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Blowout Preventer Control System Reliability

Primarily Focused on Subplate Mounted (SPM) Valves

Prepared by Roy Lindley
Edited by David McCalvin

Argonne NATIONAL LABORATORY

About the Author

Roy Lindley is a mechanical engineer and a national security program manager at Argonne National Laboratory. Lindley has over 32 years of experience in conducting and managing engineering programs including multi-discipline evaluations for major U.S. DOE projects on electric utility applications, and various energy conversion technologies. He has a varied technical scope that includes pressure vessels, structural and seismic support design, data acquisition, and code compliance analysis. Lindley is also a security expert that does laboratory testing of security systems and design recommendations.

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ACRONYMS

API	American Petroleum Institute
BAST	Best Available and Safest Technology (BSEE Program)
BOP	Blowout Preventer
BSEE	Bureau of Safety and Environmental Enforcement
BSR	Blind Shear Ram
DP	Dynamically Positioned
GOM	Gulf of Mexico
HPU	Hydraulic Power Unit
JIP	Joint Industry Project
LMRP	Lower Marine Riser Package
MTBF	Mean Time between Failures
MTTF	Mean Time to Failure
MUX	Multiplex[1]
NOV	National Oilwell Varco (owns Shaffer trademark)
OEM	Original Equipment Manufacturer[2]
OSHA	Occupational Safety and Health Administration
PM	Preventive Maintenance
RCA	Root-Cause Analysis
ROV	Remote Operated Vehicle
SEM	Subsea Electronics Module
SIB	Sensor Interface Box
SIL	Safety Integrity Level (a risk reduction parameter)
SPM	Subplate Mounted (valves)

[1] Referring to electronic/fiber-optic communications between rig and seafloor BOP.

[2] In the context of this report, Cameron, GE-Hydril, NOV and Oceaneering design, manufacture, and support BOP control systems.

EXECUTIVE SUMMARY

According to previously completed research sponsored by the Bureau of Safety and Environmental Enforcement (BSEE), roughly one-half of blowout preventer (BOP) failures are control system related [1] [2] [3] [4]. Often, control system failures are related to subplate mounted (SPM) valves, which are critical components of modern BOP control systems and are relied upon for well control in a variety of situations. This study examines control system failures, especially those related to SPM valves, and recommends actions to improve control system reliability, and hence BOP reliability.

To address BOP and SPM reliability, Argonne National Laboratory conducted a series of meetings with manufacturers, consultants, users, and operators. From these meetings, it was determined that the precise causes of BOP failures continue to be poorly understood. Although SPM valves are often blamed, there is limited data to confirm the number of BOP failures they directly cause. This may be largely because root-cause analyses (RCAs) are not routinely performed on BOP control system failures. Instead, a common practice is to replace broken or failed components and expeditiously restore the BOP to service without analysis. Performance and safety of BOPs can be improved further through industry research on root causes of SPM failures.

Control systems are complex with substantial variations among different vendor designs. Effectively, each BOP is one-of-a-kind. This non-uniformity leads to considerable difficulty in maintenance and in keeping a complete inventory of spare parts and documentation.

Investigations performed by Argonne demonstrate an overarching key finding:

There is currently no reliability requirement driving overall BOP system performance. Consequently, there is no absolute way to measure improvement and no way to definitively determine BOP reliability.

As indicated in the companion report, the BOP failure rate for shear ram function alone is theoretically estimated at 1 in 200. However, this rate assumes an optimal sequence of shuttle valve configurations. The overall failure rate could be significantly higher if actual configurations were considered and dependability[3] (for example, the ability of the shear ram to shear the pipe during a well control event) was quantified.

There are a variety of standards for individual BOP components, including SPM valves and shuttle valves. Without knowing how each component contributes to overall reliability, however, it is impossible to allocate requirements for design, procurement, fabrication, testing, operation, maintenance (including fluid maintenance), and refurbishing.

[3] *Dependability*, as used in this report, is the assurance that hardware will perform its intended purpose. For example, BSRs will shear a drill pipe under all circumstances, provided the control signal is given.

Additional findings include:

A. **<u>Offshore Rebuilding of SPMs:</u>** Rebuilding SPMs offshore is a contributing factor in control system failures. The rebuilding of SPMs requires special tools, component inspections, technician training and qualification, complete documentation of procedures, and comprehensive SPM parts management. All of these things are needed to assure that the manufacturer's quality and upgrades are incorporated. While rebuilding is common, limited offshore resources and the lack of a procedure-controlled environment (such as that in a factory) constrain this process.

B. **<u>Hydraulic Fluid Quality:</u>** Fluid quality is likely a contributing factor in control system failures. Hydraulic fluid maintenance is a meticulous and challenging process that involves knowledge of water quality, debris, additives, chemistry, biology, lubricity, and maintenance practices. Constant and competent attention to every one of these areas is necessary to ensure fluid quality. These areas are affected by poor communications among parties – especially when multiple and competing vendors are involved.

C. **<u>Standard 16D and Standard 53:</u>** Finally, the American Petroleum Institute (API) Standard 16D and Standard 53 (the most relevant BOP standards) are currently not adequate for ensuring the high reliability that BOPs require. Testing and requirements for BOPs are often related to individual components and thus cannot confirm overall system reliability. Design criteria, the associated acceptance criteria, and quality management requirements need to be driven by the performance needs of a system, not just by a system's components.

In response to these findings, Argonne puts forth the following recommendations:

1. Since BOPs are critical systems in many offshore operations, the BSEE should consider establishing targets for overall BOP system reliability and a time frame for compliance. ***Reliability targets are related to the BSEE's Best Available and Safest Technology (BAST) program and could be considered under this program.*** Establishing reliability targets is the long-term solution for uniformly driving the industry toward more reliable systems with minimal governance overhead. This could contribute to greater dependability as technology evolves. Furthermore, these targets would be applicable to all BOP systems, whether or not SPM valves are included.

2. In the short term, the BSEE should consider strategies that encourage the industry to improve offshore maintenance requirements. This includes improving training requirements, configuration management, and requirements for hydraulic fluid quality.

3. The BSEE should strive to improve information sharing between operators, rig operators, original equipment manufacturers (OEMs), and component OEMs, especially for critical systems. One strategy would be for the BSEE to collaborate with API and the industry and add specific communication requirements to API Standard 16D, Standard 53, and other applicable standards. This would ensure that all parties receive the information they need to maintain and improve reliability.

1.0 INTRODUCTION AND TECHNICAL APPROACH

During offshore drilling in the Gulf of Mexico (GOM), operational safety and environmental protection require the constant presence of physical barriers to control exposure to hydrocarbons and other well effluents. While many different barriers comprise a well plan, and the details of a barrier system can change depending on circumstances, the usual barrier of last resort is the blowout preventer (BOP). The BOP needs to be dependable and perform on demand, and for this to happen, control systems and related hydraulic system components need to be highly reliable.

Modern, deep-water subsea BOPs are complex and illustrate the adaptive nature of the oil industry. These systems, which started as above-ground manually operated equipment, have evolved into remotely operated deep-sea equivalents. Present day systems combine fiber-optic technologies with multiplex (MUX), computer controls, and scores of high-quality hydraulic components, including subplate mounted (SPM) and solenoid valves, regulators, tubing, and fittings. Modern systems perform 100 or more BOP functions. Because these systems include equipment that must be continually available, operable, and dependable, there is considerable challenge in designing and sustaining a reliable BOP. This report addresses substantive issues with downtime caused by control systems. A companion report addresses the BOP safety integrity level (SIL) [5] for the blind shear ram.

Independent of BOP vintage, SPMs are common components of the control systems. Among the many components in a BOP system, SPM valves are commonly blamed for control system failure. Since control system failures comprise a significant share of overall BOP failures, SPM valve reliability is an important factor in BOP reliability. This report focuses on the SPM valve life cycle and seeks to identify areas where this component's reliability might be enhanced.

For purposes of this report, Argonne National Laboratory's overall methodologies for collecting information on SPM valve aspects included:

1. Interactive sessions on BOP control systems and rig support from the perspectives of users with substantial hands-on experience;
2. Numerous question-and-answer sessions with BOP industry experts who have extensive control system retrofit experience;
3. The Bureau of Safety and Environmental Enforcement (BSEE) New Orleans office meetings regarding BOP documentation and examples of how BOP systems are represented and documented;
4. Manufacturer meetings with [redacted] regarding SPM design, manufacturing, distribution, refurbishment, parts, training, and available services;

5. Meetings with BOP operator specialists [redacted] concerning [redacted] work and industry initiatives;
[redacted]
7. Interactive demonstration and subsequent discussion of [redacted] BOP evaluation system, which consolidates information on regulatory compliance, American Petroleum Institute (API) standards compliance, and tools to assess BOP operational statuses; and
8. Consultation with technical specialists on the content of related API specifications in concert with editorial refinements to the reporting.

In addition, Argonne reviewed technical literature including material provided and recommended by these points of contact.

2.0 OVERVIEW OF SPM-BASED BOP CONTROL

2.1 BOP-Controlled Well Barriers

A modern BOP control system, including its control pods and accumulators, is designed to user specifications. Because of this, each BOP system is nearly one-of-a-kind. BOP systems have several hundred valves and can have many hundreds of pipe, tubing, or hose connections. These parts and components must be packed into a relatively small volume or area, and yet must still allow testing and maintenance access.

Designs based on subplate mounted (SPM) hydraulic valves are commonly, but not always, used in BOP systems. These designs are compact and versatile, and over several decades, SPM designs have evolved to become industry-accepted means of providing the high-pressure hydraulic fluid needed for BOP blind shear rams (BSRs) and other wellbore component controls. For further background information about SPM valve designs, Appendix A provides a brief history of BOP design evolution, and Appendix B explains the basics of two common BOP control systems now in use in the GOM. Appendix C provides basic information on hydraulics and the role of SPMs.

Subsea BOP controls operate wellbore barrier components (BSRs, annulars, casing shears, and variable bore pipe rams) and supporting items (such as connectors, stabs, isolation valves, regulator controls, and pod selection). Typical functions regulated by controls include, but are not limited to:

1. High-pressure open;
2. High-pressure close;
3. Variable-pressure open;
4. Variable-pressure close;
5. Lock;
6. Unlock;
7. Arm;
8. Disarm;
9. Extend; and
10. Retract.

Subplate mounted (SPM) valves are critical to well control. Individually, wellbore components can have six or more possible SPM-controlled functions. For example, SPM valves may control the functions of lock, unlock, open, high-pressure close, variable-

SPM valves are critical to well control.

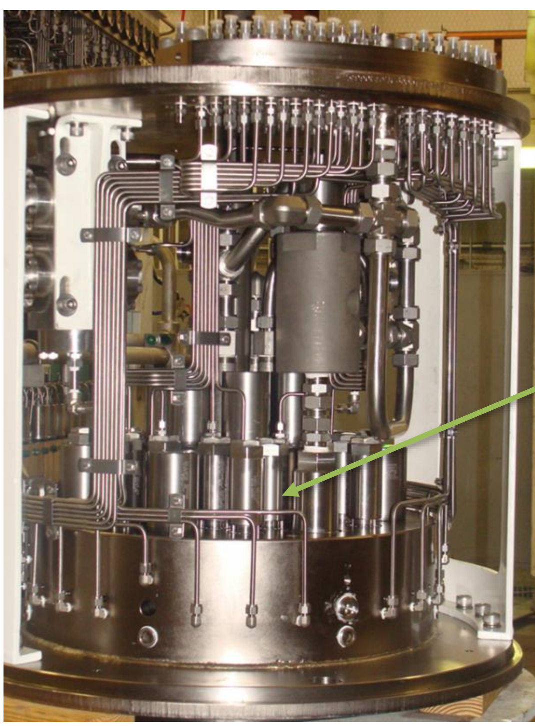
pressure open, and variable-pressure close. In most instances, a SPM valve controls logical pairs (open/close, arm/disarm, or extend/retract). Appendix D provides more information on how these actions combine to perform three critical BOP safety functions offshore.

Because BOP system designs are unique to user requirements, the total number of BOP control functions varies considerably. One key variable is the number of BOP components (for example, the number of annulars, pipe rams, casing shears, BSRs, or test rams). Other variables include the numbers and types of auxiliary and support functions, such as:

1. Choke and kill lines;
2. Stabs for electrical and hydraulic connections between the BOP stack and the lower marine riser package (LMRP);
3. Accumulators and accumulator charging and supply;
4. Hydraulic fluid pressure control;
5. LMRP to flex joint connectors;
6. Manifolds and valves pertaining to hydraulic fluid and pod selection; and
7. Various isolation valves.

2.2 Typical Subsea Control Hardware

Subsea BOP control systems are complex. Figures 1 and 2 illustrate typical BOP hydraulic control hardware. In both examples, SPMs tend to be mounted in close proximity to one another with considerable tubing linking their ports. Clusters of SPMs on a thick plate (Figure 1) have mounting positions (sized bores) that interface with fluid passages machined within the plate. This design allows SPMs to be removed and replaced without disturbing all power fluid connections. These figures illustrate BOP system complexity and typical connection situations.



SPMs

Figure 1: Example of SPM Valve Vertical Mounting on Horizontal Plate

Figure 2: Example of SPMs Mounted Horizontally within a Control Pod

Some SPMs have complete bodies (housings). Others have threaded bodies so they fit a sized bore in a large plate with several bores (Figure 1). Typically, threaded-body SPMs as shown in Figure 3 are secured or removed with a pin-type spanner wrench. This is the configuration shown in Figure 3 and discussed in more detail in Appendix E. Many of the SPM's internal parts are high precision, with polished or lapped surfaces. SPMs also rely on multiple O-rings (or "T seals" in some designs) for isolating internal zones. Both static and dynamic O-rings are susceptible to damage during installation, and dynamic O-rings wear during operation.

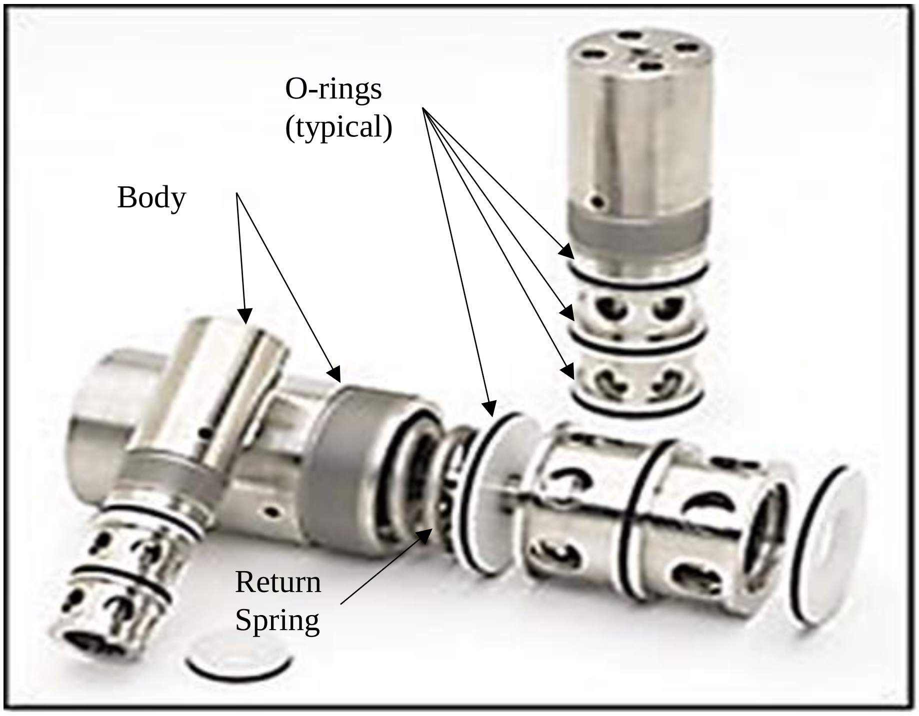


Figure 3: Typical SPM Internal Parts Removed from Valve Body

The control pods shown in Figure 1 and Figure 2 use two different SPM mounting styles. However, at a more detailed level these are likely one-of- a-kind or at the most few-of- a-kind systems. This occurs because of the different requirements and situations that exist including new versus old rigs, contractor preferences, water depth, and operator stipulations. The result of this is considerable configuration variability from one BOP to the next.

3.0 API STANDARDS APPLICABLE TO BOP EQUIPMENT

3.1 Discussion of API Specification 16D

3.1.1 General Description of Specification Requirements

Design standards for BOP control systems are part of the API Specification 16D [6]. A detailed reading of this standard indicates limited and weak coverage of design verification and design validation for BOP control systems. Significantly, there are no specific standards to control design variations after a design's initial "qualification." Qualification testing at the system level is only required for "*prototype*" control systems (Section 10.1.1). In this standard, *"A prototype control system is a first-time system of a new manufacturer or a system using major components not previously proven."* According to this standard, unless a manufacturer or buyer requires otherwise, there is no firm requirement to qualify or verify a BOP control system once it has been produced.

API 16D requires a 1,000-cycle test for SPM valve prototype components, but the acceptance criteria for these tests is undefined. Even more importantly, component testing requirements are not driven by an overall reliability standard for the BOP system.

Standards for SPM valves in both API 16D 9.2.7.2 and 9.4.1 require a 1,000-cycle test for *prototype* components at rated working pressure.[4] However, acceptance criteria for SPMs (either prototype or production versions) is undefined (API 16D 9.2.7.6, Non-ASME Coded Hydraulic Control System Components, and 9.4.1, Mechanical Equipment). "Prototype" also remains undefined, which leaves the testing of a *production* SPM's ability to flow and/or seal when closed unaddressed. Section 9.2.7.2 defines a burst rating, but leaves rating to manufacturer (Section 9.4.1 concerns prototypes). Most importantly, component requirements are not driven by an overall reliability standard for the BOP

API 16D leaves hydraulic fluid quality and maintenance requirements up to the user.

[4] Within API 16D, SPM control system valves are categorized as ***"Non-ASME Coded components"*** (Section 9.2.7.2) and ***"Mechanical Equipment"*** (Section 9.4.1). Neither section adopts a national code or standard for SPMs.

system, and the specification is silent on design revision control of qualified SPMs. At both the system and component levels, these standards are not sufficient reliability targets. Manufacturers may, and sometimes do, exceed these baseline requirements, but they do not do so consistently.

Specification 16D addresses hydraulic fluid cleanliness only in the context of starting rig operations. Topics covered include cleaned storage and mixing tanks in 4.2.4.1, and for commodity items, Section 9.5 assigns responsibility to the user for control fluids and lubricants. Manufacturers are supposed to recommend (presumably to the user) minimum hydraulic fluid requirements, but these may or may not be incorporated into operations. Furthermore, for SPMs, the identity of the "manufacturer" is not always apparent. A manufacturer could be either (or both) the BOP original equipment manufacturer (OEM) or the commodity source, such as the SPM vendor. (Appendix F provides more information on typical cleanliness practices and one additive vendor's technical recommendations.)

3.1.2 SPM Cyclic Design Basis

Per API 16D, *prototype* SPM valves are tested for a minimum of 1,000 cycles at "normal operating pressure." Pressure and flow tests are supposed to occur at conditions that "simulate the application environment," which presumably should be duty cycles and conditions. In addition, API 16D does not specify testing acceptance criteria or link production cycle testing to an application environment. Finally, reliability-related targets, such as the mean time to failure (MTTF) and the mean time between failures (MTBF), are not provided.

For much of the BOP system, the 1,000 testing cycles are intended to correspond to a 5-year service cycle. This cycle-based design margin is not always suitable, and a common practice is to annually replace 20% of SPMs and/or replace or rebuild all SPM valves every 5 years. One vendor [redacted] doubles this value in SPM testing. [redacted] is now completing tests in the range of 10,000 cycles as an internal initiative. These practices have been accepted in the industry in place of reliability specifications [7]. Some SPMs are likely functioning properly for longer than the 1,000- or even 2,000-cycle test basis. However, even with current replacement practices, many individual SPM valves only achieve a fraction of the 1,000 cycles.[5] Where root-cause failure analyses are completed (and completing them appears to be the exception), details are not communicated consistently through the supply chain to commodity suppliers for product improvement considerations.

3.1.3 SPM System Design Configuration Control

It is common to make changes to a BOP in the field. While regulations state that BOP drawings are supposed to match hardware for drilling permit applications, BOP hardware may or may not remain true to drawings during drilling. Original prints and diagrams become outdated, especially when workarounds, such as using different SPM valve

[5] Transocean reports some SPMs fail in as few as 200 cycles.

positions or control circuitry, occur. For instance, a BOP pod may have a number of blank "individual" SPM pockets. If one pocket is not working, a rig manager may instruct service personnel to install a new or different SPM in another pocket and relocate the hydraulic lines to the new pocket. With the sense of urgency to resume operations, drawings and other documentation, such as tracking models, may not be updated. Based on Argonne's conversations, configuration control is a self-policed area with inconsistency between rigs.

3.2 Discussion of API Standard 53

American Petroleum Institute (API) Standard 53 outlines requirements for the installation and testing of BOP equipment systems [8]. These requirements cover BOPs, control systems, choke and kill lines, choke manifolds, and auxiliary equipment. The standard also includes requirements for testing frequency and initiators, maintenance, the "equipment owner's" preventive maintenance (PM) program, and failure reporting requirements for API 16D equipment.

Current API Standard 53 establishes a failure reporting mechanism.

While Standard 53 has substantial value, the document is incomplete in that it does not provide a rigorous set of parameters and acceptance criteria for periodic, in-service testing. Requirements for a failure reporting program are mentioned in 6.5.3.7.4.[6] This section states that the manufacturer shall have a written procedure for problem notification. The section refers to Appendix B of Std. 53, which calls for the manufacturer to notify every equipment owner in writing of each significant problem that has been brought to the manufacturer's attention. Such written notification should occur within three weeks following the occurrence (failure). Depending on the situation, however, the "manufacturer" could be different entities. Argonne was not charged with investigating the effectiveness of this process.[7]

[6] The complete text of 6.5.3.7.4 is: "*The equipment owner shall inform the equipment manufacturer of any well control equipment that fails to perform in the field, in accordance with Appendix B [of Standard 53].*" A potential point of confusion in the case of BOPs is whether the "manufacturer" is the OEM [redacted] or the actual SPM valve manufacturer [redacted].

[7] From context, reporting appears to be intended as a way for the industry to make owners aware of failures, thus enabling them to avoid a failure.

4.0 CONTROL SYSTEMS ARE A MAJOR BOP DOWNTIME CONTRIBUTOR

4.1 Prominent Reliability Studies

Based on prominent reliability studies, the overall reliability of the BOP control system continues to account for a substantive portion of BOP system failures (Table 1). The specific percentage of failures caused just by SPM valves is not widely reported because of very limited failure analysis data.

Table 1: Reliability Studies Consolidated Data

Prominent Reliability Studies*	Holand 1997/1998	Holand, Awan 2007–2009	American Bureau Shipping 2007–2013 (Deepwater)	MCS Kenney 2014
Control system failure (% of total)	51%	46%	57%	63%
Avg. downtime per event	31 hours	65 hours	Not reported	Not reported
Estimated MTTF	Not reported	209 days	48.1 days	160–260 days

* Authoritative studies were reviewed in-depth. With technology evolution and application severity generally increasing, BOP control system failures are accounting for a larger percentage of BOP failures.

Holand's BOP reliability study for deepwater wells, which covered the years 1997–1998, looked at 4,009 BOP days of information [9]. In this grouping, 117 counted failures resulted in 3,638 hours of lost time, or 0.91 hours per BOP day. This was an average downtime of 31 hours per event, with BOP outage time accounting for 3.8% of total BOP time. Control system failures accounted for about 51% of total failures. During a more recent study period, the regulator (Minerals Management Service) granted waivers for 12 situations. Without the waiver, the percentage of BOP failures caused by control system failure would have been greater than 51%.

About half of BOP failures are control system related.

The Holand and Awan report [2], covering the years 2007–2009, is further explained in Table 2. The study found 156 failures. These failures resulted in 560 days of BOP downtime out of 15,056 BOP days in service. This amounted to 0.89 hours of downtime per BOP day and an average downtime of 86 hours for all BOP failures. This data represents failures of several different subsystems: annular preventer, connector, flexible joint, ram preventer, choke and kill valve, choke and kill lines, main control system, and others. As shown in Table 2 (excerpt from reference [2]), 72 control system failures occurred (accounting for 46% of the total number of failures) and caused an average of 65 hours of lost time per failure. Overall, total time lost to control system failures was the largest single component of failure for the subsystems studied, comprising 35% of the total number of failures. When comparing this 2007–2009 study with the late 1990s work [9], the average downtime for the control systems declined to 0.313 hours per BOP day. The MTTF of the control system (209 days) remained the largest contributor to BOP unavailability.

Table 2: Overview of BOP Failures by Subsystem

BOP Subsystem (15056 total BOP days in service)	Item Days in Service	No. of Failures	Total Lost time (hrs)	MTTF (Item days in service)	MTTF (BOP-Days)	Avg Downtime per faillure (hrs)	Avg Downtime per BOP Day (hrs)
Annular preventer	28150	24	2344.5	1173	627	98	0.156
Connector	31142	8	638	3893	1882	80	0.042
Flexible Joint	15056	1	288	15056	15056	288	0.019
Ram Preventer	77264	23	1765.5	3359	655	77	0.117
Choke and Kill Valve	160310	4	136	40078	3764	34	0.009
Choke and Kill Lines, all	15056	17	1992	886	886	117	0.132
Main Control System	15056	72	4712	209	209	65	0.313
Dummy Item	-	7	1572	-	2151	225	0.104
Total	**-**	**156**	**13448**	**-**	**97**	**86**	**0.893**
Control % of Total		46.2%	35.0%				

Holand [9] [2] does mention specific SPM failures, but does not quantify the frequency or cause of failures. Frequency and cause are difficult to determine because the customary operational practice is to rebuild or replace and to continue operations and preventive maintenance. This even extends to rebuilding all pod valves as often as every 24 months.

Information from the American Bureau of Shipping (ABS) report during 2013 came from two equipment manufacturers and three GOM drilling contractors for the period of January 1, 2007 through May 1, 2012 [3]. This study was specific to:

1. Operations in water depths to 5,000 ft.;
2. Subsea control systems with pods;
3. The MUX system;
4. Emergency and secondary controls;
5. Control panels;
6. The supporting hydraulic power unit;
7. The surface LMRP and stack-mounted accumulators; and
8. Electrical power.

For these situations, ***57% of reported failures were in the control system***. The MTTF of this data for the entire BOP system was 48.1 operating days. The definition of "control system" in this report was broader than that in Holand and Awan [10], which partially explains the lower MTTF.

ABS study: SPM valves and manifolds comprise 16% of control system failures.

At the control system component level, the ABS report [3] analyzed 115 control system failures. **Twenty-six of 115 failures were specific to "SPM and manifold," comprising 16% of subsea control system failures.** There was no information regarding cause of failure, outage times, or the precise time period for the data. In addition, there was no information as to whether the BOP remained functional had there been an emergency situation. If the SPM (or any other component of a particular design) is part of a system lacking redundancy and/or diversity, a single SPM valve can in some cases leave the BOP in a non-functioning state. Most BOP SPMs however are found in a subsea control pod assembly that is fully redundant with at least one other pod. Further detail on BOP failures and probabilities are presented in ANL's companion report [5].

A 2014 report, MCS Kenny [4], showed the MTTF for the BOP control system in the range of about 160 to 260 days for combined MUX and conventional pilot system groups. MUX systems were more complex (than conventional pilot systems) with average MTTFs about 10 days lower. ***In this study, control system failures accounted for 63% of all BOP failures.*** Failures included leakage in the control pods, solenoid malfunctions for the choke line fail safe valves, and subsea SPMs, but there was not a detailed breakdown.

4.2 Industry's Reliability Culture

The nature of the industry's reliability culture is changing. Component manufacturers, BOP OEMs, operators, and contractors do not appear to have focused intensely on improving BOP control system and SPM reliability in the past. The explanations provided by Shanks et al. [11] are:

1. Customers (contractors and operators) have not, until recently, demanded high levels of reliability;
2. Subsea downtime is often viewed as unavoidable;
3. Higher-reliability components are anticipated to require higher capital cost;
4. Detailed product performance data are not consolidated effectively to identify problem trends;
5. Developmental times and costs are seen as prohibitive; and
6. The supply of spare parts is important to some vendors' revenue.

However, even though BOPs are produced in small quantities and are heavily customized, industry perspective appears to be evolving. The competitive nature of the industry provides incentives for improved performance and higher reliability. At the same time, competition fosters communication barriers when organizations seek advantages in the marketplace.

As mentioned before, API requires the collection of failure information within Standard 53 (see 6.5.3.7.4, 7.6.5.7.4, 7.6.11.5.3, and Appendix B of Std. 53). This process covers all well control equipment and would logically include SPMs. According to the standard, this failure information should be provided by the owner, communicated to the equipment manufacturer, and then forwarded to other users. The standard does define the identity of the OEM, but not of the manufacturer. This lack of specificity about OEM sub-tier suppliers and commodity manufacturers introduces differences in interpretation and results in information for reliability improvement (especially if a true root-cause analysis has been done) not reaching those who can act on it.[8]

Some API Standard 53 definitions need refinement.

Operators and drilling contractors collect relevant information through real-time monitoring and shared maintenance logs, but do not necessarily pass details onward. This information is likely to flow to the original equipment manufacturer and even to the commodity manufacturer level because operator downtime has become a primary focus. API Standard 53 has limited information on the sharing requirements that should be followed toward improving BOP reliability.

Some industry participants have recognized the need for a more reliable BOP control system.
Reliability targets however have not been openly set or agreed upon.

[8] [redacted] details of SPM failure circumstances are usually not available or are not provided when a valve is received for repair. In an offshore situation, this information can be easily lost. Motivations toward improving reliability could help change the situation.

4.3 Key Industry Reliability-Focused Collaborations

[redacted] have BOP reliability initiatives underway. [redacted] indicated that BOP reliability initiatives were underway because senior management was seeking reductions in drilling downtime for cost savings. Also, improved BOP dependability can reduce risk and enhance safety. Despite the efforts reliability targets have not been openly set or agreed upon.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[9] If prior studies remain valid, SPMs could account for about half of the previous item 1.

[10] Appendix G lists common BOP failures mentioned to Argonne during the study. Many of these can involve SPMs.

[11] Statistically, hourly downtime percentage or contribution usually differs considerably from percent of failures.

[redacted]

4.3.3 Software Tools

A few rig owners subscribe to a risk evaluation service. [redacted] This model can evaluate BOP functions and compliance with current BOP regulations. Necessarily, the service is specific to a BOP on a particular rig. Considering the atmosphere of change, the models must exactly parallel the actual configuration of the BOP.

[redacted]

These status and monitoring tools can be useful for diagnostics and for controlling the impact of failures on the overall function and reliability of the BOP. A particularly valuable capability could be to record benchmarks and assess whether repairs or modifications have the desired outcomes. Additional monitoring systems are described in Appendix H.

[12] [redacted] a schedule for the completion of their work. Oil prices were declining markedly at the time.

5.0 MANY SPMS ARE MANUFACTURED COMMODITIES

5.1 SPM Supply Chain and Marketplace

The nature of SPMs and their part in BOP control system failures are influenced by the U.S. SPM supply chain and the marketplace in which SPMs are manufactured and distributed. To understand how SPMs from a commodity manufacturer become BOP control system components, let us look at the drilling industry's process of acquiring SPMs.

In subsea drilling, operators establish technical requirements for a specific drilling operation. These requirements include conformance to the operator's internal policies and procedures. Through a contract agreement, a rig owner is expected to provide drilling services for the operator's well campaign. In setting up a drilling operation, the rig owner specifies BOP functions to a BOP OEM who, in turn, designs, builds, tests, and often supports the BOP after delivery. In many control system designs, BOP OEMs purchase commodities such as SPMs, shuttle valves, regulators, electronics, and raw materials. Therefore, the communication pathway for component failure is not always clear, and the timely collection and dissemination of failure information that could improve SPM reliability (such as the failure notification process in Standard 53) becomes complicated.

The communication pathway for component failure is not always clear.

Presently, there are [redacted] major BOP OEMs: [redacted] provides BOP services such as retrofitting and upgrading control systems. The numbers, sizes, engineering specifications, and manufacturers of SPMs (and other hydraulic control valve designs) are determined by OEMs. As such, the majority of U.S.-produced SPMs are designed and manufactured [redacted]. Some are OEM designs produced by contract manufacturers, while others can be supplied [redacted]. This is also true for similar components in BOP control systems, such as check valves, pressure regulators, and shuttle valves.

Subplate mounted (SPM) valves are specialized products that require several high-precision parts. As such, few independent contract machine shops have adequate capabilities to manufacture them. For example, dimensional tolerances throughout the product are important, and SPMs require some exceptionally flat surfaces to function properly. Achieving these flat surfaces requires state-of-the-art grinding/lapping and inspection processes. [redacted]

[redacted]

Buyer organizations (BOP organizations or contractors seeking replacements) either select valves for applications based on catalogs or [redacted] obtain the products from the stocking distributor. [redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

5.2 SPM Design Improvement and Service Parts Approaches

[redacted] have distinct approaches toward design improvement and service parts. [redacted] [redacted] [redacted] parallel product numbers, and prefixes communicate engineering revisions. An experienced technician in the field can, without documentation readily available, identify whether a repair or seal kit corresponds with the valve needing servicing. [redacted] on the other hand, does not have ready part-number matching in the field. [redacted] the technician needs the latest service manual for a part number to assure the latest revisions are incorporated or present in the kit on hand. [redacted] this approach enables quick and thorough engineering changes and helps avoid someone using an out-of-date drawing. [redacted] companies mark products, including small parts where possible, and both strive to assure their products incorporate the latest design parts.

[redacted] This philosophy extends across all manufacturing (parts and assemblies). Numerically controlled factory equipment can produce any part on very short notice. [redacted] This approach also reduces the likelihood of producing out-of-specification parts. This practice does necessitate having suitable material on hand at all times.

[redacted] SPM design improvements include:

1. O-ring sizing that is specific and obvious to position in assembly;
2. Tightening and maintaining of smaller tolerances;
3. Standardized stepped bores for installation per a generic detailed drawing of the bores that can be easily and accurately machined;
4. Special retainer clips (which had been frequently installed with the rounded edge under pressure);
5. A nylon retainer nut instead of a castle nut to eliminate a difficult-to-assemble cotter pin; and
6. A part-numbering system that relates markings on field service kits with valve model numbers.

[redacted]

5.3 SPM Operational Influences

[redacted] offer a full range of SPM valves to the industry and work with OEMs on selection to install SPMs in BOPs. When selecting SPMs, OEMs seek to satisfy a

[13] Changes can involve a wide range of subjects, including materials, manufacturing methods, dimensions, surface finishes, assembly procedures, inspection details, and service conditions. A design change can be triggered by manufacturing optimization, responses to service failures, materials improvements, and many more issues. [redacted]

functionally focused technical specification. During this process, technical mismatches can occur, and the details of how a BOP is operated may remain a lingering unknown.

Furthermore, rapid execution of a function or quick changes between functions can create unanticipated fluid hammer effects. In turn this can cause rapid valve cycling, which leads to failure or damage. While [redacted] did not mention such specific SPM failures but [redacted] hydraulic shock damage to shuttle valves and attribute this damage to BOP surface testing on the rig prior to deployment. Rapid function executions, such as hard swapping BOP pods combined with hard conduits or short hoses, can hydraulically shock subsea SPM and shuttle valves. [redacted] encountered similar issues and have incorporated [redacted] design criteria to help ensure more reliable BOP controls.

5.4 SPM Manufacturer Product Quality Enhancements

Manufacturers of SPMs are in the process of enhancing production, quality, and reliability. [redacted]

[redacted] in equipment and manufacturing processes to assure product quality. Examples include:

1. **Continuous manufacturing readiness.** [redacted] numerically controlled tooling carousels are loaded continuously to manufacture any part at any time. [redacted] This also improves accuracy, especially when compared to older manual machining. [redacted] has invested in several state-of-the-art numerically controlled machines [redacted].
2. [redacted] **numerically controlled machining.** This equipment broadens the types of machining processes [redacted]. [redacted]
3. **Numerically controlled inspection**. Parts are placed in a fixture, and then profiles and positions are checked and recorded in an automated system.
4. **Automated optical inspection.** This process generates data files and output that show where in the tolerance range actual dimensions fall. If specific dimensions are repeatedly trending away from the midpoint of the range, manufacturing adjustments can be recognized and implemented quickly.
5. **Direct linkage between** [redacted] **CAD**[redacted] **and machine code**. Presumably, dimensions are merged with the machine code system in defining feed rates and dimensional details of tooling.

6. **X-ray fluorescence scans and records retention for raw materials.** This verifies whether a piece of metal meets the proper chemical specifications. [redacted]
7. [redacted] **line to clean finished parts.** This statistically controlled [redacted] process removes free elemental iron, chlorides, and other detrimental contaminants. Subsequent to cleaning critical parts, the parts are never touched by bare human hands.
8. **Material verification system.** Raw materials come only from known and approved sources and are then verified before manufacturing or assembly. Metallic materials come with certifications and chains of custody back to the mill. [redacted]
9. **Six-sigma system.** [redacted]
10. [redacted] **inspection system**. This system aids the examination and acceptance of lapped parts and surfaces.
11. [redacted] **lapping equipment.** This equipment enables high-precision mating facings, which make a fluid seal on contact.
12. **Automated parts storage and retrieval.** In addition to protecting parts from damage, this system provides information to cross-check part positions and engineering revisions for customer orders.
13. **Updated assembly stations.** State-of-the-art work stations provide ready access to the latest information about parts and assembly details (electronic). These stations also provide physical features that reduce the likelihood of a part being damaged during assembly.

In an effort to ensure product quality and reliability, [redacted] internal quality systems require that all SPM metallic valve materials be certified back to the mill. As a result, [redacted] do not knowingly accept materials from nonapproved suppliers or unacceptable countries of origin. This information, as well as all other inspection, testing, and service information, is archived [redacted].

5.5 SPM Manufacturer Support

Brand loyalty is common in the oil industry, and undoubtedly, foundations for this loyalty tie back to personal relationships and tradition. For example, [redacted] establishes and sustains links with its existing customers, as well as with contacts that are likely to purchase a related follow-on product (e.g. repair kits) or service (e.g. recertification, training, and asset management). Because many operators annually replace or refurbish SPMs and generally fully rebuild pods every 5 years, this is a significant business segment. Occasionally, when a BOP is being rebuilt, an

OEM will remove the valves and send them back for refurbishment and recertification. Compared to aftermarket business, therefore, the market for new BOPs is comparatively limited.

As a result of the demand for aftermarket services, each manufacturer offers training, technical support, and documentation for their products. These materials illustrate manufacturer-recommended procedures, cautions, and special tools. [redacted]

One important aftermarket product for SPM manufacturers is the SPM service kit. Generally, there are two types of SPM service kits: one that contains all parts for a full rebuild [redacted] and one that contains just elastomer type parts [redacted]. These service kits are available for rigs through normal distribution channels. [redacted] Kits from [redacted] have a shelf life of 6 years. [redacted] similar kits and uses dated packaging to shield elastomers from ultraviolet light. Through providing these aftermarket products and services, SPM manufacturers support rigs and drilling operations that require frequent SPM rebuilding or refurbishing.

5.6 SPM Supplier Maintenance Recommendations

American Petroleum Institute (API) Standard 53 requires that manufacturers offer specific maintenance recommendations; however, neither [redacted] provide complete information. While short-term (one-year) warranty/service provisions and goodwill actions exist[14], users typically develop and implement their own maintenance programs.

The programs designed by SPM users vary widely. Some users track operation cycles as one criterion for replacement, and others follow service period practices (such as changing or rebuilding 15%–25% of SPMs each year and changing all SPMs every 5 years. As discussed in the previous section, to support routine replacement practices, [redacted] offer full refurbishment services, offshore engineering support, and technical training when requested. [redacted] receive a used valve, trained technicians disassemble, clean, evaluate, and install needed parts or seal kits. The valves are then fully function-tested prior to shipment.

Manufacturers of SPMs do recommend some practices to users. For example each manufacturer recommends [redacted] assembly lubricant for valve servicing; however, neither SPM manufacturer possesses comprehensive information about how well rig owners follow these recommendations. To minimize the potential for chemical and mechanical damage to seals or some metallic parts, technicians should follow manufacturer recommendations and maintenance manuals. For example, depending on the portion of the

[14] A goodwill action would be replacing a product beyond the warranty period or if there are definitive materials or workmanship issues with an unused valve.

SPM on a [redacted] BOP, the recommended lubricant list includes [redacted] Moly Paste [redacted], feed grade silicon spray, [redacted], 10W light machine oil, and [redacted] Specific PTFE-sealing lubricants are discouraged on some stainless steel components that reside in saltwater, as corrosion rates can be accelerated. Comparatively, in a maintenance manual, [redacted] recommends petroleum jelly on SPM components. A factory-based assembly process would be more likely to follow that organization's procedures.

5.7 SPM In-Service Maintenance Realities

The realities of SPM in-service maintenance contribute to the numbers of SPM failures and resultant BOP failures. Subplate mounted (SPM) valves contain high-precision internal components, and the compact designs of SPMs rely heavily on O-rings to separate the pilot fluid chambers from power fluid chambers and to separate both chambers from the external environment. (See Figure 3 and Figure E-1 for cross sections.) Common O-ring issues and failures, [redacted], are:

1. Damage during installation from a tool, placement in groove, improper groove shape, or configuration;
2. Damage when subassembly is installed in main housing (such as sharp edges on ports or at bore entries);
3. Improper part orientation; and
4. Switching part positions (O-rings).

Suitable SPM testing equipment is generally not available offshore.

Based on vendor discussions, these situations would be **<u>less likely to occur if O-rings were installed in a factory setting by a person familiar with the particular SPM.</u>** Any one the situations [redacted] can lead to internal or even external leakage. Since SPM O-rings and metallic parts are not visible once installed, the best measures of success are flow and pressure tests. However, when SPM rebuilding occurs

Standard 53 is silent on SPM maintenance technician training.

offshore, suitable testing equipment is generally not available.In the drilling industry, a common practice is to rebuild SPM valves offshore to help expedite a BOP control system returning to service. Such repairs and replacements should require strict conformance to the manufacturer's maintenance requirements. In addition, only trained and qualified personnel should use manufacturer-approved components and lubricants. A factory setting could potentially reduce the occurrences of O-ring and SPM failures. Factory rebuilding could also provide post-rebuilding testing. However, rig operators are reluctant to depend solely on factory service because of the associated drilling downtime. Currently, API Standard 53 is silent on the aforementioned important requirements for SPM rebuilding and maintenance. As a result, SPM rebuilding continues offshore without the necessary testing equipment.

Neither [redacted] have details on rig technician training concerning SPMs or detailed knowledge of each rig's SPM part inventories.

The training of technicians and the availability of SPM parts are other major factors in SPM rebuilding. Neither [redacted] have details on the training that rig technicians receive, nor do they know how often offshore SPM rebuilding occurs or the extent of appropriate part inventories to support specific BOP systems. Both [redacted] provide service for returned products, offer parts as requested, and have offered parts inventory management services. From anecdotal user information, manufacturers outlined a range of issues found in returned SPM valves. Without consideration for frequency of occurrence these are:

1. Apparent over pressurization and/or misapplication;
2. "Rag" migrating through and eventually plugging part of hydraulic system;
3. Presence of contaminated hydraulic fluid or excessive particulate matter;
4. Valves that were never manufactured by [redacted];
5. Incorrect OEM parts;
6. Outdated repair parts;
7. NonOEM parts from unknown sources;
8. Rebuild kits that have been opened and are missing parts;
9. Incomplete rebuilds;
10. Broken or damaged internal flow control parts;
11. Broken mainsprings;
12. Clip rings that are installed backwards;
13. O-rings of similar size switched;
14. Assembly lubricant and/or hydraulic fluid not compatible with materials, including elastomers;
15. Over- or under-torqued fasteners;
16. Improper tightening sequences;
17. Seat erosion or distortion including normal wear and tear; and
18. Manufacturing defects.

Many of the issues outlined above—issues that contribute to SPM and BOP failure—can be best addressed and corrected in a factory environment. Compared to offshore circumstances, factory resources provide the combination of knowledge, correct parts, testing apparatuses, and personnel to inspect, clean, reassemble, and test SPMs.

5.8 Commodity Supplier and Service Reliability Initiatives

In response to the risks that current in-service SPM maintenance practices introduce to BOP systems, several companies have launched initiatives to improve SPM reliability. Seadrill, a drilling company, has begun collecting and compiling valve (SPM) performance in a database and plans to share this database with sub-tier suppliers in the future. Currently, Gilmore becomes aware of failures only when users or OEMs decide to share that information, and when this does occur, there is usually scant information on service history. Commonly, SPM failures appear as system failures, with the SPM listed as a subset. Gilmore is working with Seadrill to encourage users to notify the manufacturer when a valve fails.

[redacted] most, if not all, rigs maintain databases on BOP service and repair, including SPM valves and when they are changed or repaired. However, the extent and manner of keeping such information varies between rigs even within the same company. Similarly, Lloyd's Register is developing a database that records information flow between operators, drillers, and OEMs. As more and more MUX systems begin service, the outlook for getting this information improves since MUX systems collect much more information than older surface pilot systems do.[15] As these initiatives gain momentum, more information will be available to improve SPM reliability.

[15] Several organizations have promoted systems that are intended to monitor and/or assess the BOP system. See Appendix H for examples.

6.0 FINDINGS AND CONCLUSIONS

Electrohydraulic BOP control systems employ SPM valves to direct hydraulic power fluid to wellbore components, including BSRs, annulars, and variable bore pipe rams. It is important that these components and systems be reliable; however, for some time, early failures and consequential BOP outages have been an accepted norm in the drilling industry. Current maintenance and replacement programs during the typical 5-year design life seek to improve and sustain BOP reliability, and some redundant features are helpful. While these are reasonable, they are also evidence that the industry did not aggressively focus on system and component reliability early in the BOP life cycle. In examining these issues, Argonne has identified several common reliability problems. These appear in the following paragraphs.

6.1 Systems Reliability Targets

The first reliability problem that Argonne has identified is that there is not a common industry-wide target value for BOP reliability. For some time, the drilling industry has accepted BOP failures and unavailability as a normal cost of doing business. More recently, industry executives have noticed the magnitude of these costs and are now looking to reduce downtime. Increased reliability would lessen downtime while improving the likelihood of success for a well control action. Less BOP downtime is also significant to safety and reduced drilling costs.

Finding: There is no common industry-wide target value for BOP reliability.

A companion Argonne study estimated the failure rate of the BSR system to be no better than 1 in 200. This failure rate could be even higher if the whole BOP system were considered. With scores of drilling rigs operating in the GOM (58 as of February 2016), the likelihood of BOP BSR failure at a critical moment is relatively high. Based on the work of this study, Argonne believes BOP reliability can be improved to significantly lower this risk.

The life cycle of a BOP and its components (such as SPMs) includes design, procurement, fabrication, testing, operation, maintenance, and refurbishment. Users and manufacturers are exploring various reliability-driven actions for part of these phases. For example, contractors replace a certain percentage of SPMs on an annual basis, and SPM manufacturers are taking steps to lessen the likelihood of improper assembly. Overall, Argonne believes the most effective reliability improvements must occur during the design phase, as this phase establishes a component's or system's performance for the entirety of its life cycle. Current applicable standards only require a 1,000-cycle capability for a **prototype** component with limited consideration of duty cycles. For a five-year design life, this is about 4 cycles per week, which is only adequate to prove the valve or component can sustain infrequent use. While use depends on design, a manifold pressure regulator or a control valve common to several test circuits could approach or exceed 4 cycles per week. The current reliability targets for BOP systems and their components are not sufficient considering the parts these components play in BOP failure.

6.2 Offshore Rebuilding of SPMs

A second problem in SPM reliability is offshore rebuilding. When an SPM fails or is blamed for failing and a BOP is retrieved for repair, there is an urgency to complete all work as soon as possible. Often, this does not allow time for the user to return a SPM for factory rebuilding and testing. Therefore, SPMs are rebuilt offshore. Rebuilding or remanufacturing SPMs can achieve near-new performance if done properly and thoroughly. However, offshore circumstances are not optimal since the process requires:

1. Special tools;
2. Technical training and periodic requalification;
3. Complete documentation of parts and procedures; and
4. Comprehensive parts management.

Finding: Offshore SPM rebuilding circumstances are not optimal.

Among rigs, there is going to be considerable variation in all of these areas. By contrast, the original SPM manufacturer has all of the above resources plus:

1. Original component QA records;
2. Cleaning equipment;
3. Inspection equipment;
4. All parts plus current engineering updates;
5. A clean, controlled assembly environment;
6. Multiple trained technicians; and
7. Pressure and flow test equipment.

These additional resources and capabilities enable more thorough and reliable SPM rebuilding or remanufacturing than what can be achieved offshore.

6.3 Hydraulic Fluid Quality

Hydraulic fluid quality is often regarded as an essential aspect of successful BOP operation. Excessive fluid contamination is not conducive to the trouble-free operation of valves, pumps, and other hydraulic components. While uncontaminated fluid would be ideal, the reality is that some contamination is going to occur over time and will definitively occur when the system must be opened. Unfortunately, some parts of a BOP system (for example, portions of the accumulator systems) have dead end legs. Other parts are once-throughs, which allow flushing and are a bit more forgiving. In either case, fluid quality is a meticulous and challenging process requiring constant attention to:

1. Water quality;
2. Debris;
3. Additives;
4. Chemistry;
5. Biology; and
6. Maintenance practices.

Finding: Consistent hydraulic fluid quality must be maintained.

Personnel with the responsibility for maintaining all of these areas must be competent and knowledgeable.

6.4 API Standard 16D and 53 Reliability-Related Issues

Two API standards are the most relevant with regard to BOP systems. These are:

1. Standard 16D; and
2. Standard 53.

After thorough review, Argonne has concluded that these standards are not adequate for fostering the high reliability needed for BOPs. Design criteria and the associated acceptance criteria and quality management must be driven by the performance needs of the systems. Current standards outline a few points about design cycles and prototype testing, but do not define acceptance criteria. Also, some references between the standards have not been fully coordinated, and several definitions are missing or potentially confusing. Most importantly, overall BOP systems reliability criteria are not specified in these standards.

Finding: Applicable API Standards need more reliability criteria and need to be better coordinated.

7.0 RECOMMENDATIONS

According to this study, the industry has heretofore not focused on system and component reliability. Instead, the drilling industry has accepted BOP failures as a cost of drilling, resulting in BOP outages from failures during the 5-year period between major rebuilding. The industry has launched initiatives to improve reliability, including some comprehensive redesigns. From these, there is a realistic possibility of improving upon a currently estimated BSR failure rate of around 1 in 200. Prescriptive regulations or mandates are one pathway to motivate improvements. A second and more preferred regulatory approach, in Argonne's opinion, is an incentive program focusing on system performance. Such an approach can set targets and schedules, but can leave flexibility in how those targets are achieved. Based on this philosophy and the findings of this study, Argonne's specific recommendations are:

1. Since BOPs are critical systems in many offshore operations, the BSEE should consider establishing targets for overall BOP system reliability and a time frame for compliance. ***Reliability targets are related to the BSEE's Best Available and Safest Technology (BAST) program and could be considered under this program.*** This is the long-term solution for uniformly driving the industry toward more reliable systems, with minimal governance overhead. Further, this target could apply to all BOP systems, whether or not SPM valves are used.
2. In the short term, the BSEE may wish to consider governance that emphasizes training requirements, configuration control, and excellence in maintenance. These should include requirements for maintaining high levels of hydraulic fluid quality.
3. Improved information sharing between operators, rig operators, systems OEMs, and component OEMs (commodity manufacturers) could be beneficial, especially for critical systems. One strategy would be for the BSEE to collaborate with API and the industry and add specific communication requirements to API Standard 16D, Standard 53, and other applicable standards. These requirements could ensure that all parties receive the information needed to maintain and improve reliability.

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Appendix A: Brief History of Subsea BOP Development

Subsea BOPs have been in development for many years and have evolved to become more efficient and remotely operated. The development of the subsea BOP began with Stewart and Stevenson's Paul Koomey, who was instrumental in developing early subsea BOP control systems and sold 3,000 psi accumulator units as early as the late 1950s. One significant development of this era was a regulator capable of reducing 3,000 psi pressure from accumulators to the control range of 1–1,500 psi. Two of these new regulators were used as part of the 3,000 psi BOP control system, which was used to remotely control BOPs and rapidly close the BOP annular units. During this period, Stewart and Stevenson associated with contract machine shops to make in-house parts. One of these contract machine shops introduced Sam Gilmore, the individual who made hydraulic system pressure relief valves. These first BOP system control pods were deployed as single units and were heavy and long. The need to shorten the pods and reduce weight and size led to the development of compact subplate mounted (SPM) valves that could direct high-pressure hydraulic fluid (power fluid) with a small volume of hydraulic pilot fluid. Around the same time, Texaco deployed twin pods on a subsea stack, although these Payne Manufacturing units used 2,000 psi accumulators [12].

In the late 1970s, Koomey, Inc. emerged following National Lead's acquisition of the Stewart and Stevenson business unit. Eventually, Koomey, Inc. was sold to a Scandinavian entity that became part of ABB Group. In the mid-1970s, the business enterprise enjoyed about 85% of the BOP controls market and offered innovative products, including acoustic control components. Currently, Axon Corporation and Shaffer/NOV own many of Koomey's active patents. Today, across the industry, many products (including SPM valves) are referred to as being "Koomey type," regardless of the actual manufacturer.

Appendix B: Overview of Current Subsea BOP Control Systems

Current oil and gas drilling in the GOM requires robust subsea BOP equipment. To operate in the subsea environment, designers and manufacturers constantly adapt their equipment based on the latest needs and regulatory requirements. Today depths of 5,000 ft. or more are common and, while BOP systems vary widely (in regards to control systems, the numbers and types of cavities, and bore pressure ratings), two general types of BOP control system are in use:

1. Surface-supplied pilot signal fluid systems; and
2. The more recent multiplex type (MUX) systems, which feature subsea electric-powered components.

In this appendix, we will outline the main features of these two types of BOP systems.

Surface-Supplied Pilot Signal Systems

In the early days of GOM drilling, water depths were modest compared to today. As such, surface-supplied pilot BOPs, as depicted in Figure B-1, were essentially modified surface units. Hydraulic operators replaced the hand wheels of the surface unit, since there was no electric power on the sea floor. Mechanical actuators for various subsea functions were controlled through bundles of hydraulic tubes extending (via an umbilical bundle) to the surface. These small, high-pressure tubes (about 0.25-in in diameter) linked the pilot-operated SPM valves on the sea floor to the surface. Subsea SPM valves controlled the flow of hydraulic fluid to BOP function actuators (such as BSRs), and a large tube leading to the surface provided hydraulic power fluid and maintained pressure in subsea accumulators. On the

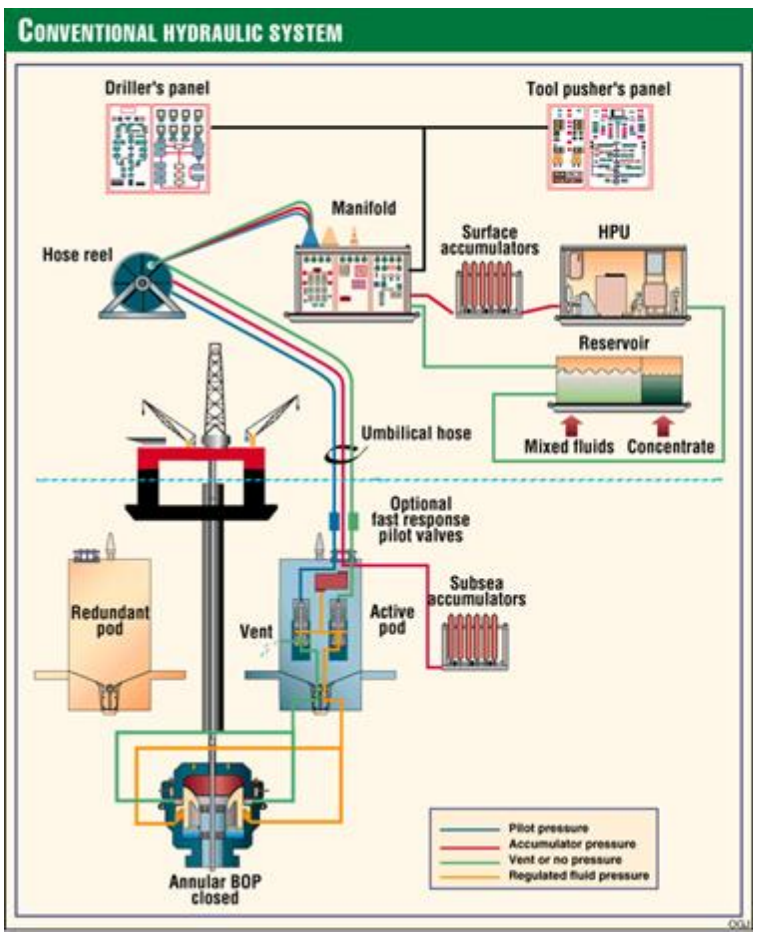

Figure B- 1: Functional Schematic of Surface Pilot-Operated BOP System

surface, switching and signals operated solenoid valves that interfaced with appropriate control tubes to the sea floor.

By their very nature, pilot-operated systems delay function response because hydraulic signals to the pilot valve on the subsea SPM must progress down a small and lengthy tube. Such designs worked well to depths of about 4,000 ft., but became limited by the sizes of the tube bundle reels required on the surface rig. Also, there was a 45-second minimum[16] standard for closing a BSR, and this became less and less practicable as depths increased. Surface-supplied pilot signal systems featured dual control pods for redundancy and reliability (shown as active and redundant in Figure B-1 and B-2 as opposed to the yellow and blue terminology). Today, approximately one-third of GOM rigs still use these systems.

MUX Systems

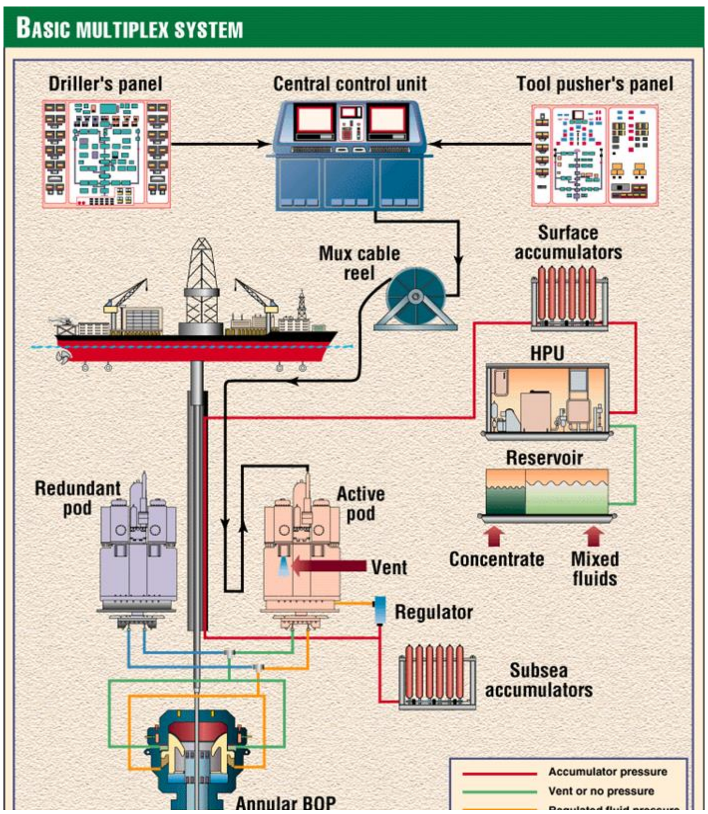

Figure B- 2: Functional Schematic of Basic Multiplex BOP Control System (yellow and blue control pods are represented as active and redundant)

About two-thirds the rigs currently operating in the GOM use a MUX-based BOP system similar to that depicted in Figure B-2. These systems have electric solenoid valves that control SPM pilot hydraulic signals on the sea floor. Early-generation MUX systems sent direct signals to the sea floor, and there was even an unsuccessful attempt to perform BOP functions using only large solenoid valves and no SPMs. Today's systems feature electronics that receive and decode bidirectional signals. These signals are sent through fiber-optic cables or standard electronic transmission, linking subsea and surface electronics. Even with included electrical power conductors, DC bundles and later-generation fiber-optic bundles are both much smaller than the older pilot system bundle.

[16] See BSEE regulation at Title 30 CFR 250. 442 (c) incorporating API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004. API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004; incorporated by reference at §§250.442,250.446, 250.517, 250.618 and 250.1708.

Surface rig reels are still large for current systems, but they are capable of accommodating more total bundle length for greater depth than surface pilot hydraulic systems. Most significantly, the time delay for a signal to arrive at the sea floor is insignificant compared to the delay of original pilot systems. Hydraulic fluid (for both pilot and power use) is typically routed at 5,000 psi to the sea floor via one or two riser-mounted conduits (as opposed to tubes in the MUX cable bundle). The hydraulic supply splits at the sea floor for subsea pilot, low-pressure, and high pressure functions.

Some computer-controlled MUX systems use proprietary software, while others use standard industrial products. Some BOPs have control and/or monitoring systems designed and implemented by entities other than the original BOP manufacturer. Software development and validations vary widely. Independent of unique software details, there must be high-control system reliability and availability for on-demand operation.

Appendix C: Hydraulic Basics and SPM Functional Analogy

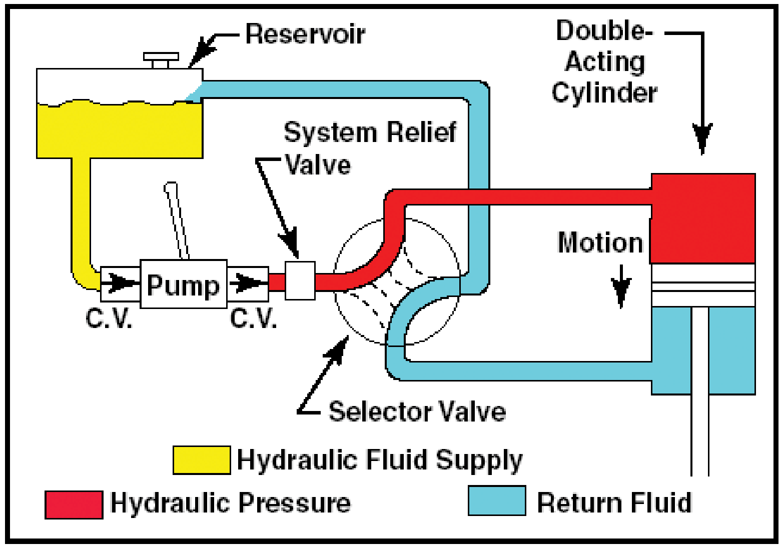

Figure C- 1: Basic Double Acting Hydraulic System

Hydraulics can generate a large force, such as that needed for a blind shear ram (BSR), by applying pressure and flow to a large cross-sectional area. In the basic system shown in Figure C-1, a pump moves pressurized fluid along the red flow path into the double-acting cylinder. A pump produces pressure over a small cross section. When that pressure is exerted over the larger area of the cylinder piston, the force of motion increases. This increase is directly proportional to the ratio of areas (cylinder versus pump), provided there is an open pathway (shown in blue) for fluid to return to the reservoir.

In this example, the selector valve is positioned to move the cylinder downward. Assuming the pump continues to run, rotating the selector valve one-quarter turn counter clockwise changes the direction of the fluid motion (dotted lines). In this example, the selector valve would be manually positioned. In more complex systems, such as those used to operate BOPs, an actuator moves the selector. If the selector is positioned to block flow to the cylinder and the pump continues to run, a system pressure relief valve opens and routes flow back to the reservoir (not illustrated).

Assume the double acting cylinder is the BSR actuator located subsea. Subplate mounted valves serve as a selector valve but with the blue line vented to the sea or a designated collection system. For the cylinder rod motion to occur the blue flow path must be open (vented properly) or hydraulic lock occurs. For a typical BOP, depending on circumstances, the hydraulic activating source is either a rig hydraulic pump or an accumulator.

Continuing the analogy, commonly encountered SPMs can be thought of as single-acting versions of this basic example, as there is no means to use hydraulic power for reverse motion. Instead of using a selector valve to return the cylinder to the starting position, an internal mechanical spring pushes flow backward through the pilot line. The pilot line might extend to the rig in older systems or to a subsea solenoid valve in newer (MUX) systems. The SPMs in a BOP system allow low volumes and pressure (pilot) hydraulic fluid to control high pressure and flow (power) hydraulic fluid.

Appendix D: SPMs Are Key to Critical BOP Safety Functions

Blowout preventers execute several critical safety control sequences: emergency disconnect, deadman, and autoshear. Specific details of these actions vary depending on the BOP system design. However, it is typical for hydraulic control signals via SPM valves to make these sequences occur. Typical initiating conditions for an automated sequence may include:

1. **Emergency Disconnect:** Measured angle at flex joint exceeds predetermined limits (usually 4 degrees);
2. **Deadman:** Loss of electrical and hydraulic power on both blue and yellow pods (but not loss of electric power to one pod and loss of hydraulic power to the other pod or loss of either electric or hydraulic power on both pods); or
3. **Autoshear:** Separation of the LMRP deck plate from the BOP stack (intentional or inadvertent).

The sequences described can also be initiated by operators. Each pilot fluid signal moves at least one SPM valve to direct hydraulic power fluid for required functions (in most cases, a sequence of functions) and/or associated functions (such as accumulator isolation valves). Short descriptions of the three basic sequences follow.

Excessive Flex-Joint Angle (Emergency Disconnect)

Rig position over the wellhead is important. During normal operation, dynamically positioned (DP) rigs strive to stay within 1 degree of the wellhead, but operations can reasonably continue up to ±3 degrees from vertical. At about 4 degrees, a DP rig usually moves off the well. At this point, moment loading (torque) at the wellhead connector becomes unacceptable.[17] What results is an emergency disconnect close-in sequence that usually separates the LMRP from the stack, closes and locks the BSRs in the stack to shear any drill pipe or shearable item in the wellbore, and opens the upper annular on the LMRP (which is separated from the BOP stack in such an event). Opening the LMRP annular releases drilling mud and enables the riser and sheared upper drill sting, if present, to move upward with the rig tensioners.

Loss of Pod Hydraulic and Electric Power (Deadman)

Regulations from the BSEE require BOP control pods (yellow and blue) to be fully operational once drilling operations commence below the surface casing. However, at any given time, only one pod actually supplies hydraulic fluid power to the active BOP. In the event that both pods lose electric and hydraulic fluid power, prearmed systems spark a deadman well control sequence. This includes blind shear action to shear and seal the bore using stored energy from the BOP accumulators. Depending on circumstances, the LMRP

[17] Moment loading on the wellhead is created by the horizontal component of the upward riser tension. The moment (ft-lbs) on a wellhead connector (necessitating emergency disconnect) is riser tension at flex joint (lbs) times the Sine of the observed deviation angle from absolute vertical times the combined height of the BOP stack and LMRP (ft).

can remain connected or can be disconnected. Disconnecting involves stab retractions for the hydraulic and electric control interfaces between the stack and the LMRP, the release of latches between the LMRP and the BOP stack, and blocking actions. The deadman sequence remains in armed status during drilling operations.

LMRP Separation (Autoshear)

Sensors between the BOP stack and LMRP detect connection status. If the LMRP separates from the stack, whether inadvertently or intentionally, an autoshear sequence is initiated automatically or manually. In either case, this predetermined sequence relies on stored energy in the stack accumulators (or another energy source on the lower BOP connected to wellhead)[18] to shear and seal the wellbore via control signals sent to SPMs. Per API 16D design requirements, there should be more accumulator capacity available than what is needed for this shearing and sealing action. Should this capacity be insufficient or should other difficulties occur, remotely operated vehicle (ROV) intervention is an option. When separation is manually initiated (deliberate), a likely routine action is to open the upper annular before the autoshear. This releases drilling mud to help assure the sheared drill sting, riser, and LMRP can move upward with the force of the rig tensioning system.

[18] Note: These are also accumulators on the LMRP charged with power or pilot hydraulic fluid.

Appendix E: Typical SPM Design

Subplate mounted (SPM) valves are available in a multitude of configurations, options, sizes, and design details.[19] They are hydraulic control valves that use pilot fluid to direct power fluid for performing subsea functions. In such an application, the SPM is the active component of a two-stage control system.

Subplate mounted (SPM) valves include a pilot activation and operational valve portions. In the cutaway cross section in Figure E-1, which illustrates a common two-position three-way configuration for SPM valves (normally closed), the pilot fluid chamber and supply port are on the left side. When pressurized pilot fluid is introduced (as in response to a function signal), the springs compress as the central rod moves to the right. This motion moves a poppet (spool section in middle or right) that opens a flow path between the power fluid inlet port and the function port on the right bottom portion of the valve body. The third port on the bottom portion of the valve is a vent port.

When pilot pressure is relieved, such as through venting or backflow in the pilot supply

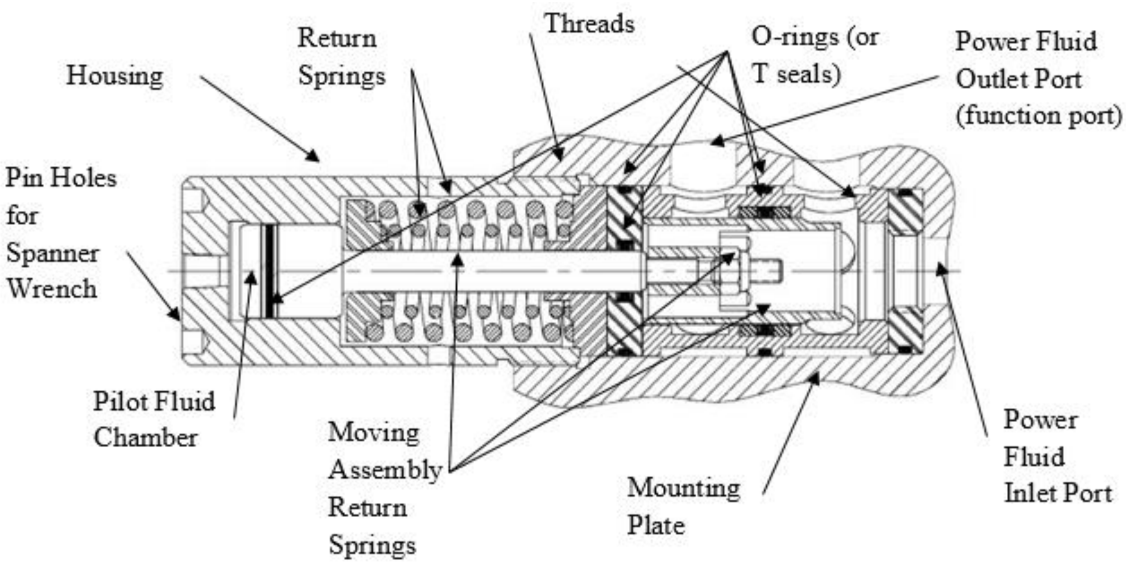

Figure E- 1: Cross Section of a Typical SPM Valve

line, the spring(s) returns the rod and poppet assembly to resting position. This opens a flow path between the function port and the vent port to enable the exit of pressurized power fluid. Also, when the poppet is moving between positions, both power and returning function fluid can exit through the vent port.

[19] For current BOPs pilot fluid pressure is about 3000 psi. Depending on regulator setting, power fluid pressure can approach 5000 psi. Common SPM port sizes are in the range of ¼ in to 1 ½ in nominal.

Appendix F: SPM Hydraulic Fluid Properties

During the course of Argonne's study, industry people mentioned that hydraulic fluid cleanliness is a significant factor affecting SPM and BOP life and operation. While API 16D is silent on the specific requirements and criteria for operations, most rig operators have established programs in this area. These sampling and analysis programs periodically check:

1. Particulates;
2. Microbe levels (bacteria, fungus, and mold);
3. Lubricant percentages; and
4. Water hardness ($CaCO_3$ level), including periodic sampling and analysis.

In addition to these measures, owners check the potable water quality used for hydraulic fluid mixing. This includes water brought from shore. Since hydraulic fluid is released to the ocean, an ongoing concern is compliance with environmental requirements.

One cleanliness measure used in mechanical equipment is particulate content. Reference [13] recommends that BOP hydraulic fluid particulates should fall between National Aerospace Standard 1638 (NAS) level 8 and 10 for a 100 mL sample, as shown in Table F-1. Notably, this is not a complete picture of fluid quality. Details on particulate lubricity, microbe level, and chemical makeup can change component performance considerably. Wetted parts of a system need to be compatible with the fluids supplied by the rig. This would include not only metals, but also the various elastomers present in SPMs and in the remainder of the system.

Table F- 1: Typical Recommended BOP Hydraulic Fluid Particulate Limits

NAS Cleanliness Definitions Particle Size in Microns for 100 mL Sample					
Class	**5–15**	**15–25**	**25–50**	**50–100**	**>100**
8	64,000	11,400	2,025	360	64
10	256,000	45,600	8,100	1,440	256

Another cleanliness measure is the control of microbes, including mold and fungus. When these microbes are present, a biocide may be used to sanitize the system. The biocide present in normal hydraulic fluid is low enough in concentration that it can be released into ocean water without negative consequences.

Lubricity is particularly important for enabling mechanical parts to move relative to each other. This is a function of concentration and depends on proper mixing at all times.

Finally, there are potential materials compatibility issues with regard to hydraulic fluids. In regards to elastomers, hydraulic fluid (according to one manufacturer [14]) is “suitable for use with nitrile, butyl, ethylene propylene, silicon, and Viton seals. PTFE and water tolerant nylon is also acceptable.” Notably, the fluid is “…not compatible with some polyurethane’s [sic}. Seal material properties can vary within a classification depending on compounding techniques. Compounding can enhance or diminish various properties and characteristics. In the case of Buna ‘N’ and Viton, certain formulae will be more resistant to water than others. Consultation with packing and seal suppliers is recommended.” Similarly, for metals, the manufacturer states, “Zinc, cadmium, and magnesium should be avoided.” **Thus, the life cycle of a BOP requires continuous attention to materials compatibility between BOP components and hydraulic fluids.** This should also be a factor when selecting and using fluid additives such as a biocide.

Appendix G: Most Mentioned BOP Operational Issues

The discussions with Argonne's points of contact for this SPM study unveiled numerous BOP operational failures. From detailed analyses of such BOP failure reports, [redacted] few BOP failures involving only one cause.

Each BOP control system involves hundreds of components. As a result, the failure or leakage of one component can cause numerous seemingly unrelated failures. Only a detailed review may isolate the most probable root cause. Unfortunately, such detailed reviews may not occur when the urgency to resume operations is an overriding concern. The following are pertinent examples of situations that, depending on propagation pathways, can directly or indirectly impact proper SPM valve function:

1. **Debris entering hydraulic fluid from hydraulic supply tank and mixing system.** There can be excessive debris and sludge accumulation in a holding tank that supplies the main hydraulic power unit (HPU). This includes accumulated metal filings. Most BOP operational systems have filters to control hydraulic fluid contamination, but some allow direct bypass of the filters when fully loaded. Other systems have a second filter, and upon switching to it, replace or clean the first filter. The previous approach assures the availability of hydraulic fluid for any function even though the fluid may not be conducive to long-term and reliable operation (for example, microbe presence can clog filters). This approach is often taken because dirty or contaminated fluid has fewer immediate consequences than hydraulic operational failure.
2. **Multiplex (MUX) cable damage.** The MUX cable for a BOP control system is subjected to the natural environment of ocean currents and wildlife. The cable degrades with use, and internal failures can necessitate replacement. While there is often a second MUX available in these cases, failures degrade communication with the subsea module and damage overall BOP control.
3. **Leaks in matching tapers due to improper seal parts or improper installation.** Some BOP control systems use two large (matching) conical tapers, one of which resides inside the second to hydraulically link an LMRP with the BOP stack. Each circuit requires a specially contoured seal between the two tapers. In the field, different seal part numbers can appear identical and may be misused. For proper sealing there is a positioning tab that must fit in a small indexing hole. If residual seal material remains in the indexing hole, the new seal cannot make proper surface contact. This can cause seal leakage, which reduces available control system flow and pressure.
4. **Leaks at fittings from improper tightening, damage, or wear.** [redacted] Offshore, a technician works with many identical fittings, and there are numerous opportunities for error (for example, improperly torqueing and failing to replace ferrules). These errors may occur due to simple interruptions, such as changing tools, reaching for another piece, changing

work position, or even a coworker making a comment. Good technicians develop work conventions to minimize the likelihood of such occurrences.

5. **Solenoid valve coil or seat failure.** Solenoid valves supply pilot fluid and must stay open long enough to fill the SPM pilot chamber. A piston in this chamber moves the SPM internal parts that control hydraulic power fluid flow for BOP function. Solenoid valve operations degrade with time and use. Adequate cooling, such as a seawater heat sink, lessens electrical degradation, but does not prevent it.
6. **Bad connection between jumper hose and hose reel on rig.** A bad connection can cause a connection leak. Connection leaks compromise hydraulic fluid flow to the subsea BOP.
7. **Low accumulator pressure.** If accumulator pressures are low, the available fluid volume for BOP functions decreases. In the extreme, this could mean essential safety functions are not available because of inadequate fluid supplies above a threshold pressure. Sometimes subsea accumulators are not charged properly because a procedure step is overlooked.
8. **Partially blocked, crimped, or leaking pilot or hydraulic power fluid line.** This can occur when an unfilled hose collapses and restricts flow. [redacted] metallic tubing can be inadvertently crushed during lifting and handling operations with a similar outcome. The consequence can be a control circuit starved for hydraulic fluid.
9. **Low or high hydraulic power fluid pressure.** If hydraulic pressure is too low, a BSR may not be able to shear a tubular in the wellbore. A high pressure (pressure above design limits) could damage the BSR and/or actuators.
10. **No pilot pressure.** If there is no pilot pressure or if pilot pressure is too low, the means to open SPMs that supply hydraulic power fluid for the main BOP functions are diminished. There are dedicated pilot fluid accumulators on a BOP to help avert this possibility.
11. **Pressure switch malfunction.** A rig-based HPU maintains accumulators and provides hydraulic fluid for normal functions when a BOP has physical connection to the rig. A low-pressure signal starts the unit, and a high-pressure signal shuts down the unit. If the HPU unit does not start, hydraulic resources at the BOP will decline. Compressor control switches work similarly.
12. **Flowmeter failure.** Flowmeters help evaluate BOP health and performance. Erroneous results could suggest there are leaks or not detect leakage, depending on the situation.
13. **Unresponsive regulator.** Regulators reduce hydraulic supply pressure for the pilot system and enable reduced power fluid pressures when needed. Pressures below maximum help extend the life of BOP annulars.

14. **Disrupted rig air.** In many setups, rig air is vital for controlling the surface HPU, which in turn supplies the subsea BOP.

Appendix H: BOP OEM Monitoring Systems

Representatives of each major BOP OEM claim to have initiatives underway to improve BOP reliability. These initiatives involve various schemes for operational data collection (presumably including SPM valve performance). In terms of new equipment, [redacted] is promoting the addition of a third subsea control pod and, [redacted], had a prototype on display at the 2015 Offshore Technology Conference (OTC). [redacted] are formally establishing databases as reference resources, not only to improve designs, but to support maintenance and maintenance planning. [redacted] product is [redacted] with a subpart called [redacted]. [redacted] product is called [redacted].

[redacted]

Per web literature, [redacted] package features [15]:

1. An array of sensors that capture data from the subsea BOP, including ram position, hydraulic fluid condition, stack accumulator bottle fluid volume, pressure and temperature, solenoid performance, and connector unlatch pressure;
2. A sensor interface box (SIB) that aggregates this information from 80-plus sensors to capture subsea stack operation data. Four SIBs each store the [redacted] package and BOP control system data, providing redundancy;
3. Wireless stingers that provide inductive data and power transfer between the lower stack and the LMRP. Removing metal-to-metal contacts results in more reliable long-term operation than traditional wet-mate connections;
4. Multiple data retrieval techniques via umbilicals, acoustic transducers, ROV, and black boxes; and
5. Three-week black box storage of time-stamped data from all sensors plus communications for the main control system.

The [redacted] provides advanced analytics, alerts, alarms, and reports that synthesize both real-time and historic BOP data into useful information. Using [redacted] [redacted] [redacted] [redacted], [redacted] [redacted] [redacted] BOP information and information from other drilling equipment on the rig can be gathered and presented to the driller and/or the drilling contractor, operator, or [redacted] personnel both on the rig and onshore.

[redacted]

[redacted] system is promoted as a predictive analysis tool based on actual performance data [16]. The system claims to enable communication of key maintenance data to operations leaders onshore or on other vessels. The system's dashboard features are:

1. Remote access to the electronic snapshot of BOP and subsystem health;

2. Graphical representation of BOP stack actions – including open, closed, unlocked, locked, normal, and check conditions for annulars, riser connectors, BSRs, and wellhead connectors;
3. Data on read-back pressures for annulars, risers, manifold regulators, and stack connector regulators; and
4. Pod view (blue/yellow), active pod (blue/yellow), and Subsea Electronics Module (SEM) (A/B) visibility.

The [redacted] maintenance module is a repository of information about corrective maintenance, maintenance due, and components needing replacement.

Both systems [redacted] were announced in 2014 and were displayed at OTC 2015. Based on industry press, only [redacted] has reported product sales: [redacted]. Neither system appears to be widely used [17]. Like current joint industry projects (JIPs), both these products and NOV's competing products offer data collection features that may be useful to support maintenance.

Several companies also offer systems to evaluate the state of a BOP and log information on component cycling when in service. Many of these same companies are working to collect failure information from operators, contractors (rig operators), BOP OEMs, SPM manufacturers, and other industry service companies. Industry standards such as API Standard 53 require this information be collected, but do not address compiling, sharing, and reporting trends.

Appendix I: Figure Credits

Certain figures in this report came from the following Internet sources during October 2015.

FIGURE:	URL:
1	http://subsea-controls.com/ (Internet brochure)
2	http://www.oceaneering.com/7/new-blowout-preventer-control-systems-deployed/
3	http://www.sme.org/uploadedImages/Publications/ME_Magazine/2009/May_09_Issue_Volume_142_No_5/13pic2.Jpg
B-1	http://www.free-online-private-pilot-ground-school.com/auxiliary-aircraft-systems.html
D-1	http://images.pennwellnet.com/ogj/images/ogj2/9548jro05.gif
D-2	http://images.pennwellnet.com/ogj/images/ogj2/9548jro02.Gif
E-1	http://www.dtl-tech.com/spm-valves

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