
- Study 4 - Blow-out Prevention Equipment Reliability Joint Industry Project (Phase I – Subsea) [50]

The definitions used in this section are mentioned below:

- **BOP failure** could be a failure of a component or the control system failure, it does not equate to complete BOP safety barrier function failure. Most BOP failures do not result in pulling the BOP out of the water as there are redundant systems to ensure the safe functioning of the BOP.
- **BOP Days** are the total number of days when the BOP was landed on the wellhead to the day it was pulled from the well head the last time.
- **Safety critical failures** happen after the installation test is completed subsea on the BOP. Once the installation test is complete, the BOP acts a well control device and any failure during this time is called safety critical failure. Non safety critical failures are those that happen on the BOP on the rig, during running or retrieving or during the installation of the BOP.
- **Mean time to failure (MTTF)** is the mean time to first failure of a component on the BOP equipment. For constant failure rate systems, MTTF is the inverse of the failure rate.

3.2 BOP Reliability

Deepwater BOP reliability was reviewed from multiple studies on wells located in GOM, Norway and Brazil. Study 1 documented reliability of subsea BOPs in offshore wells from 1992 -1996 drilled in water depth above 1,312 ft in Brazil and Norway [24, 31]. Study 2 documented reliability of subsea BOPs in the GOM for wells drilled from year 1997 and 1998 in water depth above 1,312 ft to more than 6,562 ft [24]. Study 3 documented reliability of subsea BOPs from

2007 - 2009 in water depth above 1,968 ft in GOM [31]. Study 4 focused on BOP reliability of subsea BOPs drilled from year 2004 - 2006 and identified during 7, 14 and 30-day regulatory testing currently in effect in the GoM [50].

3.2.1 Mean Time To Failure (MTTF)

Table 3.1 shows the comparison of results from Study 1, 2 and 3. The key findings of the three studies are:

- In study 1, the average MTTF in BOP days was 23 days and the average downtime per failure was 25 hours which was calculated from 138 failures.
- In study 2, the average MTTF in BOP days was 34 days and the average downtime per failure was 31 hours. This data was calculated from 117 failures which were identified.
- MTTF was longer in study 2 compared to study 1. Also the average failures caused by the downtime was little lower in the Study 2 compared to the study 1 (Table 3.1).
- In study 3, the average MTTF in BOP days was 97 days and the average downtime per failure was 86 hours. The average downtime per BOP day is 0.89 hours (Study 3) which was significantly lower compared to the earlier study 1 and 2. This data was calculated from 156 failures which were identified.
- The trend across the 3 studies shows MTTF getting significantly longer, while the time to fix the failed component is also getting longer. The longer time to fix the failed component could be attributed to the increasing complexity of the equipment which takes more time to fix.
- The MTTF on BOP components in Study 4 are higher compared to Study 1, 2 and 3 studies as Sintef studies considered testing data prior to first successful testing. Significant number of failures such as during stump test and initial wellhead test failures have been removed from Study 4 [50].

Table 3.1: BOP MTTF and Average Downtime [24, 31, 50]

Study	Location of Subsea BOPs	Period	No of Wells	BOP-days	Total lost time (hrs)	No. of failures	MTTF (BOP-days)	Avg. downtime per failure (hr.)	Avg. downtime per BOP – day (hrs)
1	Brazil and Norway wells drilled in water depth above 1,312 ft	1992 – 1996	144	3,191	3457.5	138	23.12	25.05	1.08
2	GOM wells drilled in 1,312 ft to more than 6,562 ft.	1997 – 1998	83	4,009	3637.5	117	34.26	31.09	0.91
3	GOM wells drilled in water depth above 1,968 ft	2007 – 2009	259	15,056	13,448	156	96.51	86.21	0.89
4	GOM wells	2004 - 2007	238	-	-	62	-	-	-

3.2.2 BOP Downtime

BOP downtime is defined as time lost in hours due to a failure on the BOP system without considering whether the BOP was on the wellhead or not.

1. In Study 1, the average downtime per BOP day was 1.08 hours. The highest BOP down time was attributed to control system and choke/kill line failure. The choke/kill lines caused substantial problems in this study and earlier BOP studies for “normal” water depths. It is worth noting that in the previous studies some rigs had several problems with these lines while other rigs had no problems.
2. In Study 2, the average downtime per BOP day is 0.91 hour. The highest downtime hours was caused due to failure of the ram preventers. This was due to two newer designs of ram preventers. The *Failure-to-open failure* mode was observed three times in the ram preventer in Study 2 but was not observed in earlier BOP studies. Choke and kill line downtime in Study 2 was also considerably higher than in Study 1.
3. One of the interesting facts noticed was that most BOP failures on the wellhead did not cause the BOP to be pulled as these failures were accepted. If the failure was in control system then the LMRP could be fixed by pulling the LMRP out of the water which would avoid the whole BOP to be pulled out of the water causing a longer and major downtime.
4. The few time consuming BOP failures increased the average *Lost time per BOP day* in operation.

3.2.3 BOP Failure Discussion

Figure 3.1 shows the failure distribution of the BOP as per Study 4 [50]. It can be seen that control system failures are the most likely category of failures on the BOP equipment. Due to redundancy in the control system there were not any cases where a control system failure would have comprised the well control capability. Control system failure was found during function tests. The ram and annular preventer had a similar failure distribution.

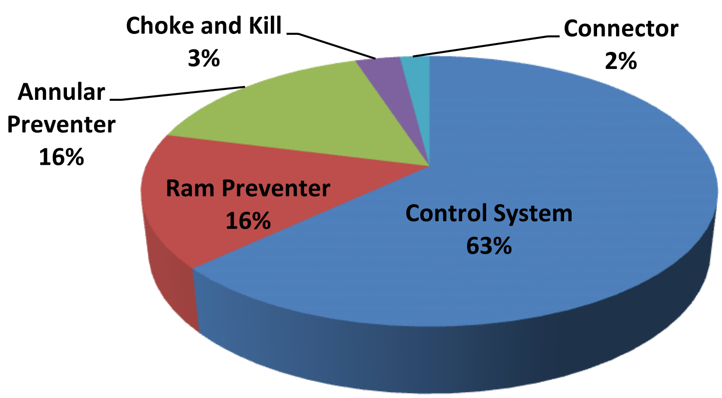

Figure 3.1: Failure Distribution from Subsea BOP from Study 4 [50]

Failures that occur when the BOP is on the rig, during running of the BOP or during the installation testing are not regarded as critical failures in terms of well control. During these phases of the operation, the BOP is not acting as a well barrier. After the installation testing is completed and accepted, the drilling starts and the BOP acts as a well barrier. All failures that happen on the BOP after the installation test are considered as safety critical failures. The criticality of each failure depends on what part of the BOP system fails and the failure mode. Some common safety critical failures are mentioned in Table 3.2.

Rams and annulars have failed at a higher rate in the safety critical period in Study 2 compared to Study 1. The severe failure mode *Loss of all functions both pods* occurred more frequently in Study 1 than Study 2. The main problem is due to the hydraulic components. A single leakage can cause the complete BOP control to become inoperable.

Table 3.2: Safety Critical Failure Summary for Study 1 to 4 [24, 31, 50]

1. Failure causing wellhead connector external leakage
2. External leakage in the connection between lower inner kill valve and the BOP stack
3. Failures to disconnect the LMRP
4. Spurious opening of the LMRP connector (Unknown cause, no autoshear in BOP)
5. Total loss of the BOP control by the main control system
6. Failures that caused loss of all functions one pod
7. Loss of all functions one pod
8. Loss of one function both pods (annular close)
9. Upper Pipe Ram leakage
10. Spurious closure of the shear ram
11. Shear ram failed to close
12. Shear ram leak in closed position
13. Failures to open pipe ram
14. Pipe ram leaked in closed position
15. Failed to shear the pipe during a disconnect situation
16. Upper and lower variable bore ram leaked at the same time
17. Pipe ram failed to close
18. Annular preventers that leaked in closed position
19. Failed to close annular incident
20. Choke and kill line leakages
21. Control system failure that caused total loss of the BOP control
22. Spurious opening of the LMRP connector (control system failure)

Table 3.3 shows the summary of the number and percentage of failures from 4 studies. The BOP Control System has the highest percentage of failures on the BOP equipment and they are identified by function tests which are required to be conducted every 7 days as per 30 CFR 250.449. This report focuses on control system issues and improvements as these are the primary source of BOP malfunction.

Examining multiple studies (Table 3.2) the following was observed:

- In study 1, 45% of the total failures were caused due to control system failure.

- In study 2, 60 of the 117 failures, or 51% were caused due to control system failure.
- In study 3, 72 of the 156 failures, or 46% were attributed to the control system failure
- In study 4, 63% of the failures was attributed to the control system

The ram and annular preventer have similar failure rates [50] and the failures noticed were due to shear ram actuator leaks, ram bonnet leaking, packer damage, shear ram failure due to closed ST locks, annular latch head leaks etc. Some of the failures which couldn't be linked to a specific BOP item were not included (Table 3.3). There is no failure data on Study 1 in public domain.

Table 3.3: Summary of BOP Failures from Studies 1 - 4 [24, 31, 50]

	Study #			
BOP Components	**1**	**2**	**3**	**4**
	No. of Failures/ Percentage			
Annular Preventer	-	12/ 10%	24/ 15%	10/ 16%
Connector	-	10/ 8%	8/ 5%	1/ 2%
Control System	45%	60/ 51%	72 / 46%	39/ 63%
Choke & Kill Valve	-	13/ 11%	4/ 2.5%	2/ 3%
Choke & Kill Lines, All	-	8/ 7%	17/ 11%	-
Ram Preventer	-	11/ 9%	23/ 15%	10/ 16%
Flexible	-	1/ 0.08%	1/ 0.06%	-
Total	138	117	156	62

Study 4 (West Engineering study) has higher MTTF for different BOP components compared to Study 1, 2 and 3 as Sintef studies considered testing data prior to first successful testing. A significant number of failures such as during stump test and initial wellhead test failures have been removed from this study. The MTTF for flexible joint was not included in the below table. There are no MTTF data available on Study 1 in public domain.

Table 3.4: MTTF of BOP Major Components from Study 2, 3 and 4 [24, 31, 50]

	Study #		
	2	**3**	**4**
Component/ System	**MTTF Operating days/failure**		
Annulars	334	627	3,723
Rams	364	655	-
• Fixed	-	-	∞
• Variable Bore Ram	-	-	6,450
• Blind Shear Ram	-	-	7,770
Casing Shear	-	-	∞
Choke and kill valves	308	3,764	106,526
Choke and kill valves, all	501	886	-
Connectors	401	1,882	19,447
Control Systems	67	209	-
• Conventional Pilot	71	242	834
• MUX	46	198	398
Flexible Joint	4,009	15,056	-

3.3 BOP Control System Reliability

3.3.1 Control System Mean Time to Failure

Figure 3.2 shows the comparison of the failures on the control system from the Study 1, 2 and 3. It can be seen that Study 3 has the highest MTTF of 209 hours which has improved significantly over the previous 2 studies.

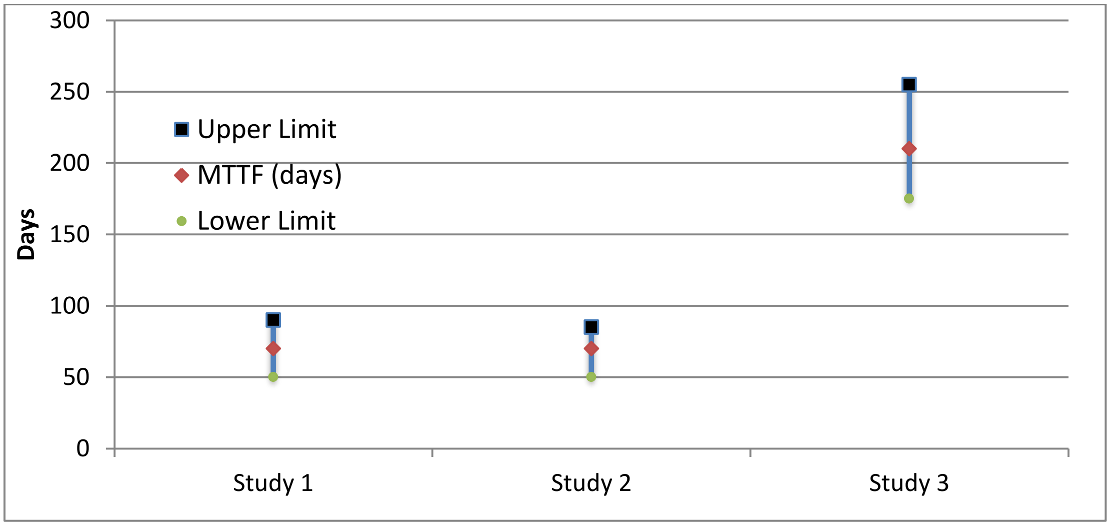

Figure 3.2: Control System MTTF Comparing Study 1, 2, 3 [31]

Figure 3.3 shows the average MTTF for the different types of control system with 90% confidence limits from Study 3. There is no significant difference between the MTTFs as the confidence bands are overlapping. A similar phenomena was seen in studies 1 and 2.

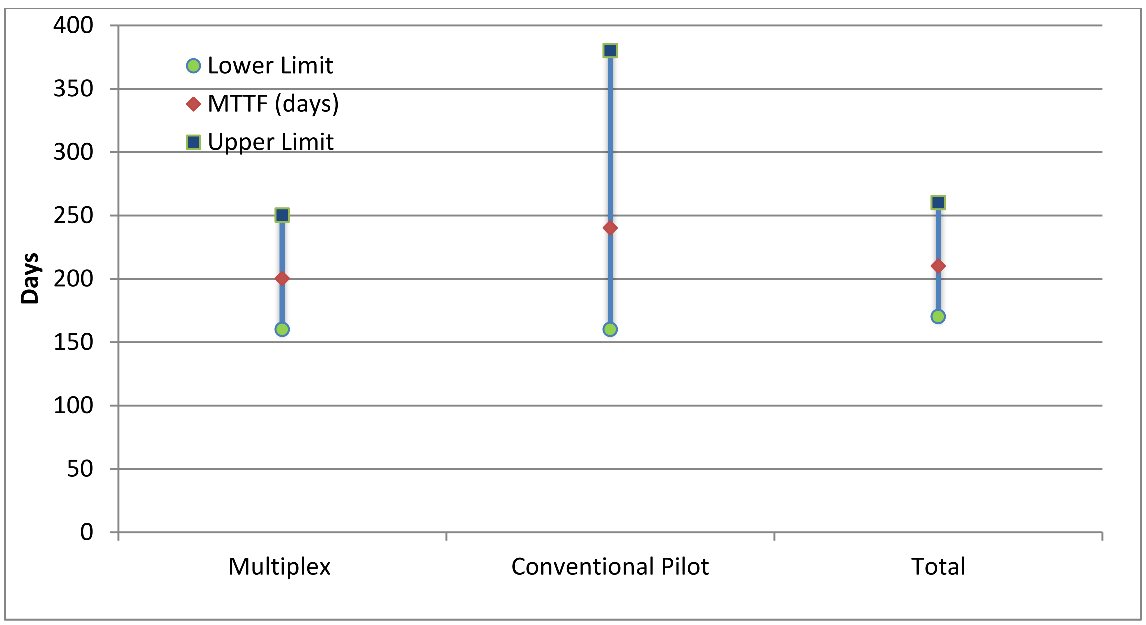

Figure 3.3: BOP Control System MTTF on Study 3 [31]

Figure 3.4 shows the average failure downtime for the different types of BOP control system for Study 3. The MUX system had the highest downtime. The increase in downtime was due to few failures of long duration.

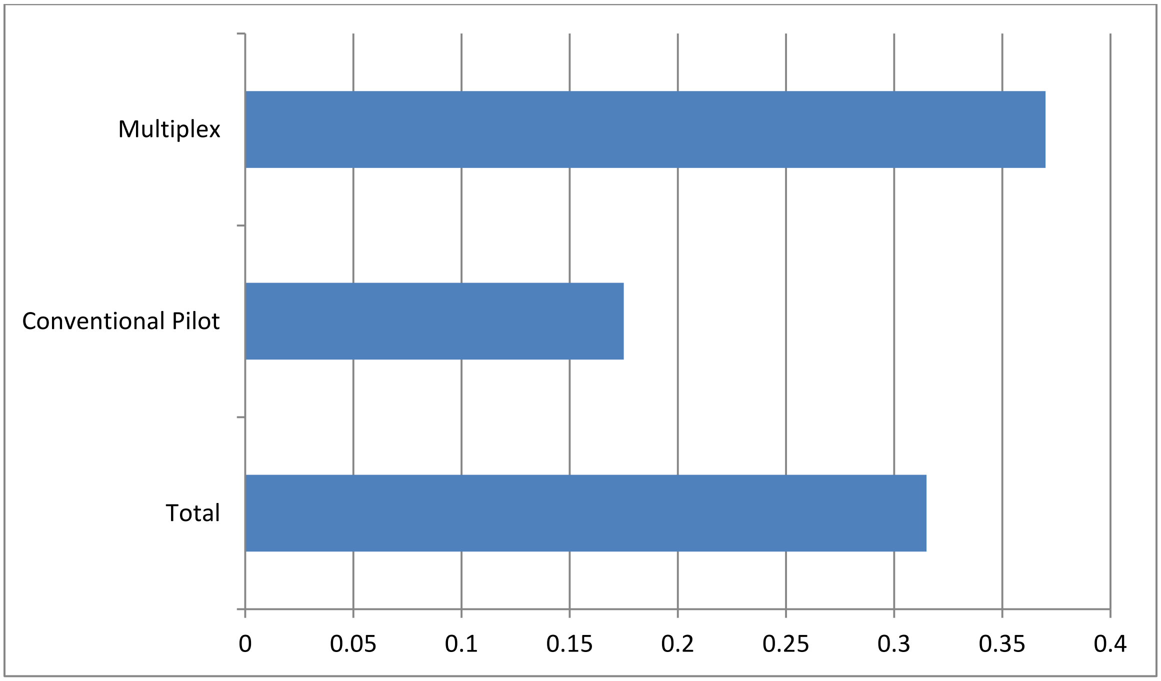

Figure 3.4: Average Failure Downtime per BOP Day on Different Types of BOP Control System for Study 3 [31]

3.3.2 Control System Failure Discussion

Most of the control system failures were due to malfunctioning of the different components in the control pods on the LMRP. Some of the failures were due to the leakages in the control pods, Subsea Plate Mounted (SPM) valves (Figure 3.5), solenoids, malfunctioning of the choke line fail safe valves or the stack connector regulator.

One failure prevented the upper variable bore ram from closing due to a shuttle valve failure.

In another case the solenoid valve was leaking in one of the pods. The failure in the solenoid was due to cut O-ring on the seal sub. In other cases the solenoid malfunction was due to a faulty end cap check valve and voltage problems.

Figure 3.5: SPM Valve [52]

A summary of the different control system failures from Study 2 [24] are presented in Table 3.5.

The additional BOP control system mentioned in Study 2 is the Pre-charged pilot hydraulic control system. The Conventional Pilot Control system is a modified version of the conventional hydraulic control system and activates the pilot valves through the pilot signal. In Pre-charged pilot hydraulic system, the pilot signal is transmitted to a pre-charged pressure to speed up the BOP response time.

On the MUX system *Loss of all functions on both pods* was observed while running the BOP. It was observed that the solenoid for selecting the blue pod was not working and had to be pulled out to replace the solenoid. Multiple problems occurred as individual components were replaced and tested which led to 189.5 hours of lost time.

The Conventional Pilot control system had *Loss of one function one pod* failure for 8 times and was due to multiple failures such as SPM valve malfunction, leakages in the lines.

Failures are documented as *Unknown* when the cause of failure is not specified. Failures are documented as *Other* when they fall in a category other than the ones mentioned in the following table. When the failures observed were resolved by switching to back up system were considered having zero lost time.

Table 3.5: Control System Failure Distribution for Study 2 [24]

Type of Failure	No. of failures	Total lost time (hrs)	Average Downtime - per BOP - day (hrs)	Days in Service (BOP - days)
Multiplex Electro Hydraulic				
Loss of all functions both pods	1	2.5	2.5	459
Loss of all functions one pod	1	189.5	189.5	
Loss of one function one pod	1	1	1	
Unknown	4	17.5	4.4	
Other	3	10	3.3	
All	**10**	**220.5**	**22.1**	
Pre-charged pilot hydraulic				
Loss of all functions both pods	1	42.5	42.5	552
Spurious operation of BOP function (s)	1	1.75	1.8	
Loss of several functions one pod	4	54.5	13.6	
Loss of one function one pod	4	14	3.5	
Unknown	2	7.5	3.8	
Other	4	18.5	4.6	
All	**16**	**138.75**	**8.7**	
Pilot Hydraulic				
Spurious operation of BOP function(s)	2	57.5	28.8	2,553
Loss of all functions one pod	6	173.5	28.9	
Loss of several functions one pod	1	135	135	
Loss of one function both pods	1	121.5	121.5	
Loss of one function one pod	8	33.5	4.2	

Loss of control of one topside panel	1	2	2	
Unknown	3	81	27	
Other	4	16	4	
All	**26**	**620**	**23.8**	
Conventional Pilot, unknown if pre-charged or not				
Loss of all functions one pod	2	3.5	1.8	445
Loss of several functions both pods	1	0	0	
Loss of several functions one pod	1	35.5	35.5	
Loss of one function one pod	2	1	0.5	
Unknown	2	2.25	1.1	
All	**8**	**42.25**	**5.3**	

A summary of the different control system failures from Study 3 are presented in Table 3.6.

- On the MUX system, *Loss of all functions in one pod* had the highest average downtime of 132.7 hours per failure.
- *Loss of all functions on both pods* was also observed on the MUX system on Study 1, 2 and 3. This is safety critical failure as the BOP cannot be operated. This failure was not observed in Study 4 as drilling was done in water depths where pilot systems were used. This indicates that failure of both pods do not occur frequently in the pilot hydraulic control system.
- In the pilot hydraulic system *Loss of several functions on one pod* had the average downtime of 252 hours per failure.

Table 3.6: Control System Failure Distribution for Study 3 [31]

Type of Failure	No. of failures	Total lost time (hrs)	Average Downtime - per failure (hrs)	Days in Service (BOP - days)
Multiplex Electro Hydraulic				
Loss of all functions both pods	1	192	192	10,942
Loss of all functions one pod	12	1592.5	132.7	
Loss of one function both pods	4	168	42	
Loss of one function one pod	10	576	57.6	
Loss of several functions one pod	1	0	0	
Other	19	1,108.5	58.3	
Unknown	8	330	41.3	
All	**55**	**3,967**	**72.1**	
Pilot Hydraulic				
Loss of all functions one pod	2	216	108	4,114
Loss of one function both pods	2	0	0	
Loss of one function one pod	6	25	4.2	
Loss of several functions one pod	2	504	252	
Other	4	0	0	
Unknown	1	0	0	
All	**17**	**745**	**43.8**	

4.0 BOP MAINTENANCE AND TESTING

4.1 BOP Maintenance and Testing Requirements

There are multiple problems which are encountered during testing and operation of the BOP in subsea. Some of the problems are:

- Control system is the most common problem with several occurrences where drilling operations has to be suspended so it can be repaired. It could take multiple days to pin point the exact failure location on a control systems before it can be fixed.
- Failure can be seen in hoses, fittings, leaking control valves and regulators. These items are closely monitored during the end of well preventive maintenance routines.
- There are few instances of leaking rams seals and annular elements (elastomers). Some drilling contractors track the expected life (closures) for the elastomers with the goal replacing them prior to predicted failure, but the can failure prematurely. Closing rams multiple times in order to get a pressure test.
- To improve the reliability of the BOP components subsea, more rigorous BOP maintenance and testing requirements need to be implemented.

4.1.1 Test Procedures / Requirements

The BOP stack is tested to make sure that the BOP will seal the well in case of kick. As per API 53 [35], more intensive BOP subsea testing has to be performed after the BOP is latched into the wellhead such as:

- The BOP to wellhead connector shall be tested to a minimum of the highest maximum anticipated well head pressure (MAWHP) to be encountered in the entire well.
- Function tests of all well control components (excluding hydraulic connectors and shear rams) on the BOP stack to verify the component's intended operations shall be performed at least once every 7 days or as operations allow. Pressure tests qualify as function tests. Casing Shear Ram (CSR) and Blind Shear Ram (BSR) shall be function tested at least once every 21 days.
- Blind shear and those valves immediately below the shear rams and above the upper pipe ram shall be high pressure tested at casing points to the casing test pressure. The high-

pressure test should be stable for at least 5 minutes. The function test interval not to exceed 21 days.

- CSR shall be high pressure tested and the pressure testing window is not to exceed 21 days.
- Function tests shall be performed from one BOP control station and one pod weekly.
- Test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab.

4.1.2 Maintenance Requirements

As per API 53 [35], the BOP shall be inspected every 5 years for repair and remanufacturing. The scheduled based inspection could be replaced by a rig specific inspection frequency which can vary from the 5 year interval if the equipment owner collects and analyzes condition based data to justify a different maintenance frequency.

4.2 SureTec BOP Testing System

Paper circular chart recorder (CCR) is normally used for documenting the testing of the BOP on rig surface (Figure 4.1). Some of the problems associated with the chart recorder are:

- Hand written notes are placed on the CCR which led to lot of data manipulation and mistakes during the recording of the tests.
- Hard to keep track and document the tests on all the different valves.
- Most leaks happened in low pressure tests and the clarity of the pressures on the chart recorder was not clear in the low ranges.
- The testing procedure is not consistent between different rigs as the offshore personnel had their own way of documenting and determining the criteria of pass and failure of the tests.
- Any testing plan changes are hard to manage and track.
- There are no standards for component or pressure path representation.
- Pressure path analysis is done manually.
- When a spreadsheet was used by field operations to keep track of all the tests on the different BOP valves, it used to take several days to figure out if all the tests were completed or not so that they can move to the next stage. This created a bottleneck which led to longer testing time which in turn led to more nonproductive rig time.

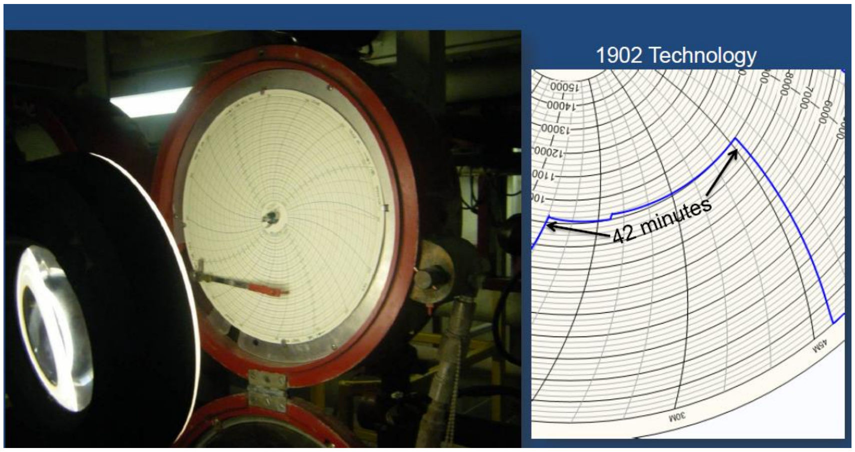

Figure 4.1: Circular Chart Recorder [54]

SureTec is a data acquisition (DAQ) software specifically used for testing the BOP on the stump and subsea. The software allows for remote BOP pressure testing which provides an independent means of witnessing a BOP pressure test from onshore. It replaces the chart recorder which was used to document the different tests performed. Around 25 rigs are using Suretec on their rigs.

SureTec uses a schematic of all the valves on the BOP, the schematic is built specifically for the type of BOP on the rig (Figure 4.2). Thermally Compensated Leak Detection (TCLD) technology has been developed to analyze the electronic data to create pressure behaviour models of systems under test to serve as benchmarks for subsequent tests. This analysis technique utilizes advanced comparative algorithms to significantly decrease the time required to accurately verify system integrity.

SureTec provides leak analysis for the low and high pressure portions of a test. Most leaks are identified during the low pressure portion of a test. In the case of the high pressure analysis, a leak is identified within 2-3 minutes of testing.

The initial test serves as the benchmark in which subsequent tests utilize the TCLD analysis for validating most tests in 6 minutes [54]. With TCLD analysis, a slight variation from a predetermined benchmark would be a clear indication of a leak. Test progress and results are presented through the use of indicators, pressure charts, and analysis graphs.

SureTec incorporates this technology into an application that automates the entire testing sequence, including clear indication of pass/fail results and entry of regulation required comments. A test report in electronic form is automatically generated at the end of the test.

As each valve is successfully tested the valve on the display turns green helping offshore personnel to keep up with the testing sequence and which valves have and have not been tested. The volume of testing fluid pumped from the rig to the BOP valves is captured every time and this helps in crosschecking if the tests are accurate. Pressure test data is saved on the rig server which is then uploaded onshore. A SureTec report gives a summary of the tests performed on all the valves for decision making (Figure 4.3, Figure 4.4).

There was lot of push back from rig personnel during implementation of SureTec. Each rig had its own way of documenting and determining the criteria of pass and failure of the tests. The test pass/fail criteria would be same on all the different rigs during the implementation of SureTec.

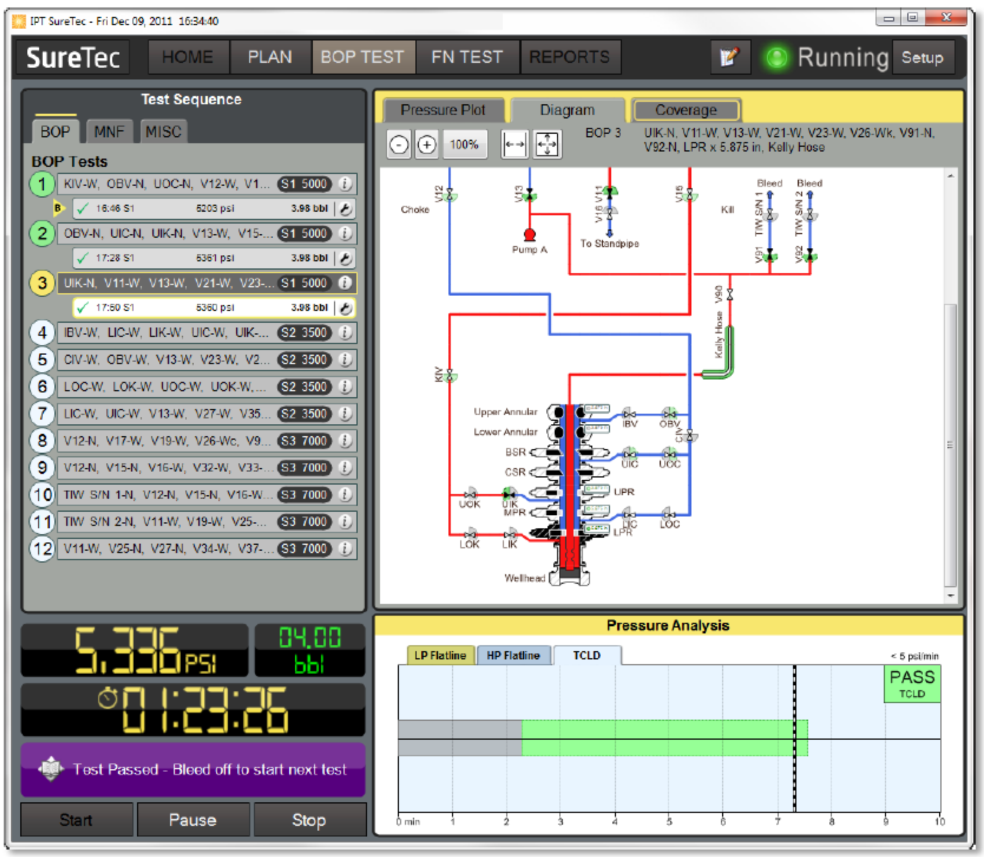

Figure 4.2: SureTec Testing Software Showing Valve Alignment and Pressure Paths [54]

✓ **All required components verified**

Legend	
✓ Verified	✗ Could not be verified
○ Not tested	Component not verified

W - Pressure from WELLBORE side	Wc - Pressure from wellbore side, CHOKE facing
N - Pressure from NON-wellbore side	Wk - Pressure from wellbore side, KILL facing

Component	Side/ Size	Verified	1	2	3	4	5	6	7	8	9	10	11	12
Choke	W	✓											✓	
Hyd TD IBOP	B	✓									✓			
IBV (NR)	N	✓							✓	✓	✓	✓	✓	✓
IBV	W	✓					✓							
Kelly Hose	Right	✓											✓	✓
Kill	W	✓												✓
LIC	W	✓			✓									
LIK	W	✓					✓							
LOC	W	✓				✓								
LOK	W	✓						✓						
Low Torque (NR)	R	✓	✓	✓	✓	✓	✓	✓	✓	✓				
Lower Annular	5.000 in	✓				✓	✓	✓						
Lower VBR	5.000 in	✓								✓	✓			
Man TD IBOP	B	✓										✓		
Middle VBR	5.000 in	✓										✓	✓	✓

Figure 4.3: Partial Component Verification Report [54]

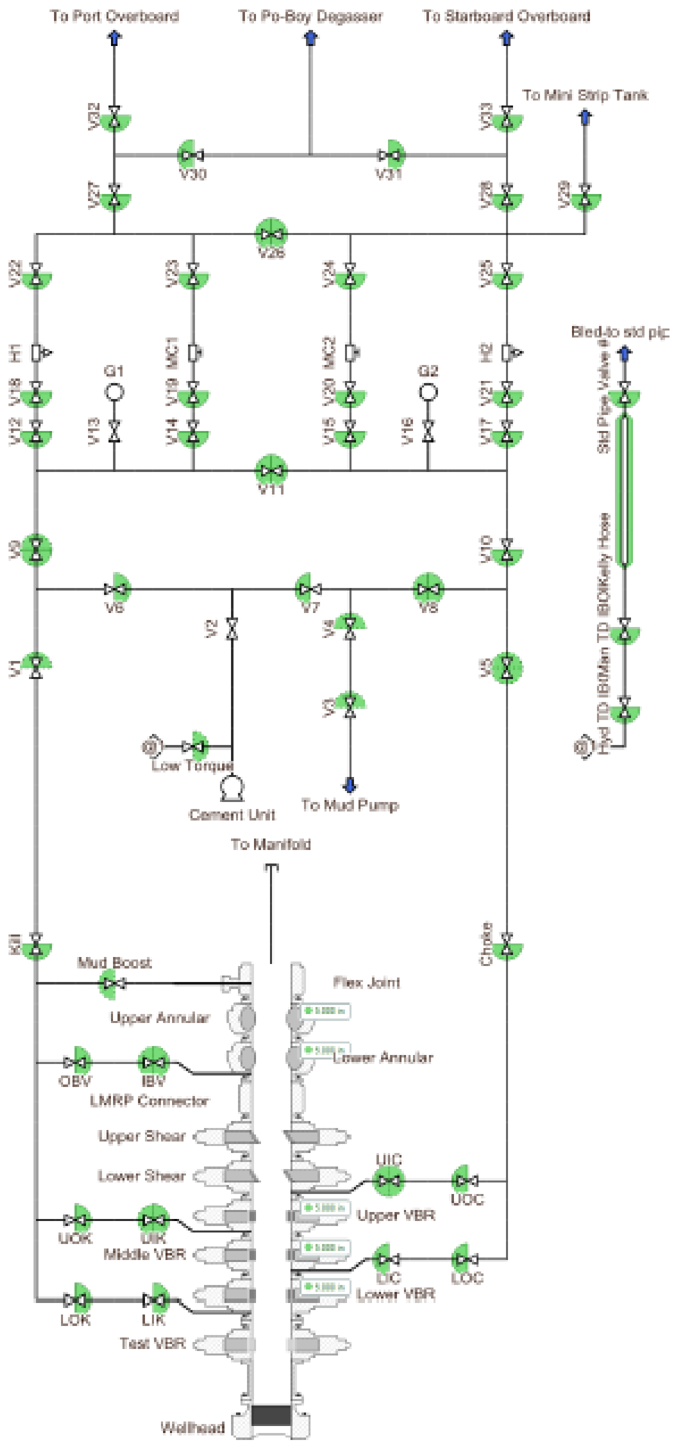

Figure 4.4: Visual Component Verification Report [54]

4.3 ARCHER'S GREENLIGHT PRESSURE TEST VERIFICATION SYSTEM

Archer's Greenlight is a pressure test verification system utilized in pressure testing of wells, well systems and well components [43]. It combines three main elements such as high-precision pressure sensor, communications module, PC-based algorithms and user interface (Figure 4.7).

Some of the benefits of the system are it consistently approves or rejects pressure tests against predetermined test criteria, removes the subjective element, generates a detailed pressure test chart which can be annotated, e-mailed and filed (Figure 4.5, Figure 4.6). This detailed pressure chart provides auditable record and unambiguous proof of compliance. The system has a built in filter which removes pressure fluxuation noticed during testing. The system will automatically give a green light when the acceptance criterion is fulfilled.

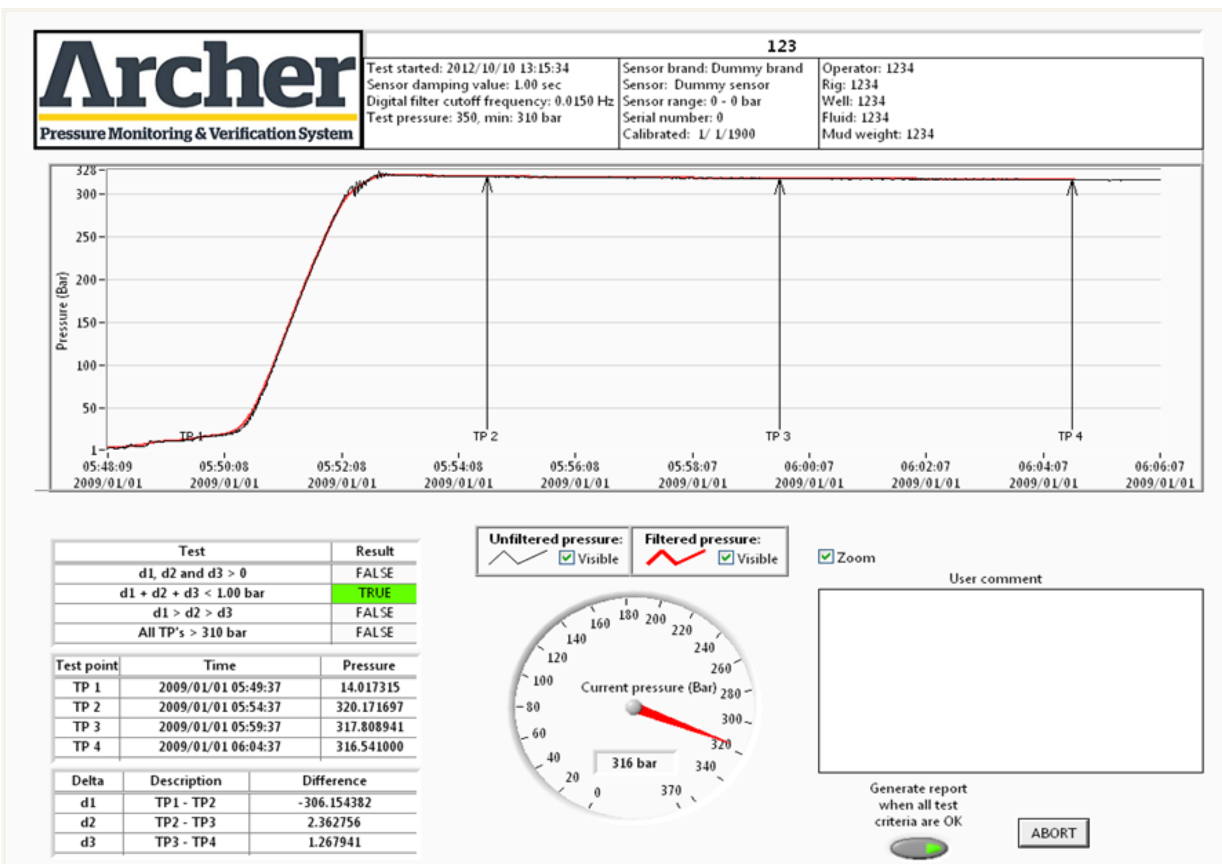

Figure 4.5: Snapshot of Pressure Test Results [43]

Test	Result
d1, d2 and d3 > 0	FALSE
d1 + d2 + d3 < 1.00 bar	TRUE
d1 > d2 > d3	FALSE
All TP's > 310 bar	FALSE

Test point	Time	Pressure
TP 1	2009/01/01 05:49:37	14.017315
TP 2	2009/01/01 05:54:37	320.171697
TP 3	2009/01/01 05:59:37	317.808941
TP 4	2009/01/01 06:04:37	316.541000

Delta	Description	Difference
d1	TP1 - TP2	-306.154382
d2	TP2 - TP3	2.362756
d3	TP3 - TP4	1.267941

Figure 4.6: Details on Pressure Test Results [43]

Some of the clients using this system are Shell, Seadrill, North Atlantic Drilling and Halliburton [43].

Figure 4.7: Greenlight Pressure Sensor with Digital Link to Communication Panel [43]

4.4 UNIVERSAL AUTOMATED SOLENOID TESTER [43]

The universal automated solenoid tester (Figure 4.8) is designed to test solenoids using low voltage DC resistance. It verifies if the solenoid is not shorted before applying the full power which prevents the propagation of damage from failed components. The solenoid tester is designed to detect and replace weakening or sticking solenoids before they fail. This helps in insuring fully performing control solenoids before they are deployed subsea.

Figure 4.8: Universal Automated Solenoid Tester [42]

5.0 BOP MONITORING AND TECHNOLOGY

5.1 REAL TIME MONITORING

When a signal is transmitted from the drilling rig to the subsea BOP to execute a command, the BOP sends a message back that the signal has been received. However, there are no devices on the BOP to send a signal that any command has been executed, such as pressure or displacement sensors confirming that hydraulics were actuated or that rams have moved or that pipe has been cut, nor are there any flow sensors measuring whether the well has been sealed.

Monitoring is used in many industries such as petrochemical, refinery and so on. Multiple sensors are placed on the equipment to be monitored equipment functionality does not change. This leads to predictable alarm on the equipment. In the oilfield, there are different wells, water depth, drilling depth, drilling scenario. So the alarm pattern is different every time and it is hard to predict if the alarm is right or wrong.

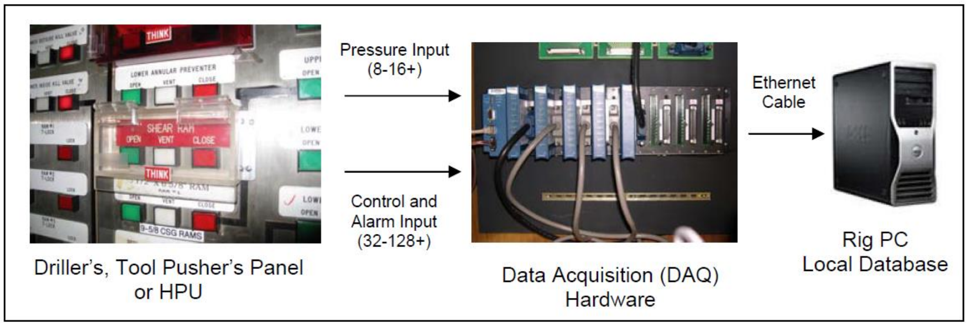

Figure 5.1: BOP Monitoring Data Acquisition System [40]

The BOP monitoring system on a hydraulic BOP control system is made up of three sub system such as data acquisition, data transfer and data analysis and presentation [40]. On the MUX BOP control system the data acquisition is part of the MUX system.

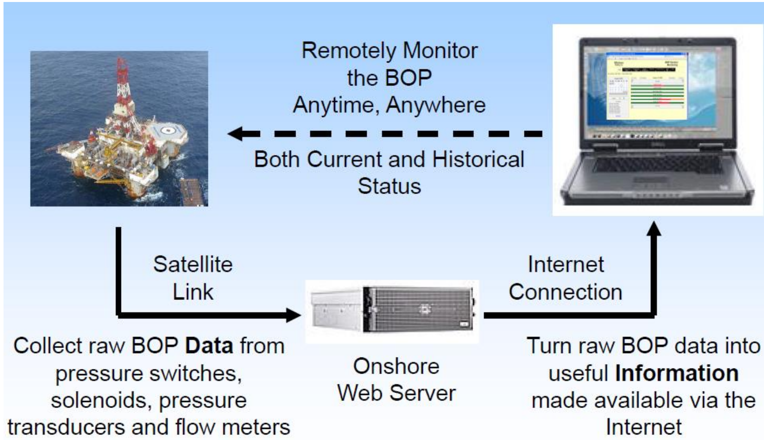

Figure 5.2: BOP Monitoring [41]

There has being significant technological advances made in the process of collection, transfer, analysis and presentation of BOP control systems. New systems have been developed which allows for fully automatic collections mode with user-friendly presentation, time logs and graphs to allow for quick decision-making. These systems can automatically acquire the data and transfer to onshore facility. At the onshore facility the data could be analysed and converted into useful information and be available for access anytime and anywhere through internet. Many of the newer rigs are incorporating this technology. The older generation BOP do not have this technology but can be retrofitted to bring it up to the same level as the newer rigs.

There are multiple technologies being developed for BOP Monitoring such as:

5.1.1 Rig Watcher

Ashford Technology has developed Rig watcher for real time BOP monitoring which helps in proactive maintenance and early identification of problems. The main aim is to allow for 24/7 monitoring of the BOP from onshore.

The main function of Rig watcher is to allow cycle maintenance which will help in determining the useful life of the BOP components. As more data such as pressure and flow versus time profile signature is collected on the equipment, good metrics can be developed which will help in identifying potential equipment problems [41].

The raw BOP data from the rig is collected from pressure switches, solenoids, pressure transducers, flow meters and transferred to the rig computer and then transferred via internet to the onshore web server. The onshore server can receive multiple data simultaneously from different rigs through the internet. This helps in maintaining a BOP monitoring database on the whole rig fleet.

Having access to live monitoring data offers lot of advantages such as [40]:

- 24/7 access to rig and BOP information anytime and anywhere.
- Monitored data presented in a user friendly web browser format.
- Subject Matter Expert (SME) can be located onshore monitoring multiple rigs at one time.

The cycle report for all the valves associated with the BOP function can be tracked. The cycle report gives a clear picture on how many times each valve has been functioned (Figure 5.3). All pressures encountered by the valves on the BOP can be monitored. Detailed daily summary reports for all the major BOP functions can be tracked.

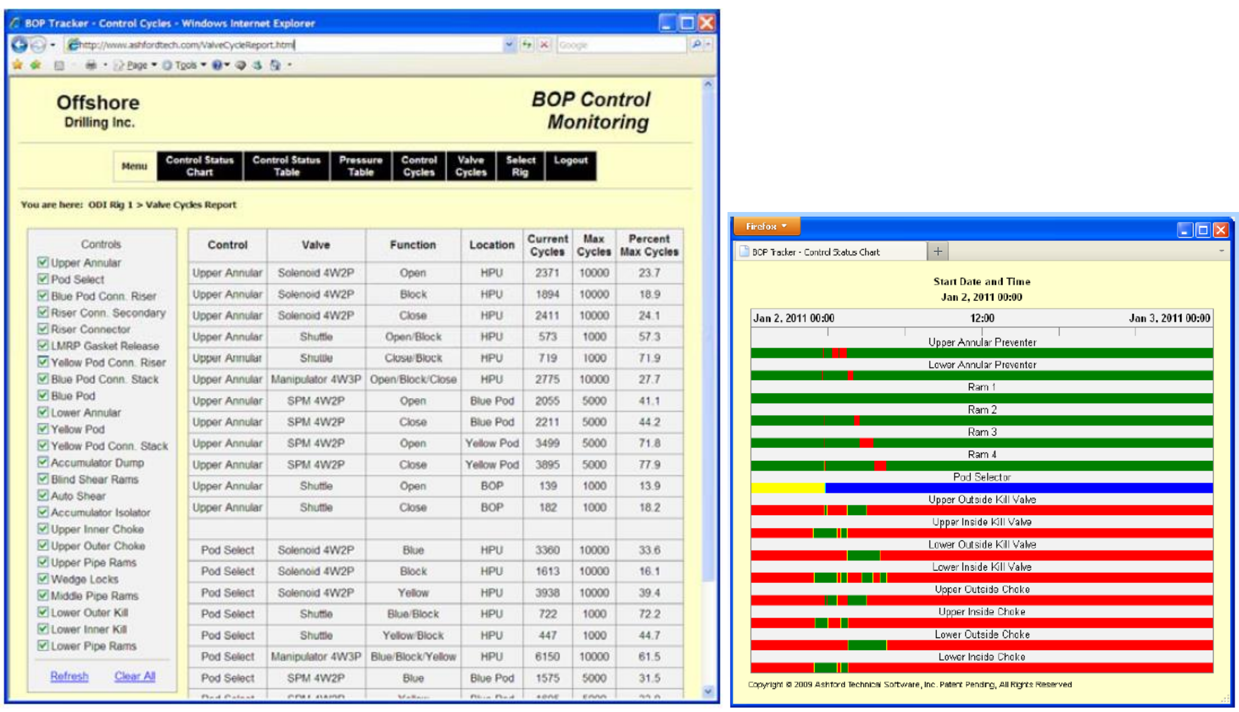

Figure 5.3: Daily Summary of All BOP Functions [40, 41]

Figure 5.4: Rig Pressure Report [40, 41]

Multiple rigs in a fleet could be monitored simultaneously in a regular basis from onshore personnel. The drilling contractors could better predict the preventative maintenance on their BOP equipment. The drilling contractors could also monitor and improve their offshore operations as they would have better access to greater amounts of data. Also, the onshore personnel could provide expert guidance to the offshore personnel.

The operators would be able to access and monitor the BOP from onshore which will help them oversee the drilling and safety of their operations.

Rig Watcher was installed on a Diamond Offshore rig in 2009 and drilled multiple wells in GOM. It will be installed in three additional rigs this year.

Rig Watcher is continually being improved and upgraded as more and more equipment data is collected and analysed.

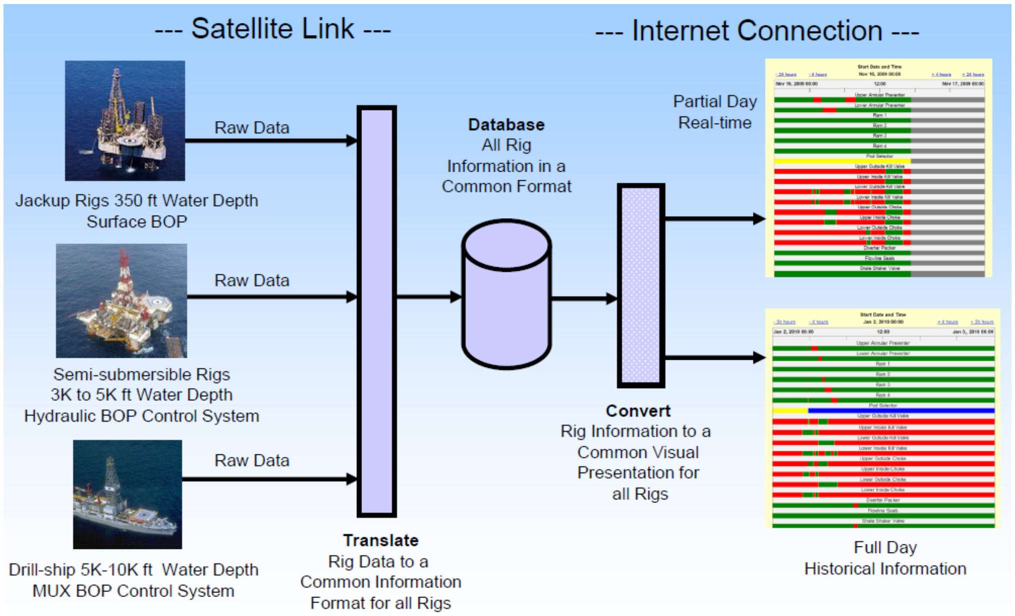

Figure 5.5: Multiple Rigs with Common Monitoring Display [41]

5.1.2 NOV BOP Dashboard System [48]

The main function of the BOP Dashboard system is to simplify complex BOP diagnostics in a simple graphical user interface format (Figure 5.6) to enable the operation to more easily assess an issue. Since early 2011, multiple companies have collaborated to develop the BOP dashboard system that takes existing alarms, analog data and events from the BOP event logger and translates them into a high level "traffic light" status. The traffic light shows the different levels of system redundancy which will allow the user to understand and make decisions based on failure of critical functions on the BOP. All the major functions on the BOP can be monitored through this system.

The levels of risk associated with each traffic light are defined by assigning three colors to provide the BOP health status. Red color would mean that there is no functionality, yellow color would mean functional but no redundancy in the equipment, green color would mean that the equipment is fully functional and has redundancy. The rig contractor who owns the BOP has the ability to manually change the traffic light severity as there is a potential for false alarms. A management of change (MOC) process will be followed to make changes to the severity of the traffic light.

The BOP dashboard is used as a communication tool for allowing communication between the operations team on BOP health issues. The event logger on the rig is the primary diagnostic system. The workflow process requires that the event logger be used to confirm the dashboard before making any decisions. All the alarms are not equally important and distinction between them must be known when using the dashboard system.

A decision tree protocol (Figure 5.7) is being developed so that the operations teams can make standard operations decisions. This would remove any potential for subjective BOP health solutions.

BP has been piloting the BOP dashboard system on Ensco DS-4 drill ship in Brazil with NOV and Ensco. BP's first installation in the GOM is planned this year on the Ensco DS-3 drill ship [57].

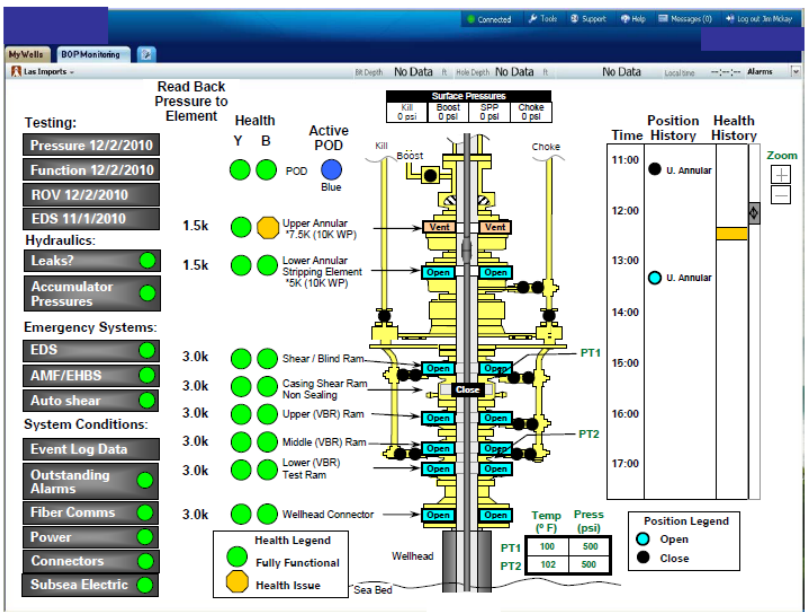

Figure 5.6: BOP Dashboard [48]

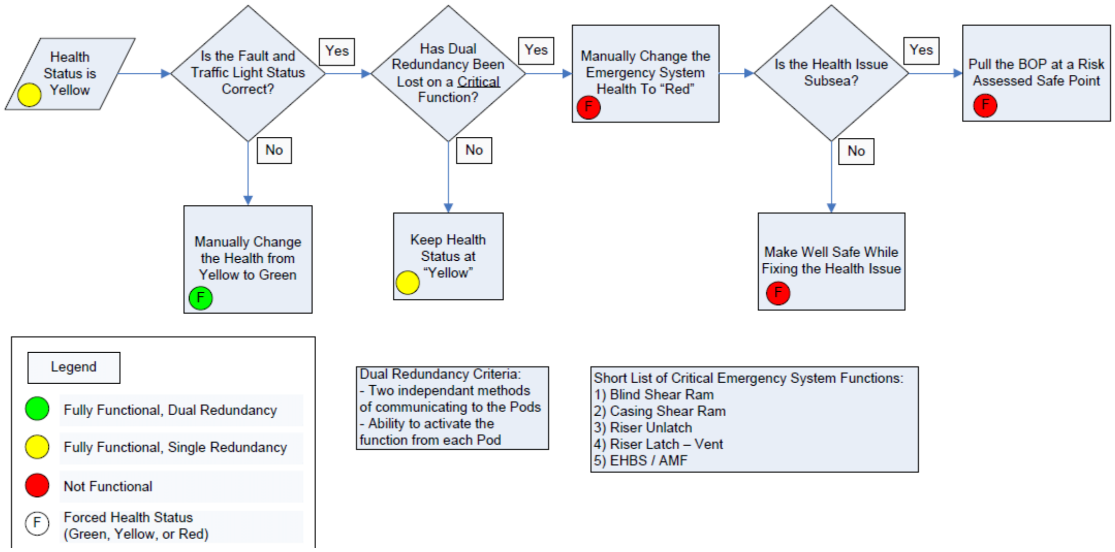

Figure 5.7: Operations Decision Tree [48]

BOP dashboard monitoring is a standard option on NOV's fifth and sixth generation BOP stack. BOP dashboard monitoring is working on multiple rigs for more than a year with major operators in the GOM.

5.1.3 GE's Drilling iBox System

GE's Drilling iBox (Figure 5.8) system is a combination of hardware and software solution which is used to convert existing data from the event logger into reports, status updates, event sequence, cycle counts. The event sequence and cycle counts can be used as condition based and predictive maintenance tool. The iBox connects to the existing data logger on the rig and provides diagnostic and predictive condition monitoring reports using the GE Intelligent Platform Proficy software package. The iBox system can be retrofitted to all the GE BOP MUX control systems. The BOP can be monitored in real time from an onshore facility to help with diagnostics and troubleshooting [55].

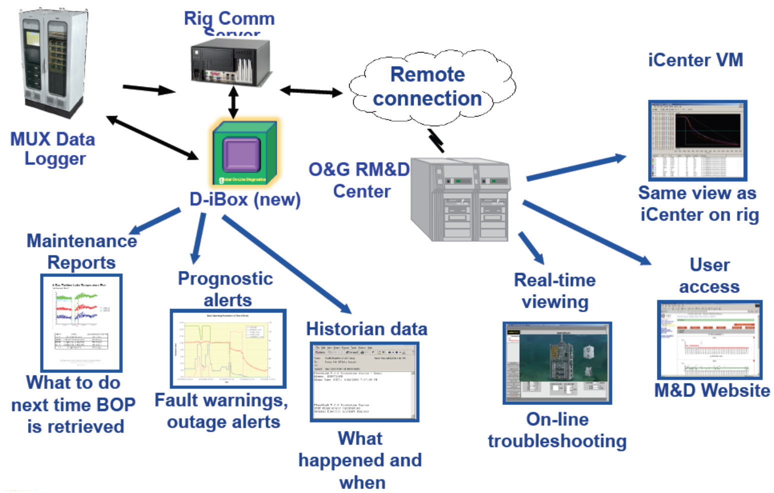

Figure 5.8: GE's Drilling iBox [30]

5.1.4 Real Time Monitoring Center [44]

Multiple companies such as BP and Talisman Energy have started Real time Monitoring Centers which enable 24/7 monitoring of well parameters from onshore location (Figure 5.9). This capability is designed to enhance the safety of deep water operations. The data that is available to the personnel at the monitoring center allows for an extra pair of eyes to monitor well parameters. The monitoring center houses full-time monitoring well parameters, and specialists who have extensive experience in deep water operation with relevant key skills in well bore monitoring. The center provides a constant communication with offshore rig teams while monitoring real time data. The real time data that is monitored includes flow in, flow out, standby pressure, mud weight, mud logging data (Figure 5.10). The center also utilizes standardized processes and procedures which have been derived from best practices across all of the deep water fleet. The accountabilities are very clear within the monitoring center as the primary control remains at all times with the offshore driller to monitor the well. There are also processes and procedures for escalating if any observed parameters fall outside a defined and agreed range.

Figure 5.9: BP Houston Monitoring Center (HMC) [44]

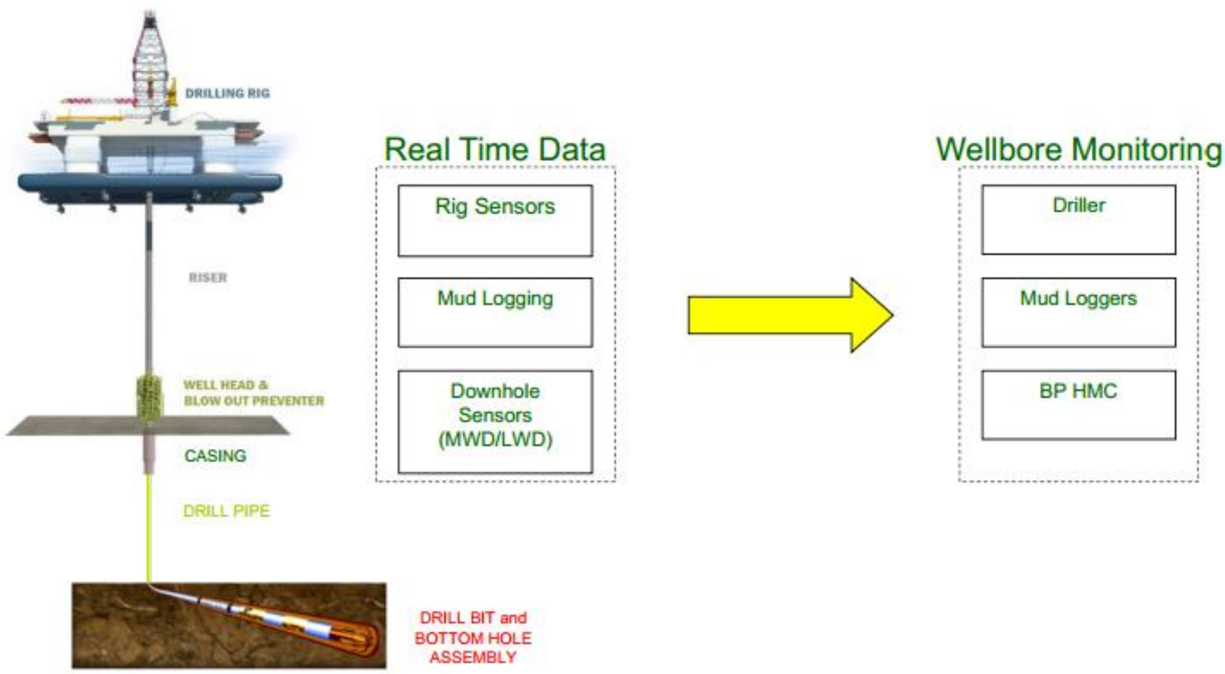

Figure 5.10: Real-Time Data & Well-Bore Monitoring Process [58]

5.1.5 Condition Based Monitoring

On one of the deepwater rigs, the BOP was unable to test shear/blind ram due to faulty SPM valves. The led to the BOP been pulled out of the water which took 14 days round trip and revenue loss of $10.1 million. The total BOP downtime loss for this drilling contractor was $80 million in 2011 and $60 million in 2012 [52]. If the drilling contractor had known the cycles the SPM valve had undergone, the part could be replaced before it failed.

Condition monitoring is continuous or periodic measurement and interpretation of data to indicate the condition of an equipment to determine the need for maintenance [46].

Condition monitoring/condition-based maintenance (CM/CBM) is a known best practice proven in the aerospace and nuclear industries. These industries involve large capital investments and a “never can fail” operating environment. The purpose of CM/CBM is to eliminate the root cause of failures and anticipate the needs of the equipment. Repairs can be planned before they turn into major failures which could lead to catastrophic results. Removing or eliminating unnecessary repairs/replacements from the work schedule manages maintenance more efficiently [60].

Drilling contractors are very interested in condition monitoring of their equipment as they want to know what to monitor, how often to monitor, when and why the equipment needs to be monitored and what to do when there is a change of condition noticed on the equipment. The current practices which involve automatically replacing existing equipment/components for new components are expensive and inefficient. Moving to a condition-based maintenance and monitoring program will require more collaboration between the original equipment manufacturer (OEM) and the drilling contractors and operators [60].

The OEM would have to provide guidance for maintenance and acceptable criteria for continued operations that are condition-based, not merely calendar-based, for hydraulic systems and other critical functions [52]. There is also a need to know when a system has changed from its normal mode of operation. Some contractors inspect equipment after a fixed, in-service period, and some carry out the inspections on a routine calendar basis. Both methods have risk.

Going forward, drilling contractors should work with OEMs to review inspection protocols and develop long-term business plans. An asset management plan that comprises baseline inspection procedures that can define changes in systems and equipment that would require repairs and ensure the assets are fit for continued service. A baseline plan would establish a system of historical performance that can ensure more meaningful capture of real-time information and enable the development of signature testing in a number of ways [53].

5.2 Ram Position Monitoring

Indirect flow meter calculations are used to estimate the ram positions. The gallon count on the surface flow meter is used to estimate the volume of fluid transferred to the rams. Each ram takes a specific amount of hydraulic fluid to activate open, close, lock and unlock functions. If less fluid is used during the ram functioning then it gives an indication that the rams have not fully functioned and would have to be investigated further. Measurement of flow to actuate the ram could be false, if oil has leaked out of the ram chamber. Once the rams are closed, they are pressure tested to make sure they have closed properly.

Ram position monitoring is offered by many vendors and utilizes a broad range of technologies, including direct ram position monitoring, indirect flow meter calculation, tail rod monitoring using ROV etc. It is worth noting that the ram position monitoring is not without its challenges. In some subsea ram tests, the packers on the ram have gotten stuck. In this case the ram position would not matter when the ram packer is not functioning.

Some of the technologies being considered to find the exact position of the Rams in the BOP at all times are described in this section.

5.2.1 GE's Ramtel [30]

Ramtel can provide the position of the rams in real time (Figure 5.11). With some sensors installed on the ram and specialized software the ram's exact position inside the bore of the BOP can be displayed. Some of the key features are:

- Show a direct method to determine ram position in conjunction with indirect flow meter calculations
- Visual indication of ram block location helps to reduce costly errors
- Installed by replacing the current cylinder head with a sensor on the tail rod
- Helps in troubleshooting the sealing or closing issues during operations or testing

Figure 5.11: GE's RamTel [30]

5.2.2 EFC Ram Sensor

EFC is working with Cameron to develop a ram position sensor which can measure the position of the rams with very high accuracy.

5.2.3 NOV's Ram Position Indicator [22]

NOV's ram position indicator is used to find the physical location of the ram using an ROV. It consists of a dial which is placed at the tail end of the BOP operator.

5.2.4 OBAR BOP Ram Position Monitoring

The Obar design works on nondestructive measurements technology and gives current positions of the ram cylinder. The system consists of multiple ultrasonic sensors inside subsea housings. This system can be retrofitted to existing BOPs. The ram position monitoring system is designed to measure the ram position in real time and user defined intervals. The monitoring system can be used during drilling activity or in a disconnected situation. The ram positions can also be transmitted acoustically to the surface.

Statoil, North Atlantic/Sea-drill and Obar AS have in 2011 and 2012 completed the first phase of a JIP where the objective was to develop and deliver an operational unit of a BOP Ram Monitoring package. The ram position monitoring system reports the current position of each individual ram piston thereby knowing the combined effect of the pair of ram. The initial design has been focused around Hydril 18-3/4" 15,000 psi ram, model 15-1/2" and 22" OD ram cylinders [39].

5.3 GE's ROV Readable HPHT Display Panel [25]

When the communication with the MUX control system is lost, the ROV can directly read some data such as well temperature, pressure, accumulator pressure and ram position indicators. All the GE subsea BOP systems can be retrofitted with this display called ROV readable HPHT display panel. The panel is operated by a battery and it is trickle charged from the MUX pods during the normal operation or it can be charged by an ROV during emergencies. The panel gauges get activated by the ROV light and provides digital readout.

Figure 5.12: ROV Readable HPHT Display Panel [25]

5.4 OBAR BOP Surveyor [45]

In a scenario when the LMRP has been disconnected from the BOP due to a kick or emergency disconnect there is no data available on the well temperature and pressure. So it will be useful to know the pressures in the closed well before latching the LMRP onto the BOP. Knowing the exact pressure in the well helps in predicting and balancing the mud weight needed during re-connection.

OBAR has a wireless autonomous data logging system (Figure 5.13, Figure 5.14) which during normal drilling or in a disconnected situation inspects the BOP and displays the pressure and temperature below the BOP rams in real time. Pressure below the lower shear ram and other cavities of the BOP can be monitored. This increases reliability and safety of the operation due to high speed data transfer and storage of data without being connected to the MUX or any other cable. One of the models available enables logging through existing hull mounted

Dynamic Positioning (DP) Transducers on the rig. The data can also be transmitted acoustically to the surface.

BOP Surveyor is a high pressure flange mounted below the Lower Shear Ram or Middle Pipe Ram. A high quality pressure and temperature instrument is fitted inside the probe. This instrument receives pressure and temperature data from the returning mud below the lower ram. The user may access the data from the rig, a nearby boat or a helicopter. The normal planned intervention is with an acoustic transceiver from the rig, either pre-mounted or launched at intermittent intervals. The system has sufficient battery capacity to operate up to 5 years under normal operation with short logging intervals (every 10 minutes). The user may set the desired logging interval from the surface.

The logged information is temporarily stored in the Subsea Datalogger which is equipped with acoustic telemetry to transmit to surface (Figure 5.13, Figure 5.14). The capacity is designed to store a high number of data samples (100,000 - 500,000) and transmitted with a high speed link to the surface for Sonardyne telemetry. At surface the data is processed and stored as per client requirements.

The subsea equipment in rated for 3,000 m (9,842 ft) water depth and all the flange and instrument equipment is rated 15,000 psi and is qualified to DNV-OS-E101 “Drilling Plant”.

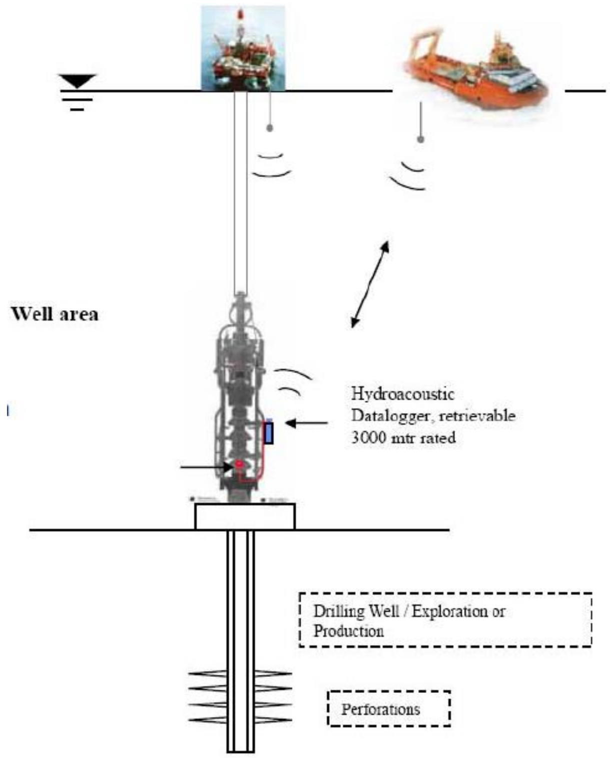

Figure 5.13: BOP Surveyor Operation [45]

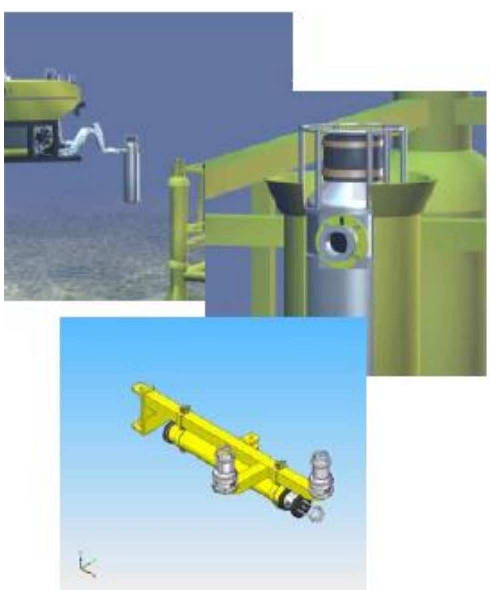

Figure 5.14: BOP Surveyor ROV Operated Version [45]

5.5 Data Acquisition Systems

There are some data acquisition systems called the Black Box which have been developed and are similar to the flight data recorder. Some of the different manufacturers of the Black Box are as follows:

5.5.1 GE's Black Box DDR System [55]

GE's Black Box DDR System is similar to the system deployed on aircraft. This system can record all the information generated during the operation of the BOP control system. This system duplicates the data which is being recorded in the event logger on the rig. The data logged into the black box can survive catastrophic events and can be recovered for forensic analysis.

5.5.2 Ashford Technology's Black Box

Ashford has developed a black box which is used to monitor and record drilling and safety equipment on a regular basis. The main function of this tool is to identify problems before they become critical. This would lead to improving the operations and increasing the safety on the rig which in turn would reduce the need for a black box. The black box could be used a forensics tool in case of a catastrophic event.

5.5.3 NOV's Black Box

NOV's BOP Black box is similar to the flight recorder, has acoustic beacon and hydrostatic release. The black box is located at the edge of the rig, if the rig starts sinking, the black box gets ejected and hits the water and is released far away from the rig. The box sinks into the ocean and can be located from its beacon signal and retrieved using an ROV. The black box records all the activities on the control system.

The older version of this black box has been a rig standard for many years. Located in the drillers shack, the problem was that during a catastrophic event if the rig sinks, the black box system will get lost in the rubble. So this new black box design makes it easy to locate after the rig has sank.

5.5.4 Trendsetter Engineering's Black Box

Trendsetter Engineering is developing a Black box which will remain with the BOP when subsea. The Black box will record all the events from cradle to grave, which is right from completion of BOP assembly till it is pulled out of service. This system will help in identifying the history of all the events concerned with the BOP operation.

6.0 ALTERNATE BOP CONTROL SYSTEMS

If the primary control system fails the back up control system is provided to activate the sequence. Some of the backup control systems available are Acoustic (Refer to Section 7.0), Remote Operated Vehicle (ROV) and Electro Hydraulic control system.

6.1 Remotely Operated Vehicle (ROV) Control System

ROV Control System is used as backup and to assist primary control system to operate the BOPs. Some of the functions performed are:

- Unlatching the riser/LMRP connecter
- Unlatching the choke and kill line
- Shear/close the shear ram
- Close the pipe ram
- Activate the ram locks
- Unlatching the wellhead connector

ROV deployment and operation can be limited by the environmental conditions. Another limitation is the limited pumping capacity of a ROV which would result in a long time to close one shear ram. Also flowing well conditions will create turbulence which will limit the operation of the ROV.

The ROV actuated systems are more reliable today compared to couple years ago. ROV systems are hard wired resulting in limited control systems failure modes and points. However, the ROV unit is not a robust system and has limited operability criteria relative to current and sea states. As ROV’s are very complex systems they require a significant amount of maintenance and do have breakdown issues rendering them unavailable.

Sometimes the ROV’s hose connections are cross connected which are due to human error which can be fixed easily. If the maintenance and testing on the ROV is done properly on the surface then there should be no reliability problems.

6.2 Electro Hydraulic Control System

This system provides a hard wired mode of communication between the subsea BOP and the rig to perform critical functions such as BSR operation and LMRP connectors command function. This system is run on backup power supply so that the failure of the primary system does not affect its functions.

6.3 DTC MODSYS

The control system has one of the highest failure rates on the BOP. When the failure cannot be fixed the well has to be shut in, the LMRP has to be retrieved out of the water to fix the component. The total down time for fixing the problems could take up to 7 days with the rig spread costs of around $1 million per day.

DTC has developed a lightweight, easily configurable, ROV compatible Modular Subsea Control System (MODSYS) which is compatible to work with all BOPs and production and workover system (Figure 6.2) Standardized, segmented units are used that helps in easily configuring for specific jobs without affecting the basic equipment. Using the MODSYS lets an ROV equipped with tooling kit to descend with a replacement control system module and install it in four to eight hours.

MODSYS has capability of real time data analysis to identify subsea component degradation before failure (Figure 6.1). The real time data analysis is done by monitoring electrical signals and how the solenoid is behaving, monitoring pressure versus time downstream of the solenoid, and pressure versus time downstream of all the regulators and directional valves. If the live data indicates that there is a wear, then the control system module can be replaced by an ROV.

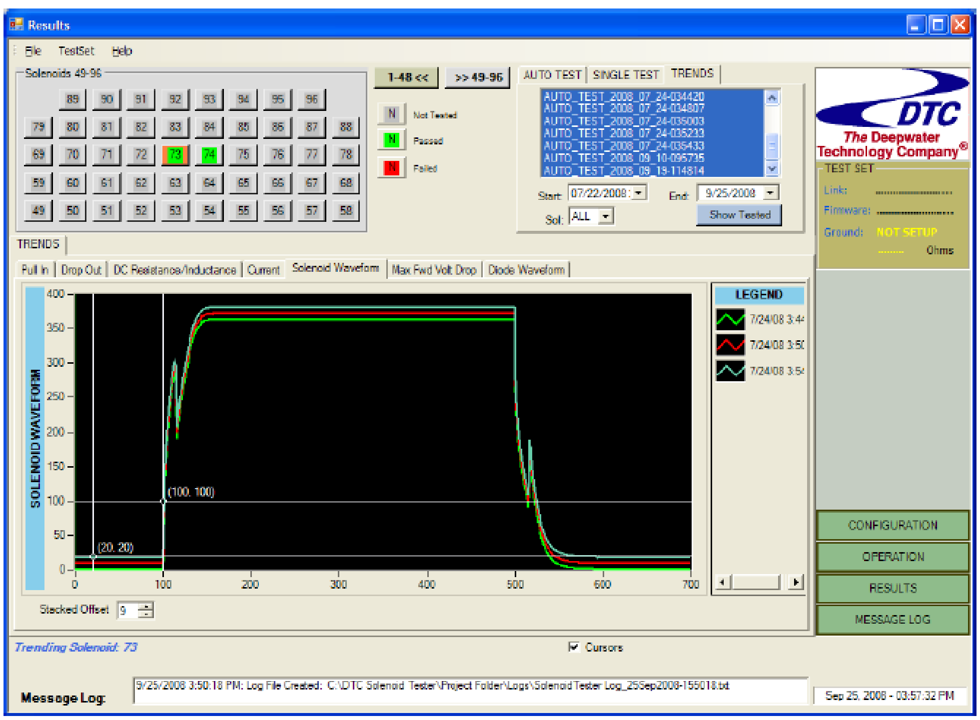

Figure 6.1: Real Time Prognostics [42]

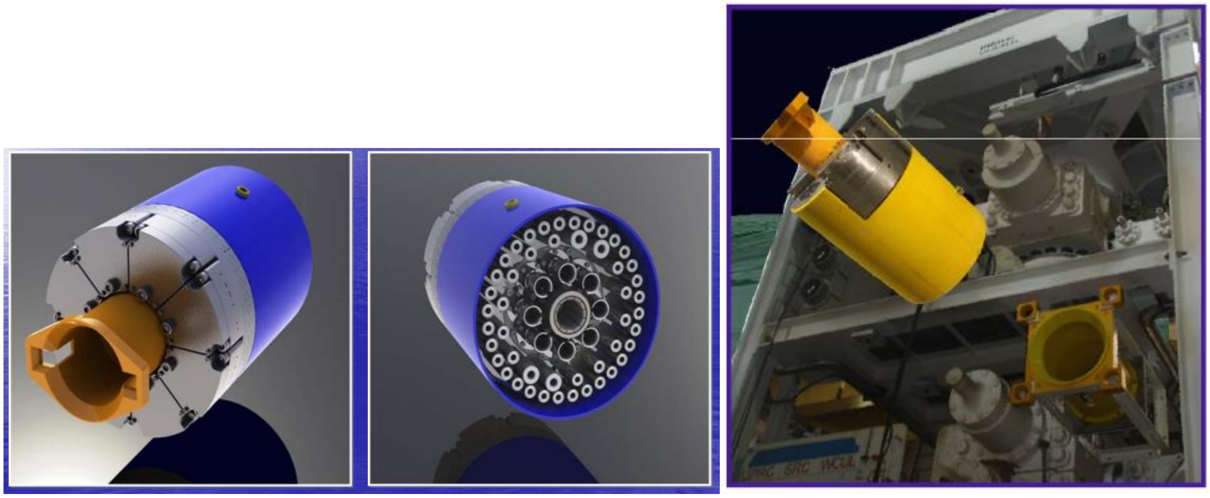

Figure 6.2: DTC Modsys Control System Packaged in ROV Retrievable Modules [42]

MODSYS control was incorporated in the ATP's Oil and Gas Subsea Isolation Device (SID) on the Titan platform in GOM and was in operation for more than 20 months in 4,000 ft of water [33]. The SID (Figure 6.3) which consists of double ram preventer, two blind/shear ram was controlled by the MODSYS system.

MODSYS control system has been on an acoustically controlled SID for two years on the Aban Offshore's drill ship in 8,000 ft of water in Brazil [33].

Figure 6.3: Subsea Isolation Device with MODSYS [42]

The MODSYS control system is lighter weight compared to equivalent control system which results in ease of control system retrieval to the surface by an ROV (Figure 6.4).

System	Weight	LMRP footprint		Weight	Functions
DTC MODSYS®	9,400 lbs	*(24" X 36")*	*112 Functions**	100%	100%
Cameron Mark I	10,000 lbs	*(36" X 34")*	*72 Functions*	106%	64%
Cameron Mark II	15,000 lbs	*(36" X ??")*	*112 Functions*	160%	100%
Cameron Mark III	18,500 lbs	*(45" X 71")*	*120 Functions***	196%	107%
NOV Shaffer	28,000 lbs	*(66" X 66")*	*112 Functions*	297%	100%
Oceaneering	38,000 lbs	*(??" X ??")*	*120 Functions*	404%	107%
GE Hydril	23,700 lbs	*(42" x 108")*	*96 Functions*	252%	86%
Drilling Controls, Inc	24,000 lbs	*(52" X 67")*	*83 Functions*	255%	74%

Figure 6.4: Comparison of Control System (per one Yellow or Blue System) [37]

The MODSYS has a simple design which allows for very reliable system due to:

- Commonality of components such as identical latch mechanism on all the modulus, fewer spares due to interchange ability of parts
- All modules are ported with drilled manifolds which leads to no tubing or fittings, reduces leaks and eliminates assembly errors
- Maintenance takes off line which results in increased up time
- Spare pod not required for pod replacement as few modules are enough for maintenance

6.4 Qualification of New Technology

When new technology has to be qualified, multiple standards and governing documents must be considered as they provide guidance, requirements and input to the process.

DNV-RP-A203 [47]

DNV developed the RP-A203 for qualifying new hardware and software technology which outlines the work processes needed to ensure that new technology is qualified in a systematic and well documented way. This document is published as a recommended practice. Focus is on technologies related to the oil and gas industry where the reliability of the new technology is crucial in order to sustain economically valid field development.

This document discusses the framework of how a technology qualification process will be implemented. The process deals with a structured set of steps, which are intended to provide qualification evidence and to ensure that qualification requirements are met. These steps are: technology qualification basis, technology assessment, threat assessment, technology qualification plan, execution of the plan, and performance assessment.

If the technology in the performance assessment meets the requirements stated in the technology qualification basis, the technology is considered as qualified. If not, the technology must be modified to achieve these requirements.

Multiple acoustic systems have been qualified per DNV-RP-A203 standard.

API RP 17Q [55]

API RP 17Q provides a methodology for qualification of subsea technology. DNV RP A203 covers hardware and software but API RP 17Q is only concerned with subsea equipment. The qualification process is created on Failure Mode Assessment (FMA) and Product Qualification Sheet (PQS). The FMA is a modified form of Failure Mode Effect and Criticality Analysis (FMECA). The PQS contains the information of each component, operating parameters, qualification requirements, interfaces etc. The PQS is maintained throughout the qualification process and is considered the final qualification documentation of a component. The qualification is conducted between the supplier and the operator through the exchange of FMA and PQS. When the acceptance criteria and requirements are met then the technology is considered qualified.

Technology Readiness Level [49]

Technology Readiness Level (TRL) is not a standard but is a systematic measurement system where the maturity of a particular technology is assessed. The original TRL was developed by NASA for the aerospace industry. It consists of TRL1 to TRL9 where the first level indicates that the basic principles were observed and reported for technology and the last level proves the technology through successful operation.

Multiple companies such as Statoil, Aker Solutions, BP have developed guidance in qualification of new technology within company and to suppliers that supply new technology.

7.0 ACOUSTIC CONTROL SYSTEM

7.1 Acoustic Control System

The Acoustic system is an emergency backup system used in case of failure of primary control system. It is separate from the primary control system and is designed to operate the below selected functions in case the primary control fails. Possible failures include:

- Transmission of signals
- Mechanical operation of control pod
- Loss of power fluid pressure

Critical emergency functions such as shearing the pipe and securing the well are performed by the acoustic control system by using the stored energy in the subsea accumulator.

7.2 History

Acoustics is the scientific study of sound which includes sound generation, transmission, and reception. The sinking of Titanic in 1912 and the start of World War I provided the impetus for the next wave of progress in underwater acoustics. Anti-submarine listening systems were developed. Between 1912 and 1914, a number of patents related to use of sound to locate objects were granted in Europe and the U.S. The development of both active and passive sonar *(Sound Navigation and Ranging)* proceeded rapidly during the war, driven by the first large scale deployments of submarines.

In 1919, the first scientific paper on underwater acoustics was published [5] theoretically describing the refraction of sound waves produced by temperature and salinity gradients in the ocean. The range predictions of the paper were experimentally validated by transmission loss measurements.

After World War II, the development of sonar systems was driven largely by the Cold War, resulting in advances in the theoretical and practical understanding of underwater acoustics, aided by computer-based techniques [15].

Acoustics has evolved over the past one hundred thirteen years. Again another milestone in acoustic history was reached with digital subsea acoustics. Digital acoustics could provide primary control of the blowout preventer from the rig, support vessel or anywhere in the world using a satellite link.

Different types of equipment utilize different frequencies. The high frequencies have short range but usually are good for high resolution applications. The low frequencies have long range but usually are good for lower resolution capability. Therefore, it is important to match the appropriate frequency to the desired application. Figure 7.1 is an example of different frequency range for different applications.

Figure 7.1: Frequency Range for Different Applications [17]

7.3 General Description

Acoustics usually refer to any system which operates underwater using signals within the "Acoustic Spectrum". Acoustic systems are used in a variety of applications such as [17]:

- Control (Blowout Preventer)
- Positioning (Dynamic Positioned Vessel, Remotely Operated Vessel, Autonomous underwater vehicle)
- Communications (Divers)
- Data Transfer (Loggers, Autonomous underwater vehicle)
- Imaging (Remotely Operated Vehicle Navigation)
- Profiling (Bathymetry)
- Sound Velocity Measurement (for ensuring accuracy of acoustic systems)

The acoustic control system is a remote control system that eliminates the requirement for either fixed electric cables or hydraulic control lines linking the surface and the subsurface wellhead equipment. Control cables or lines are susceptible to physical damage from various sources. If these cables become severed, complete loss of control of the subsea equipment is experienced.

The acoustic control system is an optional secondary emergency backup system which allows functioning of critical BOP stack functions using underwater acoustic communication signals. An acoustic system is independent of the primary blowout preventer control system, allowing continued control of select, critical functions if the surface control system was lost for some reason. The acoustic system can be adapted to a Conventional control system or the Multiplex (MUX) control system.

Acoustic BOP controls are unaffected by any damage to the primary hard-wired system. These are remote sonar systems using coded pulse or burst signals, with frequencies in the 5-40 kHz range. Systems consist of a surface unit that is fixed or portable or both (rechargeable), thru-hull mounted transducers and/or dunking transducers and subsea transceivers and hydraulic control pod mounted on the subsea BOP stack. The electro/hydraulic subsea module is interfaced with the primary BOP hydraulic control system.

The principal function of acoustics is to have the ability to shut in the well during drilling operations using the BOP and to disconnect the LMRP through the use of encoded acoustic signals. Acoustics would be used only as a last resort or if all the other methods have failed [18]. Acoustic back-up systems have been mandatory in Norway since 1981 and are mandatory when working with Petrobras in Brazil. They are not frequently used in the US GOM. These systems use independent accumulators and are independent of the regular controls in an emergency situation [23]. The two broad types of signals used in acoustic systems are:

- Analog
- Digital

Analog systems have been used for a long time in the industry. Monotonic analog systems are basic acoustic systems which operate using single frequency transmissions (Figure 7.2). There are many older BOP systems which still use an analog system. Up until the mid-nineties, a large proportion of the underwater acoustic world operated with monotonic frequencies [17]. During the nineties, more companies began to use Compressed High Intensity Radar Pulse (CHIRP) which is a signaling technique taken from the Radar industry (Figure 7.2). More advanced systems utilize CHIRP signalling which reduces interference, and increases accuracy and range. The analog systems are limited to 8 - 16 channels. Conventional narrow band acoustic signals have a frequency that does not change appreciably with time. There are several problems with this approach. For instance, narrow band signals are subject to catastrophic interference. This could occur when another signal of the same frequency is transmitted in the near vicinity of the desired signal. This could also occur due to poor immunity to propagation multipath or reflections of the original signal. Additionally, a constant-frequency signal is easy to intercept, and is therefore not well suited to applications in which information assurance is important.

Figure 7.2: Monotonic and Chirped Signal [17]

The delivery of digital systems commenced around 10 years ago. Digital acoustics have been used for positioning for the GOM and Campos basin when multiple drilling rigs have been operating to avoid channel interference. Analog systems have limitations of 14 channels in while digital systems can have hundreds of channels.

7.4 Applications / Functions Served by Acoustics

7.4.1 BOP

The main functions of the acoustic system for BOP equipment are back-up control of emergency safety critical functions and activating emergency disconnect sequences.

The acoustic control system can be programmed to perform any emergency safety critical function such as shearing the pipe and securing the well by using the stored energy in the subsea accumulator.

There are two independent receptors in the BOP actuating an acoustic pod with dedicated hydraulic accumulators, independent from other BOP systems, with usable fluid volume at least to complete LMRP disconnection sequence increased by 10% [8]. The accumulators shall have pressure monitoring and pressure gauges for verification with ROV. The acoustic system can actuate the following functions:

- Closing and locking of blind shear for shearing drill pipe
- Closing and locking of casing shear
- Closing and locking of the pipe ram
- Retraction of stacks or unlocking of kill/choke connectors
- Primary locking of the LMRP connector
- Secondary unlocking of the LMRP connector
- Other necessary functions for the safe disconnection of the LMRP

7.5 TYPICAL ACOUSTIC EQUIPMENT CONFIGURATIONS

The three main companies supplying back up acoustic BOP control systems are Kongsberg, Sonardyne and Nautronix which support offshore drilling operations.

The main components in a typical subsea acoustic control systems are (Figure 7.4):

Surface equipment

- Surface control units (one fixed and one portable with the same function)
- Transducers (hull mounted for the fixed control unit and portable)

Subsea equipment

- Subsea Control Unit (SCU) or Subsea Electronic Module (SEM)
- Transducers (one on each side of the BOP)
- Subsea valve package (solenoid valves and pilot valves)
- Accumulators
- Shuttle valves

The acoustic system (Figure 7.3) is completely independent as it has its own power supply and hydraulic resources. The subsea system is located on the BOP stack and includes a Hydraulic Block, the Hydraulic Valve Package (HVP), a set of accumulators, the acoustic Subsea Electronic Module (SEM) and two transducers assembled on arms with an automatic deployment system. The HVP contains the valves of hydraulics but also the solenoids ordered by the acoustic SEM. It is fed by accumulators specific to the acoustics. The transducers connected to the SEM make it possible to communicate with the rig surface. The SEM which is autonomous due to its lithium battery contains all the electronics of command [19].

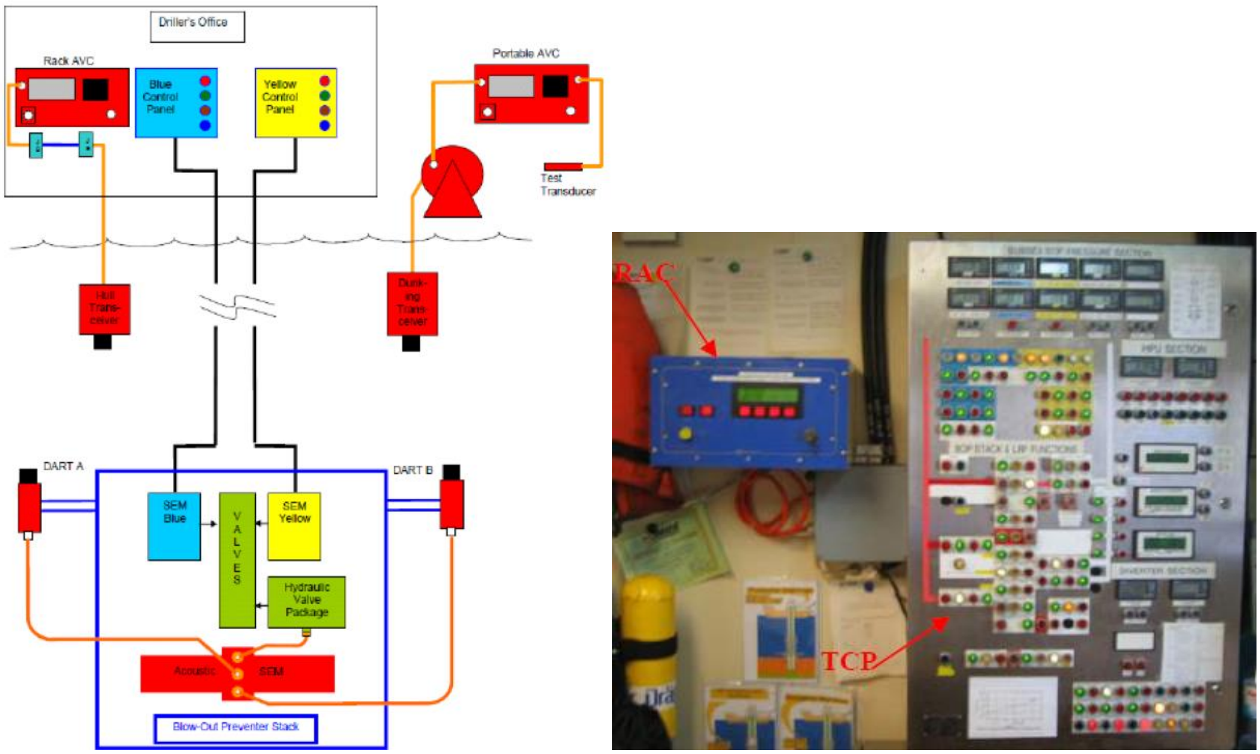

Figure 7.3: Acoustics System Schematic and Acoustic System (Blue Box) Hardwired on the Rig [21, 19]

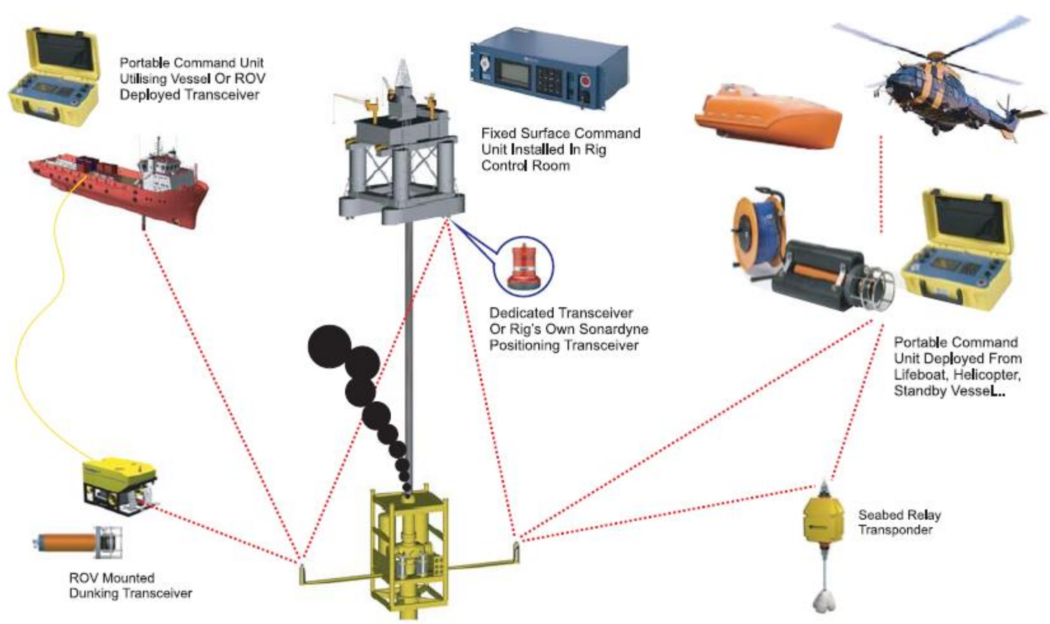

Figure 7.4: Application of Acoustic System [20]

7.5.1 Surface Equipment

The fixed unit (Figure 7.5) is installed permanently on the drilling rig and operates through a hull mounted acoustic transceiver.

If the rig is fitted with an acoustic positioning system manufactured by the same company as the BOP acoustic control system then the existing hull mounted transceiver could be used. The beacons used by the dynamic rig positioning can be used for BOP acoustics only if it is made by the same vendor. If not, the transceiver is mounted on the hull. Each acoustic vendor's equipment generates different signals which are not compatible with other vendors.

Hull Transceiver (Figure 7.5) are the fixed surface transceiver which are installed on deployment poles and are typically 10-15 feet below the vessel hull and clear of the main noise source such as the ship's thrusters.

The fixed control unit has buttons to initiate an EDS and a digital display which provides operating instructions and status information.

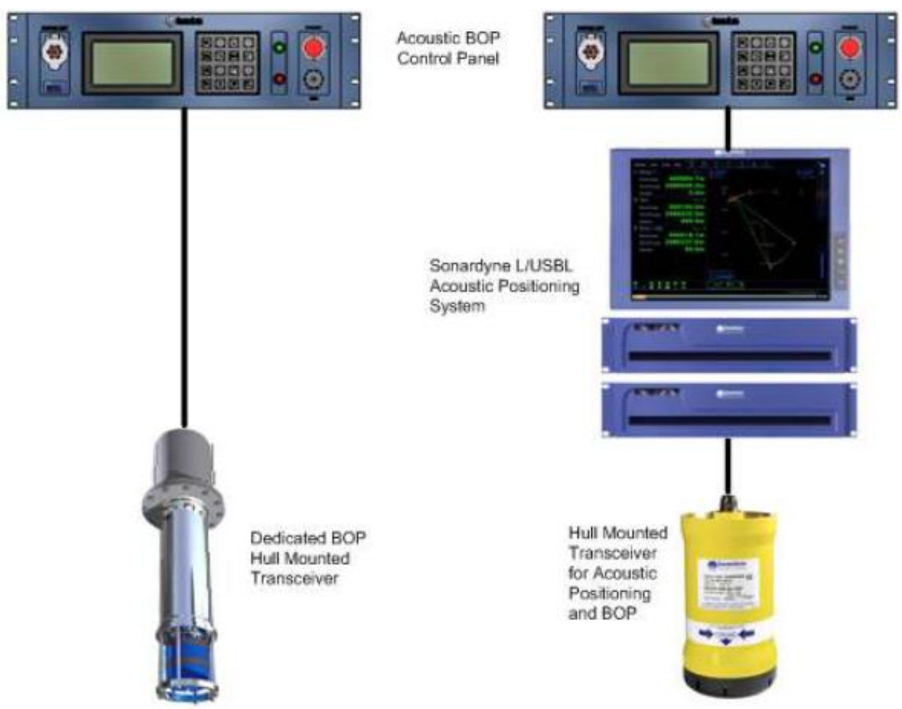

Figure 7.5: BOP Control System [12]

The portable control units are self-contained units and can be used instead of the fixed unit. Multiple portable units can be used such as one placed next to the each lifeboat in case there is no time to activate the acoustic system from the driller shack. The portable units may be taken on a lifeboat or in a helicopter and used to shut in the well in case of an emergency well control scenario.

The portable units are housed in a splash-proof portable case, with carrying handle and strap for easy deployment and have an internal rechargeable battery with over 10 hours of operation per charge. It can be operated via the PC display using a touch screen/ trackball combination [19].

If the master system does not function then the manual control system can be used for control, if the manual system fails than the portable unit can be used. In case of a blackout on the rig, the portable unit can be opened and powered within 30 seconds.

Multiple functions can be defined such as an emergency system which may perform a single automatic and predefined sequence of BOP valve operations with a two hand, two-button operation. Using a two hand, two button operation promotes safety as it avoids activation of the system by mistake. The portable unit is supplied with a dunking transceiver and cable (Figure 7.6).

The portable unit is a self-contained unit that can be used as an alternative to the permanently installed surface unit. It can be operated from a small vessel, a life raft or a helicopter, using the dunking transceiver and cable supplied.

The portable dunking transceivers can be water depth rated to around 12,000 ft (depending on the manufacturer) and can be fitted to an ROV. During a subsea blow-out, the portable transceiver fitted to an ROV can be moved close to the wellhead to communicate over a shorter range and away from any oil and gas plume. This gives a much higher signal to noise ratio and higher probability of successful communication [12].

Different dunking transducers (Figure 7.6) are used depending on the water depth the acoustic system is used. Some typical transducer configurations are:

- 50 degree dunking transducer suitable for use in water depths down to 4500 ft operations.
- 30 degree dunking transducer suitable for use in water depths down to 12,000 ft operations.
- 180 degree dunking transducer suitable for use in water depths down to 1,500 ft operations.

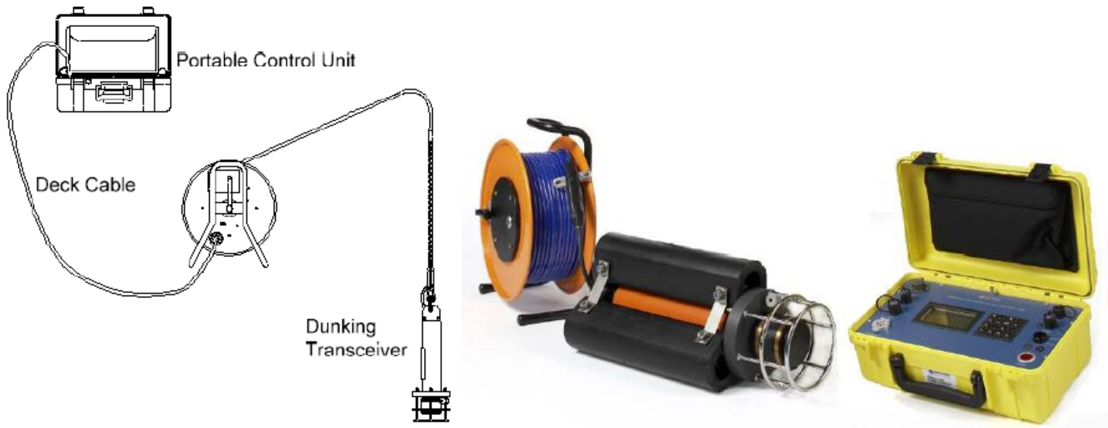

Figure 7.6: Portable Surface Control System [12]

7.6 SUBSEA EQUIPMENT

The subsea system (Figure 7.7) consists of a Subsea Control Unit (SCU) also called SEM, two independent units which makes the subsea equipment fully redundant. Each SEM is equipped with:

- Transceiver
- Control & sensor electronics
- Transducer
- Lithium battery

The subsea system is fully redundant and consists of two acoustic transceivers with an option of having up to four transceivers. The transceivers are connected to the SEM in the BOP.

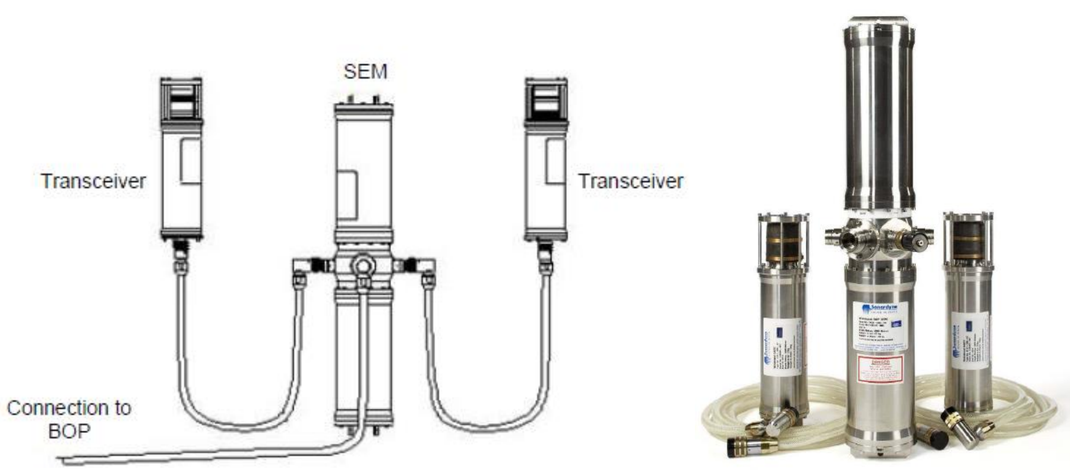

Figure 7.7: Subsea System [12]

The SEM provides the interface to the OEM BOP and functions up to 12 pilot valve solenoids to operate the BOP hydraulic functions and reading back up to 12 pressure operated status switches and 4 analog sensors which indicate the internal status of the BOP. The SEM can interface to BOPs from all of the major manufacturers.

For full redundancy, the subsea system consists of two separate SCUs and two Subsea Communication Transducers along with two interface cables to the BOP. The SCUs are mounted on the BOP and translate acoustic command signals from the Accumulator Control Unit (ACU) into operational commands which are used to operate hydraulic control valves on the BOP. Once the command signal has been given (by the operator), a confirmation signal is transmitted by the SCU to the surface main control unit. For improved reliability, the control system can also read the status of the SCU including various hydraulic control valves and sensor read backs [12].

Two subsea redundant acoustic transceivers are used on the BOP. If the riser is damaged and is tilted to one side of the BOP, then there is a chance of failure of one of the transceivers. The two redundant transceivers also help in avoiding the masking of the signals by the riser.

All housings are constructed from super duplex steel and the system is depth rated to 12,000 ft. The SEM is self-powered by a battery or by an umbilical connection. The battery can be run for up to 18 months.

The subsea transceivers are installed on arms which are typically 8-10 feet long (Figure 7.8). The arms swing out from the BOP stack to enable an unobstructed 'line-of-sight' path to the surface for reliable communication.

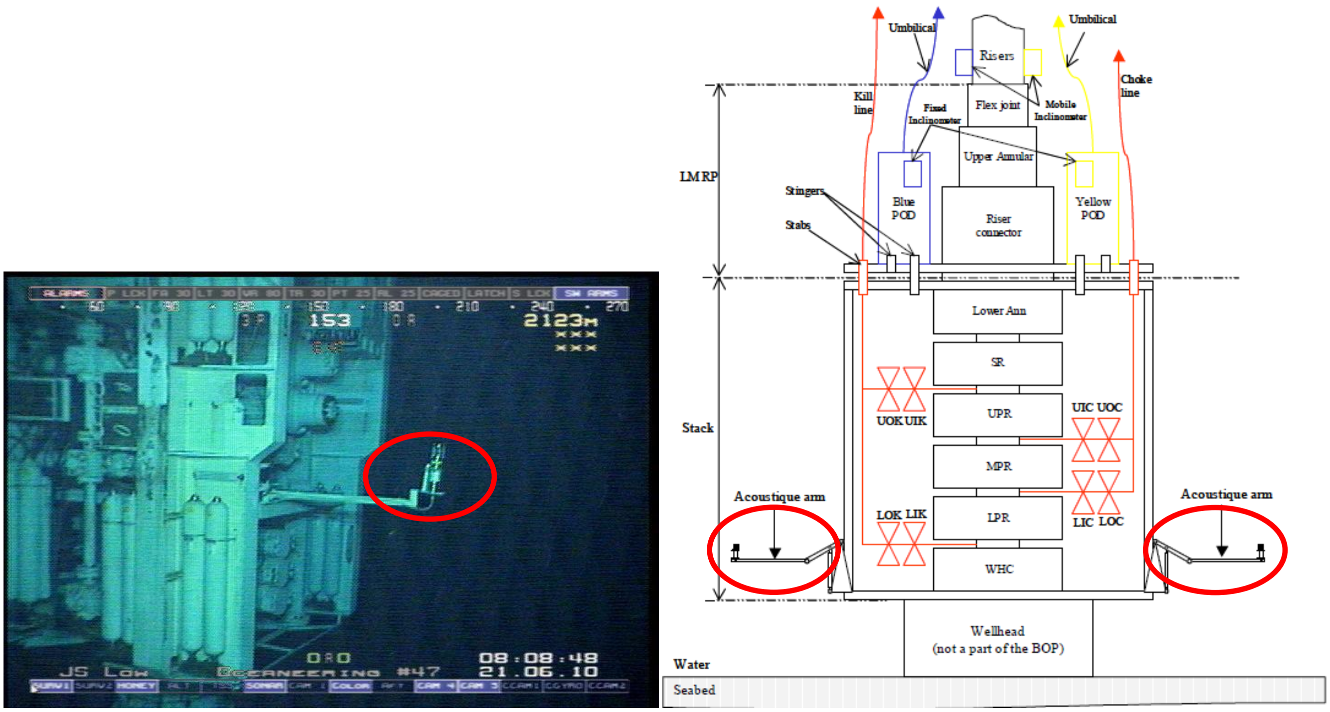

Figure 7.8: Placement of Transponders Attached to Arms on BOP [12, 19]

7.7 CHALLENGES OF USING SUBSEA ACOUSTICS

Some of the historical issues associated with older generation (mid 1970's) acoustic BOP control systems were failures due to housing integrity, battery life and component reliability. These issues caused a loss of confidence by the drilling community [23]. Some of the present challenges and solutions associated with using acoustic BOP technology are listed below:

7.7.1 Additional Requirements

When using acoustics there are many additional requirements that need to be taken into consideration such as; the volumetric capacities of the accumulators needed to meet or exceed the provisions in API 53, Section 13.3. If the acoustic system is used as a secondary control system, it must be demonstrated to BSEE (ref. §250.416) [36] that the acoustic system will function in the proposed environment and conditions of the specific well. This includes written procedures for operating the BOP and proper techniques to prevent accidental disconnect of BOP components and competency of authorized personnel trained to operate and maintain BOP components. Requirements range from; equipment, training, maintenance, meeting standards and additional associated costs to use acoustics as a control system.

7.7.2 Installation

Acoustic pods are bulky and space for secure placement is limited on the stack. These transceivers can be positioned up to 300 ft away from the BOP on tripods for a direct line of sight.

7.7.3 Training

The subsea personnel that will be functioning or maintaining the acoustic control system on the rig are required to be trained in the proper operation and maintenance of the equipment. As this equipment will be used for emergency purposes, the offshore personnel need to be fully conversant in the operation of this equipment [6].

7.7.4 Single Point Failure

All functions utilized with an acoustic system require the installation of an additional shuttle valve per function on the BOP the acoustic system will be actuating (i.e. valve, ram, connector, etc.), creating a possible leak point (Figure 7.9) or additional single point of failure. If the shuttle valve fails, the critical safety functions on the BOP system cannot be activated via electro-hydraulic, MUX cable or acoustics, and would ultimately lead to pulling the BOP stack so that the failed component could be investigated and corrected.

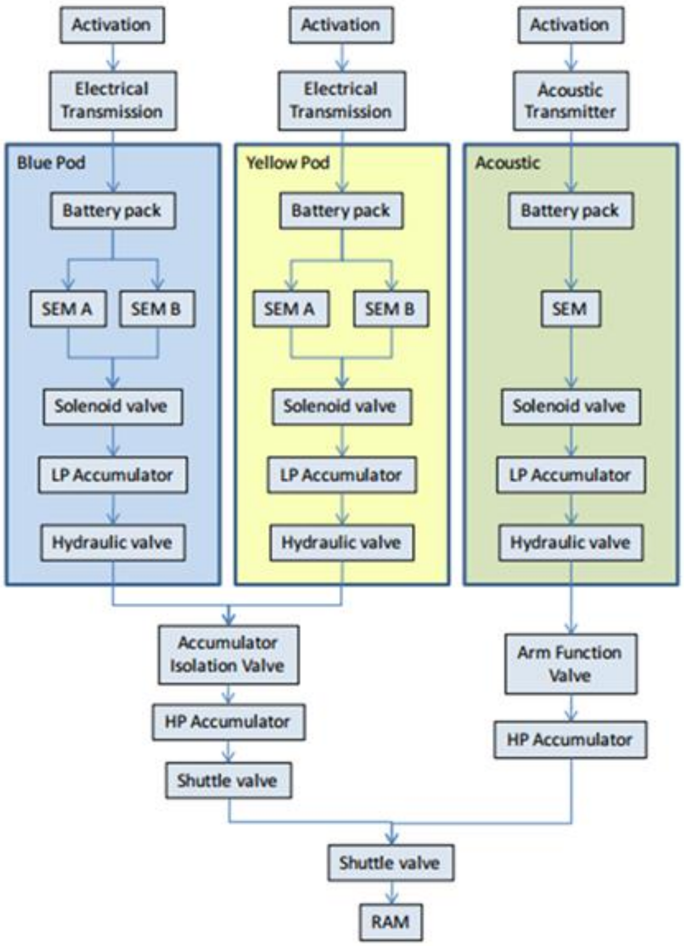

Figure 7.9: Single Point Failure at the Shuttle Valve [61]

7.7.5 False Activation

There is potential for false activation of the acoustic system subsea due to following reasons:

- Receiving signals from other acoustic systems in the area (chances are low)
- Water or air ingress in the acoustic valves or electric cabling
- Inadvertent release of the disconnect button by rig personnel

The following two case histories indicate the potential failure modes of acoustic back-up control systems:

- An incident was reported as a result of air being introduced into the acoustic system through the cables which led to the disconnection and damage of the LMRP. Root cause of failure: Cables were not properly tested prior to the deployment.

- An acoustic control system was subject to accidental activation. The BOP was pulled due to the unknown events that led to the activation. The accident was investigated by going through the operation log in the acoustic control unit and it was found that the system was activated by rig personnel by mistake.

7.7.6 Functioning During Blowout

Noise from a Wild Well [12]

There has been a concern of how the noise from a wild well or other subsea noise may interfere with the successful transmission of the acoustic signals to the BOP stack. Noise from a wild well could be the high flow of drilling mud, oil, gas or the mixture of all the above. The issue of the extreme level of noise from a wild well has largely been a source of concern for acoustic control systems. Acoustic systems were employed during the Macondo incident and gained operational experience during the aftermath demonstrating reliable two-way acoustic communication can be consistently achieved, even within a few feet of the blowout [12].

During the Macondo operations to cap the well, a number of acoustic transponders were connected to pressure sensors within the containment cap. These transponders were located only feet away (Figure 7.10) from the venting plume and were interrogated every few seconds by an ROV-mounted transceiver. They were able to consistently transmit pressure data in real time despite the extreme levels of noise present.

Additionally valuable information on the level and spectral content of the noise was gathered by the acoustic supplier, which will be used to produce further enhancements to acoustic BOP backup systems.

Figure 7.10: Transponders Operating Close to Subsea Blowout [12]

Oil and Gas Plume in the Water Column [12]

No test data was found to be available to establish if an acoustic control system would work when the well is flowing with mud, oil or gas plume during a blowout condition. One test that has been performed as part of new rig commissioning is dumping all mud tanks into the moon pool to intentionally create a mud plume between the hydrophones and sea floor beacons. This test consistently interrupted communications with older acoustic systems (pre-1990). With some modern acoustic systems this test does not noticeably affect operation. It is not known how close this test resembles a plume of well bore fluids at the BOP, nor has this test been performed with all modern acoustic systems [6].

Even with widely spaced dual stack mounted transceivers, communication cannot be relied upon in the presence of mud clouds or gas plumes. There has been some experimentation with placing remote hydrophones or relay beacons on the sea floor 100 m (328 ft) from the BOP stack to improve communications during a blowout; however, to date no published results have been found.

The subsea blowout with a large oil and gas plume present in the water column above the wellhead can have a detrimental effect upon acoustic signals which pass through it, and for this reason, a system has been developed to circumvent any plume. The surface transceiver can be fitted to an ROV and during a subsea blow-out the ROV can be moved close to the wellhead to communicate over a shorter range and away from any plumes. In doing this, a much higher signal to noise ratio and greater probability of successful communications is established.

Additionally, a relay beacon or hydrophone can be deployed on the seabed at the beginning of a drilling operation, a suitable distance away from the wellhead, where it can communicate horizontally to the BOP. This enables acoustic signals from the surface to avoid the need to pass through any oil and gas plumes in the water column below the rig to the BOP. The signals can be transmitted from the rig, received by the relay transponder and passed to the transceivers mounted on the BOP. This capability is present within the current generation of acoustic BOP control systems and provides a flexible range of communication options (Figure 7.11).

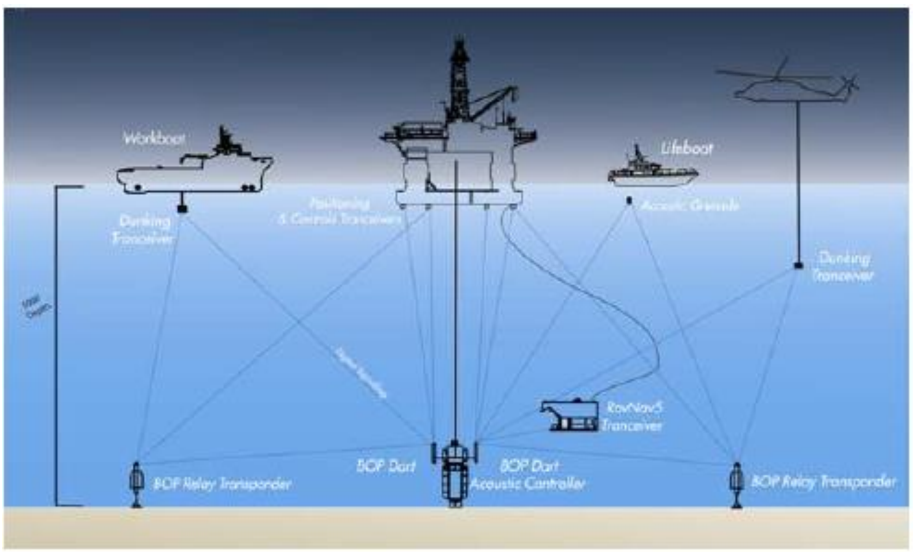

Figure 7.11: Communication Path Options [12]

7.7.7 Environmental Conditions

Areas with high ambient noise subsea have experienced issues with acoustic systems. Some of the challenges in designing subsea acoustic systems are listed below:

<u>Multipath Effects [12]</u>

Operating in a wide range of water depths has caused issues in the Gulf of Mexico. Rigs have experienced problems moving from deepwater to shallow water, where some of the areas of operation are in only a few hundred feet of water. The gain (filter setting) of the system was set for deeper water. The transmitted commands would reverberate between the surface and seafloor and is known as “multipath”. The BOP-mounted receivers could not decode the commands and thus did not function properly in shallow water. System gains were reduced to eliminate the multipath effect. Similarly, problems arise if a rig set up for shallow water moves to significantly deeper water. In this case, a signal that worked in shallow water may be too weak to reach the BOP in deep water. Depending on system design, changing transmit gain may require system modification by the manufacturer [6].

There is an abundance of reflections from hard surfaces. Vertical channels are characterized by little time dispersion, whereas horizontal channels may have extremely long multi-path spreads, whose value depend on the water depth. As per acoustic manufacturers as long as the horizontal system is not greater than the vertical distance, there is no issue with transmitting signals.

Thermocline [12]

The difference in temperature between water layers (deep water thermocline) and variations in salinity will affect the transmission of the acoustic signal to the BOP stack when installed in deep water. While it is true that variations in temperature (deep water thermocline) and salinity between water layers can cause refraction of acoustic signals, this is absolutely not an issue for the vertical or near-vertical communication path between a drilling rig and its BOP stack, and only affects communications over long horizontal distances. If the horizontal range does not exceed the water depth, there will be no issues due to refraction.

For example, for a wellhead located in 1,000 m (3,280 ft) water depth, the area on the surface from which communication will be entirely unaffected by thermal or salinity differences, would be a diameter 2,000 m (6,561 ft) centered above the wellhead.

This is clearly demonstrated by the fact that every deepwater dynamically positioned rig and drillship uses an acoustic positioning system in addition to GPS/DGPS, as a reference input to the dynamic positioning system. These systems operate by using a hull mounted acoustic transceiver to interrogate, and receive replies from an array of seabed acoustic beacons over a transmission path that is very similar to that of an acoustic BOP system (i.e. near-vertical). These systems operate 24 hours a day 365 days a year in all regions and all environments from tropical to arctic, without suffering from any form of unreliability due to thermal or salinity effects.

The acoustic manufactures can model acoustic transmission paths based upon detailed measurement of the sound velocity profile through the water column. The manufactures can provide evidence from many different locations, to confirm that near-vertical acoustic propagation does not suffer from any such unreliability.

A typical sound velocity profile and raytrace from the Gulf of Mexico is shown below (Figure 7.12) for illustration. Ray tracing is used to calculate the path of sound through the ocean up to very large distance.

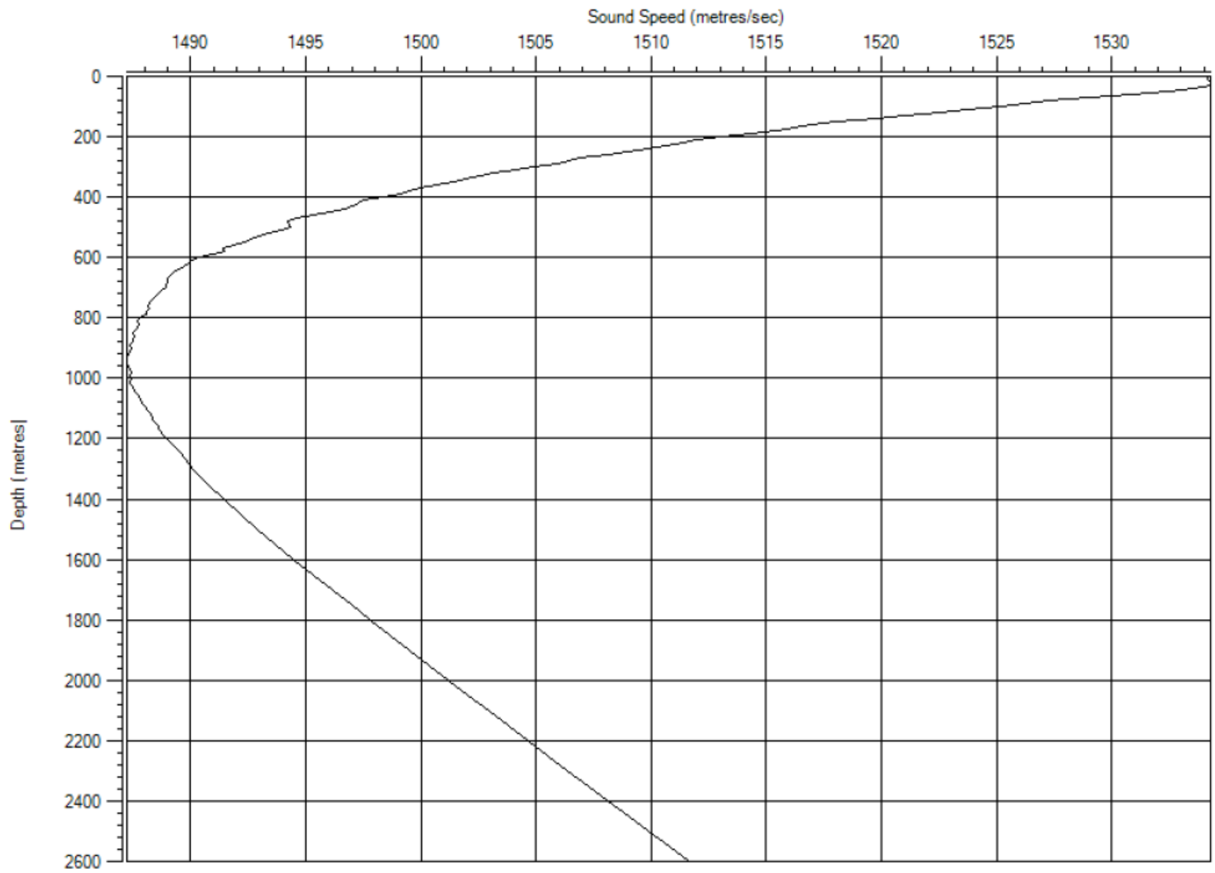

Figure 7.12: Sound Speed Variation with Water Depth [12]

Figure 7.13 shows variation in sound speed (horizontal axis) plotted against water depth (vertical axis) from the surface to 2,600 m (8,530 ft) depth. As is typical for a sound velocity profile, the variation in sound speed close to the surface is due primarily to thermal effects, whereas below 1,000m it is due principally to pressure effects. The manner in which this sound speed variation affects the propagation path is shown in the plot below.

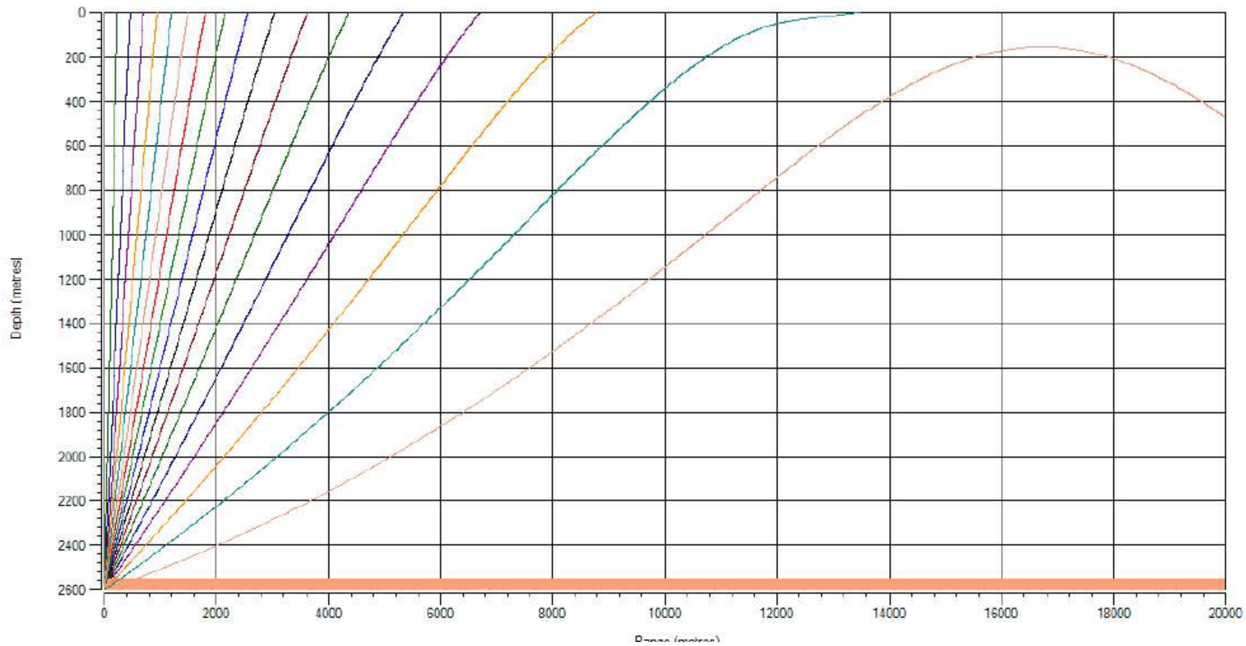

Figure 7.13: Propagation Path to Seabed (2,600 meters) to Surface [12]

This plot shows the path taken by sound waves launched from the seabed at different angles and clearly shows that the propagation path is essentially a straight line until the horizontal range reaches 8,000 – 12,000 m (26,246 - 39,370 ft), i.e. 3 to 4 times the water depth. Only beyond this range do the effects of refraction begin to have an impact. If the rig remains within a horizontal range of 8,530 ft (equal to the water depth) the propagation path is completely unaffected by refraction.

Signal to Noise Ratio [6, 23]

Some of the subsea noises are classified as manmade or ambient noise. Manmade noise is mainly caused by machinery noise such as; thrusters, pumps, reduction gears, power plants or shipping activity such as hull fouling, animal life on hull, cavitation, etc. The ambient noise is due to hydrodynamics for example; movement of water, tides, currents, storms, wind, rain, seismic and biological phenomena. Noise can come from many sources such as:

- Drill string impacting riser – low frequency
- Thruster noise – fixed speed variable pitch thrusters are noisier than fixed pitch variable speed thrusters
- ROV generated noise
- General field noise from additional vessels
- Self-noise due to reverberation of transmitted signals from nearby structures

- Other users in drilling locality with acoustic systems that use the same or similar frequencies

Subsea noise interference with the acoustic signal from the surface is one of the main challenges faced by the drilling contractors [23]. The manufacturers of acoustic BOP control systems specify water depth capability based on the assumption of "normal" noise levels. But acoustic system performance depends on a number of factors, one of which is the signal to noise ratio at the receiver. There are receivers both at the surface and on the stack. Noise generating components on the surface (such as thrusters) are managed during the design and commissioning of the rig.

As mentioned, noise affects acoustic telemetry and positioning systems, causing loss of communications. All acoustic telemetry systems require a specific signal that is greater than the in band, or in channel noise that the receiving device is operating within. If the noise level rises such that the signal cannot be detected, then communications are lost. The perception of noise also manifests itself due to additional attenuation of signals. One of the more common forms of signal attenuation is air. Thrusters operating at high tip speeds under DP drilling vessels cavitate the surrounding water, causing "clouds" of aeration within the water and causing additional attenuation of the signal over standard attenuation coefficients.

Line of Sight [23]

The two communicating transducers/transceivers must be able to acoustically "see" each other. Line of sight communication is a requirement of acoustic systems. Stack mounted components have not always been located such that clear line of sight to the surface is present. These problems are solved with current generation systems with the deployment of dual stack mounted transceivers on arms such that clear line of sight to a single surface transceiver is possible regardless of the relative geometry of the stack and the rig mounted transceiver.

Range and Bandwidth

Long range requires low frequencies which do not support high data rates. Long-range systems that operate over several tens of kilometres may have a bandwidth of only a few kHz, while a short-range system operating over several meters may have more than a hundred kHz bandwidth [6].

Interference

The older analog systems could interfere with or falsely initialize the acoustic system. The digital acoustics are used in multiple subsea applications such as vessel positioning and construction and do not interfere with each other.

Latency

The speed of sound through water is 1,500 m/s so there is a time delay of few seconds in activating the acoustic systems depending on the water depth.

7.8 Equipment Failures

Downtime

As any subsea failure, the cost of failure is significant. To fix any faulty acoustics, the well has to be plugged and the BOP stack would have to be pulled, repaired on the surface and run back into the water. A single failure could potentially cost millions of dollars in a deep water operation.

Housing Failures

There have been problems with water entering the acoustic housing during subsea operations. This has been improved by using triple redundant seals in the housing covers and water integrity tests (hydro test) completed before operation.

Maintenance

Additional equipment creates additional maintenance time, pre-run function test time, and troubleshooting difficulty. When the BOP is pulled out of water and if the battery on the acoustic system is 50%, then the battery is changed. Normally the batteries are changed after 6-9 months.

The BOP acoustics have specific channels which are used for communication. If nearby rigs or supply vessels use these channels for some other purpose, this could lead to shortening the battery on the acoustics system.

Weekly Tests

Most drilling contractors are not confident of completing the weekly function tests on the acoustic system. If the acoustic system subsea does not communicate with the surface unit, it is usually tested again in couple of hours till the transmission is successfully completed. In the worst case scenario the BOP stack has to be pulled to the surface so that the acoustic system can be fixed.

8.0 RELIABILITY OF ACOUSTIC SYSTEMS

Reliability of the current acoustic system under consideration is measured by the following two criteria:

- Reliability of acoustic signal when transmitted and received
- Reliability of acoustic Subsea Electronic Module (SEM)

There is a lack of reliability data on acoustic BOP operation. Analog BOP acoustics have been longer in operation than digital BOP acoustics. As such there is more reliability data on analog acoustics compared to digital acoustics. Digital BOP acoustics were introduced in 2003. Therefore limited amount of operational reliability data is available. There is also not much information about incidents where an acoustic system has been used to operate the BOP during a blowout, either successfully or unsuccessfully [7]. Due to this lack of significant reliability data for digital acoustic system, the statements in the following sections have to be further evaluated as more and more data becomes available.

Some of the key references in this review include:

- Study A - Phase II, Reliability of subsea BOP systems [5]
- Study B - Phase IV, Reliability of subsea BOP systems [5]
- Study C - Phase V, Subsea BOP systems, Reliability and Testing [5]
- Study D - Phase I DW, Reliability of subsea BOP systems for Deepwater Application [5, 24]
- Study E - Phase II DW, Reliability of subsea BOP systems for Deepwater Application [31]
- Study F - Guidelines on subsea BOP systems [38]
- Study G - Reliability of Acoustic BOP Controls [5]

8.1 RELIABILITY DATA REVIEW

In the BOP studies carried out by SINTEF [31] in the 1980's and early 1990's, reliability data for analog acoustic systems were systematically collected. It was observed that from time to time it could be difficult to communicate with acoustic signals through the water column due to temperature layers that could be present in the water column. It has conservatively been assumed that the acoustic system will function as required in nine out of ten attempts.

In the study conducted by Oil and Gas UK [38] in July 2012, they suggested that acoustics ha questionable reliability and can be affected by subsea noise when used near development cluster wells with flowing subsea injections wells. There is also a suggestion of adjusting, verifying and calibrating the acoustic system for the water depth and environment in which it will be used.

Table 8.1 shows the available statistical data regarding acoustic BOP control system reliability [5]. The latest data available were for 1992 - 1996 which shows that there were thirteen failures recorded in 3,718 BOP days when acoustic system were used in drilling in Brazil, Norway, Italy and Albania. Looking at all the data available it can be seen that the reliability has increased from 35 failures/6,161 days = 0.005 failures/day to 13 failures/3,718 days = 0.003 failures/day. Failures on the acoustic systems were typically noticed during testing of the acoustic systems. Weekly function testing of the acoustics system when the BOP is located at the seafloor was a requirement starting from 1992. More testing was conducted after 1992 compared to previous years. This shows that even though more tests (more samples) were conducted after 1992 less amount of failure was observed.

The Study E was conducted on the Gulf of Mexico (GOM) wells and the BOPs did not have acoustic backup control system.

Table 8.1: Acoustic Reliability Data Experience [5]

Year Completed	Study	Drilling period and area	No. of wells	Total no. of BOP days	BOP days w/acoustic system	No. of failures recorded	Downtime caused by acoustic system (hrs)
1985	A	1977-1983, Norway	150	8,115	6,161	35	458.5
1987	B	1984-1986, Norway	58	3,809	3,809	13	455
1989	C	1987-1989, Norway	47	2,636	2,636	8	134
1997	D	1992-1996, Brazil, Norway, Italy, Albania	138	4,846	3,718	13	258.5
1999	E	1997-1998, US GOM OCS	83	4,009	0	-	-
Total:			**476**	**23,415**	**16,324**	**69**	**1,306**

The total BOP days in this study is defined as the total number of days from when the BOP is landed on the wellhead to the time when it is next pulled from the wellhead. If the BOP has to be pulled during operation due to a failure then this is included in the total BOP time.

8.2 Observation of Failures

Table 8.2 identifies the BOP location when acoustic system failures were observed. The acoustic equipment is tested on the rig prior to running into the water. Table 8.2 shows that on average 31 failures/69 total failures or 45% of the acoustic failure occurred on the rig during installation (prior to running) and during running the BOP. Table 8.2 also shows that on average 38 failures/69 total failures or 55% of the failures occurred when the BOP was on the wellhead. This study is interested in those failures when the BOP is on the wellhead.

Table 8.2: Overview of Acoustic System Failures for multiple studies [5]

Study	Location of BOP			Total
	On the rig prior to running	On the wellhead	During running BOP	
A	22	13	-	35
B	3	9	1	13
C	-	7	1	8
D	5	8	-	13
Total	**29**	**38**	**2**	**69**

8.3 Failure Modes

Table 8.3 details the failure modes observed during the BOP installation test and during regular BOP tests or operation.

Critical failures in terms of well control do not occur when the BOP is on the rig or during running of the BOP and installation testing. BOP is not acting as a well barrier during these phases of the operation. After the BOP installation testing is completed and accepted the drilling starts and the BOP starts acting as a well barrier. Safety critical failures occur only after the installation test is complete and are of interest from a safety point of view. A total of 19 failures were recorded during the regular test/operation when the BOP was on the well head.

Table 8.3: Failure Modes [5]

Failure mode	BOP is on the wellhead		
	Installation test	Regular test or operation	Total
Failed to operate BOP	11	11	22
Failed to function on hull mounted transducer	-	3	3
Spurious operation one BOP function	2	-	2
Failed to operate one BOP function by the acoustic system	3	3	6
Loss of redundancy (one of two electronic channels dead)	1	-	1
Wrong valve position indication	-	1	1
No readback signal	1	-	1
Unknown	-	1	1
Total	**18**	**19**	**37**

It is noticed that the majority of failures affect the complete BOP system and result in nonoperation of the system. There were only few failures which affected one function only.

Table 8.4 shows the failure modes versus the type of failure that have occurred during regular test/operation. It also shows that the electric/electronic, mechanical and signal transmission are equally responsible (four to five failures) for the critical failure modes *Failed to operate BOP* and *Failed to function on hull mounted transducer*.

Table 8.4: Type of Failure versus Failure Mode [5]

Failure mode	Type of failure for failures observed during regular test or operation				
	Electric/-electronic	Mechanical	Signal transmission	Unknown	Total
Failed to operate BOP	2	4	4	1	**11**
Failed to function on hull mounted transducer	3	-	-	-	**3**
Failed to operate one BOP function by the acoustic system	-	2	-	1	**3**
Wrong valve position indicated	1		-	-	**1**
Unknown	-	1	-	-	**1**
Grand Total	**6**	**7**	**4**	**2**	**19**

8.4 Failure Frequencies

Table 8.5 shows that Study C has higher Mean Time to Failure (MTTF) of 2,636 days compared to other studies. The reasons for difference in MTTF have not been investigated by the study but it is suggested that random statistical variations could be the cause.

Table 8.5: Acoustic System Reliability Comparison from Different Studies [5]

Study	Failure mode	BOP is on the wellhead		
		Regular test or operation	**BOP days in service**	**MTTF (days)**
Study A	Failed to operate BOP	5	6161	685
	Failed to function on hull mounted transducer	2		
	Wrong valve position indication	1		
	Unknown	1		
	Study A Total:	9		
Study B	Failed to operate BOP	3	3809	952
	Failed to function on hull mounted transducer	1		
	Study B Total:	4		
Study C	Failed to operate BOP	1	2636	2636
	Study C Total:	1		
Study D	Failed to operate BOP	2	3718	744
	Failed to operate one BOP function by the acoustic system	3		
	Study D Total:	5		
	Total:	**19**	**16324**	**859**

Table 8.6 shows that the *Failure to operate BOP (mechanical, electric/electronic failure)* had a shorter MTTF of 2,332 days compared to other failure modes. *Failed to operate BOP* (signal transmission problems) were not mentioned in the (Table 8.6) in the study as this is described as a random failure which comes and goes and therefore, depends on testing frequency. If the acoustic signal from the rig is not transmitted to the acoustic BOP control, it is usually tested again in couple of hours till the transmission is successfully completed.

Table 8.6: Failure Mode Specific to MTTFs [5]

Failure mode	Regular test or operation	BOP days in service	MTTF (days)
Failed to operate BOP (mechanical, electric/electronic failure)	7	16,324	2,332
Failed to operate BOP (signal transmission problems)	4	16,324	-
Failed to function on hull mounted transducer	3	16,324	5,441
Failed to operate one BOP function by the acoustic system	3	16,324	5,441
Wrong valve position indication	1	16,324	16,324
Unknown	1	16,324	16,324
Total	**19**	-	-

8.5 Probability of Acoustic System Function Failure

In Table 8.6, *Failed to operate BOP (signal transmission problems)* failures which affect the complete acoustic system have been used to calculate the unavailability of the acoustic system. A total of 602 acoustic tests were conducted [5].

The on demand probability of failure was estimated by: No. of failures/No. of demands. The on demand probability of failure can be calculated based on 4 signal transmission failures during 602 tests conducted: 4/602 = 0.66%.

The Mean Fractional Dead time (MFDT) of a component calculates the mean proportion of the time when the component is in a failed state and is used for the *Failure to operate BOP (mechanical, electric/electronic failure)* and *Failed to function on hull mounted transducer* failure mode. Since the acoustic is function tested every week, the MFDT is 0.21%.

The cumulative probability that the acoustic system will fail when it is needed is calculated as 0.66% + 0.21% = 0.87%. Any of the above failure modes, such as a signal failure or a mechanical, electrical, electronic or a transducer failure could lead to the failure of the acoustic system.

The calculated probability that the acoustic system will fail when needed is assumed to be optimistic due to the underreporting of the successful acoustic signal transmissions. However the unsuccessful transmission of acoustic signal is the major cause of failure.

8.6 Acoustic Suppliers Reliability Data

8.6.1 Nautronix

Below is the field reliability data provided by one of the acoustic vendors from a four well drilling campaign where both hard wired umbilical and digital acoustic systems were used during offshore operations. While drilling three of the four wells the “hard wired system” had an average success rate of 100% over 58,766 transmissions. During the fourth well the umbilical failed but acoustic system was used as primary control system to complete the drilling operation. The acoustic system backup mitigated the need to pull the stack to fix the umbilical problem and thus allowed the completion of the operation. Table 8.7 shows the digital acoustic system to have a reliability of 99.3% over 12,001 transmissions during the four well campaign. This signal transmission success rate is similar or slightly better than the reliability data discussed in section 8.1.3. The sample size (number of transmissions) using the digital acoustic system is small compared to umbilical system sample size. Therefore, although the overall success probability from Table 8.8 is comparable to numbers in Table 8.7, more data is required for digital acoustic system transmission before a definite conclusion can be reached.

Table 8.7: Transmissions with Digital Acoustic System [1]

TRANSMISSIONS USING NAUTRONIX ACOUSTIC NASBOP SYSTEM										
Well	Depth (Meters)	Duration (days)	Transmissions (%)						Total Transmissions	Overall Success
			Acoustic Rx OK	Retry 1	Retry 2	Retry 3	Retry 4	Failed		
A	1,434	7	97.5	2.06	0.21	0.16	0	0.05	1,895	**99.93%**
B	1,691	10	98	1.8	0.1	0.03	0.06	0	3,134	**100%**
C	1,715	13	94.28	2.74	0.64	0.46	0.21	1.66	3,902	**98.33%**
D	1,545	5	96.12	2.38	0.13	0.16	0.16	1.04	3,070	**98.95%**

Table 8.8: Transmissions with Umbilical System [1]

TRANSMISSIONS USING CUSTOM PROVIDED UMBILICAL (Hard Wired) SYSTEM										
Well	Depth (Meters)	Duration (days)	Transmissions (%)						Total Transmissions	Overall Success
			Acoustic Rx OK	Retry 1	Retry 2	Retry 3	Retry 4	Failed		
A	1,434	7	95.7	4.27	0.02	0.02	0	0	12,931	**100%**
B	1,691	10	96.56	3.42	0	0.02	0	0	20,702	**100%**
C	1,715	13	96.74	3.23	0.02	0.01	0	0.01	25,133	**99.99%**
D	The hard wired modem could not be used during this well (umbilical failure)									**0%**

8.6.2 Sonardyne

Below are the reliability data provided by a Sonardyne. The standard system has two transceiver also called Deep-rated Acoustic Remote Transceiver (DART) and two Subsea Electronics Modules (SEMs). The DART is used to communicate with the surface acoustic equipment. The SEM provides an interface to the BOP stack. Only a single cable can be connected to the Hydraulic Valve Package.

Figure 8.1 shows the system reliability diagram of the standard system when one DART is not operational due to masking by the riser.

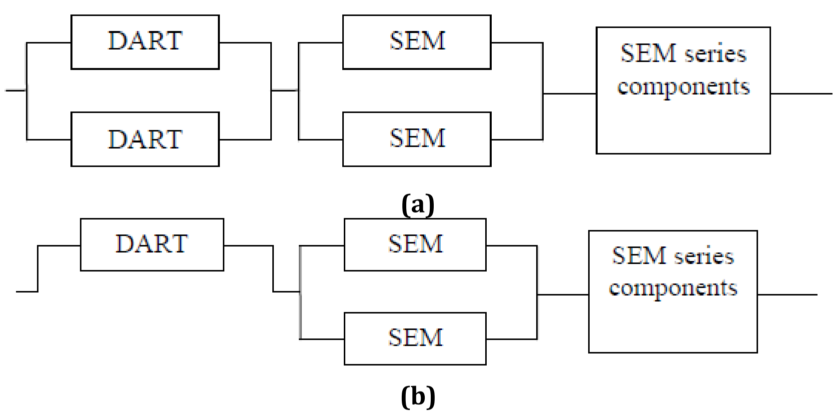

Figure 8.1: System Reliability Diagram for Standard System [12]

Figure 8.2 illustrates the system reliability diagram if the single cable/connector on client pod can be duplicated as there will be no SEM series component. If one of the DARTs is not functional then the reliability of the system is reduced further.

When the interface connection between the BOP and the acoustics system is increased from one to two and DARTs are increased from two to four, the reliability (

Table 8.9) of the whole system goes up drastically.

The Mean Time Between Failures (MTBF) is summarized for each of the above system configurations (Table 8.6). It shows the MTBF could be increased drastically by an additional cable/connector on the client pod (Figure 8.2) or by connecting two DARTs to each SEM (Figure 8.3). However, when one of the DARTs is masked, the reliability of the whole system is still high for enhanced redundancy (connecting two DARTs to each SEM) system (Figure 8.3).

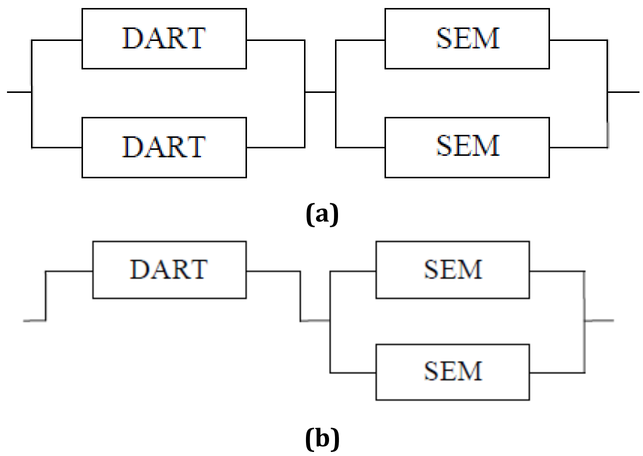

Figure 8.2: System Reliability Diagram for Dual Connector on Client Pod [12]

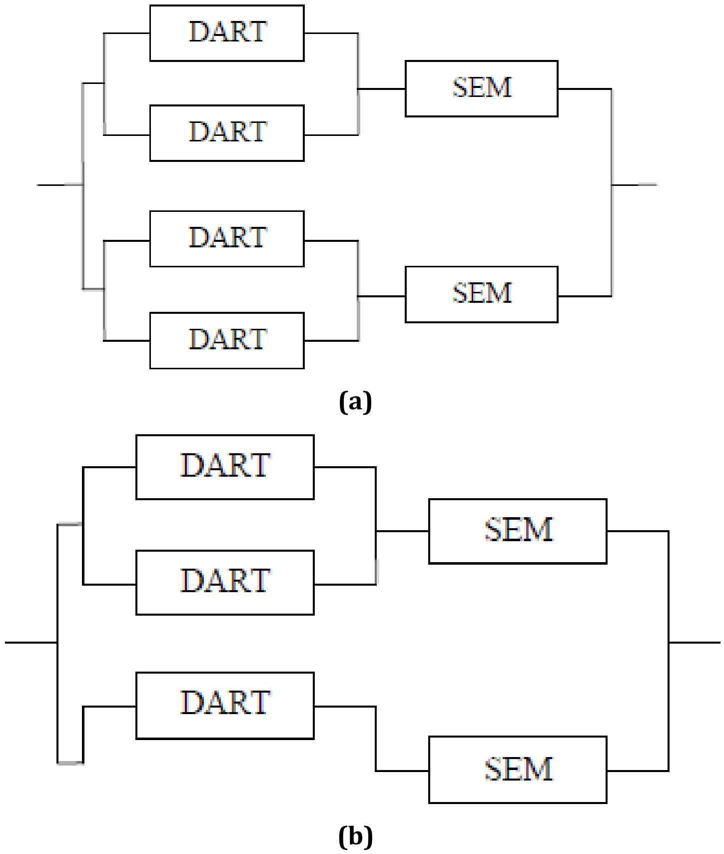

Figure 8.3: System Reliability Diagram with Enhanced Redundancy of Four DARTs [12]

Table 8.9: Mean Time Between Failures for Each Configuration [12]

System	Unshadowed DARTs			One DART Shadowed		
	Diagram	MTBF (hours)	Failures per million hours	Diagram	MTBF (hours)	Failures per million hours
1	1a	3.44×10^{6}	0.29	1b	164,000	6.09
2	2a	10.7×10^{9}	9.2×10^{-5}	2b	172,000	5.8
3	3a	39.4×10^{9}	2.5×10^{-5}	3b	14.9×10^{9}	6.7×10^{-5}

9.0 ACOUSTIC SYSTEM APPLICATION HISTORY

9.1 ESG Case Study [32]

The Environmental Safety Guard (ESG) consists of two shear/blind rams and two latches, to unlatch the riser or the complete package. Pre-charged accumulators provide hydraulic power and control via a single lightweight umbilical and an acoustic control system. While connected, the umbilical cable provides the primary control, with the acoustics as back-up, but if a disconnection is carried out, the acoustics must provide primary control and monitoring until reconnection takes place.

The ESG was deployed on the 1-SHEL-14-RJS deepwater well in the Campos Basin offshore Brazil. Despite a positive test at 500 m (1,640 ft) below sea level, water ingress penetrated inside the subsea transducer module (on the rig side) and the acoustics signal from surface could not be recognized [28]. After the initial problems the ESG system worked extremely well without any problems. At the end of the well a full function test was done and the acoustic system remained fully operable.

This places greater demands on the integrity of the acoustic control system than would be the case for a conventional back up system. A Hazard Identification (HAZID) exercise was held to find potential issues for the use of Surface BOP on BM-C-10. There was a concern on the reliability of the ESG acoustic control system so a specific study on reliability of acoustic BOP controls was completed between May and October 2002. The study [32] concluded that: "Although it can be stated that the reliability of an acoustic BOP control system (digital) is more reliable than the earlier designs, a recommended failure to function on demand frequency cannot be established based on experience. For the purpose of further analyses where a reliability figure for the acoustic system is required, it is recommended to assume that 1 out of 100 attempts to activate fails, i.e. 1%."

The above results led to the decision of selecting a digital acoustic system as the primary control system. Also the MUX cable backup was specified for the first wells until the acoustic reliability could be proven.

9.2 Acoustics as Primary Control System [27]

In 2009, Murphy Oil installed a Floating Drilling Production Storage and Offloading (FDPSO) system in West Africa (Azurite project) in around 4,500 ft water depth. The FDPSO has a surface BOP and a subsea isolation device (SID also called short BOP) on the seabed.

SID or similar systems (Figure 9.1) are used in conjunction with the Surface BOP. The SID is designed to seal the well and disconnect the riser from the seafloor during emergency. The SID has double shear rams and a bank of high pressure fluid. Activation of the SID allows the well to be sealed, and the vessel to move away from the location in case of an emergency disconnect situation.

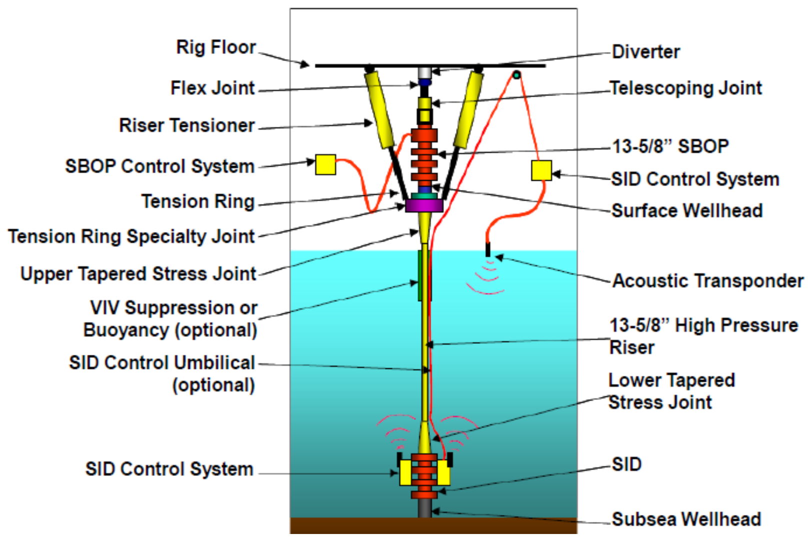

Figure 9.1: Surface BOP and SID/Subsea Shut-Off Device [18]

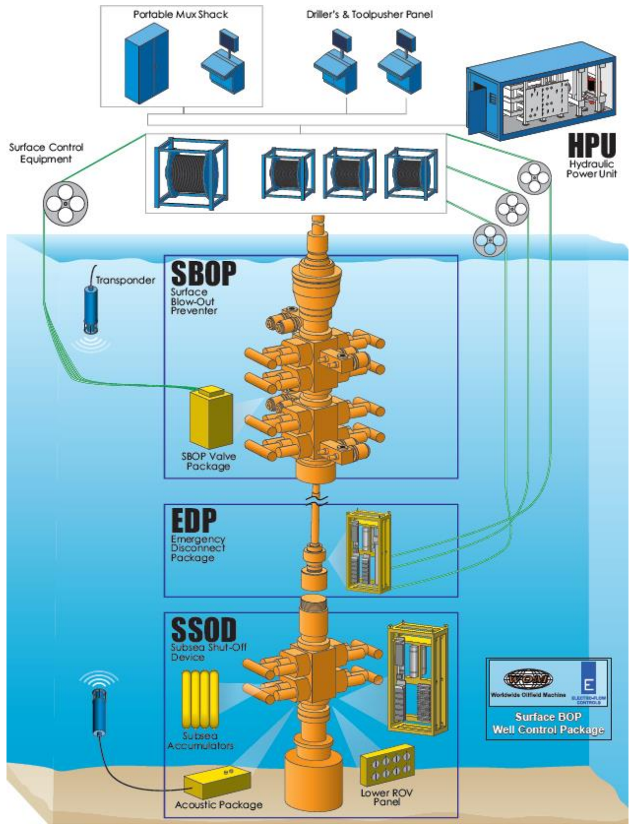

Figure 9.2: Surface BOP and SID/Subsea Shut-Off Device [26]

The SID in the Azurite project was controlled by an acoustic system. The acoustic subsea BOP system uses surface transducers, mounted at the base of the moonpool that send/receive acoustic signals to/from transducers mounted on the SID. The acoustic subsea-BOP system performed reliably during these operations. Therefore, the decision was made to omit the umbilical and use acoustical control alone for SID control. This system would provide the following eight functions that could be operated from a panel in the driller's control room.

- Reset
- Arm
- Close lower shear
- Close upper shear
- Primary unlatch upper connector
- Secondary unlatch upper connector
- Latch upper connector
- Latch lower connector

Strategic timing and sequencing of six of the eight functions quickly closes both rams and releases the upper connector to allow the riser column to detach safely and move away from the SID. The intention was to create a controlled retreat of the riser column to prevent damage to those components or to the tensioning system.

This sequence was customized to work in concert with the Azurite tensioning system. Constant pinging of the controls ensures communication at all times. Parameters such as battery life, accumulator pressure, and communications health are recorded and stored. Some communication errors were initially experienced when support vessels were present nearby the FDPSO. The acoustic system has been fine-tuned since and continues to perform reliably.

The screen shots shown in Figure 9.3 and Figure 9.4 show the capability of a typical acoustic system. The main screen on the left shows a mimic of the SID with the different valves and commands annotated. These are requested at operator specified intervals and provide a means of continuously monitoring the integrity of the acoustic link. All commands and responses are automatically logged within the system [12].

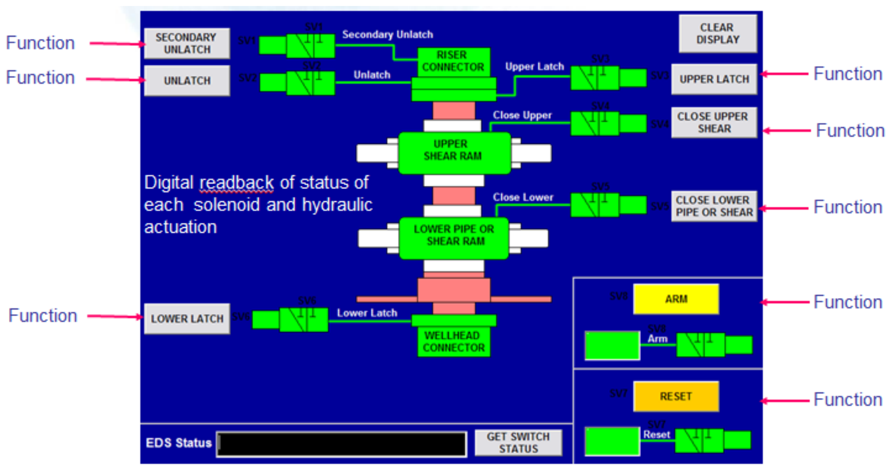

Figure 9.3: Eight Function Acoustic Application [12]

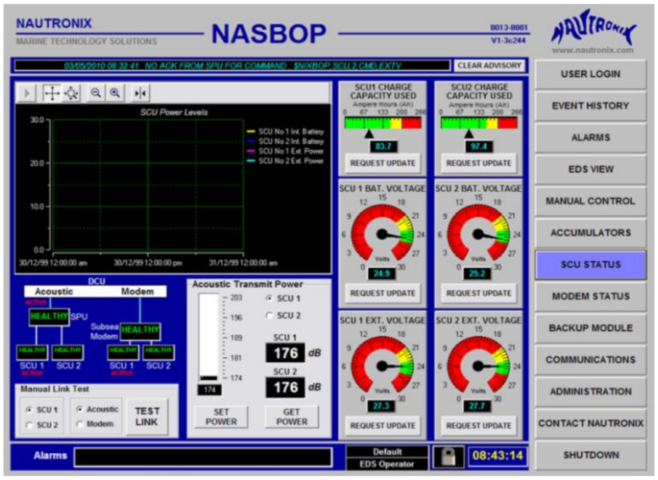

Figure 9.4: System Information Display [12]

9.3 Capping Stack

The capping stack (Figure 9.5) is safety equipment which would be used to stop flow of oil in the unlikely event of blowout during drilling. The capping stack system will use an acoustic BOP control system as a primary function to monitor pressure and temperature in real-time inside the well.

The capping stack used on the Macondo well had transponders attached to it to monitor pressure and temperature. The signals were interrogated by transceiver attached to the ROVs. Live data was provided by the acoustic system for many days during this incident.

There is a need to control all the functions on the capping stack acoustically. More than 100 channels on the acoustic system would be needed to control all the functions on the capping stack. This would require four bigger size subsea electronic modules.

Some suppliers are working on acoustic systems which would have 128 functions and can control all the BOP functions.

Figure 9.5: Capping Stack [12]

9.4 VESSEL OF OPPORTUNITY

If the rig has an emergency situation and the portable acoustic control unit on the rig cannot be accessed then the acoustic system from the neighbouring rig could be programmed to function the BOP acoustic control system.

9.5 ROV RETRIEVABLE ACOUSTIC SYSTEMS

A modular subsea control system has been developed by DTC International. This system is a modular subsea control system and can provide a fully retrievable acoustic system which includes retrievable batteries.

One of the important features that the control system provides is its ability to be deployed and retrieved using a work-class ROV equipped with a tooling skid. This is significant as it allows repairs to be made to the acoustic system, even batteries replaced, without bringing the stack to the surface. This fundamental feature allows a quick, safe, and economical means to maintain the control system with minimal downtime. As the acoustic system is retrievable subsea, components can be replaced in a matter of hours and the need to bring the stack to the surface for control component repair/replacement is eliminated, resulting in cost savings.

The modular system is designed to incorporate various configurations in a small lightweight module which means that independent failed components can be changed out with ease, while the system's built-in flexibility allows new modules to be added as required, and the system's capabilities expanded or customized.

DTC's modular control system was customized for SID acoustic equipment and was deployed on the Aban Abraham drillship in 2011 and is currently operating for Petrobras in Brazil [33].

9.6 Acoustics Replacing MUX System [3]

There has been an operator funded development program on-going since 2008 involving Cameron and Nautronix. The technology being developed is called NASMUX. NASMUX acoustics system would be the primary communication link to the subsea BOP by removing the umbilical system and would be rated for a maximum water depth of 15,000 ft. The benefits of an acoustic solution for MUX communication are:

- Improvement in safety by eliminating moon pool handling of umbilical as riser is run into the water
- Elimination of downtime caused by umbilical damage
- Elimination of umbilical's and reels which would lead to reduction in the cost & handling
- Reduction in deck space requirement
- Reduction in running time due to gain on time required to clamp umbilical

Around 128 channels can be used to monitor and control the BOP functions. DNV has granted "Feasibility of Technology" in accordance with DNV-RP-A203. In 2014 a production unit will be launched.

9.7 Macondo Operations

Frequency allocation on vessels during Macondo well containment operations was a challenge. Some vessels were using analog signals and others were using digital signals. Deepsea Drillers II & III used Kongsberg Hipap Combined LBL System. Five vessels used Hipap for ROV or vessel tracking. This used up all available twenty tone channels. Transocean Enterprise, Q 4000, Holiday Chouest, Clear Leader, OI 3 all used Sonardyne Wideband. Toisa Pisces and Helix Producer which are oil collection vessels used Sonardyne Wideband [59].

Critical vessels were required to have seabed transponder arrays. At the end of the Macondo Containment operation nearly all Wideband 1 codes (>200) were allocated [59].

Macondo operations would have been impossible using just the older analog acoustics or more dangerous with so many vessels working in close proximity. Macondo proved extreme non interfering vessel positioning with digital acoustics. During the Macondo incident with so many vessels operating in such close proximity, it would not previously have been possible for them all to use acoustic positioning without mutual interference, potentially impacting safety.

The challenge became more acute when the Subsea scenario was also taken into account, with a large number of remotely operated vehicles (ROVs) also being positioned using acoustics. This is illustrated in Figure 9.6.

It was only the use of digital acoustic technology that enabled such a complex multi-user operation to be conducted without mutual interference and in close proximity to the extreme noise source of the Macondo blowout. Acoustic was used to recover pressure data from within the containment cap, demonstrating that the acoustic telemetry will operate error-free within a few feet of a major Subsea blowout.

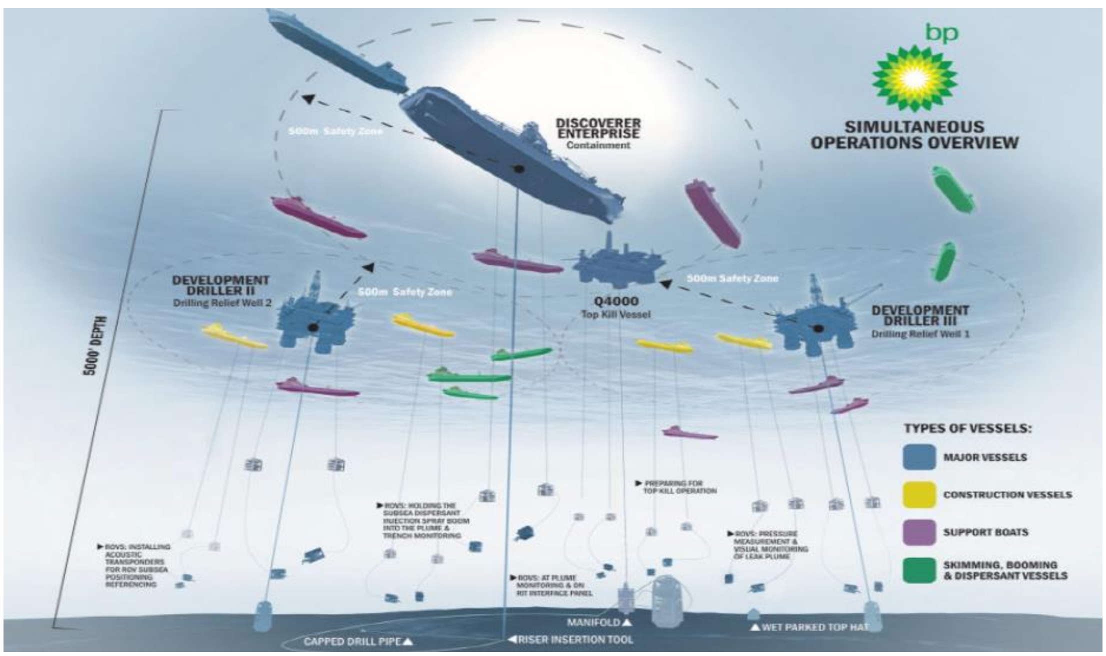

Figure 9.6: Multi User Operations in Macondo Subsea Scenario [13]

9.8 ADDITIONAL SAFETY MEASURES

An additional acoustics portable control system could be kept on standby at a shore base or on a local support vessel in the event that the rig's system cannot be operated or the rig is destroyed. An additional ROV-mountable transceiver could also be kept available for emergency intervention by ROV.

A single cable usually connects the SEM to the client BOP due to the availability of one connector on the BOP. This leads to a single point failure which could be eliminated if BOP manufacturers provide dual connectors on their BOPs, as two cables could then be used.

A serial communication link could be provided from the acoustic backup system to the main BOP stack, in order that pressure and status information from within the BOP stack could be retrieved acoustically even if all multiplex cable communication to the BOP has been lost. This would simplify and reduce the risk of operations following a major incident. Some acoustic manufacturer's backup system include such a serial link, but modifications would be required on most clients' BOP control systems to make use of it.

Some of the technologies a particular operator would like to see in BOP control systems are more diagnostic capabilities which are found on production control systems such as Solenoid monitoring, trend analysis, valve signature etc.

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