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Executive summery

The goal with this thesis was to look into consequences for implementing the API 53 standard for Transocean Norway. As it looks today the new requirements in the API 53 will be implemented as internal requirements within Transocean. Transocean operates in all the major oil and gas markets in the world and cannot operate with different regulations for each area. There is as of today no indication of regulatory requirements to change in Norway as a consequence of the new API 53. There may however be an updated version of Det Norske Veritas (DNVs) offshore standard (OS) with regards to drilling plant.

I will in this thesis look into what Transocean Norway have to do to be in compliance with the new Standard and thereby new internal requirements. To be able to find the what actions Transocean Norway have to do I have made a GAP analysis between the new API 53 and Transocean Well Control Handbook. This has been a comprehensive work and I will in this thesis look into the findings. The API 53 contains mostly good oil field practice which has not been stated as a standard in the past, but there are also new requirements especially with regards to backup systems and secondary control systems as Emergency Shut Down (ESD), Autoshear, Deadman and ROV intervention all as a consequence of Macondo. Testing procedures is also more comprehensive than before and there are both positive and negative sides with this.

The main goal of a new standard like API 53 is increased reliability and safer operation on an oil rig. For 5 out of 7 rigs Transocean Norway will have to upgrade the Blow out preventers (BOPs) and associated equipment with new technical solutions which has to be provided and engineered by Original equipment manufacturers (OEMs). I will look into the different implications, challenges and advantages with an implementation.

Table of Contents

List of Figures

List of Tables

Acknowledgment
I will thank Asgeir Lillejordet for guidance and support and the help he have given me by acting as guiding partner throughout this thesis, Henry Meling for many clarifying comments as a member of the API committee. Thank you to Steve Butler which has assisted me with solutions and quotes from suppliers as this upgrade will start on Transocean Leader in August/September.

I will also thank Tore Markset for guidance and support with choosing topic of thesis and start up.

This work is an independent thesis and do not necessarily reflect Transocean's view and is not written on behalf of Transocean as a company.

Glossary

AOC - Acknowledgement of compliance

ANSI – American National Standard Institute

API – American Petroleum Institute

BOP – Blow Out Preventer

BP – British Petroleum

BSR – Blind Shear Ram

BOEMRE – Bureau of Ocean Energy Management, Regulation and Enforcement

CMMS – Computerized Maintenance Management System

DEMAS - Deadman Autoshear

DNV – Det Norske Veritas

DP – Drill Pipe

DP – Dynamic Positioned

DW – Deep-water

EDS – Emergency Disconnect System

GOM – Gulf of Mexico

HWDP – Heavy Weight Drill Pipe

ISO – International Organization for Standardization

LMRP – Lower Marine Riser Package

MASP - Maximum Anticipated Surface Pressure

MAWHP – Max Anticipated well head pressure

MMS – Mineral Management Service

NCS - Norwegian continental shelf

NOC – National Oil Company

NSA – Norwegian Shipowners' Association

OLF – Oljeindustirens landsforening

OEM - Original Equipment Manufacture

OS – Offshore Standard

PR – Pipe Ram

PSAN – Petroleum Safety Authority Norway

ROV – Remote Operated Vehicle

RP – Recommended Practice

RWP – Rated Work Pressure

1. Problem description

1.1 Introduction and background

On April 20, 2010 11 people died in a blowout/explosion and a fire at the Macondo well operated by BP on Deepwater Horizon. One of the consequences was an oil spill which lasted until July 15 when a cap was installed. Not before 4th of august tests showed that the well had reached a static condition. (BP, 2010)The quantity of oil released into the Gulf of Mexico is difficult to estimate, but it is undeniable that the blowout has caused significant losses on the regional tourism and fishing industries and damaged wildlife and the environment (Kritisne L. McAndrews, 2011) As a consequence of this incident the U.S government reacted with a 6 months moratorium on deep-water drilling and arctic drilling, to take a step back and look at the regulations. This was only the start when the US government started to look at the regulations. The Obama administration created a new Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) which replaced the old Mineral Management service (MMS). A bipartisan national commission on the BP oil spill and offshore drilling operations was established and tasked to provide recommendations on how the government can prevent similar incidents in the future. (Kritisne L. McAndrews, 2011) 8th of June the United States department of the interior minerals management service issued National notice to lessees and operators of federal oil and gas leases, outer continental shelf (NTL No. 2010-N05) the main points in this notice were:

- Recertification of Blow Out Preventer (BOP) (inspection & design review)
- Maintain BOP to American Petroleum Industry (API) standards
- Verification of Shearing capacity at Maximum Anticipated Surface Pressure (MASP)
- Autoshear and Deadman for DP vessels
- Remotely Operated Vehicle (ROV) minimum function (Lower Marine Riser Package (LMRP) Conn / Blind Shear Ram (BSR) / one Pipe Ram (PR))
- ROV testing on surface
- Pull BOP after using shear rams
- Deadman subsea test
- ROV test subsea (one function per well)
- Personnel Trained in Deep-water (DW) well control (service, 2010)

UK's Energy and climate change committee report recommended:

- 2 sets of shear rams

- Inspection regime to avoid single point failure (specifically battery charge)
- General better spill prevention and response requirement

And the Norwegian PSA has not initiated any technical changes. In the Norwegian regulation it is already a requirement for an alternative activation system for activating critical functions on the blowout preventer for use in the event of an evacuation on floating facilities. It is not stated what type to use but all rigs working on the Norwegian continental shelf has an acoustic system (Meling, 2012). PSA has identified three main subjects the industry needs to work with:

- organization and management
- risk management
- barrier management. (PSAN, 2012):

One of the points in the BP investigation report under Operating Management System where BOP design and assurance. This is what this thesis will focus on. As a consequence of Macondo the different standard organizations started to review their relevant standards not only in the US but throughout the offshore industry. As the Macondo incident did not only affect the US but were a wakeup call for the whole industry. API has worked with changing the Recommended Practice (RP) 53 to a standard 53 as there is no API standard for the well control equipment except for the spec its built after at the time when it were new or after major upgrades. This meaning that a BOP built in 1983 is built after API spec at the time with the revision valid at the time. None of the new specs are retroactively, but is valid as of the date written on the front.

1.2 Problem description

This thesis will look into the following problem description. **What implications will implementation of API 53 have for Transocean Norway? What challenges will an implementation give?**

Sub problem descriptions:

What does Transocean Norway need do to be in compliance?

Will implementation of API 53 increase the reliability of well control equipment and thereby the safety of rig personnel?

What advantages will there be after implementation?

Prerequisite:

1. Only consequences for Transocean Norway
2. API 53 4th ed Ballot 2 see comments under.
   Due to the balloting process for any API document is pretty rigid the Jan 16th vote was the 2nd Ballot and was accompanied by 300+ comments. The process require that every comment is reviewed and addressed one way or another and this needs to happen during a committee meeting (with quorum representation) The 1st ballot yielded in excess of 1000 comments and ultimately required the document to be re-written, hence the 2nd ballot. The 1st meeting to review the comments from ballot #2 will take place 27th March and it is hard to know how long it will take before all the comments are addressed and the document released. In particular some parts of the rules in API 53 Standard are very controversial and have generated a very significant push back of late from the industry (in particular the North Sea UK sector). Earliest publication of the standard is Q3 2012
3. Only one shear ram for moored floaters as long as a written risk assessment is in place for each location.
4. Confidential due to above comment.

1.3 Main objectives and sub objectives

1.3.1 Main objective

The main objective with thesis is to establish what implication an implementation of API 53 will have for Transocean Norway.

1.3.2 Sub Objectives

1. To establish what standards Transocean follow to day.
2. To establish what Transocean Norway have to do to be in compliance with API 53.
3. To identify implications of implementing API 53
4. To identify if the reliability of the well control equipment will be increased. Look into the advantages after implementation and who will gain on it.

1.3.3 Project activities

1. Assess the way the requirements are today in Norway and in Transocean.
2. Make a GAP analysis between API 53 and Transocean Well Control Handbook
3. Develop plans over what Transocean Norway has to do. Who will it affect and do day have the available resources?
4. Asses the different implications and evaluate if the equipment have been improved to be more reliable in a Well Control situation.

1.4 Research approach

To be able to achieve this objective there will be interviews and discussions with competent and experienced personnel from different levels in the subsea management in Norway, involved personnel in the API committee, subsea personnel from National Oil company –Statoil, PSAN employed personnel e.g.

How test and verify the hypothesis. Use interviews and experienced personnel with regards to well control equipment.

2. Teori

When operating on the Norwegian continental shelf (NCS) all mobile units need to have an Acknowledgement of compliance (AOC). An AOC is a "certification" that the unit is within the framework of the regulations. AOC is defined by OLF and NSA to be ”*a PSA acknowledgement to the effect that a mobile facility's technical condition and the applicant's organization and management system are assessed to be in conformity with relevant requirements of Norwegian shelf rules*" (Oljeindustriens.landsforening, 2011) An AOC will not give a right to operate on NCS but it is mandatory for all mobile drilling units which will be operating on the NCS. When applying for an AOC the rules and regulation at the time of applying is the correct measure. This means that the AOC from 2000 is given on behalf of the given rules and regulations applicable on this time.

For mobile facilities that are registered in a national ships' register which is all mobile facilities working in Norway (Meling, 2012) the Norwegian regulations has to be followed and the DNV OS E101 is used to demonstrate the compliance with regards to Well control equipment. It would have been more sufficient if the whole Norwegian offshore industry followed the same standards. Today the fixed installations are in compliance with NORSOK. But for testing Norsok D-010 Annex A (Table 2) is mandatory for all installation working on the NCS.

2.1 Norwegian regulations

Within the Norwegian regulations there are some paragraphs which are of special interest with regards to well control equipment. As this thesis is about well control equipment I will focus on these paragraphs. In the Norwegian facilities regulations it is stated.

> *The Norwegian Facilities regulations Section 49 - Well control equipment States" Well control equipment shall be designed and capable of activation such that it ensures both barrier integrity and well control. For drilling of top hole sections through risers or conductors, equipment shall be installed with a capacity to divert shallow gas and formation fluids away from the facility until the personnel have been evacuated.*
>
> *The pressure control equipment used in well interventions shall have remote-controlled valves with mechanical locking mechanisms in the closed position.*
>
> *Well intervention equipment shall have a remote-controlled shear/blind ram as close to the Christmas tree as possible.*
>
> *Floating facilities shall have an alternative activation system for activating critical functions on the blowout preventer for use in the event of an evacuation.*

Floating facilities shall also have the capacity to disconnect the riser package after the shear ram has cut the work string." (Petroleum.Safety.Authority.Norway, 2010) *Fail safe close?*

The guideline refer to the Norsok D-001 D-002 and D-010 as "a should" be used to be in compliance with the regulation, or For mobile facilities that are registered in a national ships' register, DNV OS-E101 Chapter 2, Paragraph 5, C 100-500 may be used as an alternative to NORSOK D-001. (Petroleum.Safety.Authority.Norway, 2010) The guideline to a regulation is only a recommendation of which standard to follow to be in compliance, a company can choose any standard but if they use other than what is recommended in the guideline they have to prove that this standard is of a high enough level. (Dørum, 2012)

The Regulations relating to conducting petroleum activities (the activities regulations) also have 3 relevant paragraphs.

Section 45 - Maintenance "The responsible party shall ensure that facilities or parts thereof are maintained, so that they are capable of carrying out their intended functions in all phases of their lifetime."

Section 47 - Maintenance programme "Fault modes that constitute a health, safety or environment risk, cf. Section 44, shall be systematically prevented through a maintenance programme. This programme shall include activities for monitoring performance and technical condition, which ensure identification and correction of fault modes that are under development or have occurred. The programme shall also contain activities for monitoring and control of failure mechanisms that can lead to such fault modes."

Section 51 - Specific requirements for testing of blowout preventer and other pressure control equipment "The blowout preventer with associated valves and other pressure control equipment on the facility shall be pressure tested and function tested, cf. Sections 45 and 47. The blowout preventer with associated valves and other pressure control equipment on the facility shall undergo a complete overhaul and recertification every five years."

In the guideline for section 51 it is referred to NORSOK D-010 section 15.4 Drilling BOP which again referrers to API RP 53 and NORSOK D-001 see table 1 on next page. It is also attached a table of testing pressures and frequencies. In this guideline it also refers to Norsok D-010 and Annex A which is a table describing the routine leak testing of drilling BOP and well control equipment.

The guideline states "should be used" to make sure the equipment can fulfill its intended functions. Norsok is only in use on the fixed installations in Norwegian continental shelf when we only look at well control equipment, except for table 1 and 2.

Well control equipment is defined as all equipment used to control well pressure during drilling, well testing, completion, work over and well intervention activities. (DNV, 2012)

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead connector and drilling BOP with kill/choke line valves.	NORSOK D-001
B. Function	The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the well bore with or without tools/equipment through the BOP.	
C. Design construction selection	1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. The BOP WP shall exceed the MWDP including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the well bore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 4. When running non shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non shearable item. 5. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 6. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 7. There shall be an outlet below the LPR. This outlet shall be used as the last resort to regain well control in a well control situation. 8. HTHP: The BOP shall be furnished with surface readout pressure and temperature. 9. Deep water: 9.1. The BOP should be furnished with surface readout pressure and temperature. 9.2. The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. 9.3. Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) 9.4 From a DP vessel it shall be possible to shear full casing strings and seal thereafter. If this is not possible the casings should be run as liners.	NORSOK D-001 API RP 53
D. Initial test and verification	See Annex A, Table A.1.	
E. Use	The drilling BOP elements shall be activated as described in the well control action procedures.	
F. Monitoring	See Annex A, Table A.1.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Annex A, Table A.2.	

Table 1 Drilling BOP (NORSOK.standard, 2004)

	Frequency / Element	Stump	Before drilling out of casing: Surface	Before drilling out of casing: Deeper casing and liners	Before well testing	Periodic: Weekly	Periodic: Each 14 days	Periodic: Each 6 months
BOP	Annulars	MWDP 1)	Function	MSDP 1)	TSTP 1)	Function	MSDP 1)	WP x 0,7
	Pipe rams	MWDP	Function	MSDP	TSTP	Function	MSDP	WP
	Shear rams	MWDP	Function	MSDP	TSTP	Function		WP
	Failsafe valves	MWDP	Function	MSDP 3)	TSTP	Function	MSDP 3)	WP
	Well head connector	MWDP	MSDP		TSTP		MSDP	WP
	Wedge locks	Function						
Choke/kill line and manifold	Choke/kill lines	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	manifold	MWDP	MSDP	MSDP	TSTP		MSDP	WP
	Valves	Function	Function	Function	Function		Function	
	Remote chokes							
Other equipment	Kill pump	WP 2)		MSDP			MSDP	WP
	Inside BOP	MWDP 2)		MSDP	TSTP		MSDP	WP
	Stabbing valves	MWDP 2)		MSDP	TSTP		MSDP	WP
	Upper kelly valve	MWDP 2)		MSDP			MSDP	WP
	Lower kelly valve	MWDP 2)		MSDP			MSDP	WP

Legend

WP	working pressure
MWDP	maximum well design pressure
MSDP	maximum section design pressure
Function	Function testing: testing shall be done from alternating panels/pods.
TSTP	tubing string test pressure
1)	Or maximum 70 % of WP
2)	Or at initial installation
3)	From above if restricted by BOP arrangement

NOTE 1 All tests shall be 1,5 MPa to 2 MPa/5 min and high pressure/10 min.

NOTE 2 If the drilling BOP is disconnected/re-connected or moved between wells without having been disconnected from its control system, the initial leak test of the BOP components can be omitted. The wellhead connector shall be leak tested.

NOTE 3 The BOP with associated valves and other pressure control equipment on the facility shall be subjected to a complete overhaul and shall be recertified every five years. The complete overhaul shall be documented.

Table 2 Annex A from Norsok D-010 - Routine leak testing of drilling BOP and well control equipment

2.2 DNV

Det Norsk Veritas (DNV) is a an independent and autonomous foundation which deliver services as advisory, assessment, certification, classification, materials technology and testing, software solution, technology qualification, training and verification. Relating to offshore industries DNV undertakes classifications, certification verifications and consultancy services relating to quality of ships, offshore units and installations, they also carries to research in relation to these functions.

DNVs hierarchy of offshore documents is divided into tree.

- Offshore service specifications. Provide principles and procedures of DNV classifications, certification, verifications and consultancy services
- Offshore standards which provides technical provisions and acceptance criteria for general use by the offshore industry as well as the technical basis for DNV offshore services.
- Recommended practices which provide proven technology and sound engineering practices as well as guidance for the highest level offshore services specifications and offshore standards. (DNV, 2009)

Governments worldwide are moving from a traditional rules-based regime to a system of functional requirements where safety must be demonstrated on the basis of risk evaluations. DNV is an independent supplier of verification, certification, quality assurance and marine operations and can assist to reduce and manage risk.

As referred to in the guideline for the facilities regulation the DNV OS E101 is used if the mobile drilling unit is registered in a national ship register. DNV OS E101 is an offshore standard covering the whole drilling plant. With regards to well control equipment Transocean Norway have chosen to be in compliance with DNV OS E101 Chapter 2 Section 5 C.

DNV OS E101 is an offshore standard where the latest revision was published in 2009. The purpose of this standard is to provide an internationally acceptable standard of safety for drilling and well intervention facilities by defining minimum requirements for the design, materials, construction, testing and commissioning of such facilities. (DNV, 2009) The standard was written as a worldwide standard but the regulation in the country of operation may in some cases have additional requirements. Chapter 2 Section 5 C. Well Control Systems is the relevant part for mobile facilities that are registered in a national ships' register.

DNV published in January 2012 a new revised version of DNV-RP-E101 recertification of well control equipment for the Norwegian Continental Shelf.

The purpose of DNV RP E101 is to describe DNVs recommendations for recertification. The process is to verify and document that the equipment condition and properties are within the specified acceptance criteria as well as the specified recognized codes and standards. The recertification shall ensure that documentation of the condition of the equipment is available. (DNV, 2012)

DNV OS E101 references Well control equipment after uses standards as listed in the table below.

Table C1 International or national references		
System	*Reference No.*	*Title*
BOPs	API Spec 6A	Wellhead and Christmas Tree Equipment
	API Spec 16A	Drill Through Equipment
	API Spec 16D	Control Systems for Drilling Well Control Equipment
	API RP 53	Blowout Prevention Equipment Systems for Drilling Operations
	ISO 10423	Petroleum and natural gas industries - Drilling and production equipment - Specification for valves, wellhead and Christmas tree equipment
Choke and kill systems	API Spec 16C	Choke and Kill Systems
Diverter systems	API RP 64	Diverter Systems Equipment and Operations
	API Spec 6D	Specification for Pipeline Valves
Marine risers	API Spec 16F	Specification for Marine Drilling Riser Equipment
	API Spec 16R	Marine Drilling Riser Couplings
	API RP 16Q	Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems
	API Bul 16J	Comparison of Marine Drilling Riser Analyses

Figur 1 DNV OS E101 International or national references

2.3 API

American Petroleum Institute described as API during this thesis was founded on March 20, 1919. When founded the main focus areas were;

- to afford a means of cooperation with the government in all matters of national concern
- to foster foreign and domestic trade in American petroleum products
- to promote in general the interests of the petroleum industry in all its branches
- to promote the mutual improvement of its members and the study of the arts and sciences connected with the oil and natural gas industry. (API, 2011)

API had three main focus areas which were statistics, standardization and taxation. (Fanning, 1959)

Standardization of oil field equipment became during World War I important. Drilling delays resulted from shortages of equipment at the drill site, and the industry attempted to overcome that problem by pooling equipment. The program reportedly failed because there was no uniformity of pipe sizes, threads and coupling. Thus, the new association took up the challenge of developing industry-wide standards and the first standards were published in 1924.

Today, API maintains more than 500 standards and recommended practices covering all segments of the oil and gas industry to promote the use of safe, interchangeable equipment and proven and sound engineering practices. Generally all API standards are to be reviewed and revised, reaffirmed, or withdrawn at least every 5 year. An extension may be given as a onetime thing and is only valid for 2 years.

American Petroleum institute is today revising what was API recommended practice 53 to a standard API 53. This work has taken longer time than planned and was first planned to be publisher in 2011. The latest now is Q3 2012.

API recommended practice 53, first edition were published in February 1976 it came to supersede and replace API Bulletin D13 as referred to Installation and Use of Blowout Preventer Stacks and Accessory Equipment and were published in 1966. Later a second edition of the API RP 53 was published in May 1984. The goal of a recommended practice is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling equipment, and preservation of the environment for land and marine drilling operations. (Department, 1997)

When a Blow Out Preventer is manufactured it is after a API spec. API spec 6A 16 A etc. API spec 6A was approved by ISO the International organization for standardization which is a worldwide federation of national standards bodies. A ISO standard in the case for API spec 6A ISO 10423 is the equivalent name was prepared by Technical committee for Materials, equipment and offshore structure for petroleum, petrochemical and natural gas industries, Subcommittee for drilling and production equipment within ISO. API spec 16A (ISO 13533:2001) Petroleum a gas industries—Drilling and production Equipment—Drill-through equipment is what a new BOP is built after today. This spec concerns mainly design criteria's, material handling and quality control. Not the operational part as the API 53 will do.

3. Transocean

Transocean is a leading international provider of offshore contract drilling services for oil and gas wells. Transocean owns or has partial ownership interests in and operates a fleet of 130 mobile offshore drilling units consisting of 50 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh-Environment semisubmersibles and drillships), 25 Midwater Floaters, 10 High-Specification Jackups, 44 Standard Jackups and one swamp barge. In addition, they have 2 Ultra deepwater drillships and 4 high specification jackups under construction. (Transocean, 2012) They have 4 High spec flotars and 3 midwater floaters in Norway.

As Transocean was the rig owner of Deepwater Hoizon where 11 people lost their lives the incident had a major impact on the company. In the investigation BP investigation under Contractor and service provider assurance, Well control practices, rig process safety and BOP design and assurance were addressed with recommendations. (Kritisne L. McAndrews, 2011)

As an immediately action after the incident an Alert was issued Alert 6 Moored rigs subsea well control equipment Operation, maintenance and testing. There were also issued another alert which covered other aspects than the well control equipment part. Alert 6 was issued in 11th of May 2011 and revised the 7th of June formally to capture clarifications. (M. Rogers, 2011) The first alert issued had some points which were not possible to adhere to due to the technology. While the exact causes of this event were still under investigation when the alert was published, the nature of this accident compelled Transocean as a company to re-enforce the existing Policies and Procedures.

In particular alert 6 highlights the existing inspection, testing and maintenance requirements for Well Control Equipment and provides specific guidance for testing Emergency BOP systems. All installation had to verify capabilities and equipment and reply to the upper management. As one of the actions of these replies the Well control handbook were updated and the subsea organization were changed.

3.1 Well control equipment management

February 2012 the Transocean subsea management where gathered in Genève to go through the organizational changes with the new subsea support team. The support team is now divided in to operations, support, major spare program and projects. One of the goals for the changes is to increase the management involvement in BOP operations. Each division will have their own dedicated Well control equipment manager and team. Their task will be to promote proactive maintenance management, ensure the quality of execution is what expected, coach and mentor the offshore crews.

One thing is to have the equipment in place but the personnel operating it is as important. A Subsea competency assessment has been implemented to ensure that each subsea offshore has the adequate knowledge and understanding of his tasks. An individual development plan is created after the assessment to focus on the areas where each individual can improve.

27th of July 2011 a revised Subsea maintenance philosophy was issued. This philosophies purpose is to identify what maintenance is to be done and when. Who to take responsibility and how the task shall be planned, this to avoid that the maintenance to be shortened down or ignored at critical path. It is known that when the maintenance of equipment start to go on rig down time the customer which rent the rig starts to push, and then you have an effect which involves the whole organization. It is not only the subsea engineer offshore which is responsible and accountable for the task but also managers both offshore and onshore.

Subsea maintenance philosophy has divided planned maintenance into two tree different categories: Planned maintenance tasks that can only be carried out when the equipment is accessible on the surface. Additional tasks following extraordinary operating conditions and planned maintenance tasks that are performed out of the critical path and do not require the BOP stack to be on surface. By better planning the restricted time can be used more sufficient utilized with regards to personnel needed and available spare parts. The plan should be documented and reviewed after completion of the work. If corrective jobs are identified during the work they shall be included in the plan for further tracking and a corrective job should be made in the Computerized Maintenance Management system (CMMS).

The increased focus and changed standards post Macondo and the delays getting equipment through the OEM shops makes it important to make critical spare parts available. This has resulted in an initiative called "Tranter list". This is a list over all the critical spare parts which are in reality all the parts on the BOP with long lead time. This list was initiated by Paul Tranter, Vice president Assets (floaters) in Transocean in May 2011.

- 1 off wellhead connector
- 1 off each of the BOP ram bodies
- 1 set pipe ram bonnets
- 1 set shear ram bonnets
- 1 set super shear ram bonnets or booster bonnets
- 1 off LMRP/riser connector
- 1 off lower annular
- 1 off upper annular
- 1 off subsea flex joint
- 4 off failsafe close valves
- 2 off dual failsafe close valves

- 2 off failsafe open valves (if applicable)
- 1 off mini collet connector (if applicable)
- 1 off flexible hose C&K moonpool
- 1 off flexible hose C&K LMRP
- 1 off flexible hose booster moonpool
- 1 off Choke and Kill Gooseneck
- 1 off Choke and Kill 'Kick Outs'
- 1 off Slip Joint
- C and K manifold valve assemblies, one min per size in each manifold

3.2 How a standard is followed in Transocean

Transocean Norway follows the Norwegian regulation which set the ground rules. With regards to well control equipment DNV OS E101 is followed and as mentioned before this standard referees to several API documents. With regards to testing of well control equipment Norsok D-010 Annex A routine leak testing of drilling BOP and well control equipment is applicable. Transocean is an international company and has to have the same base guide throughout their operation. It is difficult to follow one standard in Norway one in Brazil and on in Angola. Transocean well control handbook refers to API as a base and local regulatory requirements in addition but it has to meet API or above.

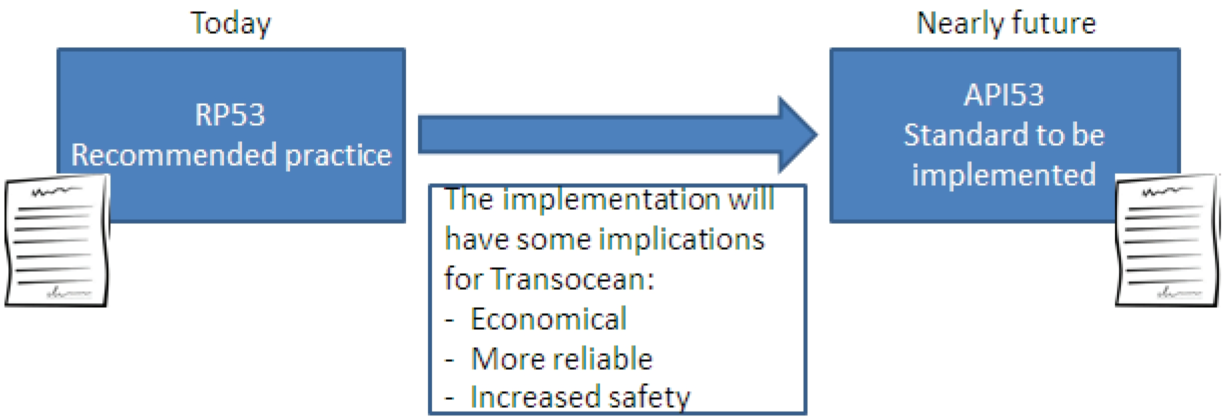
Over the years, equipment has been designed to conform to various standards. The well control equipment has to comply with the specification API 6, API 16 A etc and the revision level as was used in the original design and commissioning. If the equipment has been subsequently upgraded to another standard the new standard shall apply. (Transocean, 2011)

Judging from this theory and Transocean as a company I state the following hypothesis:

1. Economic consequences for Transocean as this looks to be an internal requirement within the company and not Norwegian regulation requirement.
2. More reliable equipment in well control situations more redundant backup system and secondary control systems.

4. Methods

The thesis analyzes the impacts on Transocean by implementing the new API 53 standard. The starting point is existing theory and practice, and therefore a deductive approach. The problem formulation and hypothesis can be summarized in the following model:



Figur 2 There is expected implications of the implementation of the new standard.

Some parts of the thesis are a descriptive study, where the objective is "to portray an accurate profile of persons, events or situations" (Robson, 2002, p. 59). These parts aim to describe the existing recommended practice, and the new standard to be implemented. The main objective is however to investigate the implications and consequences the implementation will have on Transocean Norway. Therefore, this thesis is mainly a casual study which"...focuses on studying a situation or a problem in order to explain the relationships between variables" (Saunders et.al, 2007, p. 598).

I have worked based on specific questions from my experience in the industry, discussions with teaching supervisor and on existing theory. I used the main objective and the sub objectives to create questions. There were made a set of interviewee question to reflect over, but also more informal question rose directly to relevant experienced personnel. The formal question is included as attachment no.01. The thesis does not have the rationale to explain why companies within the industry follow standards, but rather how the companies are affected by implementing new standards.

This chapter justifies the chosen method, and will start with the research design. Afterwards I will explain how data was captured, before we will go through how the analysis of the data was done.

4.1 Research design

A research design is the general plan of how to answer a problem definition (Saunders et.al, 2007, p. 131). Of this reason it is crucial that the design ensures information caption in an effective manner. I have used case studies to investigate the relationship, and (Robson, 2002, p. 178) defines this as ”a strategy for doing research which involves an empirical investigation of a particular contemporary phenomenon within its real life context using multiple sources of evidence”. This is a well fitted strategy to answer my problem definition, as it investigates if existing theory and practice matches a given context. The most common form for case studies is interviews, and this is what I have used to gather information on how companies, in the opinion of the people interviewed, are affected by new standards. Interviews give non-numerical data or data that is not quantified – qualitative data (Saunders et.al, 2007). In addition I have gathered qualitative data from the existing and the new standard, to investigate the differences between the two. To understand some quantitative implications, I have asked for quotes from suppliers on technical upgrades on systems to be compliant.

The thesis studies Transocean Norway which I am familiar with after working there for 7 years in different positions, both onshore and offshore. The main focus will be on the internal Norwegian operation, but also external control partners and members of the API committee developing the new standard have participated with their knowledge.

4.2 Data gathering

There are a lot of information with regards to procedures, standards, and good oil field practice in Transocean. You can easily find procedures, manuals and handbooks on the intranet. All documentation is gathered there to maintain that no personnel operate after an old revision document or procedure. The thesis' description of the internal procedures on how a standard is followed is based on this formal information. The developed interview guide takes its starting point in the well-known procedures as well. Secondary data, or data created for other purposes (Saunders et.al, 2007), are with other words the base for the first part of this thesis.

The study of internal procedures and the GAP analysis between the new standard, and the standard which we operate after with regards to well control equipment, are used to understand what Transocean in Norway have to change to be compliant. The secondary data are detailed, and a GAP analysis will give a starting point on assessing what implications the change actually will have. The main findings from the GAP analysis are included in chapter 5 Analysis. It should be mentioned that some personal experience and informal chats with colleagues might have affected the analysis.

I have also used semi-structured interviews for information gathering. I have talked to several peoples representing different partners:

- National oil contractor
- Training partner and well control department
- Internal control manager
- PSAN

The interviews are done via telephone, e-mail and face-to-face. In advance I made an interview guide based on the sub objectives and sub problem descriptions of the thesis (attachment no.01). This preparation ensured that I had a list of topics and questions I needed to cover, and this helped me to remember everything during the interviews. At the same time it gave me the opportunity to ask follow-up questions, and to dig deeper when needed based on the competency of the person I interviewed.

I used face-to-face interview when I was able, but in some cases I had to use telephone and even e-mail due to benefits such as access, pace and costs. However, I am aware of the challenges of establishing personal contact and also the use of for instance a recorder when using telephone instead of face-to-face (Saunders et.al, 2007)

One of the main restrictions by semi-structured interviews is that you cannot execute as many as by using for instance surveys. Interviews require much more time, and therefore you are able to gather less data. In this thesis I have collected a good representation of people to interview, and together they will give an overall picture. They have different experience and specialties, and will focus on different things in their responses. I used a recorder during the interviews, but also notes, that I transcribed shortly after the interviews. (Saunders et.al, 2007)

I am an employee in Transocean Norway, which might have given me the benefit of being what Gabriel denotes as “a fellow-traveler” (Gabriel, 2000, p. 136). This is the reason why I gained a foothold in the first place, and probably also the reason for my chosen respondents to participate and be honest in the interviews – actually I am one of them, and it is a part of my job. I have also had good use of my knowledge within the organization and the equipment used in the organization. I am also aware and understand the challenges the company are heading. In addition I have had the opportunity to execute unstructured interviews during my everyday work, but this will not necessary give representative data as they speak to me as a colleague without thinking that it will end up in my thesis. This data will together with my own experience be an addition to the interviews and the written procedures, as it is a part of my background information. All in all, I have tried to be as objective as possible.

As described, different methods are used to gather data to investigate my main question, and it has resulted in both qualitative and quantitative data. The different data are used to build different parts of the analysis, but at the same time they will complement one another. In that way I am ensured more reliable data and maybe it will be easier to generalize the results. The study is trying to explain how the different factors are related at the time where the study was executed. In this connection semi-structured interviews, observation, secondary data and own experience will give a good opportunity to dig deeper and answer how instead of what, who and where. (Saunders et.al, 2007)

4.3 Data analysis

This thesis has as mentioned a deductive approach, and is trying to find a pattern based on existing theory, but at the same time be open to possible new findings.

A compressive GAP analysis was made to clarify the deviation between Transocean procedures, DNV OS E101 and the new API 53. I used an excel spreadsheet as a template for the gap where I went through every section in the API 53 and found the corresponding description in Transocean well control manual and DNV OS E101. This GAP has 499 lines over 97 pages. If described in one of these documents Transocean Norway will have a requirement of compliance. API 53 consists of requirements, procedures and good oil field practice. There are findings in the GAP which is not described in Transocean Well control handbook or in DNV OS E101, but is well known practice and is well established routine on all of the 7 rigs. These findings are not relevant for this thesis and thereby not described any further. I have evaluated all these findings together with Steve Butler a senior subsea supervisor on Transocean Leader only the technical disparities and changes in procedures are further discussed in the chapter 5 Analysis. Each finding with a disparity between the API 53 was found and will be addressed and discussed in section 5 Analysis.

The interviews for this thesis were transcribed directly. Results are shown through quotes, and in general when I have showed to different partners' views and opinions. It is also used as a basis for comparison assessing the GAP analysis.

5. Analysis

What implications will implementation of API 53 have for Transocean Norway? What challenges will an implementation give?

It is a commercial issue in this question because if the API 53 becomes a Norwegian requirement the cost will be the customers and not rig owners cost. Transocean contract take in to account the possibility for regulatory changes and this is the customers cost. (Lillejordet, 2012) If on the other hand Transocean have an internal requirement to be in compliance with API 53 this cost is Transocean cost. Transocean Leader is scheduled for SPS autumn 2012 and the rig will be upgraded to be in compliance with API 53. I will go through the upgrades further down when analyzing what Transocean Norway need to do to be in compliance.

All implications of implementing the API 53 is listed in next section, here I have gone into detail over what Transocean has to do to be in compliance and what solutions are available. One of the challenges is the cost as mentioned before, but also the capacity of the OEM workshops. The Tranter list went in as an order mid last year and was done as a proactive action to make sure we have the equipment needed (Lillejordet, 2012). Another issue with the OEMs is that the market is increasing and OEM workshop especially in Norway keep losing their people to the rig market. A subsea engineer is something the new rigs coming into Norway need to buy because it is no school to get them from it is only experience within the position and as a trainee, this increases the value of this position.

5.1 What does Transocean Norway need do to be in compliance?

A Gap analysis between the API 53, Transocean procedures, DNV OS E101 has been made. The major findings from this analysis will be listed below. The new API 53 contains a lot of information and good oil field practice which is not mentioned in Transocean procedures or DNV OS E101 but is in place and is nothing new. I will not focus on the minor things which are in place but not covered as a requirement or policy.

The GAPs is with regards to the backup and emergency systems as Autoshear, Deadman and ROV intervention. There is no change to acoustic as this will still be an optional system. It is a requirement within the standard that all subsea stacks shall have an Autoshear, Deadman system and ROV intervention system to meet closing requirements described in the API 53.

As mentioned in the prerequisites there are also a GAP with regards to shear rams. What is stated in Transocean well control handbook, DNV OS E101 is included in the GAP and extract in the table below.

A subsea BOP stack with class 6 mean that the BOP stack have a combination of a total of six ram and or annular preventers installed. (e.g. Two annulars and four ram preventers.) The latest information received from the API committee members states that there will be a requirement for 2 shear rams. (Meling, 2012) With a moored rig a risk assessment can be conducted and the risk of operating on each location with one blind shear ram is within the parameters the operation can be conducted with one blind shear ram. (Lillejordet, 2012) Transocean in Norway have 5 moored rigs all class 6, with 2 annulars (or capabilities to have two) 3 pipe rams and 1 blind shear ram. Today it will not be prioritized to rebuild them to a class 7. The cost of such rebuild can end up to be a major cost due to complications it will have on weight, height, associated equipment as cranes, moonpool e.g. The consequence of replacing one of the tree pipe rams over to a blind shear ram will give less redundancy if a situation occurs where a pipe ram failed and it will not be possible to do in case of completion work with a special need of a casing ram in the ram configuration. This risk will be set up against the risk of running with one blind shear ram with the capabilities to shear the heaviest HWDP on the rig and seal of the well.

API 53	Transocean Well control handbook	DNV OS E101	GAP
7.1.3.5 Subsea BOP stacks shall be Class 5 or greater and consisting of the following: a) a minimum of one annular preventer; b) a minimum two pipe rams (excluding the test rams); c) a minimum of two sets of shear rams (at least one capable of sealing) for shearing the drill pipe and tubing in use	2.3.2 10M AND 15M STACKS One (1) 5M (10M stack) or 10M (15M stack) annular type preventer and four (4) 10M or 15M psi ram type preventers (of which one [1] will be a blind/shear ram). 2.3.4 BLIND/SHEAR RAMS • There must be at least one (1) set of blind/shear type rams. • The blind/shear rams must be capable of shearing the highest grade and heaviest drill pipe on the rig (HWDP excluded) and sealing of the well in one operation.	DNV OS E101 103 The blowout preventer shall in general consist of the following, as a minimum: — a BOP stack consisting of: — one bag-type or annular preventer — one blind shear ram for fixed/anchored units — two shear rams for DP units, where one ram is a blind shear ram and the other is a casing shear/super shear ram —two pipe rams.	No requirement for a two shear rams on a moored rig.

Tabell 1 GAP - BOP stack configuration

5.1.1 Emergency backup system – Deadman and Autoshear

In the API53 there is a new requirement for both a Deadman system and an Autoshear. Both these systems have been optional before and there has not been a requirement for them. There is no requirement for them in the Transocean well control manual or in the DNV OS E101. In the Transocean manual ROV intervention, deadman and acoustic is stated as an emergency system, but in API Deadman and Autoshear and EDS is define as emergency backup systems. Acoustic and ROV intervention is defined as a Secondary control system which shell be tested with a set frequency and within a set time interval. (API, 201X) See extract from the GAP below.

API 53	Transocean Well control manual	GAP
Autoshear		
7.3.18.2 Autoshear shall be installed on all subsea BOP stacks.	In the event that subsea BOP functions are inoperative due to a failure of the main control system an emergency back-up system(s) should be included on the BOP, emergency back-up systems (ROV intervention, deadman or acoustics).	No requirement for all tree systems but a backup system.
7.3.18.5 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.	In the event that subsea BOP functions are inoperative due to a failure of the main control system an emergency back-up system(s) should be included on the BOP, emergency back-up systems (ROV intervention, deadman or acoustics).	None
7.3.18.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and 7. Surface testing Autoshear (or equivalent) circuit test All assigned components to be tested prior to deployment and all functions to respond. Components required to secure the well to be tested prior to deployment and within 90 seconds. Subsea testing Autoshear (or equivalent) circuit test All assigned components to be tested/commissioning or within 5 years of previous test, unable to verify criteria when installed subsea	SURFACE TESTING EDS, DEADMAN AND AUTOSHEAR FUNCTIONS • All functions and sequences of the EDS, Autoshear and Deadman will be fully tested at commissioning, when any changes are made (including software change) and during any BOP control system recertification. • Each system will be tested prior to deployment of the BOP at the start of every well. If there are multiple sequences involved, only one will have to be tested with full hydraulics, while the other sequences should be "dry fired". The EDS sequence will be initiated from each control station on the rig. • All sequences must be tested at least once within 5 years of previous testing. Sequences should be alternated with each successive test. SUBSEA TESTING EDS, DEADMAN AND AUTOSHEAR FUNCTIONS • EDS, Deadman and Autoshear functions must be tested during commissioning and at least once every five years.	No requirement for 90second respond time in Transocean or DNV.

API 53	Transocean Well control manual	GAP
Deadman system		
7.3.19.2 A Deadman system shall be installed on all subsea BOP stacks.	In the event that subsea BOP functions are inoperative due to a failure of the main control system an emergency back-up system(s) should be included on the BOP, emergency back-up systems (ROV intervention, deadman or acoustics).	No requirement for all tree systems but a backup system.
7.3.19.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7. Surface testing Deadman (or equivalent) circuit test All assigned components to be tested Prior to deployment and all functions to respond. Components required to secure the well to be tested prior to deployment and within 90 seconds. Subsea testing Deadman (or equivalent) circuit test All assigned components to be tested/commissioning or within 5 years of previous test, unable to verify criteria when installed subsea	SURFACE TESTING EDS, DEADMAN AND AUTOSHEAR FUNCTIONS • All functions and sequences of the EDS, Autoshear and Deadman will be fully tested at commissioning, when any changes are made (including software change) and during any BOP control system recertification. • Each system will be tested prior to deployment of the BOP at the start of every well. If there are multiple sequences involved, only one will have to be tested with full hydraulics, while the other sequences should be "dry fired". The EDS sequence will be initiated from each control station on the rig. • All sequences must be tested at least once within 5 years of previous testing. Sequences should be alternated with each successive test. SUBSEA TESTING EDS, DEADMAN AND AUTOSHEAR FUNCTIONS • EDS, Deadman and Autoshear functions must be tested during commissioning and at least once every five years.	

Tabell 2 GAP - Autoshear and Deadman system

Autoshear is a control valve with a pin connected to the bottom of the LMRP plate and measures the movement between the plate and the lower stack. If the gap between the LMRP and the Lower BOP exceed a set distance the blind shear ram is automatically activated and seals the well.

Autoshear and Deadman shall be installed on all subsea BOP stacks. This is not installed on any 5 of the moored rigs in Transocean Norway. As this have never been a requirement and has not been part of the API spec for the actual BOPs.

As a solution for this BOP supplier, Cameron has come up with an approach for Autoshear Module, Hydraulic Deadman built together. The DEMAS system is a standalone system fed from the Acoustic Accumulators (via ROV Panel), on the system the pressure will go straight to a trigger valve which is pushed down by a Hydraulic plunger. If the LMRP is lifted the plunger will lift off the trigger valve and cause an Auto shear, if the hydraulics is cut out from the piston the plunger will lift and the trigger valve will function as a Deadman system. Hydraulic plunger is pushed down from the pilot and main systems; ALL these have to fail before Deadman is achieved. (Butler, 2012)

For Transocean Leader which is the first of the 5 rigs going into shipyard for an upgrade Cameron have made a quote for the systems listed under. In addition to this system engineering and project management will be an additional cost. The delivery time after approved purchase order is 24-26 weeks.

- Controls – Auto share valve module
- Controls – Hydraulic Deadman kit Control system
- Controls – Acoustic/Autoshear Isolation ROV panel
- Controls
  - HPU Software Changes to include Diverter Sequencing
  - HPU Software Changes to include Port / Starboard Overboard line sensing and Alarm
  - Diverter Packer Pressure adjustment
  - Slipjoint Packer Pressure Adjustment

During this shipyard the BOP will be dismantle and a 5 yearly recertification will be performed with accordance to DNV RP E101 Recertification of Well Control Equipment for the Norwegian Continental Shelf. This shipyard is a SPS and a 5 yearly class of the whole drilling rig.

5.1.2 Secondary control system - ROV intervention

As stated before API do now call ROV intervention and Acoustic a secondary control system. This will be a GAP

API 53	Transocean Well control manual	GAP
7.3.20 Secondary Control System **ROV Intervention**		
7.3.20.1.1 The BOP stack shall be equipped with ROV intervention equipment which at a minimum allows the closing of the critical functions (each shear ram, one pipe ram, ram locks and unlatching of the LMRP connector).	In the event that subsea BOP functions are inoperative due to a failure of the main control system an emergency back-up system(s) should be included on the BOP, emergency back-up systems (ROV intervention, deadman or acoustics).	No requirement for all tree systems but a backup system.
7.3.20.1.2 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators or other external hydraulic power source. The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions. This source shall be available at all times.	Not mentioned	This will have to be supplied by the customer. Transocean is responsible for having the possibility to meet the API

7.3.20.1.3 All critical functions shall be fitted with API 17H receptacles	In accordance to API	
7.3.20.1.4 If multiple receptacle types are used, a means of positive identification of the receptacle type and function shall be required	In accordance to API	
7.3.20.1.5 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and 7. Surface testing ROV functions ROV – critical functions (shear rams close, one pipe ram close and LMRP unlock/unlatch) to be tested prior deployment and closing criteria to be 45 second for the rams LMRP connector.	SURFACE TESTING BOP ROV FUNCTIONS • All critical ROV functions (as defined by API) will be tested at commissioning, when any changes are made and during any BOP control system recertification. • All ROV functions will be tested prior to deployment of the BOP at the start of every well. SUBSEA TESTING OF BOP ROV FUNCTIONS • As a minimum, one critical ROV function (i.e. Pipe ram or shear ram) will be tested upon installation on the wellhead. Following this initial test and as applicable, one other function will be tested every 3 months. ROV Subsea testing will be conducted using BOP fluid only. Where practicable, functions should be alternated between tests.	Not possible as it is today. The ROVs in use on the Norwegian continental shelf do not have the capacity and if a hot line to be used the flow will not be good enough.
7.3.20.1.6 All critical functions shall meet the closing time requirements in 7.3.10.5. Consideration shall be given for functions requiring 26 gal or less to be plumbed 3/8 in. (9.5 mm) ID and for those functions greater than 26 gal to be plumbed with 3/4 in. (19.5 mm) ID minimum.	No requirements mentioned.	As the ROV and the hot stab panel is to day this is not possible.

Tabell 3 GAP - ROV Intervention

The subsea BOP shall have a possibility to be operated with a high flow ROV system which will be able to close critical functions (each shear ram, one pipe ram, ram locks and unlatching of the LMRP connector). The closing time shall be for rams and LMRP connector within 45 seconds.

Winter 2010 Transocean performed a surface test on Transocean Winner to check the potential of our minireel and hot stab system. The hotstab mini reel located on cellar deck was used, the hose was ½" and the hose is 380 meter long.

Closing time with 1500 psi (using hot line regulator on cellar deck) the closing time is 3 min and 52 sec).

Closing time with 2700 psi (using hotline regulator on cellar deck) the closing time is 1 min and 12 sec).

Opening time with 1500 psi using main unit is 34 sec.

In the API 53 it is stated that Hydraulic fluid can be supplied by the ROV, stack mounted accumulators or other external hydraulic power source. The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions. This source shall be available at all times. (API, 201X) There is different solutions to be able to be in compliance one is to have a minireel system from the rig installed on a guide wire at all time when the BOP is subsea to meet the requirement. The minireel has to be able to deliver high enough flow in a sufficient size hose. In case of a fire on the rig the minireel hose can be exposed and lost. Another option is to use the accumulators on the BOP stack to provide sufficient fluid, or a separate accumulator bank located on seabed. In all of these solutions the ROV has to be down at all time, there is a weather requirement for launching the ROV and in harsh environment which it is in Norway this can be a challenge. For improving the hydraulic flow in the minireel there should be performed a hydraulic flow analysis to verify what the restrictions in the system is, it can be the hose itself or bends in the control console of the system.

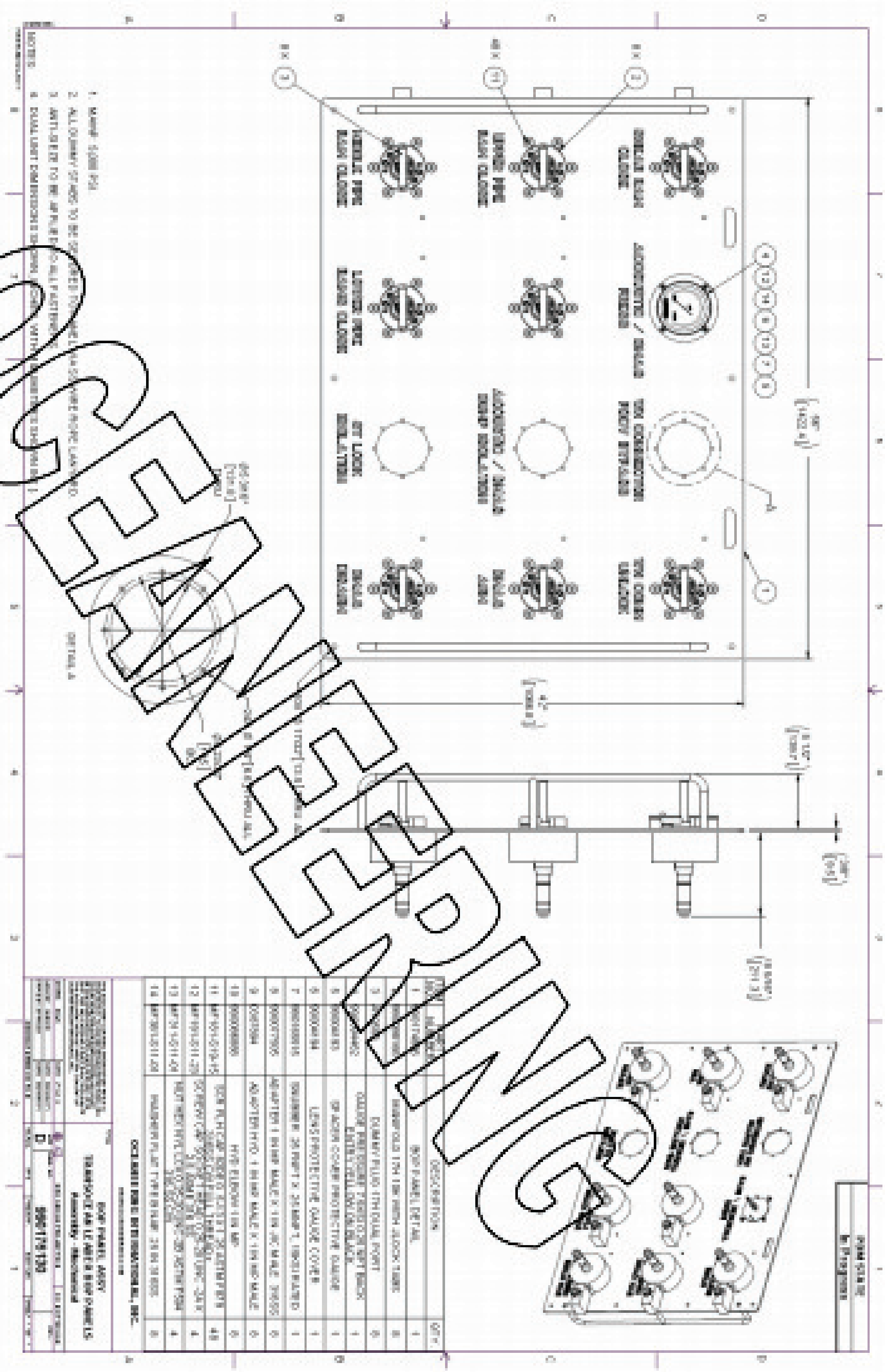
The operator supplies the ROV service through a third party. Transocean will have to supply a high flow ROV panel with the possibility to reach the requirement to close critical functions (shear rams close, one pipe ram close and LMRP unlock/unlatch) within 45 and 45 seconds to unlatch LMRP connector. As long as this is not requirement in Norway the operator will most likely not use any effort to rent equipment as accumulator bank to have subsea with the ROV, upgraded ROV pumping capacity etc. As long as there is a functional acoustic system which operate as a backup control system this will not likely to be prioritized? (Meling, 2012) But it is however possible on the drill ship Discover America currently operating in the Gulf of Mexico for Statoil an accumulator skid for the BOP is installed subsea near the BOP to supply sufficient flow capacity. (Meling, 2012) This BOP Auxiliary Accumulator System is delivered by Oceaneering and is a high pressure system also called a Six Shooter. It is an independent source of subsea accumulator volume which consists of six piston style accumulators. The “six shooter” is connected to the BOP stack with the use of a ROV, a Hydraulic flying lead and a high flow hot stab.

Figur 3 Oceaneering Six shooter and high flow intervention panel (International, 2012)

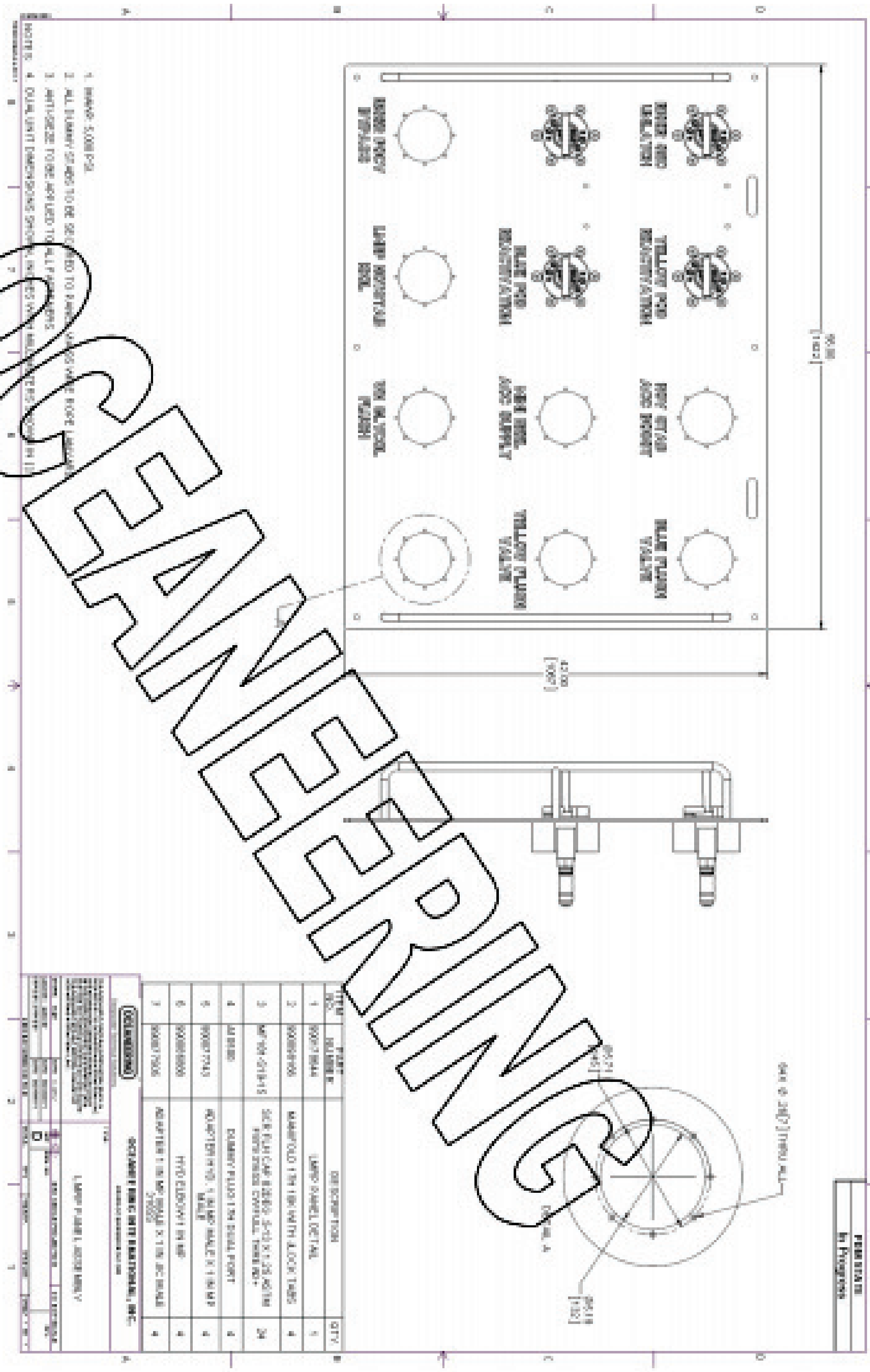
ITEM	QTY	DESCRIPTION	UNIT PRICE	EXTENSION
1	1	**PN 990176130: BOP Panel Assembly** • 316 SS Panel, 3/8" THK, 56" x 42" • Qty (8) Manifold, 17H with J-Lock Tabs • Qty (8) Non-pressure retaining Dummy Plugs • Qty (1) Pressure Gage, 250-7500 PSI Range • Qty (2) Panel Cutouts for IKM Valves **Data Book: (1) hard copy, (1) soft copy, c/w** • Panel Component Certifications • General Assembly Drawings • Bill of Materials	[redacted]	[redacted]
2	1	**PN 990179126: LMRP Panel Assembly** • 316 SS Panel, 3/8" THK, 42" x 56" • Qty (4) Manifold, 17H with J-Lock Tabs • Qty (4) Non-pressure retaining Dummy Plugs • Qty (8) Panel Cutouts for IKM Valves **Data Book: (1) hard copy, (1) soft copy, c/w** • Panel Component Certifications • General Assembly Drawings • Bill of Materials	[redacted]	[redacted]
3	2	**PN 0033465: 17H HI FLOW STAB, SINGLE PORT**	[redacted]	[redacted]
4	1	**Expedite fee, 6 weeks delivery from date PO accepted**	[redacted]	[redacted]
			TOTAL	[redacted]

Tabell 4 Quote from supplier of ROV high flow panel.

Oceaneering have come with a proposal for this job to Transocean Leader and what is needed. The problem will be to test it as long as the customer does not supply a ROV and fluid capacity when it is not a requirement.



Figur 4 BOP panel assy Transocean Leader BOP panels Mechanical



Figur 5 LMRP panel assembly Transoecan Leader

5.1.3 Secondary control system - Acoustic Control Systems

API 53	Transocean Well control manual	GAP
7.3.20.2 Acoustic Control Systems		
7.3.20.2.1 The acoustic control system is an optional secondary control system designed to operate designated BOP stack and LMRP functions and may be used when the primary control system is inoperable.	The acoustic system is a backup system that can be armed or disarmed and operated with an acoustic signal to control functions on the acoustic pod.	None
7.3.20.2.7 Testing the acoustic system shall be in accordance with Table 6 and Table 7 and Annex D. Surface testing acoustic system All assigned functions shall be tested prior to deployment and all assigned components to respond All functions required to secure the well shall be tested prior to deployment and within 90 seconds. Subsea testing Communication test not to exceed 21 days. One function to be tested during initial subsea test.	SURFACE TESTING ACOUTSIC FUNCTIONS • If an acoustic system is installed, all the acoustic functions will be tested at commissioning, when any changes are made and during any BOP control system recertification. • All acoustic functions will be tested prior to deployment of the BOP at the start of every well. SUBSEA TESTING OF ACOUSTIC FUNCTIONS • As a minimum, one acoustic function (Blind Shear rams) will be tested upon installation on the wellhead. Thereafter communications to the acoustic pod will be tested and validated by physically operating one function, not to exceed 21 days between tests.	No requirement for 90second respond time in Transocean or DNV at surface testing
7.3.20.2.8 Response times shall be in accordance with Table 6 and 7	See above	See above

Tabell 5 GAP - Secondary control system Acoustic

There is no requirement for having the acoustic system in API 53 but as mentioned in the start of this chapter, but all units operating on the Norwegian continental shelf has this. The Norwegian facilities regulation demands for an alternative activation system for activating critical functions on the blowout preventer for use in the event of an evacuation. Also Brazil has a requirement for Acoustic system. (Peetsold, 2012) This has been the only system on the market PSAN has accepted as a sufficient system. (Dørum, 2012) It is also a requirement for Acoustic in Brazil. ROV intervention system which is in use in Norway do not fulfill this requirement as it cannot pump sufficient high flow, in case of an evacuation the rig will be abandon with no possibilities to use a ROV unit, supply fluid with a minireel etc. The mobilization time of mobilizing a boat with sufficient ROV capacity is far more than for an Acoustic system. An acoustic system send an acoustic signal through a separate control unit and a dunking transducer, down to a subsea transducer located on the BOP. From here the signal goes into a subsea control unit, to a solenoid valve, which sends the signal from the acoustic package, gives the pilot signal to the SPM which accord to the Solenoid valve. This SPM will then open and give full unregulated operation pressure to the function chosen. This transducer is remotely operated and in case of an evacuation it will be possible to operate it from the lifeboat, deployed from a helicopter even if it is no contact with the rig.

There are different practices of testing the acoustic on the rigs in Transocean Norway, some rigs test it according to the well control manual. One function (Blind Shear rams) upon installation on the wellhead, thereafter communications to the acoustic pod tested and validated by physically operating one function, not to exceed 21 days between tests. Other rigs operate one function with the acoustic on the weekly function tests. Some never tests subsea only check the communication. The downside of testing the Acoustic to often can be that there is no regulator on the system as it is only for use if all other communication with the BOP is lost. This meaning that it goes straight on full operating pressure 3000 or 5000psi depending on the system. The requirement in API for 90 second respond time will never be an issue, the system will respond within 20-30 seconds due to unregulated operating pressure. (Butler, 2012) It is not possible to take the time on this when the BOP stack is subsea because you do not have a read back pressure which is your only indication of that

5.1.4 Pressure test frequency

The precautions of a low pressure test to be 200-300psi and should be stable for at least five minutes with no visible leaks is the same within Transocean, API, Norsok D010 and DNV. And the importance of performing the low pressure test before the high pressure test is also stated in both API 53 and Transocean well control handbook.

<table>
<tr><th>Component to be Tested</th><th>Pressure Test - Low Pressure psi (MPa)</th><th>Pressure Test - High Pressure psi (MPa)</th></tr>
<tr><td>Annular preventer</td><td>200 to 300 (1.38 to 2.1)</td><td>Minimum of 70 % of annular RWP</td></tr>
<tr><td>Ram preventers</td><td></td><td></td></tr>
<tr><td>Fixed/variable ram</td><td>200 to 300 (1.38 to 2.1)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>Blind/blind shear</td><td>200 to 300 (1.38 to 2.1)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>Casing shear rams</td><td>Function test</td><td>N/A</td></tr>
<tr><td>Hydraulic connectors</td><td>200 to 300 (1.38 to 2.1)</td><td>RWP of equipment above connector or wellhead system, whichever is lower.</td></tr>
<tr><td>Choke, kill, gas bleed line and valves</td><td>200 to 300 (1.38 to 2.1)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>BOP control system</td><td></td><td></td></tr>
<tr><td>Manifold and BOP lines</td><td>N/A</td><td>Control system operating pressure</td></tr>
<tr><td>Accumulator pressure</td><td>Verify precharge</td><td rowspan="4">N/A</td></tr>
<tr><td>Close time</td><td rowspan="3">Function test</td></tr>
<tr><td>Pump capability</td></tr>
<tr><td>Control stations</td></tr>
<tr><td>Emergency and secondary systems</td><td>According to table 6.</td><td></td></tr>
<tr><td colspan="3">Pre-deployment inspection and testing shall be performed in accordance with equipment owners' PM program.</td></tr>
<tr><td colspan="3">The low-pressure test should be stable for at least five (5) minutes with no visible leaks.
The high-pressure test should be stable for at least five (5) minutes with no visible leaks.
Well control equipment may have a higher rated working pressure (RWP) than for the well site. The site-specific test requirement shall be considered for these situations.</td></tr>
</table>

Tabell 6 Pre deployment surface testing according to API 53

The surface pressure testing program in Transocean is according to the API 53. Transocean philosophy to test to rated work pressure (RWP) prior to deployment is to provoke a failure at surface where it is easy to repair it, instead of having to pull the BOP stack on a different stage when the function may fail on a lower pressure. (Lillejordet, 2012)

The Norsok D-010 Annex A has no requirement for pressure testing up to Rated work pressure on stump each time. Backup systems as acoustic, EDS, Deadman and

Autoshear do not have any testing described. There is a requirement for pressure testing the BOP stack to Maximum well design pressure on stump and to work pressure each 6 months. (Norsok, 2001) Both Transocean testing procedures and API is more restrict than the Norsok.

Testing of emergency backup and secondary control systems is described in the chapters 5.1.1 -5.1.3. this testing requirements in not mentioned at all in the Norsok D-010 Annex A.

Component to be Tested	**Pressure Test - Low Pressure psi (MPa)**	**Pressure Test - High Pressure psi (MPa)**
Annular preventer	200 to 300 (1.38 to 2.1)	Minimum of MAWHP or 70 % of annular RWP, whichever is lower
Ram preventers		
Fixed/variable ram Blind/blind shear	200 to 300 (1.38 to 2.1)	Initial pressure test, upon landing the BOP, pressure tested to the maximum MAWHP for the well program for the stack installed. Subsequent tests, pressure tested to the MAWHP for the upcoming well section.
Casing shear rams	Function test	N/A
Well head or stack connectors	200 to 300 (1.38 to 2.1)	Initial pressure test , upon landing the BOP, to the maximum MAWHP for the well program. Subsequent tests, pressure tested to the MAWHP for the upcoming well section.
Choke, kill, gas bleed line, and valves	200 to 300 (1.38 to 2.1)	Initial pressure test, upon landing the BOP, pressure tested to the maximum MAWHP for the well program. Subsequent tests, pressure tested to the MAWHP for the upcoming well section.
Choke manifold		
Upstream of chokes	200 to 300 (1.38 to 2.1)	Same as rams
Downstream of chokes	200 to 300 (1.38 to 2.1)	RWP of choke(s) outlet, valve(s) or line(s), whichever is lower.

Adjustable chokes	Function test only - verification of back-up system	
BOP control system		
Manifold and BOP lines	N/A	Optional
Accumulator pressure	N/A	N/A
Close time	Function test	N/A
Control stations	Function test	N/A
Safety valves Kelly, kelly valves, drill pipe safety valves, IBOPs, etc.	200 to 300 (1.38 to 2.1)	A minimum of the MAWHP
Auxiliary Equipment		
Riser slip joint	Flow test	
Poor boy degasser/MGS	Optional	
Trip tank, flo-show, etc.	Flow test	
Emergency and secondary systems	According to table 7	
Subsea tests shall be performed upon initial installation, at intervals not to exceed 21 days (for wellbore testing) and/or in accordance with owners' PM program.		
The low-pressure test should be stable for at least five (5) minutes. The high-pressure test should be stable for at least five (5) minutes. Flow-type test should be of sufficient duration to observe for significant leaks. Well control equipment may have a higher RWP than required for the well site. The site-specific test requirement shall be utilized for these situations. MGS requires a one-time hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed. Bleed valves shall be tested at annular pressure on the wellbore side and at MAWHP on the choke/kill line side.		

Tabell 7 Subsea pressure testing according to API 53

Transocean testing procedures states that for initial subsea pressure test it is not necessary to duplicate the pressure test if already carried out on surface. This is a GAP from API53 where it is required to have a pressure test to MAWHP when landed on well head same as a normal biweekly pressure test see table 7.

3.2 Equipment to be pressure and function tested

The following equipment must be tested:

- *All components of the BOPs, annulars, wellhead components and their connections must be function and pressure tested. Prior to installation, rams will be tested with ram locks engaged. For hydraulically activated locks, the closing pressure must be bled off prior to testing*
- *All variable bore rams must be tested using the largest and smallest sizes of pipe in use excluding drill collars and bottom hole assemblies*
- *When installed, casing rams must be tested prior to running the applicable casing string*
- *There is no requirement to function test the following subsea:*

- *Release or latching type components (choke, kill, riser and wellhead connectors).*
- *Ram locking devices.*
- *Cameron Super Shear Rams* (Transocean, 2011)

5.2 Will implementation of API 53 increase the reliability of well control equipment, and thereby the safety?

This question has been asked my interviewees and there have been different feedback. It is two things here one is if we extend the testing can we then say this have increased the reliability. A good pressure test is valid at the time of test it is not possible to know any outcome 2 hours after or 2 days after (Lillejordet, 2012).

The testing requirement of testing the BOP stack after landed on Well head when you also made a full pressure test to Rated working pressure on surface do not have any increase in the reliability of the BOP (Meling, 2012). This point will only be implemented if the standard is implemented in DNV OS E101 or the Regulation adopts the requirement which do not seem likely. An initial pressure test to MAWHP after landing the BOP where discussion and voted upon in the API committee. Transocean and Statoil voted against this proposal. "A problem I find with the API 53 is that it is written for the Gulf of Mexico and to please the US government after Macondo. There are a lot of small companies operating only in the GoM and they have the same amount of votes that the bigger companies have." (Meling, 2012) The cost of extra pressure after landing the BOP stack is approximately 6 hours rig time (depending on the rig) which the oil companies have to take. Henry Meling's opinion is that this will not happen in Norway if it is not a requirement. Will the reliability of the BOP stack increase if it is tested both before deployed, and after landed? If testing the BOP to RWP on surface to provoke failures which can become visible after several lower pressure tests subsea to MAWHP this can increase the reliability of the equipment and avoid subsea failure and down time (Lillejordet, 2012). But excessive testing of equipment can also result in testing equipment to failure by wear and tear after each pressure test operation.

Another issue is how many backup systems do we need? (Meling, 2012) If the rig has an acoustic system should we then install a ROV intervention system when there is already a system which is more adequate for NCS?

5.3 What advantages will there be after implementation?

After implementing the DEMAS system there will be a quicker response on auto disconnect if the hydraulic and both pods is lost. The human factor will be lost versus rigging up with an acoustic system where you are reliable of a person operating the system. The DEMAS is fully automatically and no decision needs to be made (Butler, 2012). If the rig doesn't have an acoustic system an installation of DEMAS will require extra accumulators which can make a space issue, but this is not an issue in Norway where all the rigs have a separate accumulator bank for the acoustic. It is allowed to use the same accumulators for both Deadman and Autoshear.

In case of a ship on collision course there will only be need for disconnecting LMRP and the Autoshear will cut the string, and seal the well bore automatically if required. All pipe going into the hole shall be possible to cut and there shell be a shear calculation performed on the highest graded drill pipe (DP) and/or Heavy weight drill pipe (HWDP)

ROV intervention will increase the flow and make the response time on 45 second reachable. It will also be installed with J hooks for more reliable operation by the ROV. To be in compliance here the oil companies which are responsible for 3rd party suppliers will have to deliver a ROV with sufficient capacity and enough volume. As long as the acoustic is the only system meeting the requirements in Norway Statoil will not adopt this part of the standard (Meling, 2012).

Clearer requirements with regards to testing, Transocean have had a rigid test procedure, but there have been different ways of performing it as long as there have been no regional requirements and no requirements from the oil companies. Testing has in some cases been solved with exemptions from Well control handbook without a sufficient reason. “Statoil has sorted out what they find clear and relevant for Norway and added these points to Statoil’s management system, as for example testing of acoustic. This is an area where it is different practices due to no clear requirements in what to test? How to test? How often to test? Some places it is tested when landed, some only check for communication, some test the shear ram when convenient. This is a result of no clear regulatory requirements.” (Meling, 2012) Another side of increased testing is if tested too much this can result in premature failure of the BOP (Peetsold, 2012). Especially the acoustic system which is unregulated can get “worn out” with increased testing.

One advantage is that the industry will run in one direction with clear standard and within Transocean all rigs will have the same requirement for being in compliance with API 53. As Transocean subsea improvement plan states “we have to acknowledge and address a changed world”. Within the same improvement plan in accordance with customer we have to proactively address known and anticipated changes (in particular API 53) and accept that our customers especially worldwide oil companies will have a global procedures and API 53 will in many of this cases be set as an expectation (Lillejordet, 2012).

The total cost of the upgrade to be performed on Transocean Leader will be 361.000USD this will be a Transocean cost as long as the Norwegian regulations is not changed. All upgrades done on Transocean Leader autumn 2012 will be such cost.

In the prerequisites I included “only one shear ram for moored floaters as long as a written risk assessment is in place for each location.” This will be an advantage that for each well a risk assessment has to be made and every risk with regards to an operational BOP should be discussed. It will increase the focus on evaluating what can go wrong especially with regards to major hazards and mitigating measures to reduce this hazard to as low as reasonable practical. “It was in the last minute we got this change into API 53, luckily because in many situations it will be more sufficient to run a stack with 3 pipe rams and one shear ram instead of two shear rams and two annulars” (Meling, 2012). The BOPs are getting heavier and bigger and the older wellheads are not designed for this weights and sizes. This results in extensive wellhead fatigue (Lillejordet, 2012). The OEMs have now designed compact ram blocks which are the same size as a double but have three pipe rams instead of two. There were not time or budget for changing Transocean Leaders ram block during SPS 2012, but there are plans for changing them during SPS 2017 (Butler, 2012).

6. Summary and Conclusion

API 53 was changed from a RP to a standard as a consequence of Macondo in 2011. The oil industry had no clear standard for operation of the Well control equipment and it was practiced different from each area of the world and even within NCS. Backup systems and emergency control systems was not required and testing if installed was not required. Only Norway and Brazil had a governmental requirement for Acoustic system but still no requirements for testing.

Overall Transocean Norway will have an internal requirement for compliance with API 53. This will implicate in a technical upgrade on 5 out of 7 rigs working in Norway.

Transocean Norway needs to upgrade the 5 out of 7 rigs with a DEMAS system and install a ROV high flow intervention panel. The engineering cost of the total package is approximately 361 000USD there will also be installation costs and it will be most sufficient to do this work when the BOP is stripped for five year recertification. As the requirement will be internal for Transocean this will be a Transocean cost. Transocean can upgrade the rig with technical solutions which we are in control over, but it will not be possible to reach the requirement for 45 seconds closing time on ROV system if not the operator contract a sufficient ROV with enough capacity and/or an accumulator bank.

The reliability of the BOP will increase as there will be more backup systems. The DEMAS system has designed out human errors and is fully automatically. The Autoshear will shear and seal the well, if the gap between LMRP and the Lower stack exceed a set limit. Dead man will activate if the hydraulic and both pods is lost.

Transocean voted against new testing requirement for testing the stack to MAWHP as an initial subsea test together with Statoil, Exxon and Shell. There have so far not been any changes to internal requirements to perform this extra pressure test. The operators as Statoil, Exxon and Shell will most likely not implement it either and it will be difficult to get approximately 6 hours rig operation time to perform such a test when the stack is already tested to a RWP as part of the pre deployment plan (Meling, 2012).

The main challenge will be for Transocean Norway to get the operators to commit for their responsibility which exceeds the Norwegian regulations. Transocean can do the upgrades as far as we are responsible for, but as long as the API 53 is not Norwegian regulation the operator will continue to be compliant with the existing regulation.

As described previously in this thesis the standard is not jet published and there can be changes from what is described in this thesis. Transocean has decided to start with this upgrades in August 2012 when Transocean Leader is coming along quay side for 5 yearly SPS. The risk of having to postpone the work 5 years was a risk Transocean was not willing to take, this upgrade will increase the reliability of the safety critical equipment and make the rig a safer place to work. There have to be made rig specific quotes for each of the 4 remaining rigs as the system is not identically, but the philosophy of building the Deadman and the Autoshear together as one unit will be the same.

A similar work has started in Houston for verifying what the rigs operating in the GoM will have to do to be in compliance. On some rigs this is more extensive as they do not have an emergency accumulator package.

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Appendix

Appendix 01 Questions for evaluation

Appendix 02 Drawing Cameron

Appendix 03 API 53 4th ed Ballot 2

Appendix 01 Questions for evaluation.

What implicates and challenges will an implementation of API 53 have? (Old rigs, Market, OEM deliveries etc)

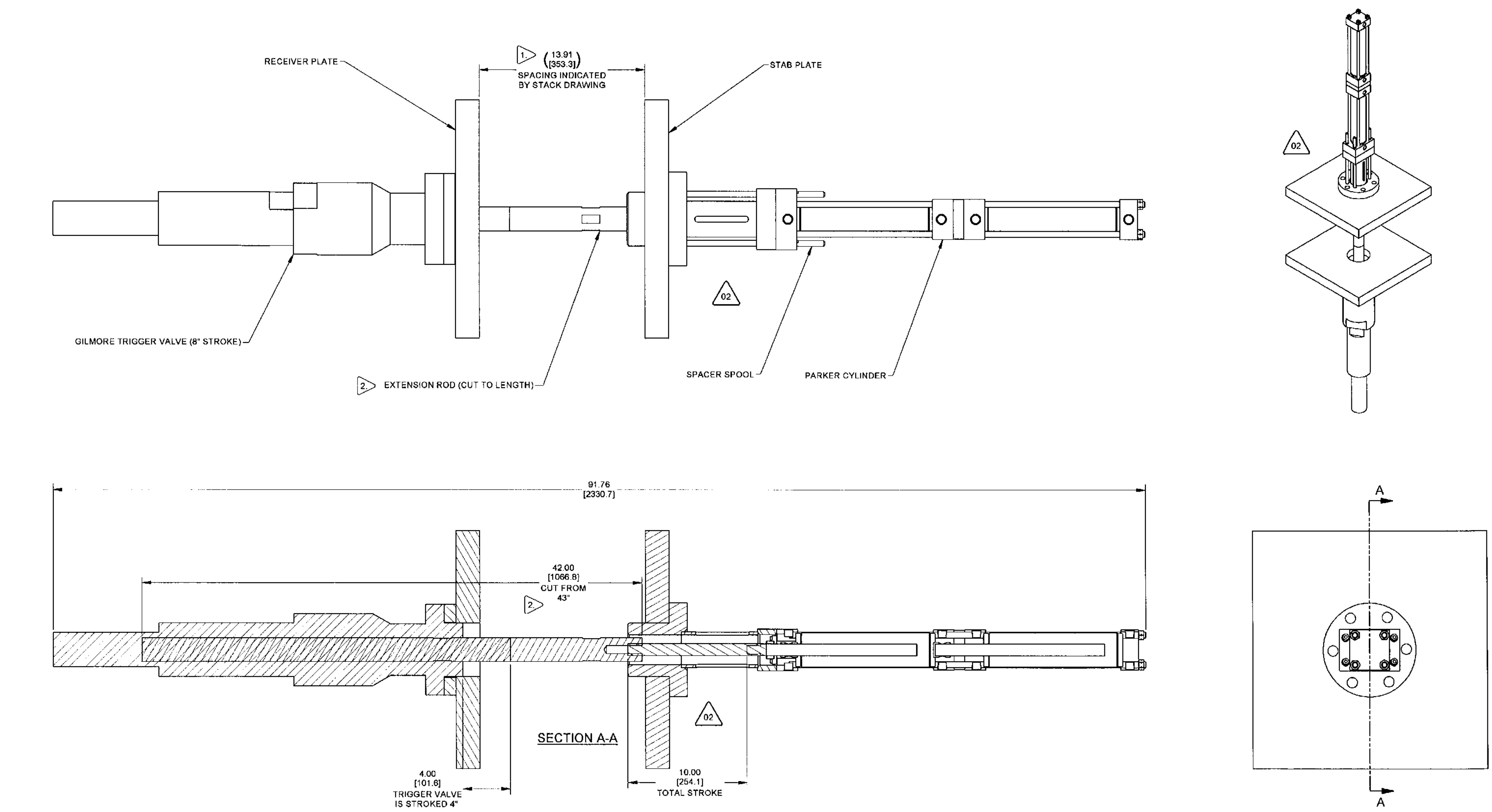
What advantages will there be after an implementation?

Who will benefit on an implementation?

How do you believe the implementation of API 53 will affect the integrity of well control equipment?

In how matters do you believe the reliability of the well control will increase?

Appendix 02 Drawing Cameron



NOTES:

1. SPACING BETWEEN STAB AND RECIEVER PLATE WILL CHANGE DEPENDING ON STACK

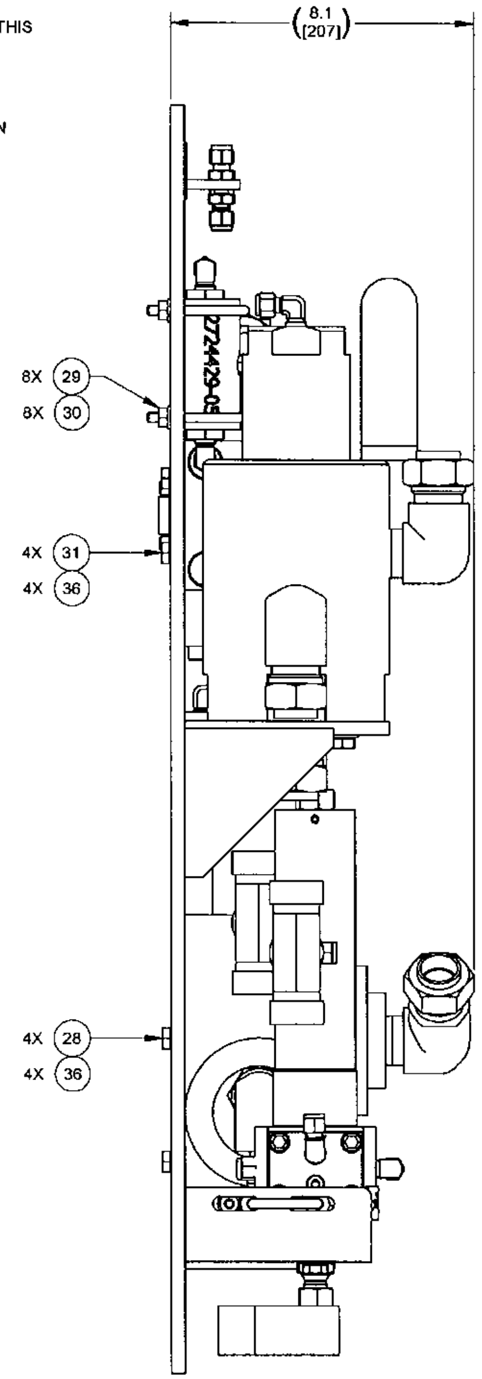
2. FINAL CUT LENGTH WILL DEPEND ON SPACING BETWEEN STAB AND RECIEVER PLATES

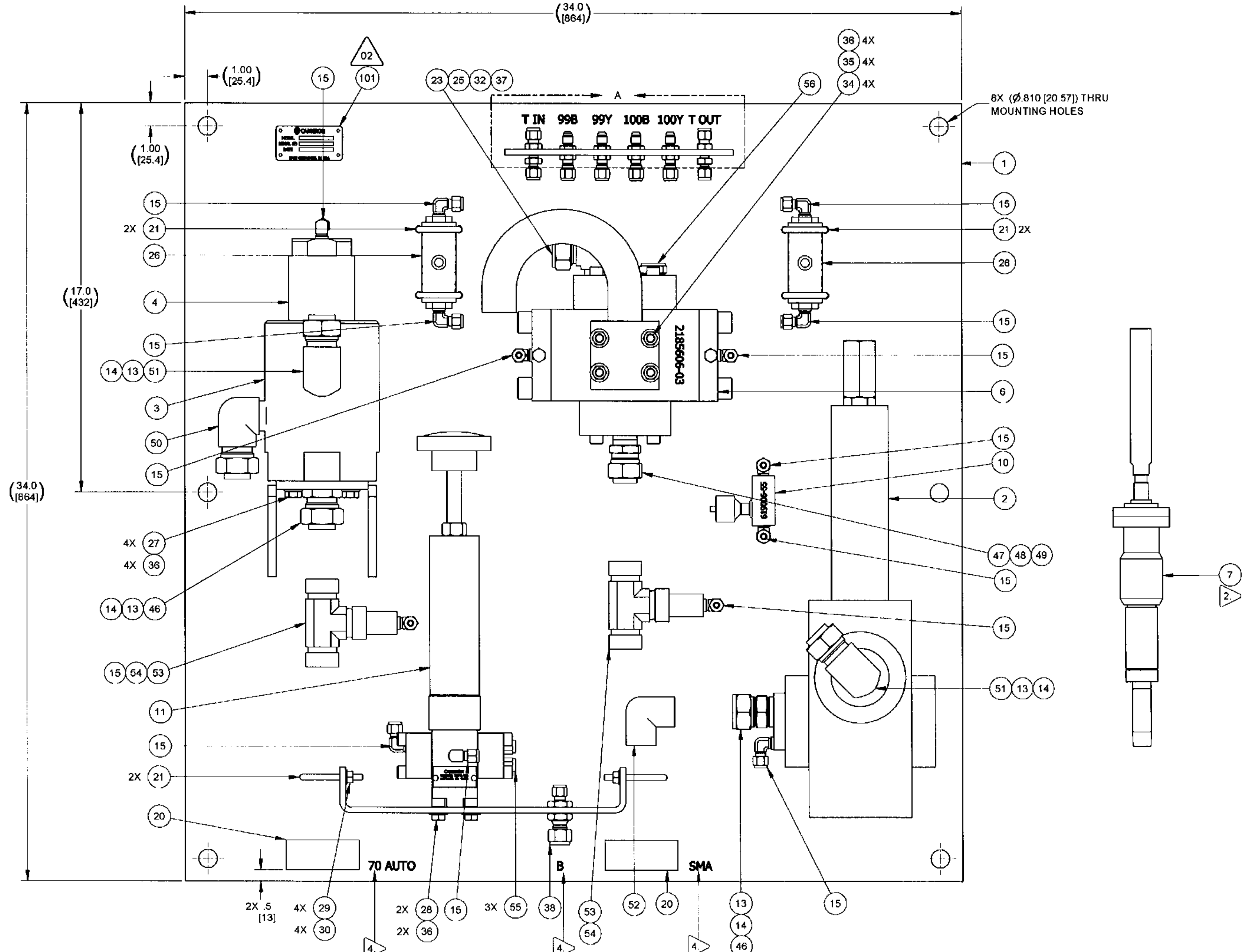
THIRD ANGLE	DESIGNED IN INCHES / DIMENSIONAL UNITS: INCHES [MILLIMETERS]	MACHINING TOLERANCES UNLESS OTHERWISE SPECIFIED		SURFACE TREATMENT	DO NOT SCALE	CAMERON DRILLING SYSTEMS
		X [0.]: ± .1 = [2.5]	ANGLES: ± 2°		DRAWN BY: EARHARTCJ, DATE 28 Jun 10	
MACHINED FILLET RADII .015-.050 [0.38-1.27]. BREAK ALL SHARP EDGES .01-.03 [0.2-0.8] RADII OR 45°. SURFACE FINISH IN MICRO (µ) INCHES (Ra). INTERPRET DRAWING PER ASME Y14.5, ASME Y14.36, AND AWS A2.4 STANDARDS. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS. ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.		XX [0.X]: ± .03 = [0.8]	250 RA ON ALL MACHINED SURFACES	MATERIAL & HEAT TREAT	CHECKED BY: TODDIG, DATE 28 Jun 10	DEADMAN SYSTEM W/ GILMORE 8" STROKE TRIGGER VALVE
					APPROVED BY: ESTESI, DATE 28 Jun 10	
		XXX [0.XX]: ± .015 = [0.38]		ESTIMATED WEIGHT: 631.9 LBS 313.9 KG	INITIAL USE B/M: 2274570-36	SHEET 1 OF 1 — SK-171703-01 — REV 02

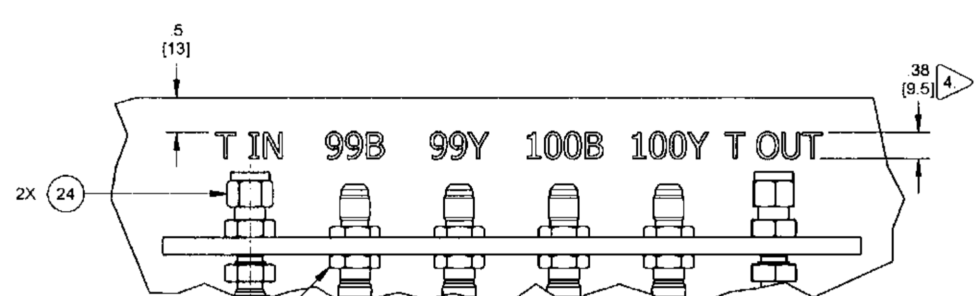
INVENTOR - D

NOTES:

1. ALL DIMS ARE REFERENCE.
2. ITEM 7 SHIPPED AS A LOOSE ITEM TO THIS ASSEMBLY.
3. TUBING RUNS OMITTED FOR CLARITY.
4. 3/8" LOW STRESS STAMP TEXT AS SHOWN







DETAIL A

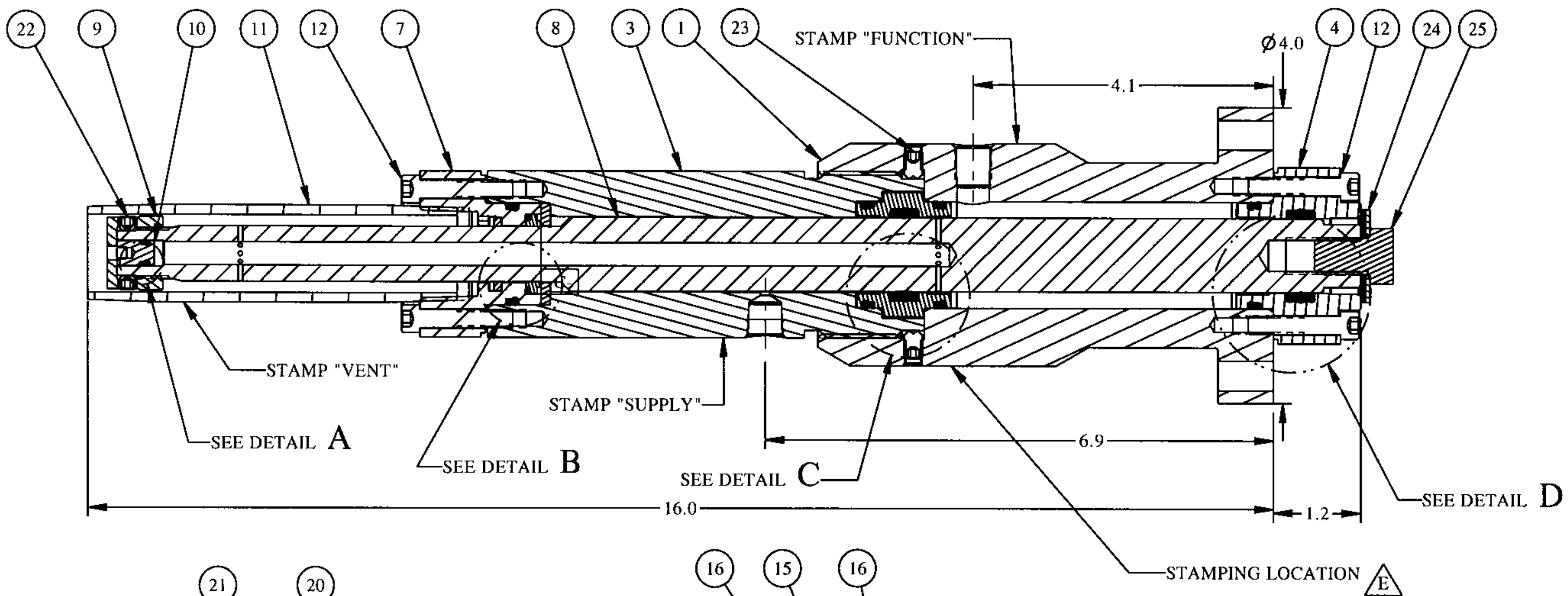
THIS DRAWING AND THE CONFIDENTIAL TRADE SECRET INFORMATION ON IT ARE THE PROPERTY OF CAMERON. POSSESSION DOES NOT CONVEY ANY RIGHTS TO DISCLOSE, REPRODUCE OR USE SAME FOR ANY PURPOSE OTHER THAN THAT GRANTED BY EXPRESS WRITTEN PERMISSION OF CAMERON. THIS DRAWING IS TO BE RETURNED TO CAMERON UPON ITS REQUEST OR COMPLETION OF AUTHORIZED USE.

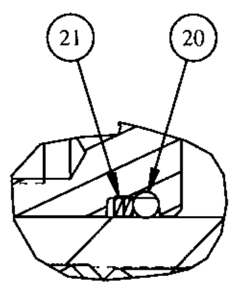
THIRD ANGLE	DESIGNED IN INCHES DIMENSIONAL UNITS INCHES [MILLIMETERS]	MACHINING TOLERANCES UNLESS OTHERWISE SPECIFIED	SURFACE TREATMENT	DO NOT SCALE	CAMERON — DRILLING SYSTEMS
MACHINED FILLET RADII .015-.050 [0.38-1.27]. BREAK ALL SHARP EDGES .01-.03 [0.2-0.8] RADII OR 45°. SURFACE FINISH IN MICRO (µ) INCHES (Ra). INTERPRET DRAWING PER ASME Y14.5, ASME Y14.36, AND AWS A2.4 STANDARDS. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS. ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.	X [0.] ± = [] ; XX [0.X] ± = [] ; XXX [0.XX] ± = []	ANGLES ± ° ; RA ON ALL MACHINED SURFACES	MATERIAL & HEAT TREAT	DRAWN BY: M FOWLER, DATE 30 Jul 10 CHECKED BY: I TODD, DATE 30 Jul 10 APPROVED BY: M KENNEDY, DATE 30 Jul 10	ASSEMBLY DRAWING, AUTOSHEAR VALVE MODULE, 4000 PSI MAIN REGULATED OUTPUT, 1500 PSI 2ND
			ESTIMATED WEIGHT: 323 LBS 146.5 KG	INITIAL USE B/M 2020756-16	SHEET 1 OF 1 — SK-122156-16-04 — REV 02

INVENTOR - D

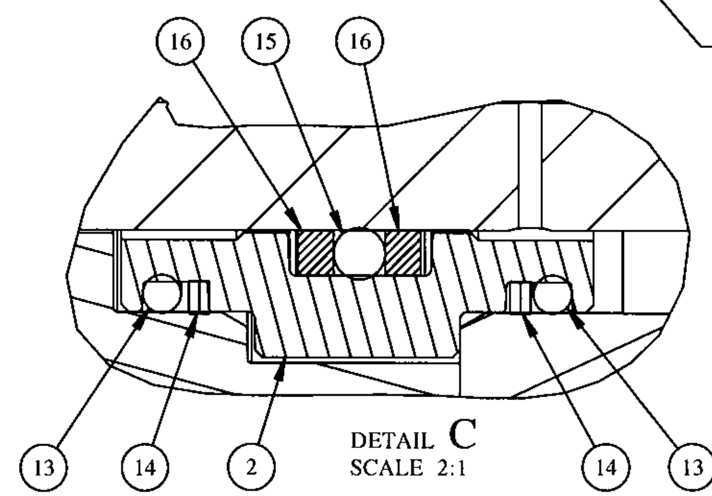
CHANGED STAMPING NOTE AND MAWP			
ECO #	REV	APPROVED BY	DATE
426	E	MES	02/02/10

CT0100





DETAIL A
SCALE 2:1



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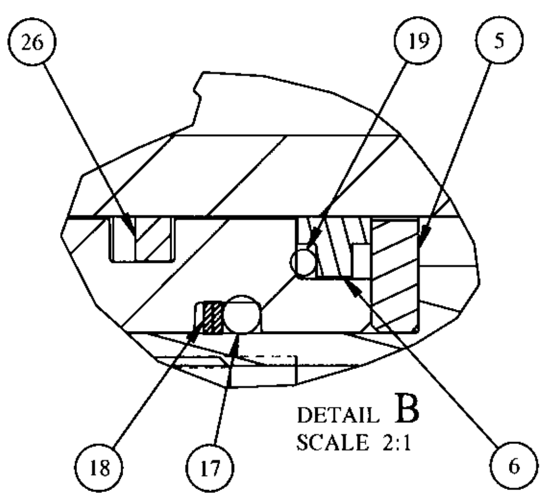
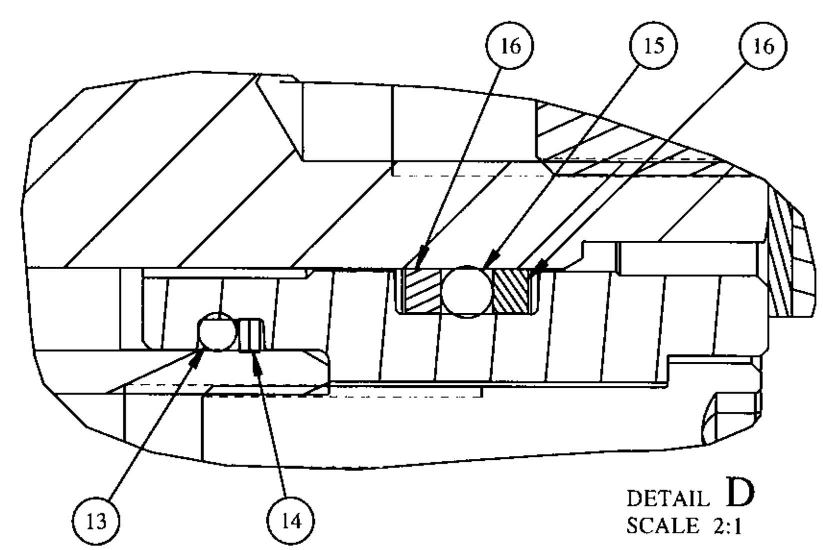
SCALE 2:1



DETAIL B
SCALE 2:1



DETAIL D
SCALE 2:1

ITEM NO	QTY	PART NO	DESCRIPTION	RK	SK
1	1	CT0112	HOUSING, UPPER		
2	1	CT0117	SEAL CAGE		
3	1	CT0109	HOUSING, LOWER		
4	1	CT0114	GLAND, TOP		
5	1	CT0107	SPACER		
6	1	CT0106	BRIDGE SEAL	X	X
7	1	CT0105	GLAND, BOTTOM		
8	1	CT0104	SHAFT	X	
9	1	CT0103	STOP RING		
10	1	CT0102	END PLUG		
11	1	CT0101	SHAFT PROTECTOR		
12	16	HK0420SS	SHCS, 1/4-20 UNC X 1-1/4, 316 SS		
13	3	ER124C	O-RING, BUNA-N	X	X
14	3	EB124ST	BACKUP RING, SPIRAL	X	X
15	2	ER214C	O-RING, BUNA-N	X	X
16	4	CT0110	WEAR RING	X	X
17	1	ER123C	O-RING, BUNA-N	X	X
18	1	EB123KT	BACKUP RING, SKARF CUT, TEFLON	X	X
19	1	ER021C	O-RING, BUNA-N	X	X
20	1	ER009C	O-RING, BUNA-N	X	X
21	1	EB009KT	BACKUP RING, SKARF CUT, TEFLON	X	X
22	2	HS040301SS	CUP SET SCREW, 1/4-20 X 3/16" 316		
23	2	HS040601SS	CUP SET SCREW, 1/4-20 X 3/8" 316		
24	2	HW0801SS	WASHER, 1-1/4 X 17/32 X 1/16, 316SS		
25	1	HH0812SS	HHCS, 1/2-13 UNC X 3/4 LG, 316SS		
26	1	CT0160	WEAR RING 3/4"	X	X

E MAWP 5000 PSI
Cv (S TO F) - 0.7
Cv (F TO V) - 0.7
PORTS : VENT - 1" NPT MALE
SUPPLY AND FUNCTION - 1/4" NPT
FLUIDS: WATER & MINERAL OIL BASED HYDRAULIC FLUIDS
TEMP RANGE: -20°F TO 200°F
APPROX WEIGHT - 19 LBS
FIELD SERVICEABLE

NOTES 1. ALL STAMPED TEXT TO BE 1/8" TALL
2. ITEMS 24 AND 25 ARE FOR SHIPPING ONLY

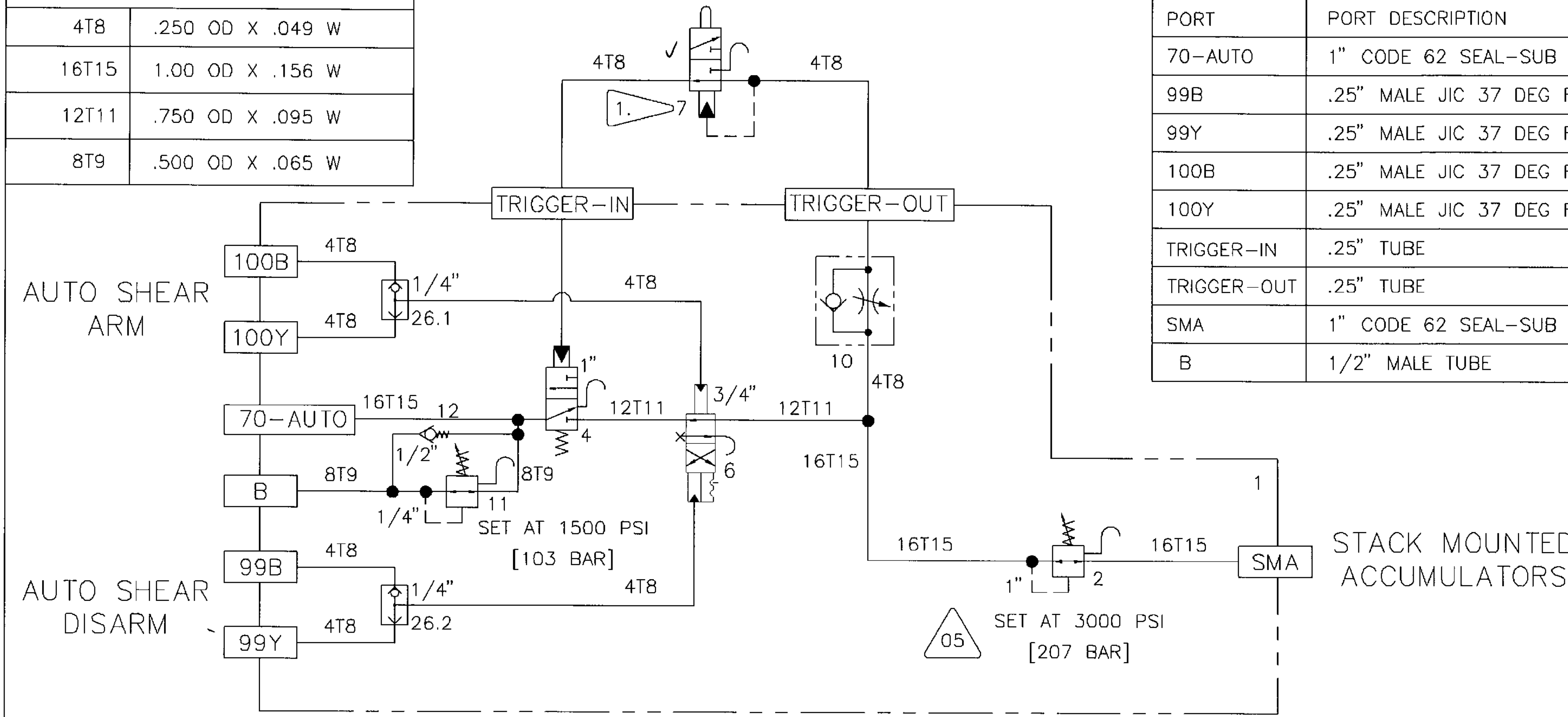
TUBING LEGEND
(ALL TUBING IS 316/316L)

4T8	.250 OD X .049 W
16T15	1.00 OD X .156 W
12T11	.750 OD X .095 W
8T9	.500 OD X .065 W

NOTES:
1. ITEM 7 SHIPPED AS A LOOSE ITEM TO THIS ASSEMBLY.

CUSTOMER CONNECTIONS

PORT	PORT DESCRIPTION
70-AUTO	1" CODE 62 SEAL-SUB
99B	.25" MALE JIC 37 DEG FLR
99Y	.25" MALE JIC 37 DEG FLR
100B	.25" MALE JIC 37 DEG FLR
100Y	.25" MALE JIC 37 DEG FLR
TRIGGER-IN	.25" TUBE
TRIGGER-OUT	.25" TUBE
SMA	1" CODE 62 SEAL-SUB
B	1/2" MALE TUBE



UNLESS OTHERWISE SPECIFIED: ALL DIMENSIONS ARE IN INCHES. BREAK ALL SHARP EDGES / FILLET .01 - .03 R OR 45°.
INTERPRET DWG PER ASME Y14.5 STANDARD. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS.
ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.

05 REV

CAD

TOLERANCE UNLESS OTHERWISE SPECIFIED
.X ±
ANGLES ±0.5°
.XX ±
250 AA ON ALL MACHINED SURFACES
.XXX ±

SURFACE TREATMENT

MATERIAL & HEAT TREAT

DO NOT SCALE

DRAWN BY	M FOWLER	DATE AUG 3, 2010
CHECKED	I TODD	DATE AUG 3, 2010
APPROVED	M KENNEDY	DATE AUG 3, 2010

CAMERON
Cameron
P.O. Box 1212
Houston, TX 77251-1212

FLOW DIAGRAM, AUTOSHEAR VALVE MODULE, GLOBAL MARINE 456 - CR LUIGS

SUPERSEDES | DATED | INITIAL USE B/M 2020756-16 | SHEET 1 OF 1 | SK-122156-16-05

B SIZE SHEET

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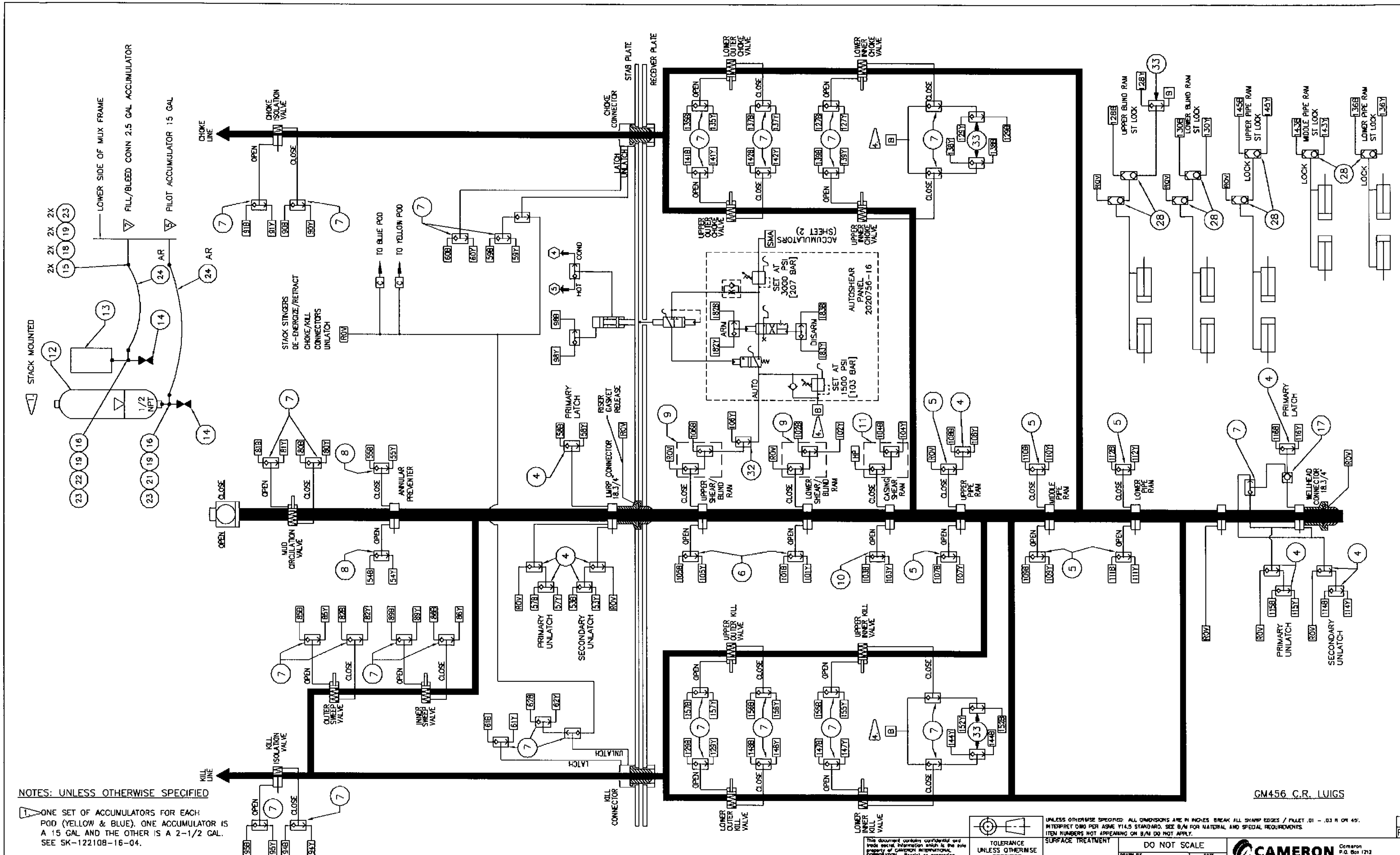
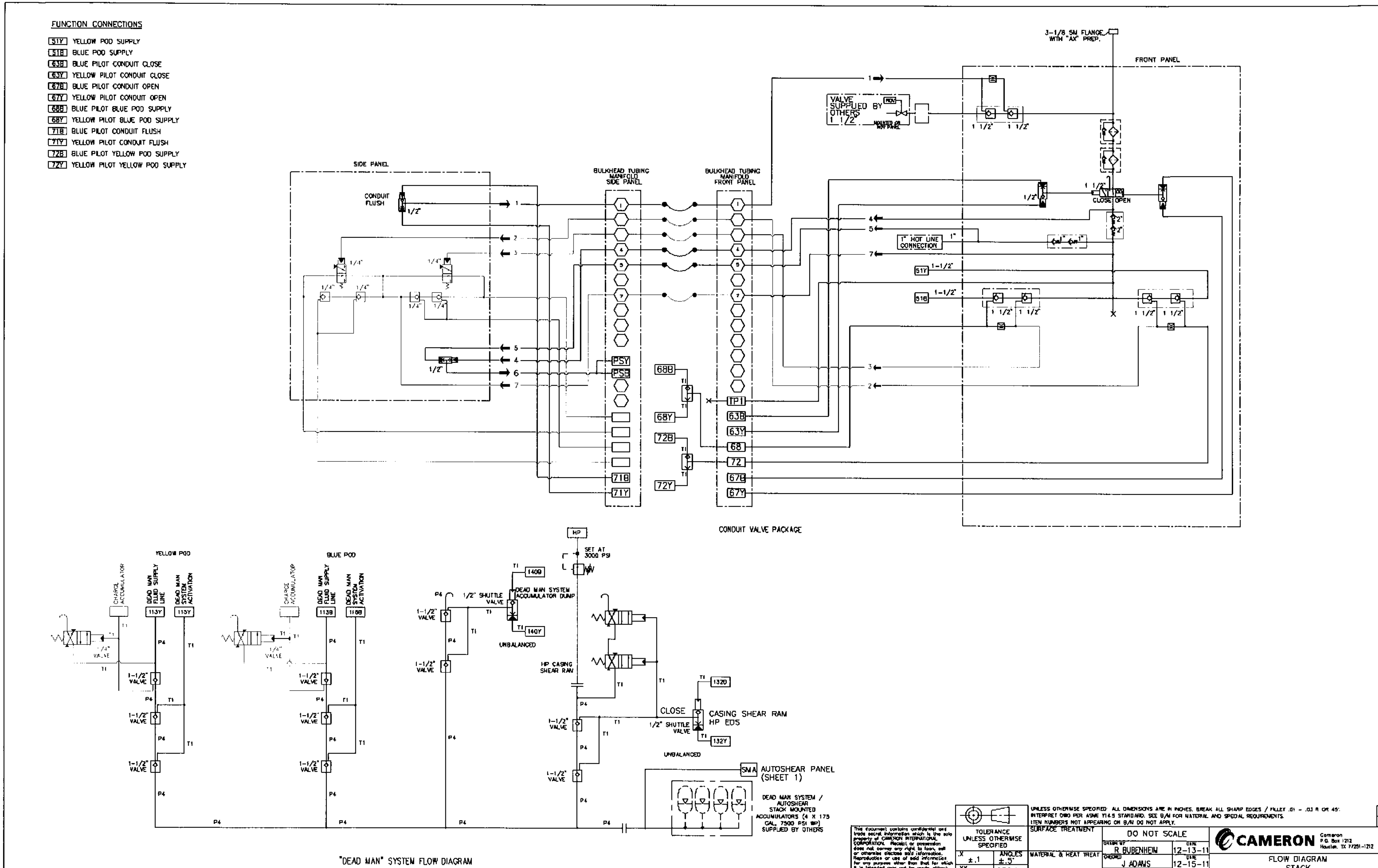


NOTES: UNLESS OTHERWISE SPECIFIED

1. ONE SET OF ACCUMULATORS FOR EACH POD (YELLOW & BLUE). ONE ACCUMULATOR IS A 15 GAL AND THE OTHER IS A 2-1/2 GAL. SEE SK-122108-16-04.
2. CONDUIT VALVE PACKAGE – SK-122120-16-05.
3. "DEAD MAN" SYSTEM – SK-122094-16.

UNLESS OTHERWISE SPECIFIED: ALL DIMENSIONS ARE IN INCHES. BREAK ALL SHARP EDGES / FILLET .01 – .03 R OR 45°. INTERPRET DWG PER ASME Y14.5 STANDARD. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS. ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.

TOLERANCE UNLESS OTHERWISE SPECIFIED	SURFACE TREATMENT	DO NOT SCALE	CAMERON, Cameron, P.O. Box 1212, Houston, TX 77251-1212
.X ±.1 / ANGLES ±.5°	MATERIAL & HEAT TREAT	DRAWN BY R BUBENHEIM, DATE 12-12-11	FLOW DIAGRAM STACK CR LUIGS
.XX ±.03 / 250 MACHINED SURFACES		CHECKED J ADAMS, DATE 12-15-11	
.XXX ±.060	SUPERSEDES	APPROVED M KENNEDY, DATE 1-3-12	
	DATED	INITIAL USE B/M 2020724-16	SHEET 1 of 2 — SK-122124-16-16 — REV 01



CAD

UNLESS OTHERWISE SPECIFIED: ALL DIMENSIONS ARE IN INCHES. BREAK ALL SHARP EDGES / FILLET .01 - .03 R OR 45°. INTERPRET DWG PER ASME Y14.5 STANDARD. SEE B/M FOR MATERIAL AND SPECIAL REQUIREMENTS. ITEM NUMBERS NOT APPEARING ON B/M DO NOT APPLY.

TOLERANCE UNLESS OTHERWISE SPECIFIED		
.X ±.1	ANGLES ±.5°	
.XX ±.03	250/ ALL ON ALL MACHINED SURFACES	
.XXX ±.060		

SURFACE TREATMENT

MATERIAL & HEAT TREAT

DO NOT SCALE

DRAWN BY	R BUBENHEIM	12-13-11
CHECKED	J ADAMS	12-15-11
APPROVED	N KENNEDY	1-3-12

CAMERON
Cameron
P.O. Box 1212
Houston, TX 77251-1212

FLOW DIAGRAM
STACK
CR LUIGS

SUPERSEDES | DATED | INITIAL USE B/M 2020724-16 | SHEET 2 OF 2 | SK-122124-16-16 | REV 01

Appendix 03 API 53 4th ed Ballot 2

Draft 2

Blowout Prevention Equipment Systems for Drilling Wells

API STANDARD 53
FOURTH EDITION, XXX 201X

This draft is for committee balloting purposes only.

FOREWORD

This standard represents a composite of the practices employed by various operating and drilling companies in drilling operations. This standard is under the jurisdiction of the API Drilling and Production Operations Subcommittee.

The first edition of API 53, published in February 1976, superseded API Bulletin D13, *Installation and Use of Blowout Preventer Stacks and Accessory Equipment*, February 1966. The Second Edition of API 53 was issued in May 1984 and the Third Edition of API 53 was issued in March 1997. This edition supersedes all previous editions of this standard.

Drilling operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as metropolitan sites, wilderness areas, ocean platforms, deepwater sites, barren deserts, wildlife refuges, and arctic ice packs. The information presented in this standard is based on this extensive and wide-ranging industry experience.

The goal of this standard is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling equipment, and preservation of the environment for land and marine drilling operations. This standard was published to facilitate the broad availability of proven, sound engineering and operating practices. This standard does not present all of the operating practices that can be employed to successfully install and operate blowout preventer systems in drilling operations. Practices set forth herein are considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices can be utilized to accomplish the same objectives. Individuals and organizations using this standard are cautioned that operations must comply with requirements of federal, state, or local regulations. These requirements should be reviewed to determine whether violations can occur.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The term “shall”, as used in this standard, denotes a minimum requirement in order to conform to the specification.

The term “should”, as used in this standard, denotes a recommendation or that which is advised but not required in order to conform to the specification.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually and updated quarterly by API, 1220 L Street, N.W., Washington, D.C. 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

Contents

1 Scope

1.1 Purpose

The purpose of this standard is to provide information that can serve as a guide for installation and testing of blowout prevention equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating). Blowout prevention equipment systems are composed of all systems required to operate the blowout preventers (BOPs) under varying rig and well conditions. These systems are

a) blowout preventers (BOPs)

b) choke and kill lines,

c) choke manifolds,

d) control systems, and

e) auxiliary equipment.

The primary functions of these systems are to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled volumes to be withdrawn from the wellbore. Diverter and rotating head systems (rotating control devices) are not addressed in this standard; their primary purpose is to safely divert or direct flow rather than to confine fluids to the wellbore.

Meeting these minimal standards within three years of the publication date of this standard is deemed a reasonable time period to implement these changes.

1.2 Well Control

Procedures and techniques for well control are not included in this publication since they are beyond the scope of equipment systems contained herein. Rig-specific procedures shall be developed and made available, at the well site, for managing blowout preventers, maintenance, operations, and installation under specific well and environmental conditions.

1.3 BOP Installations

In some instances, this standard contains a section pertaining to surface BOP installations followed by a section on subsea BOP installations. A delineation was made between surface and subsea equipment installations so these practices would also have utility in floating drilling operations.

1.4 Equipment Arrangements

Recommended equipment arrangements as set forth in this publication are adequate to meet specified well conditions. It is recognized that other arrangements can be equally effective and can be used in meeting well requirements and promoting safety and efficiency.

1.5 Extreme High and Low-temperature Operations

Although operations are being conducted in areas of extremely high and low temperatures, a section specifically applicable to these services was not included since current practice generally results in protecting the existing BOP equipment from these environments.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API Spec 5L, *Line Pipe*

API Spec 6A, *Wellhead and Christmas Tree Equipment*

API Spec 16A, *Specification for Drill-through Equipment*

API Spec 16C, *Choke and Kill Systems*

API Spec 16D, *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

API Spec 17D, *Subsea Wellhead and Christmas Tree Equipment*

API Spec 17H, *Recommended Practice for Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems*

API RP 75, *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*

API RP 500, *Classification of Locations for Electrical Installations at Petroleum Facilities*

API RP 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2*

ASME B1.20.1, *Pipe Threads, General Purpose (Inch)*

ASME B31.3, *Process Piping*

ASME Boiler and Pressure Vessel Code, Section IX, *Welding and Brazing Qualifications*

NACE MR0175/ISO 15156 (all parts), *Petroleum and natural gas industries - Materials for use in H_2S-containing environments in oil and gas production*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purposes of this standard, the following terms, definitions, and abbreviations apply.

3.1.1
accumulator
A pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

3.1.2
adapter spool
A spool used to connect drill-through equipment with different end connections, nominal size designation and/or pressure ratings to each other.

3.1.3
annular blowout preventer
A blowout preventer that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or an open hole.

3.1.4
articulated line
An articulated line is a choke or kill line assembled as a unit, with rigid pipe, swivel joints, and end connections, designed to accommodate specified relative movement between end terminations.

3.1.5
bell nipple (mud riser, flow nipple)
A piece of pipe, with inside diameter equal to or greater than the blowout preventer bore, connected to the top of the blowout preventer or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker pit.

NOTE This pipe usually has a second side outlet for the fill-up line connection.

3.1.6
blind ram
A closing and sealing component in a ram blowout preventer that seals the open wellbore.

3.1.7
blind shear ram
A closing and sealing component in a ram blowout preventer that first shears certain tubulars in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore.

3.1.8
blowout
An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout).

3.1.9
blowout preventer
BOP
Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, or in an open hole during well drilling, completion and testing operations.

NOTE A blowout preventer is not: a gate valve(s), workover control package, subsea shut-in device (SSID or SID), well control components (per API 16ST), intervention control packages, diverters, rotating heads or rotating circulating devices, snubbing or stripping packages.

3.1.10
blowout preventer (BOP) control system (closing unit)
The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

3.1.11
blowout preventer (BOP) stack
The complete assembly of well control equipment, including preventers, spools, valves, and nipples connected to the top of the casing head.

3.1.12
buffer tank
A targeted, horizontal, cylindrical tank that changes the direction of fluid flow downstream of the choke and serves as a flow director to the flare line or gas buster.

3.1.13
casing shear ram
A closing component in a ram blowout preventer that is capable of shearing or cutting certain tubulars,

NOTE Casing shear rams are not required to seal.

3.1.14
choke
A device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas.

3.1.15
choke line valve
The valve(s) connected to and a part of the BOP stack that controls the flow to the choke manifold.

3.1.16
choke manifold
An assembly of valves, chokes, gauges, and lines used to control the rate of flow from the well when the BOPs are closed.

3.1.17
clamp connection
A pressure-sealing device used to join two items without using conventional bolted flange joints.

NOTE The two items to be sealed are prepared with clamp hubs. These hubs are held together by a clamp containing two to four bolts.

3.1.18
close-assist valve
A valve capable of automatically closing via mechanical or hydraulic means, or a combination thereof.

3.1.19
closing ratio
The ratio of the wellhead pressure to the pressure required to close the BOP.

3.1.20
competent person
A person with characteristics or abilities gained through training, experience or both, as measured against the manufacturer's or equipment operator’s established requirements.

3.1.21
conductor pipe
A relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the up flowing drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well.

NOTE Conductor pipe is usually cemented.

3.1.22
control manifold
The system of valves and piping to control the flow of hydraulic fluid to operate the various components of the BOP stack.

3.1.23
control panel, remote
A panel containing a series of controls that will operate the valves on the control manifold from a remote point.

3.1.24
control pod
An assembly of subsea valves and regulators that when activated from the surface will direct hydraulic fluid through special apertures to operate the BOP equipment.

3.1.25
drill floor substructure
The foundation structure(s) on which the derrick, rotary table, drawworks, and other drilling equipment are supported.

3.1.26
drill pipe safety valve
An essentially full-opening valve located on the rig floor with threads to match the drill pipe connections in use.

NOTE This valve is used to close off the drill pipe to prevent flow.

3.1.27
drilling spool
A connecting component either flanged or hubbed, fitted between BOP equipment, with outlets.

3.1.28
drilling string float
A check valve in the drill string that will allow fluid to be pumped in to the well but will prevent flow from the well through the drill pipe.

3.1.29
drive pipe
A relatively short string of large diameter pipe driven or forced into the ground to function as conductor pipe.

3.1.30
fill-up line
A line usually connected into the bell nipple above the BOPs to facilitate adding drilling fluid to the hole while pulling out of the hole to compensate for the metal volume displacement of the drill string being pulled.

3.1.31
flex/ball joint
A device installed directly above the subsea BOP stack and below the telescopic riser joint to permit relative angular movement of the riser to reduce stresses due to vessel motion and environmental forces.

3.1.32
flow line
The piping which exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.33
full-bore valve
A valve with unobstructed flow area dimension equal to or greater than the nominal connection size.

3.1.34
function test
Closing and opening (cycling) equipment to verify operability.

3.1.35
gate valve
A valve that employs a sliding gate to open or close the flow passage.

NOTE The valve may or may not be full opening.

3.1.36
hang off
An action whereby that portion of the drill string below the ram BOP remains in the hole supported by a tool joint resting atop the closed pipe rams.

3.1.37
hydrogen sulfide
H_2S
A highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon bearing formations.

3.1.38
hydrogen sulfide equipment service
Equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide (H_2S).

3.1.39
hydrostatic head
The pressure that exists at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.40
inside blowout preventer (BOP)
A device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow.

3.1.41
integral valve
A valve embodied in the diverter unit that operates integrally with the annular sealing device.

3.1.42
interlock sequencing
An arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another function.

3.1.43
intervention
Well maintenance performed on a subsea production or injection well to restore or increase well productivity.

3.1.44
kelly cock
A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

3.1.45
kelly valve, lower
An essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the drill pipe tool joint outside diameter.

NOTE 1 This valve can be closed under pressure to remove the kelly and can be stripped into the hole for snubbing operations.

NOTE 2 Some lower kelly valve models are not designed to withstand external pressure encountered in stripping operations.

3.1.46
kick
Influx of formation liquids or gas into the wellbore.

NOTE Without corrective measure, this condition can result in a blowout.

3.1.47
kill line
A high pressure line between the pumps and some point below a BOP.

NOTE This line allows fluids to be pumped into the well or annulus with the BOPs closed.

3.1.48
lost returns
Loss of drilling fluid into the formation resulting in a decrease in pit volume.

3.1.49
maximum anticipated surface pressure
MASP
The maximum pressure exerted from a full column of fluids (gas, water, oil, mud) for a given bottom hole pressure and gas mixture (i.e. specific gravity).

NOTE MASP can apply to either the wellhead or exposed casing shoe or formation.

3.1.50
maximum allowed wellhead pressure
The highest pressure predicted to be encountered at the wellhead on a subsea well.

NOTE This pressure prediction is based on bottom-hole pressure minus a full column of fluids for a given bottom-hole pressure and fluid mixture.

3.1.51
maximum expected wellhead shear pressure
The expected pressure at the wellhead for a given hole section, a specific shear pressure, specific operating piston design, and drill pipe material specifications, to achieve shearing.

3.1.52
minimum calculated operating pressure
The minimum calculated pressure to effectively close and seal a ram-type BOP against a wellbore pressure equal to the maximum rated working pressure of the BOP divided by the closing ratio specified for that BOP.

3.1.53
minimum internal yield pressure
The lowest pressure at which permanent deformation will occur.

3.1.54
opening ratio
The ratio of the well pressure to the pressure required to open the BOP.

3.1.55
overburden
The pressure on a formation due to the weight of the earth material above that formation.

NOTE For practical purposes, this pressure can be estimated at 1 psi/ft of depth.

3.1.56
pipe ram
A closing and sealing component in a ram blowout preventer that seals around tubulars in the wellbore

3.1.57
pit volume indicator
A device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.58
pit volume totalizer
A device that combines all of the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.59
plug valve
A valve whose mechanism consists of a plug with a hole through it on the same axais the direction of fluid flow.

NOTE Turning the plug 90 degrees opens or closes the valve. The valve may or may not be full-opening.

3.1.60
pressure-containing
The prevention of a release of pressurized fluids to the environment.

3.1.61
pressure-controlling
The control of the movement of pressurized fluids.

3.1.62
pressure gradient, normal
The subsurface pressure proportional to depth, which is roughly equal to the hydrostatic pressure of a column of salt water (0.465 psi/ft).

3.1.63
pressure regulator
A control system component which permits attenuation of control system supply pressure to a satisfactory pressure level to operate components downstream.

3.1.64
rated working pressure
The maximum internal pressure that equipment is designed to contain or control.

NOTE 1 Indicative of wellbore wetted rated components or systems.

NOTE 2 Rated working pressure should not be confused with test pressure.

3.1.65
rated operating pressure
The maximum internal pressure that equipment is designed to perform specific function(s).

NOTE 1 Indicative of control system and BOP hydraulic chamber systems or components.

NOTE 2 Rated operating pressure should not be confused with test pressure or rated working pressure.

3.1.66
repair
Activity involving disassembly, reassembly, and testing of equipment with or without the replacement of parts.

NOTE Repair does not include machining, welding, heat treating, other manufacturing operations or the replacement of bodies.

3.1.67
remanufacture
Activity involving disassembly, reassembly and testing of equipment, with or without the replacement of parts, where machining, welding, heat treating or other manufacturing operations are employed.

NOTE Remanufacture does not include the replacement of bodies.

3.1.68
shearing ratio
The higher value of the closing ratios provided by the manufacturer.

NOTE The shearing ratio is dependent on piston size or booster addition.

3.1.69
shuttle valve
A slide valve with two inlets and one outlet that prevents movement of hydraulic fluid between two redundant subsea control pods.

3.1.70
space out
The procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea BOP rams on which drill pipe is to be suspended (hung off) and so that no tool joint is opposite a set of BOP rams after drill pipe is hung off.

3.1.71
spacer spool
A spool used to provide separation between two components with equal sized end connections.

3.1.72
stored hydraulic fluid
The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.

3.1.73
subsea BOP
Blowout preventer stack designed for use on subsea wellhead and wellhead assemblies, complete with redundant controls.

NOTE A subsea BOP provides the capability to remotely shear and seal the wellhead bore. Also provides the capability to circulate from the surface through the wellhead.

3.1.74
trip gas
An accumulation of gas which enters the hole while a trip is made.

3.1.75
umbilical
A control hose bundle or electrical cable that runs from the reel on the surface to the subsea control pod on the LMRP.

3.1.76
usable hydraulic fluid
The hydraulic fluid recoverable from the accumulator system between the maximum accumulator operating pressure and 200 psi (1.38 MPa) above precharge pressure.

3.1.77
visual position indicator
VPI
A visible means of determining the position of a valve, ram, connector or annular activation to indicate the full open or close position.

3.1.78
well servicing
The maintenance work performed on a surface oil or gas well system to improve or maintain the production from a formation already producing in the well.

NOTE Well servicing usually involves repairs to the pump, rods, gas lift vales, tubing, packers, etc.

3.1.79
workover
Operations performed on a surface producing well to restore or increase production.

NOTE A workover may be done to wash out sand, acidize, hydraulically fracture, mechanically repair or for other reasons.

3.2 Abbreviations

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society for Testing and Materials

BOP	blowout preventer
cm	centimeter
EH	electro-hydraulic
HCR	high closing ratio
H_2S	hydrogen sulfide
IADC	International Association of Drilling Contractors
ID	inside diameter
IOM	installation, operation, and maintenance
ISO	International Organization of Standardization
LMRP	lower marine riser package
m	meter
m^3	cubic meter
MBR	minimum bend radius
MPa	megapascal
MASP	maximum anticipated surface pressure
MAWP	maximum anticipated wellhead pressure
MEWSP	maximum expected wellhead shear pressure
MUX	multiplex systems
MWP	maximum working pressure
NACE	National Association of Corrosion Engineers
OEM	original equipment manufacturer
OD	outside diameter
psi	pounds per square inch
PGB	permanent guide base
PM	preventive maintenance
PQR	procedure qualification
RWP	rated working pressure

ROP	rated operating pressure
SSC	sulfide stress cracking
VPI	visual position indicator
WPS	weld procedure specification

4 BOP Pressure Sealing Components

4.1 General

4.1.1 This section addresses the pressure-containing elements of the BOP system. As defined by API 16A, these are components exposed to wellbore fluids whose failure to function as intended would result in a release of retained fluid to the atmosphere.

4.1.2 In the BOP stack these pressure-containing elements include primarily flanges and hubs, as well as the bolting and clamps that join them, as well as ring-joint gaskets.

4.1.3 They also include, in subsea BOP systems, the subsea wellhead connector, its wellhead gasket, the lower marine riser package (LMRP) connector, its gasket, and finally the choke and kill lines on the LMRP and on the marine riser system.

4.1.4 This section also addresses the pressure-controlling sealing elements of the BOP system. As defined by API 16A, these are components intended to control or regulate the movement of wellbore fluids. They include the wellbore-wetted elastomeric components in the BOP system (e.g. ram block seals) and in the main bore of marine riser system.

4.1.5 Finally, consideration is given to the non-wetted elastomeric sealing elements in the subsea control system and in actuators, specifically the seals isolating hydraulic control fluid from the environment.

4.2 Flanges and Hubs

4.2.1. When flanged or studded connections are used in BOP systems, they shall be in accordance with API 6A (Type 6B or Type 6BX) or API 17D (Type API 17SS or API 17SV) designs.

4.2.2 When clamp type hub connections are used in BOP systems they shall be in accordance with API 16A, Type 16B or 16BX designs.

4.2.3 If non-API clamp hub connections are used, they shall be of equal or superior design to other end connections (OEC) as defined in API 16A.

4.2.4 For flanges and clamp hubs, API 6A, API 16A and API 17D give sizes, service conditions, dimensions, and other design requirements.

4.2.5 Non-API ring joint gaskets may be used in flanges or hubs. In such cases the resulting non-API connection is considered as an OEC (see 4.4).

4.2.6 Manufacturers shall provide users with complete information on service conditions, dimensions, and other specifications for flanges and hubs used in BOP systems.

4.3 Bolting and Clamps

4.3.1 Bolting - studs and nuts - for pressure-containing joints in BOP systems shall be in accordance with API 6A, API 16A, and API 17D, as applicable. This requirement also extends to bolting used for clamp connections.

4.3.2 Bolting used in the pressure end-load path of proprietary design of subsea wellhead connectors shall be in accordance with the manufacturer's written specification.

4.3.3 The danger of using sub-standard or inferior bolting cannot be overstated. A recognized quality assurance program shall be used in the procurement and documentation of bolting for BOP systems, refer to API 17N.

4.3.4 All BOP system bolting and nuts shall be part of the preventive maintenance (PM) program for the system.

4.3.5 The program shall include frequent visual inspection to confirm tightness and corrosion or surface conditions.

4.3.6 The equipment owners PM program must identify frequency, NDE type testing and acceptance criteria for the bolts and nuts.

4.3.7 Clamps for pressure-containing hubs, in BOP systems, shall be maintained, inspected and installed in accordance with API 16A.

4.3.8 Clamps for non-API hubs, the requirements for other end connections (OEC) in API 6A shall be applied.

4.3.9 Preventive maintenance (PM) on clamps must include frequent visual inspection to confirm tightness and surface condition.

4.3.10 In addition, it is vitally important to perform NDE of the ears or areas where the bolts make up the clamp, owing to high stresses in these areas.

4.3.11 The equipment owners PM program shall identify frequency, NDE type testing and acceptance criteria for the clamps.

4.4 Ring-joint Gaskets

4.4.1 For BOP system application, with API flanged and studded connections or with API clamp hub connections, use API Type RX and BX ring-joint gaskets.

4.4.2 RX gaskets are used with API Type 6B flanges and 16B hubs.

4.4.3 BX gaskets are used with Type 6BX flanges, with Type 17SS and 17SV flanges, and with Type 16BX hubs.

4.4.4 SRX and SBX gaskets (refer to API 17D) may be used in lieu of RX and BX gaskets.

4.4.5 Detailed specifications for ring-joint gaskets, including gasket materials, coatings, plating, and identification marking, are included in API 6A, in API 16A, and in API 17D.

4.4.6 For other end connections (OEC), including proprietary hubs and modified API flanges, other ring-joint gaskets may be specified; examples include AX, CX, and VX type gaskets, as well as Grayloc®

seals. These are acceptable in such applications, consistent with the OEC requirements given in API 16A and API 6A.

4.4.7 API Type R ring gaskets shall not be used on well control equipment.

4.5 External Pressure Effects on Ring-joint Gaskets

4.5.1 For subsea BOP system applications, external pressure capacity may be a performance concern in the design of sealing for pressure-containing joints. This is especially so as water depth and thus ambient hydrostatic pressure increase. It is of special concern because of the potential for unanticipated loss of fluid gradient due to gas in solution, as well as to lost circulation events.

4.5.3 Just as with the flange and hub connections themselves, manufacturers shall provide users with complete information on external pressure capacity and performance of ring joint gaskets used in BOP systems. This includes API RX, BX, SRX, and SBX gaskets used in API flanges and hubs, as well as proprietary gaskets (AX, CX, etc.) used in OEC.

4.5.4 Subsea BOP system users shall survey and evaluate all pressure-containing joints in the BOP system, to ensure adequate performance under the effects of external pressure for the specific subsea applications.

4.6 Subsea Wellhead Connector and Wellhead Gasket

4.6.1 In subsea BOP systems the connection of the BOP to the wellhead is made by a proprietary-design wellhead connection and metal-to-metal sealing gasket.

4.6.2. Because these elements of the BOP system are not per API design specification, and are not classified as other end connections (OEC), manufacturers shall provide the equipment owners with complete information on service conditions, load capacities, and basic (non-proprietary) dimensions of the wellhead connector.

4.6.3 The external pressure capacity and performance of all gasket seals shall be provided to the equipment owner, along with information on available contingency seals.

4.6.4 The subsea wellhead connector may also incorporate a hydrate seal. This seal, typically an elastomeric seal against the outside of the wellhead, acts to prevent external hydrate buildup resulting from gas migrating from shallow well annuli into the connector-to-wellhead interface.

4.7 Subsea Lower Marine Riser Package Connector and Gasket

4.7.1 If the subsea BOP system includes BOP's in the lower marine riser package (e.g., annular BOP's) then the LMRP riser connector shall be considered as a pressure-containing joint of the system.

4.7.2 In such cases, the provisions in 4.6 for the wellhead connector and gasket shall apply to the riser connector and gasket.

4.8 Subsea Choke and Kill Lines

4.8.1 Subsea BOP systems include choke and kill (C&K) access lines built into the BOP stack and LMRP, and integrated with the marine riser system.

4.8.2 These two fluid access lines provide redundancy, as well as multiple access points to the BOP stack and allow for well control operations as follows:

— circulating down one line and up the other line;

— circulating down the drill pipe and up either line.

4.8.3 On the BOP stack and the LMRP, the choke and kill lines are provided with multiple gate valves for closure and pressure control, with flange or hub connections per API 6A, API 16A, and API 17D, as applicable.

4.8.4 The remote connection of the choke and kill lines from the BOP stack to the LMRP is made by proprietary connection, either pin and box (with elastomeric radial seal) or hub and connector (with metal-to-metal gasket).

4.8.5 The connection of the choke and kill lines integrated in the marine riser is made, joint-to-joint, by proprietary box-and-pin, stab-in couplings (with elastomeric radial seal).

4.8.6 All of these choke and kill connections are pressure-containing connections.

4.8.7 Their metal gasket seals, whether API or OEC or proprietary, shall conform to the same conditions as described in sections 4.4, 4.5, and 4.6.

4.8.8 Special considerations shall be taken to ensure performance in deep water is not impacted by negative or external pressures acting on the system.

4.8.9 The choke and kill connection elastomeric seals shall conform to the same conditions as described in sections 19.9 and 19.10.

4.9 Wetted Elastomeric Sealing Components

4.9.1 Elastomeric wellbore (wetted) sealing components include annular packers and ram block seals.

4.9.2 In subsea BOP systems the environmental seals of each marine riser coupling are typically elastomeric. The primary telescopic joint seal assembly consists of a hydraulic or pneumatic pressure-energized elastomeric packing element(s). All of these are considered pressure-controlling seals.

4.9.3 All BOP system elastomeric seal elements shall be addressed in the equipment owners preventive maintenance (PM) program for the system.

4.9.4 This PM program shall include frequent visual inspection to confirm condition.

4.9.5 The manufacturers shall provide the equipment owner with information to include in the PM program identifying frequency of inspection or renewal, and acceptance criteria for all elastomeric seals.

4.9.6 Care shall be taken to clean and inspect for damage or degradation of all elastomeric seals on riser connectors and on choke and kill connections prior to and/or during running the marine riser.

4.10 Fluid Service Conditions for Wetted Sealing Components

4.10.1 The fluid environment of wellbore wetted surfaces will vary, depending on well circumstances.

4.10.2 Manufacturer/provider shall provide material compatibility testing results to to the equipment owner, to ensure correct fluid service rating and performance. This is especially critical if the equipment owner plans well testing back to the rig.

4.10.3 It is important to note that some blends of drilling and completion fluids have detrimental effects on elastomeric seals. The original equipment manufacturer shall be consulted regarding compatibility with drilling and completion fluids.

4.10.4 Consideration shall be given to elastomeric seal compatibility with high pressure, high temperature (HPHT) conditions.

4.10.5 Considerations shall also be given to elastomeric seal compatibility with extreme low temperature and pressure variations.

4.10.6 Elastomeric components shall be changed out, as soon as possible, after exposure to hydrogen sulfide, under pressure.

4.11 Non-Wetted Elastomeric Components

4.11.1 The non-wetted, non-wellbore elastomeric sealing elements in the BOP system are used in two applications: control system components and hydraulic actuators. These are the seals isolating hydraulic control fluid from the environment; they are neither pressure-containing nor pressure controlling.

4.11.2 In the subsea control system the primary hydraulic system seal between the male and female sections of the control pods is accomplished with resilient seals of the O-ring, pressure-energized, or face-sealing types.

4.11.3 In the hydraulic junction boxes there are stab subs or multiple check valve-type quick disconnect couplings, where again the primary seals are O-rings.

4.11.3 In addition to the control system, hydraulic actuators utilize elastomeric seals. These actuators include BOP actuating systems and gate valve actuators.

4.11.4 Non-wetted elastomeric seals that are routinely disconnected and exposed (e.g. control system connections) shall be visually inspected for damage or degradation each time they are exposed on deck.

4.12 Equipment Marking and Storage

4.12.1 Marking and storage of Sealing Components of BOP systems shall be per API 6A, API 16A, and API 17D, as applicable, including identification marking of ring gaskets, bolts, nuts, clamps, and elastomeric seals.

4.12.2 Elastomeric seals in particular shall be marked or tagged using a codification system developed by the equipment manufacturer.

4.12.3 At a minimum the markings shall include information regarding the durometer hardness, generic type of compound, date of manufacture (month/year), lot/serial number, manufacturer's part number, and the operating temperature range of the component.

4.12.4 Specialized components, including proprietary design BOP seals and packing units, shall be stored in accordance with the original equipment manufacturers recommendations.

5 Blowout Preventers for Hydrogen Sulfide Service

5.1 Applicability

5.1.1 Where there is reasonable expectation of encountering hydrogen sulfide gas zones that could potentially result in the partial pressure of the hydrogen sulfide exceeding 0.05 psia (0.00034 MPa) in the gas phase at the maximum anticipated pressure, BOP equipment modifications should be made.

5.1.2 Recommended safety guidelines for conducting drilling operations in such an environment can be found in API 49.

5.2 Equipment Modifications

5.2.1 Equipment modifications should be considered since many metallic materials in a hydrogen sulfide environment (sour service) are subject to a form of hydrogen embrittlement known as sulfide stress cracking (SSC). This type of spontaneous brittle failure is dependent on the metallurgical properties of the material, the total stress or load (either internal or applied), and the corrosive environment.

5.2.2 A list of acceptable materials is given in NACE MR0175.

5.2.3 A list of specific items to be changed on annular and ram type BOPs and valves for service in a hydrogen sulfide environment shall be furnished by the manufacturer.

5.2.4 All metallic materials which could be exposed to hydrogen sulfide under probable operating conditions shall be highly resistant to sulfide stress cracking.

5.2.5 The maximum acceptable hardness for all preventer and valve bodies and spools shall be in accordance with NACE Std MR0175 or ISO 15156.

NOTE For the purposes of this provision, ISO 15156 is equivalent to NACE MR0175.

5.2.6 Ring-joint gaskets shall meet the requirements of API Spec 16A and be of the material and hardness specified in API 6A.

5.2.7 All bolts and nuts used in connection with flanges, clamps, and hubs shall be selected in accordance with provisions of API 6A.

5.2.8 All lines, crosses, valves, and fittings in the choke manifold system and the drill string safety valve shall be constructed from materials meeting applicable requirements of API 5L and API 6A.

5.2.9 Choke and kill hoses or flexible lines installed that permit entry of gas or hydrocarbons, shall meet the fire test requirements of API 16C (gas permeation and fire test properties).

5.2.10 With the exception of the drill string safety valves, the heat treating and other applicable requirements, in NACE MR0175 or ISO 15156 shall be implemented.

5.2.11 Field welding upstream of the chokes shall be kept to a minimum. If performed, original shop construction standards and procedures shall be implemented. All work processes, NDE inspection and testing shall be performed in accordance with the requirements of NACE MR0175 or ISO 15156.

5.2.12 Elastomeric components are also subject to hydrogen sulfide attack. Nitrile elastomeric components which meet other requirements can be suitable for hydrogen sulfide service provided drilling fluids are properly treated. Service life shortens rapidly as temperature increases from 150°F to 200°F

(65.6℃ to 93℃). In the event flowline temperatures in excess of 200℉ (93℃) are anticipated, the equipment manufacturer shall be consulted.

5.2.13 After drilling a well having more than a minimal content of H_2S, the rubber elements shall be replaced before drilling a new well.

5.2.14 Rubber elements shall be replaced if the BOP is activated and shut in for an emergency event during a sour well drilling operation or inspected and tested in accordance with equipment owner's maintenance program.

5.2.15 API 16A, Annex F, lists H_2S, CO_2, and hydrocarbon test mixtures which may be used to determine the hydrogen sulfide resistance of rubber. The test results are formulation/application specific and should not be generalized. The rubber to metal bond is often ignored in fluid test programs. Where a rubber compound is bonded to two different metals, i.e. in variable bore rams, the potential for galvanic corrosion exists. This type of corrosion can destroy rubber to metal bonds.

5.2.16 Changes prescribed by the equipment manufacturer to render equipment acceptable for service in a hydrogen sulfide environment shall be considered. The equipment manufacturer shall be consulted for any repairs or remanufacturing and replacement parts prior to the commencement of drilling operations.

6 Surface BOP Systems

6.1 Surface BOP Stack Arrangements

6.1.1 Surface BOP Stack Pressure Designations

6.1.1.1 Every installed ram BOP shall have, as a minimum, a working pressure equal to 500 psi (3.5 MPa) greater than the maximum anticipated surface pressure to be encountered.

6.1.1.2 Blowout preventer equipment is based on rated working pressures and designated as 2K, 3K, 5K, 10K, 15K, and 20K, and 25K as described in Table 1.

Table 1 — Surface BOP Pressure Designations

Pressure Designation	Rated Working Pressure
2K	2000 psi (13.8 MPa)
3K	3000 psi (20.7 Mpa)
5K	5000 psi (34.5 Mpa)
10K	10,000 psi (69.0 Mpa)
15K	15,000 psi (103.5 Mpa)
20K	20,000 psi (138.0 Mpa)
25K	25,000 psi (172.4 MPa)
NOTE 1 psi = 0.006894757 MPa.	

6.1.2 BOP Stack Classifications

6.1.2.1 The quantity of pressure containment sealing components in the vertical wellbore of a BOP stack shall be used to identify the classification or "class" for the BOP system installed. The designation Class 6 represents a combination of a total of six ram and/or annular preventers installed (e.g. two annular and four ram preventers or one annular and five ram preventers, in the case of the Class 6 described).

6.1.2.2 After the classifications of the BOP stack has been identified, the next nomenclature identifies the quantity of annular type preventers installed and designated by an alphanumeric designation (e.g. A2 identifying two annular preventers installed).

6.1.2.3 The final alphanumeric designation shall be assigned to the quantity of rams or ram cavities, regardless of their use, installed in the BOP stack. The rams or ram cavities shall be designated with an "R" followed by the numeric quantity of rams or ram cavities. (e.g. R4 designates that four ram type preventers are installed).

EXAMPLE A Class 6 BOP system installed with two annular and four ram type preventers is designated as "Class 6-A2-R4".

6.1.2.4 Annular preventers having a lower rated working pressure than ram preventers are acceptable.

6.1.2.5 A minimum of one set of blind rams shall be installed when ram type preventers are to be installed. This requirement shall apply to 3K or lesser-rated working pressure systems and a minimum Class 2 BOP stack arrangement.

6.1.2.6 For a 5K rated system, a minimum of a Class 3 stack arrangement, with one set of blind and pipe rams shall be installed. The third device may be a ram or annular type preventer, whichever is desired.

6.1.2.7 The minimum stack arrangement for Class 4 BOP's shall include one annular, one blind or blind shear and one pipe ram. The fourth device may be a ram or annular type preventer, whichever is desired.

6.1.2.8 Blind shear rams (minimum of one) capable of shearing the drill pipe in use and sealing, shall be installed on all BOP systems 10K and greater pressure rated system. A minimum Class 4 stack arrangement shall apply.

6.1.2.9 For 15K and greater pressure rated systems, a Class 5 BOP arrangement or greater shall be installed. The minimum requirements for a Class 5 BOP shall include one annular, two shear rams (at least one capable of sealing) and two pipe rams.

6.1.2.10 The minimum stack arrangement for Class 6 BOP's shall include one annular, two shear rams (at least one capable of sealing) and two pipe rams in the arrangement. The sixth device may be a ram, annular type preventer or test ram system, whichever is desired.

6.1.2.11 For all Class BOP arrangements, a risk assessment shall be performed to identify ram placements and configurations to be installed.

6.1.2.12 The kill line shall be the lowermost line connected to the BOP stack.

6.1.2.13 Rig-specific stack identifying nomenclature (choke line, kill line, rams, and annulars, etc.) shall be made part of the drilling program.

6.1.3 Ram Locks

Ram-type preventers shall be equipped with extension hand wheels or hydraulically operated locks.

6.1.4 Spare Parts

The following BOP spare parts (for the service intended) shall be carefully stored, maintained in accordance with OEM recommendations, and be readily available:

a) a complete set of ram sealing elements for each size and type of ram BOP being used;

b) a complete set of bonnet or door seals for each size and type of ram BOP being used;

c) plastic packing for BOP secondary seals;

d) ring gaskets to fit end connections;

e) a spare annular BOP packing element and a complete set of seals;

f) a flexible choke or kill line.

6.1.5 Replacement Assemblies Storage

6.1.5.1 When storing BOP metal parts and related equipment, the parts shall be coated and maintained with a protective coating to prevent rust.

6.1.5.2 The equipment manufacturer shall be consulted regarding replacement assemblies.

6.1.6 Drilling Spools

6.1.6.1 Choke and kill lines may be connected either to side outlets of the BOPs, or to a drilling spool installed below at least one BOP capable of closing on pipe.

6.1.6.2 Utilization of the BOP side outlets reduces the number of stack connections and overall BOP stack height. However, a drilling spool is used to provide stack outlets (to localize possible erosion in the less expensive spool) and to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations.

6.1.6.3 Drilling spools for BOP stacks shall meet the following minimum qualifications.

a) Pressure rated arrangements of 3K and 5K shall have two side outlets no smaller than a 2 in. (5.08 cm) nominal diameter and be flanged, studded, or hubbed. Pressure rated arrangements of 10K and greater shall have two side outlets, one 3 in. (7.62 cm) and one 2 in. (5.08 cm) nominal diameter as a minimum, and be flanged, studded, or hubbed.

b) Drilling spools shall have a vertical bore diameter the same internal diameter as the mating BOPs and at least equal to the maximum bore of the uppermost wellhead or wellhead assembly.

c) Drilling spools shall have a rated working pressure equal to the rated working pressure of the installed ram BOP.

6.1.6.4 For drilling operations, wellhead or wellhead assembly outlets shall not be employed for choke or kill lines.

6.2 Choke Manifolds, Choke Lines, and Kill Lines – Surface BOP Installations

6.2.1 General

6.2.1.1 The choke manifold, choke lines, and kill lines consist of high-pressure pipe, fittings, flanges, valves, and manual and/or hydraulic operated adjustable chokes. This manifold can bleed-off wellbore pressure at a controlled rate or can stop fluid flow from the wellbore completely, as required.

6.2.1.2 Choke and kill hoses or flexible lines installed that permit entry of gas or hydrocarbons, shall meet the fire test requirements of API 16C (gas permeation and fire test properties).

6.2.2 Installation Guidelines – Choke Manifold

6.2.2.1 Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) shall have a working pressure equal to or greater than the rated working pressure of the ram BOPs in use. This equipment shall be tested when installed in accordance with provisions of Section 8.

6.2.2.2 For working pressures of 3000 psi (20.7 MPa) and greater, flanged, welded, clamped, or other end connections that are in accordance with API 6A, shall be employed on components subjected to well pressure.

6.2.2.3 The choke manifold shall be placed in a readily accessible location, preferably outside the rig substructure.

6.2.2.4 Minimum nominal inside diameter for lines downstream of the chokes shall be equal to or greater than the nominal connection size of the chokes.

6.2.2.5 Lines downstream of the choke manifold are not required to contain the rated choke manifold pressure (see Section 8 for testing considerations).

6.2.2.6 Although not shown in the example equipment illustrations, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines. When buffer tanks are employed, provision shall be made to direct the flow path and to isolate a failure or malfunction.

6.2.2.7 All choke manifold valves shall be full bore and full opening.

6.2.2.8 Two valves shall be installed adjacent to the BOP stack for installations with rated working pressures of 5000 psi (34.5 MPa) and greater. One of these two valves shall be remotely controlled.

6.2.2.9 A minimum of one remotely operated choke shall be installed on all manifold systems rated 5000 psi (34.5 MPa).

6.2.2.10 A minimum of two remotely operated chokes shall be installed on manifold systems rated 10,000 psi (69.0 MPa) and greater.

6.2.2.11 Choke manifold configurations shall allow for re-routing of flow (in the event of eroded, plugged, or malfunctioning parts) without interrupting flow control.

6.2.2.12 Figure 1 through Figure 3 illustrate examples of choke manifolds for various working pressures. Additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges or measuring devices and/or manifolding of vent lines can be dictated by the conditions anticipated for a particular well.

6.2.2.13 Materials used in construction and installation shall be suitable for the expected in accordance API 16C.

6.2.2.14 The manifold and piping shall be protected from freezing by heating, draining, filling with fluid or other appropriate means.

6.2.2.15 Test pressure gauges and chart recorders or data acquisition systems shall be used and all testing results recorded. Analog pressure measurements shall be made at not less than 25 % and not more than 75 % of the full pressure span of the gauge.

6.2.2.16 It is acceptable for gauges used during the course of normal operations to read full scale and not serve as a test gauge.

6.2.2.17 Electronic pressure gauges and chart recorder or data acquisition systems shall be utilized within the manufacturer's specified range.

6.2.2.18 Pressure measurement devices shall be calibrated per OEM procedures annually.

6.2.2.19 Calibrations shall be traceable to a recognized national standard.

6.2.2.20 The choke control station, whether at the choke manifold or remote from the rig floor, shall be as convenient as possible and include all monitors necessary to furnish an overview of the well control situation.

NOTE The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, and pump strokes enhances the ability to control the well.

6.2.2.21 Power systems for remotely operated valves and chokes shall be sized to provide the necessary pressure and volume.

6.2.2.22 Any remotely operated valve or choke shall be equipped with an emergency backup power source.

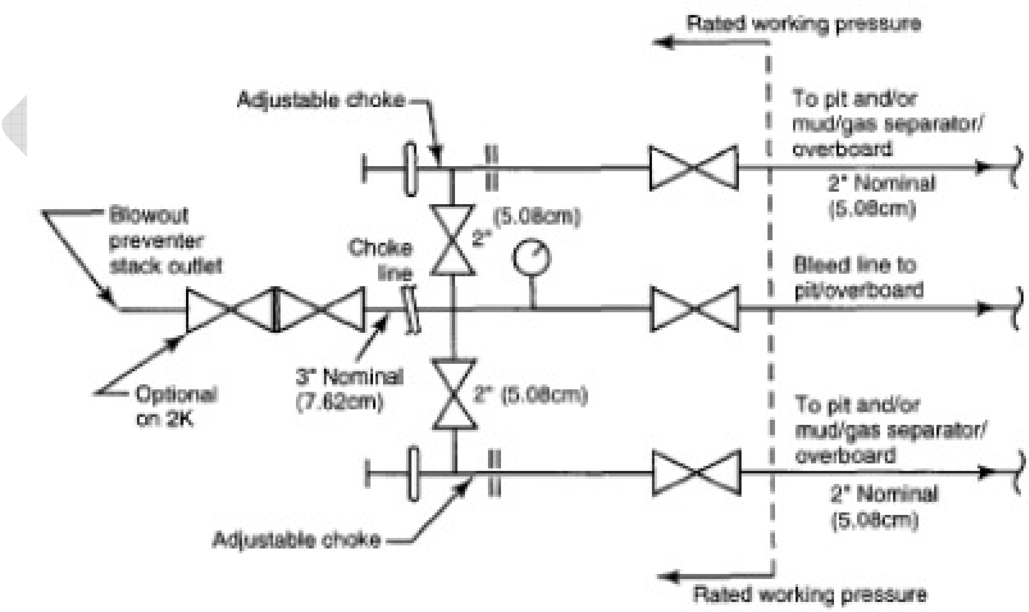


Figure 1 — Example Choke Manifold Assembly for 2K and 3K Rated Working Pressure Service – Surface BOP Installations

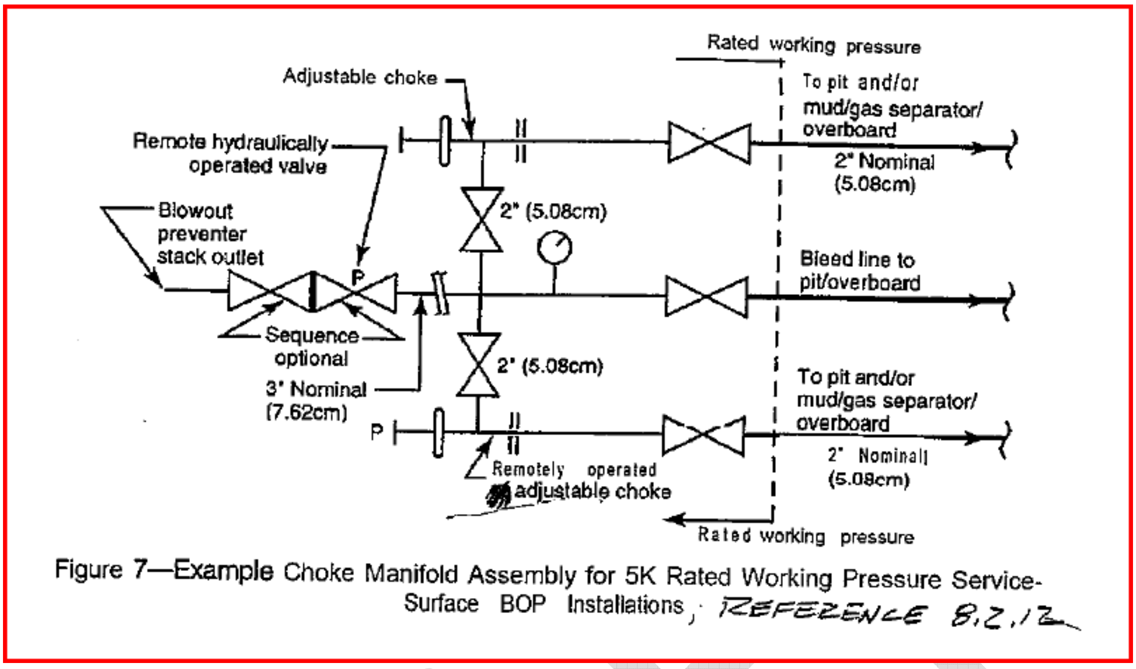


Figure 2 — Example Choke Manifold Assembly for 5K Rated Working Pressure Service – Surface BOP Installations

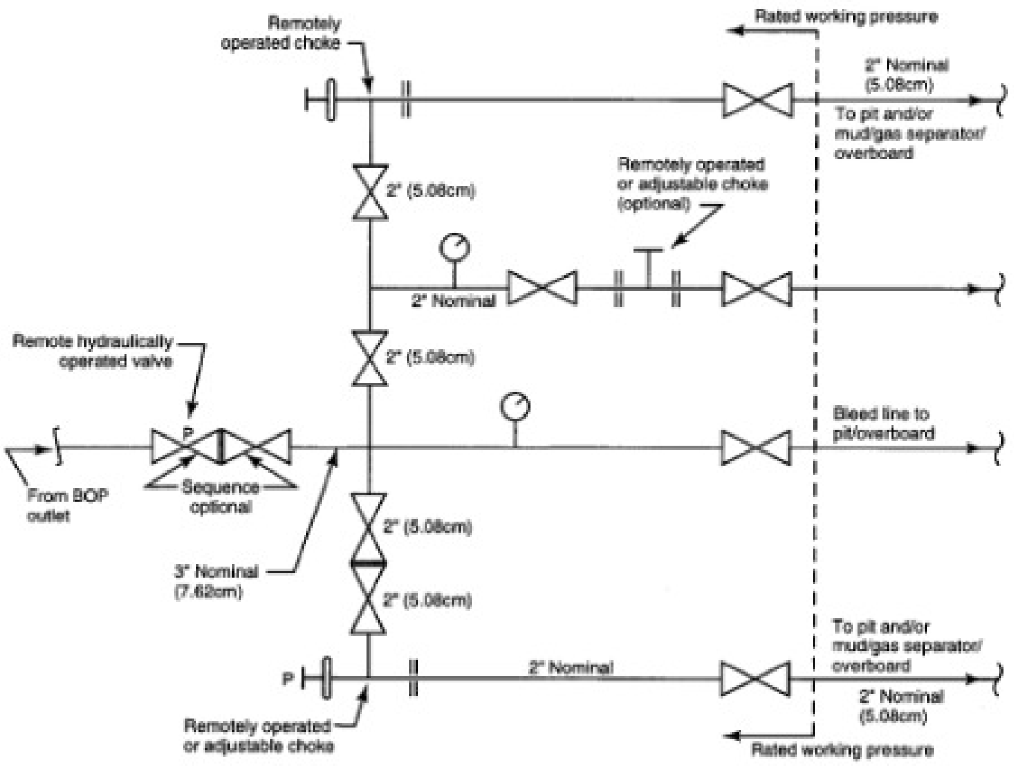


Figure 3 — Example Choke Manifold Assembly for 10K, 15K, and 20K Rated Working Pressure Service – Surface BOP Installations

6.2.3 Installation Guidelines – Choke Lines

6.2.3.1 General

The choke line connects the BOP to the choke manifold.

6.2.3.2 Choke Line Bends

6.2.3.2.1 Choke lines shall be as straight as possible. Because erosion at bends is possible during operations, flow targets shall be used at short radius bends and on block ells and tees. The degree to which pipe bends are susceptible to erosion depends on the bend radius, flow rate, flow medium, pipe wall thickness, and pipe material.

6.2.3.2.2 Ninety degree block ells and tees shall be targeted in both flow directions. Short radius pipe bends ($R/d < 10$) shall be targeted in the direction of expected flow where

R is the radius of pipe bend measured at the centerline in inches (centimeters).

d is the nominal diameter of the pipe in inches (centimeters).

6.2.3.2.3 For large radius pipe bends ($R/d > 10$), targets are generally unnecessary.

6.2.3.2.4 See API 16C for equipment-specific requirements for flexible choke lines and articulated line assemblies.

6.2.3.2.5 Consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration.

6.2.3.2.6 For articulated line assemblies, consult with the manufacturer's guidelines to determine the degree of relative movement allowable between end points.

6.2.3.3 Other Factors

6.2.3.3.1 Choke lines shall be firmly secured to withstand the dynamic effect of fluid flow and the impact of drilling solids. Supports and fasteners located at points where piping changes direction shall be capable of restraining pipe deflection. Special attention should be paid to the end sections of the line to prevent line whip and vibration.

6.2.3.3.2 Based on erosion velocity and other considerations, the choke line bore shall be sized in accordance with the following.

a) For 3K and 5K pressure rated systems, the minimum size for choke lines is 2 in. (5.08 cm) nominal diameter. For 10K, 15K, and 20K pressure rated systems, the minimum size is 3 in. (7.62 cm) nominal diameter.

b) For air or gas drilling operations, the minimum nominal diameter pipe size shall be 4 in. (10.16 cm) nominal diameter.

c) The bleed line (the line that bypasses the chokes) shall be at least equal in nominal diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum backpressure. It also permits high volume bleed-off of well fluids to relieve casing pressure with the preventers closed.

6.2.4 Installation Guidelines – Kill Lines

6.2.4.1 General

The kill line connects the drilling fluid pumps to a side outlet on the BOP stack and provides a means of pumping into the wellbore when the normal method of circulating down through the kelly or drill pipe cannot be employed. Figure 4, Figure 5, and Figure 6 illustrate example kill line installations for various working pressure service.

6.2.4.2 Kill Line Bends

6.2.4.2.1 Kill lines shall be as straight as possible. Because erosion at bends is possible during operations, flow targets shall be used at short radius bends and on block ells and tees. The degree to which pipe bends are susceptible to erosion depends on the bend radius, flow rate, flow medium, pipe wall thickness, and pipe material.

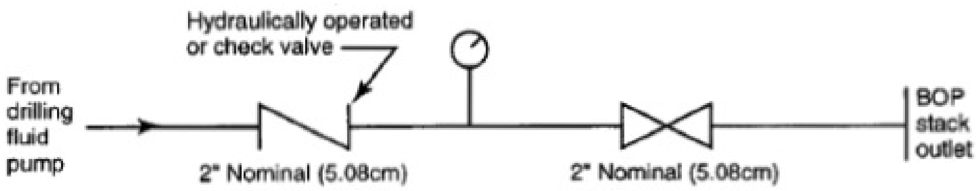
6.2.4.2.2 Ninety-degree block ells and tees shall be targeted in both flow directions. Short radius pipe bends (R/d < 10) shall be targeted in both flow directions where:

R is the radius of pipe bend measured at the centerline in inches (centimeters).

d is the nominal diameter of the pipe in inches (centimeters).

6.2.4.2.3 For large radius pipe bends (R/d > 10), targets are generally unnecessary.

6.2.4.2.4 See API 16C for equipment specific requirements for flexible kill lines, and articulated line assemblies. Consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration. For articulated line assemblies, consult the manufacturer's guidelines to determine the degree of relative movement allowable between end points.



NOTE Threaded connections optional for 2K-rated working pressure service.

Figure 4 — Example Kill Line Assembly for 2K and 3K Rated Working Pressure Service – Surface BOP Installations

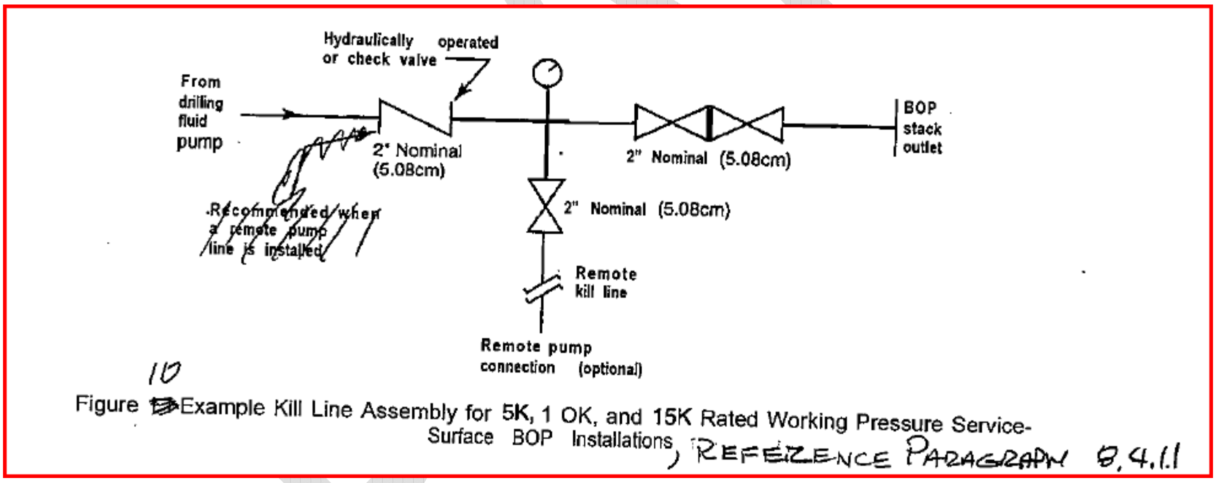


Figure 5 — Example Kill Line Assembly for 5K, 10K , and 15K Rated Working Pressure Service – Surface BOP Installations

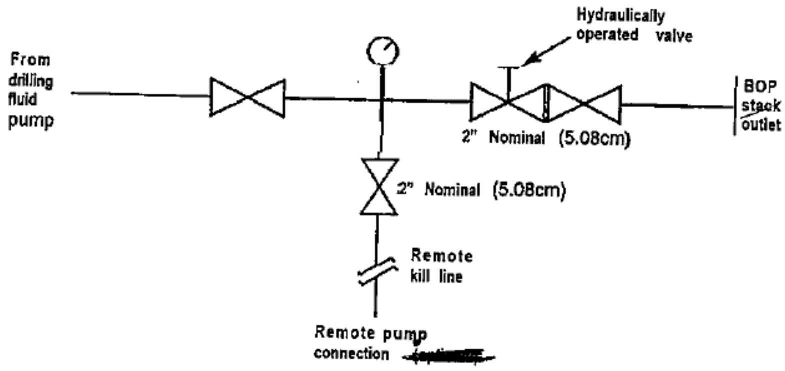


Figure ~~12~~ 11—Example Kill Line Assembly for 5K, 1 OK, and 15K Rated Working Pressure Service-Surface BOP Installations, REFERENCE PARAGRAPH 8.4.1.1

Figure 6 — Example Kill Line Assembly for 5K, 10K, and 15K Rated Working Pressure Service – Surface BOP Installations

6.2.4.3 Other Considerations – Kill Lines

6.2.4.3.1 The location of the stack kill line connection depends on the particular configuration of BOPs and spools employed but shall be below the lowermost ram-type BOP.

6.2.4.3.2 On selective high-pressure, critical wells a remote kill line is commonly employed to permit use of an auxiliary high-pressure pump if the rig pumps become inoperative or inaccessible. This line is normally connected to the kill line near the BOP stack and extended to an auxiliary high-pressure pump at a location affording maximum safety and accessibility.

6.2.4.3.3 The same guidelines that govern the installation of choke manifolds and choke lines apply to kill line installations. See Figures 1, 2, and 3 for examples of choke and kill manifolds installations at various rated working pressures and API 16C for equipment specifications for kill lines.

6.2.4.3.4 Periodic operation, inspection, testing, and maintenance shall be performed on the same schedule as employed for the BOP stack in use.

6.2.4.3.5 Materials used in construction and installation shall be suitable for the expected range of temperature exposure.

6.2.4.3.6 The kill line shall be protected from freezing by heating, draining, filling with appropriate fluid or other appropriate means.

6.2.4.3.7 The kill line shall not be used as a fill-up line during normal drilling operations.

6.2.5 Maintenance – Choke Manifold, Choke Lines, Kill lines

Maintenance shall be performed on the same schedule employed for the BOP in use and shall include checks for wear, erosion and plugged or damaged lines. Frequency of maintenance will depend upon usage. See Section 8 for testing, inspection, and general maintenance of kill manifold systems.

6.2.6 Spare Parts – Choke Manifold, Choke Lines, Kill Lines

The following spare parts (for the service intended) shall be properly stored, maintained in accordance with OEM recommendations and be readily available:

a) a one complete valve for each size installed;

b) two repair kits for each valve size utilized;

c) any part required for operation such as hose, flexible tubing, electrical cable, pressure gauges, small control line valves, fittings, and electrical components.

6.3 Control Systems for Surface BOP Stacks

6.3.1 General

6.3.1.1 Control systems for surface BOP stacks shall be designed and manufactured in accordance with API 16D.

6.3.1.2 The purpose of the BOP Control System is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

6.3.1.3 BOP control systems for surface installations (land rigs, offshore jackups, and platforms) provide hydraulic power fluid in a return-to-tank circuit as the actuating medium.

6.3.1.4 The individual control is typically provided by directional valve mounted on the Hydraulic Control Manifold, but may also be provided by a pilot signal to a directional control valve mounted on the stack equipment in a valve pod.

6.3.1.5 The minimum required components of the BOP control system shall include:

a) control fluid

b) control fluid reservoir

c) control fluid mixing system

d) pump systems

e) accumulator system

f) control system valves, fittings and components

g) control stations

6.3.2 Control Fluid

6.3.2.1 A suitable control fluid (hydraulic oil or fresh water containing a lubricant) shall be used as the control system operating fluid.

6.3.2.2 Control fluid shall be selected and maintained to meet minimum OEM properties and equipment owner requirements.

6.3.2.3 Water-based hydraulic fluids are typically used and are a mixture of potable water and a water-soluble lubricant additive. These fluids are available in concentrated or pre-mixed form.

6.3.2.4 Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32°F (0°C) are anticipated.

6.3.2.5 Diesel oil, kerosene, motor oil, chain oil, or any other similar fluid shall not be used as a control fluid because of the possibility of explosions or resilient seal damage.

6.3.3 Control Fluid Reservoir

6.3.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

6.3.3.2 To prevent over-pressurization, vents shall be inspected and maintained to insure they are not plugged or capped.

6.3.3.3 Batch mixing fluid is acceptable, or filling the reservoir with hydraulic fluid not requiring mixing is also acceptable.

6.3.3.4 All reservoir instrumentation shall be tested in accordance with equipment owner maintenance program to insure they are in proper working order.

6.3.3.5 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner maintenance program to insure indication of fluid level in each of the individual reservoirs are in proper working order.

6.3.4 Control Fluid Mixing System

6.3.4.1 The control fluid mixing system shall be tested to insure proper functionality of the automatic operating system.

6.3.4.2 The automatic mixing system should be tested to insure it is manually selectable over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

6.3.4.3 A manual override of the automatic mixing system should be tested to insure proper operation.

6.3.5 Pump Systems

6.3.5.1 A pump system consists of one or more pumps.

6.3.5.2 Each pump system shall have an independent power source, such as electric or air.

6.3.5.3 At least one pump system shall be available at all times.

6.3.5.4 With the accumulators isolated from service and with one pump system or one power system out of service, the remaining pump system(s) shall have the capacity, within two minutes to:

a) close the annular BOP and,

b) open the hydraulically operated choke valve(s) and,

c) provide the minimum operating pressure recommended by the manufacturer to close the annular and effect a seal on the minimum diameter drill pipe in use, or open the hydraulically operated choke valve(s), whichever is greater.

6.3.5.5 The same pump system(s) may be used to provide control fluid to control both the BOP stack and the diverter system.

6.3.5.6 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure.

6.3.5.7 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system rated working pressure and automatically stop between 97-100% of the system rated working pressure.

6.3.5.8 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system rated working pressure and automatically stop between 95-100% of the system rated working pressure.

6.3.5.9 Air pumps shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

6.3.5.10 Each pump system shall be protected from over pressurization by a minimum of two devices:

— one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed the working pressure of the control system;

— the second device, such as a certified relief valve, to limit the pump discharge pressure and flow in accordance with API 16D.

6.3.5.11 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

6.3.5.12 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

6.3.6 Hydraulic Control Unit Location

6.3.6.1 The hydraulic control unit shall be located in a safe place that is easily accessible to rig personnel in an emergency.

6.3.6.2 It shall be located to prevent excessive drainage or flow back from the operating lines to the reservoir.

6.3.6.3 If the accumulator banks are located a substantial distance from or below the BOP stack, additional reservoir volume or alternative means shall be provided to compensate for flow back in the closing lines.

6.3.7 Accumulator Systems

6.3.7.1 General

6.3.7.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions.

6.3.7.2 This is achieved by the hydraulic compression of an inert gas with the hydraulic power unit (HPU).

6.3.7.3 Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

6.3.7.4 Inert gas shall be used for pre-charging of surface accumulators.

6.3.7.5 The accumulators typically used in surface control systems are bladder type, which uses a flexible diaphragm to provide separation of the inert gas from the hydraulic fluid.

6.3.8 Accumulator Drawdown Test

6.6.2.1 The accumulator system shall be capable of, with pumps inoperative, performing the accumulator drawdown test (see worksheet Annex A), consisting of closing from a full open position at zero (0) wellbore pressure:

— the largest volume annular BOP and

— four smallest volume ram type BOPs with

— the remaining system pressure at least 200 psi above the precharge pressure.

6.3.9 Control System Response Time

6.3.9.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

6.3.9.2 Measurement of closing response time begins when the close function is activated at any control panel and ends when the BOP or valve is closed affecting a seal.

6.3.9.3 A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting.

6.3.9.4 The BOP control system shall be capable of closing each ram BOP within 30 seconds.

6.3.9.5 Closing time shall not exceed 30 seconds for annular BOPs smaller than 18 3/4 inch nominal bore and 45 seconds for annular preventers of 18 3/4 inch nominal bore and larger.

6.3.9.6 Response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

6.3.10 Accumulator Precharge

6.3.10.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions.

6.3.10.2 The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

6.3.10.3 The precharge pressure shall be per original OEM design, but not to exceed the rated working pressure of the accumulator.

6.3.10.4 Rapid discharge for dedicated shear systems shall take into account temperature affects on the precharge gas, see example Annex B.

6.3.10.5 The precharge pressure on each accumulator bottle shall be measured prior to each BOP stack installation on each well and adjusted if necessary.

6.3.11 Accumulators, Valves, Fittings, and Pressure Gauges Requirements

6.6.11.1 The precharge pressure for bladder type accumulators shall be greater than 25% of the system rated working pressure, to prevent damage to the bladder.

6.6.11.2 Bladder and float type accumulators shall be mounted in a vertical position.

6.6.11.3 A pressure gauge for measuring the accumulator precharge pressure shall be available for installation at any time.

6.6.11.4 Those pressure gauges shall be calibrated to 1% of full scale, and used to not less than 25 percent or more than 75 percent of the full pressure span of the gauge.

6.6.11.5 No accumulator bottle shall be operated at a pressure greater than its rated working pressure.

6.6.11.6 Supply-pressure isolation valves and bleed-down valves shall be provided on each accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

6.3.12 Control System Valves, Fittings and Components

6.3.12.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a working pressure at least equal to the rated working pressure of the control system.

6.3.12.2 Conformity of Piping Systems

6.3.12.1.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

6.3.12.1.2 Pipe, pipe fittings and components shall conform to specifications of ASME B31.3.

6.3.12.1.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

6.3.12.1.4 Welding shall be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with ASME Boiler and Pressure Vessel Code, Section IX.

6.3.12.1.5 All rigid or flexible lines between the control system and BOP stack shall meet the fire test requirements of API 16D, including end connections, and shall have rated working pressure equal to the rated working pressure of the BOP control system.

6.3.12.1.6 All control system interconnect piping, tubing, hose, linkages, etc., shall be protected from damage during drilling operations, and day-to-day equipment movement.

6.3.12.1.7 The control system shall be equipped to allow isolation of both the pumps and the accumulators from the manifold and annular control circuits, thus allowing maintenance and repair work.

6.3.12.1.8 The control system shall be equipped and maintained with measurement devices to indicate

a) accumulator pressure,

b) regulated manifold pressure,

c) regulated annular pressure, and

d) air supply pressure.

6.3.12.1.9 The control system shall be equipped with a pressure-regulating valve to permit manual control of the annular preventer operating pressure.

6.3.12.1.10 The control system shall be equipped with a regulating valve to control the operating pressure on the ram BOPS.

6.3.12.1.11 The control unit shall be equipped with a bypass valve to allow full accumulator pressure to be applied on the manifold.

6.3.12.1.12 Manually operated control valves must be clearly marked to indicate which function(s) each operates, and the position of the valves (e.g. open, closed, etc).

6.3.12.1.13 The control valve handle that operates the blind rams shall be protected to avoid unintentional operation, but still allow full operation from the remote panel without interference.

6.3.12.1.14 All control system analog pressure gauges shall be calibrated to 1% of full scale at least every three (3) years.

6.3.12.1.15 Analog gauges shall be used at not less than 25 % or more than 75 % of the full pressure span of the gauge.

6.3.12.1.16 Electronic pressure measurement devices shall be accurate to 1% and utilized within the manufacturer's specified range.

6.3.13 Control Stations

6.3.13.1 The control system shall be equipped with two control stations for operation of BOP functions.

6.3.13.2 One control station shall be controlled from a position readily accessible to the driller and the other a safe distance from the rig floor.

6.4 Auxiliary Equipment-Surface BOP Installations

6.4.1 Kelly Valves

An upper kelly valve is installed between the swivel and the kelly. A lower kelly valve is installed immediately below the kelly.

6.4.2 Drill Pipe Safety Valve

A spare drill pipe safety valve should be readily available (i.e., stored in open position with wrench accessible) on the rig floor at all times. This valve or valves should be equipped to screw into any drill string member in use. The outside diameter of the drill pipe safety valve should be suitable for running into the hole.

6.4.3 Inside Blowout Preventer

An inside blowout preventer, drill pipe float valve, or drop-in check valve should be available for use when stripping the drill string into or out of the hole. The valve(s), sub(s), or profile nipple should be equipped to screw into any drill string member in use.

6.4.4 Field Testing

The kelly valves, drill pipe safety valve, and inside blowout preventer should be tested in accordance with Table 2 and Table 3.

6.4.5 Drill String Float Valve

6.4.5.1 A float valve is placed in the drill string to prevent upward flow of fluid or gas inside the drill string. The float valve is a special type of backpressure or check valve. A float valve in good working order will prohibit backflow and a potential blowout through the drill string.

6.4.5.2 The drill string float valve is usually placed in the lowermost portion of the drill string, between two drill collars or between the drill bit and drill collar. Since the float valve prevents the drill string from being filled with fluid through the bit as it is run into the hole the drill string must be filled from the top, at the drill floor, to prevent collapse of the drill pipe. The two types of float valves are described in the following.

a) The flapper-type float valve offers the advantage of having an opening through the valve that is approximately the same inside diameter as that of the tool joint. This valve will permit the passage of balls, or go-devils, which may be required for operation of tools inside the drill string below the float valve.

b) The spring-loaded ball, or dart, and seat float valve offers the advantage of an instantaneous and positive shut-off of backflow through the drill string.

6.4.5.3 These valves are not full-bore and thus cannot sustain long duration or high volume pumping of drilling fluid or kill fluid. However, a wireline retrievable valve that seals in a profiled body that has an opening approximately the same inside diameter as that of the tool joint may be used to provide a full-open access, if needed.

6.4.6 Trip Tank

A trip tank is a low-volume, (100 barrel (15.9 m^3) or less), calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well. A trip tank may be of any shape, provided the capability exists for reading the volume contained in the tank at any liquid level. The readout may be direct or remote, preferably both. The size and configuration of the tank should be such that volume changes approximately one-half barrel can be easily detected by the readout arrangement. Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations.

Other uses of the trip tank include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following a cement job, calibrating drilling fluid pumps, etc. The trip tank is also used to measure the volume of drilling fluid bled from or pumped into the well as pipe is stripped into or out of the well.

6.4.7 Pit Volume Measuring and Recording Devices

Automatic pit volume measuring devices are available which transmit a pneumatic or electric signal from sensors on the drilling fluid pits to recorders and signaling devices on the rig floor. These are valuable in detecting fluid gain or loss.

6.4.8 Flow Rate Sensor

A flow rate sensor mounted in the flow line is recommended for early detection of formation fluid entering the wellbore or a loss of returns.

6.4.9 Poor Boy Degasser

The poor boy degasser is used to separate gas from drilling fluid that is gas cut. The separated gas can then be vented to a safe distance from the rig. Generally, two basic types of mud gas separators are in use. The most common type is the atmospheric poor boy degasser, sometimes referred to as a gas buster or mud/gas separator. Another type of poor boy degasser is designed such that it can be operated at moderate backpressure, usually less than 100 psi (0.69 MPa), although some designs are operated at gas vent line pressure which is atmospheric plus line friction drop. All separators with a liquid level control may be referred to as pressurized poor boy separators. Both the atmospheric and pressurized poor boy degasser have advantages and disadvantages. Some guidelines are common to both types of poor boy degassers. A bypass line to the flare stack must be provided in case of malfunction or in the event the capacity of the poor boy degasser is exceeded. Precautions must also be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the wall of the vessel. Provisions must be made for easy clean out of the vessels and lines in the event of plugging. Unless specifically designed for such applications, use of the rig poor boy degasser is not recommended for well production testing operations.

The dimensions of a separator are critical in that they define the volume of gas and fluid a separator can effectively handle.

6.4.10 Degasser

A degasser may be used to remove entrained gas bubbles in the drilling fluid that are too small to be removed by the poor boy separator. Most degassers make use of some degree of vacuum to assist in removing this entrained gas. The drilling fluid inlet line to the degasser should be placed close to the drilling fluid discharge line from the poor boy separator to reduce the possibility of gas breaking out of the drilling fluid in the pit.

6.4.11 Flare Lines

All flare lines should be as long as practical with provisions for flaring during varying wind directions. Flare lines should be as straight as possible and should be securely anchored.

6.4.12 Standpipe Choke

An adjustable choke mounted on the rig standpipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed-off pressure between BOPs during stripping operations. See Figure 7 for an example standpipe choke installation.

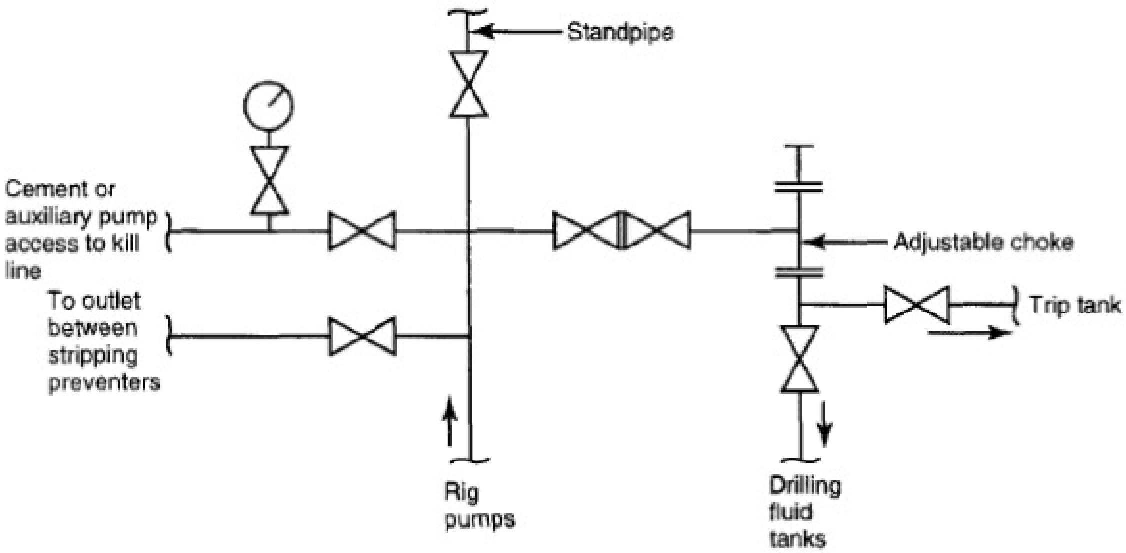


Figure 7 — Example Standpipe Choke Installation

6.4.13 Top Drive Equipment

There are two ball valves (sometimes referred to as kelly valves or kelly cocks) located on top drive equipment. The upper valve is air or hydraulically operated and controlled at the driller's console. The lower valve is a standard ball kelly valve (sometimes referred to as a safety valve) and is manually operated, usually by means of a large hexagonal wrench. Generally, if it becomes necessary to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the top drive valves. However, flow up the drill pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions:

a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve;

b) most top drive manual valves cannot be stripped into 7 5/8 in. (19.37 cm) or smaller casing;

c) once the top drive's manual valve is disconnected from the top drive, another valve or spacer shall be installed to take its place.

6.5 Inspection, Maintenance, and Testing — Surface BOP Systems

6.5.1 Purpose

The purposes for various field test programs on drilling well control equipment are to verify

a) that specific functions are operationally ready,

b) the pressure integrity of the installed equipment, and

c) the control system and BOP compatibility.

6.5.2 Types of Tests

6.5.2.1 General

Test programs incorporate visual inspections, functional operations, pressure tests, maintenance practices, and drills. Descriptions of these basic types of tests are provided in 6.5.2.2 through 6.5.2.5.

6.5.2.2 Inspection Test

The common collective term used to state the various procedural examination of flaws that can influence equipment performance. These inspection tests may include, but are not limited to visual, dimensional, audible, hardness, functional, and pressure tests. Inspection practices and procedures vary and are outside the scope of this document.

6.5.2.3 Function Test

A function test is the operation of a piece of equipment or a system to verify its intended operation. Function testing may or may not include pressure testing.

6.5.2.4 Pressure Test

A pressure test is the periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system.

6.5.2.5 Hydraulic Operator Test

6.5.2.5.1 A hydraulic operator test is the application of a pressure test to any hydraulic operated component of hydraulic-actuated equipment. Hydraulic operator tests are specified by the OEM or equivalent.

6.5.2.5.2 Site-specific applications of the different types of tests on well control equipment should be incorporated during field acceptance tests, initial rig-up tests, drills, periodic operating tests, maintenance practices, and drilling and/or completion operations.

6.5.2.5.3 Techniques and step-by-step or how-to-test procedures shall be developed for each rig because of the varying equipment, different installation arrangements and well-specific drilling and/or completion programs.

6.5.2.5.4 Pressure test programs for the wellhead and casing should be prescribed by the lease operator on an individual well basis.

6.5.2.5.5 Manufacturer operating and maintenance documents, contractor or equipment owner's maintenance programs, and operating experiences shall be incorporated into the site-specific test procedures.

6.5.2.6 Crew Drills

The proficiency with which drilling crews operate the well control equipment is as significantly important as the operational condition of the equipment. Crew drills and well control rig practices are outside the scope of this document and are addressed in API 59.

6.5.2.7 Crew Competency

Maintenance and testing shall be performed or supervised by a competent person(s).

6.5.3 Test Criteria

6.5.3.1 Function Tests

6.5.3.1.1 As operations allow, all operational components of the BOP equipment systems shall be function tested at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

6.5.3.1.2 Function tests shall be alternated weekly from the driller's panel and from remote panels where all BOP functions are included (see sample worksheets in Annex A).

6.5.3.1.3 Remote panels where all BOP functions are not included should be function tested upon the initial test and monthly there-after.

6.5.3.1.4 Actuation times shall be recorded in a database for evaluating trends (see sample worksheets in Annex A).

6.5.3.1.5 Release or latching type components of well control systems (choke, kill, riser, wellhead connectors, etc.) and emergency or secondary systems are typically only functioned at the start or completion of the well.

6.5.3.2 Pressure Tests

6.5.3.2.1 All blowout prevention components that can be exposed to well pressure shall be tested first to a low pressure of 200 psi to 300 psi (1.38 MPa to 2.1 MPa) and then to a high pressure.

6.5.3.2.2 When performing the low-pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure can initiate a seal that can continue to seal after the pressure is lowered, therefore misrepresenting a low-pressure condition.

6.5.3.2.3 A stable low test pressure shall be maintained for at least five (5) minutes.

6.5.3.2.4 The initial high-pressure test on components that could be exposed to well pressure (BOP stack, choke manifold, and choke/kill lines) shall be to the rated working pressure of the ram BOPs, 500 psi (3.5 MPa) above MASP, or to the rated working pressure of the wellhead that the stack is installed on, whichever is lower.

6.5.3.2.5 Initial pressure tests are defined as those tests that should be performed on location before the well is spudded or before the equipment is put into operational service.

6.5.3.2.6 Annular BOPs, with a joint of drill pipe installed, shall be tested to the test pressure applied to the pipe ram preventers, or to a minimum of 70 % of the annular preventer working pressure, whichever is less.

6.5.3.2.7 The lower kelly valves, kelly, kelly cock, drill pipe safety valves, inside BOPs and top drive safety valves, shall be tested with water pressure applied from below to a low pressure and to the rated working pressure, or 500 psi (3.5 MPa) above MASP, whichever is lower.

6.5.3.2.8 There can be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these shall be covered in the site-specific well control pressure test program.

6.5.3.2.9 Subsequent high-pressure tests on the well control components shall be to a minimum pressure of 500 psi (3.5 MPa) above the maximum anticipated surface pressure, but not to exceed the working pressure of the ram BOPs or wellhead. The maximum anticipated surface pressure shall be determined by the operator based on specific anticipated well conditions.

6.5.3.2.10 Annular BOPs, with a joint of drill pipe installed, shall be tested to a minimum of 70 % of their working pressure, wellhead rated working pressure, or to the test pressure of the ram BOPs, whichever is less.

6.5.3.2.11 A stabilized high test pressure shall be maintained for at least five (5) minutes with no visible leaks.

6.5.3.2.12 With larger size annular BOPs some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This packer creep movement should be considered when monitoring the pressure test of the annular.

6.5.3.2.13 Pressure shall be released only through pressure release lines and bleed valves.

6.5.3.2.14 Where possible, the return volume measured to confirm all pressure has been bled off. Where this is not possible, extreme caution shall be taken to ensure pressure is bled off safely.

6.5.3.2.15 Pressure test operations shall be alternately controlled from the various control stations.

6.5.3.2.16 All pressure tests on hydraulic chambers of annular or ram-type preventers shall be tested to the maximum operating pressure of the component, or as recommended by the manufacturer.

6.5.3.2.17 The hydraulic chamber tests shall be performed on both the opening and the closing chambers of the equipment installed and shall be documented.

6.5.3.2.18 Pressure shall be stabilized for at least five (5) minutes. Subsequent pressure tests shall be performed on hydraulic chambers upon the next installation or in accordance with th equipment owner's preventative maintenance program.

6.5.3.2.19 The initial pressure test on the closing unit valves, manifolds, gauges, and BOP hydraulic control lines shall be to the rated working pressure (RWP) of the control unit. Subsequent pressure tests of closing unit systems shall be performed following the disconnection or repair of any operating pressure containment seal in the BOP control system, but limited to the affected component.

6.5.3.2.20 All valves (except check valves) shall be low and high pressure tested in the direction of flow. Valves that are required to seal against flow from both directions shall be tested from both directions.

6.5.3.2.21 Check valves installed on the kill line shall be low and high pressure tested in the opposite direction of flow.

6.5.3.2.22 Drifting the BOP shall be performed upon completion of the initial BOP test on the wellhead assembly. This may be achieved using the test plug, wear bushing tools, or other large bore tools. Subsequent drifting shall be determined by the equipment owner's maintenance program or well specific operations.

6.5.3.3 Pressure Test Frequency

Pressure tests on the well control equipment should be conducted as follows:

a) prior to spud or upon installation;

b) after the disconnection or repair of any pressure containment seal in the BOP stack, choke line, or choke manifold, but limited to the affected component;

c) in accordance with the equipment owner's preventative maintenance program;

d) not to exceed 21 days.

Table 2 and Table 3 include a summary of the test practices for surface BOP stacks and related well control equipment.

6.5.3.4 Test Fluids

6.5.3.4.1 Well control equipment shall be pressure tested with water or water with addtives.

6.5.3.4.2 Air should be removed from the system before test pressure is applied.

6.5.3.4.3 Control systems and hydraulic chambers shall be tested using clean control system fluids with lubricity and corrosion additives for the intended service and operating temperatures.

6.5.3.5 Pressure Measurement Devices

6.5.3.5.1 Pressure gauges and chart recorders or data acquisition systems shall be used and all testing results shall be recorded.

6.5.5.3.2 Analog pressure measurements shall be made at not less than 25 % and not more than 75 % of the full pressure span of the gauge.

6.5.3.5.3 Electronic pressure gauges and chart recorder or data acquisition systems shall be utilized within the manufacturer's specified range.

6.5.3.5.4 Pressure measurement devices shall be calibrated per OEM procedures annually. Calibrations shall be traceable to a recognized national standard.

Table 2 — Pressure Test Practices, Surface BOP Systems, Initial Test

Component to be Tested	Recommended Pressure Test - Low Pressure [a] psi (MPa)	Recommended Pressure Test - High Pressure [b,c] psi (MPa)
Annular preventer	200 to 300 (1.38 to 2.1)	Minimum of 70% of annular BOP working pressure
Operating chambers	Upon installation or in accordance with PM program	Minimum of 1500 (10.3)
Ram preventers		RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Fixed pipe	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Variable bore	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Blind/blind shear	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Operating chamber	Upon installation or in accordance with PM program	Maximum operating pressure recommended by the ram BOP manufacturer.
Choke and kill lines and valves	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Operating chamber	Upon installation or in accordance with PM program	Maximum operating pressure recommended by the valve manufacturer
Choke Manifold		
Upstream of last high-pressure valve	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower.
Downstream of last high-pressure valve	200 to 300 (1.38 to 2.1)	RWP of system downstream of last high-pressure valve
Adjustable chokes	Function test only	Verification of back-up system
BOP control system		
Manifold and BOP lines	N/A	Control system maximum operating pressure
Accumulator pressure	Verify precharge	N/A
Close time	Function test	N/A
Pump capability	Function test	N/A
Control stations	Function test	N/A
Safety valves		
Kelly, kelly valves, and floor safety valves	200 to 300 (1.38 to 2.1)	RWP of components or 500 psi (3.5 MPa) above MASP
Auxiliary Equipment		
Poor boy degasser	Visual and NDE inspection	Flow test
Trip tank, flo-show, etc.	Visual and manual verification	Flow test

NOTE Upon installation or in accordance with the equipment owner's preventative maintence program.

[a] The low-pressure test shall be stabilized for at least five (5) minutes with no visible leaks. Flow-type test shall be of sufficient duration to observe for significant leaks.

[b] The high-pressure test shall be stabilized for at least five (5) minutes with no visible leaks.

[c] Well control equipment may have a higher rated working pressure than required for the well site. The site-specific test requirements shall be used for these situations.

Table 3 — Pressure Test Practices, Land and Bottom-Supported Rigs, Subsequent Tests

Component to be Tested	Recommended Pressure Test - Low Pressure [a] psi (MPa)	Recommended Pressure Test - High Pressure [b] psi (MPa)
Annular preventer	200 to 300 (1.38 to 2.1)	Lesser of 70% of annular RWP, RWP of wellhead, or ram preventer test pressure
Ram preventers		
Fixed pipe	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Variable bore	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Blind/blind shear	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Casing rams (prior to running casing)	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Choke and kill lines and valves	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Choke Manifold		
Upstream of last high-pressure valve	200 to 300 (1.38 to 2.1)	RWP of ram BOPs, 500 psi (3.5 MPa) above MASP or RWP of the wellhead system, whichever is lower
Downstream of last high-pressure valve	200 to 300 (1.38 to 2.1)	RWP of system downstream from last high-pressure valveGreater than the maximum anticipated surface shut-in pressure
Adjustable choke	During choke drill	Verification of back-up system
BOP control system		
Manifold and BOP lines	Function test in accordance with equipment owners' PM program	In accordance with equipment owner's PM program
Accumulator pressure	Function test in accordance with equipment owners' PM program	
Close time	Function test in accordance with equipment owners' PM program	
Pump capability	Function test in accordance with equipment owners' PM program	
Control stations	Verify functionality of back-up systems	
Safety valves		
Kelly, kelly valves, and floor safety valves	200 to 300 (1.38 to 2.1)	RWP of components or 500 psi (3.5 MPa) above MASP
Auxiliary Equipment		
Poor boy degasser	Optional flow test	N/A
Trip tank, flo-show, etc.	Visual and manual verification	Daily
Subsequent tests shall not exceed 21 days (for wellbore testing) and/or in accordance with the owner's preventative maintenance program.		

[a] The low-pressure test shall be stabilized for at least five (5) minutes with no visible leaks. Flow-type test shall be of sufficient duration to observe for significant leaks.

[b] The high-pressure test shall be stabilized for at least five (5) minutes with no visible leaks.

6.5.3.6 Test Documentation

6.5.3.6.1 The results of all BOP equipment pressure and function tests shall be documented (see worksheet in Annex A).

6.5.3.6.2 Pressure tests shall be performed with a pressure chart recorder or equivalent data acquisition system and signed by pump operator, contractor's representative, and operating company representative.

6.5.3.6.3 Problems observed during testing and any actions taken to remedy the problems shall be documented.

6.5.3.6.4 Manufacturers shall be informed of well control equipment that fails to perform in the field (see API 16A.)

6.5.3.7 General Testing Considerations

6.5.3.7.1 All personnel shall be alerted when pressure test operations are to be conducted and when testing operations are underway.

6.5.3.7.2 Only designated personnel shall enter the test area to inspect for leaks when the equipment involved is under pressure.

6.5.3.7.3 Tightening, repair, or any other work shall be done only after verification that the pressure has been released and all parties have agreed that there is no potential of trapped pressure.

6.5.3.7.4 All lines and connections that are used in the test procedures shall be adequately secured.

6.5.3.7.5 All fittings, connections and piping used in pressure testing operations shall have pressure ratings greater than the maximum anticipated test pressure.

6.5.3.7.6 The type, pressure rating, size, and end connections for each piece of equipment to be tested shall be verified as documented by permanent markings on the equipment or by records that are traceable to the equipment.

6.5.3.7.7 When a BOP stack is tested on the wellhead, a procedure shall be available to monitor pressure on the casing if the test plug leaks.

6.5.3.7.8 Regulators used for control of BOP and diverter systems shall be unaffected by loss of signal.

6.5.3.7.9 Verification tests of the remote and main control panels shall include a simulated loss of power to the control unit and to the control panel.

6.5.3.7.10 Stack alignment shall be checked and connection make-up shall be verified in accordance with 6.1

6.5.3.7.11 If hydrogen sulfide bearing formations are anticipated, the equipment owner shall provide certification of compliance with NACE MR0175 or ISO 15156 for well control equipment, as described in Section 5.

6.5.4 Surface BOP Stack Equipment

6.5.4.1 For the purpose of this section, the surface BOP stack equipment includes the wellbore pressure-containing equipment above the wellhead, including the ram BOPs, spool(s), annular(s), choke and kill valves, and choke line to the choke manifold. Equipment above the uppermost BOP is not included.

6.5.4.2 Where conditions allow, the entire stack should be pressure tested as a unit.

6.5.4.3 Annular BOPS shall be tested with the smallest OD pipe to be used during the well operations.

6.5.4.4 Fixed bore pipe rams shall be tested only on the pipe OD size that matches the installed pipe ram blocks.

6.5.4.5 Variable bore rams shall be initially pressure tested on the largest and smallest OD pipe sizes that will be used during the weld operations.

6.5.4.6 Blind ram BOPs and blind shear ram BOPS should not be tested when pipe is in the stack.

6.5.4.7 The capability of the shear ram and ram operator shall be verified with the BOP manufacturer for the planned drill string. The shear ram and preventer design and/or metallurgical differences among drill pipe manufacturers may require high closing pressures for shear operations.

6.5.4.8 Prior to testing each ram BOP, the secondary rod seals (emergency pack-off assemblies) shall be checked to ensure the seals have not been energized. Should the ram shaft seal leak during the test, the seal shall be repaired rather than energizing the secondary packing.

6.5.4.9 During the initial test, ram BOPs equipped with ram locks shall be pressure tested with ram locks in the closed position and closing pressure bled to zero. Manual locks either screw clockwise or counter-clockwise, to hold the rams closed. Hand wheels should be in place and the threads on the ram locking shaft shall be in a condition that allows the locks to be easily operated.

6.5.4.10 The BOP elastomeric components that can be exposed to well fluids shall be verified by the OEM as appropriate for the drilling fluids to be used and for the anticipated temperatures to which exposed. Consideration shall be given to the temperature and fluid conditions during well testing and completion operations.

6.5.4.11 The manufacturers' markings for BOP elastomeric components, including the durometer hardness, generic type of compound, date of manufacture, part number, and operating temperature range of the component shall be verified and documented.

6.5.4.12 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for six (6) months or longer.

6.5.4.13 Flexible choke and kill lines shall be tested to the same pressure, frequency, and duration as the ram BOPs.

6.5.4.14 A precharged surge bottle can be installed adjacent to the annular preventer if contingency well control procedures include stripping operations.

6.5.4.15 The drill pipe test joint and casing ram test sub shall be constructed of pipe that can withstand the tensile, collapse, and internal pressures that will be placed on them during testing operations.

6.5.5 Chokes and Choke Manifolds

6.5.5.1 The choke manifold upstream of and including the last high pressure valves shall be tested to the same pressure as the ram BOPs (see Table 2 and Table 3).

6.5.5.2 The valves and adjustable chokes shall be operated daily to verify operability.

6.5.5.3 The adjustable choke back-up pneumatic/hydraulic control system shall be checked to ensure operation in the event of loss of primary supply in accordance with equipment owners' PM program.

6.5.5.4 The frequency of the choke drill shall be at initial installation and subsequent testing, at each casing point or in accordance with equipment owners' maintenance program.

6.5.5.5 Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required (see Table 2 and Table 3).

6.5.6 In-the-field Control System Accumulator Capacity

6.5.6.1 General

6.5.6.1.1 It is important to distinguish between the standards for in-the-field control system accumulator capacity established in this document and the design requirements established in API 16D.

6.5.6.1.2 API 16D provides sizing guidelines for designers and manufacturers of control systems. In the factory, it is not possible to exactly simulate the volumetric demands of the control system piping, hoses, fittings, valves, BOPs, etc. On the rig, efficiency losses in the operation of fluid functions result from causes such as friction, hose expansion, control valve interflow as well as heat energy losses. Therefore, the establishment by the manufacturer of the design accumulator capacity provides a safety factor. This safety factor is a margin of additional fluid capacity which is not actually intended to be usable to operate well control functions on the rig. For this reason, the control system design accumulator capacity formulas established in API 16D are different from the demonstrable capacity guidelines provided in this standard.

6.5.6.1.3 The original control system manufacturer shall be consulted in the event that the field calculations or field testing should indicate insufficient capacity or in the event that the volumetric requirements of equipment being controlled are changed, such as by the modification or change out of the BOP stack.

6.5.6.2 Drawdown Test

6.5.6.2.1 The purpose of the drawdown test is to verify that the accumulator system is maintained to support the fluid volume and pressure requirements of the BOPs in use.

6.5.6.2.2 This test shall be performed after the initial nipple-up of the BOPs, after any repairs that required isolation/partial isolation of the system, or every 6 months from previous test; using the following procedure (see sample worksheets and examples in Annex A).

1) Position a properly sized joint of drill pipe or a test mandrel in the BOPs.

2) Turn off the power supply to all accumulator charging pumps (air, electric, etc.).

3) Record the initial accumulator pressure. Manifold and annular regulators shall be set at the manufacturer's recommended operating pressure for the BOP stack.

4) Individually close the four (4) smallest BOP rams (excepting blind or blind shear ram BOPs) and record the closing times. To simulate closure of the blind or blind shear rams, open one set of the pipe rams. Closing times shall meet the response times stipulated in 6.3.2.

NOTE Volumes associated with substituting a pipe ram for a BSR may be different, but closing the same ram combination confirms consistent operation).

5) Open the hydraulic operated valve(s) and record the time and volume required.

6) Close the (largest) annular BOP and record the closing time.

7) Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.38 MPa) above precharge pressure.

NOTE 1 When performing the accumulator drawdown test, wait a minimum of 1 hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a failed test.

NOTE 2 Because it takes time for the gas in the accumulator to warm up after performing all of the drawdown test functions, you should wait 15 minutes after recording the initial pressure, if the final pressure was less than 200 psi (1.4 MPa) above the precharge pressure. If there is an increase in pressure, indications are that the gases are warming and there is still sufficient volume in the accumulators. If the 200 psi (1.4 MPa) above precharge pressure has not been reached after 15 minutes you may have to wait an additional 15 minutes due to ambient temperatures negatively affecting the gas properties. After thirty minutes from the time the final pressure was recorded, if the 200 psi (1.4 MPa) above precharge has not been reached, then it will be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

6.5.7 Inspections and Maintenance

6.5.7.1 Periodic Maintenance

6.5.7.1.1 Inspection and maintenance of the well control equipment shall be performed in accordance with the equipment owner's maintenance program.

6.5.7.1.2 The equipment owner's maintenance program shall address inspection (internal/external visual, dimensional, NDE, etc) and pressure integrity testing.

6.5.7.1.3 Inspections shall be performed every 90 days, after each well, or in accordance with documented equipment owner's reliability data, whichever is greater.

6.5.7.1.4 Certain well operations or conditions (milling, well control events, bromide use, etc.) will require more frequent inspection and maintenance.

6.5.7.2 Visual Inspection — Flexible Choke and Kill Hoses

6.5.7.2.1 An internal visual inspection of flexible choke and kill hoses through the entire length of the hose shall be performed annually.

6.5.7.2.2 An external visual inspection of flexible choke and kill hoses shall be performed between each well.

6.5.7.2.3 The internal and external inspection programs shall be specified by the equipment owner's maintenance program in accordance with equipment manufacturer's recommendations.

6.5.7.3 Inspections for Repair or Remanufacturing

6.5.7.3.1 Well control system components shall be inspected at least every five years for repair or remanufacturing, in accordance with equipment owners' preventive maintenance program or the manufacturer's guidelines. Individual components (e.g. ram bonnets, valve actuators) can be inspected on a staggered schedule.

6.5.7.3.2 As an alternative, a rig specific inspection frequency can vary from this five-year interval if the equipment owner collects and analyzes condition-based data (including performance data) to justify a different frequency. This alternative may include trending, dynamic vs. static seals, corrosion resistant alloy inlays in sealing surfaces, resilient vs. metal-to-metal seals, replaceable wear plates, etc.

6.5.7.3.3 Certain equipment should undergo a critical inspection (internal/external visual, dimensional, NDE, etc) annually and shall not exceed three years for: e.g., shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft piston button/foot, welded hubs, ram cavities, and ram blocks.

6.5.7.3.4 Recommended wear tolerances (ram blocks and ram cavities) shall be provided by the manufacturer and the equipment owner's maintenance program shall be provided by or check against the manufacturer's allowable wear limits.

6.5.7.3.5 Inspections shall be performed by a competent person(s).

6.5.7.3.6 Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.

6.5.8 Maintenance

6.5.8.1 Installation, Operation, and Maintenance Manuals

The manufacturer's installation, operation, and maintenance (IOM) manuals shall be available on the rig for all BOP equipment installed on the rig.

6.5.8.2 Connections

6.5.8.2.1 Studs and nuts shall be checked for proper size and grade.

6.5.8.2.2 After a pressure seal is broken, the connection shall be established by applying the appropriate torque (in accordance with API 6A) to the connection studs and/or bolts.

6.5.8.2.3 Manuals or bulletins containing torque specifications shall be available on the rig.

6.5.8.2.4 Torque shall be applied to studs and/or bolts in a criss-cross manner.

6.5.8.2.5 The appropriate lubricant shall be used with the corresponding torque.

6.5.8.2.6 After the initial pressure test is completed, all bolts shall then be rechecked for proper torque.

6.5.8.2.7 When making up connections, excessive force should not be required to bring the connections into alignment.

6.5.8.2.8 When making up proprietary (non-API) clamp hub connections, the manufacturer's recommended procedure shall be followed.

6.5.8.3 Replacement Assemblies

6.5.8.3.1 Replacement parts shall be designed for their intended use by industry approved and accepted practices. After installation, the affected pressure-containing equipment shall be pressure tested.

6.5.8.3.2 If replacement assemblies are acquired from a non-original equipment manufacturer, the assemblies shall meet or exceed the original equipment specifications and be fully tested, design verified, and supported by traceable documentation in accordance with relevant API specifications.

6.5.8.3.3 Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

6.5.8.4 Equipment Storage

6.5.8.4.1 When a BOP, component, or assembly is taken out of service for an extended period of time, it shall be completely washed, steam cleaned, and machined surfaces coated with a corrosion inhibitor.

6.5.8.4.2 For BOPs, the rams or sealing element shall be removed and the internals washed, inspected, and coated with a corrosion inhibitor.

6.5.8.4.3 Connections should be covered and protected.

6.5.8.4.4 The hydraulic operating chambers should be flushed with a corrosion inhibitor and hydraulic connections plugged.

6.5.8.4.5 The equipment should be stored in a manner to protect it from environmental damage.

6.5.8.5 Weld Repairs

6.5.8.5.1 Weld repairs on pressure-containing and load-bearing components shall only be performed in accordance with API 16A, API 6A, manufacturer's standards, or other applicable standards.

6.5.8.5.2 All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE Std MR0175 or ISO 15156.

6.5.8.5.3 Verification of compliance shall be established through the implementation of the repairer's written weld procedure specification (WPS) and the supporting procedure qualification (PQR).

6.5.8.5.4 Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, Article II.

6.5.8.5.5 The original equipment manufacturer should be consulted to verify proposed weld procedures.

6.5.8.6 Poor Boy Inspection and Maintenance

6.5.8.6.1 Equipment owner's maintenance program shall include removal of inspection plates and clearing of debris.

6.5.8.6.2 Vent ports and lines shall be inspected to ensure debris or other deficiencies do not impair the operability of the system.

6.5.8.6.3 An inspection program to consider corrosion and erosion shall be performed annually. This shall be included in the equipment owner's maintenance program.

6.5.8.6.4 Inspect vent lines to ensure they are adequately braced and vented.

6.5.8.6.5 Gauges shall be inspected for damage and operation and replaced with a properly sized gauge for the rated pressure of the system.

6.5.9 Quality Management

6.5.9.1 Planned Maintenance Program

6.5.9.1.1 A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, shall be employed on each rig.

6.5.9.1.2 Records of maintenance performed and repairs made shall be maintained on file at the rig site and retained at an offsite location for the well control equipment.

6.5.9.2 Manufacturer's Product Alerts/Equipment Bulletins

Copies of equipment manufacturers' product alerts or equipment bulletins shall be maintained at the rig site for the well control equipment.

6.5.10 Records and Documentation

6.5.10.1 Posted Documentation

6.5.10.1.1 Drawings showing ram space-out and bore of the BOP stack and a drawing of the choke manifold showing the pressure rating of the components shall be posted on the rig floor and maintained up to date (see Figure 8 for an example drawing).

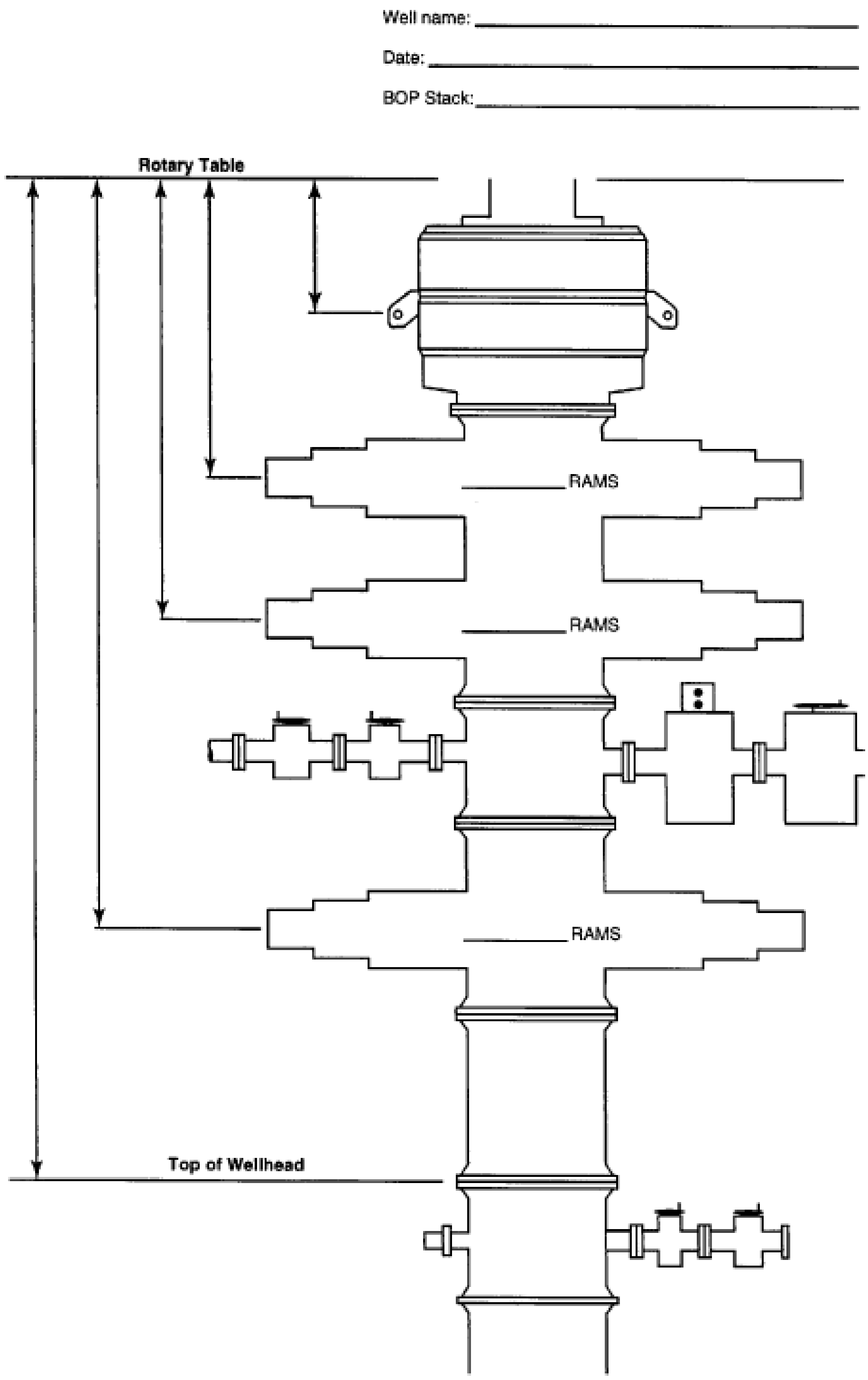


Figure 8 — Example Illustration of Surface Ram BOP Space-out

6.5.10.1.2 Shear pressure calculations shall be posted on the rig floor and updated in accordance with drilling operations (e.g. drill pipe properties, MASP, leak-off test, etc).

6.5.10.1.3 Annular closing pressures against various tubular(s) shall be posted on the rig floor.

6.5.10.2 Operation and Maintenance Manuals

6.5.10.2.1 Rig manuals, including equipment drawings, specifications and bills of material, shall be at the rig site to identify the equipment and allow the procurement of correct replacement parts.

6.5.10.2.2 Changes to the well control equipment shall be documented through the use of a management of change system in accordance with API 75.

6.5.10.3 Equipment Data Book and Certification

6.5.10.3.1 Equipment records, such as API manufacturing documentation, NACE certification, and factory acceptance testing reports, should be retained.

6.5.10.3.2 Copies of the manufacturer's equipment data book and third party certification should be available for review.

6.5.10.4 Maintenance History and Problem Reporting

6.5.10.4.1 A maintenance and repair historical file shall be retained by serial number or unique identification number for each major piece of equipment. This file shall follow the equipment when it is transferred.

6.5.10.4.2 Equipment malfunctions or failures shall be reported in writing to the equipment manufacturer in accordance API 16A and Annex B.

6.5.10.4.3 A log of all failures shall be retained at the rig site and a designated offsite location.

6.5.10.4.4 Details of the BOP equipment, control system and essential test data, shall be maintained from the beginning to the end of the well and considered for use in condition based analysis.

6.5.10.5 Test Procedures and Test Reports

6.5.10.5.1 Testing after major modifications or equipment weld repairs shall be performed according to the manufacturer's written procedures.

6.5.10.5.2 Rig specific procedures for installation, removal, operation, and testing of all well control equipment installed shall be available and followed.

6.5.10.5.3 Pressure and function test reports shall be developed, recorded, and retained including pre-installation, initial and all subsequent tests for each well.

6.5.10.5.4 These documents shall be retained for two years at the rig site and a designated offsite location.

6.5.10.6 Shearing Pipe & Other Operational Considerations

6.5.10.6.1 Some of these considerations are not specific to subsea operations and may apply to surface operations.

6.5.10.6.2 Through the development of specific guidelines, operational procedures and a thorough risk assessment the risk can be mitigated or managed to address those concerns.

6.5.10.6.3 It is important to understand the effects of increasing wellbore pressure and its impact on the shearing capabilities of drill pipe and closing annulars against casing strings. For those reasons, it is important to understand the equipment designs, use and interfaces between those components run in the wellbore and the BOP and control systems.

6.5.10.6.4 Hanging off drillpipe and get the annular open as soon as possible, to reduce the response time and complexity of the well control operation

6.5.10.6.5 Limit the maximum wellbore pressure that below the annular, to a specific pressure (e.g. .2500 psi or lower) before reverting to a ram preventer before performing the well kill operation.

6.5.10.6.6 One set of shear rams capable of shearing any drill pipe that might be across the stack at 2500 psi [17.2 MPa], MASP or in the water depth and mud weights to be encountered.

6.5.10.6.7 If the BSR or CSR is closed during a well control event, when pipe is sheared, the BOP shall be inspected and tested at first opportunity.

6.5.10.6.8 Shearing capabilities shall be determined by actual shear data for the pipe, BOP type and configuration.

6.5.10.6.9 Post shearing calculations on rig floor for all to view and be aware of those pressures. See Table 4 for an example of shearing calculations.

Table 4 — Example of One Method to Calculate Shear Pressure Given Well and Equipment Specific Data

BOP Operator Closing Ratio	**Control System Operating Pressure** psi (MPa)	**Surface Shear Pressure**[a] psi (MPa)	**MAWP at TD** psi (MPa)	**MEWSP** psi (MPa)	**Maximum Expected Mud Weight at TD**
14.64	5000 (34.5)	3174 (21.9)	5000 (34.5)	927 (6.4)	15.2
Maximum closing pressure (MASP) = surface shear pressure + (MASP/operator closing ratio) + (mud wt hydrostatic/operator closing ratio) Maximum closing pressure (MAWP) = surface shear pressure + (MAWP/operator closing ratio) + (mud wt hydrostatic/operator closing ratio)					
[a] Data taken from actual test results for pipe.					

6.5.10.6.10 If shearing pressures approach the restart pressure (10 % threshold) of the accumulator charging pumps consideration should be given to change the pump restart pressure nearer to the maximum operating pressure of the system, especially if large accumulator volumes are being utilized.

6.5.10.6.11 If a single ram cannot both shear and seal, this system shall close two rams; one that will shear and one that will seal well bore pressure. Additional functions may be added as requested at order and shall not interfere with the main purpose of shearing and sealing the well.

7 Subsea BOP Systems

7.1 Subsea BOP Stack Arrangements

7.1.1 Subsea BOP Stack Pressure Designations

7.1.1.1 Blowout preventer equipment is based on rated working pressures and designated as 5K, 10K, 15K, 20K, and 25K as described in Table 5.

Table 5 — Subsea BOP Pressure Designations

Pressure Designation	Rated Working Pressure
5K	5000 psi (34.5 MPa)
10K	10,000 psi (69.0 MPa)
15K	15000 psi (103.5 MPa)
20K	20,000 psi (138.0 MPa)
25K	25,000 psi (172.4 MPa)
NOTE 1 psi = 0.006894757 MPa.	

7.1.1.2 Every installed ram BOP shall have, as a minimum, a working pressure equal to 500 psi (3.5 MPa) greater than the maximum anticipated surface pressure to be encountered.

7.1.1.3 Diverters and rotating heads (rotating control devices) are not considered blowout prevention equipment and are not addressed in this Standard. Refer to other API documents regarding the design, manufacturing, proper use, installation, handling, and maintenance.

7.1.2 BOP Stack Classifications

7.1.2.2 The quantity of pressure containment sealing components in the vertical wellbore of a BOP stack shall be used to identify the classification or "class" for the BOP system installed. The designation Class 6 represents a combination of a total of six ram and/or annular preventers installed (e.g. two annular and four ram preventers or one annular and five ram preventers, in the case of the Class 6 described).

7.1.2.3 After the classifications of the BOP stack has been identified, the next nomenclature identifies the quantity of annular type preventers installed and designated by an alphanumeric designation (e.g. A2 identifying two annular preventers installed).

7.1.2.4 The final alphanumeric designation shall be assigned to the quantity of rams or ram cavities, regardless of their use, installed in the BOP stack. The rams or ram cavities shall be designated with an "R" followed by the numeric quantity of rams or ram cavities. (e.g. R4 designates that four ram type preventers are installed.

7.1.2.5 An example of a CLASS 6 BOP system installed with two annular and four ram type preventers shall be designated as "Class 6-A2-R4".

7.1.3 Subsea BOP Stack Arrangements

7.1.3.1 The ram BOP positions and outlet arrangements on subsea BOP stacks shall provide reliable means to handle potential well control events. Specifically for floating operations, the arrangement should provide a means to:

a) close in on the drill string and on casing or liner and allow circulation;

b) close and seal on open hole and allow volumetric well control operations;

c) strip the drill string using the annular BOP(s);

d) hang off the drill pipe on a ram BOP and control the wellbore;

e) shear logging cable or the drill pipe and seal the wellbore;

f) disconnect the riser from the BOP stack;

g) circulate the well after drill pipe disconnect;

h) circulate across the BOP stack to remove trapped gas.

7.1.3.2 Annular preventers having a lower rated working pressure than ram preventers are acceptable.

7.1.3.3 The kill line shall be the lowermost line connected to the BOP stack.. Placement of this outlet shall be below the lowermost pipe ram, or below the test ram (if installed).

7.1.3.4 For BOP's that have lines installed on each side of the outlet below the lowermost ram, either may be designated as a Choke Line or Kill Line.

7.1.3.5 Rig specific stack identifying nomenclature (choke line, kill line, etc.) shall be made part of the drilling program.

7.1.3.6 Subsea BOP stacks shall be Class 5 or greater.

7.1.3.7 Blind shear rams (minimum of one) capable of shearing the drill pipe in use and sealing, shall be installed on all 10K BOP systems.

7.1.3.8 For 15K and greater pressure rated systems, the minimum requirements are one annular, two shear rams (at least one capable of sealing) and two pipe rams (excluding a test ram).

7.1.3.9 The minimum stack arrangement for Class 6 BOP's shall include one annular, two shear rams (at least one capable of sealing) and two pipe rams in the arrangement (excluding test ram).

7.1.3.10 For all Class BOP arrangements, a risk assessment shall be performed to identify ram placements and configurations and take into account annular and large tubular for well control management.

7.1.4 Spare Parts

The following BOP spare parts (for the service intended) shall be properly stored, maintained in accordance with OEM recommendations and be readily available:

a) a complete set of ram rubbers for each size and type of ram BOP installed;

b) a complete set of bonnet or door seals for each size and type of ram BOP installed;

c) ring gaskets to fit end connections;

d) a spare annular BOP packing element and a complete set of seals;

e) a flexible choke or kill line, if in use.

7.1.5 Replacement Assemblies Storage

7.1.5.1 When storing BOP metal parts and related equipment, they should be coated with a protective coating to prevent rust.

7.1.5.2 The original equipment manufacturer shall be consulted regarding replacement assemblies.

7.1.5.3 If replacement assemblies are acquired from a non-original equipment manufacturer, the assemblies shall be equivalent or superior to the original equipment and fully tested, design verified, and supported by traceable documentation in accordance with relevant API specifications.

7.1.6 Drilling Spools

7.1.6.1 To reduce the overall height of subsea BOP stack arrangements, the use of drilling spools is not recommended.

7.1.6.2 For subsea arrangements, choke and kill lines shall be connected to the side outlets of the BOPs**.**

7.1.7 Adapter Spools

7.1.7.1 Adapter spools are used to connect drill-through equipment with different end connections, nominal size designation and/or pressure ratings to each other. Some typical applications in a subsea stack are:

— the connection between the LMRP and the lower stack;

— between the lowermost BOP and the wellhead connector.

7.1.7.2 Adapter spools for BOP stacks shall meet the following minimum specifications:

— have a minimum vertical bore diameter equal to the internal diameter of the mating equipment;

— have a rated working pressure equal to the lowest rated end connection of the mating equipment.

7.1.8 Spacer Spools

7.1.8.1 Spacer spools are used to provide separation between two drill-through components with equal sized end connections (nominal size designation and pressure rating). Typically, they are used to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations but may serve other purposes in a stack as well.

7.1.8.2 Spacer spools for BOP stacks shall meet the following minimum specifications:

a) have a vertical bore diameter the same internal diameter as the mating equipment;

b) have a rated working pressure equal to the rated working pressure of the mating equipment;

c) shall not have any penetrations capable of exposing the wellbore to the environment, without dual isolation capabilities.

7.2 Choke Manifolds, Choke Lines and Kill Lines — Subsea BOP Installations

7.2.1 General

7.2.1.1 The choke manifold assembly for subsea BOP installations has the same purpose as the choke manifold assembly for surface installations: it is used to bleed-off the wellbore pressure at a controlled rate or can stop fluid flow from the wellbore completely, as required.

7.2.1.2 Moonpool choke and kill drape hoses or flexible lines installed that permit entry of gas or hydrocarbons, shall meet the requirements of API 16D (gas permeation and fire test properties).

7.2.1.3 Those hoses or flexible lines serving as the choke and kill lines on the LMRP are not required to meet the fire test requirements of API 16C

7.2.1.4 Figure 9 shows an example choke manifold assembly for a subsea installation for 5000 psi (34.5 MPa), 10,000 psi (69.0 MPa), or 15,000 psi (103.5 MPa) rated working pressure service.

7.2.1.5 Features of a choke manifold assembly include the following:

a) manifolded choke and kill lines to permit pumping or flowing through either line;

b) a remotely controlled adjustable choke and a manually adjustable choke system to permit control through either the choke or kill line;

c) tie-ins to both drilling fluid and cement unit pump systems.

7.2.2 Installation Guidelines - Choke Manifolds - Subsea BOP Installations

7.2.2.1 Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) shall have a minimum working pressure at least equal to the rated working pressure of the ram BOPs in use. This equipment shall be tested when installed in accordance with provisions of Section 14

7.2.2.2 For working pressures of 3000 psi (20.7 MPa) and above, flanged, welded, hubbed, or other end connections in accordance with API 6A, shall be employed on components subjected to well pressure.

7.2.2.3 Although not shown in the example equipment illustrations, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines. When buffer tanks are employed, provision shall be made to isolate a failure or malfunction,

7.2.2.4 The main header shall be 3 in. (7.62 cm) nominal pipe diameter or larger. All other components should be 2 in. (5.08 cm) nominal pipe diameter or larger. The assembly shall have a minimum number of turns and be securely anchored. Turns in the assembly shall be targeted in both directions.

7.2.2.5 All choke manifold valves shall be full bore. During operations, all valves shall be fully opened or fully closed.

7.2.2.6 A minimum of one remotely operated choke shall be installed on 5K (34.5 MPa) systems and a minimum of two remotely operated chokes on 10K and greater manifold systems.

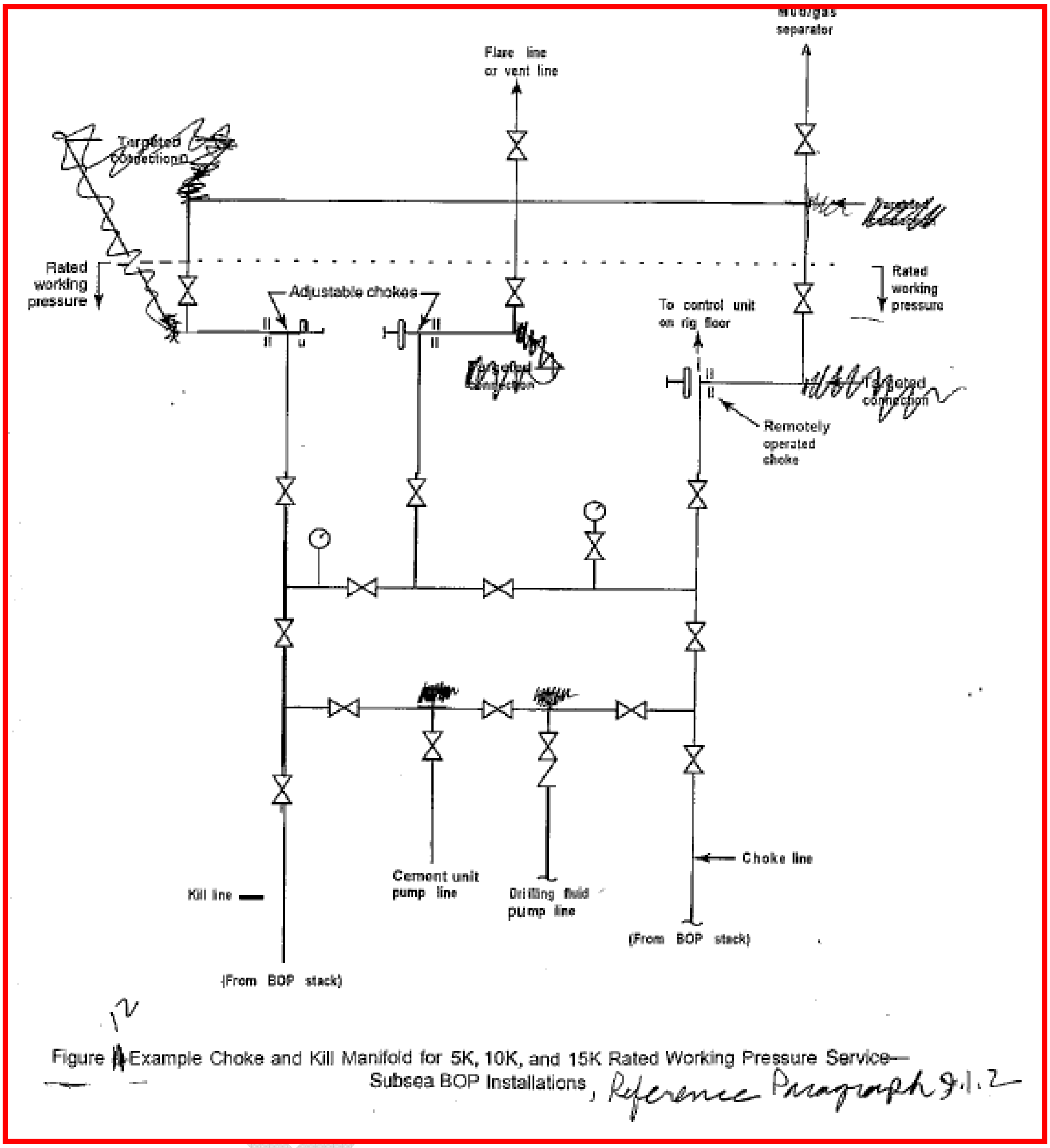


Figure 9 — Example Choke and Kill Manifold for 5K, 10K, and 15K Rated Working Pressure Service – Surface BOP Installations

7.2.2.7 Choke manifold configurations shall allow for re-routing of flow (in the event of eroded, plugged, or malfunctioning parts) without interrupting flow control.

7.2.2.8 Materials used in construction and installation shall be suitable for the expected range of temperature exposure.

7.2.2.9 The manifold and piping shall be protected from freezing by heating, draining, filling with appropriate fluid, or other appropriate means.

7.2.2.10 Pressure gauges shall be installed to easily observe drill pipe and annulus pressures at the station where well control operations are conducted.

7.2.2.11 The choke control station, whether at the choke manifold or remote from the rig floor, shall be conveniently located and shall include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, and pump strokes enhances control of the well.

7.2.2.12 Power systems for remotely operated valves and chokes shall be sized to provide the necessary pressure and volume.

7.2.2.13 Any remotely operated valve or choke shall be equipped with an emergency backup power source

7.2.2.14 Initial testing of the choke manifold assembly to the rated working pressure of the ram BOPS shall be performed when the BOP stack is on the test stump (prior to running subsea). Subsequent pressure tests of the choke manifold assembly shall be conducted in accordance with applicable provisions of Section 7.6.

7.2.2.15 Lines downstream of the chokes or the last valves downstream of chokes are not required to contain rated manifold working pressure (see Table 9 and Table 10 for testing considerations).

7.2.2.16 Lines downstream of the choke manifold shall be securely anchored and permit flow direction either to a poor boy degasser, vent lines, or to production facilities or emergency storage.

7.2.2.17 Modifications such as additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges, and manifolding of bypass lines may be dictated by the conditions anticipated for a particular well.

7.2.3 Installation Guidelines — Choke and Kill Lines

7.2.3.1 General

For subsea BOP installations choke and kill lines are connected (through the choke manifold) to permit pumping or flowing through either line.

7.2.3.2 Choke and Kill Line Bends

7.2.3.2.1 Choke and Kill lines should be as straight as possible. Because erosion at bends is possible during operations, flow targets shall be used at short radius bends and on block ells and tees. The degree to which pipe bends are susceptible to erosion depends on the bend radius, flow rate, flow medium, pipe wall thickness, and pipe material. Short radius pipe bends (R/d < 10) should be targeted in the direction of expected flow or in both directions if bidirectional flow is expected, where

R is the radius of pipe bend measured at the centerline in inches (centimeters);

d is the nominal diameter of the pipe in inches (centimeters).

7.2.3.2.2 For large radius pipe bends (R/d > 10), targets are generally unnecessary. Ninety-degree block ells and tees shall be targeted in the direction of flow.

7.2.3.2.3 For flexible lines, consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration.

7.2.3.3 Other Considerations

7.2.3.3.1 Choke and kill lines for subsea BOP installations are installed opposite one another on the exterior of the marine riser (see Figure 10). The riser installed choke and kill lines shall be identical in size and pressure rating, and shall be 3 in. (7.62 cm) nominal diameter or larger. Either line can serve the choke or kill function.

7.2.3.3.2 The line connected to the lowermost outlet of the BOP shall be designated as the Kill Line. Placement of this outlet shall be below the lowermost pipe ram, or below the test ram (if installed). One choke line and one kill line connection shall be located above the lowermost ram BOP.

NOTE If test rams are installed and the kill outlet is below the test ram then, running a test plug to test the wellbore side of the valves shall be required after the tested seals have been broken or during the subsequent BOP test, in accordance with equipment owner's maintenance program.

7.2.3.3.3 Selection of choke and kill line connectors joining the LMRP and BOP lines must take into consideration the ease of connect/disconnect operations and the dependability of sealing elements for those emergency situations where it is necessary to disconnect the LMRP from the BOP stack and then reconnect again prior to resuming normal operations.

7.2.3.3.4 LMRP to BOP Connector pressure sealing elements shall be inspected, changed as required, and tested before being placed in service. Once in service, testing these connectors is accomplished as part of BOP testing.

7.2.3.3.5 Pressure ratings of all lines and sealing elements shall equal or exceed the rated working pressure of the ram BOPs.

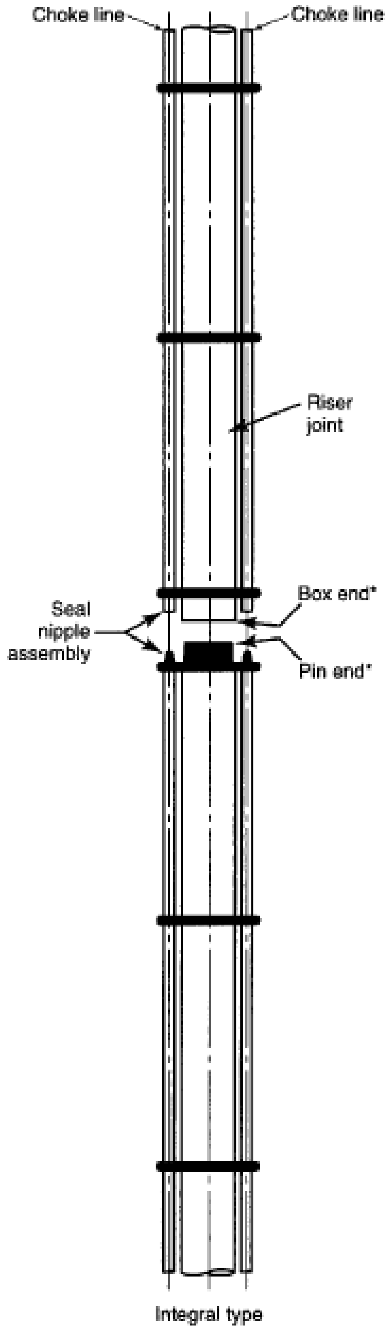
7.2.3.3.6 Subsea choke/kill lines are connected on adjoining riser joints by box-and-pin, stab-in couplings. The box contains an elastomeric radial seal which expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized.

7.2.3.3.7 Each BOP outlet connected to the choke or kill line shall have two full-opening valves mounted adjacent to the preventers. These valves shall be hydraulically operated open and pressure assisted close.

NOTE If spring closure only valves are employed they shall be capable of closing under differential pressure conditions and full flow potential across the valve. If spring or passive closure is unable to close the valves under the prescribed conditions then, power assisted closure of the valves shall be required.

7.2.3.3.8 Location of the choke and kill line openings on the BOP stack depends on the particular configuration of the preventers and the operator's preferred flexibility for well control operations. Example arrangements are shown in Figure 11. Other arrangements will meet well control requirements.

7.2.3.3.9 All flexible lines in the choke and kill line system shall have a pressure rating equal to or exceeding the rated working pressure of the ram BOPS. Figure 12 and Figure 13 illustrate example flexible lines for subsea BOP installations.



*May be reversed.

Figure 10 — Example Riser-mounted Kill and Choke Lines for Subsea BOP Installations

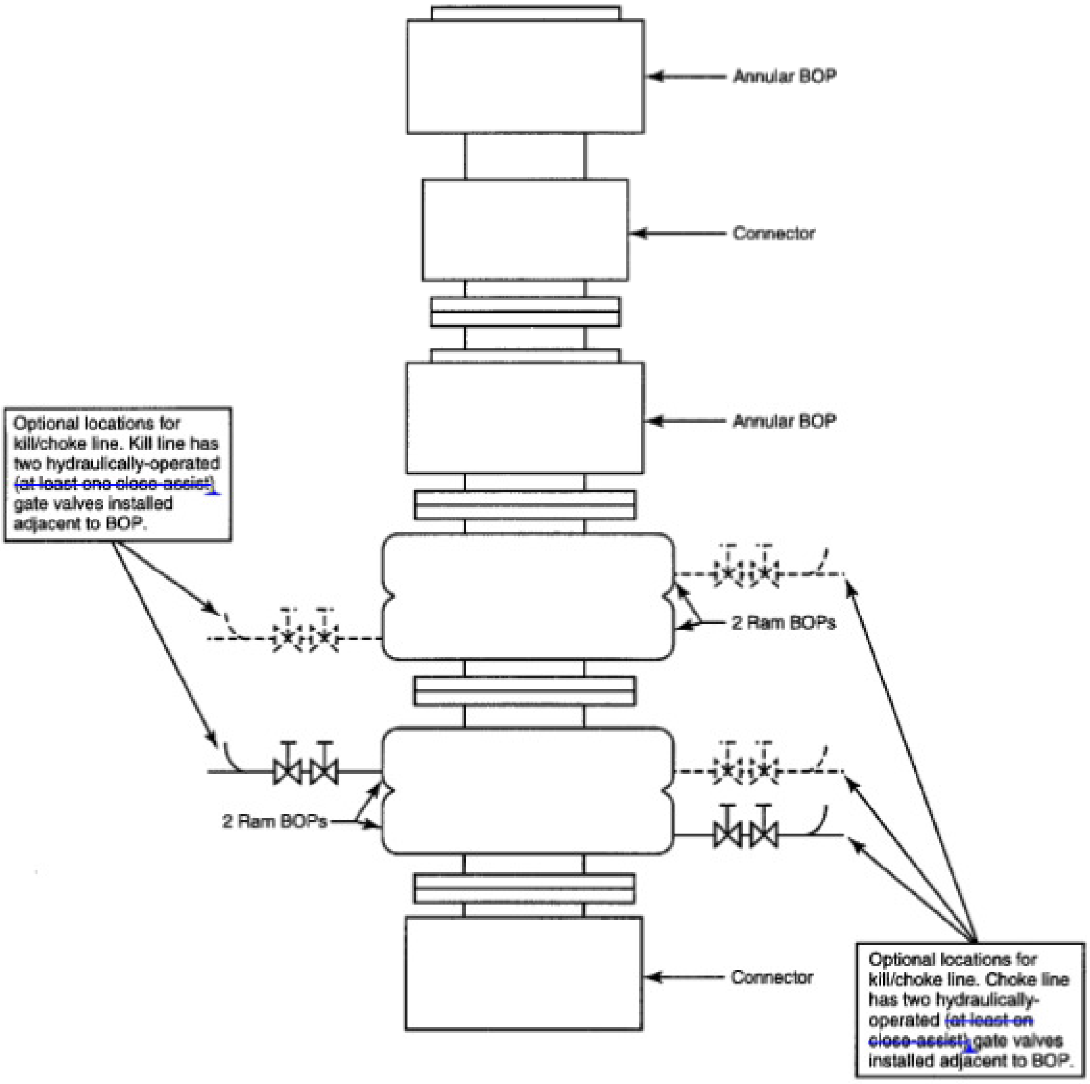


Figure 11 — Example Subsea BOP Stack Illustrating Optional Locations for Choke/Kill Lines

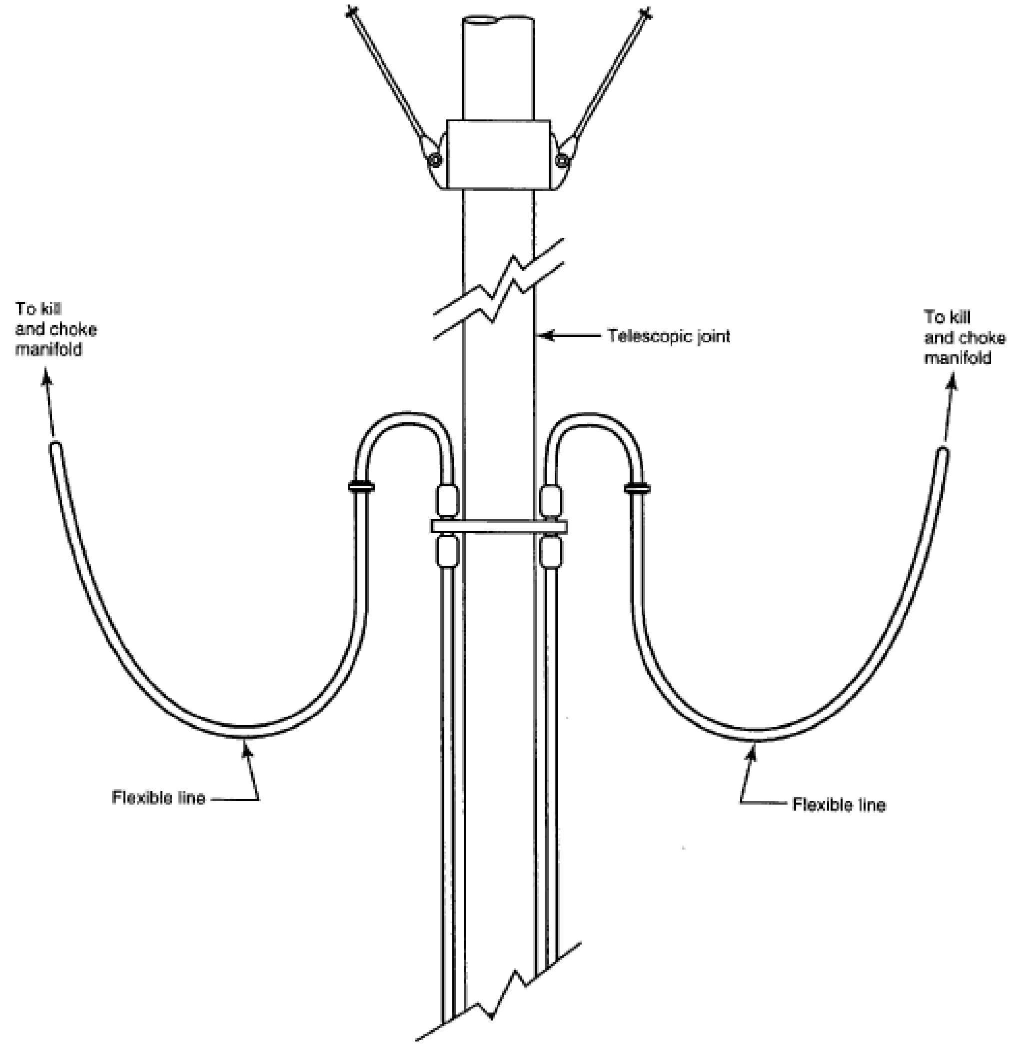


Figure 12 — Example Flexible Connection at the Top of Marine Riser for Choke/Kill Lines

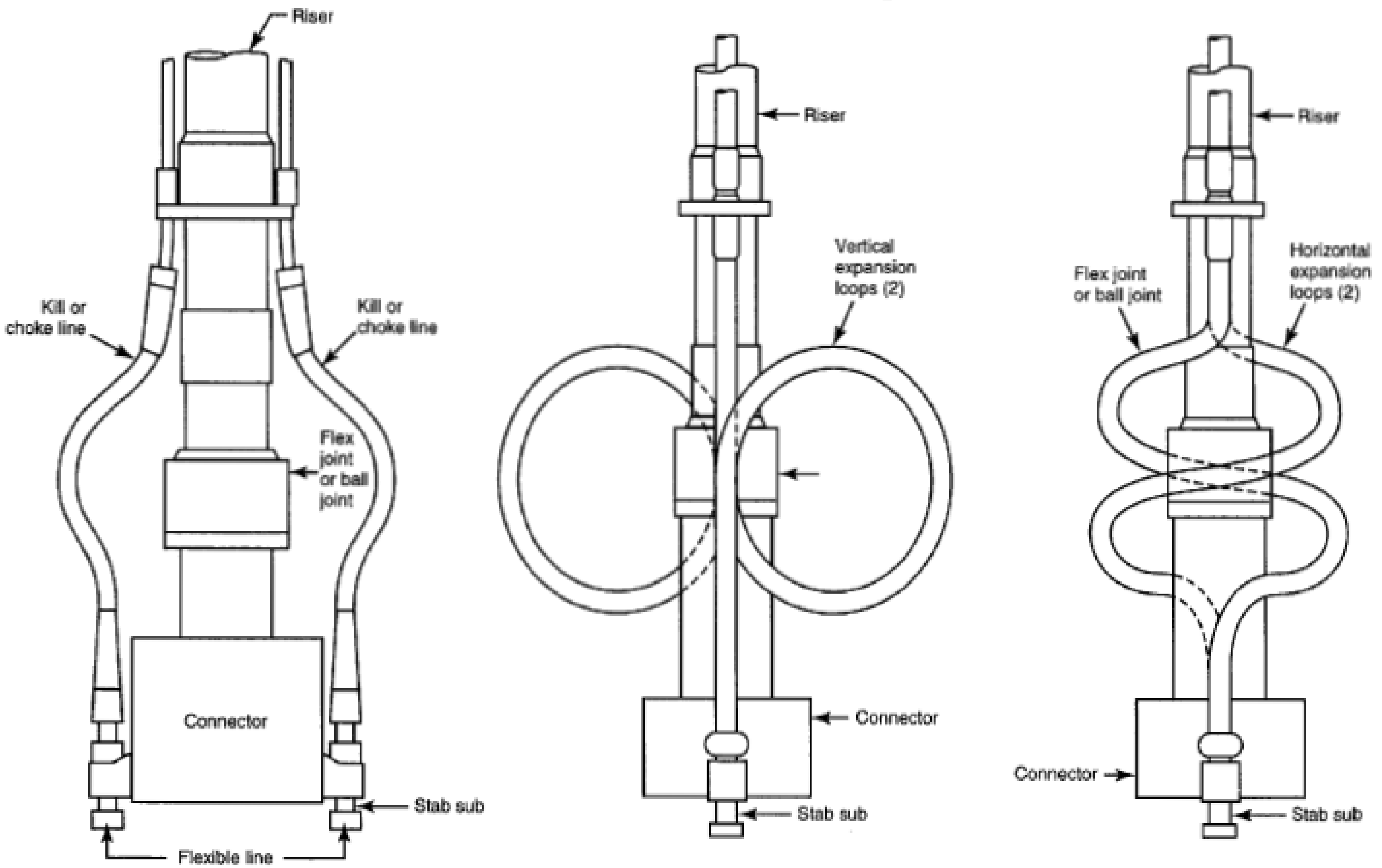


Figure 13 — Example Flexible Connection at the Bottom of Marine Riser for Kill/Choke Lines

7.2.3.3.10 Flexible choke and kill line minimum bend radius and operating displacement limits shall be determined by the manufacturer's guidelines. These guidelines shall determine the proper length, proper routing and allow full deflection of the flex joint.

7.2.3.3.11 All lines shall be firmly secured to withstand the dynamic effect of fluid flow and the impact of drilling solids. Supports and fasteners located at points where piping changes direction shall be capable of restraining pipe deflection. Special attention should be paid to the end sections of the line to prevent line whip and vibration.

7.2.3.3.12 The minimum nominal inside diameter for lines downstream of the chokes shall be the nominal connection size of the chokes.

7.2.3.3.13 Lines downstream of the choke manifold are not required to contain the rated choke manifold pressure (see Section 14 for testing considerations).

7.2.3.3.14 The bleed line (the line that bypasses the chokes) shall be at least equal in diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum backpressure. It also permits high volume bleed-off of well fluids to relieve casing pressure with the preventers closed.

7.2.3.4 Maintenance

Maintenance of the choke and kill line assemblies shall be performed in accordance with the BOP test schedule, and shall include checks for wear, erosion and plugged or damaged lines. See Section 14 for recommendations for testing, inspection, and general maintenance of choke and kill line systems.

7.2.3.5 Spare Parts

The following spare parts (for the service intended) shall be properly stored, maintained in accordance with OEM recommendations and readily available:

a) one complete valve for each size installed;

b) two repair kits for each valve size utilized;

c) any part required for operation such as hose, flexible tubing, electrical cable, pressure gauges, control line valves, fittings, and electrical components.

7.3 Discrete Hydraulic Control Systems for Subsea BOP Stacks

7.3.1 General

7.3.1.1 Control systems for subsea BOP stacks shall be designed and manufactured in accordance with API 16D.

7.3.1.2 The purpose of the BOP control system is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

7.3.1.3 BOP control systems for subsea installations provide hydraulic power fluid in either a vent-to-sea circuit or a return-to-tank circuit as the actuating medium.

7.3.1.4 The individual control is typically provided by an individual pilot line to a valve in the control pod, which is mounted on the LMRP.

7.3.1.5 The minimum required components of the BOP control system shall include the following:

— control fluid;

— control fluid reservoir;

— control fluid mixing system;

— pump systems;

— accumulator system;

— control system valves, fittings and components;

— control stations;

— umbilicals & reels;

— control pods;

— emergency systems;

— secondary control systems.

7.3.2 Control Fluid

7.3.2.1 A suitable control fluid (fresh water containing a lubricant) shall be used as the control system operating fluid.

7.3.2.2 Control fluid shall be selected and maintained to meet minimum OEM properties and equipment owner requirements.

7.3.2.3 Water-based hydraulic fluids are typically used and are a mixture of potable water and a water-soluble lubricant additive. These fluids are available in concentrated or pre-mixed form.

7.3.2.4 Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32°F (0°C) are anticipated.

7.3.3 Control Fluid Reservoir

7.3.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

7.3.3.2 To prevent over-pressurization, vents shall be inspected and maintained to insure they are not plugged or capped.

7.3.3.3 Batch mixing fluid is acceptable, or filling the reservoir with hydraulic fluid not requiring mixing is also acceptable.

7.3.3.4 All reservoir instrumentation shall be tested in accordance with equipment owner maintenance program to insure they are in proper working order.

7.3.3.5 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner maintenance program to insure indication of fluid level in each of the individual reservoirs are in proper working order.

7.3.4 Control Fluid Mixing System

7.3.4.1 The control fluid mixing system shall be tested to insure proper functionality of the automatic operating system.

7.3.4.2 The automatic mixing system should be tested to insure it is manually selectable over the ranges recommended by the manufacturer of the water soluble lubricant additive including proper proportioning of ethylene glycol.

7.3.4.3 A manual override of the automatic mixing system should be tested to insure proper operation.

7.3.5 Pump Systems

7.3.5.1 A pump system consists of one or more pumps.

7.3.5.2 Each pump system shall have an independent power source, such as electric or air.

7.3.5.3 At least one pump system shall be available at all times.

7.3.5.4 The combination of all pump system(s) shall be capable of charging the accumulator system from the minimum calculated operating pressure to the system maximum rated pressure in fifteen minutes.

7.3.5.5 With the loss of one pump system, the remaining pump system(s) shall have the capacity to charge the accumulator system from precharge pressure to the system rated working pressure within 30 minutes.

7.3.5.6 The same pump system(s) may be used to provide control fluid to control both the BOP stack and the diverter system.

7.3.5.7 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure.

7.3.5.8 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system rated working pressure and automatically stop between 97 % –100 % of the system rated working pressure.

7.3.5.9 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system rated working pressure and automatically stop between 95 % – 100 % of the system rated working pressure.

7.3.5.10 Air pumps shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

7.3.5.7.3 Each pump system shall be protected from over-pressurization by a minimum of two devices as follows:

— one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed the rated working pressure of the control system;

— the second device, such as a certified relief valve, to limit the pump discharge pressure and flow in accordance with API 16D.

7.3.5.12 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

7.3.5.13 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

7.3.6 Accumulator Systems

7.3.6.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions.

7.3.6.2 This is achieved by the hydraulic compression of an inert gas with the hydraulic power unit (HPU).1.5.15

7.3.6.3 Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

7.3.6.4 Inert gas shall be used for pre-charging of accumulators.

7.3.6.5 The gas used shall be in accordance with the accumulator design.

7.3.6.6 Subsea accumulators shall have the capability of being dumped subsea, prior to recovering the BOP and LMRP to surface.

7.3.7 Main Accumulator System

The main accumulator system consists of the surface accumulator system and LMRP accumulators that are part of the control system (if applicable).

7.3.8 Dedicated Accumulator System

The dedicated accumulators can be supplied by the main accumulator system, but shall not be affected if the main supply is depleted or lost (see 7.4.12 for emergency and secondary systems).

7.3.9 Accumulator Drawdown Requirements

With pumps inoperative, the main accumulator system shall be capable of performing the accumulator drawdown test (see worksheet Annex A), consisting of closing from a full open position and opening (full stroke) at zero (0) wellbore pressure:

— the largest volume annular BOP, and

— four smallest volume ram type BOPs, excluding test rams, with

— the remaining system pressure at least 200 psi (1.4 MPa) above the precharge pressure.

7.3.10 Control System Response Time

7.3.10.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

7.3.10.2 Measurement of closing response time begins when the close function is activated at any control panel and ends when the BOP or valve is closed affecting a seal.

7.3.10.3 A BOP can be considered closed when the regulated operating pressure has recovered to its nominal setting or other demonstrated means.

7.3.10.4 The following response times shall be met by at least one of the surface/subsea power supplies:

a) close each ram BOP within 45 seconds;

b) close each annular BOP within 60 seconds;

c) unlatch the riser (LMRP) connector within 45 seconds.

7.3.10.5 Response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

7.3.11 Accumulator Precharge

7.3.11.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions.

7.3.11.2 The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

7.3.11.3 The precharge pressure on each accumulator bottle shall be measured prior to each BOP stack installation on each well and adjusted if necessary.

7.3.11.4 The precharge pressure shall be calculated using Methods A, B, or C, in accordance with the original OEM sizing calculation design (see example in Annex C).

7.3.11.5 The precharge pressure calculations shall take into account the well specific conditions (e.g. water depth, drill pipe shear pressure, mud weight, temperature, etc.).

7.3.11.6 The design of the BOP, mechanical properties of drill pipe and wellbore pressure may necessitate higher closing pressures for shear operations.

7.3.11.7 The subsea precharge pressure shall not exceed the rated working pressure of the accumulator.

NOTE The precharge pressure for subsea accumulators can exceed the pump pressure for deepwater applications which will affect surface testing.

7.3.12 Pressure Gauges Requirements

7.3.12.1 The precharge pressure for bladder type accumulators shall be greater than 25% of the system rated working pressure, to prevent damage to the bladder.

7.3.12.2 Bladder and float type accumulators shall be mounted in a vertical position.

7.3.12.3 A pressure gauge for measuring the accumulator precharge pressure shall be available for installation at any time.

7.3.12.4 Those pressure gauges shall be calibrated to 1 % of full scale, and used to not less than 25 % or more than 75 % of the full pressure span of the gauge.

7.3.12.5 No accumulator bottle shall be operated at a pressure greater than its rated working pressure.

7.3.12.6 Supply-pressure isolation valves and bleed-down valves shall be provided on each accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

7.3.13 Control System Valves, Fittings, and Components

7.3.13.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a working pressure at least equal to the rated working pressure of the control system.

7.3.13.2 Conformity of Piping Systems

7.3.13.2.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

7.3.13.2.2 Pipe, pipe fittings and components shall conform to specifications of ASME B31.3.

7.3.13.2.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

7.3.13.2.4 Welding shall be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with ASME Boiler and Pressure Vessel Code, Section IX.

7.3.13.2.5 All rigid or flexible lines, umbilical hoses, rigid conduit and hot line supply hoses between the control system and BOP are not required to meet the fire test requirements of API 16D, on those rigs with a autoshear and deadman system installed.

7.3.13.2.6 All control system interconnect piping, tubing, hoses, linkages, etc., shall be protected from damage during drilling operations, and day-to-day equipment movement and shall have a rated working pressure equal to the working pressure of the BOP control system.

7.3.13.2.7 The control system shall be equipped with a regulating valve to control the operating pressure on annular preventer(s).

7.3.13.2.8 The control system shall be equipped with a regulating valve to control the operating pressure on the ram BOPs.

7.3.13.2.9 The control system shall be capable of providing high-pressure power fluid to the shear rams, in accordance with manufacturer's recommendations.

7.3.13.2.10 Manually operated control valves shall be clearly marked to indicate which function(s) each operates, and the position of the valves (e.g. open, closed, etc).

7.3.13.2.7.3 The control valve handle that operates the blind rams shall be protected to avoid unintentional operation, but still allow full operation from the remote panel without interference.

7.3.13.2.12 All control system analog pressure gauges shall be calibrated to 1 % of full scale at least every three (3) years.

7.3.13.2.13 Analog gauges shall be used at not less than 25 %or more than 75 %of the full pressure span of the gauge.

7.3.13.2.14 Electronic pressure measurement devices shall be accurate to 1 % and utilized within the manufacturer's specified range.

7.3.13.2.15 The control system shall be equipped to allow isolation of the pumps and the accumulators from the control circuits, thus allowing maintenance and repair work.

7.3.13.2.16 The control system shall be equipped and maintained with measurement devices to indicate

— accumulator pressure,

— regulated manifold pressure,

— regulated annular pressure,

— air supply pressure,

— manifold and annular read-backs, and

— flow metering.

7.3.13.2.17 Isolated accumulator(s) shall be provided for the pilot control system that may be supplied by a separate pump or through a check valve from the main accumulator system. Provision, shall be made to supply hydraulic fluid to the pilot accumulator(s) from the main accumulator system if the pilot pump becomes inoperative.

7.3.13.2.18 Provisions shall be made to supply hydraulic fluid to the pilot accumulator(s) from the main accumulator system if the pilot pump becomes inoperative.

7.3.14 Control Stations

7.3.14.1 The subsea BOP control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations.

7.3.14.2 One location shall be in a non-classified (non-hazardous) area as defined in API 500 and API 505.

7.3.15 Umbilicals and Reels

7.3.15.1 Umbilical control hose bundles provide the main supply of power fluid and pilot signals from the surface hydraulic control manifold to the subsea control pods mounted on the BOP stack.

7.3.15.2 The subsea umbilical is run, retrieved, and stored on the hose reel.

7.3.15.3 The umbilicals shall be secured to the pod lines or riser by clamps to prevent abrasive and flexing damage.

7.3.15.4 The outer sheath should be visually inspected for damage on retrieval.

7.3.15.5 The umbilical shall be tested to MWP and documented on an annual basis.

7.3.15.6 Re-terminations, repairs or splices shall be tested to manufacturers recommended MWP.

7.3.15.7 The pilot signals are routed to the hose reels through the appropriate length of surface umbilical jumper hose bundle from the hydraulic connections located on the control manifold.

7.3.15.8 The end terminations should be inspected at retrieval.

7.3.15.9 It is recommended to use stainless steel fittings.

7.3.15.10 There shall be two or more means of surface to subsea fluid supply.

7.3.15.11 Hose reels are used to store, run, and retrieve the umbilical hose bundles that communicate the main hydraulic power fluid supply and command pilot signals to the subsea mounted BOP control pods.

7.3.15.12 The hose reels are equipped with hose reel manifolds having valves, regulators, and gauges for maintaining control through the subsea umbilical of selected functions during running and retrieving of the pod or lower marine riser package and/or the BOP stack.

7.3.15.13 The hose reel shall be equipped with a brake and a mechanical lock which shall be engaged when the hose has been spooled out to desired length.

7.3.15.14 The hose reel drive mechanism shall be protected to prevent accidental injury from rotating components to personnel.

7.3.15.15 The hose reel controls shall be clearly marked with which reel they control.

7.3.15.16 The hoses & reels should be visually inspected on a daily basis for leakage, or failed valves, hoses, fittings or gauges.

7.3.15.17 Hose sheaves should facilitate running and retrieving the subsea umbilical from the hose reel through the moonpool and support the moonpool loop which is deployed to compensate for vessel heave.

7.3.15.18 Sheaves shall maintain a larger radius than the MBR of the umbilical.

7.3.15.19 Hose sheaves shall be mounted to permit three-axis freedom of movement and prohibit damage to the umbilical in normal ranges of anticipated movement.

7.3.15.20 Sheave mounting supports shall be at least the SWL of the sheave.

7.3.15.21 Consider fleet & lead angles when locating the sheaves,

7.3.16 Subsea Control Pods

7.3.16.1 There shall be two fully redundant control pods on a subsea stack.

7.3.16.2 Each control pod should contain all necessary valves and regulators to operate the BOP stack functions.

7.3.16.3 The control pods may be retrievable or non-retrievable.

7.3.16.4 The control line from each control pod shall be connected to a shuttle valve that is connected to the function to be operated.

7.3.17 Emergency Systems

7.3.17.1 Emergency disconnect sequence (EDS) shall be installed on all subsea BOP stacks that are run from a dynamically position vessel.

7.3.17.2 The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a required state and disconnect the LMRP from the lower stack.

7.3.17.3 The number of sequences, timing, and functions of the EDS are specific to the rig, equipment, and location.

7.3.17.4 There shall be two separate locations from which the EDS can be activated.

7.3.18 Autoshear System

7.3.18.1 Autoshear is a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP.

7.3.18.2 Autoshear shall be installed on all subsea BOP stacks within three years of the published date of this document.

7.3.18.3 The Autoshear system shall normally be armed while latched onto a wellhead. A Management of Change shall be required to disarm the system.

7.3.18.4 The hydraulic accumulator system may be used for both the Autoshear and Deadman systems, as well as, for secondary control systems.

7.3.18.5 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.3.19 Deadman System

7.3.19.1 The Deadman system is designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and communication (pilot) in both subsea control pods.

7.3.19.2 A Deadman system shall be installed on all subsea BOP stacks within three years of the published date of this document.

7.3.19.3 The Deadman system shall normally be armed while latched onto a wellhead.

7.3.19.4 A Management of Change shall be required to disarm the system.

7.3.19.5 The hydraulic accumulator system may be used for both the Autoshear and Deadman systems, as well as, for secondary control systems.

7.3.19.6 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.3.20 Secondary Control System

7.3.20.1 ROV Intervention

7.3.20.1.1 The BOP stack shall be equipped with ROV intervention equipment, which at a minimum allows the closing of each shear ram, one pipe ram, and unlatching of the LMRP connector. These functions shall operate independently of the primary BOP control system.

7.3.20.1.2 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators or other external hydraulic power source.

7.3.20.1.3 The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions.

7.3.20.1.4 All receptacles shall mate with API 17H high-flow stabs.

7.3.20.1.5 All critical functions requiring 26 gal or less can be plumbed 3/8 in. (9.5 mm) ID minimum and for those functions greater than 26 gal shall be plumbed with 3/4 in. (19.5 mm) ID minimum.

7.3.20.2 Acoustic Control Systems (Optional)

7.3.20.2.1 The acoustic control system is designed to operate designated BOP stack and LMRP functions and is typically used when the primary control system is inoperable.

7.3.20.2.3 At a minimum the acoustics shall be capable of operating critical functions.

7.3.20.2.4 The hydraulic accumulator system may be used for both the acoustic system and emergency control systems.

7.3.20.2.5 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.3.20.2.6 Acoustic accumulators shall be capable of being dumped subsea, prior to recovering the BOP to surface.

7.3.20.2.7 Testing the acoustic system shall be in accordance with Table 6, Table 7, or Table 8.

7.4 Electro-hydraulic and Multiplex Control Systems for Subsea BOP Stacks

7.4.1 General

7.4.1.1 Control systems for subsea BOP stacks shall be designed and manufactured in accordance with API 16D.

7.4.1.2 The purpose of the BOP control system is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

7.4.1.3 Electrical command signals operate subsea solenoid valves which, in turn, provide hydraulic pilot signals directly to operate the pod valves that direct power fluid to the subsea functions.

7.4.1.4 Subsea MUX BOP control systems typically provide hydraulic power fluid in a vent-to-sea circuit.

7.4.1.5 The minimum required components of the BOP control system shall include the following:

— control fluid;

— control fluid reservoir;

— control fluid mixing system;

— pump systems;

— accumulator system;

— control system valves, fittings and components;

— control stations;

— umbilicals and reels;

— rigid conduit(s);

— control pods;

— emergency systems;

— secondary control systems.

7.4.2 Control Fluid

7.4.2.1 A suitable control fluid (fresh water containing a lubricant) shall be used as the control system operating fluid.

7.4.2.2 Control fluid shall be selected and maintained to meet minimum OEM properties and equipment owner requirements.

7.4.2.3 Water-based hydraulic fluids are typically used and are a mixture of potable water and a water-soluble lubricant additive. These fluids are available in concentrated or pre-mixed form.

7.4.2.4 Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32°F (0°C) are anticipated.

7.4.3 Control Fluid Reservoir

7.4.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

7.4.3.2 To prevent over-pressurization, vents shall be inspected and maintained to insure they are not plugged or capped.

7.4.3.3 All reservoir instrumentation shall be tested in accordance with equipment owner maintenance program to insure they are in proper working order.

7.4.3.4 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner maintenance program to insure indication of fluid level in each of the individual reservoirs are in proper working order.

7.4.4 Control Fluid Mixing System

7.4.4.1 The control fluid mixing system shall be designed for automatic operation.

7.4.4.2 The control fluid mixing system shall be tested to insure proper functionality of the automatic operating system.

7.4.4.3 The control fluid mixing system should be tested to insure it is manually selectable over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

7.4.4.4 A manual override of the automatic mixing system should be tested to insure proper operation.

7.4.5 Pump Systems

7.4.5.1 A pump system consists of one or more pumps.

7.4.5.2 Each pump system shall have an independent power source, such as electric or air.

7.4.5.3 At least one pump system shall be available at all times.

7.4.5.4 The combination of all pump system(s) shall be capable of charging the accumulator system from the minimum calculated operating pressure to the system maximum rated pressure in fifteen (15) minutes.

7.4.5.5 With the loss of one pump system, the remaining pump system(s) shall have the capacity to charge the accumulator system from precharge pressure to the system rated working pressure within thirty (30) minutes.

7.4.5.6 The same pump system(s) may be used to provide control fluid to control both the BOP stack and the diverter system.

7.4.5.7 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure.

7.4.5.8 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system rated working pressure and automatically stop between 97-100% of the system rated working pressure.

7.4.359 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system rated working pressure and automatically stop between 95-100% of the system rated working pressure.

7.4.5.10 Air pumps shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

7.4.5.11 Each pump system shall be protected from over pressurization by a minimum of two devices as follows:

— one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed the rated working pressure of the control system;

— the second device, such as a certified relief valve, to limit the pump discharge pressure and flow in accordance with API 16D.

7.4.5.12 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

7.4.5.13 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

7.4.6 Accumulator Systems

7.4.6.1 General

7.4.6.1.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions. This is achieved by the hydraulic compression of an inert gas with the hydraulic power unit (HPU). Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

7.4.6.1.2 Inert gas shall be used for pre-charging of surface accumulators. The gas used shall be in accordance with the accumulator design.

7.4.6.1.3 Subsea accumulators shall have the capability of being dumped subsea, prior to recovering the BOP and LMRP to surface.

7.4.6.2 Main Accumulator System

The main accumulator system consists of the surface accumulator system and LMRP accumulators that are part of the control system (if applicable).

7.4.6.3 Dedicated Accumulator System

7.4.6.3.1 The dedicated accumulators for emergency systems or secondary systems can be supplied by the main accumulator system, but shall not be affected if the main supply is depleted.

7.4.6.3.2 A dedicated accumulator system shall be provided for the pilot control systems; this may be supplied through a check valve from the main accumulator system.

7.4.6.4 Accumulator Drawdown Requirements

With pumps inoperative, the main accumulator system shall be capable of performing the accumulator drawdown test (see worksheet Annex A), consisting of closing from a full open position and opening (full stroke) at zero (0) wellbore pressure:

— the largest volume annular BOP, and

— four smallest volume ram type BOPs, excluding test rams, with

— the remaining system pressure at least 200 psi above the precharge pressure.

7.4.6.5 Control System Response Time

7.4.6.5.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

7.4.6.5.2 Measurement of closing response time begins when the close function is activated at any control panel and ends when the BOP or valve is closed affecting a seal.

7.4.6.5.3 A BOP can be considered closed when the regulated operating pressure has recovered to its nominal setting or other demonstrated means.

7.4.6.5.4 The following response times shall be met by at least one of the surface/subsea power supplies:

a) close each ram BOP within 45 seconds;

b) close each annular BOP within 60 seconds;

c) unlatch the riser (LMRP) connector within 45 seconds;

d) response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

7.4.6.6 Accumulator Precharge

7.4.6.6.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions.

7.4.6.6.2 The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

7.4.6.6.3 The precharge pressure on each accumulator bottle shall be measured prior to each BOP stack installation on each well and adjusted if necessary.

7.4.6.6.4 The precharge pressure shall be calculated using Method A, B, or C, per the original OEM sizing calculation design, see example Annex C.

7.4.6.6.5 The precharge pressure calculations shall take into account the well specific conditions (e.g. water depth, drill pipe shear pressure, mud weight, temperature, etc.).

7.4.6.6.6 The design of the BOP, mechanical properties of drill pipe and wellbore pressure may necessitate higher closing pressures for shear operations.

7.4.6.6.7 The subsea precharge pressure shall not exceed the rated working pressure of the accumulator.

NOTE The precharge pressure for subsea accumulators can exceed the pump pressure for deepwater applications which will affect surface testing.

7.4.6.7 Pressure Gauges Requirements

7.4.6.7.1 The precharge pressure for bladder type accumulators shall be greater than 25 % of the system rated working pressure, to prevent damage to the bladder.

7.4.6.7.2 Bladder and float type accumulators shall be mounted in a vertical position.

7.4.6.7.3 A pressure gauge for measuring the accumulator precharge pressure shall be available for installation at any time.

7.4.6.7.4 Those pressure gauges shall be calibrated to 1 % of full scale, and used to not less than 25 % or more than 75 % of the full pressure span of the gauge.

7.4.6.7.5 No accumulator bottle shall be operated at a pressure greater than its rated working pressure.

7.4.6.7.6 Supply-pressure isolation valves and bleed-down valves shall be provided on each accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

7.4.7 Control System Valves, Fittings and Components

7.4.7.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a rated working pressure at least equal to the rated working pressure of the control system.

7.4.7.2 Conformity of Piping Systems

7.4.7.2.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

7.4.7.2.2 Pipe, pipe fittings and components shall conform to specifications of ASME B31.3.

7.4.7.2.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

7.4.7.2.4 Welding shall be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with ASME Boiler and Pressure Vessel Code, Section IX.

7.4.7.2.5 All rigid or flexible lines, MUX cables, rigid conduit and hot line supply hoses between the control system and BOP are not required to meet the fire test requirements of API 16D, on those rigs with a autoshear and deadman system installed.

7.4.7.2.6 All control system interconnect piping, tubing, hose, linkages, etc., shall be protected from damage during drilling operations, and day-to-day equipment movement and have a working pressure equal to the rated working pressure of the BOP control system.

7.4.7.2.7 The control system shall be equipped to allow isolation of the pumps and the accumulators from the control circuits, thus allowing maintenance and repair work.

7.4.7.2.8 The control system shall be equipped and maintained with measurement devices to indicate

— surface accumulator pressure,

— LMRP accumulator pressure (if applicable),

— stack accumulator pressure,

— pod supply pressure,

— pilot supply pressure,

— all control pod regulator pressures, and

— flow metering.

7.4.7.2.9 The control system shall be equipped with a regulating valve to control the operating pressure on annular preventer(s).

7.4.7.2.9 The control system shall be equipped with a regulating valve to control the operating pressure on the ram BOPS.

7.4.7.2.10 The control system shall be capable of providing high pressure power fluid to the shear rams, in accordance with manufacturer's recommendations.

7.4.7.2.11 All control system analog pressure gauges shall be calibrated to 1 % of full scale at least every three (3) years.

7.4.7.2.7.4 Analog gauges shall be used at not less than 25 % or more than 75 % of the full pressure span of the gauge.

7.4.7.2.13 Electronic pressure measurement devices shall be accurate to 1 % and utilized within the manufacturer's specified range.

7.4.8 Control Stations

7.4.8.1 Control systems shall clearly identify each function and the function position (e.g. open, closed, etc).

7.4.8.2 The following functions shall be protected to avoid unintentional operation:

— shear rams close;

— riser connector unlock (LMRP connector unlock);

— wellhead connector unlock;

— EDS.

7.4.8.3 The subsea BOP control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations. One location shall be in a non-classified (non-hazardous) area as defined in API 500 and API 505.

7.4.8.4 The central control unit shall be supplied with electrical power from an uninterruptible power supply.

7.4.8.5 The main control unit shall be located in a safe, dry area. All functions shall be operable from and monitored from a remote control panel located on the rig floor, interfacing with the central control unit.

7.4.8.6 The control unit shall maintain function status memory in the event of power interruption.

7.4.8.7 Upon restoration of power, the system shall display the status of all functions as they were prior to the loss of power.

7.4.9 Data Acquisition & Remote Monitoring

7.4.9.1 Critical Data shall be captured or logged during the course of well drilling operations.

7.4.9.2 Data captured shall include (as a minimum) time and date stamp, solenoid functions energized, regulator and read-back pressures, and subsea accumulator pressures.

7.4.9.3 Data shall be retained in a manner that is easily retrievable (e.g. transmission to shore monitoring, backup).

7.4.10 Umbilicals and Reels

7.4.10.1 There shall be two or more means of surface to subsea fluid supply. The rigid conduit(s) are attached to the riser and provide the primary hydraulic supply to the subsea control pods.

7.4.10.2 The hotline hose supplies power fluid from the surface to the subsea control pods mounted on the LMRP. The hotline is run, retrieved, and stored on the hose reel.

7.4.10.3 The hotline(s) shall be secured to the riser by clamps to prevent abrasion and flexing damage.

7.4.10.4 The outer sheath should be visually inspected for damage on retrieval.

7.4.10.5 The umbilical shall be tested to MWP in a documented integrity test on an annual basis Re-terminations, repairs or splices shall be tested to manufacturers recommended MWP.

7.4.10.6 The MUX electrical cable supplies power, communications, and control of the subsea control pods. The MUX cable is run, retrieved, and stored on a cable reel.

7.4.10.7 The electrical conductors and electrical insulation shall not be used as load bearing components in the cable assembly.

7.4.10.8 All underwater electrical umbilical cable terminations shall be sealed to prevent water migration into the cable in the event of connector failure or leakage and to prevent water migration from the cable into the subsea connector termination in the event of water intrusion into the cable.

7.4.10.9 Individual connector terminations shall be physically isolated so that seawater intrusion does not cause electrical shorting.

7.4.10.10 The hose/MUX reel shall be equipped with a brake and a mechanical lock which shall be engaged when the hose has been spooled out to desired length.

7.4.10.11 The hose/MUX reel drive mechanism shall be protected to prevent accidental injury from rotating components to personnel.

7.4.10.7.4 The hose/MUX reel controls shall be clearly marked with which reel they control.

7.4.10.13 The hoses, cables, & reels should be visually inspected on a daily basis for damage and proper operation.

7.4.10.14 Hose/cable sheaves should facilitate running and retrieving the hotline from the hose reel through the moonpool and support the moonpool loop which is deployed to compensate for vessel heave.

7.4.10.15 Sheaves shall maintain a larger radius than the MBR of the umbilical.

7.4.10.16 Hose/cable sheaves shall be mounted to permit three-axis freedom of movement and prohibit damage to the umbilical in normal ranges of anticipated movement.

7.4.10.17 Sheave mounting supports shall be at least the SWL of the sheave.

7.4.10.18 Consider fleet and lead angles when locating the sheaves.

7.4.11 Subsea Control Pods

7.4.11.1 There shall be two fully redundant control pods on a subsea stack.

7.4.11.2 Each control pod should contain all necessary valves and regulators to operate the BOP stack functions.

7.4.11.3 The control pods may be retrievable or non-retrievable.

7.4.11.4 The control line from each control pod shall be connected to a shuttle valve that is connected to the function to be operated.

7.4.11.5 Auxiliary subsea electrical equipment that is not directly related to the BOP control system shall be connected in a manner to avoid disabling the BOP control system in the event of a failure in the auxiliary equipment.

7.4.12 Emergency Systems

7.4.12.1 Emergency Disconnect Sequence (EDS) shall be installed on all subsea BOP stacks that are run from a dynamically position vessel.

7.4.12.2 The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a required state and disconnect the LMRP from the lower stack.

7.4.12.3 The number of sequences, timing and functions of the EDS are specific to the rig, equipment and location.

7.4.12.4 There shall be two separate locations from which the EDS can be activated.

7.4.13 Autoshear System

7.4.13.1 Autoshear is a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP.

7.4.13.2 Autoshear shall be installed on all subsea BOP stacks within three years of the published date of this document.

7.4.13.3 he Autoshear system shall normally be armed while latched onto a wellhead. A Management of Change shall be required to disarm the system.

7.4.13.4 The hydraulic accumulator system may be used for both the Autoshear and Deadman systems, as well as, for secondary control systems. This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.4.14 Deadman System

7.4.14.1 The Deadman system is designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and communication (pilot) in both subsea control pods.

7.4.14.2 A Deadman system shall be installed on all subsea BOP stacks within three years of the published date of this document

7.4.14.3 The Deadman system shall normally be armed while latched onto a wellhead. A Management of Change shall be required to disarm the system.

7.4.14.4 The hydraulic accumulator system may be used for both the Autoshear and Deadman systems, as well as, for secondary control systems.

7.4.14.5 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.4.15 Secondary Control System

7.4.15.1 ROV Intervention

7.4.15.1.1 The BOP stack shall be equipped with ROV intervention equipment, which at a minimum allows the closing of each shear ram, one pipe ram, and unlatching of the LMRP connector. These functions shall operate independently of the primary BOP control system.

7.4.15.1.2 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators or other external hydraulic power source.

7.4.15.1.3 The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions.

7.4.15.1.4 All receptacles shall mate with API 17H high-flow stabs.

7.4.15.1.5 All critical functions shall be fitted with API 17H high-flow receptacles.

7.4.15.1.6 All critical functions requiring 26 gal or less can be plumbed 3/8 in. (9.5 mm) ID minimum and for those functions greater than 26 gal shall be plumbed with 3/4 in. (19.5 mm) ID minimum.

7.4.15.2 Acoustic Control Systems (Optional)

7.4.15.1 The acoustic control system is designed to operate designated BOP stack and LMRP functions and is typically used when the primary control system is inoperable.

7.4.15.2 At a minimum the acoustics shall be capable of operating critical functions.

7.4.15.3 The hydraulic accumulator system may be used for both the acoustic system and emergency control systems.

7.4.15.4 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.4.15.5 Acoustic accumulators shall be capable of being dumped subsea, prior to recovering the BOP to surface.

7.4.15.6 Testing the acoustic system shall be in accordance with Table 6 or Table 7.

7.5 Auxiliary Equipment-Subsea BOP Installations

7.5.1 Kelly Valves

An upper kelly valve is installed between the swivel and the kelly. A lower kelly valve is installed immediately below the kelly.

7.5.2 Drill Pipe Safety Valve

A spare drill pipe safety valve should be readily available (i.e., stored in open position with wrench accessible) on the rig floor at all times. This valve or valves should be equipped to screw into any drill string member in use. The outside diameter of the drill pipe safety valve should be suitable for running into the hole.

7.5.3 Inside Blowout Preventer

An inside blowout preventer, drill pipe float valve, or drop-in check valve should be available for use when stripping the drill string into or out of the hole. The valve(s), sub(s), or profile nipple should be equipped to screw into any drill string member in use.

7.5.4 Field Testing

The kelly valves, drill pipe safety valve, and inside blowout preventer should be tested in accordance with Table 9 and Table 10.

7.5.5 Drill String Float Valve

7.5.5.1 A float valve is placed in the drill string to prevent upward flow of fluid or gas inside the drill string. The float valve is a special type of backpressure or check valve. A float valve in good working order will prohibit backflow and a potential blowout through the drill string.

7.5.5.2 The drill string float valve is usually placed in the lowermost portion of the drill string, between two drill collars or between the drill bit and drill collar. Since the float valve prevents the drill string from being filled with fluid through the bit as it is run into the hole, the drill string must be filled from the top, at the drill floor, to prevent collapse of the drill pipe. The two types of float valves are described in the following.

a) The flapper-type float valve offers the advantage of having an opening through the valve that is approximately the same inside diameter as that of the tool joint. This valve will permit the passage of balls, or go-devils, which may be required for operation of tools inside the drill string below the float valve.

b) The spring-loaded ball, or dart, and seat float valve offers the advantage of an instantaneous and positive shut-off of backflow through the drill string.

7.5.5.3 These valves are not full-bore and thus cannot sustain long duration or high volume pumping of drilling fluid or kill fluid. However, a wireline retrievable valve that seals in a profiled body that has an opening approximately the same inside diameter as that of the tool joint may be used to provide a full-open access, if needed.

7.5.6 Trip Tank

A trip tank is a low-volume, (100 barrels [15.9 m^3] or less), calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well. A trip tank may be of any shape provided the capability exists for reading the volume contained in the tank at any liquid level. The readout may be direct or remote, preferably both. The size and configuration of the tank should be such that volume changes approximately one-half barrel can be easily detected by the readout arrangement. Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations.

Other uses of the trip tank include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following a cement job, calibrating drilling fluid pumps, etc. The trip tank is also used to measure the volume of drilling fluid bled from or pumped into the well as pipe is stripped into or out of the well.

7.5.7 Pit Volume Measuring and Recording Devices

Automatic pit volume measuring devices are available which transmit a pneumatic or electric signal from sensors on the drilling fluid pits to recorders and signaling devices on the rig floor. These are valuable in detecting fluid gain or loss.

7.5.8 Flow Rate Sensor

A flow rate sensor mounted in the flow line is recommended for early detection of formation fluid entering the wellbore or a loss of returns.

7.5.9 Poor Boy Degasser

The poor boy separator is used to separate gas from drilling fluid that is gas cut. The separated gas can then be vented to a safe distance from the rig. Generally, two basic types of mud gas separators are in use. The most common type is the atmospheric poor boy degasser, sometimes referred to as a gas buster or mud/gas separator. Another type of poor boy degasser is designed such that it can be operated at a moderate backpressure, usually less than 100 psi (0.69 MPa), although some designs are operated at gas vent line pressure which is atmospheric plus line friction drop. All separators with a liquid level control may be referred to as pressurized poor boy degassers.

Both the atmospheric and pressurized poor boy separators have advantages and disadvantages. Some guidelines are common to both types of poor boy degassers. A bypass line to the flare stack must be provided in case of malfunction or in the event the capacity of the poor boy degasser is exceeded. Precautions must also be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the wall of the vessel. Provisions must be made for easy clean out of the vessels and lines in the event of plugging. Unless specifically designed for such applications, use of the rig poor boy degasser is not recommended for well production testing operations.

The dimensions of a separator are critical in that they define the volume of gas and fluid a separator can effectively handle.

7.5.10 Degasser

A degasser may be used to remove entrained gas bubbles in the drilling fluid that are too small to be removed by the poor boy separator. Most degassers make use of some degree of vacuum to assist in removing this entrained gas. The drilling fluid inlet line to the degasser should be placed close to the drilling fluid discharge line from the poor boy degasser to reduce the possibility of gas breaking out of the drilling fluid in the pit.

7.5.11 Flare Lines

All flare lines should be as long as practical with provisions for flaring during varying wind directions. Flare lines should be as straight as possible and should be securely anchored.

7.5.12 Standpipe Choke

An adjustable choke mounted on the rig standpipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed-off pressure between BOPS during stripping operations. See Figure 7 for an example standpipe choke installation.

7.5.13 Top Drive Equipment

There are two ball valves (sometimes referred to as kelly valves or kelly cocks) located on top drive equipment. The upper valve is air or hydraulically operated and controlled at the driller's console. The lower valve is a standard ball kelly valve (sometimes referred to as a safety valve) and is manually operated, usually by means of a large hexagonal wrench. Generally, if it becomes necessary to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the top drive valves. However, flow up the drill pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions:

a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve;

b) most top drive manual valves cannot be stripped into 7 5/8 in. (19.37 cm) or smaller casing;

c) once the top drive's manual valve is disconnected from the top drive, another valve or spacer must be installed to take its place.

7.5.14 Guide Frames

The BOP guide frame, a four-post structure attached to the BOP assembly, is a means for guiding the complete BOP/LMRP assembly's primary alignment onto the permanent guide base (see API 17D). The upper section of the guide structure acts as primary guidance for the lower marine riser package. The guide structure also acts as the structural mounting for the various components of the remote control system and the choke/kill connectors or stab subs. The guide structure should have sufficient strength to protect the BOP stack from damage during handling and landing operations.

7.5.15 Underwater Television

An underwater television system for visual inspection of the wellhead, BOP stack, marine riser, and other allied underwater components generally consists of a television camera and high intensity lights attached to a telescoping guide frame. This guide frame normally attaches around two of the guidelines. The assembly can be lowered and retrieved by a special umbilical cable that supports the package plus furnishes all electrical circuitry for the television camera and lights. Surface equipment includes a powered reel for the umbilical cable and a television monitor with allied electronic equipment and camera remote control.

7.5.16 Slope Indicator

This device is a circular glycerin- filled, plexiglas-covered slope indicator used to measure the angular deflection of components to which it is attached. A chrome plated ball bearing inside the slope indicator moves about circular black and white bands (graduated in degrees-painted on the base) to indicate angular position. Slope indicators are typically installed on the permanent guide base, BOP guide frame, LMRP guide frame, and first joint of riser above the lower ball/flex joint.

7.5.17 Pin Connector/Hydraulic Latch

This hydraulically operated connector is used to connect the drilling riser to the conductor housing before the BOP stack is run to allow returns back to the surface. This assembly can also be used in conjunction with a subsea diverter application.

7.5.18 Mud Booster Line

Some riser strings are equipped with a mud booster line. This is an additional auxiliary line used to increase volume and flow rate of drilling fluid up the riser and to allow circulating the riser above a shut in BOP stack. Booster lines normally terminate into the riser just above the lower flexhall joint on the LMRP.

7.5.19 Auxiliary Hydraulic Supply Line (Hard/Rigid Conduit)

An auxiliary hydraulic supply line, referred as a hard or rigid conduit, is a metallic line attached to risers joints. The purpose of this auxiliary line is to supply control fluid from the surface accumulator system to the control pods and subsea accumulators mounted on the BOP and/or LMRP assemblies.

7.5.20 Riser Tensioning Support Ring

A riser tensioning support ring is attached (integrally or remotely) to the telescopic joint outer barrel to allow tensioning of the riser. The tensioning ring is the mechanical link between the riser and the tensioner cables on the rig. The riser tensioners allow relative movement of the drilling vessel with respect to the stationary riser.

7.6 Testing and Maintenance Subsea BOP Stacks and Well Control Equipment

7.6.1 Purpose

The purpose for various field test programs on drilling well control equipment are to verify

a) that specific functions are operationally ready,

b) the pressure integrity of the installed equipment, and

c) the control system and BOP compatibility.

7.6.2 Types of Tests

7.6.2.1 General

7.6.2.1.1 Test programs incorporate visual inspections, functional operations, pressure tests, maintenance practices, and drills. Descriptions of these basic types of tests are provided in 7.6.2.2 through 7.6.2.5.

7.6.2.1.2 A visual inspection (by ROV) should be performed. Operability and integrity can be confirmed by function and pressure testing.

7.6.2.1.3 Site-specific procedures for tests on well control equipment shall be incorporated into acceptance tests, initial and subsequent tests, drills, periodic operating tests, maintenance practices, and drilling and/or completion operations.

7.6.2.1.4 Pressure test programs for the subsea wellhead and casing shall be prescribed by the operator on an individual well basis.

7.6.2.1.5 Manufacturer operating and maintenance documents, contractor maintenance programs, and operating experiences shall be incorporated into the site-specific procedures.

7.6.2.2 Inspection Test

7.6.2.2.1 The common collective term used to state the various procedural examination of flaws that can influence equipment performance.

7.6.2.2.2 Inspection tests may include, but are not limited to, visual, dimensional, audible, hardness, functional, and pressure tests. Inspection practices and procedures are outside the scope of this document.

7.6.2.3 Function Test

A function test is the operation of a piece of equipment or a system to verify its intended operation. Function testing typically does not include pressure testing. Actuation test, operating test, and readiness test are other terms commonly used synonymously for function test.

7.6.2.4 Pressure Test

A pressure test is the periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system. “Wellbore test” is another descriptive term frequently used synonymously for pressure test.

7.6.2.5 Hydraulic Chamber Test

A hydraulic chamber test is the application of a pressure test to any hydraulic operating chamber specified by the manufacturer for such items as:

— BOP operator cylinders and bonnet assemblies,

— hydraulic valve actuators,

— hydraulic connectors, etc.

7.6.3 Crew Drills

The proficiency with which drilling crews operate the well control equipment is as significantly important as the operational condition of the equipment. See API 59 for more information on crew drills and well control rig practices.

7.6.4 Crew Competency

Maintenance and testing shall be performed or supervised by a competent person(s).

7.6.5 Test Criteria

7.6.5.1 Function Tests

7.6.5.1.1 All well control components of the BOP stack shall be function tested at least once a week, or as operations allow, to verify the component's intended operations. Pressure tests qualify as function tests.

7.6.5.1.3 Function test schedules shall be developed for testing alternate combinations of all panels and pods on a weekly rotation.

7.6.5.1.4 Remote panels where all BOP functions are not included shall be function tested upon the initial test and monthly thereafter (e.g. lifeboat panels, etc.).

7.6.5.1.5 All ROV function testing shall be performed in accordance with Table 6, Table 7, or Table 8.

7.6.5.1.6 Three ROV critical functions are required, BSR close, MPR close and LMRP disconnect. Additional ROV functions may be added to suit the specifics of the well operations and equipment installed.

7.6.5.1.7 All ROV intervention critical functions shall be fitted with high-flow type receptacles in accordance with API 17H.

7.6.5.1.8 Actuation times shall be recorded as a database for evaluating trends (see sample worksheets in Annex A).

7.6.5.1.9 Release or latching type components of subsea well control systems (choke, kill, riser, wellhead connectors, etc.) and emergency backup systems are typically only function tested at the start or completion of the well.

Table 6 — Surface Testing of Secondary, Emergency, and Other Systems

System Type	Secondary Systems Test	
	Components Function Tested	**Frequency**
Acoustic	All assigned functions	Prior to deployment
ROV – critical functions	All ROV critical functions	Prior to deployment
	Emergency Systems Test	
Deadman (or equivalent)[a]	All assigned components	Prior to deployment
Autoshear (or equivalent)[a]	All assigned components	Prior to deployment
Emergency disconnect sequence[b]	All assigned components	Prior to deployment

[a] Deadman and autoshear on all rigs within three years from the publish date of this document,

[b] EDS not required on moored vessels.

Table 7 — Subsea Testing of Secondary, Emergency and Other Systems

System Type	Secondary Systems Test	
	Components Function Tested	**Frequency or Criteria**
Acoustic	Communications	Not to exceed 21 days between tests
	One function	One time during initial subsea BOP test
ROV – critical functions	One BSR or pipe ram	One time during initial subsea BOP test
	Lower marine riser package connector	Not required - consider functioning during storm evacuation, repair, maintenance, and end of well or program
	Emergency Systems Test	
Deadman (or equivalent)[a]	All assigned components	Commissioning or within 5 years of previous test
Autoshear (or equivalent)[a]	All assigned components	Commissioning or within 5 years of previous test
Emergency disconnect sequence[b]	All assigned components	Commissioning or within 5 years of previous test

[a] Deadman and autoshear on all rigs within three years from the publish date of this document,

[b] EDS not required on moored vessels.

Table 8 — Other Systems Test

System Type	Type of Test	Frequency
Riser Recoil	Full riser recoil test with BOP installed subsea[a]	A controlled riser recoil test during commissioning, at rig acceptance (as per contract agreement), system design change or software changes to recoil system.
	Simulated function test on surface[b]	Yearly

[a] Test is to be performed with BOP installed subsea (do not perform over or near subsea production infrastructure)

[b] A simulated test does not require installation of the BOP.

7.6.5.2 Pressure Tests

7.6.5.2.1 All blowout prevention components that can be exposed to well pressure shall be tested first to a low pressure of 200 psi to 300 psi (1.38 MPa to 2.1 MPa) and then to a high pressure.

7.6.5.2.2 When performing the low-pressure test, do not apply a higher pressure and bleed down to the low-test pressure. The higher pressure can initiate a seal that can continue to seal after the pressure is lowered therefore, misrepresenting a low-pressure condition.

7.6.5.2.3 A stabilized low- and high-test pressure shall be maintained for at least five (5) minutes with no visible leakage.

7.6.5.2.4 The initial high-pressure test on components that can be exposed to well pressure (BOP stack, choke manifold, and choke/kill lines) shall be to the rated working pressure of the ram BOPs, or to the rated working pressure of the wellhead assembly that the stack is installed on, whichever is lower. Initial pressure tests are defined as those tests performed before the well is spudded (stump test) or before the equipment is put into operational service (upon landing subsea).

7.6.5.2.5 Annular BOPs, with a joint of drill pipe, tubing, or a test mandrel installed, shall be tested to a minimum of 70 % of the annular preventer rated working pressure, or to the wellhead assembly rated working pressure, whichever is the less.

7.6.5.2.6 The lower kelly valves, kelly, kelly cock, drill pipe safety valves, and top drive safety valves, should be tested with water from the wellbore side to a low pressure and to the rated working pressure, MASP + 500 psi (3.4 MPa) or wellhead assembly pressure rating, whichever is lower.

7.6.5.2.7 There can be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these should be covered in the site-specific well control pressure test program.

7.6.5.2.8 Choke and kill line connections shall be tested to the working pressure of the ram BOPs while running the riser.

7.6.5.2.9 After landing the subsea BOP stack the BOP-to-wellhead connector shall be tested to the rated working pressure of the ram BOPs, MASP + 500 psi (3.5 MPa) or the wellhead assembly pressure rating, whichever is lower.

7.6.5.2.10 Subsequent high pressure tests on the well control components shall be to a pressure of 500 psi (3.5 MPa) above the MASP (maximum anticipated surface pressure), but not to exceed the rated working pressure of the ram BOP's or wellhead assembly.

7.6.5.2.11 With larger size annular BOPs some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This packer creep movement should be considered when monitoring the pressure test of the annular.

7.6.5.2.12 Pressure test operations shall be alternately controlled from the various onsite control stations and panels.

7.6.5.2.13 Pressure test operations shall be alternately controlled from the various onsite control stations and panels.

7.6.5.2.7.6 All valves (except check valves) shall be tested in the direction of flow.

7.6.5.2.15 Valves that require seal against flow from both directions shall be tested from both directions.

7.6.5.2.16 Drifting the BOP shall be performed prior to deployment and upon completion of the initial BOP test on the wellhead assembly. This may be achieved using the test plug, wear bushing tools, or other large bore tools.

7.6.5.3 Hydraulic Chamber Test

7.6.5.3.1 All pressure tests on hydraulic chambers on annular or ram type preventers and hydraulically operated valves and connectors shall be tested to the maximum operating pressure of the component or as recommended by the equipment owner.

7.6 5.3.2 The tests shall be performed on both the opening and the closing chambers of the equipment installed.

7.6.5.3.3 Pressure shall be stabilized for at least five (5) minutes with no visible leakage.

7.6.5.3.4 The pressure tests on the BOP control system shall be to the maximum operating pressure of the system, with no visible leakage.

7.6.5.4 Pressure Test Frequency

7.6.5.4.1 Pressure tests on the well control equipment shall be conducted as follows:

a) prior to running the BOP subsea and upon installation;

b) after the disconnection or repair of any pressure containment seal in the BOP stack, choke line, choke manifold, or wellhead assembly, but limited to the affected component;

c) in accordance with equipment owner's preventive maintenance program;

d) not to exceed 21 days.

7.6.9.4.2 Tables 3 and 4 include a summary of the recommended test practices for subsea BOP stacks and related well control equipment.

7.6.9.4.3 Chamber pressure tests shall be performed yearly or when equipment is repaired or remanufactured.

7.6.9.4.4 Pressure tests of the BOP control system shall be performed following the disconnection or repair, limited to the affected component.

7.6.5.5 Test Fluids

7.6.5.5.1 The stump and initial installation pressure tests shall be conducted with water.

7.6.5.5.2 During operations, the drilling fluid in use is acceptable to perform subsequent tests of the subsea BOP stack, to reduce the risk of an influx from hydrostatic pressure reductions.

7.6.5.5.3 Control systems and hydraulic chambers shall be tested using control system fluids.

7.6.5.6 Pressure Measurement Devices

7.6.5.6.1 Test pressure gauges, chart recorders, and/or data acquisition systems shall be used and all testing results documented.

7.6.5.6.2 It is acceptable for gauges used during the course of normal operations to read full scale and not serve as a test gauge.

7.6.5.6.3 Analog test pressure measurements shall be made at not less than 25 % and not more than 75 % of the full pressure span.

7.6.5.6.4 Electronic pressure gauges and chart recorders, or data acquisition systems shall be utilized within the manufacturer’s specified range.

7.6.5.6.5 Electronic test pressure transducers shall be calibrated per OEM recommendations.

7.6.5.6.6 Pressure measurement devices shall be calibrated per OEM procedures annually. Calibrations shall be traceable to a recognized national standard.

Table 9 — Recommended Pressure Test Practices, Floating Rigs with Subsea BOP Stacks, Initial Test

Component to be Tested	**Recommended Pressure Test - Low Pressure** [a] psi (MPa)	**Recommended Pressure Test - High Pressure** [b,c] psi (MPa)
Annular preventer	200 to 300 (1.38 to 2.1)	Minimum of 70% of annular RWP
Operating chambers	N/A	Maximum operating pressure recommended by the annular manufacturer
Ram preventers		
Fixed pipe	200 to 300 (1.38 to 2.1)	RWP of ram BOPs or wellhead system, whichever is lower
Variable bore	200 to 300 (1.38 to 2.1)	RWP of ram BOPs or wellhead system, whichever is lower
Blind/blind shear	200 to 300 (1.38 to 2.1)	RWP of ram BOPs or wellhead system, whichever is lower
Casing shear rams	Function test	RWP of ram BOPs or wellhead system, whichever is lower
Operating chamber	N/A	Maximum operating pressure recommended by the ram BOP manufacturer.
Wellhead or stack connector	200 to 300 (1.38 to 2.1)	RWP of ram BOPs or wellhead system, whichever is lower
Choke and kill line and valves	200 to 300 (1.38 to 2.1)	RWP of ram BOPs or wellhead system, whichever is lower
Operating chamber	N/A	Maximum operating pressure recommended by the valve manufacturer
BOP choke Manifold		
Upstream of chokes	200 to 300 (1.38 to 2.1)	Working pressure of ram BOPs
Downstream of chokes	Rated working pressure of ram BOPs	Optional
Adjustable choke	During choke drill	Verification of back-up system
BOP control system		
Manifold and BOP lines	N/A	Control system maximum operating pressure
Accumulator pressure	Verify precharge	N/A
Close time	Function test	N/A
Pump capability	Function test	N/A
Control stations	Function test	N/A
Safety valves		
Kelly, kelly valves, and floor safety valves	200 to 300 (1.38 to 2.1)	RWP of components or 500 psi (3,4 MPa) above MASP
Auxiliary Equipment	200 to 300 (1.38 to 2.1)	Optional
Riser slip joint	Flow test	N/A
Poor boy separator	Flow test	N/A
Trip tank, flo-show, etc.	Flow test	N/A
Upon installation or in accordance with equipment owners' preventive maintenance program.		

[a] The low-pressure test should be stable for at least five (5) minutes with no visible leaks.

[b] The high-pressure test should be stable for at least five (5) minutes with no visible leaks.

[c] Well control equipment may have a higher rated working pressure (RWP) than for the well site. The site-specific test requirement shall be considered for these situations.

Table 10 —Pressure Test Practices, Floating Rigs with Subsea BOP Stacks, Subsequent Tests

Component to be Tested	Recommended Pressure Test - Low Pressure [a] psi (MPa)	Recommended Pressure Test - High Pressure [b] psi (MPa)
Annular preventer	200 to 300 (1.38 to 2.1)	Minimum of 70% of annular RWP or 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead assembly
Ram preventers		
Fixed pipe	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
Variable bore	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
Blind/blind shear (initial installation)	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
Casing shear rams	Function test only	N/A
Wellhead or stack connector	N/A	N/A
Choke and kill lines and valves	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
Kill line and valves below a test ram	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
BOP choke manifold		
Upstream of chokes	200 to 300 (1.38 to 2.1)	A minimum of 500 psi (3.5 MPa) above the MASP, but not to exceed the RWP of the wellhead
Downstream of chokes	Optional	Optional
Adjustable choke(s)	During choke drill	Verification of back-up systems
BOP control system		
Manifold and BOP lines	N/A	Optional
Accumulator pressure	N/A	N/A
Close time	Function test	N/A
Control stations	Function test	N/A
Safety valves		
Kelly, kelly valves, drill pipe safety valves, IBOPs, etc.	200 to 300 (1.38 to 2.1)	Greater than the maximum anticipated surface shut-in pressure
Auxiliary Equipment	N/A	N/A
Riser slip joint	Flow test	N/A
Poor boy separator	Optional	N/A
Trip tank, flo-show, etc.	Flow test	N/A
Subsequent tests shall not exceed 21 days (for wellbore testing) and/or in accordance with owners' preventive maintenance program.		

[a] The low-pressure test should be stable for at least five (5) minutes.

[b] The high-pressure test should be stable for at least five (5) minutes. Flow-type test should be of sufficient duration to observe for significant leaks.

[c] Well control equipment may have a higher RWP than required for the well site. The site-specific test requirement shall be utilized for these situations.

7.6.5.7 Test Documentation

7.6.5.7.1 The results of all BOP equipment pressure and function tests shall be documented (see example worksheet Annex A)

7.6.5.7.2 Pressure test shall be performed with a pressure recorder or equivalent data acquisition system and signed by the pump operator, contractor's tool pusher, and operator's representative.

7.6.5.7.3 Problems observed during testing and any actions taken to remedy the problems shall be documented.

7.6.5.8 General Testing Considerations

7.6.5.8.1 A public address announcement to all personnel shall be made to alert when pressure test operations are to be conducted. Only necessary personnel shall be allowed to enter the cordoned off test area.

7.6.5.8.2 Only personnel authorized by the well site supervisor shall go into the test area to inspect for leaks when the equipment involved is under pressure.

7.6.5.8.3 Tightening, repair, or any other work shall be done only after pressure has been released and all parties have agreed that there is no possibility of pressure being trapped.

7.6.5.8.4 When testing from the cement unit, pressure shall be released only through pressure release lines and the return volume measured to confirm all pressure has been bled off.

7.6.5.8.5 All lines and connections that are used in the test procedures shall be adequately secured.

7.6.5.8.6 All fittings, connections, and piping used in pressure testing operations shall have pressure ratings greater than the maximum anticipated test pressure.

7.6.5.8.7 The type, pressure rating, size, and end connections for each piece of equipment to be tested shall be verified as documented by permanent markings on the equipment or by records that are traceable to the equipment.

7.6.5.8.8 The drill pipe test joint should be pipe that can withstand the tensile, collapse, and internal pressures that will be placed on it during the test operation.

7.6.5.8.9 A procedure shall be available to monitor pressure on the casing should the test plug leak.

7.6.5.8.10 Flexible choke and kill lines should be tested to the same pressure, frequency, and durations as the ram BOPs.

7.6.5.8.11 All ROV ports shall be function tested on surface prior to BOP deployment. Additionally, one pipe ram port shall be function tested on initial subsea test.

7.6.6 Subsea BOP Stack Equipment

7.6.6.1 The subsea stack equipment includes the subsea wellbore pressure-containing equipment above the wellhead and below the ball/flex joint. This equipment includes the wellhead and LMRP connectors, ram BOPs, spool(s), annular(s), choke and kill valves, and choke and kill lines.

7.6.6.2 Unless restricted by height, the entire stack should be pressure tested as a unit.

7.6.6.3 Annular BOPs should be tested using the smallest OD pipe to be used.

7.6.6.4 Fixed bore pipe rams should be tested only on the pipe OD size that matches the installed pipe ram blocks.

7.6.6.5 Variable bore rams should be initially pressure tested on the largest and the smallest OD pipe sizes that can be used during the well operation.

7.6.6.6 Blind rams and blind shear rams should not be tested when pipe is in the stack. The capability of the shear ram and ram operator should be verified with the manufacturer for the planned drill string. The shear ram preventer design and/or metallurgical differences among drill pipe manufacturers may require high closing pressures for shear operations.

7.6.6.7 When drill pipe hang-off is a possibility during well control, hang-off procedures should be preplanned. The manufacturer's recommended hang-off load capacity for fixed-bore ram blocks should be considered. Example hang-off procedures are included in API 59. The original ram BOP equipment manufacturer should be consulted regarding hanging off drill pipe on variable bore ram BOPs.

7.6.6.8 Prior to surface testing each ram BOP, the secondary rod seal (emergency pack-off assembly) should be checked to ensure the seals have not been energized. Should the ram shaft seal leak during the stump test, the seal shall be repaired rather than energizing the secondary packing.

7.6.6.9 All ram-type BOPs with ram locks shall be pressure tested with the locks in the closed position and the closing pressure vented during stump testing.

7.6.6.10 The uppermost BSR and the hang-off ram BOP shall be pressure tested with locks in the locked position and closing pressure vented, during the initial installation test.

7.6.6.11 The BOP elastomeric components that can be exposed to well fluids should be verified by the BOP manufacturer as appropriate for the drilling fluids to be used and for the anticipated temperatures. Consideration should be given to the temperature and fluid conditions during well testing and completion operations.

7.6.6.12 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for six (6) months or longer and has not been preserved according to equipment owner guidelines.

7.6.6.13 Valve actuator spring integrity shall be tested prior to deployment, for all well control valves, to confirm that the valve actuator will close or open the valve gate to its normal close or normal open position, without hydraulic assistance.

7.6.6.14 If visual position indicators are not available then, pressure testing or flow against the valve(s) shall be performed.

7.6.7 Chokes and Choke Manifolds

7.6.7.1 The choke manifold upstream of and including the last high pressure valves (see Section 10) should be tested to the same pressure as the ram BOPs.

7.6.7.2 The valves and adjustable chokes should be operated daily to verify operability. Choke manifold valves should be serviced according to equipment owner's maintenance program.

7.6.7.3 The auto choke back-up pneumatic/hydraulic control system shall be checked to ensure operation in the event of loss of primary supply in accordance with equipment owner's maintenance program.

7.6.7.4 The frequency of the choke drill shall be at initial installation and subsequent testing, at each casing point or in accordance with equipment owners' maintenance program.

7.6.7.5 Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required (see Table 9 and Table 10).

7.6.8 In-the-field Control System Accumulator Capacity

7.6.8.1 General

It is important to distinguish between the standards for in-the-field control system accumulator capacity established in this document and the design requirements established in API 16D.

API 16D provides sizing guidelines for designers and manufacturers of control systems. In the factory, it is not possible to exactly simulate the volumetric demands of the control system piping, hoses, fittings, valves, BOPs, etc. On the rig, efficiency losses in the operation of fluid functions result from causes such as friction, hose expansion, control valve interflow as well as heat energy losses. Therefore, the establishment by the manufacturer of the design accumulator capacity provides a safety factor. This safety factor is a margin of additional fluid capacity which is not actually intended to be usable to operate well control functions on the rig.

For this reason, the control system design accumulator capacity formulas established in API 16D are different from the demonstrable capacity guidelines provided in this document.

The original control system manufacturer shall be consulted in the event that the field calculations or field testing should indicate insufficient capacity or in the event that the volumetric requirements of equipment being controlled are changed, such as by the modification or change out of the BOP stack.

7.6.8.2 Drawdown Test

7.6.8.1 The purpose of this test is to verify that the accumulator system is properly sized to support the fluid volume and pressure requirements of the BOPS on the rig.

7.6.8.2 A drawdown test should be performed prior to running the BOPs subsea, upon the initial landing of the stack, after any repairs that required isolation/partial isolation of the system, or every 6 months after the stack has been deployed, using the following procedures (see sample worksheets and examples in Annex A).

a) Position a properly sized joint of drill pipe or a test mandrel in the BOPs.

b) Turn off the power supply to all accumulator charging pumps (air, electric, etc.).

c) Record the initial accumulator pressure. Manifold and annular regulators should be set at the manufacturer's recommended operating pressure for the BOP stack.

d) Individually close and open the four (4) smallest ram BOPs (excluding blind/shear ram BOPs), recording the closing time and fluid volume required for each function. To simulate the functioning of the blind/shear rams, close and open one set of pipe rams again. Closing times shall meet response times established in 6.3.2.

NOTE Volumes associated with substituting a pipe ram for a BSR may be different, but closing the same ram combination confirms consistent operation.)

e) Open the choke and kill hydraulic operated valves and record the time and volume required.

f) Close and open largest annular BOP and record the time and volume.

g) Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.38 MPa) above precharge pressure.

NOTE 1 When performing the accumulator drawdown test, wait a minimum of one hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a failed test.

NOTE 1 Because it takes time for the gas in the accumulator to warm up after performing all of the drawdown test functions, you should wait 15 minutes after recording the initial pressure, if the final pressure was less than 200 psi above the precharge pressure. If there is an increase in pressure, indications are that the gases are warming and there is still sufficient volume in the accumulators. If the 200 psi above precharge pressure has not been reached after 15 minutes you may have to wait an additional 15 minutes due to ambient temperatures negatively affecting the gas properties. After thirty minutes from the time the final pressure was recorded, if the 200 psi (1.38 MPa) above precharge has not been reached, then it will be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

7.6.9 Inspections

7.6.9.1 Prior to Depolyment

7.6.9.1.1 Prior to deployment, the well control equipment should be cleaned, visually inspected, and preventative maintenance performed.

7.6.9.1.2 The equipment owner’s maintenance program shall address inspection (internal/external visual, dimensional, NDE, etc.) and pressure integrity testing.

7.6.9.1.3 Inspections shall be performed in accordance with documented equipment owner’s reliability data.

7.6.9.1.4 Certain well operations or conditions (milling, well control events, bromide use, etc.) will require more frequent inspection and maintenance.

7.6.9.2 Inspection of Flexible Choke and Kill Hoses

7.6.9.2.1 An internal inspection of flexible choke and kill hoses through the entire length of the hose shall be performed annually.

7.6.9.2.2 An external visual inspection of flexible choke and kill hoses along the entire length of the hose in accordance with equipment owner’s maintenance program.

7.6.9.3 Inspections for Repair or Remanufacturing

7.6.9.3.1 At least every five years, the well control system components shall be inspected for repair or remanufacturing, in accordance with equipment owners’ preventive maintenance program or the manufacturer’s guidelines. Individual components (e.g. ram bonnets, valve actuators) can be inspected on a staggered schedule.

7.6.9.3.2 As an alternative, a rig specific inspection frequency can vary from this five year interval if the equipment owner collects and analyzes condition based data (including performance data) to justify a different frequency.

7.6.9.3.3 This alternative may include dynamic vs. static seals, corrosion resistant alloy inlays in sealing surfaces, resilient vs. metal to meal seals, replaceable wear plates, etc.

7.6.9.3.4 Certain equipment should undergo a critical inspection (internal/external visual, dimensional, NDE, etc) annually, or upon recovery if exceeding one year: e.g., shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft piston button/foot, welded hubs, ram cavities, and ram blocks.

7.6.9.3.5 Recommended wear tolerances (ram blocks and ram cavities) shall be provided by the manufacturer and the equipment owner's maintenance program shall check against the manufacturer's allowable wear limits.

7.6.9.3.6 Inspections shall be performed by a competent person(s).

7.6.9.3.7 Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.

7.6.9.3.8 Manufacturer's installation, operation, and maintenance (IOM) manuals should be available on the rig for all BOP equipment installed on the rig.

7.6.9.4 Connections

7.6.9.4.1 Studs and nuts shall be checked for proper size, type, and grade after repair or remanufacture of components as recommended by the OEM.

7.6.9.4.2 After a pressure seal is broken, the connection shall be established by applying the appropriate torque (in accordance with API 6A or OEM recommendations) to the connection studs and/or bolts.

7.6.9.4.3 Manuals or bulletins containing torque specifications shall be available on the rig.

7.6.9.4.4 Torque shall be applied to studs and/or bolts in an even and criss-cross manner.

7.6.9.4.5 The appropriate lubricant shall be used with the corresponding torque, (in accordance with API 6A or OEM recommendations).

7.6.9.4.6 After the initial pressure test is completed, all bolts shall then be rechecked for proper torque.

7.6.9.4.7 When making up proprietary (non-API) clamp hub connections, the manufacturer's recommended procedure shall be followed.

7.6.9.5 Replacement Assemblies

7.6.9.5.1 Replacement parts shall be designed for their intended use by industry approved and accepted practices. After installation of the replacement assembly,, the affected pressure-containing equipment shall be pressure tested.

7.6.9.5.2 If replacement assemblies are acquired from a non-original equipment manufacturer, the assemblies shall be equivalent to or superior to the original equipment and be fully tested, design verified, and supported by traceable documentation in accordance with relevant API specifications.

7.6.9.5.3 Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

7.6.9.6 Equipment Storage

7.6.9.6.1 When a BOP, component, or assembly is taken out of service for an extended period of time, it shall be completely washed, steam cleaned, and machined surfaces coated with a corrosion inhibitor.

7.6.9.6.3 For BOPs, the rams or sealing element should be removed and the internals washed, inspected, and coated with a corrosion inhibitor.

7.6.9.6.3 Connections should be covered and protected.

7.6.9.6.4 The hydraulic operating chambers should be flushed with a corrosion inhibitor and hydraulic connections plugged.

7.6.9.6.5 The equipment should be stored in a manner to protect it from environmental damage.

7.6.9.7 Weld Repairs

7.6.9.7.1 Weld repairs on pressure-containing and load-bearing components shall only be performed in accordance with API 16A, API 6A, manufacturer's standards, or other applicable standards.

7.6.9.7.2 All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE Std MR0175 or ISO 15156.

7.6.9.7.3 Verification of compliance shall be established through the implementation of the repairer's written weld procedure specification (WPS) and the supporting procedure qualification (PQR).

7.6.9.7.4 Welding shall be performed in accordance with a WPS, written and qualified in accordance with Article II of ASME BPVC, Section IX, Article II.

7.6.9.7.5 The original equipment manufacturer should be consulted to verify proposed weld procedures.

7.6.9.8 Poor Boy Degasser/Mud Gas Separator Inspection and Maintenance

7.6.9.8.1 Equipment owner's maintenance shall include removal of inspection plates and cleaned of debris.

7.6.9.8.2 Vent ports and lines shall be inspected to ensure debris or other deficiencies do not impair the operability of the system.

7.6.9.8.3 An inspection program to monitor corrosion and erosion shall be performed annually. This shall be included in the equipment owner's maintenance program.

7.6.9.8.4 Prior to spud, pump water or drilling fluid into the separator inlet and verify unobstructed flow from the separator or connections.

7.6.9.8.5 If the poor by degasser is equipped with a float to regulate liquid discharge, observe that the float properly regulates liquid discharge.

7.6.9.8.6 If manufactured to ASME code or equivalent specification, a one-time hydrostatic pressure of 150 psi (1.0 MPa) shall be performed, where documentation does not currently exist.

7.6.9.8.7 If weld repairs are made to the poor boy degasser mud/gas separator, NDE and inspection shall be performed in accordance with equipment owner's PM program.

7.6.10 Quality Management

7.6.10.1 Planned Maintenance Program

7.6.10.1.1 A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, shall be employed on each rig.

7.6.10.1.2 Records of maintenance performed and repairs made shall be retained on file at the rig site and retained at an offsite location for the well control equipment.

7.6.10.2 Manufacturer's Product Alerts/Equipment Bulletins

Copies of equipment manufacturers' product alerts or equipment bulletins shall be maintained at the rig site for the well control equipment.

7.6.11 Records and Documentation

7.6.11.1 Posted Documentation

7.6.11.1.1 Drawings showing ram space out and bore of the BOP stack and a drawing of the choke manifold showing the pressure rating of the components shall be posted on the rig floor and maintained up to date (see Figure 14 for an example drawing).

7.6.11.1.2 Shear pressure calculations shall be posted on the rig floor and updated in accordance with drilling operations (e.g. drill pipe properties, MAWP, MEWSP, etc).

7.6.11.1.3 Annular closing pressures against various tubular(s) shall be posted on the rig floor.

7.6.11.2 Operation and Maintenance Manuals

7.6.11.2.1 Rig manuals, including equipment drawings, specifications and bills of material, shall be at the rig site to identify the equipment and allow the procurement of correct replacement parts.

7.6.11.2.2 Changes to the well control equipment shall be documented through the use of a management of change system in accordance API 75.

7.6.11.3 Equipment Data Book and Certification

7.6.11.3.1 API manufacturing documentation, NACE certification, and factory acceptance testing reports should be retained.

7.6.11.3.2 Copies of the manufacturer's equipment data book and third-party certification should be retained for review.

7.6.11.4 Maintenance History and Problem Reporting

7.6.11.4.1 A maintenance and repair historical file shall be retained by serial number or unique identification for each major piece of equipment.

7.6.11.4.2 The maintenance and repair historical file shall follow the equipment when it is transferred.

7.6.11.4.3 Equipment malfunctions or failures shall be reported in writing to the equipment manufacturer in accordance with Annex B.

7.6.11.4.4 A log of all failures shall be retained at the rig site and a designated offsite location.

7.6.11.4.5 Details of the BOP equipment, control system and essential test data, shall be retained from the beginning to the end of well and considered for use in in condition-based analysis.

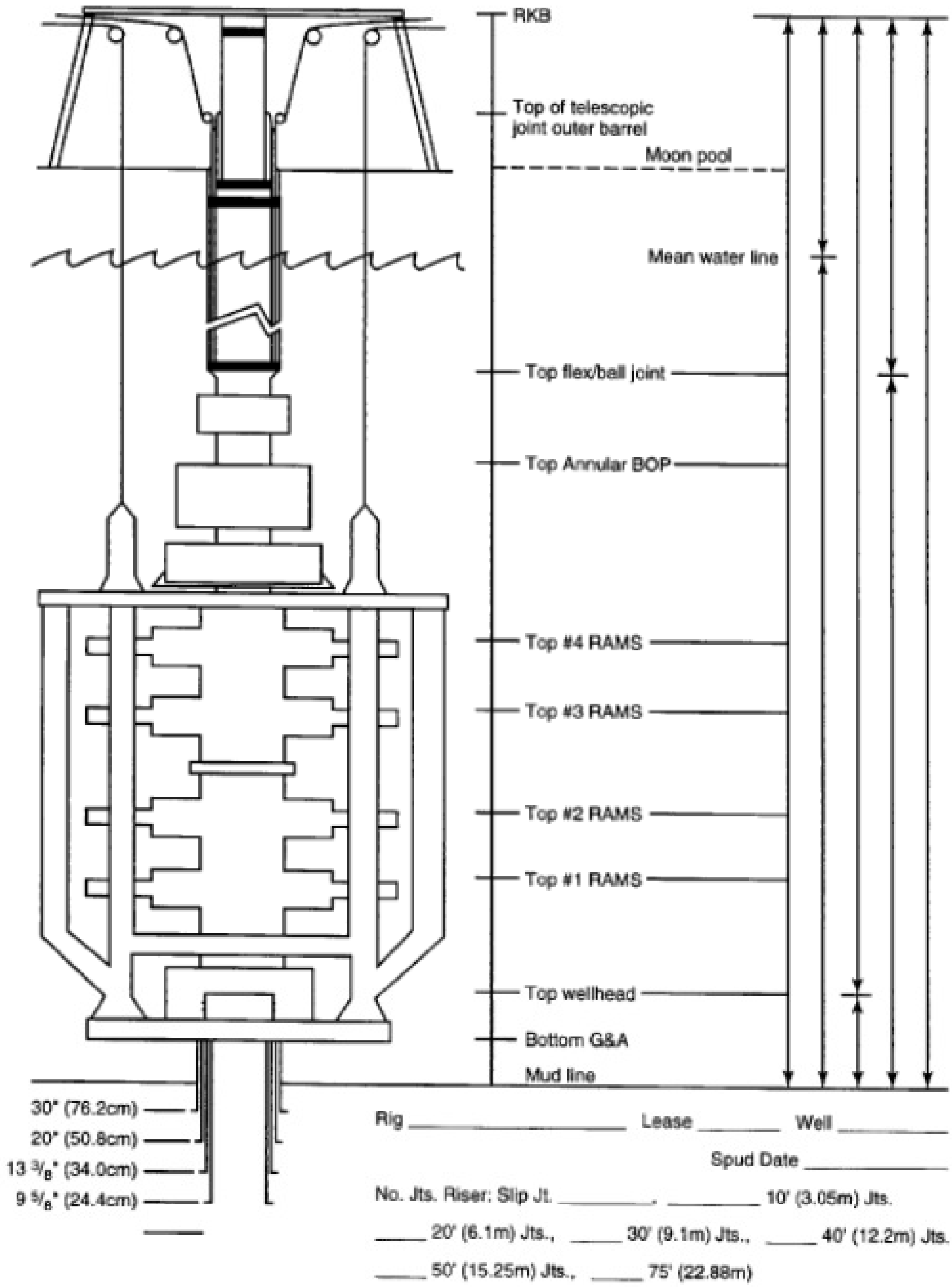


Figure 14 — Example Illustration of Subsea Ram BOP Space-out

7.6.11.5 Procedures and Test Reports

7.6.11.5.1 Testing after equipment weld remanufacturing shall be performed according to the manufacturer's written procedures.

7.6.11.5.2 Rig specific procedures for all repairs, installation, and removal of BOP's, operating and testing of well control equipment installed shall be available and followed.

7.6.11.5.3 Pressure and function test reports shall be recorded and retained including pre-installation and all subsequent tests for each well. These documents shall be retained for a minimum period of two years at rig site and a designated offsite location.

7.6.11.5.4 Deadman, Autoshear, EDS, acoustic and other tests shall be performed xx and retained on file at the rig site and a designated offsite location.

7.6.11.5.5 Pressure and function testing of all ROV critical functions shall be documented, detailing flowrates, test pressures and timing for actuation of the functions.

7.6.11.6 Shearing Pipe & Other Operational Considerations

7.6.11.6.1 Some of these considerations are not specific to subsea operations and may apply to surface operations.

7.6.11.6.2 Through the development of specific guidelines, operational procedures and a thorough risk assessment the risk can be mitigated or managed to address those concerns.

7.6.11.6.3 It is important to understand the effects of increasing wellbore pressure and its impact on the shearing capabilities of drill pipe and closing annulars against casing strings. For those reasons, it is important to understand the equipment designs, use and interfaces between those components run in the wellbore and the BOP and control systems.

7.6.11.6.4 Hanging off drillpipe and get the annular open as soon as possible, to reduce the response time and complexity of the well control operation

7.6.11.6.5 Limit the maximum wellbore pressure that below the annular, to a specific pressure (e.g. .2500 psi or lower) before reverting to a ram preventer before performing the well kill operation.

7.6.11.6.6 One set of shear rams capable of shearing any drill pipe that might be across the stack at 2500 psi (17.2 MPa), MASP or in the water depth and mud weights to be encountered.

7.6.11.6.7 If the BSR or CSR is closed during a well control event, when pipe is sheared, the BOP shall be inspected and tested at first opportunity.

7.6.11.6.8 Shearing capabilities shall be determined by actual shear data for the pipe, BOP type, and configuration.

7.6.11.6.9 Post shearing calculations on rig floor for all to view and be aware of those pressures. See Table 11 for an example of shearing calculations.

Table 11 — Example of One Method to Calculate Shear Pressure Given Well and Equipment Specific Data

BOP Operator Closing Ratio	**Control System Operating Pressure** psi (MPa)	**Surface Shear Pressure**[a] psi (MPa)	**MAWP at TD** psi (MPa)	**MAWSP** psi (MPa)	**Maximum Expected Mud Weight at TD**
14.64	5000 (34.5)	3174 (21.9)	5000 (34.5)	927 (6.4)	15.2
Maximum closing pressure (MASP) = surface shear pressure + (MASP/operator closing ratio) + (mud wt hydrostatic/operator closing ratio) Maximum closing pressure (MAWP) = surface shear pressure + (MAWP/operator closing ratio) + (mud wt hydrostatic/operator closing ratio)					
[a] Data taken from actual test results for pipe.					

7.6.11.6.10 If shearing pressures approach the restart pressure (10 % threshold) of the accumulator charging pumps consideration should be given to change the pump restart pressure nearer to the maximum operating pressure of the system, especially if large accumulator volumes are being utilized.

7.6.11.6.11 If a single ram cannot both shear and seal, this system shall close two rams; one that will shear and one that will seal well bore pressure. Additional functions may be added as requested at order and shall not interfere with the main purpose of shearing and sealing the well.

7.6.11.6.12 In the event non-shearable equipment is across the BOP and the emergency and secondary system(s) have been disarmed, the priority of preserving life shall be given and the EDS reduced to the single function of disconnecting the LMRP from the well. Rig-specific well control and equipment management procedures shall address this and other specific tasks.

Annex A
(informative)

Forms

Annex B
(normative)

Failure Reporting

B.1 User Recommendations

B.1.1 The operator of drill-through equipment manufactured to this American National Standard shall provide a written report to the equipment manufacturer of any malfunction or failure which occurs.

B.1.2 This report shall include as much information as possible on the operating conditions that existed at the time of the malfunction or failure, as accurate a description as possible of the malfunction or failure, and any operating history of the drill-through equipment leading up to the malfunction or failure (e.g. field repair, modifications made to the drill-through equipment, etc.).

B.2 Manufacturer's Recommendations

B.2.1 Manufacturer's Internal Recommendations

B.2.1.1 All significant problems experienced with drill-through equipment furnished to this American National Standard noted during its manufacture, testing or use shall be formally communicated to the individual or group within the manufacturer's organization responsible for the design and specification documents.

B.2.1.2 The manufacturer shall have a written procedure that describes forms and procedures for making this type of communication, and shall provide written records of progressive design, material changes or other corrective actions taken for each model and size of drill-through equipment.

B.2.2 Manufacturer's External Recommendations

B.2.2.1 All significant problems experienced with drill-through equipment furnished to this American National Standard shall be reported in writing to each and every operator of the drill-through equipment within three weeks after the occurrence.

B.2.2.2 Design changes resulting from a malfunction or failure history of drill-through equipment covered in the scope of this standard shall be communicated within fourteen days after the design change by the manufacturer to each and every operator using the model or size drill-through equipment having the malfunctions or failures, and all models of other drill-through equipment that could have similar potential problems.

Annex C
(informative)

Example Sizing Calculation

Bibliography

[1] API Spec 16Q, *Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*

[2] API RP 16ST, *Coiled Tubing Well Control Equipment Systems*

[3] API Spec 17D, *Subsea Wellhead and Christmas Tree Equipment*

[4] API RP 17N, *Recommended Practice for Subsea Production System Reliability and Technical Risk Management*

[5] API RP 49, *Drilling and Drill Stem Testing of Wells Containing Hydrogen Sulfide*

[6] API RP 59, *Recommended Practice for Well Control Operations*

[7] API RP 64, *Diverter Systems Equipment and Operations*