Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

API SPECIFICATION 16D (SPEC 16D)
SECOND EDITION, JULY 2004
EFFECTIVE DATE, JANUARY 2005

American
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Upstream Segment

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FOREWORD

This specification is under the jurisdiction of the API Subcommittee on Standardization of Drilling Well Control Systems. It represents a composite of industry-accepted practices and standard specifications employed by various equipment-manufacturing companies. The goal of this specification is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling rig and associated equipment, and preservation of the environment for land and marine drilling operations. In some instances, reconciled composites of these practices are included in this publication. Suggested revisions are invited and should be submitted to the API, Standards Department, 1220 L Street, NW, Washington, DC 20005, or by e-mail to standards@api.org.

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1 Scope

1.1 GENERAL

These specifications establish design standards for systems, that are used to control blowout preventers (BOPs) and associated valves that control well pressure during drilling operations. The design standards applicable to subsystems and components do not include material selection and manufacturing process details but may serve as an aid to purchasing. Although diverters are not considered well control devices, their controls are often incorporated as part of the BOP control system. Thus, control systems for diverter equipment are included herein. Control systems for drilling well control equipment typically employ stored energy in the form of pressurized hydraulic fluid (power fluid) to operate (open and close) the BOP stack components. Each operation of a BOP or other well component is referred to as a control function. The control system equipment and circuitry vary generally in accordance with the application and environment. The specifications provided herein describe the following control system categories:

a. *Control systems for surface mounted BOP stacks.* These systems are typically simple return-to-reservoir hydraulic control systems consisting of a reservoir for storing hydraulic fluid, pump equipment for pressurizing the hydraulic fluid, accumulator banks for storing power fluid and manifolding, piping and control valves for transmission of control fluid to the BOP stack functions.

b. *Control systems for subsea BOP stacks (common elements).* Remote control of a seafloor BOP stack requires specialized equipment. Some of the control system elements are common to virtually all subsea control systems, regardless of the means used for function signal transmission.

c. Discrete hydraulic control systems for subsea BOP stacks. In addition to the equipment required for surface-mounted BOP stacks, discrete hydraulic subsea control systems use umbilical hose bundles for transmission of hydraulic pilot signals subsea. Also used are dual subsea control pods mounted on the LMRP (lower marine riser package), and housing pilot operated control valves for directing power fluid to the BOP stack functions. Spent water-based hydraulic fluid is usually vented subsea. Hose reels are used for storage and deployment of the umbilical hose bundles. The use of dual subsea pods and umbilicals affords backup security.

d. *Electro-hydraulic/multiplex control systems for subsea BOP stacks.* For deepwater operations, transmission subsea of electric/optical (rather than hydraulic) signals affords short response times. Electro-hydraulic systems employ multi-conductor cables, having a pair of wires dedicated to each function to operate subsea solenoid valves which send hydraulic pilot signals to the control valves that operate the BOP stack functions. Multiplex control systems employ serialized communications with multiple commands being transmitted over individual conductor wires or fibers. Electronic/optical data processing and transmission are used to provide the security of codifying and confirming functional command signals so that a stray signal, cross talk or a short circuit should not execute a function.

e. *Control systems for diverter equipment.* Direct hydraulic controls are commonly used for operation of the surface mounted diverter unit. Associated valves may be hydraulically or pneumatically operated.

f. *Auxiliary equipment control systems and interfaces.* For floating drilling operations, various auxiliary functions such as the telescopic joint packer, 30 in. latch/pin connection, riser annulus gas control equipment, etc., require operation by the control system. These auxiliary equipment controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and requirements for similar equipment.

g. *Emergency disconnect sequenced systems (EDS).* (Optional) An EDS provides automatic LMRP disconnect when specific emergency conditions occur on a floating drilling vessel. These controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and requirements for similar equipment.

h. *Backup Systems* (Optional). When the subsea control system is inaccessible or non-functional, an independent control system may be used to operate selected well control, disconnect, and/or recovery functions. They include acoustic control systems, ROV (Remotely Operated Vehicle) operated control systems and LMRP recovery systems. For surface control systems, a reserve supply of pressurized nitrogen gas can serve as a backup means to operate functions in the event that the pump system power supply is lost. These controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and requirements for similar equipment.

i. *Special deepwater/harsh environment features* (Optional). For deepwater/harsh environment operations, particularly where multiplex BOP controls and dynamic positioning of the vessel are used, special control system features may be employed. These controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and requirements for similar equipment.

2 Normative References

ABS Class Society Rules: CDS (Certification of Drilling Systems)

API
- RP 14F *Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities*
- RP 500 *Recommended Practice for Classification of Locations for Electrical Installations*

ANSI[1]
- Y32.10 *Graphic Symbols for Fluid Power Diagrams*

ASME[2]
- B31.1 *Power Piping*
- B31.3 *Process Piping*
- *ASME Boiler and Pressure Vessel Code*

AWS[3]
- A2.4-86 *Welding Symbols Chart*
- D1.1 *Structural Welding Code—Steel*

ISO/IEC[4]
- IEC 529 *Degrees of Protection by Enclosures*
- ISO 1219 *Fluid Power—systems and components—graphic symbols and circuit diagrams*
- ISO 13628-8/
- API RP 17H *ROV interfaces on subsea production systems*
- ISO 14224 *Collection and exchange of reliability and maintenance data for equipment*

NACE International[5]
- RP0176 *Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production*

Other Standards
- British Design Code BS-5500 *Specification for Unfired Fusion Welded Pressure Vessels*
- DOT Spec 3AA2015 *Welding, Cutting and Brazing*
- German Design Code AD-Merkblaetter
- NEMA 4X

3 Terms, Definitions, and Abbreviated Terms

Graphic symbols for fluid power diagrams shall be in accordance with ANSI Y32.10 and/or ISO Standard 1219, latest editions. For the purposes of this specification, the following definitions apply:

3.1 accumulator: A pressure vessel charged with non-reactive or inert gas used to store hydraulic fluid under pressure for operation of blowout preventers.

3.2 accumulator bank: An assemblage of multiple accumulators sharing a common manifold.

3.3 accumulator precharge: An initial inert gas charge in an accumulator, which is further compressed when the hydraulic fluid is pumped into the accumulator, thereby storing potential energy.

3.4 acoustic control system: A subsea control system that uses coded acoustic signals for communications and is normally used as an emergency backup having control of a few selected critical functions.

3.5 air pump/air-powered pump: Air driven hydraulic piston pump.

3.6 annular BOP: A device with a generally toroidal shaped steel-reinforced elastomer packing element that is hydraulically operated to close and seal around any drill pipe size or to provide full closure of the wellbore.

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[1]American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036. www.ansi.org
[2]ASME International, 3 Park Avenue, New York, New York 100160-5990. www.asme.org
[3]American Welding Society, 550 N.W. LeJeune Road, Miami, Florida 33135. www.aws.org
[4]International Organization for Standardization, 1, rue de Varemb'e, Case postale 56, CH-211, Geneva 20, Switzerland. www.iso.org
[5]NACE International, 1440 South Creek Drive, P.O. Box 218340, Houston, Texas 77218-8340. www.nace.org

3.7 arm: To enable the operation of a critical function or functions.

3.8 backup: An element or system that is intended to be used only in the event that the primary element or system is non-functional.

3.9 blind ram BOP: A BOP having rams which seal against each other to close the wellbore in the absence of any pipe.

3.10 block position: The center position of a three-position control valve.

3.11 blowout: An uncontrolled flow of pressurized wellbore fluids.

3.12 BOP (blowout preventer): A device that allows the well to be sealed to confine the well fluids in the wellbore.

3.13 BOP closing ratio (ram BOP): A dimensionless factor equal to the area of the piston operator divided by area of the ram shaft.

3.14 BOP control system: The system of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels and other items necessary to hydraulically operate the BOP equipment.

3.15 BOP stack: The assembly of well control equipment including BOPs, spools, valves, and nipples connected to the top of the casing head.

3.16 BOP stack maximum rated wellbore pressure: The pressure containment rating of the ram BOPs in a stack.

Note: In the event that the rams are rated at different pressures, the BOP stack maximum rated wellbore pressure is considered equal to the lowest rated ram BOP pressure. In stacks that do not contain any ram BOP, the BOP stack maximum rated wellbore pressure is considered equal to the lowest rated BOP pressure.

3.17 central control unit (CCU): The central control point for control and monitoring system functions and communications.

3.18 check valve: A valve that allows flow through it in one direction only.

3.19 choke line: A high-pressure line connected below a BOP to transmit well fluid flow to the choke manifold during well control operations.

3.20 choke and kill valves: BOP stack-mounted valves that are connected below selected BOPs to allow access to the wellbore to either choke or kill the well.

3.21 closing unit (closing system): See BOP control system.

3.22 commodity item: A manufactured product purchased by the control system manufacturer for use in the construction of control systems for drilling well control equipment.

3.23 control fluid: Hydraulic oil, water based fluid, or gas which, under pressure, pilots the operation of control valves or directly operates functions.

3.24 control hose bundle: A group of pilot and/or supply and/or control hoses assembled into a bundle covered with an outer protective sheath.

3.25 control line: A flexible hose or rigid line that transmits control fluid.

3.26 control manifold: The assemblage of valves, regulators, gauges and piping used to regulate pressures and control the flow of hydraulic power fluid to operate system functions.

3.27 control panel: An enclosure displaying an array of switches, push buttons, lights and/or valves and various pressure gauges or meters to control or monitor functions. Control panel types include: diverter panel; rig floor panel; master panel; and mini or auxiliary remote panel. All of these panels are remote from the main hydraulic manifold and can be pneumatic, electric or hydraulic powered.

1. Diverter Panel—A panel that is dedicated to the diverter and flowline system functions.
2. Rig Floor Panel (Driller's Panel)—The BOP control panel mounted near the driller's position on the rig floor.
3. Master Panel (Hydraulic or Electric)—The panel mounted in close proximity to the primary power fluid supply. All control functions are operable from this panel including all required regulators, gauges, meters, audible alarms, and visible alarms.

4. Mini or Auxiliary Remote Panel (Toolpusher's Panel)—A full or limited function panel mounted in a remote location for use as an emergency backup.

3.28 control pod: The assemblage of valves and pressure regulators which respond to control signals to direct hydraulic power fluid through assigned porting to operate functions.

3.29 control valve (surface control system): A valve mounted on the hydraulic manifold which directs hydraulic power fluid to the selected function (such as annular BOP close) while simultaneously venting the opposite function (annular BOP open).

3.30 control valve (subsea control system): A pilot operated valve in the subsea control pod that directs power fluid to operate a function.

3.31 dedicated: An element or system that is exclusively used for a specific purpose.

3.32 disarm: To disable the operation of a critical function or functions.

3.33 disconnect:

1. Unlatch and separation of the LMRP connector from its mandrel.
2. Unlatch and separation of the BOP stack connector from the wellhead.

3.34 discrete hydraulic control system: A system utilizing pilot hoses to transmit hydraulic pressure signals to activate pilot-operated valves assigned to functions.

3.35 diverter: A device attached to the wellhead or marine riser to close the vertical flow path and direct well flow (typically shallow gas) into a vent line away from the rig.

3.36 drift-off: An unintended lateral move of a dynamically positioned vessel off of its intended location relative to the wellhead, generally caused by loss of station keeping control or propulsion.

3.37 drive-off: An unintended lateral move of a dynamically positioned vessel off its location driven by the vessel's main propulsion or station keeping thrusters.

3.38 "dunking" transducer: A portable hydrophone.

3.39 dynamic positioning (automatic station keeping): A computerized means of maintaining a vessel on location by selectively driving thrusters.

3.40 electric pump: An electrically driven hydraulic pump, usually a three-plunger (triplex) pump.

3.41 electro-hydraulic (EH) control system: A system utilizing electrical conductor wires in an armored subsea umbilical cable to transmit command signals to solenoid-operated valves which in turn activate pilot-operated control valves assigned to functions.

Note: One pair of wires is dedicated to each function.

3.42 factory acceptance testing: Testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings.

3.43 function: Operation of a BOP, choke or kill valve or other component, in one direction (example, closing the blind rams is a function, opening the blind rams is a separate function).

3.44 hose bundle: See control hose bundle.

3.45 hydraulic conduit: An auxiliary line on a marine drilling riser used for transmission of control fluid between the surface and the subsea BOP stack.

3.46 hydraulic connector: A mechanical connector that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack.

3.47 hydrophone: An underwater listening device that converts acoustic energy to electric signals or converts electric signals to acoustic energy for acoustic transmission.

3.48 interflow: The control fluid lost (vented) during the travel of the piston in a control valve during the interval when the control valve's inlet and vent points are temporarily interconnected.

3.49 jumper: A segment of hose or cable used to make a connection such as a hose reel junction box to the control manifold.

3.50 junction box (J-box) (electrical): An enclosure used to house the termination points of electrical cables and components that may also contain electrical components required for system operation.

3.51 junction box (J-box) (hydraulic or pneumatic): A bolt-on plate having multiple stab-type terminal fittings used for quick connection of the multi-hose bundle to a pod, hose reel or manifold.

3.52 kill line: A high-pressure line from the mud pumps to a connection below a BOP that allows fluid to be pumped into the well or annulus with the BOP closed during well control operations.

3.53 LMRP (lower marine riser package): The upper section of a two-section subsea BOP stack consisting of the hydraulic connector, annular BOP(s), flex/ball joint, riser adapter, flexible choke and kill lines, and subsea control pods.

Note: This interfaces with the lower subsea BOP stack.

3.54 limit switch: A hydraulic, pneumatic or electrical switch that indicates the motion or position of a device.

3.55 manifold: An assemblage of pipe, valves, and fittings by which fluid from one or more sources is selectively directed to various systems or components.

3.56 mixing system: A system that mixes a measured amount of water soluble lubricant and, optionally, glycol to feed water and delivers it to a storage tank or reservoir.

3.57 multiplex (MUX) control system: A system utilizing electrical or optical conductors in an armored subsea umbilical cable such that, on each conductor, multiple distinct functions are independently operated by dedicated serialized coded commands.

Note: Solenoid-operated valves in turn activate pilot-operated valves assigned to functions.

3.58 non-retrievable control pod: A pod that is fixed in place on the LMRP and not retrievable independently.

3.59 paging: A computer display method of conveying or mapping between displays or screens to allow increased information or control utilizing multiple screens, but not displayed simultaneously.

3.60 pilot fluid: Control fluid that is dedicated to the pilot supply system.

3.61 pilot line: A line that transmits pilot fluid to operate a control valve.

3.62 pipe ram BOP: A hydraulically operated assembly typically having two opposed ram assemblies that move inward to close on pipe in the wellbore and seal the annulus.

3.63 pipe rams: Rams whose ends are contoured to seal around pipe to close the annular space.

3.64 pod: See control pod.

3.65 pop-up display/control dialog box: A display or control that appears on a computer screen to allow increased access to a control item. An auxiliary display of data, a message, or a supplemental operational request, either as a result of a command given to a control system by an operator, or a system alarm notification.

3.66 potable water: A water supply that is acceptably pure for human consumption.

Note: On an offshore rig, it is usually produced by watermakers and used as supply water for mixing control fluid for a subsea control system.

3.67 power fluid: Pressurized fluid dedicated to the direct operation of functions.

3.68 PQR: Procedure qualification record.

3.69 precharge: See accumulator precharge.

3.70 pressure biased control system: A discrete hydraulic control system utilizing a means to maintain an elevated pressure level (less than control valve actuation pressure) on pilot lines such that hydraulic signal transmission time is reduced.

3.71 pressure vessel: For BOP control systems, a pressure vessel is a container for the containment of internal fluid pressure.

3.72 qualification test: A one-time (prototype) test program performed on a newly designed or significantly redesigned control system or component to validate conformance with design specifications.

3.73 ram BOP: A blowout preventer that uses rams to seal off pressure in the wellbore.

3.74 rapid discharge accumulators: Accumulators required to satisfy their functional fluid demand in less than 3 min. This includes dedicated shear (both surface and subsea), dead man systems, autoshear accumulators, some acoustic and special purpose accumulators.

3.75 rated working pressure: The maximum internal pressure that equipment is designed to contain or control under normal operating conditions.

3.76 reaction time: The actual time elapsed between initiation of a command to completion of the function.

3.77 readback: An indication of a remote condition.

3.78 reel (hose or cable): A reel, usually power driven, that stores, pays-out and takes-up umbilicals, either control hose bundles or electrical cables.

3.79 regulator (pressure): A hydraulic device that reduces upstream supply pressure to a desired (regulated) pressure.

Note: It may be manually or remotely operated and, once set, should maintain the regulated output pressure unless reset to a different pressure.

3.80 reliability analysis: Control systems for well control equipment are custom designed in accordance with the buyer's requirements. When specifying a highly complex control system (e.g., one employing an assortment of deepwater features), the buyer may prescribe a level of formal reliability analysis. One purpose is to identify elements exhibiting unacceptable failure probability. Failure analysis, as part of the design process, can help to avoid single point failure modes and the use of unreliable components. ISO 14224 provides guidelines for selecting a suitable procedure for performing system reliability analysis.

3.81 relief valve: A device that is built into a hydraulic or pneumatic system to relieve (dump) any excess pressure.

3.82 remote panel: See control panel.

3.83 reservoir: A storage tank for BOP control system fluid.

3.84 response time: The time elapsed between activation of a function at any control panel and complete operation of the function.

3.85 retrievable control pod: A subsea pod that may be run or retrieved remotely using a wire line, drill pipe, or other means, without retrieval of the LMRP or BOP stack.

3.86 return-to-reservoir circuit: A hydraulic control circuit in which spent fluid is returned to the reservoir.

3.87 rigid conduit: Hydraulic conduit.

3.88 riser connector (LMRP connector): A hydraulically operated connector that joins the LMRP to the top of the lower BOP stack.

3.89 selector valve: A three position directional control valve that has the inlet port blocked and the operator ports blocked in the center position.

3.90 shared: An element or system that may be used for more than one purpose.

3.91 shear ram BOP (blind/shear rams): Rams having cutting blades that will shear tubulars that may be in the wellbore. Shearing blind rams additionally close and seal against the pressure below. Casing shear rams are designed specifically to shear casing, and may not seal the well bore.

3.92 sheave: A wheel or rollers with a cross-section designed to allow a specific size of rope, cable, wire line or hose bundle to be routed around it at a fixed bend radius that is normally used to change the direction of, and support, the line.

3.93 shuttle valve: A valve with two or more supply ports and only one outlet port.

Note: When fluid is flowing through one of the supply ports the internal shuttle seals off the other inlet port(s) and allows flow to the outlet port only.

3.94 solenoid valve: An electrical coil operated valve which controls a hydraulic or pneumatic function or signal.

3.95 spent fluid: Hydraulic control fluid that is vented from a function control port when the opposite function is operated.

3.96 stored hydraulic fluid volume: The fluid volume recoverable from the accumulator system between the system rated working pressure and the precharge pressure.

3.97 straight-through function: Subsea function that is directly operated by a pilot signal without interface with a pod-mounted, pilot-operated control valve.

3.98 system rated working pressure: The maximum design pressure at which control fluid is stored in the accumulator assembly.

3.99 test pressure: The pressure at which the component or system is tested to verify structural and pressure integrity.

3.100 type certification testing: Testing by a manufacturer of a representative specimen (or prototype) of a product which qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture.

3.101 umbilical: A control hose bundle or electrical cable used to control subsea functions.

3.102 usable hydraulic fluid: The fluid volume recoverable from the accumulator system between the system rated working pressure and the minimum operating pressure.

3.103 vent position: The position of a control valve that vents spent fluid to ambient or to the reservoir.

3.104 vent-to-environment circuit: A hydraulic or pneumatic control circuit in which spent fluid is vented locally to sea or atmosphere.

3.105 volumetric efficiency (VE): The ratio of deliverable fluid volume to total gas volume of a bottle, based on design conditions and calculation method (see 4.2.3.1).

3.106 watch circle: The rig offset perimeter around the well location for which special procedures are to be initiated to prepare to disconnect the drilling riser or actually implement the disconnect to prevent damage due to excessive offset.

3.107 water-based hydraulic fluid: A control liquid mixture composed mainly of water with additives to provide lubricity, anti-foaming, anti-freeze, anti-corrosion and anti-bacterial characteristics.

3.108 wellhead connector (stack connector): A hydraulically-operated connector that joins the BOP stack to the subsea wellhead.

3.109 WPS: Welding procedure specification.

4 General Control System Design Requirements

4.1 GENERAL

Well control systems and equipment identified in Section 1 and related auxiliary equipment, which may be designed and/or supplied by control system manufacturers for the intended use of oil well drilling rigs, shall meet or exceed these specifications.

Materials selected to accomplish the design intent shall meet or exceed the requirements of these specifications.

4.2 DESIGN REVIEW

Prior to manufacturing the equipment or issuing equipment from stock to fill the sales order requirements, the manufacturer's responsible engineering authority shall verify that the design satisfies all requirements in accordance with these specifications. The design review will give particular emphasis to the following considerations.

4.2.1 Service Conditions

The manufacturer shall define the following:

a. Sizing and capacity requirements.
b. System rated working pressure.
c. Temperature Ratings—The control system shall be designed to be operational within the ambient temperatures anticipated or the operational environment must be controlled to within the temperature ratings of the equipment.

d. The environment classification temperature range(s) as listed in Table 1.
e. Location.
   1. Land.
   2. Offshore.
      i) Surface.
      ii) Subsea.
f. Well Control Equipment Specifications—Annexes A and B are checklists for use by the purchaser to provide information describing the BOP stack and other well control equipment such that the control system may be properly designed.

Table 1—Ambient Temperature Classification Chart

Environment	Degrees °F		Degrees °C	
Classification	High	Low	High	Low
Tropical	140	32	60	0
Mild	120	20	50	– 13
Cold	120	– 4	50	– 20
Extreme Cold	120	– 23	50	– 30
Polar	120	– 40	50	– 40
Crucial	Controlled Environment			

4.2.2 Design Data Documentation Requirements

Design data documentation shall be retained by the manufacturer for each system design type for a minimum of 10 years after delivery of the last unit of the subject design.

The design data documentation shall include a Table of Contents and be arranged in an orderly and understandable manner.

Following is an example of Design Data Documentation content:

a. Title Page.
b. Foreword.
c. Table of Contents.
d. Typical Sizing/Capacity Calculations.
e. System Rated Working Pressure.
f. Temperature ratings and environment classification(s) of the various subsystems.
g. Drawings/Calculations to document compliance to specifications.
h. Utilities Consumption List.
i. List of Applicable Standards and Specifications.
j. Equipment Location Designations.

4.2.3 Accumulator System Calculations

4.2.3.1 Volumetric Capacity

The functional requirement of the accumulator is to provide sufficient usable hydraulic fluid volume and pressure to actuate the specified well control equipment, and to provide sufficient remaining pressure to maintain sealing capability. The sizing calculation methods are intended to be conservative sizing guides, and shall not be used as a basis for field performance. The accumulator minimum required volume design factors, F_v and F_p, vary for each method. Control system valve interflow is taken into account as part of the volume design factors, and is not required to be accounted for separately.

The Functional Volume Requirements (FVR) identified in 5.1.3, 5.1.4, 5.1.5, 5.2.3, 5.2.4, 5.5.3, and 5.8 may be satisfied by Bottle Volume (BV) from surface and/or subsea stack-mounted accumulators as determined in accordance with the calculation method selected from Table 2. Stack-mounted accumulators may be used to supplement the main hydraulic supply for subsea BOP stacks, but are not specifically required.

$$FVR = BV * \text{minimum of } (VE_v \text{ and } VE_p) \text{ for surface or stack-mounted bottles}$$

$$FVR = \text{minimum of } (BV_{surf} * VE_{v,surf} + BV_{sm} * VE_{v,sm}) \text{ and } (BV_{surf} * VE_{p,surf} + BV_{sm} * VE_{p,sm}) \text{ for systems with both surface and stack mounted } (_{SM}) \text{ bottles}$$

where:

FVR = Functional Volume Required from 5.1.3, 5.1.4, 5.2.3, 5.2.4, and 5.5.3,

BV = Bottle Volume,

VE = Volumetric Efficiency, deliverable fluid volume / total gas volume of a bottle, based on design conditions and calculation method (A, B, or C). See 4.2.3.1.1 for VE calculation procedure,

VE_v = VE for volume limited case,

VE_p = VE for pressure limited case.

All of the accumulator sizing calculation methods will have four conditions of interest, precharged (Condition 0), charged (Condition 1), discharged to minimum required function-operating pressure (Condition 2), and totally discharged (Condition 3).

Condition 0: Precharged. The accumulator bottles filled with only precharge gas at its initial pressure and ambient temperature. The precharge pressure should be specified with a temperature. Precharge pressure is not to exceed the working pressure of the accumulator. Any precharge pressure less than the working pressure of the accumulator may be used as long as the functional requirements of pressure and volume and minimum design factors is satisfied.

Note: Consideration for pressure fluctuation due to temperature fluctuation should be considered, to prevent precharge pressure from exceeding working pressure at elevated ambient temperatures. For example, precharge pressure might be specified at 100°F, and a chart or table provided for this specified precharge at lower temperatures. For ideal gas relations, precharge pressure is corrected to the charged condition temperature. $P_c/T_c = P_3/T_0$ where $T_1 = T_0$. (Temperatures and pressures in absolute units.) V_0 is the precharge volume of the accumulator in the normal discharged/precharge state.

Condition 1: Charged. The hydraulic charge pressure is the pump stop pressure, except for the rapid discharge systems. The rapid discharge accumulators shall use the pump start pressure if the accumulator pressure fluctuates with pump pressure (as the main accumulator normally does). For example, this might be 2700 psig for a 3000 psig accumulator system. If the rapid discharge accumulator is isolated with a check valve, so that the accumulator normally stays pressured to the "pump stop pressure," then the "pump stop pressure" shall be used. For example, this might be the case for a dedicated shear circuit, or an acoustic accumulator. Pressure compensation for water depth is the hydrostatic column of the control system fluid. The gas temperature of the charged condition is the assumed ambient temperature. For some special-purpose accumulators, an additional design case will be at a gas temperature resulting from adiabatic compression. See example in appendix involving a normally closed valve with hydraulic assist circuit.

Condition 2: Minimum operating pressure. This is the minimum operating pressure for functional requirements, i.e., the pressure-limited case. Annular closing pressure would be required to be considered for diverter operations, rams bore working pressure divided by rams closing ratio is considered for both surface and subsea BOP stacks, valve opening pressure is considered for subsea stacks, and shear pressure requirements are considered for shear circuits both surface and underwater. Other minimum operating pressure requirements may be considered or specified by the purchaser. Some accumulator systems may have to be designed to satisfy multiple minimum required pressure conditions. For example, a dead man circuit may require pipe shearing at a higher pressure than a connector unlatch function. The shear would occur earlier in the sequence, with a lower discharged volume; the required pressure at the end of the sequence would be lower, but with a larger accumulator discharge volume. That accumulator would be expected to satisfy both requirements. Volume design factor for this condition is the pressure-limited factor, F_p, listed in Table 2. Note the pressure for Condition 2 cannot be less than ambient hydrostatic pressure, nor less than precharge pressure at full discharge conditions. Full discharge condition may be adiabatic, and temperature and pressure may be much lower than original precharge.

Condition 3: Total discharge. This case represents discharging as much fluid as possible, typically all of the fluid, but in certain cases may be limited by accumulator pressure equalizing with the subsea hydrostatic pressure before all fluid is discharged. This is designated the volume-limited condition. The total hydraulic volume available would be $V_3 - V_1$. Volume design factor for this condition is the volume-limited factor F_v, listed in Table 2.

Note: For stack-mounted accumulators, it is possible to have precharge pressures below seawater hydrostatic pressure. For this case, the full discharge is calculated similarly to Condition 2, where the minimum pressure is the hydrostatic pressure, and the volume design factor for volume limited discharge is applied. For example, this might be the case for a 3000 psi accumulator precharged on the surface to 3000 psig (3014.7 psia) at 100°F, and submerged to a working depth of 10,000 ft with a hydrostatic pressure of 4464.7 psia, and a surface-charging pressure of 3000 psig, or 7464.7 psia. A set of discharge conditions with adiabatic expansion can cause a sufficient temperature drop that the gas pressure temporarily drops below sea hydrostatic until the gas warms sufficiently.

Table 2—Calculation Method Overview

Maximum gas pressure, psia	Surface systems		Subsea systems		
	Surface accumulators	Rapid discharge systems, such as dedicated shear system	Surface accumulator (including credit for any stack-mounted accumulators) for subsea systems	Main hydraulic supply supplement stack-mounted accumulator	Rapid discharge systems (e.g., autoshear, deadman) dedicated shear systems, and some acoustic and special-purpose accumulators
Functional volume requirements	5.1.4: Close one annular and all rams and open one side outlet line 5.1.5.1: twice pilot function volume needed to close all BOPs in the BOP stack 5.5.3: operate all of the divert mode functions	Volume and pressure requirement specified by purchaser. Usually 100% of function and required pressure times method design factor for volume.	5.2.3.1: Close and open one annular and four rams 5.2.3.2: pilot function volume needed to close and open one annular and four ram BOPs in the BOP stack 5.5.3: operate all of the divert mode functions	Volume and pressure requirement specified by purchaser. May be required in order to meet closing times if flow supply from surface is inadequate without added subsea supply.	5.8.2.2, 5.9.1: Volume and pressure requirement specified by purchaser. Usually 100% of function and required pressure times method design factor for volume.
< 5015 psia	Method A	Method C	Method A	Method A	Method C
> 5015 psia	Method B	Method C	Method B	Method B	Method C

Method A	Method B	Method C
ideal gas, isothermal	real gas, NIST data, isothermal	real gas, NIST data, adiabatic
1.5 volume design factor for volume-limited condition, F_v	1.4 volume design factor for volume-limited condition, F_v	1.1 volume design factor for both volume and pressure-limited conditions, F_v and F_p
1.0 volume design factor for pressure-limited condition, F_p	1.0 volume design factor for pressure-limited condition, F_p	

4.2.3.1.1 Volumetric Efficiency Calculations

The basis of the volumetric efficiency calculation is the following equation for fluid withdrawal at the condition of interest i:

$$VE_i = (V_i - V_1) / (V_0 \times F)$$

where:

V_0 = gas volume at condition 0 (precharge),

V_1 = gas volume at 1 (charged),

V_i = gas volume at withdrawal condition of interest: 2 (minimum operating pressure), or 3 (total discharge),

F = Volume Design Factor for the condition of interest = F_p for Condition 2 (pressure-limited), or F_v for Condition 3 (volume-limited).

Gas volume can expressed by the following:

$$V_i = m / \rho_i$$

where:

m = mass of the gas,

ρ_i = density of gas at condition i (pressure and temperature).

so:

$\mathrm{VE}_i = ((m/\rho_i) - (m/\rho_1))/((m/\rho_0) \times F)$

$\mathrm{VE}_i = ((1/\rho_i) - (1/\rho_1) /((1/\rho_0)) \times F)$

$\mathrm{VE}_i = ((\rho_0/\rho_i) - (\rho_0/\rho_1))/F$

where:

ρ_0 = density at precharge

(adjusted for temperature change from original precharge temperature),

for stack-mounted accumulators supplementing surface main accumulator supply, the precharge is adjusted for all (or sometimes part) of the head of sea water column (usually 0.445 psi/ft),

ρ_1 = density when accumulator when fully charged at the "pump stop pressure" plus hydrostatic pressure of control fluid column (usually fresh water at 0.433 psi/ft) for accumulator on main hydraulic supply.

For Condition 2 pressure-limited case, $\mathrm{VE_p} = (\rho_0 / \rho_2 - \rho_0 / \rho_1) / \mathrm{F_p}$ [ρ_2 must be > = ρ_0]:

ρ_2 = density when accumulator is at the minimum operating pressure as the greater of the following:

= calculated minimum operating pressure plus hydrostatic pressure of sea water column,

= component minimum operating pressure plus hydrostatic pressure of sea water column,

= user specified minimum operating pressure, such as to close annular preventer, operate special equipment, etc.

For Condition 3 volume-limited case:

$$\mathrm{VE}_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/F_v$$
$$\mathrm{VE}_v = (1.0 - \rho_0/\rho_1)/F_v$$
ρ_3 = total discharge case, $\rho_3 = \rho_0$

For Optimum Precharge:

$$\mathrm{VE}_v = \mathrm{VE}_p = (1.0 - \rho_0/\rho_1)/F_v$$
$$\mathrm{VE}_v = \mathrm{VE}_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/F_p$$

Rearranged for Optimum Precharge Density:

$$\rho_0 = F_p/(F_v/\rho_2 - (F_v - F_p)/\rho_1)$$

These equations are further evolved for Methods A, B, and C in the following sections.

4.2.3.1.2 Method A (Ideal Gas, Isothermal Discharge, Pressures below 5015 psia, 1.5 Volume Design Factor for Volume-limited Discharge, 1.0 Volume Design Factor for Pressure-limited Discharge):

Method A (ideal gas, isothermal discharge) is consistent with the method used in earlier editions of this publication, and is retained in this document because of long usage with satisfactory results in the field for surface accumulator performance. It is a simple calculation, and has provided satisfactory field results for most surface accumulator sizing for both surface and subsea BOP stacks. BOP control system surface accumulator banks commonly have relatively long discharge times for their full liquid volume discharge. The surface accumulator will normally satisfy the adiabatic requirement for single functions (e.g., closing the annular preventer on a three-ram BOP stack), due to the time lag usually expected between BOP functions. This time lag allows the accumulator to absorb heat from the environment, and the accumulator performance will approximate constant temperature discharge; in conjunction with the with specified volume design factor allowance for this arrangement, this sizing has usually been adequate, allowing for field variations in ambient temperature, gauge-reading variances, pump pressure switch settings, real gas compressibility factors, near-adiabatic discharge pressure/temperature drops for single functions, etc.

Method A has been found to be inadequate for:

a. Higher accumulator operating pressures (over 5015 psia).
b. Accumulators that require rapid discharge of most of their fluid at high pressure ratios.

This is the case for many stack mounted accumulator circuits and some surface accumulator circuits, such as dedicated shear systems.

Method A Calculations:

The general equations use the appropriate volume design factors and also are modified to be based on pressure, recognizing that the density of an ideal isothermal gas is proportional to pressure P:

$$\rho_i = k \times P_i \text{ where } k \text{ is a constant}$$
$$VE_p = (P_0/P_2 - P_0/P_1)/1.0 \; [P_2 \text{ must be} >= P_0]$$
$$VE_v = (1.0 - P_0/P_1)/1.5$$

Notes:
if P_0 is less than hydrostatic sea pressure, then P_3 = sea water hydrostatic absolute pressure (does not equal P_0), and $VE_v = (P_0/P_3 - P_0/P_1)/1.5$
if P_2 is less than hydrostatic sea pressure, then P_2 = sea water hydrostatic absolute

Optimum Precharge $P_0 = 1.0/(1.5/P_2 - 0.5/P_1)$

Where P_i are as described for associated densities ρ_i in 4.2.3.1.1:

See 4.2.3.1 for Bottle Volume calculation using these Volumetric Efficiencies.

See Annex C for example calculations.

4.2.3.1.3 Method B (Real Gas, Isothermal Discharge, Pressures above 5015 psia, 1.4 Volume Design Factor for Volume-limited Discharge, 1.0 Volume Design Factor for Pressure-limited Discharge):

Method B (real gas, isothermal discharge) shall be used for hydraulic supply accumulators, both surface and underwater, when the pressures exceed 5015 psia. This sizing method may be used instead of Method A, as it is more accurate and may slightly reduce the number of required bottles because a lower Volume-Limited Volume Factor is used.

Method B Calculations:

For Method B, the general equations become:

$$VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.0(\rho_2 \text{ must be} >= \rho_0)$$
$$VE_v = (1.0 - \rho_0/\rho_1)/1.4$$

Notes on the pressures to determine these densities:

if P_0 is less than hydrostatic sea pressure, then P_3 = sea water hydrostatic pressure (does not equal P_0) and $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1) / 1.4$

if P_2 is less than hydrostatic sea pressure, then P_2 = sea water hydrostatic absolute

Optimum Precharge Density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$

Densities for the various pressures at the ambient, isothermal temperature are to be based on NIST gas table data (http://webbook.nist.gov/chemistry/fluid).

.See 4.2.3.1 for Bottle Volume calculation using these Volumetric Efficiencies.

See Annex C for example calculations.

4.2.3.1.4 Method C (Real Gas, Adiabatic Discharge, 1.1 Volume Design Factor (for Both Volume and Pressure Limited Discharge):

Method C (real gas, adiabatic discharge) is required for rapid discharge accumulators. Rapid-discharge accumulators are defined as accumulators required to satisfy their functional volume requirement in less than 3 min. This includes dedicated shear (both surface and subsea stack-mounted), dead man system, autoshear, and some acoustic and special purpose accumulators. Method C may be used instead of either A or B for systems not requiring a rapid discharge.

Note that for a given accumulator volume, precharge conditions, and full-charge conditions, Methods B and C have the same stored hydraulic fluid. The difference between the method B and C is due to the difference between an adiabatic discharge which will cool the gas significantly for high-pressure ratios, and an isothermal discharge. Optimal accumulator sizing differences will occur because optimal precharge for an accumulator will be different when temperature effects are considered. Basically, the precharge pressure after adiabatic discharge, with the lower temperature and pressure that occurs with this discharge, will be slightly above the minimum required operating pressure. For Method C, adiabatic expansion shall be used for discharge pressure temperature relationship. This will be conservative with regard to available pressure, as accumulators will have heat transfer from the environment, but it will occur over a period of time that cannot be accurately assessed.

Design charging pressure shall be the "pump start pressure" for accumulators subject to main hydraulic supply pressure fluctuations. Design charging pressure shall be the "pump shut-off pressure" for accumulators that are isolated by check valve(s) from the main hydraulic supply pressure fluctuations.

Method C Calculations:

For Method C, the general equations become:

$$VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1 \ (\rho_2 \text{ must be} >= \rho_0)$$
$$VE_v = (1.0 - \rho_0/\rho_1)/1.1$$

Calculate the P_3 that would result from constant entropy expansion from P_1 (ρ_1) down to ρ_0. If calculated P_3 is less than hydrostatic sea pressure, then P_3 = sea water hydrostatic pressure. Calculate ρ_3 for this new pressure, and $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$.

Optimum Precharge Density $\rho_0 = \rho_2$

Optimum Precharge P_0 = pressure which gives the density ρ_0 (using NIST data)

Since this Method is based on an adiabatic expansion, the densities and temperatures for Conditions 2 and 3 must be determined based on a constant entropy from Condition 1 to the pressure condition of interest (based on the NIST gas table data. [http://webbook.nist.gov/chemistry/fluid]).

For those special purpose accumulators that require rapid charge (in less than 3 min.), the volume calculations for the Condition 1 density and temperature shall be conducted for both (a) the adiabatically compressed temperature, starting from discharged condition at ambient seafloor temperature, and (b) isothermally charged at the ambient seafloor temperature.

P_1 = Condition 1 (fully charged) pressure used to determine density ρ_1,

= "pump stop pressure" plus hydrostatic pressure of control fluid column (usually fresh water at 0.433 psi/ft) for accumulator isolated by check valve from main hydraulic supply,

= "pump start pressure" plus hydrostatic pressure of control fluid column (usually fresh water at 0.433 psi/ft) for accumulator on main hydraulic supply,

= the charging pressure for rapid discharge special purpose accumulators.

See 4.2.3.1 for Bottle Volume calculation using these Volumetric Efficiencies.

4.2.3.2 Stored Hydraulic Fluid Volume

The stored hydraulic fluid volume shall be used in determining the pump system sizing and reservoir capacity required. The stored hydraulic fluid volume is the hydraulic fluid stored in the accumulator from precharge condition to pump stop pressure.

4.2.4 Reservoirs and Reservoir Sizing

4.2.4.1 General

A suitable control fluid shall be selected in accordance with 9.5.

Water-based hydraulic fluids are usually a mixture of potable water and a water-soluble lubricant additive. When ambient temperatures at or below freezing are expected, sufficient volume of ethylene glycol or other additive acceptable to the control system manufacturer shall be mixed with the water-based hydraulic fluid to prevent freezing.

Hydraulic fluid reservoirs shall be cleaned and flushed of all weld slag, machine cuttings, sand and any other contaminants before fluid is introduced. Cleanout ports/hatches shall be provided for each reservoir to facilitate cleaning. Cleanout ports shall be minimum 4 in. diameter.

To prevent overpressurization, each reservoir shall have suitable vents that have flow capacity in excess of the incoming flow capacity (including flow from accumulators for the mixed fluid reservoir). These vents shall not lend themselves to being mechanically plugged, or capped.

Accumulator capacity that is vented back to reservoir during normal operation of the system shall be included in reservoir sizing requirement.

4.2.4.2 Return-to-Reservoir Hydraulic Reservoirs

The hydraulic fluid reservoir usable capacity shall be at least twice the stored hydraulic fluid capacity of the accumulator system. Air vents shall be installed of sufficient size to avoid overpressurization of the tank during hydraulic fluid transfers or nitrogen transfers if nitrogen (or other inert gas) backup system is installed. Return-to-reservoir hydraulic systems do not require an automatic mixing system. Batch mixing fluid is acceptable, or filling the reservoir with hydraulic fluid not requiring mixing is also acceptable.

Offshore rig control systems shall have an audible and visible alarm to indicate low fluid level in each of the applicable individual reservoirs, as outlined in 4.2.4, except that the main fluid reservoir activates between 30% – 45% usable capacity remaining. The alarm shall sound and illuminate at the power unit, driller's control station and a minimum of one auxiliary remote panels, if equipped. As an option, a low level alarm/cutoff may be provided to shut down the pumps before cavitation can occur.

4.2.4.3 Vent-to-Environment Hydraulic Reservoirs

4.2.4.3.1 Main Mixed Fluid Reservoir

The control system fluid reservoir usable capacity shall be at least equal to the total accumulator stored hydraulic fluid volume. There should be sufficient volume in the reservoir above the upper hydraulic fluid fill valve shut off level to permit draining the largest bank of accumulators back into the tank without overflow.

4.2.4.3.2 Lubricant Neat Fluid Reservoir

The lubricant/additive reservoir shall be sized using the maximum anticipated ratio for mixing the control system's hydraulic fluid and shall contain sufficient lubricant/additive to mix at least ten (10) times the total accumulator power fluid volume capacity of control system fluid.

4.2.4.3.3 Anti-freeze Reservoir

The ethylene glycol (or other suitable anti-freeze) reservoir, if required, shall be sized using the maximum anticipated ethylene glycol/water ratio for the minimum anticipated ambient temperature to which the control fluid will be exposed. The reservoir shall contain sufficient ethylene glycol to mix at least 1.5 times the total accumulator hydraulic fluid volume of control system fluid.

4.2.4.3.4 Hydraulic Fluid Mixing System

The hydraulic fluid mixing system shall be designed for automatic operation. The system shall automatically stop when the mixed fluid reservoir reaches the upper hydraulic fluid fill valve shut-off level. The mixing system shall automatically restart when the fluid level decreases not more than 10% below the fill valve shut-off level. The mixing system shall be capable of mixing the fluids at a mixture ratio suitable to combat freezing at anticipated ambient temperature and supply an output flow rate at least equal to the combined discharge flow rate of the pump systems.

The automatic mixing system should be manually selectable over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol. A manual override of the automatic mixing system shall be provided.

4.2.4.3.5 Reservoir Alarms

An audible and visible alarm shall be provided to indicate low fluid level in each of the individual reservoirs. The alarm control shall be preset to activate when 50% – 75% of the reservoir usable volume has been drained. The alarm shall sound and illuminate at the master, driller's and a minimum of one auxiliary remote panel, if provided. As an option, a low-level alarm/cutoff may be provided to shut down the pumps before cavitation can occur.

4.3 EQUIPMENT DESIGN SPECIFICATIONS

4.3.1 General

Loss of any rig power services (electricity, compressed air, etc.) shall not immediately cause the loss of control of the well control equipment. The hydraulic power fluid is stored in accumulators, available if pump power is lost. Remote control panels shall have adequate backup power available as specified in this document. No single point failure in subsea BOP control equipment should cause the loss of control of both pods.

At least two control stations shall be provided. The hydraulic control manifold may serve as one of those control stations. At least one control station shall be full function.

Surface and subsea control function circuitry shall be self-contained such that a leak or failure in one component or circuit element shall not cause the operation of any other function.

The surface and subsea control system manufacturer's design and component selection process shall ensure that commodity items, sub-vendor materials, and the manufacturer's own equipment meet or exceed applicable industry standards and these specifications.

The purchaser shall provide complete description of, and functional specification for:

a. The equipment to be operated;
b. Service conditions; and
c. Any application details necessary for the manufacturer to design and build a control system that complies with these specifications.

Annexes A and B serve as checklists for the purchaser to specify which functions are to be controlled. Annex A is a form to be used by the purchaser to specify the operating and interface requirements of a surface control system. Annex B is a form to be used by the purchaser to specify the operating and interface requirements of a subsea control system.

4.3.2 Hydraulic Control Manifold

The hydraulic control manifold is the assemblage of hydraulic control valves, regulators and gauges from which the system functions are directly operated. It allows manual regulation of the power fluid pressure to within the rating specified by the BOP manufacturer. The hydraulic control manifold provides direct pressure reading of the various supply and regulated pressures.

An isolation valve with nominal bore size at least equal to the control manifold supply piping size shall be provided for supply of control fluid from an alternate source. This valve shall be plugged when not in use.

A minimum of two (2) independent hydraulic pressure control circuits shall be provided (typically, manifold and annular BOP regulated pressure circuits).

4.3.2.1 Common Pressure Control Manifold

The hydraulic control manifold includes a common power fluid supply, pressure regulation and control valves for operation of the ram BOPs and choke and kill valves. This circuit shall be provided with a manifold regulator bypass valve or other means to increase the manifold pressure, not to exceed working pressure of the stack system operators. The manifold shall be designed to function at system rated working pressure in an emergency.

4.3.2.2 Annular BOP Control Manifold

The manifold components shall include a dedicated pressure regulator to reduce upstream manifold pressure to the power fluid pressure level that meets the BOP manufacturer's recommendations. The regulator shall respond to pressure changes on the downstream side with sensitivity sufficient to maintain the set pressure ± 150 psi.

The annular BOP pressure regulator shall be remotely controllable. Direct manual valve and regulator operability shall permit closing the annular BOP and/or maintaining the set regulated pressure in the event of loss of the remote control capability.

4.3.2.3 Hydraulic Control Manifold Valves

Placing the control valve handle on the right side (while facing the valve) closes the BOP or choke or kill valve, the left position shall open the BOP or choke or kill valve. The center position of the control valve is called the "block" or "vent" position. In the center position, power fluid supply is shut off at the control valve. The other ports on the four-way valve may be either vented or blocked depending on the valve selected for the application. The hydraulic circuit schematics shall clearly indicate the center position control valve port assignments for the particular control system.

Valves and gauges shall be clearly functionally labeled.

Protective covers or other means which do not interfere with remote operation shall be installed on the blind/shear ram and other critical function control valves. Lifting of these covers or deliberate sequential action is required to enable local function operation.

4.3.3 Remote Operation

All functions on the hydraulic control manifold shall be operable from the Rig Floor control station.

For offshore installations:

a. An isolated pilot supply (pneumatic or hydraulic) shall be provided for the remote operation of the surface manifold-mounted control valves. Loss of pilot supply shall not affect the manual operation of the control system.
b. The remote control system shall permit operation of all the surface control valves at least two (2) times after the loss of rig air and electric power.

4.3.3.1 Remote Control Panels

A minimum of one (1) remote control panel shall be furnished. This is to ensure that there are at least two (2) locations from which all of the critical system functions can be operated. Its capability shall include the following:

a. All panel control functions shall require two-handed operation. Regulator control may be excluded from this requirement.
b. Panel control devices shall be spaced to prevent unintended operations.
c. All analog circular mechanical meter movements shall have a movement of 120° or greater. All analog displays shall have a minimum resolution of 5%. System accuracy shall be within ± 2.5% of full scale.
d. All pressure readings shall be displayed in psi. Additional units of measure are optional.
e. Keyboards, CRTs, video displays, alphanumeric displays, etc., suitable for use in the area classification of the location in which they are installed, may be used as a full control and monitoring station. If both the BOP and diverter are in use, the entire BOP stack status and diverter status shall be simultaneously displayed. The capability to operate any function shall include an "enable" entry, designed as a two-handed operation. Pop-up controls used in conjunction with normally complete status displays are permitted to activate functions. The use of menu driven controls and paging to determine system status shall be avoided in this application. If a multiple set of display panels is used at a control station, failure of one or more display panels shall be anticipated. Therefore, each control station display panel shall be capable of displaying the entire BOP stack and diverter status. In this failure mode, paging on an active display panel is acceptable. Auxiliary displays that are not used as one of the control stations shall be exempt from these requirements.
f. No more than 150V RMS shall be connected to any control system component mounted in a control panel face or any component requiring routine adjustment.
g. Any voltage higher than 150V RMS shall be confined inside an enclosure requiring tools to gain access. Appropriate high voltage warning signs shall be mounted on the enclosure.
h. No hydraulic lines or components containing hydraulic fluid shall be mounted inside of any control panel in such a way that a hydraulic leak would render all or part of the system electrical controls inoperative. Electro-hydraulic components may be mounted in a dedicated junction box provided that any hydraulic leak will not migrate to other parts of the control system, or cause a loss of system power from short circuits or otherwise render the remainder of the control system inoperative.
i. In addition to the above requirements, all electrical components, panel, etc., exposed to a hazardous atmosphere as defined in API RP 500 and IEC 529 and shall be certified as suitable for use in the hazardous location in which they are installed.

j. Rig floor panels shall be designed to meet the recommendations of API RP 14F.
k. If an air purge system is used, a loss of air purge in any junction box or control panel shall activate an alarm at the affected panel and at the rig floor panel. Means shall be provided to electrically disconnect or totally isolate the panel or junction box if the condition is considered hazardous.
l. A transparent safety cover or other lock-out means that does not obstruct visibility of function status shall be employed to avoid unintended operation of critical functions including, but not limited to, shear rams, wellhead connector, LMRP connector and pod latches. These functions are to be clearly identified and to have uniquely different look and feel from other controls and each other.
m. All panels shall be designed and connected in such a way that a component failure in one panel should not affect the operation or indication at the other panel(s) or the manifold.
n. Electro-hydraulic or electro-pneumatic devices mounted inside junction enclosures should be vented to the outside of the enclosure. Consideration should be taken in manifolding multiple vents and sizing vent lines to avoid back pressure to other components.
o. Failure of a remote control circuit component, including a conductor/cable, should not cause any function to be unintentionally operated.
p. All electrical circuits and/or components common to the entire control system (i.e., control circuits, memory circuits, alarm circuits, cables, etc.) should be located at the central control point at or near the control manifold so that disabling of one of the remote panels will not affect the other panels. Therefore, all remote panels should be connected in parallel.

One control station shall be accessible to the driller; it may be the hydraulic manifold in some installations. If the rig floor control station is a remote panel, the panel display shall be physically arranged as a graphic representation of the BOP stack. Its capability shall include the following:

aa. Control all the hydraulic functions that operate the BOPs and choke and kill valves and any other critical functions.
bb. For offshore installations, display the position of the control valves and indicate when the electric pump is running.
cc. For offshore installations, provision for electric and pneumatic back up power supplies for remote control operation shall be provided.
dd. Provide control of the annular BOP regulator pressure setting.
ee. Provide control of the manifold regulator bypass or override valve or alternatively provide remote control of the manifold regulator pressure setting.
ff. The Rig Floor Panel shall be equipped with displays for readout of the following:
  1. Accumulator pressure.
  2. Manifold regulated pressure.
  3. Annular BOP regulated pressure.
  4. Rig air pressure (air operated panels only) or low air supply warning (electric panels).
gg. In addition, Rig Floor Panels for offshore rigs shall have audible and visual alarms to indicate:
  1. Low accumulator pressure.
  2. Low rig air pressure.
  3. Low hydraulic fluid reservoir level.
  4. Panel on standby power (if applicable).

4.3.3.2 Optional Remote Control Methods

Remote control from the remote panels of the hydraulic control manifold valves may be actuated by pneumatic (air), hydraulic, electro-pneumatic, or electro-hydraulic remote control systems. The remote control system shall be designed such that manual operation of the control valves at the hydraulic control unit will override the position previously set by the remote controls. The designer shall consider hose length and size, response time and temperatures (freezing potential) when designing remote controls. The power supply for the remote controls shall be isolated from the main system so that a failure in the remote control circuit will not affect the manual operation of the control valves.

4.3.4 BOP Control Valves, Fittings, Lines and Manifolds

4.3.4.1 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 system or subsystem in which the component is installed.

Note: Some function operating requirements may allow the use of subsystem rated working pressures other than the system rated working pressure.

4.3.4.2 Piping Systems

All piping components and all threaded pipe connections shall conform to the design and tolerance specifications per recognized industry/international standards. Allowable end connections include (but are not limited to) American National Standard Taper Pipe Thread, SAE industrial o-ring boss port connections, and SAE four-bolt flange connections. Pipe and pipe fittings shall conform to specifications of ANSI B31.3 or an equivalent recognized international standard. If welded fittings are used, (see 8.4) the welder shall be certified for the applicable qualified procedure required. All rigid or flexible lines between the control system and BOP stack shall be flame retardant, including end connections, and shall have a rated working pressure at least equal to the rated working pressure of the system or subsystem in which the piping is installed.

All control system interconnect piping, tubing, linkages, etc., should be protected from damage from drilling operations, drilling equipment movement and day-to-day personnel operations.

4.3.4.3 Electrical Power Supplies

The electrical power supply to electro-pneumatic or electro-hydraulic panels shall automatically switch to an alternate source of electric supply when primary power is interrupted. The alternate source of electric power supply shall be capable of maintaining operation of the remote functions for a minimum of two hours if the primary source is lost.

5 Categories of Control System Application

Note: Each category listed in Section 1 is described in detail in this section.

5.1 CONTROL SYSTEMS FOR SURFACE-MOUNTED BOP STACKS

BOP control systems for surface installations (land rigs, bottom-founded offshore mobile rigs and platforms) normally supply hydraulic power fluid as the actuating medium in a return-to-reservoir circuit. The elements of the BOP control system normally include:

a. Storage (reservoir) equipment for supplying ample control fluid to the pumping system.
b. Pumping systems for pressurizing the control fluid.
c. Accumulator bottles for storing pressurized control fluid.
d. Hydraulic control manifold for regulating the control fluid pressure and directing the power fluid flow to operate the system functions (BOPs and choke and kill valves).
e. Remote control panels for operating the hydraulic control manifold from remote locations.
f. Hydraulic control fluid.

5.1.1 Response Time

Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For surface installations, the BOP control system shall be capable of closing each ram BOP within 30 sec. Closing time shall not exceed 30 sec. for annular BOPs smaller than $18^3/4$ in. nominal bore and 45 sec. for annular preventers of $18^3/4$ in. and larger. Response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time. 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. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting.

Note: If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

Conformance with response time specifications shall be demonstrated by manufacturer's calculations, by simulated physical testing or by interface with the actual BOP stack.

5.1.2 Pump Systems

5.1.2.1 The manifold pumping unit provides power fluid for all of the control system hydraulic functions. The same pumping unit may be used to provide fluid power for the control of both the BOP and diverter system. The manifold pumping unit shall comprise a minimum of two (2) pump systems with at least two (2) independent power systems.

The manifold pumping unit shall satisfy the following requirements:

a. 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 to, within two (2) minutes:
   1. Close one (1) annular BOP (excluding the diverter) on open hole.
   2. Open the hydraulically operated choke valve(s).
   3. Provide final pressure at least equal to the greater of the minimum operating pressure recommended by the manufacturer(s) of both the annular BOP and choke valve(s).
b. The cumulative output capacity of the pump systems shall be sufficient to charge the entire accumulator system from precharge pressure to the system rated working pressure within 15 minutes.

*An independent power supply is a source of power that is not impaired by any fault which disables the power to the other pump system(s). Examples of independent power supplies:

1. One pump may be powered from the emergency buss on an all electric power rig.
2. On electric drive rigs, separate electric motors and motor controllers constitute independent power supplies providing they are fed from separate busses or from busses that can be isolated by means of a buss tie circuit breaker.
3. Compressed air is not considered an independent power supply unless the compressor is powered by a different prime mover, or the electric motors for compressors is powered by a system which is independent from the primary electrical supply for the pumps, a separate buss, or if there is sufficient stored air to meet item a above.

5.1.2.2 Each pump system shall provide a discharge pressure at least equivalent to the system rated working pressure. Air driven pump systems shall be capable of charging accumulators to system rated working pressure with a 75 psi air supply to drive the pump.

5.1.2.3 Each pump system shall be protected from overpressurization by a minimum of two (2) devices designed to limit the pump discharge pressure.

a. One device shall ensure that the pump discharge pressure does not exceed the system rated working pressure.
b. The second device, normally a relief valve, shall be set to relieve at not more than 10% above the system rated working pressure. The relief valve(s) and vent piping shall accommodate the maximum pumping capacity at not more than 133% of system rated working pressure. Verification shall be provided by either design calculation or testing.

Devices used to prevent pump over-pressurization shall be installed directly in the control system supply line to the accumulators and shall not have isolation valves or any other means that could defeat their intended purpose. Relief devices on main hydraulic surface supplies shall be automatically resetting; rupture discs and/or non-resetting relief valves can cause the complete loss of pressure control.

5.1.2.4 Primary pumps shall automatically start when the actual system working pressure has decreased to approximately 90% of the system rated working pressure, and automatically stop between 97% – 100% of the system rated working pressure.

Secondary pumps shall provide operation similar to the primary pumps, except that the set point to start the pump may be adjusted slightly lower so that both pump systems do not start simultaneously. The secondary pump control shall not stop the pump at less than 95% of the system rated working pressure and shall start the pump automatically prior to the pressure decreasing below 85% of the system rated working pressure.

5.1.3 Accumulator Bottles and Manifolds

5.1.3.1 Accumulators shall meet design requirements of and be documented in accordance with applicable normative references listed in Section 2.

Note: Accumulators shall comply with 9.2.3.

5.1.3.2 The accumulator system shall be designed such that the loss of an individual accumulator and/or bank will not result in more than 25% loss of the total accumulator system capacity.

5.1.3.3 Accumulator designs include bladder, piston and float types. Selection of type may be based on purchaser preference and manufacturer's recommendations considering the intended operating environment.

5.1.3.4 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.

5.1.3.5 Accumulators shall be precharged with nitrogen. Compressed air or oxygen shall not be used to precharge accumulators.

5.1.3.6 The precharge pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions. The amount of precharge pressure is a variable depending on specific operating requirements of the equipment to be operated and the operating environment. Precharge pressure shall not exceed the rated working pressure of the accumulator.

5.1.4 Accumulator Volumetric Capacity Requirements

The BOP accumulators shall have a minimum usable power fluid volume, with pumps inoperative, to satisfy the two following requirements:

a. A FVR (Functional Volume Requirement) of one hundred percent (100%) of the BOP manufacturer's specified volume to close from a full open position at zero (0) wellbore pressure, one annular BOP and all of the ram BOPs in the BOP stack and to open the valve(s) of one side outlet on the BOP stack. The volume design factor for volume-limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1. If more than one annular BOP is present, the larger closing volume requirement shall be used for sizing purposes.
b. The calculated pressure of the remaining accumulator fluid after discharge of the required volume including the volume design factor for pressure-limited discharge shall exceed the minimum calculated operating pressure required to close one annular, any ram BOP (using the ram-type BOP closing ratio, excluding the shear rams) and to open and hold open required side outlet valve(s) at the maximum rated wellbore pressure of the stack. The volume design factor for pressure limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1.

5.1.5 Pilot System Requirements

5.1.5.1 If the BOP control system uses hydraulic pilot fluid for remote operation of the control manifold, these pilot accumulator requirements shall apply:

a. The minimum FVR (Functional Volume Requirement) of the pilot accumulator system shall be equal to two hundred percent (200%) of the pilot operating volume to safely function close all the BOPs in the BOP stack. The volume design factor for the volume limited discharge shall be determined by the sizing calculation method selected per 4.2.3.1.
b. The volume design factor for pressure limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1. Precharge pressure for the pilot system shall be no lower than the minimum required pilot pressure. The minimum pilot pressure shall be the greater of the following:
    1. Pressure required to function any pilot operated control valve installed in the control manifold at its system rated working pressure.
    2. Pressure required to pilot any pilot operated regulator installed in the control manifold to the minimum safe operating pressure as determined by the OEM equipment manufacturer and the BOPs to be controlled.

5.1.5.2 The pilot accumulator shall be charged either by a dedicated pump or by the main hydraulic supply. If it is charged by a dedicated pump, the primary accumulator shall be available as a selectable backup power source. The pilot accumulator shall be charged by and replenished by the primary accumulator system, and isolated from the primary hydraulic power fluid supply by a check valve. If minimum required pilot pressure is greater than the precharge pressure of the primary hydraulic power fluid supply, a separate pump should be required. Precharge pressure for the pilot system shall be no lower than the minimum required pilot pressure.

5.2 CONTROL SYSTEMS FOR SUBSEA BOP STACKS (COMMON ELEMENTS)

Note: This section includes specifications for equipment that is common to both discrete hydraulic and EH/MUX control systems for subsea BOP stacks.

5.2.1 Response Time

The control system for a subsea BOP stack shall be designed to deliver power fluid at sufficient volume and pressure to operate selected functions within allowable response times. The control system shall have a closing response time not exceeding 45 sec. for each ram BOP. Closing response time for each annular BOP shall not exceed 60 sec. Operating response time for each choke and kill valve (either open or close) shall not exceed the minimum observed ram close response time. The response time to unlatch the riser (LMRP) connector shall not exceed 45 sec.

Conformance with response time specifications shall be demonstrated by manufacturer's calculations, by simulated physical testing or by interface with the actual BOP stack.

5.2.2 Pump Systems

5.2.2.1 The manifold pumping unit provides power fluid for all of the control system hydraulic functions. The same pumping unit may be used to provide fluid power for the control of both the BOP and diverter system. The manifold pumping unit shall comprise a minimum of two (2) pump systems with at least two independent power systems. The cumulative output capacity of the pump systems shall be sufficient to charge the entire accumulator system from precharge pressure to the system rated working pressure within 15 min. With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the entire accumulator system from precharge pressure to the system rated working pressure within 30 min.

An independent power supply is a source of power that is not impaired by any fault which disables the power to the other pump system(s). Examples of independent power supplies:

1. One pump may be powered from the emergency buss on an all electric power rig.
2. On electric drive rigs, separate electric motors and motor controllers constitute independent power supplies providing they are fed from separate busses or from busses that can be isolated by means of a buss tie circuit breaker.
3. Compressed air is not considered an independent power supply unless the compressor is powered by a different prime mover, or the electric motors for compressors is powered by a system which is independent from the primary electrical supply for the pumps, a separate buss, or if there is sufficient stored air to meet the 30 min. requirement above.

5.2.2.2 Isolated accumulators shall be provided for the pilot control system, which may be supplied by a separate pump. The dedicated pilot pump, if used, can be either air powered or electric powered.

5.2.2.3 Air pumps, if used, shall be capable of charging the accumulators to the system rated working pressure with 75 psi minimum air pressure supply. Provision shall be made to supply hydraulic fluid to the pilot accumulators from the primary accumulator system if the pilot pump becomes inoperative. Alternatively, a standby pilot system pump shall be provided.

5.2.2.4 The pump systems shall have controls for automatic operation.

5.2.2.5 Primary pumps shall automatically start when the actual system working pressure has decreased to approximately 90% of the system rated working pressure, and automatically stop between 97% – 100% of the system rated working pressure.

5.2.2.6 Secondary pumps shall provide operation similar to the primary pumps, except that the set point to start the pump may be adjusted slightly lower so that both pump systems do not start simultaneously. The secondary pump control shall not stop the pump at less than 95% of the system rated working pressure and shall start the pump automatically prior to the pressure decreasing below 85% of the system rated working pressure.

5.2.2.7 Over pressure protection shall comply with 5.1.2.3.

5.2.3 Accumulator Requirements and Sizing for Subsea Systems

5.2.3.1 Accumulator Volumetric Capacity Requirements

The hydraulic control system for a subsea BOP stack shall have a minimum total usable power fluid volume, with the pumps inoperative, to satisfy the following requirements:

a. A minimum FVR (Functional Volume Requirement) of one hundred percent (100%) of the power fluid volume required to open and close, at zero (0) wellbore pressure, the ram BOPs (to a maximum of four (4) ram BOPs having the least cumulative operating volume requirements) and one (1) annular BOP in the BOP stack, based on the annular BOP with the larger volume requirement. The fluid volume required for BOP ram locking, if provided, shall be included in this volumetric requirement. The volume design factor shall be determined by the sizing calculation method selected per 4.2.3.1. For pilot functions not directly related to the operation of the minimum required BOP or diverter functions, the manufacturer shall determine the needed FVR.
b. The pressure of the remaining accumulator volume after opening and closing four (4) of the ram BOPs and one annular BOP including the volume design factor for pressure limited discharge the selected calculation method, shall exceed the calculated minimum system operating pressure. The calculated minimum system operation pressure shall exceed the greater of the following:
   1. The minimum calculated operating pressure required (using the closing ratio) to close any ram BOP (excluding shearing pipe) at the maximum rated wellbore pressure of the BOP stack.
   2. The minimum calculated operating pressure required to open and hold open any choke or kill valve in the stack at the maximum rated wellbore pressure of the BOP stack.
   3. The normal minimum recommended closing pressure for the annular preventer, closing on the smallest diameter tubular in the string.

Some of the accumulators can be mounted on the subsea BOP stack to reduce response time and/or serve as a backup supply of power fluid. These stack-mounted accumulators supplementing the main hydraulic supply are not categorized as rapid discharge accumulators, and therefore are subject to sizing Method A or B.

5.2.3.2 Pilot System Requirements

5.2.3.2.1 The minimum FVR (Functional Volume Requirement) of the pilot accumulator system shall be equal to or exceed the pilot operating volume to safely function one (1) annular BOP and four (4) ram BOPs close and open. The volume design factor for the volume limited discharge shall be determined by the sizing calculation method selected per 4.2.3.1.

5.2.3.2.2 For systems with subsea pods controlled with hydraulic pilot umbilicals, the usable fluid volume (remotely piloted valve operator volume plus (+) pilot hose expansion volume as published by the hose manufacturer) shall accommodate operating both subsea control pods simultaneously.

5.2.3.2.3 For systems with subsea pods operated with electric remote control signals, each pod pilot accumulator has a minimum FVR (Functional Volume Requirement) to function one (1) annular BOP and four (4) ram BOPs close and open.

5.2.3.2.4 The volume design factor for pressure limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1. Precharge pressure for the pilot system shall be no lower than the minimum required pilot pressure. The minimum pilot pressure shall be the greater of the following:

a. Pressure required to function any pilot operated control valve installed in the subsea pod at its system rated working pressure.
b. Pressure required to pilot any pilot operated regulator installed in the subsea pod to the minimum safe operating pressure as determined by the OEM equipment manufacturer and the BOPs to be controlled.
c. Minimum pilot pressure required to function a pressure biased hydraulic piloted system.

5.2.3.2.5 The pilot accumulator shall be charged either by a dedicated pump or by the main hydraulic supply. If it is charged by a dedicated pump, the primary accumulator shall be available as a selectable backup power source. The pilot accumulator shall be charged by and replenished by the primary accumulator system, and isolated from the primary hydraulic power fluid supply by a check valve. If minimum required pilot pressure is greater than the precharge pressure of the primary hydraulic power fluid supply, a separate pump should be required.

5.2.3.3 Subsea Hydraulic Supply Isolation

Accumulators mounted subsea shall have a subsea-mounted, surface-controlled valve to isolate the accumulators so that the pump system pressure may be directed straight-through to a selected BOP stack function. Means shall be provided to prevent inadvertent flow of the fluid stored in the subsea accumulators back to the surface. This is to prevent loss of the backup power fluid supply if the supply line(s) become severed.

5.2.3.4 Subsea Accumulator Pressure Relief

When a fully charged subsea accumulator is retrieved to the surface unvented, its internal pressure could exceed the rated working pressure of the accumulator. A means shall be provided to allow venting or equalizing the subsea accumulator pressure prior to or during retrieval of the accumulators to the surface.

5.2.3.5 Alternative Subsea Accumulator Pre-charge Gas

Where usable hydraulic fluid volume considerations dictate, particularly for deepwater applications, helium may be used as the precharge gas instead of nitrogen. The application may be for augmentation of usable power fluid or where increased flotation of floats is desired. If helium is used, special requirements for containment of helium gas shall be considered. Among these requirements are leakage past seals, permeability through elastomers, solubility of gas in operating fluid and discharge heat transfer (potential formation of hydrates or ice).

5.2.4 Control Manifold

5.2.4.1 General

The control manifold is an assemblage of valves, gauges, regulators, and a flow meter for operating and monitoring all of the system functions. The manifold has a power fluid supply, pod-selector valve and for discrete hydraulic systems, a separate pilot-fluid manifold for operating subsea control valves. The pilot manifold contains the necessary valves to send pilot signals to all of the subsea pilot-operated valves. When a valve on the control manifold is operated, a pilot signal is sent to a subsea control valve which, when operated, allows flow of power fluid to operate a BOP or another stack function.

5.2.4.2 Surface Functions

A control manifold shall be provided for the surface controlled functions, such as the telescopic joint packer, diverter, tension ring, and/or gas handler, if equipped. This subsystem shall employ return-to-reservoir hydraulics.

5.2.4.3 Regulators

The surface manifold regulator section employs hydraulic pressure regulators to provide the hydraulic pilot signals to the subsea hydraulic pressure regulators. Provisions shall be made such that any rig service failures to the system will not cause the loss of the subsea pressure regulator setting nor cause the loss of remote control of the subsea regulators. Provisions shall be made for manual intervention and control of the surface regulators at the control manifold.

5.2.4.4 Control Manifold Components

The control manifold shall be equipped with a flowmeter which measures the volume of flow supplied subsea from the pumps and surface accumulators.

The control manifold shall include pressure gauges to indicate the accumulator pressure, pilot system pressure, main hydraulic subsea supply pressure, all subsea regulator pilot pressures, and all regulated pressures and rig air pressure. The control manifold shall contain a visible and audible alarm for low accumulator pressure, low rig air pressure, low mixed-fluid reservoir level, loss of primary electrical power supply and low pilot-supply pressure.

5.2.4.5 Control Manifold Interface

The control manifold interface shall be designed so that all control signals and power fluid supplies have redundant access (two (2) separate jumpers, umbilical hose bundles, reels and control pods) to the shuttle valves on the BOP stack functions. If the pods are designed to be retrievable, each retrievable pod shall be individually retrievable to the surface without loss of operability of any of the BOP stack functions through the other pod.

5.2.4.6 Critical Control Functions

Valve handles that control critical functions such as shear rams, wellhead and riser connector and connector secondaries shall be provided with latchable hinged covers or other means to prevent inadvertent operation. The covers or other means must not interfere with remote operating capability. Each valve, regulator and gage shall be clearly labelled to indicate its function. Each control valve shall additionally indicate its position status.

5.2.4.7 Pressure Regulation for Blind/Shear Rams

The control system shall supply high-pressure power fluid to close the blind/shear rams, in accordance with BOP manufacturer's recommendations for shearing pipe. A lower-pressure regulated hydraulic supply should be provided for blind ram closure, if recommended by the BOP manufacturer. The higher and lower pressures may be supplied by adjusting the regulated pressure setting for the blind/shear rams using a common subsea manifold regulator.

5.2.4.8 Hydraulic Fluid Filtration

The main hydraulic power fluid supply and hydraulic pilot supply to the control manifold shall be filtered in accordance with the control system manufacturer's recommendations. A dual filter parallel arrangement with isolation valves for independent fluid routing shall be used. Filters may permit manual or automatic bypassing clogged elements rather than interrupting system operation and if bypassed, shall have a bypassing indicator.

5.2.5 Remote Control and Monitoring Panels

5.2.5.1 General

The subsea BOP control system shall afford control of all of the subsea BOP stack functions including remotely adjustable pressure regulator settings. In addition, the control station shall afford monitoring of all critical pressures. Both control and monitoring shall be afforded from at least two separate locations. At least one control station (not necessarily full function) shall be in a non-classified (non-hazardous) area as defined in API RP 500 or IEC 529.

5.2.5.2 Discrete Hydraulic Control Systems

A discrete hydraulic control system shall include item a below, additional control stations may be configured as items b or c below.

a. Rig Floor Panel: A full-function panel mounted near the driller's position.
b. Manual control capability by direct operation of the control valves at the main hydraulic manifold.
c. (Optional) Auxiliary Remote (Toolpusher's) Panel: (Required if both items a and b above are located in hazardous areas. A control panel for BOP stack functions which need not have pressure regulation capability.

5.2.5.3 Electro-hydraulic or Multiplex BOP Control System

An electro-hydraulic or a multiplex BOP control system shall include a Rig Floor Panel (A full function panel accessible to the driller on the rig floor) and at least one of the following two optional remote control and monitoring panels (or console):

a. Central Control Unit with full functional and pressure regulation capability or (for some PLC based systems) a redundant PLC console with full functional and pressure regulation capability.
b. Auxiliary Remote (Toolpusher's) Panel: A control with full functional and pressure regulation capability.

5.2.5.4 Panel Lamps

Panel lamps (or other means of visual indication) used to indicate function status shall track the position of the hydraulic control valves. Red, amber and green shall be used as standard colors for control panel indicator lights (or displays). Green shall indicate that the function is in its normal drilling position. Red shall indicate that the function is in an abnormal position. Red or green shall be on whenever the block (amber) indication is on, and thereby indicate the function's last selected position. The last position of block function shall not be displayed when an electrical power loss in the surface panel(s) could result in an incorrect indication.

Other indicator colors may be used for information display on particular functions such as selection of yellow or blue subsea control pods.

Panel displays (lamps, meters, etc.) should be sufficiently luminous to be readily discernible in all conditions of ambient light in which the panel will be operated.

5.2.5.5 Safety Requirements

A transparent safety cover or other lock-out means that does not obstruct visibility of function status shall be employed to avoid unintended operation of at least the following functions:

a. Riser connector unlock.
b. Riser connector secondary unlock.
c. Shear rams close and high pressure shear rams close.
d. Wellhead connector unlock.
e. Wellhead connector secondary unlock.
f. Emergency disconnect sequence activate (if applicable).
g. Any other function which could adversely affect normal operation if inadvertently operated.

5.2.6 Hydraulic Manifold Electric Remote Panel Interfaces

The control manifold functions as described in 5.2.4 shall be operable from and/or indicated at one or more additional remote panels connected in parallel to the Rig Floor Panel.

5.2.7 Rig Floor Panel

The Rig Floor Panel display shall be physically arranged as a graphic representation of the BOP stack/LMRP. Its capability shall include at least the following:

a. Control all functions associated with BOP stack and LMRP including stack/LMRP mounted choke and kill line valves.
b. Display the current position status of all functions and last position status when functions are placed in the center (block) position. In the event of an electrical power loss to the panels, the last position of any block function shall not be displayed when the system power is restored, to avoid possible incorrect indication.
c. Provide control of annular BOP regulator and manifold regulator remotely. This control shall be capable of being overridden at the control manifold (except in a MUX system) described in 5.2.4. As specified in 5.2.4, any failure of remote operation shall not cause the loss of subsea regulator pressure setting.
d. The following pressure readout displays shall be provided:
   1. Accumulator pressure.
   2. Surface manifold pilot pressure.
   3. Subsea annular BOP regulator pilot pressure.
   4. Subsea annular BOP regulated (readback) pressure.

5. Subsea manifold regulator pilot pressure.
6. Subsea manifold regulated (readback) pressure.
7. Rig air supply pressure.

e. A resetable flowmeter readout shall be provided to indicate the total volume used to operate subsea functions.

f. The following indicating or warning lights with audible alarm shall be provided:

1. Low accumulator pressure.
2. Low manifold pilot pressure.
3. Low rig air pressure.
4. Low mixed fluid level.
5. Low lubricant fluid level.
6. Low glycol level (if applicable).
7. Primary power/standby power in use indicating light.
8. Pump running light (if electric motor driven pumps are provided).
9. Low air purge pressure (if applicable), a separate indicator lamp shall be provided for each purged enclosure.
10. Loss of pump system electric power supply.

Alarm set points shall be established within the limits of safe operation. Alarms should be activated prior to reaching unsafe levels.

5.2.8 Auxiliary Remote (Toolpusher's) Panel

The auxiliary remote (toolpusher's) panel shall be located in a non-hazardous area away from the drill floor. The preferred location for the panel should be at the tool pusher's office, integral to the Central Control Unit or at the location close to the lifeboat station. All panel control functions shall require two-handed operation. This panel shall be physically arranged as a graphic representation of the BOP stack/LMRP.

Its capability shall include at least the following:

a. Control all functions associated with BOP stack and LMRP including stack/LMRP mounted choke and kill line valves except wellhead (stack) connector secondary and pod latches.

b. Display the position status of all functions.

c. Visual indication shall be provided (as applicable) for the following (audible alarms, with or without mute capability may be provided):

1. Low accumulator pressure alarm.
2. Low manifold pilot pressure alarm.
3. Low rig air pressure.
4. Low mixed fluid level.
5. Low lubricant fluid level.
6. Low glycol level (if applicable).
7. Primary power/standby power in use indicating light.
8. Pump running light (if electric motor driven pumps are provided).

d. The secondary remote panel shall display the following pressure readings:

1. Accumulator pressure.
2. Subsea manifold BOP regulated readback pressure.
3. Subsea annular BOP readback pressure.

e. The secondary remote panel shall display a resetable flowmeter totalizer readout to indicate the volume used to operate subsea functions.

5.2.9 Electric Power Supplies

The primary electric power supply connected for remote control of the control manifold shall automatically switch to an alternate source of electric supply when the primary power is interrupted.

The secondary power source shall be an uninterruptable power supply or a battery pack and shall be capable of maintaining operation of the remote functions for a minimum of 2 hours following loss of primary electric power. This standby power source will not supply power to the pump systems.

5.2.10 Hose Reels and Hose Handling Equipment

5.2.10.1 General

Hose reels are used to store, run and retrieve the umbilical hose bundles which communicate the main hydraulic power fluid supply and command pilot signals to the subsea mounted BOP control pods. The hose reel assembly shall be prepared and coated to withstand direct exposure to salt water spray (see 8.6).

The hose reel shall be equipped with a device that prevents operation of the drum when the jumper hose assembly is connected at the reel.

Two (2) independent hose reels shall be provided. Each reel shall be clearly identified as to the subsea control pod to which it is connected by hose bundle. The reels and corresponding pods shall be color coded yellow and blue.

The hose reel can have payout and take up controls located on the reel or at a remote location. If a remote control station is used, there shall also be controls at the reel capable of overriding the remote controls.

5.2.10.2 Hose Reel Drum

The hose reel drum radius shall be equal to or greater than the minimum bend radius recommended by the manufacturer of the subsea umbilical, for the type of service intended.

The hose reel drum shall be equipped with a brake capable of overriding and stalling the motor. The brake should be capable of supporting the weight of the fully deployed subsea umbilical when it is suspended in water.

The hose reel drum shall have a mechanical locking device that permits operation of the hose reel manifold (if equipped) and ability to connect the junction box when parked.

5.2.10.3 Hose Reel Drive

The hose reel drive shall have a minimum torque capacity of 1.5 times the maximum anticipated torsional load, which is typically the load applied by the unsupported length of deployed hose. Consideration shall be made to the fluid weight inside the hose and the effect of buoyancy on any submerged section.

5.2.10.4 Hose Sheaves

Additional hose handling equipment includes hose sheaves. Hose sheaves facilitate running and retrieving the subsea umbilical from the hose reel through the moonpool and support the storm loop which is deployed to compensate for vessel heave. All components of the hose sheave assembly shall be constructed from corrosion resistant materials or be properly coated to withstand exposure to salt water spray.

Sheaves shall be mounted to permit three-axis freedom of movement. The design shall prohibit damage to the umbilical in normal ranges of motion. The sheave shall be stamped with a safe working load based on the force required to overcome the maximum operating reel tension. The safe working load shall exceed the greater of the following calculated forces:

a. Two (2) times the calculated force required to overcome the rated braking capacity of the reel at the minor wrap diameter of the drum.
b. Two (2) times the calculated force required to overcome the maximum motor torque output at the minor wrap diameter of the drum.

Sheave assemblies shall be qualification tested to 1.5 times the safe working load and meet design acceptance criteria.

Wheels, shoes, or rollers which support a bend in the subsea umbilical shall provide a bend radius greater than the minimum bend radius recommended by umbilical manufacturer.

5.2.11 Hose Reel Manifold

The hose reels may be 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 LMRP and/or the BOP stack. All functions required to run, land and retrieve the LMRP and/or the BOP stack shall remain fully active during running, landing and retrieval. A list of these functions shall be included in the operator's manual.

5.2.12 Subsea Control Pods

5.2.12.1 General

5.2.12.1.1 A minimum of two control pods shall be used, affording redundant control of all subsea functions. The surface control manifold directs pilot command signals to operate the pressure regulators, control valves, and straight-through functions in both pods.

5.2.12.1.2 Each control pod shall contain all the pressure regulators, valves and straight-through functions required to operate all subsea functions.

5.2.12.1.3 Isolation means shall be provided so that, if one pod or umbilical is disabled, the other pod and the subsea functions shall remain operable.

5.2.12.1.4 An umbilical strain relief/radius guard shall be employed at the pod/umbilical interface to prevent the umbilical from being subjected to a bend radius less than the umbilical manufacturer's minimum recommended bend radius.

5.2.12.1.5 The subsea pressure regulators in each pod shall provide regulated pressures to ensure proper operation of the designated function(s). The valves and regulators shall be sized to supply the volume required to operate each function within its specified response time.

5.2.12.1.6 Pods shall be color-coded, striped or otherwise distinguished so that identification by subsea cameras is easily discernible.

5.2.12.1.7 Pod seals should be designed to retain sealing integrity (after re-stabbing and latching the pod) in the event that the pod is separated from the receiver blocks while under pressure.

5.2.12.1.8 Subsea components shall be designed to minimize the corrosive effect of salt water on the materials. Sacrificial anodes are recommended for dissimilar metal junctures.

5.2.12.2 Retrievable Pods

5.2.12.2.1 Retrievable Pod Assembly

Redundancy of the subsea control equipment shall be mandatory. This may allow one pod to be retrieved for repair while maintaining control with the other pod.

The pod assembly should include the hydraulic regulators, hydraulic pilot operated subsea function valves, stab(s), interfacing port seals, pod locks and all mechanical apparatus to operate the BOP stack which may require maintenance during the drilling operation.

5.2.12.2.2 LMRP Receiver Blocks

These blocks are mounted on the LMRP and are designed for landing and locking the pod assembly. Porting in the LMRP receiver blocks directs control fluid from the pod to appropriate outlet connections to operate the riser connector and other hydraulic actuated riser functions.

5.2.12.2.3 Pod Locks

Surface controlled locking devices are required to latch retrievable hydraulic control pods to the LMRP receiver blocks. The pod locks are normally hydraulically activated. A separate means to unlock in the event hydraulic lines are severed is recommended in addition to the hydraulic lock.

5.2.12.2.4 Stack Receiver Blocks

These blocks are mounted on a spring housing which is mounted atop the BOP stack frame. The blocks are ported to direct power fluid from the pod to the appropriate outlet connections to operate BOP stack functions. The spring housing assembly should be designed to maintain proper alignment and provide proper preload against the pod seals. When the LMRP is landed and locked, communication paths between the stack hydraulic control function connections and the surface control equipment are established. Since the pods are stabbed to the stack receiver blocks, the LMRP (including the pods) can be retrieved independently of the BOP stack.

5.2.12.3 Non-retrievable Pods

Non-retrievable pods shall be designed in accordance with the same specifications as retrievable pods except that the pod assembly is fixed to the LMRP. This eliminates the need for pod locks as the pods can only be retrieved along with the LMRP. The stack block interfaces between the pod assembly and the BOP stack function control lines.

5.2.13 Avoidance of Unintended Disconnect

Special safeguards shall be implemented to avoid the unintended disconnect of the LMRP connector or the wellhead connector. These measures include:

a. On all control panels the device for operating the LMRP connector unlatch function shall be physically different (look and feel) from the devices that actuate other functions. The device for activating the wellhead connector unlatch shall be of a third type different configuration.
b. For touch-screen control operations, a special warning shall appear on the screen when the touch command is given to operate either the LMRP connector unlatch or wellhead connector unlatch. Only after acknowledging such warning, will the function be operable.
c. An optional interlock device may be used to prevent the operation of the unlatch function of the LMRP connector unless the shear ram BOP is closed.

5.3 DISCRETE HYDRAULIC CONTROL SYSTEMS FOR SUBSEA BOP STACKS

5.3.1 General

Floating drilling rigs such as drillships and semi-submersibles experience vessel motion that necessitates placement of the BOP stack on the sea floor. The control systems used on floating rigs are usually vent-to-environment hydraulic systems (spent hydraulic fluid vents to sea or local atmosphere) and therefore employ water-based hydraulic control fluids. In addition to the conventional components used on surface BOP control systems, subsea hydraulic control systems require hydraulic umbilical hose bundles deployed from storage reels to carry function pilot signals and power fluid from the surface to the subsea BOP stack. Pilot- operated valves, controlled from the surface, are usually mounted in control pods on the LMRP and direct hydraulic power fluid to the annular and ram BOPs, choke and kill valves and hydraulic connectors.

5.3.2 Redundancy

Because the subsea BOP stack is not easily accessible for maintenance and repair, redundant (backup) system elements shall be deployed. Specifically, these include:

a. Two (2) complete sets of pilot-operated control valves with each set mounted in one of two control pods located on the LMRP.
b. Two (2) control hose bundles, each stored on and deployed from an umbilical reel, to connect the two subsea pods to the surface control equipment.
c. Two (2) or more means of surface/subsea power fluid supply (e.g., hydraulic conduits, hydraulic umbilical hose[s]). At least one of these means shall satisfy the response time requirements specified in this section, and two (or more) supplies shall be selectable from at least two primary control stations.

5.3.3 Accumulators and Manifolds

Accumulators and manifolds for hydraulic control systems for subsea BOP stacks shall meet the requirements of 5.2.

5.4 ELECTRO-HYDRAULIC AND MULTIPLEX (MUX) CONTROL SYSTEMS FOR SUBSEA BOP STACKS

5.4.1 General

Electro-hydraulic/multiplex (MUX) control systems employ multi-conductor armored subsea umbilical cables deployed from storage reels aboard the vessel. The cables transmit coded commands that activate solenoid operated pilot valves in the subsea pods. Within the pod, each solenoid valve activates a pilot-operated control valve to direct power fluid to a particular function.

5.4.2 Redundancy

Because the subsea BOP stack is not easily accessible for maintenance and repair, redundant (backup) system elements shall be deployed. Specifically these include:

a. Two (2) complete sets of solenoid valves and pilot-operated control valves with each set mounted in each control pod located on the LMRP.
b. Two (2) control cables, each stored on and deployed from an umbilical reel, to connect the two subsea pods to the surface control equipment.
c. Two (2) or more means of surface/subsea power fluid supply. (examples: hydraulic conduit[s], hydraulic umbilical hose[s]). At least one of these means shall satisfy the response time requirements specified in this section, and two (or more) supplies shall be selectable from at least two primary control stations.

5.4.3 Electrical Power

Electrical power (excluding the pump systems) shall be supplied from one or more uninterruptable power supplies with backup battery capacities to operate the controls for at least 2 hours.

5.4.4 Command Signals

Electrical command signals transmitted over lengthy subsea umbilical cables have shorter response times than hydraulic pilot signals transmitted over hose bundles of equal length. 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.

A MUX control system processes multiple signals on each signal conductor in the umbilical. Multiplex systems serialize and code the command signals which are then sent subsea via shared conductors in the umbilical cable. Multiplex control system logic can incorporate additional security by requiring transmission of a coded message to the subsea pod, return of the message to the surface by the pod electronics package for verification, and re-transmitting the verified command before execution of the function.

An electro-hydraulie system has a pair of conductor wires in the subsea umbilical cable dedicated to each function.

5.4.5 Central Control Unit (CCU)

In systems employing a CCU, the CCU is the central control point (corresponding to the hydraulic control manifold of a discrete hydraulic control system). When used to satisfy the requirements of 5.2.4 and 5.2.5, the CCU shall provide full functional and pressure regulation capability.

Upon restoration of power, following an electrical power interruption, the CCU shall boot up all functions in the non-energized position. The status of the system at the time of loss of power shall be displayed and/or recorded in some form. The last position of block function shall not be displayed when an electrical power loss in the surface panel(s) could result in an incorrect position indication.

5.4.6 Electrical Power and Signal Distribution Cables

5.4.6.1 Two complete independent subsea umbilical cables shall be used. Each electrical umbilical cable shall contain all communications and/or power conductors required to control all the subsea functions through one pod. The severing, opening, or shorting of one cable assembly should not disable the surface equipment and the pod connected to the other cable should remain fully functional

5.4.6.2 Shipboard cabling from the electrical control units to the cable reels should be routed along separate paths, where practical, to reduce the possibility of both cables being simultaneously damaged.

5.4.6.3 All armored cable shall be designed to avoid kinking and twisting. The cable shall be designed to be capable of supporting at least, two times the anticipated load which is typically the load applied by the unsupported length of deployed cable. The electrical conductors and electrical insulation shall not be used as load bearing components in the cable assembly.

5.4.6.4 All underwater electrical umbilical cable terminations shall prevent water migration up the cable in the event of connector failure or leakage and prevent water migration from the cable into the subsea connector termination in the event of water intrusion into the cable. Conductor terminations shall ensure that seawater intrusion does not cause electrical shorting. A pressure compensated junction box or pressure balanced field installable, testable cable termination containing dielectric fluid may be used to accomplish this.

5.4.6.5 Underwater connectors shall be provided with pressure test ports to verify the seal integrity of mated plug-receptacles. These ports shall be plugged and sealed when not in use for testing.

5.4.7 Cable Reels and Cable Handling Equipment

5.4.7.1 Cable Reels

The cable reels shall be designed to run and retrieve the cable without damaging or kinking the cable.

The cable reel can have payout and take up controls located on the reel or at a remote location. If a remote control station is used, there shall also be controls at the reel capable of overriding the remote controls.

The cable reel drum radius shall be equal to or greater than the minimum bend radius recommended by the manufacturer of the subsea cable for the type of service intended.

The cable reel drive shall have a minimum torque capacity of 1.5 times the maximum torsional load, which is typically the load applied by the unsupported length of the deployed cable. Consideration shall be made to the effect of buoyancy of any submerged section.

5.4.7.2 Brakes and Locking Mechanism

The cable reel brake shall have sufficient capacity to stall the cable reel at full drive motor torque output. A mechanical locking mechanism shall be available to lock the drum in position.

5.4.7.3 Electrical Components

All electrical control functions and electrical power required to run, land and retrieve the LMRP and/or the stack shall remain fully active during running, landing and retrieval. All electrical terminations, junction boxes, slip rings, etc., shall be protected against moisture and shall be suitable for the classification of the areas where installed.

Slip ring contact assemblies shall be of a non-oxidizing material suitable for the surrounding atmosphere. Contacts shall be designed to minimize the possibility of flash over between the contacts. Slip ring contact material shall be designed to minimize wear and avoid formation of resulting conductive dust which could cause signal degradation and short circuits.

Slip rings located in a hazardous area is defined in API RP 500 and IEC 529 and shall be certified as suitable for use in the hazardous location in which they are installed.

5.4.7.4 Cable Sheaves

Cable sheaves facilitate running and retrieving the subsea umbilical from the reel through the moonpool and support the storm loop which is deployed to compensate for vessel heave. All components of the cable sheave assembly shall be constructed from corrosion resistant materials or be properly coated to withstand exposure to salt water spray.

Sheaves shall be mounted to permit three-axis freedom of movement. The design shall prohibit damage to the umbilical in normal ranges of motion. The sheave shall be stamped with a safe working load (SWL) based on the force required to overcome the maximum operating reel tension. The SWL shall exceed the greater of the following calculated forces:

a. Two (2) times the calculated force required to overcome the rated braking capacity of the reel at the minor wrap diameter of the drum.
b. Two (2) times the calculated force required to overcome the maximum motor torque output at the minor wrap diameter of the drum. Hose sheaves shall be mounted to permit three-axis freedom of movement. The design shall prohibit damage to the umbilical in normal ranges of anticipated movement.

Sheave assemblies shall be qualification tested to 1.5 times the SWL and meet design acceptance criteria.

The cable sheave design shall permit installation of the umbilical without disconnecting from the assemblies to which the umbilical may be terminated.

Wheels or rollers which support a bend in the subsea umbilical shall provide a bend radius greater than the minimum bend radius recommended by cable manufacturer.

5.4.8 Subsea Control Pods/Manifolds and Electrical Equipment

The control pod serves as the subsea control valve manifold and contains all of the pressure regulators and control valves required to operate the subsea functions. A minimum of two (2) sets of electrical and/or electro-hydraulic control pods and manifolds shall be provided for the redundant control of all subsea functions.

In the event of failure of one pod/manifold, the disabled pod shall not affect the operation of the other pod/manifold or the subsea functions.

A cable strain relief/radius guard shall be employed at the cable/pod interface, if necessary, to ensure the minimum bend radius of the cable is not exceeded.

Electro-hydraulic and multiplex control pods may be retrievable. In such a case, suitable electrical connectors shall be used to ensure the integrity of the power supply, signal command and readback circuits through disconnect and re-connect of the pod.

5.4.9 Subsea Electrical Equipment

5.4.9.1 All electrical connections which may be unintentionally exposed to seawater shall be protected from excessive electrical current to prevent overloading the subsea electrical supply system in the event of water intrusion.

5.4.9.2 All electrical apparatus to be used subsea is to be temperature rated to be fully operational on a continuous basis while exposed to surface ambient conditions without the use of auxiliary cooling or heating external to the enclosure where the electrical apparatus is located.

5.4.9.3 All subsea electrical equipment shall be designed to be suitable for use subsea with particular attention paid to mechanical vibration and shock induced while drilling. Plug-in devices shall be mechanically secured.

5.4.9.4 Auxiliary subsea electrical equipment which is not directly related to the BOP control system shall be connected in such a manner to avoid disabling the BOP control system in the event of a failure in the auxiliary equipment.

All electrical and electronic chambers shall be double sealed at all areas exposed to seawater or hydrostatic pressure and should have a provision for a test port. These test ports shall be plugged and sealed when not in use for testing. A chamber containing electrical components which is filled with dielectric fluid and pressure compensated to the ambient pressure surrounding the stack may be sealed using a single seal.

5.5 DIVERTER CONTROL SYSTEMS

5.5.1 General

The diverter control system shall be designed to preclude closing-in of the well with the diverter. This requires opening one or more vent lines as well as closing normally open mud system valves (if applicable) prior to closing the diverter annular sealing device. Operation to open the vent valve and close the mud line (return) valve shall occur before the diverter packer is closed. The pumps and/or reservoirs used to operate the diverter system shall either be common to the BOP control system or dedicated to the diverter system. If a dedicated system is used, the diverter control system shall have a control fluid reservoir sized to hold a minimum of two times the fluid volume required to charge the diverter system accumulator. See reservoir requirements of return-to-reservoir systems.

Land rigs and bottom-supported offshore rigs have similar diverter requirements, which are different from floating rig requirements. Land rigs and bottom-supported offshore rigs typically use the BOP stack control system to operate the diverter equipment as the diverter system and BOP stack are not in use at the same time. For systems of this type, temporary labels or graphics may be installed on the BOP control manifold and remote panels during top hole drilling. Alternatively, either separate controls on the remote panel(s), or dedicated hydraulic controls may be provided. Separate panel controls for a common hydraulic manifold shall have a mode select control on the panel.

5.5.2 Response Time

A diverter control system shall be capable of operating the vent line and flow line valves (if any) and closing the annular packing element on pipe or open hole within 30 sec. of actuation if the packing element has a nominal bore of 20 in. or less. For elements of more than 20 in. nominal bore, the diverter control system must be capable of operating the vent line and flow line valves (if any) and closing on pipe in use within 45 sec.

Conformance with response time specifications shall be demonstrated by manufacturer's calculations, by simulated physical testing or by interface with the actual BOP stack.

5.5.3 Accumulator Volumetric Capacity

The diverter control system shall have an accumulator FVR (Functional Volume Requirement) to provide one hundred percent (100%) of the power fluid volume (with pumps inoperative) required to operate all of the divert mode functions. The volume design factor for volume limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1.

The volume design factor for pressure limited accumulator discharge shall be determined by the sizing calculation method selected per 4.2.3.1. The pressure of the remaining accumulator fluid operating all of the required divert mode functions, including the required pressure limited discharge volume design factor for the selected calculation method, shall exceed the calculated minimum system operating pressure. The calculated minimum system operation pressure shall exceed the greater of the following:

1. The minimum calculated operating pressure required to close the diverter packing element on drill pipe at the maximum rated wellbore pressure of the diverter system.
2. The minimum calculated operating pressure required to open and hold open any overboard valve in the diverter flow line system at the maximum rated wellbore pressure of the diverter system.

5.5.4 Pump Systems

The pump system(s) shall be capable of recharging the diverter control system accumulators to system rated working pressure within five (5) minutes after one complete divert mode operation.

Note: This is the operation to the divert mode, not to the divert mode plus return to drilling mode.

System overpressure protection shall comply with Section 5.1.2.3.

Primary pumps shall automatically start when the actual system working pressure has decreased to approximately 90% of the system rated working pressure, and automatically stop between 97% – 100% of the system rated working pressure.

If provided, secondary pumps shall provide operation similar to the primary pumps, except that the set point to start the pump may be adjusted slightly lower so that both pump systems do not start simultaneously. The secondary pump control shall not stop the pump at less than 95% of the system rated working pressure and shall start the pump automatically prior to the pressure decreasing below 85% of the system rated working pressure.

5.5.5 Alternative Power Fluid Supply

A secondary power fluid supply shall be employed to permit operation of the diverter system should the primary power fluid supply become disabled. This can be accomplished by alternative pump system capacity, separate isolated accumulator capacity, nitrogen back-up capacity or other means. The secondary supply shall be capable of meeting the recommendations of 5.2.2. The secondary supply shall be automatically or selectively available on demand.

When the diverter control system is supplied with an alternative power fluid supply from the BOP control system, the accumulator capacity, pump capacity and reservoir capacity shall comply with the above requirements for a self-contained diverter control system. An isolation valve shall be installed at any direct interconnection between the BOP accumulators and the diverter accumulators keeping the two systems isolated under normal operating conditions. The function of these isolation valves shall be clearly labeled and their position status shall be clearly visible.

5.5.6 Diverter Control Manifold

The diverter control manifold consists of control valves, regulators and gauges. The control valves shall be arranged so that they represent the actual diverter equipment arrangement and be clearly identified as to their purpose and functional position. The diverter control system shall be designed to prohibit closing the diverter packer unless a vent line has been opened. If the diverter in use is equipped with an insert packer and/or pressure energized flow line seals, the control system sequencing circuitry shall additionally prevent closing the diverter packer if the insert packer is unlocked or if the flow line seals and/or overshot packer are not energized.

Where applicable, the control system shall be capable of switching the diverted flow from one vent line to the other (e.g., port to starboard) while the diverter packer is closed without shutting in the well.

Regulators used in the diverter control system shall reduce operating pressure to within the manufacturer's limits for the components being operated and be capable of adjustment to within the recommended operating parameters. If relief valves are used to limit maximum pressure, they shall be of the self-reseating type and must reseat within 25% below the relief setting. An air storage or nitrogen back-up system shall be provided with capability to operate all of the pneumatic functions at least twice in the event of loss of rig air pressure.

5.5.7 Diverter Control Stations

All of the diverter control functions shall be operable from the rig floor.

A second control station shall be provided in an area remote from the rig floor. The remote area control station shall be capable of operating all diverter system functions including any necessary sequencing and control of the direction of the diverted flow. Loss of remote control capability should not interrupt or alter the automatic sequencing from the main control unit.

5.6 AUXILIARY EQUIPMENT, CONTROL SYSTEM FEATURES AND INTERFACES

5.6.1 General

Auxiliary control systems referred to in this section shall comply with the guidelines stated in 5.2 where applications are of a typical or similar nature.

5.6.2 Latch and/or Subsea Diverter Controls

If the riser/diverter system is employed while drilling below the surface pipe, a latch/pin connector with a ball/flex joint is typically used to connect to the wellhead. A subsea diverter assembly may also be deployed. A dedicated umbilical hose bundle and reel may be used for transmitting function operating signals. Control valves may be located at the hose reel console. The rig floor panel may provide remote control.

5.6.3 Riser Fill/Dump Valve Controls

A jumper hose from the subsea pod or a direct umbilical may be used to control the riser fill/dump valve. Remote control may be built into the hose reel console and/or the driller's control panel.

5.6.4 Control for Upper Riser Accessories

Riser components such as upper ball joint, telescopic joint packing element pressure, stowable tensioner ring, and remotely operated hydraulic choke and kill connectors may be controlled from the Rig Floor Panel via the surface control manifold and dedicated jumper hoses.

5.6.5 Ancillary Subsea Electronics

Drilling in deep water has enhanced the importance of monitoring subsea parameters. Typical ancillary functions integrated into the Signal Transmission and Electrical Power Supply array of an Electro-Hydraulic (MULTIPLEXED) BOP Control System may include the following:

a. Measurement of riser angle.
b. Measurement of riser stresses.
c. Measurement of BOP stack angle.
d. Measurement of sea bottom currents and water temperature.
e. Measurement of wellbore fluid temperature at the wellhead.
f. Measurement of wellbore pressure at the wellhead.
g. Transmission of underwater television images.
h. Control of TV camera functions (pan, tilt, etc.).

i. Control and power of underwater TV lights.
j. Valve and BOP position indicators.

The transmission of data and power for these types of functions may be through independent conductors in the subsea electronic umbilical or may be integrated into the main BOP Control System itself. When integrated as part of the main BOP Control System, detailed analysis and system integrity checking shall be performed to confirm the ancillary functions in no way impair, jeopardize, or degrade the purpose and operation of the BOP Control System.

5.7 EMERGENCY DISCONNECT SEQUENCED SYSTEMS (EDS) (OPTIONAL)

5.7.1 An EDS shall be provided for a deepwater floating drilling rig when there is a requirement to rapidly disconnect the riser in the event of an inability to maintain rig position within a prescribed watch circle. Excursion of the rig beyond the limits of the watch circle could result in the full extension of the riser telescopic joint and/or the riser tensioners potentially causing damage to the riser or wellhead. Such excursion could be caused by "drive-off" or "drift-off" of a dynamically positioned vessel or failure of one or more mooring lines on a moored vessel. The EDS shall be designed to ensure that the well is shut in as part of the functional sequence. The EDS release time is the time duration from the initiation of the command at the surface to the disconnect of the LMRP, and should be as short as practicable. Ideally, the well will be left in a secured condition (blind/shear rams closed and sealed) prior to disconnect. On systems equipped with autoshear capability, shear ram closure may be initiated upon disconnect of the LMRP.

5.7.2 The list of functions to be included in an EDS is rig/operator dependent, but, as a minimum shall include release of the LMRP connector and closure of at least one blind/shear ram. Other EDS functions may include pod stingers (retract), choke and kill stabs (retract), choke and kill valves (close/block), riser-fill valve (open), acoustic stabs (retract), and ram BOP/annular BOP (block).

5.7.3 The allowable EDS time is dependent on parameters such as the operating water depth, vessel configuration, orientation of the vessel to the environment, design environment, and the ability of the LMRP to disconnect at high riser angles.

5.7.4 The actual EDS time is dependent on variables such as which functions are designated, the time required to operate the EDS and other constituent functions, such as riser recoil control. A range of 30 – 90 sec. (not including autoshear) is typical.

Note: Although normally used on DP vessels, an EDS may be employed on a moored vessel, if specific operating conditions require it as an added safety feature.

5.8 BACKUP CONTROL SYSTEMS (OPTIONAL)

5.8.1 General

In the event that supply of power fluid or pilot signals is lost, a backup control system may be employed to operate selected functions. Types of backup control systems for subsea controls include (but are not limited to) acoustic control systems, ROV (Remotely Operated Vehicle) operated control systems, and LMRP recovery systems. For surface installations, a nitrogen gas powered backup system may be used. Multiple backup control systems, such as acoustic, deadman, and/or autoshear system, and the main hydraulic supply of the control system may be powered by a shared accumulator. A shared accumulator is not required to provide the allowable calculated volume of any discrete function more than once.

For example: An accumulator from which shear ram can be operated by both acoustic operation and auto shear circuit does not need to allow for the function of the shear ram more than once. If the shear ram is already closed by the acoustic operation and the auto shear circuit is then actuated by the acoustic release of the LMRP connector and subsequent lift off, the shear ram BOP is already closed, and additional volume for this is not needed. If the acoustic function did not close the shear ram prior to the autoshear function, then the required hydraulic volume in the shared accumulator is still available for the shear ram to close via the autoshear method of actuation.

The functional requirements of these systems is specified by the purchaser. If dedicated accumulators are used, the FVR for these systems is usually one hundred percent (100%) of the equipment manufacturer's specified operation volumes to be functioned. The volume design factor used shall be in accordance with Section 2. The accumulator sizing method selected should reflect the discharge and pressure requirements of the system.

5.8.2 Acoustic Control Systems

Acoustic signal transmission may be used as an emergency backup means for controlling critical BOP stack functions. The acoustic control system includes a surface electronics package, subsea electronic package and a subsea electro-hydraulic package.

5.8.2.1 Acoustic System Subsea Accumulators

Optional sources of power fluid to operate the acoustic system functions include:

a. A dedicated bank of subsea accumulators charged from the primary subsea power fluid supply through an isolation valve. This arrangement enables the acoustic system to be functional in the event that the primary system has lost signal transmission, pod mechanical function or has experienced power fluid pressure depletion.
b. When the primary control system subsea accumulators, which are normally isolated from the acoustic system, are used to supply all or part of the required fluid volume by means of an isolation valve which is opened when a function is acoustically commanded. It is important to note that this arrangement does not provide functional backup in the event that stack mounted accumulator volume or pressure is depleted.

5.8.2.2 Accumulator Volumetric Capacity

The acoustic subsea accumulator system shall be compensated for subsea hydrostatic pressure gradient and shall have a minimum FVR of one hundred per cent (100%) of the power fluid (without input replenishment) to operate all functions selected for emergency operations. The required volume design factor for volume limited discharge is specified by the calculation method selected in 4.2.3.1. The calculated pressure of the remaining accumulator fluid, after operating all of the required functions, including the required volume design factor for pressure-limited discharge of the selected calculation method, shall exceed the calculated minimum system operating pressure. Note that this pressure may include shearing pipe for this application. Any precharge pressure may be used which satisfies the functional requirements. The functions typically selected for emergency operation include:

a. Riser Connector—Unlock.
b. Shear Ram—Shear.
c. Upper Ram—Close.
d. Middle Ram—Close.
e. Ram Locks—Lock (if applicable).

5.8.2.3 Acoustic System Hydraulic Control Functions

The acoustic control system should be designed such that the electric control system functions can be tested without actuation of the BOP stack functions. To accomplish this, a two-way acoustic communication system is recommended. Commands are sent subsea from the surface control unit while accumulator pressure is shut off subsea. Status monitoring signals are sent back to the surface to verify electric function signal reception.

The design basis for an acoustic system shall specify whether the accumulator is to be designed as a rapid discharge system (deliver the FVR in less than 3 min., Method C). This basis along with operating pressure and specified operational requirements will determine whether design method A, B or C is to be used per Table 2.

Solenoid valves provide hydraulic pilot signals to shift hydraulic valves to the open position. These in turn direct the accumulator supply pressure that operates the BOP stack functions. The solenoid coils must be isolated from seawater. The hydraulic valves should be connected to the stack functions by way of shuttle valves (or alternate means) to allow acoustic operation of the stack without affecting operability from the main control system.

A manifold supply isolation valve should facilitate testing the actuation of the solenoid valves without power fluid being supplied to the BOP stack control valves.

A means should be provided to allow venting of the subsea accumulator pressure prior to or during retrieving the accumulators to the surface.

Hydraulic components and piping systems should have a rated working pressure at least equal to the rated working pressure of the control system.

5.8.2.4 Acoustic System Electronic Control Functions

The acoustic control electronic system is intended to provide security command signal coding to prevent operation by other equipment in close proximity. Frequencies used shall avoid interference with other equipment on and in the vicinity of the drilling rig. Water depth and slant range capacity shall meet purchaser specifications.

Two (2) actions shall be required to initiate the function(s) (i.e., actuate the "arm" function and actuate the "close" control function).

A minimum of two (2) subsea transducers providing parallel sending and receiving capability in a "space diversity receiver" system (where each transducer is connected to a separate receiver) shall be used. Capability for extending and retracting the subsea transducer arms, if used, can be included in the primary control system design or an automatic means may be incorporated.

Subsea battery power to operate the acoustic control system shall be capable of sustaining operation for a minimum of 180 days after deployment without recharging, assuming operation of 100 command functions over a period of 180 days. A low battery alarm shall be provided.

Combined or separate battery chargers may be used to charge the batteries for the surface and subsea battery systems. Means shall be employed to ensure the safety of charging subsea batteries within a sealed container.

Subsea electronics and battery pack shall be housed in a watertight container designed to withstand the subsea pressure to which it is exposed. If both are within the same container, the battery pack shall be insulated from the electronics.

Subsea electrical equipment shall meet the applicable recommendations of 5.4.9.

The surface control equipment shall include a portable, battery operated control unit with a portable, cabled, omnidirectional (horizontal) beam pattern, "dunking" transducer. A single portable surface control unit shall be used with both a vessel mounted transducer and a "dunking" transducer by exchanging respective cables. This portable control unit shall afford communication capability to meet purchaser specifications. The battery shall afford 50 transmissions in four hours of operation. The system shall afford performance of a minimum of 10 transmissions within the first 10 minutes of operation. A low battery alarm shall be provided. A test unit or suitable means of testing the full operational circuitry of the portable console unit will be provided.

5.8.3 ROV (Remote Operated Vehicle) Operated Control Systems

5.8.3.1 ROV Intervention Interfaces

ISO 13628-8/API RP 17H provides design standards for ROV intervention fixtures.

Means may be provided to use hydraulic power supplied by an ROV to operate critical BOP stack functions. This system may serve as a backup control if the primary control systems are inoperative. The ROV operated system may also serve as a pressure assist as needed.

Each ROV connection shall be pressure balanced so that it does not tend to disengage the connection by the pressure reaction forces.

Some ROVs have a special provision for storing a limited volume of a suitable hydraulic fluid in a bladder reservoir. This fluid may be used for operating functions requiring less than the usable bladder volume without subsequent flushing or maintenance.

Note: In the event that a function is operated using sea water as control fluid, subsequent flushing and/or maintenance at the surface is required.

5.8.3.2 ROV Operated Functions

The capability to unlock the riser and wellhead connectors by means of ROV interventions may be provided. In an emergency situation, the ability to shut in the well by means of ROV intervention may be useful. Other optional functions include the following:

a. Blind/Shear Rams Close.
b. Pipe Rams Close.
c. Choke or Kill Valves Open.
d. Choke or Kill Valves Close.
e. Accumulator Discharge.
f. Ram Locking Mechanisms.

For a multi-function system, an operating panel may be mounted on the BOP stack in an accessible location and clearly labeled for identification by the ROV television cameras.

ROV actuated valves may be used to perform various functions. ROV-actuated stack-mounted valve(s) shall have rated working pressure(s) equal to or exceeding the rated working pressure of the subsystem in which it is installed.

5.8.4 LMRP Recovery System

Means may be provided for the recovery of the LMRP in the event that the riser and/or control system is in a non-functional condition, or for the recovery of the BOP and LMRP in the event of an accident resulting in the BOP stack being dropped to the sea floor.

Recovery systems may consist of an LMRP frame-mounted holding fixture, a re-entry funnel to which are connected LMRP lifting slings and hydraulic function hoses, a stinger assembly run on drill pipe and one or more darts which are used after re-entry to select the control functions to prepare the stack for LMRP recovery. Such systems may interface with the LMRP control hoses through shuttle valves. These systems are normally limited to use when the BOP stack is in a vertical position.

5.8.5 Backup Nitrogen Power Supply

A nitrogen backup system consists of a number of high-pressure gaseous nitrogen bottles manifolded together to provide emergency power fluid to the control manifold. The nitrogen backup system is connected to the control manifold through an isolation valve and a check valve. If the accumulator/pump unit is not able to supply power fluid to the control manifold, the nitrogen backup system may be activated to supply high-pressure gas to the manifold to close the BOPs.

The nitrogen backup shall be connected to the control manifold in a manner that will prevent flow of nitrogen into the accumulator circuit and prevent hydraulic fluid from entering the nitrogen backup circuit. The nitrogen backup circuit or the control manifold shall contain valving to allow controlled bleed down of high-pressure nitrogen gas to prevent uncontrolled dumping of the pressurized nitrogen into the reservoir.

Nitrogen backup circuits may also be used with pneumatic or electro-pneumatic remote control circuits as an emergency power source should rig air pressure be lost. It is imperative that the nitrogen pressure be regulated to within the rated working pressure of the subsystem it operates and further protected from overpressurization by a relief valve.

5.9 SPECIAL DEEPWATER/HARSH ENVIRONMENT FEATURES (OPTIONAL)

5.9.1 General

For deepwater/harsh environment operations, particularly where multiplex BOP controls and dynamic positioning of the vessel are used, special control system features may be employed.

Autoshear and deadman systems are optional safety systems that are designed to automatically shut in the wellbore during unplanned emergency events. These systems both utilize subsea accumulators to provide power fluid, and may be powered by a shared accumulator, such as acoustic system, that is not discharged into the main hydraulic supply. A single control system may incorporate both the autoshear and the deadman features. Both the autoshear system and the deadman system shall be manually armed and disarmed.

The sequence of events in these systems is specified by the purchaser. The FVR for these systems is usually one hundred percent (100%) of the equipment manufacturer's specified operation volumes to be functioned. Items that are functioned by multiple systems do not require adding the functional volume to the common accumulator more than once. The volume design factor used shall be in accordance with 4.2.3. Usually these systems have a short time frame for operation and Method C would be indicated for the accumulator sizing calculation.

5.9.2 Autoshear Systems

Autoshear is a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP. When the autoshear is armed, a disconnect of the LMRP closes the shear rams. This is considered a "rapid discharge" system.

5.9.3 Deadman Systems

A deadman system is a safety system that is designed to automatically close the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a "rapid discharge" system.

6 Periodic Inspection and Maintenance Procedure

The manufacturer shall provide the purchaser with information necessary to establish inspection and maintenance procedures for control systems for well control equipment. Inspections and maintenance procedures shall take into consideration the manufacturer's published recommendations.

Inspection recommendations, where applicable, may include:

a. Verification of instrument accuracy.
b. Relief valve settings.
c. Pressure control switch settings.
d. Precharge pressure in accumulators.
e. Pump systems.
f. Fluid levels.
g. Lubrication points.
h. General condition of:
    1. Piping systems.
    2. Hoses.
    3. Electrical conduit/cords.
    4. Mechanical components.
    5. Structural components.
    6. Filters/strainers.
    7. Safety covers/devices.
    8. Control system sizing.

9. Battery condition.

i. Reference Documents.

1. API RP 14F, Latest Edition.
2. API RP 500, Latest Edition.

7 Documentation

7.1 GENERAL

All documentation shall be dated. Revision status if applicable will be indicated and a person having responsibility for its completeness, accuracy and proper distribution shall sign each document.

7.2 QUALITY CONTROL RECORDS

The following records shall be maintained by the manufacturer for a period of not less than five (5) years:

a. Material specifications and certifications.
b. Hazardous area certifications.
c. Hydrostatic test charts.
d. Performance test and measurements.
e. Materials/components list.
f. Engineering drawings.
g. Certificate of compliance to API Spec 16D.
h. Contract information including:

1. Purchaser name and purchase order number.
2. Manufacturers serial number.
3. EX-works delivery date.
4. Destination/rig name.
5. API monogram (if applicable).
6. Manufacturers identification/model numbers.

i. Design data documentation (if applicable).

7.3 MANUFACTURING DOCUMENTATION

A document file to ensure that equipment specifications are met during the purchasing and manufacturing processes shall be established and employed by the control system manufacturer. The documentation shall include:

a. Purchase control specifications.
b. Engineering specifications.
c. Manufacturing standards.
d. Quality control procedures.

Material traceability or serialization and commodity items is not required, unless otherwise specified herein.

7.4 TEST PROCEDURES

Test procedures shall be written, dated and signed by an engineering authority having responsibility for ensuring that the product meets the intended application specifications. The procedure shall at least include the following:

a. Reference documentation list.
b. Test equipment and apparatus list.
c. Personnel safety instructions.
d. Pre-test inspection, servicing and assembly requirements.
e. Detailed instructions (as applicable) for:

1. Flushing and fluid cleanliness requirements.
2. Utilities verification.
   i)Electric motor voltage, frequency, phase balance, amperage and insulation resistance.
   ii)Air supply pressure and flow capacity.
3. Hydrostatic test requirements.
4. Operational limit settings.
5. Functional requirements.
6. Records and data requirements.
7. Post test procedures, preservation and protection requirements.

f. Quality witness and acceptance.
g. Special considerations.

1. Requirements to ensure proper interface of system components permitted when delivery of components precludes availability of all components during factory tests.
2. Calculations acceptable to ensure design specifications are met where actual measurement of performance is not practical.

7.5 CERTIFICATIONS

7.5.1 Type Certification

Type certifications may be used for commodity items, manufactured equipment and/or components when the conformance to applicable specifications has been confirmed on at least one unit of the type and where other units of the same type are produced in the same manner, and in accordance with the same specifications. Subsequent units of the accepted type shall be periodically audited to ensure compliance to specifications.

The intent of type certification is to reduce per item documentation and testing for high usage items and items supplied for maintenance spares.

Failure of a type certified item to conform to specifications during periodic audit shall require the manufacturer to inform the known purchasers of like equipment subsequent to the last audit (in writing), of the failure and of necessary action to insure the integrity of the equipment.

7.5.2 Hydrostatic Test Certificates

The control system manufacturer shall provide hydrostatic test certificates for piping and component systems subjected to internal pressure of 250 psi or more. Pressure measurement and transmitting devices shall be tested to their own rated working pressures. Piping and containment devices shall be tested:

a. to 1.5 times the rated working pressure for factory acceptance tests.
b. to rated working pressure for field tests.

Holding time for test pressure shall be five (5) min. after stabilization. Test recorder charts shall be available, dated, witnessed, and identified to the particular equipment to accredit manufacturer's certifications.

7.5.3 Hazardous Area/Electrical Certificates

Manufacturer's certificates of compliance to applicable electrical codes shall be required for all electrical equipment and apparatus for installation in explosive environments as defined in API RP 500 or IEC 529.

7.5.4 Accumulator Certificates

Seamless accumulators shall be furnished with ASME-U-1A certificates, or equivalent documentation from other pressure vessel codes referenced in Section 2. Welded accumulators shall be documented with weld and NDE reports as well as hydrostatic test reports and manufacturer's certification to acceptable design and manufacturer requirements meeting ASME Section VIII Division I or other pressure vessel codes referenced in Section 2.

Note: Accumulators shall comply with 9.2.3.

7.5.5 Relief Valve Certificates

Relief valves shall be separately tested and adjusted using a low flow rate tester comparable to a dead weight tester. A certificate of the relief valve setting and operation shall be provided indicating the set point and the pressure at which the relief valve reseats. Relief valves shall reseat within twenty five percent of the set pressure.

Relief valves shall additionally be type tested to determine the maximum flow rate through the relief valve without exceeding 115% of the relief valve's set pressure.

7.5.6 Certificate of Compliance

Manufacturer's certificate of compliance shall certify that all specifications set forth in this document for the design, manufacturing, testing, and corrosion protection have been met for the intended service. All records pertaining to the design, manufacture, and testing shall be duly filed and retained by the manufacturer.

8 Manufacturing Processes

8.1 STRUCTURAL STEEL

Structural steel shall conform to the manufacturer's specification. The minimum strength level, group, and class shall be specified by the manufacturer's specification. Unidentified steel shall not be used.

8.2 STEEL GROUPS

Steel can be grouped according to strength level and welding characteristics as follows:

a. Group I designates mild steels with specified minimum yield strengths of 40 ksi (280 MPa) or less. Carbon equivalent is generally 0.40% or less, and these steels may be welded by any of the welding processes as described in AWS D1.1 or equivalent recognized international standard.
b. Group II designates intermediate strength steels with specified minimum yield strengths of over 40 ksi (280 MPa) through 52 ksi (360 MPa). Carbon equivalent ranges up to 0.45% and higher, and these steels require the use of low hydrogen welding processes.
c. Group III designates high strength steels with specified minimum yield strengths in excess of 52 ksi (360 MPa). Such steels may be used, provided that each application is investigated with regard to the following:
    1. Weldability and special welding procedures which may be required.
    2. Fatigue problems which may result from the use of higher working stresses.
    3. Notch toughness in relation to other elements of fracture control, such as fabrication, inspection procedures, service stress, and temperature environment.

8.3 STRUCTURAL SHAPE AND PLATE SPECIFICATIONS

Unless otherwise specified by the designer, structural shapes and plates shall conform to one of the specifications listed in ASTM standards.

8.4 WELDING

8.4.1 General

All welding of external or internal pressure containing components shall comply with the welding requirements of the *ASME Boiler and Pressure Vessel Code Section IX* (Ref Section 9.1.) or other pressure vessel codes referenced in Section 2. Verification of compliance shall be established through the implementation of the manufacturer's Welding Procedure Specification (WPS) and the supporting Procedure Qualification Record (PQR).

When welded, pressure containing (15 psi or greater) components require impact testing. Verification of compliance shall be established through the implementation of the manufacturer's WPS and supporting PRQ.

8.4.2 Pressure-containing Fabrication Weldments

Pressure containing fabrication weldments described here pertain to primary pressure-containing members.

Full penetration welds may be used for pressure-containing fabrication. Typical examples are listed in AWS D1.1 Charts, A2.4-86.

8.4.3 Load-bearing Weldments

Load bearing weldments are essential to the operation or installation of equipment and are not in contact with the contained pressurized fluid. These include, but are not limited to, lifting points and equipment mounting supports. The manufacturer shall define joint design for load bearing weldments.

Weld repairs to manufacturer's designated primary pressure-containing members shall be performed in accordance with the manufacturer's written welding procedure.

Welding and completed welds shall meet the quality control requirements of Section 7 and Section 8 of this specification.

8.4.4 Weld Surfacing

Overlay (other than ring grooves) is intended for corrosion resistance and wear resistance. The manufacturer shall use a written procedure that provides controls for consistently meeting the manufacturer specified material surface properties in the final machined condition. As a minimum this shall include inspection methods and acceptance criteria. Qualification shall be in accordance with Article II and III of ASME Section IX for corrosion resistant weld metal overlay or hardfacing weld metal overlay as applicable.

8.4.5 Welding Controls

Welding shall be performed in accordance with the WPS, qualified in accordance with Article II of ASME Section IX or equivalent recognized international standard. The WPS shall describe all the essential, non-essential and supplementary essential variables (see ASME Section IX or equivalent recognized international standard). Welders and welding operators shall have access to and shall comply with the welding parameters as defined in the WPS.

Weld joint types and sizes shall meet the manufacturer's design requirements.

8.4.6 Design of Welds

All welds that are considered part of the design of a production part shall be specified by the manufacturer to describe the requirements for the intended weld.

Dimensions of groove and fillet welds with tolerances shall be documented in the manufacturer's specification. Weld types and symbols are listed in AWS D1.1 Charts, A2.4-86.

8.4.7 Preheating

Preheating of assemblies or parts, when required, shall be performed to manufacturer's written procedures.

8.4.8 Instrument Calibration

Instruments to verify temperature, voltage, and amperage shall be serviced and calibrated in accordance with the written specification of the manufacturer performing the welding.

8.4.9 Welding Consumables

Welding consumables shall conform to American Welding Society or consumable manufacturer's approved specifications. Welding consumables shall only be used within the limitations of ASME IX, except that filler metals bearing the "G" classification may not be used interchangeably. Such filler metals must be qualified individually. The qualification of filler metals bearing the "G" classification shall be limited to heats or lots of the same nominal chemical composition as originally qualified by PQR testing.

The manufacturer shall have a written procedure for storage and control of weld consumables. Materials of low hydrogen type shall be stored and used as recommended by the consumable manufacturer to retain their original low hydrogen.

8.4.10 Post-weld Heat Treatment

Post-weld heat treatment of components shall be performed to the manufacturer's written procedures.

Furnace post-weld heat treatment shall be performed in equipment meeting the requirements specified by the manufacturer.

Local post-weld heat treatment shall consist of heating a band around the weld at a temperature within the range specified in the qualified welding procedure specification. The minimum width of the controlled band adjacent to the weld, on the face of the greatest weld width, shall be the thickness of the weld. Localized flame heating is permitted provided the flame is baffled to prevent direct impingement on the weld and base material.

8.4.11 Welding Procedure and Performance Qualifications

8.4.11.1 General

All weld procedures, welders and welding operators shall be qualified in accordance with the qualification and test methods of Section IX, *ASME Boiler and Pressure Vessel Code* or other recognized international standard.

8.4.11.2 Base Materials

The manufacturer shall use ASME Section IX P number materials.

The manufacturer may establish an equivalent P number (EP) grouping for low alloy steels not listed in ASME Section IX with nominal carbon content equal to or less than 0.35%.

Low alloy steels not listed in ASME Section IX with a nominal carbon content greater than 0.35% shall be specifically qualified for the manufacturer's specified base material.

Qualification of a base material at a specified strength level shall also qualify that base material at all lower strength levels.

8.4.11.3 Heat Treat Condition

All testing shall be performed with the test weldment in the post weld heat treated condition. Post-weld heat treatment of the test weldment shall be according to the manufacturer's written specifications.

8.4.11.4 Procedure Qualification Record

The PQR shall record all essential and supplementary essential variables of the weld procedure used for the qualification test(s). Both the WPS and the PQR shall be maintained as records in accordance with the requirements of Section 7 of this specification.

8.4.12 Other Requirements

8.4.12.1 Article I of ASME Section IX applies with an optional addition for impact testing found below.

When impact testing is required by the base material specification, the testing shall be performed in accordance with ASTM A-370 using the Charpy V-Notch technique. Results of testing in the weld and base material Heat Affected Zone (HAZ) shall meet the minimum requirements of the base material. Records of results shall become part of the PQR.

When impact testing is required of the base material, one set of three (3) test specimens each shall be removed at the $^1/_4$ in. thickness location of the test weldment for each of the weld metal and base material Heat Affected Zone (HAZ). The root of the notch shall be oriented normal to the surface of the test weldment and located as follows:

a. Weld metal specimens shall be 100% weld metal.
b. HAZ Specimens (3 each) shall include as much HAZ material as possible.
c. When weld thickness of the product is equal to or greater than two (2) in., impact testing as defined in this section shall be performed on weld metal and HAZ material removed within $^1/_4$ in. thickness from the root.

8.4.12.2 Article II of ASME Section IX applies with additions found below.

The post-weld heat treatment of the test weldment and the production weldment shall be in the same range as that specified on the WPS. Allowable range for the post-weld heat treatment on the WPS shall be a nominal temperature ±25°F. The stress relieving heat treatment(s), time(s), at temperature(s) of production parts shall be equal to or greater than that of the test weldment.

Chemical analysis of the base materials for the test weldment shall be obtained from the supplier or by testing, and shall be a part of the PQR.

8.4.12.3 ASME Section IX, Article III, applies as written.

8.4.12.4 ASME Section IX, Article IV, applies as written.

8.5 CATHODIC PROTECTION

Equipment to be deployed subsea shall be cathodically protected in accordance with applicable recommendations of NACE Standard RP-01-76 *Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production*. Manufacturer shall specify materials, sizes, locations and method of installation of cathodic protectors in accordance with these NACE standards.

8.6 PAINTING

Abrasive blast cleaning methods, painting materials and standards of measurement shall meet the applicable recommendations of The Society of Protective Coatings (SSPC) guidelines for the intended environment of installation. Manufacturer shall specify materials, application and verification in written procedures.

9 Commodity Items

9.1 GENERAL

For the purpose of this specification, commodity items are defined as manufactured products purchased by the control system manufacturer for use as constituent elements of control systems for drilling well control equipment. Commodity items are items which are manufactured to specifications and documentation typically established by subvendors rather than by the control system manufacturer and include such items as may be commercially available for other industrial applications.

Commodity items shall meet or exceed accepted applicable industry standards for the intended use in control systems governed by this specification.

Commodity items for the purpose of this specification are divided into the following classifications:

a. Pressure-containing components.
b. Electrical and electronic equipment and installations.
c. Mechanical equipment.
d. Fluids and lubricants.

9.2 PRESSURE-CONTAINING COMPONENTS

9.2.1 General

All pressure-containing (15 psi or greater) or pressure-controlling components shall require a documented standard material specification to the manufacturer's written requirements for the metallic materials to be used.

9.2.2 Pressure Vessels—General

Pressure vessels having internal or external working pressures above 15 psi (103 KPa) shall meet or exceed the mandatory appendices of *ASME Boiler and Pressure Vessel Code*, Section VIII, Division I, Rules for Construction of Pressure Vessels, or equivalent pressure vessel code.

9.2.3 Accumulators

9.2.3.1 Accumulators shall be specified with a rated working pressure such that the ASME (or equivalent pressure vessel code) certification results in a minimum hydrostatic test pressure value of one and one-half (1.5) times system rated working pressure. Certification of hydrostatic test witnessed by the appropriate inspector (in accordance with pressure vessel code requirements) shall be evident by the appropriate code inspection stamp permanently affixed to each accumulator shell. Accumulator shells shall include a permanently affixed serial number. Written test reports certifying acceptance of the accumulator shell test shall be maintained by the control system manufacturer for each serial numbered unit. Traceability to the original accumulator shell manufacturer shall be maintained.

9.2.3.2 Each precharged accumulator bottle inclusive of all components in the final configuration assembly item shall be hydrostatically tested to the system rated working pressure.

9.2.3.3 The control system manufacturer shall maintain a quality history file including hydrostatic test charts to document that each serial numbered unit successfully held the test pressure (within 1.5%) for a minimum of five minutes after stabilization (see 7.5.2). Sufficient time for pressure stabilization should be allowed to compensate for the temperature effect on the nitrogen precharge.

9.2.4 Pipe, Tubing and Connections

9.2.4.1 Pipe, tubing and connections used in hydraulic or pneumatic circuits subjected to internal pressure exceeding 15 psi shall be compatible with the fluid medium and have a calculated minimum burst pressure rating at least three (3) times greater than the maximum pressure to which the component may be subjected.

9.2.4.2 For specific piping design requirements (including appropriate material stress level, pressure reduction for joints or attachments, and operational considerations) see ANSI/ASME B31.1 and ANSI/ASME B31.3, latest editions.

9.2.5 Hoses and Hose Connections

Burst pressure for hoses shall be determined by actual pressure test conducted on lot samples and certified by the hose manufacturer. This testing shall include end connections if permanently attached. The hose assembly shall be tested to 1.5 times the rated working pressure.

9.2.6 Threaded and Welded Connections

9.2.6.1 Piping and hose metal components shall be burr-free, clean and free of loose scale and other foreign material prior to assembly. Assembly of threaded connections using Teflon tape or non-soluble thread preparations shall require care in use and shall be subjected to subsequent flushing to avoid plugging or malfunction of control system components.

9.2.6.2 Design of threaded piping connections shall be in accordance with 9.2.4.

9.2.6.3 Welding of connections shall be accomplished by certified welders in accordance with applicable codes and manufacturers' qualified written procedures.

9.2.6.4 All piping and tubing installations shall be hydrostatically tested to one and one-half (1.5) times design working pressure by the control system manufacturer during factory acceptance testing. Air supply piping and instrument air systems shall be bubble tested (soap solution on each connection). Air receivers shall be built according to one of the pressure vessel codes listed in Section 2 and shall be protected from over pressurization.

9.2.7 Non-ASME Coded Hydraulic Control System Components

9.2.7.1 Components in this category include control valves, check valves, pressure reducing/regulating valves, solenoid valves, pressure switches, pressure transducers, gauges, relief valves, pump fluid ends and other components in the hydraulic system.

9.2.7.2 Components used in the hydraulic circuits of control systems complying with this specification shall be rated by the component manufacturer for rated working pressures equal to or greater than the maximum system pressure to which they may be subjected. The burst pressure rating shall be at least two (2) times the rated working pressure rating of the components.

9.2.7.3 Hydraulic and pneumatic components integral with electric/electronic devices are also subject to the electrical and electronic equipment and installation specifications presented in 9.3 of this specification.

9.2.7.4 Non-pressure compensated vessels and partially compensated vessels subjected to external pressure greater than 15 psi differential (e.g., one atmosphere subsea housings for electronics) shall have the following features and characteristics:

a. Allowable design stress for the vessel shall not exceed two thirds of yield strength for primary membrane stress. Combined stresses for primary membrane plus bending and all secondary stresses, not to exceed yield strength of the material. Stress definitions are as specified by the ASME pressure vessel code; equivalent stress may be used rather than stress intensity, if desired.
b. Design factor for stability (e.g., collapse) shall be at least 1.5.
c. Each vessel shall be permanently marked in a conspicuous manner to indicate the maximum rated external pressure for which the vessel is designed.
d. Each vessel shall be external pressure tested. This test may be performed with or without electronics in place. Test pressure for external pressure shall be at least 1.25 times rated external pressure.
e. If the vessel should flood at depth, the vessel shall be able to safely withstand this internal pressure when retrieved to the surface, or the vessel shall have relief capability to ensure that safe internal pressure is not exceeded.
f. Vessel shall have a safe vent capability to allow pressure inside the vessel to be safely equalized to atmosphere prior to opening the vessel for service. This may be a plug, cap, end piece that allows pressure to safely vent while still having sufficient structural capacity to retain the pressure.

9.2.7.5 Nitrogen cylinders used in conjunction with blowout preventers and diverter control systems for emergency backup systems shall meet the Department of Transportation (DOT) Specification 3AA2015 as a minimum. Nitrogen cylinders shall physically bear the DOT inspector's mark, registered identifying symbol, test date and supplier's mark.

9.2.7.6 All components used in the construction of control systems shall be new equipment. Component selection shall be based on a minimum history of 2 years of acceptable performance in a similar environment and application, or on simulated cycle testing of a minimum 1,000 cycles at the working pressure. Components not normally cycled shall be qualified for an equivalent two (2) years of service. Components used for qualification tests shall not be used in the construction of deliverable equipment.

9.3 ELECTRICAL AND ELECTRONIC EQUIPMENT AND INSTALLATION

9.3.1 All electrical components shall be rated at 100% duty cycle for use in the full ambient temperature range to which they will be exposed.

9.3.2 All electrical apparatus designed for use in a hazardous atmosphere as defined by (API RP 500 or equivalent recognized international standard) shall be tested and approved as suitable for such use by a recognized third party testing agency. (i.e., FM, UL, CSA, BASEFFA, etc.)

9.3.3 All electrical components shall be capable of operating within specifications at a voltage range of ± 10% nominal rated voltage.

9.3.4 All electrical conductor insulation shall be rated at 1.5 times the peak operating voltage or 50 volts, whichever is greater.

9.3.5 All electrical copper conductors routed external to an enclosure shall be stranded wire of a minimum of 18 AWG. No solid wire shall be used external to an enclosure or in areas of high vibration.

9.3.6 Minimum bend radii of flexible electrical cables shall not be less than cable manufacturers' recommendations over the expected ambient temperature range of the equipment.

9.3.7 Electrical components shall be designed or packaged in a manner to prevent corrosion caused by condensation and/or exposure to a salt-laden atmosphere. All electrical apparatus exposed to uncontrolled atmospheric conditions (i.e., deck-mounted equipment) shall be of NEMA 4X or equivalent recognized international standard construction.

9.3.8 Printed circuit cards shall be constructed and mounted in a manner to minimize the flexing effects of vibration and shock.

9.3.9 All socket mounted components shall be mechanically restrained in their sockets. This can be accomplished by means of a restrainer or with a vibration resistant socket design.

9.3.10 All control system cabinets, skids, and externally mounted components shall be grounded through dedicated ground conductors to a common ground system. Where possible, all electrical control and power circuits should be isolated from the above described ground system. All ground conductors in the above system shall be sized for the maximum expected ground fault current in accordance with the National Electrical Code.

9.3.11 Semiconductor devices are not to be used singularly as a means to electrically isolate circuits which may be exposed to Class I Div. I hazardous atmospheres per API RP 500 or equivalent recognized international standard (i.e., air purge system failure).

9.3.12 All enclosures which contain more than one power source shall include a door or cover mounted tag stating the number of power sources and voltages present. All enclosures which may contain voltages in excess of 50V shall include a door or cover mounted tag stating the maximum voltage which may be present.

9.3.13 An electrical enclosure may be used in a hazardous location as defined in API RP 500 to house nonexplosion-proof electrical components. The enclosure, including conduit and/or cable gland penetrations into the enclosure, shall be designed and certified to meet or exceed the specific requirements for the area in which it is installed. Cable gland penetrations into the enclosure and electrical enclosures meeting this specification shall be appropriately labelled by an independent certifying authority to show zone classifications.

9.3.14 All intrinsically safe circuits shall use blue terminals, blue wire, and be tagged with blue tags indicating the presence of intrinsically safe circuits. In addition, all intrinsically safe circuits shall be physically isolated from non-intrinsically safe circuits by means of separate enclosures or insulating barriers.

All electrical conductor maximum ampacities shall be sized using the edition of the National Electric Code in effect at the time of equipment manufacture and/or installation.

9.3.15 Aluminium wire shall not be used.

9.4 MECHANICAL EQUIPMENT

9.4.1 Pod valves shall be designed to minimize interflow. Consideration shall be given to effective spring closure in the absence of pressure assist closing. Prototype springs shall be tested to 1,000 cycles and retain the minimum design spring constant. All pod valve prototypes shall be cycled a minimum of 1,000 times at normal operating pressure. All pod valve prototypes shall be pressure and flow tested at conditions that simulate the application environment, including the "vent" port pressure environment. Cap screws holding valves and regulators together shall be corrosion resistant.

9.4.2 Tubing restraints shall be employed where failure may cause personal injury. Hoses, cables and other umbilical restraints shall not cause bending radius to be less than the minimum specified by the umbilical manufacturer.

9.4.3 Clamps for control umbilical hoses and cables shall be designed to hold maximum loads induced by hose or cable weight, current and wave action. They shall be tested in accordance with manufacturer's written specifications. Construction materials shall be corrosion resistant.

9.4.4 Operator guards shall be provided for all rotating equipment.

9.4.5 All plugged ports shall be provided with plugs rated to the pressure to be blanked off and be engaged to sufficient thread depth to contain the rated pressure.

9.4.6 All check valves and shuttle valves shall be cycled and pressure and flow tested to ensure proper function under normal working conditions.

9.4.7 On-site Assembly Checklists shall be prepared to assist service personnel in assembly of the control systems such that repairs and corrections are minimized during system checkout and acceptance tests.

9.4.8 After any factory repairs, function tests from all stations shall be repeated to ensure that the repair did not adversely affect the operation of any function from any one control point.

9.4.9 The control system components shall be assembled in such a manner that repairs can be made in a timely manner. Control panels and valves shall be vented in such a manner to prevent actuation of other functions.

9.5 FLUIDS AND LUBRICANTS

Control fluids and lubricants are user responsibilities. However, manufacturers shall recommend minimum requirements for their equipment related to cleanliness, lubricity, testing methods, temperature and environmental safety.

10 Testing

10.1 QUALIFICATION TESTING

10.1.1 Control Systems

Qualification testing shall be required for prototype control systems. A prototype control system is a first time system of a new manufacturer or a system using major components of a type not previously proven. An in-plant test shall be performed to demonstrate that the prototype control system meets closing time requirements set forth in this specification (see 5.1). For units that are to be used subsea, calculated volumes for stack mounted accumulators (at the rig design water depth) shall be applied to a bank of surface accumulators (precharged for zero water depth) to simulate subsea accumulator delivered volumes. The pressure drop in riser mounted rigid conduits shall be calculated for the maximum flow required (at maximum design depth), and a hose with equivalent pressure drop may be used for the in-plant tests.

10.1.2 Fire Tests

10.1.2.1 The control lines, and any component of the control lines to a surface-mounted BOP stack or diverter, located in a division one (1) area, as defined by API RP 500 (area classification), shall be capable of containing the hose rated working pressure in a flame temperature of 1300°F (700°C) for a 5-minute period.

A prototype of each type of flexible hose shall be qualification tested to demonstrate that the hoses are capable of meeting the following fire integrity requirements:

a. The objective of the fire test is to confirm the pressure-containing capability of a hose design during a fire.
b. The fire tests shall be carried out at independent testing establishments having suitable experience in this type of work.
c. The potential exists for a hazardous rupture of the pressure boundary components of the hose being fire tested. Safety of personnel is of paramount importance and adequate means of protection is necessary.
d. A representative test piece of the prototype hose shall be internally pressurized with water before the start of the test to the design working pressure of the hose. This pressure shall be maintained during the fire test without any addition of water.
e. The design and construction of the test rig shall be suitable for the intended pressure and temperature. Relief arrangements shall be provided to prevent overpressurization including that caused by heating and in the event of failure of the test piece, to ensure that the energy released can be safely dissipated.

10.1.2.2 The fire test shall be conducted as follows:

a. The test piece shall include at least one end coupling and a length of exposed hose of not less than "L" meters where,

$$L = \frac{\text{Nominal hose diameter (mm)}}{300} + 1.5$$

b. The test piece shall be heated in a furnace fueled by gas or oil until the average temperature reading of six thermocouples is at least 1300°F (700°C). Temperatures are to be measured at the middle and ends of the test piece by three (3) pairs of thermocouples located diametrically opposite to each other at a distance of 1 in. (25 mm) from the surface of the test piece.
c. The test piece shall be exposed to the test temperature (1300°F [700°C]) for a minimum of 5 min.
d. Instrument readings shall be recorded at 1-min. intervals. Readings to be recorded are as follows:
   1. Thermocouple average temperature.
   2. Internal hydraulic pressure of test piece.
   3. Volume of water added to maintain the internal hydraulic pressure of the test piece.
e. A test will be deemed a failure if within the duration of the test either of the following occurs:
   1. The rated working pressure of the hose cannot be maintained.
   2. It is necessary to add water to maintain the rated working pressure of the hose.

10.1.2.3 A test report shall be issued and is to include the following information:

a. A statement confirming that a flexible hose specimen, representative of the type, size and pressure rating of the hose for which certification is sought has been tested in accordance with this specification.
b. A description and diagram of the fire test furnace and associated apparatus.
c. A description and drawing showing the construction and dimensions of the test specimen.
d. Time of test start, time at which the average temperature reading of the six thermocouples rose to 700°C and time at which the test was terminated.
e. A table of the instrument readings recorded in accordance with 10.1.2.3.
f. Volume of water (if any) added during the test to maintain the rated working pressure of the hose. It should be stated if no water added.
g. Observations made during the course of the test that may have a bearing on the results recorded, whether or not the test specimen met the requirements of this test specification.

10.2 FACTORY ACCEPTANCE TESTING

10.2.1 Accumulator System Test

Every accumulator system shall be tested to verify that an accumulator discharge valve does not inadvertently close by performing the following:

a. With at least 50% of the accumulators isolated from service and the remainder fully charged, shut the pump systems off.
b. Free flow the hydraulic accumulator supply through the largest regulator and control valve while recording the accumulator system pressure. Simulation of control line losses by restricting the flow rate may be employed to compensate for control line size and length.
c. The accumulator pressure should decline steadily to the approximate precharge pressure, then drop to zero psi (flowmeter reading is an alternate indication).
d. Close the flow path, then check precharge pressure of each accumulator to ensure no loss of precharge pressure or trapped pressure has occurred caused by improper operation of an accumulator discharge valve. Close the flow path and wait at least 15 min. for temperature and pressure stabilization.
e. Repeat test for the remaining accumulators.

10.2.2 Subsystem Components

10.2.2.1 Subsystems such as control panels, pumping systems, electrical power supplies, hose reels, etc., shall be individually factory acceptance tested for compliance with these specifications. A system factory acceptance test shall be conducted using as many of the integrated subsystems as practical.

10.2.2.2 Quality control personnel shall witness key aspects of the setup and testing process.

10.2.2.3 When a subsystem is to be integrated with other equipment which is not supplied by the manufacturer, or if other equipment is supplied at a different time, the test procedures shall specify all parameters which can be measured in a partial test to verify conformance to the specifications. The test shall be considered "in process" and documentation shall be supplied to the purchaser which spells out final integrated test requirements.

10.2.2.4 Subsystems shall be marked only after factory testing ensures conformance to these specifications.

11 Marking

11.1 TEMPORARY MARKING

Materials received in the manufacturer's facilities for use in products to be manufactured to API Spec 16D shall be temporarily marked to identify them to traceable documents when required. These markings shall be removed only after a level of manufacturing has been reached whereby a permanent identification can be affixed. A manufacturing record shall be maintained by the permanent identification listing all temporary markings that have been removed.

Materials that have been found to be non-conforming shall be temporarily marked with identification to the non-conformance report until such time that the material has been dispositioned in accordance with an approved procedure.

11.2 PERMANENT MARKING

Permanent markings shall be affixed in a manner to prevent them from being covered by further assembly. Material which has been the subject of non-conformance reporting shall be marked conspicuously showing identity of the non-conformance report. Material requiring in-process inspection and nondestructive inspection shall be permanently marked and traceable to the inspection records.

11.3 TRACEABILITY MARKING METHODS

Temporary marking may be affixed by tags, adhesive labels or painted on. Where markings may interfere with machining, welding, etc., the operator may temporarily remove the marking for the procedure providing the marking is affixed immediately upon completion of the procedure.

Permanent markings may be engraving, stamping, etching, castings, or metal deposit. These markings shall be permanent and visible after complete assembly. The method of marking shall take into consideration the integrity of the part in its intended application.

11.4 MANUFACTURER'S IDENTIFICATION MARKINGS

Manufacturers shall affix at least one permanent marking containing, as a minimum, the manufacturer's name or mark, and the part number or other suitable unique identification on each control system, subsystem and component provided. Manufacturers may affix other markings at their discretion.

11.5 EQUIPMENT NAME PLATE DATA

The master control panel (and other major assemblies) of control systems supplied in accordance with this specification shall be affixed with a name plate. The name plate information shall include, as a minimum, the following:

a. Manufacturer's name or mark.
b. Model name and/or number.
c. Date of manufacture.
d. Power fluid volumetric capacity that the system is designed to provide.
e. System rated working pressure.
f. API Spec 16D.

See Annex D for API Monogram marking requirements.

11.6 OTHER MARKINGS

Marking required by certification authorities shall be in accordance with the specifications of such authority.

12 Storing and Shipping

12.1 PROTECTION AND PRESERVATION

Prior to shipment, units and assemblies shall be substantially drained of test fluid. As an exception, hydraulic umbilicals may remain filled with fluid provided the contained fluid description and any warning of hazard or temperature is conspicuously displayed to shippers and handlers. The painting and color of finished surfaces shall be the option of the manufacturer unless specified on the purchase order. All reasonable precautions shall be taken to prevent damage in transit to transparent surfaces, threads or service entries, and operating parts. Exposed ports shall be plugged. If extended storage of units and assemblies is anticipated, the manufacturer shall be consulted for preservation measures to be employed.

12.2 PACKING

All lifting points or instructions shall be conspicuously displayed to shippers and handlers.

For export shipment, units and assemblies shall be securely crated or mounted on skids so as to prevent damage and facilitate sling handling. All enclosed electrical and electronic housings shall have desiccant (or alternative) protection for a minimum of four months storage from date of shipment.

12.3 IDENTIFICATION

Unit manufacturer's assembly or serial number shall be displayed on weatherproof material rigidly attached to the unit. If the unit is enclosed in sealed crating, the same information shall be permanently painted on the exterior of the crate in addition to attachment on the unit.

12.4 INSTALLATION, OPERATION AND MAINTENANCE DOCUMENTATION

12.4.1 Form of Deliverable Documentation

The manufacturer of each control system or subsystem shall furnish documentation essential to the installation, operation, and maintenance of the equipment within the manufacturer's scope of supply.

The installation, operation and maintenance documentation to meet this specification may include general product data and manuals as well as product specific documentation.

12.4.2 Content of Deliverable Documentation

A minimum of two (2) sets of the installation, operation and maintenance documentation shall be provided. One set shall be maintained by the manufacturer for a minimum of 1 year after delivery.

Following is an example (sequence of presentation is optional):

a. Index—Table of Contents and location of information.
b. Contract information consisting of the following:
   1. Buyer's purchase order number.
   2. Supplier's identification number.
   3. Supplier's Contract information.
   4. Calendar month of delivery.
   5. Scope of supply.
c. Technical data (as applicable) consisting of the following:
   1. Design calculations in accordance with 4.2.3.
   2. Temperature ratings in accordance with 4.2.1, Table 1.
   3. Area classification, zone and gas group of electric equipment in accordance with 9.3.
d. Safety precautions.
e. Installation, interface and testing data.
f. Operating characteristics.
g. General maintenance data consisting of the following:
   1. Recommended preventive maintenance and schedules.
   2. Recommended fluids, lubricants and capacities.
   3. Recommended list of maintenance and critical spare parts.
   4. Troubleshooting methods.
h. Product specific maintenance data consisting of the following:
   1. Assembly drawings and Bills of Materials showing identification and general location of replaceable commodity items.
   2. Electric, hydraulic and pneumatic schematics showing point-to-point connection identifications.
   3. Interconnect diagrams showing point-to-point interconnections.
i. Glossary/Appendix listing general definitions of terms used in the text and schematic symbols used in the support documentation.

Annex A

(Informative)

Table A.1—Control System —Control System Operating and Interface Requirements for Surface Bop Stack

Regulatory Agency Compliance Required Yes ___________ No________
Regulatory Agency(s) MMS________________ HSE ________ NPD __________ Other _____

BOP Stack — Size ________________________ Working Pressure ______________
BOP Stack —Rams ________________________ Annular BOP(s)____________ Valves _________
—Valves Failsafe Open ____________ Failsafe Close __________________

Annular BOP _____ Quantity ______________ Size ________ Working Pressure ______________
Manufacturer ______________________________ Model ________________________

Ram BOPs ______ Quantity ______________ Size ________ Working Pressure ______________
Ram Locks Yes ❑ No ❑ Type _________________________
Pipe Rams Closing Ratio__________________
Shear Ram Operating Pressure ______________ Size ________ Type __________ Grade _____
Shear Rams Closing Ratio*_________________ Pipe to Shear____ Shearing Pressure _____________
Manufacturer ______________________________ Model ________________________

Choke Valve(s) Quantity ______________ Size ________ Working Pressure ______________

Operating Pressure (Against Working Pressure) Open _______ Close_________________________
Manufacturer ______________________________ Model ________________________

Kill Valve(s) Quantity ______________ Size ________ Working Pressure ______________
Operating Pressure (Against Working Pressure) Open _______ Close_________________________
Manufacturer ______________________________ Model ________________________

Hydraulic Pump Systems
Electric Powered Quantity ______________ Size ________ Working Pressure ______________
Electricity Available: V_____________ A __________ Type_____ Grade_____

Air Powered Quantity ______________ Size ________ Working Pressure ______________
Air Pressure ______________ CFM _______

Remote Panel(s) Quantity ______________ Area Classification _________________________
____

Location of Choke Connection(s) (to Show on Panel Graphic) ______________________________

Location of Kill Connection(s) (to Show on Panel Graphic) ________________________________

Table A-2—Surface Stack Hydraulic Control System Control Function List (Select as Applicable)

No.	Control Function			Closing Ratio	Gallons Required	2 Pos.
1	Annular BOP	Open	Close	N/A	____	____
2	Upper Pipe Rams	Open	Close	______	____	____
3	Middle Pipe Rams	Open	Close	______	____	____
4	Lower Pipe Rams	Open	Close	______	____	____
5	Choke Valve	Open	Close	N/A	____	____
6	Kill Valve	Open	Close	N/A	____	____

Table A-3—Diverter System Hydraulic Control System Control Function List (Select as Applicable)

Diverter Model____________

No.	Control Function		Gallons Required	Operating Pressure Max	2 Pos. Min
1	Diverter Unit	Open	______	______	______
		Close	______	______	______
2	Port/Starboard Selector	Port	______	______	______
		Starboard	______	______	______
3	Vent Valve	Open	______	______	______
		Close	______	______	______
4	Port Overboard Valve	Open	______	______	______
		Close	______	______	______
5	Starboard Overboard Valve	Open	______	______	______
		Close	______	______	______
6	Flowline Valve	Open	______	______	______
		Close	______	______	______
7	Diverter Lockdown Dogs	Latch	______	______	______
		Unlatch	______	______	______
8	Insert Packer Lockdown Dogs	Latch	______	______	______
		Unlatch	______	______	______
9	Flowline Seal	Energize	______	______	______
		Vent	______	______	______
10	Filling Line Valve	Open	______	______	______
		Close	______	______	______
11	Overshot Packer Seal	Energize	______	______	______
		Vent	______	______	______
12	Other (Specify)	(Specify)	______	______	______
		(Specify)	______	______	______

Note which functions (if any) are to be interconnected for sequencing.

Annex B

Table B-1—Control Operating and Interface Requirements Subsea BOP Stack

Regulatory Agency Compliance Required   Yes ________   No________
Regulatory Agency(s) MMS________________   HSE _______   NPD _________   Other _____

Control System Type ____________________   Hydraulic ____   EH__________   MUX ______
Maximum Water Depth __________________   Hydraulic Control Pressure ____________________

BOP Stack—Size ____________________   Working Pressure ____________________
BOP Stack—Ram ____________________   Annular BOP(s)___________   Failsafe Valves ______
Valves are: FSO _______   FSC ________   FAO__________   FAC _______
Subsea Umbilicals
Manufacturer ________________________   Model____________   Length ________________

Subsea Hydraulic Supply Lines
Umbilical Hose   Quantity & Length ______   Size ________   Working Pressure ______________
Supply Hose   Quantity & Length ______   Size ________   Working Pressure ______________
Hydraulic Conduit   Quantity & Length ______   Size ________   Working Pressure ______________

Annular BOP(s)_____   Quantity _____________   Size ________   Working Pressure ______________
Manufacturer ______________________________________   Model ______________________

Shear Ram BOP(s)   Quantity _____________   Size ________   Working Pressure ______________
Shear Ram Locks   Yes ❑   No ❑   Type ______________________
Closing Ratio   Pipe Size and Grade   Shear Pressure for Specified Pipe (Surface)
Ram BOPS   Quantity _____________   Size ________   Working Pressure ______________

Ram Locks   Yes ❑   No ❑   Type ______________________
Closing Ratio ____
Manufacturer ________________________   Model ______________________

Riser Connector   Size ________   Working Pressure ______________
Manufacturer ________________________   Model ______________________
Wellhead Connector   Size ________   Working Pressure ______________
Manufacturer ________________________   Model ______________________
Choke Valve(s)   Quantity _____________   Size ________   Working Pressure ______________
Manufacturer ________________________   Model ______________________
Choke Outlet Location(s)____
Kill Valve(s)   Quantity _____________   Size ________   Working Pressure ______________
Manufacturer ________________________   Model ______________________
Kill Outlet Location(s)____
LMRP Accumulators
Quantity _________   Size_________   Working Pressure ________________   Banks ___________

BOP Accumulators
Quantity _________   Size_________   Working Pressure ________________   Banks ___________

Table B-1 (continued)—Control Operating and Interface Requirements Subsea BOP Stack

Hydraulic Pump Systems

Electric Powered Quantity ______________ Size ________ Working Pressure ______________

Electricity Available: V___________ A __________ Hz _____

Phase __________

Air Powered Quantity ______________ Size ________ Working Pressure ______________

Air Pressure Required______

Air Volume Required _______

Remote Panels

Hazardous Location Quantity ________________ Area Classification_________________

Safe Location Quantity ________________ Area Classification_________________

Table B-2—Subsea Stack Hydraulic Control System Control Function List (Select as Applicable)

No.	Control Function			Gallons	Control Pressure	Pos.
1	Pod Select	Blue	Yellow	____________	____________	3
2	Upper Annular BOP	Open	Close	____________	____________	3
3	Lower Annular BOP	Open	Close	____________	____________	3
4	Riser Connector	Unlock	Lock	____________	____________	2
5	Riser Connector Secondary	Unlock	Vent	____________	____________	3
6	Upper Pipe Rams	Open	Close	____________	____________	3
7	Shear Rams	Open	Close	____________	____________	3
8	High Pressure Shear Rams	Close	Vent	____________	____________	1
9	Upper Pipe Rams	Open	Close	____________	____________	3
10	Middle Pipe Rams	Open	Close	____________	____________	3
11	Lower Pipe Rams	Open	Close	____________	____________	3
12	Wellhead Connector	Unlock	Lock	____________	____________	3
13	Wellhead Connector Secondary	Unlock	Vent	____________	____________	2
14	Pod Latch	Latch	Unlatch	____________	____________	2
15	Blue Hydraulic Stabs	Extend	Retract	____________	____________	3
16	Yellow Hydraulic Stabs	Extend	Retract	____________	____________	3
17	Choke & Kill Stabs	Extend	Retract	____________	____________	3
18	Annular BOP Outer Bleed	Open	Close	____________	____________	2
19	Annular BOP Inner Bleed	Open	Close	____________	____________	2
20	LMRP Choke & Kill Test Valve	Close	Open	____________	____________	2
21	Upper Outer Choke	Open	Close	____________	____________	2
22	Upper Inner Choke	Open	Close	____________	____________	2
23	Lower Outer Choke	Open	Close	____________	____________	2
24	Lower Inner Choke	Open	Close	____________	____________	2
25	Upper Outer Kill	Open	Close	____________	____________	2
26	Upper Inner Kill	Open	Close	____________	____________	2
27	Lower Outer Kill	Open	Close	____________	____________	2
28	Lower Inner Kill	Open	Close	____________	____________	2
29	Shear Rams Locks	Lock	Unlock	____________	____________	2
30	Upper Rams Locks	Lock	Unlock	____________	____________	2
31	Middle Rams Wedgelocks	Lock	Unlock	____________	____________	2
32	Middle Rams Wedgelocks	Lock	Unlock	____________	____________	2
33	Lower Rams Locks	Lock	Unlock	____________	____________	2
34	Blue Supply Pilot Check	Vent	Check	____________	____________	2
35	Yellow Supply Pilot Check	Vent	Check	____________	____________	2

No.	Control Function			Gallons	Control Pressure	Pos.
36	LMRP Accum Isolator	Open	Close	________	________	2
	LMRP Accum Dump	Open	Close	________	________	2
37	Lower Stack Accum Isolator	Open	Close	________	________	2
	Lower Stack Accum Dump	Open	Close	________	________	2
38	LMRP Failsafe Supply	Open	Close	________	________	2
39	Lower Stack Failsafe Supply	Open	Close	________	________	2
40	Acoustic Accum Isolator	Open	Close	________	________	2
	Acoustic Accum Dump	Open	Close	________	________	2
41	Subsea Manifold Regulator	Incr	Decr	________	________	2
42	Failsafe Assist Regulator	Incr	Decr	________	________	2
43	Upper Annular BOP Regulator	Incr	Decr	________	________	2
44	Lower Annular BOP Regulator	Incr	Decr	________	________	2

HOSE REEL "LIVE" FUNCTIONS

1 ______________________________

2 ______________________________

3 ______________________________

ACOUSTIC FUNCTIONS

1 ______________________________

2 ______________________________

3 ______________________________

4 ______________________________

ROV FUNCTIONS

1 ______________________________

2 ______________________________

3 ______________________________

4 ______________________________

Table B-3—Subsea Stack Hydraulic Control System Control Readback Function List (Select as Applicable)

No.	Readback Function	Required
1	Surface Accumulator Supply Pressure	________
2	Surface Pilot Supply Pressure	________
3	Rig Air Supply Pressure	________
4	Subsea manifold Regulator Pilot Pressure	________
5	Subsea Manifold Regulated Pressure	________
6	Failsafe Assist Regulator Pilot Pressure	________
7	Failsafe Assist Regulated Pressure	________
8	Upper Annular BOP Regulator Pilot Pressure	________
9	Upper Annular BOP Regulated Pressure	________
10	Lower Annular BOP Regulator Pilot Pressure	________
11	Lower Annular BOP Regulated Pressure	________
12	Other (Specify)	________

Table B-4—Subsea Diverter Hydraulic Control System Control Function List (Select as Applicable)

No.	Control Function			2 Pos.
1	Diverter Unit	Open	Close	
2	Flow Selector	Port	Starboard	
3	Diverter Lockdown	Latch	Unlatch	
4	Vent Valve	Open	Close	
5	Port Overboard Valve	Open	Close	
6	Starboard Overboard Valve	Open	Close	
7	Flowline Valve	Open	Close	
8	Insert Packer Lockdown Dogs	Latch	Unlatch	
9	Flowline Seal	Energize	Vent	
10	Filling Line Valve	Open	Close	
11	Ball Joint Pressure		Range	
12	Overshot Packer	Energize	Vent	
13	Trip Tank	Open	Close	
14	Support Ring	Open	Close	
15	Other (Specify)			

Note which functions (if any) are to be interconnected for sequencing.

Annex C

C.1 Summary of Examples

Example	System Case	Equipment Subcase	Design Method	Operating Pressure	Precharge Pressure*	Surface Bottles**	Stack Bottles**	Total Bottles**
1	Surface API BOP		A	3000 psig	1000 psig	7	N/A	7
2			B	3000 psig	1000 psig	7	N/A	7
3	Subsea API BOP (7500′ WD)	Surface bottles only	A	5000 psig	1719 psig	66	0	66
4		Surface and stack-mounted bottles	A/B	5000 psig	1719 psig/ 5404 psig	54	28	82
5			B/B	5000 psig	1821 psig/ 5404 psig	58	28	86
6	Rapid Discharge (Shear Rams)	Surface	C	4700 psig	2200 psig	21	N/A	21
7		Subsea (7500′ WD)	C	4700 psig	5000 psig	N/A	68	68
8		Subsea with helium precharge (7500′ WD)	C	4700 psig	5000 psig	N/A	44	44
9	Special Purpose Subsea (7500′ WD)	Hydraulic assist for normally closed valve	C	1500 psig	4676 psig	N/A	2	2

* Surface Precharge @ 70 degrees.
** 13.8 gallon bottles

Descriptions of the example systems are on the following sections, followed by sections showing the detailed example calculations.

Note: The example calculations using NIST data for density and entropy (Design Methods B and C) are based on properties as of November 2003. From time to time, the underlying correlations in the NIST webbook are updated and its reported properties may vary somewhat in the future. Also, the API Accumulator Design Software uses a different equation of state gas model that provides close and acceptable agreement to the NIST values, but may give slightly different real gas properties. The differences are considered negligible in terms of applying the API design methods and should give essentially the same design results.

C.1.1 Examples 1 and 2: BOP Stack Configuration for Surface BOP

BOP Stack Description	Bore Size in.	Rated Working Pressure psig	Closing Volume gal	Opening Volume gal	Closing Ratio	Pressure to Close Against RWP psig
Annular BOP	$13^5/_8$	5,000	18.0	NR		
Pipe Ram BOP	$13^5/_8$	5,000	7.0	NR	10.00	500
Pipe Ram BOP	$13^5/_8$	5,000	7.0	NR	10.00	500
Pipe Ram BOP	$13^5/_8$	5,000	7.0	NR	10.00	500
Side Outlet Valve	4.0	5,000	NR	0.5		
Total Functional Volume Requirement (FVR)			39.0	+ 0.5	= 39.5	= FVR
For a standard surface system, the minimum FVR is 100% of the power fluid volume required to close, at zero wellbore pressure, the ram BOPs and one annular BOP, and to open one side outlet valve(s).						

Environmental Conditions	
Surface temperature at precharge	70°F

Pump Stop Pressure (Condition 1 Charged Pressure)	3,000 psig	Use the pump stop pressure for Methods A and B

Minimum Operating Pressures (MOP), Condition 2	
Pressure to close ram against RWP	500 psig
Pressure to close annular	1,000 psig
Pressure to open side outlet valve	1,000 psig
Pressure req't = Maximum	1,000 psig

Surface Accumulator bottles					
Gas volume per bottle	13.8 gal	Gas type	nitrogen		
Pressure rating of bottles	3,000 psig				

C.1.2 Examples 3, 4, and 5: BOP Stack Configuration for Subsea BOP

BOP Stack Description	Bore Size in.	Rated Working Pressure psig	Closing Volume gal	Opening Volume gal	Closing Ratio	Pressure to Close Against RWP psig
Annular BOP	**$18^{3}/_{4}$**	**10,000**	**70.0**	**70.0**		
Annular BOP	**$18^{3}/_{4}$**	**10,000**	**70.0**	**70.0**		
Shear Ram BOP	**$18^{3}/_{4}$**	**15,000**	**54.0**	**50.0**	NR	**NR**
Pipe Ram BOP	**$18^{3}/_{4}$**	**15,000**	**28.0**	**22.0**	7.00	**2,143**
Pipe Ram BOP	**$18^{3}/_{4}$**	**15,000**	**28.0**	**22.0**	7.00	**2,143**
Pipe Ram BOP	**$18^{3}/_{4}$**	**15,000**	**28.0**	**22.0**	7.00	**2,143**
C&K Valve	**4**	**15,000**	**NR**	**NR**		
Total functional volume requirement			**208.0**	**+ 186.0**	**= 394.0**	**= FVR**
For a standard subsea system, the minimum FVR is 100% of the power fluid volume required to open and close, at zero wellbore pressure, the ram BOPs (to a maximum of four) and one annular BOP.						
User specified volume requirement from stack mounted accumulators, if used:					70.0 gals	= subsea FVR
User comment: **Based on largest fluid consumer (annular closing volume)**						

Minimum Operating Pressures (MOP)	psig		**Environmental Conditions**	
Pressure to close ram against RWP	**2,143**		Water depth	7,500 ft
Pressure to open C&K Valve	**1,500**		Air gap	50 ft
Pressure to close annular	**1,000**		Surface temp. at precharge	70°F
Pressure requirement = Maximum	**2,143**		Subsea (mudline) water temp.	35°F

Fluid Densities and Head Pressures			
Sea water	**8.54** lb/gal	0.444 psi/ft	3227 psig
Control fluid	**8.33** lb/gal	0.433 psi/ft	3267 psig including air gap

Pump Stop Pressure (Condition 1 Charged Pressure)	**5,000** psig	Use the pump stop pressure for Methods A and B

Surface Accumulator Bottles						
Gas volume per bottle	**13.8** gal		Gas type	**nitrogen**		
Pressure rating of bottles	**5,000** psig					

Stack-mounted Accumulator Bottles						
Gas volume per bottle	**13.8** gal		Gas type	**nitrogen**		
Pressure rating of bottles	**7,000** psig					

C.1.3 Examples 6, 7, and 8: BOP Equipment Configuration for Rapid Discharge System

BOP Equipment Sequence of Operation and Description	Bore Size in.	Rated Working Pressure psig	Closing or Opening Volume gal	Closing Ratio	Minimum Operating Pressure psig
1. Casing Shear Ram BOP	**$18^3/_4$**	**15,000**	**54.0**	**7.00**	**2,200**
2. Blind Shear Ram BOP	**$18^3/_4$**	**15,000**	**28.0**	**7.00**	**1,374**
3. LMRP Connector or Choke Valve	—	**15,000**	**15.0**	**NR**	**1,500**
Total functional volume requirement (FVR)			**97.0**		
For a rapid discharge system, the minimum FVR basis is as specified by the user.					

Pump Start Pressure (Condition 1 Charged Pressure)	**4,700** psig
For Method C: Use "pump stop pressure" for accumulator isolated by check valve from main hydraulic supply; use "pump start pressure" for accumulator on main hydraulic supply.	

Accumulator Bottles	
Gas volume per bottle	**13.8** gal
Pressure rating of bottles	**7,000** psig

For Subsea Examples 7 and 8	
Environmental Conditions	
Water depth	**7,500** ft
Air gap	**50** ft
Surface temperature at precharge	**70**°F
Subsea (mudline) water temperature	**35**°F

Fluid Densities and Head Pressures			
Sea water	**8.54** lb/gal	**0.444** psi/ft	**3327** psig
Control fluid	**8.33** lb/gal	**0.433** psi/ft	**3267** psig including air gap
Riser fluid	**16** lb/gal	**0.831** psi/ft	**6275** psig including air gap

Example 1: Surface BOP Stack—Method A

C.2 Example 1—Surface API BOP Designed With Method A

Legend
Input
Calculated
Transferred

Design sequence: 1. Define stack configuration and operating parameters
2. Select desired precharge pressure (and temperature)
3. Calculate required number of bottles

Total Functional Volume Requirement (FVR) = 39.5 gallons (from BOP Configuration for Surface BOP Examples)

Condition 0 Data			
Optimum Precharge = 1.0/(1.5/P2 – 0.5/P1)		*762* psia	747 psig @ 70°F
Input Precharge Pressure at Surface, Cond. 0	70°F	1,000 psig	*1,015* psia
Pressure at maximum temperature	120°F	*1,096* psig	*1,110* psia
Pressure at maximum temperature with ideal gas law P2 = P1 x T2/T1			

Condition 1 Data—Surface Accumulator	3,000 psig	*3,015* psia

Design Factors per Table 2	**Volume Limited**	**Pressure Limited**
Method A	**1.5**	**1.0**

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic Data	Temp	Pressure	
	°F	psig	psia
Surface Accumulator		**Method A**	
1. Tabulate ambient air temperature, pressures psig & psia			
Condition 0: Precharged Accumulators	70	1,000	1,015
Condition 1: Accumulators Charged	70	3,000	*3,015*
Condition 2: Pressure Requirement (MOP)	70	1,000	*1,015*
2. Use Method A pressure-based volumetric efficiency formulas:			
Pressure limited VE_p = (P0/P2 – P0/P1)/1.0		**VE_p**	*0.663*
Volume limited VE_v = (1.0 – P0/P1)/1.5		**VE_v**	*0.442*
3. Volumetric Efficiency VEsurf = min(VE_p, VE_v).		**min. = VE**	*0.442*

Calculate Number of Bottles			
Minimum required surface accumulator volume = FVR / VE_{surf}			
	# of bottles	**Bottle Volume**	**Usable Volume**
Surface bottles required	*6.5* bottles	*89.3* gals	
Round up to desired integer	*7* bottles	*96.6* gals	*42.7* gals

Performance Table	Temp	Pressure		Volume, gals.	
	°F	psig	psia	Gas	Liquid
1. Tabulate surface temperature and pressures					
2. Enter surface bottle volume as the Condition 0 initial gas volume					
3. (Method A) Use ratio of absolute pressures to calculate gas volumes for Conditions 1 to 3					
4. Liquid volume for each condition = Bottle volume minus gas volume					
Functional Steps—Surface Bottles					
Condition 0: Precharge	70	1,000	1,015	96.6	0.0
Condition 1: Charged	70	3,000	3,015	*32.5*	*64.1*
Condition 2: MOP	70	1,000	1,015	*96.6*	0.0
Condition 3: Fully discharged	70	1,000	1,015	*96.6*	0.0

Summary

	# of bottles	Precharge	
		Pressure, psig	Temperature, °F
Surface accumulator	7	1,000	70

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	64.1			
Condition 2: MOP	0.0			
From Condition 1 to 2: Pressure Design	*64.1*	*64.1*	39.5	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	*64.1*	*42.7*	39.5	**YES**

Example 2: Surface BOP Stack—Method B

C.3 Example 2—Surface API BOP Designed With Method B

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define stack configuration and operating parameters
2. Select desired precharge pressure (and temperature)
3. Calculate required number of bottles

Total Functional Volume Requirement (FVR) = 39.5 gallons (from BOP Configuration for Surface BOP Examples)

Condition 1 Data	Pressure, psig	psia	density, ρ_1
Using the NIST tables determine the charged gas density ρ_1, based upon gas temperature and pressure.			
Surface Accumulator	3,000	*3,015*	***14.038*** lb/ft^3 @ 70°F
Condition 2 Data (at BOP)			
Using NIST tables determine the MOP gas density ρ_2, based upon gas temperature & pressure.			
MOP	*1,015*	1,000	***5.024*** lb/ft^3 @ 70°F

Condition 0 Data				
Optimum Precharge density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$				3.997 lb/ft^3 @ 70°F
1. Using the NIST tables determine the optimum precharge gas pressure based upon gas density and temperature.				
Optimum Precharge Pressure		807 psia		792 psig
Input Precharge Pressure at Surface, Cond. 0	70°F	1,000 psig	*1,015* psia	***5.024*** lb/ft^3
Pressure at maximum temperature	120°F	*1,113* psig	***1,128*** psia	5.024 lb/ft^3
2. Using the NIST tables determine the precharge gas density ρ_0, based upon gas temperature and pressure.				
3. Using the NIST tables determine the gas pressure at maximum temperature based upon the gas density and temperature.				

Design factors per Table 2	**Volume Limited**	**Pressure Limited**
Method B	**1.4**	**1.0**

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic Data	Temp	Pressure		Gas Density, ρ
	°F	psig	psia	lb/ft^3
Surface Accumulator	**Method B**			
1. Tabulate ambient air temperature, pressures psig and psia				
Condition 0: Precharged accumulators	70	1,000	1,015	5.024
Condition 1: Accumulators charged	70	3,000	*3,015*	14.038
Condition 2: Pressure Requirement (MOP)	70	1,000	*1,015*	5.024
2. Use Method B density-based Volumetric Efficiency formulas:				
Pressure limited VEp = $(\rho_0/\rho_2 - \rho_0/\rho_1)/1.0$			**VE$_p$**	*0.642*
Volume limited VEv = $(1.0 - \rho_0/\rho_1)/1.4$			**VE$_v$**	*0.459*
3. Volumetric Efficiency VEsurf = min(VE$_p$, VE$_v$)			**min. = VE**	*0.459*

Calculate Number of Bottles

Minimum required surface accumulator volume = FVR/VE_{surf}

	# of Bottles	Bottle Volume	Usable Volume
Surface bottles required	6.2 Bottles	*86.1* gals	
Round up to desired integer	7 Bottles	*96.6* gals	*44.3* gals

Performance Table	Temp	Pressure		Volume, gals.		Gas Density
	°F	psig	psia	Gas	Liquid	lb/ft^3
1. Tabulate bottle temperatures, pressures, and densities						
2. Enter Bottle Volume as the Condition 0 Initial gas volume						
3. (Method B) Use ratio of densities to calculate gas volumes for Conditions 1 to 3						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume						
Functional Steps—Surface Bottles						
Condition 0: Precharge	70	1,000	1,015	96.6	0.0	5.024
Condition 1: Charged	70	3,000	3,015	*34.5*	*62.1*	14.038
Condition 2: MOP	70	1,000	1,015	*96.6*	0.0	5.024
Condition 3: Fully discharged = Condition 0	70	1,000	1,015	*96.6*	0.0	5.024

Summary

	# of bottles	Precharge	
		Pressure, psig	Temperature, °F
Surface accumulator	7	1,000	70

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	62.1			
Condition 2: MOP	0.1			
From Condition 1 to 2: Pressure Design	*62.0*	*62.0*	39.5	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	*62.0*	*44.3*	39.5	**YES**

Example 3: Subsea BOP Stack—Method A (Surface Accumulator Only)

C.4 Example 3 – Subsea API BOP With Only Surface Accumulators Designed With Method A

Legend
Input
Calculated
Transferred

Design sequence: 1. Define stack configuration and operating parameters
2. Select desired precharge pressure (and temperature)
3. Calculate required number of bottles

Total Functional Volume Requirement (FVR) = 394.0 gallons (from BOP Configuration for Subsea BOP Examples)

Condition 0 Data—Method A			
Optimum Precharge = 1.0/(1.5/P2 – 0.5/P1) =	*1,734* psia		1,719 psig @ 70°F
Input Precharge pressure at surface	**70**°F	**1,719** psig	*1,734* psia
Pressure at maximum temperature	**120**°F	*1,883* psig	*1,897* psia
1. Calculate Pressure at maximum temperature with ideal gas law P2 = P1 x T2 / T1			

Condition 1 Data	5,000 psig	*5,015* psia

Condition 2 Data	MOP (surface) =	2,143 psig	
MOP + SW head + 14.7		*5,485* psia at BOP	
For surface accumulator, less control fluid head		*2,218* psia	*2,203* psig

Design factors per Table 2	**Volume Limited**	**Pressure Limited**
Method A	**1.5**	**1.0**

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic Data	Temp	Pressure	
Method A	°F	psig	psia
Surface Accumulator		**Method A**	
1. Tabulate ambient air temperature, pressures psig & psia			
Condition 0: Precharged accumulators	70	1,719	1,734
Condition 1: Accumulators charged	70	5,000	*5,015*
Condition 2: Pressure Requirement (MOP)	70	2,203	*2,218*
2. Use Method A pressure-based Volumetric Efficiency formulas:			
Pressure limited VE_p = (P0/P2 – P0/P1)/1.0		**VE_p**	*0.436*
Volume limited VE_v = (1.0 – P0/P1)/1.5		**VE_v**	*0.436*
3. Volumetric Efficiency VEsurf = min(VE_p, VE_v)		**min. = VE**	*0.436*

Calculate Number of Bottles			
	# of bottles	**Bottle Volume**	**Usable volume**
Surface bottles required	*65.5* bottles	*903.6* Gals	
Round up to desired integer	*66* bottles	*910.8* Gals	*397.1* gals

Performance Table	Temp	Pressure		Volume, gals.	
	°F	psig	psia	Gas	Liquid
1. Tabulate surface temperature and pressures					
2. Enter Surface Bottle Volume as the Condition 0 Initial Gas Volume					
3. (Method A) Use ratio of absolute pressures to calculate gas volumes for Conditions 1 to 3					
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume					
Functional Steps—Surface Bottles					
Condition 0: Precharge	70	1,719	1,734	910.8	0.0
Condition 1: Charged	70	5,000	5,015	*314.9*	*595.9*
Condition 2: MOP	70	*2,203*	2,218	*712.0*	198.8
Condition 3: Fully discharged	70	*1,719*	1,734	*910.8*	0.0

Summary

	# of bottles	Precharge	
		Pressure, psig	Temperature, °F
Surface accumulator	66	1,719	70

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	595.9			
Condition 2: MOP	198.8			
From Condition 1 to 2: Pressure Design	*397.1*	*397.1*	394.0	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	*595.9*	*397.3*	394.0	**YES**

Example 4: Subsea BOP Stack—Method A (Surface) and Method B (Stack-mounted)

C.5 Example 4 – Subsea API BOP with Surface Accumulators Designed with Method A and Stack-mounted Designed with Method B

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define stack configuration and operating parameters
2. Specify minimum volume desired from stack mounted bottles
3. Select desired precharge pressure (and temperatures)
4. Calculate required number of surface bottles

Total Functional Volume Requirement (FVR) = 394.0 gallons (from BOP Configuration for Subsea BOP Examples)

Condition 1 Data	Surface psig	Bottle psia	density, ρ_1
Using the NIST tables determine the charged gas density, ρ_1, based upon gas temperature and pressure.			
Surface Accumulator	5,000	*5,015*	NR lb/ft^3 @ 70°F
Stack-mounted Accumulator	5,000	*8,282*	***29.676*** lb/ft^3 @ 35°F

Condition 2 Data	MOP (surface) = 2,143 psig		
Using NIST tables determine the MOP gas density, ρ_2, based upon gas temperature & pressure.			Density, ρ_2
MOP + SW head + 14.7	*5,485* psia at BOP		***23.678*** lb/ft^3 @ 35°F
For surface accumulator—control fluid head	*2,218* psia	*2,203* psig	NR lb/ft^3 @ 70°F

Surface Accumulator Condition 0 Data—Method A				
Optimum Precharge = 1.0/(1.5/P2 – 0.5/P1)	*1,734* psia	1,719 psig @	70°F	
Input Precharge pressure @ surface	<u>70</u>°F	<u>1719</u> psig	*1,734* psia	
Pressure at maximum temperature	<u>120</u>°F	*1883* psig	*1,897* psia	
1. Calculate Pressure at maximum temperature with ideal gas law P2 = P1 x T2/T1				
Stack-mounted Accumulator Condition 0 Data—Method B				
Optimum Precharge density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$		*21.907* lb/ft^3		
Optimum Precharge Pressure	***4,860*** psia	4,845 psig @	35°F	
@ Surface Temperature	***5,419*** psia	5,404 psig @	70°F	
Input precharge pressure at surface	<u>70</u> °F	<u>5,404</u> psig	*5,419* psia	***21.907*** lb/ft^3
Pressure @ maximum temperature	120 °F	*6,196* psig	***6,210*** psia	21.908 lb/ft^3
Pressure @ subsea temperature, Cond. 0	35 °F	*4,845* psig	***4,860*** psia	21.908 lb/ ft^3
Pressure @ Sea water head, Cond. 3 limit	35 °F	*3,327* psig	*3,342* psia	***16.625*** lb/ft^3
1. Using the NIST tables determine precharge gas densities at ρ_0 and ρ_3 limit, based upon gas temperature and pressure.				
2. Using the NIST tables determine the gas pressure at maximum temperature based upon the gas density and temperature.				

Design factors per Table 2	**Volume Limited**	**Pressure Limited**
Method A	**1.5**	**1.0**
Method B	**1.4**	**1.0**

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic data	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia	Gas Density, ρ lb/ t³	
Surface accumulator	**Method A**				
1. Tabulate ambient air temperature, pressures psig and psia					
Condition 0: Precharged accumulators	70	1,719	1,734	NR	
Condition 1: Accumulators charged	70	5,000	*5,015*	NR	
Condition 2: Pressure Requirement (MOP)	70	2,203	*2,218*	NR	
2. Use Method A pressure-based Volumetric Efficiency formulas:					
Pressure limited VE_p = (P0/P2 – P0/P1)/1.0		**VE_p**	*0.436*		
Volume limited VE_v = (1.0 – P0/P1)/1.5		**VE_v**	*0.436*		
3. Volumetric Efficiency VE_{surf} = min(VE_p, VE_v)		**min. = VE_{surf}**	*0.436*		
Stack-mounted accumulator	**Method B**				
1. Tabulate temperature and pressures psig and psia, and gas densities for each Condition from above					
Condition 0: Precharged accumulators	35	1,578	*4,860*	21.907	
Condition 1: Charged accumulators	35	5,000	*8,282*	29.676	
Condition 2: Pressure Requirement (MOP)	35	2,203	*5,485*	23.678	
Condition 3: Discharged	35	1,578	4,860	21.907	To precharge pressure
2. Use Method B density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.0$		**$VE_{p\text{-}sm}$**	*0.187*		
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.4$					
If P0 is less than hydrostatic sea pressure, $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.4$		**$VE_{v\text{-}sm}$**	*0.187*		
3. Volumetric Efficiency VE_{sm} = min(VE_p, VE_v)		**min. = VE_{sm}**	*0.187*		

Calculate Number of Bottles, Stack Mounted and Surface

1. Minimum required stack accumulator volume = subsea FVR/VE_{sm}
2. Calculate resulting SM usable Pressure Limited and Volume Limited with subsea FVR/$VE_{p\text{-}sm}$ and subsea FVR/$VE_{v\text{-}sm}$
3. Minimum required surface accumulator volume = (FVR - V_{sm} * VE_{sm})/VE_{surf} **Usable volume, gals**

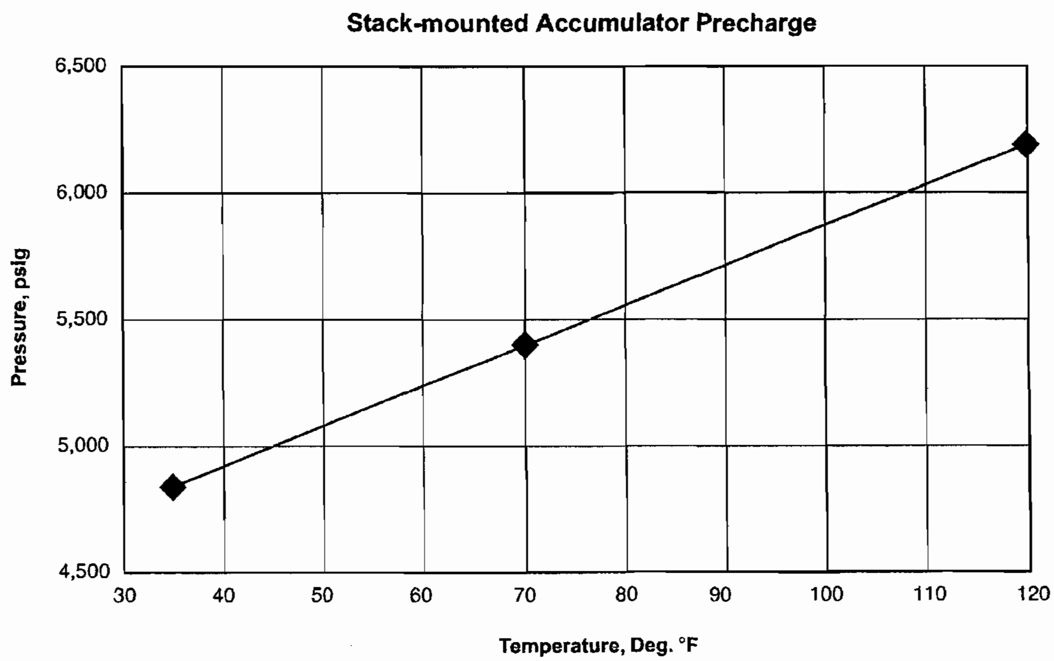
	# of bottles		Bottle Volume		Press. Ltd.		Vol. Ltd.
Stack-mounted bottles required	*27.1*	bottles	*374.3*	gals			
Round up to desired integer	*28*	bottles	*386.4*	gals	*72.3*		*72.3*
Surface bottles required, Vol. Ltd.	*53.5*	bottles	*737.6*	gals			
Surface bottles required, Press. Ltd.	*53.5*	bottles	737.9	gals			
Select higher number	*53.5*	bottles			**Usable volume**		
Round up to desired integer	*54*	bottles	*745.2*	gals	*324.9*	gals	

Performance Table	Temp °F	Pressure, Surf. Equiv. psig	Bottle Pressure psia	Volume, gals. Gas	Volume, gals. Liquid	Gas Density lb/ft^3
1. Tabulate surface temperature and pressures						
2. Enter Surface Bottle Volume as the Condition 0 Initial Gas Volume						
3. (Method A) Use ratio of absolute pressures to calculate gas volumes for Conditions 1 to 3						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume						
Functional Steps—Surface Bottles						
Condition 0: Precharge	70	1,719	1,734	745.2	0.0	NR
Condition 1: Charged	70	5,000	5,015	*257.6*	*487.6*	NR
Condition 2: MOP	70	2,203	2,218	*582.6*	162.6	NR
Condition 3: Fully discharged	70	1,719	1,734	*745.2*	0.0	NR
1. Tabulate stack-mounted bottle temperatures, pressures, and densities						
2. Enter stack-mounted Bottle Volume as the Condition 0 Initial Gas Volume						
3. (Method B) Use ratio of gas densities to calculate gas volumes for Conditions 1 to 3						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume						
Functional Steps—Stack-mounted Bottles						
Precharged accumulators @ surface	70	5,404	*5,419*	386.4	0.0	21.907
Condition 0: Precharged accumulators	35	*1,578*	4,860	386.4	0.0	21.907
Condition 1: Charged	35	5,000	8,282	285.2	*101.2*	29.676
Condition 2: MOP	35	*2,203*	5,485	*357.5*	28.9	23.678
Condition 3: Fully discharged	35	1,578	4,860	386.4	0.0	21.907

Summary

Accumulator Location	# of bottles	Precharge	
		Pressure, psig	Temperature, °F
Surface	54	1,719	70
Stack-mounted	28	5,404	70

Liquid Volumes, gal	Actual		With Volume Factor			FVR	Meets req'ts?
	Surface	Stack MDT.	Surface	Stack MDT.	Total		
Condition 1: Charged	487.6	101.2					
Condition 2: MOP	162.6	28.9					
From Condition 1 to 2: Pressure Design	*324.9*	*72.3*	*324.9*	*72.3*	*397.2*	394.0	**YES**
Condition 3: Fully discharged	0.0	0.0					
From Condition 1 to 3: Volume Design	*487.6*	*101.2*	*325.0*	*72.3*	*397.3*	394.0	**YES**
Condition 2: MOP (Stack-mounted)				*72.3*		70	**YES**
Condition 3: Discharged (Stack-mounted)				*72.3*		70	**YES**


Stack-mounted Accumulator Precharge
6,500
6,000
5,500
5,000
4,500
Pressure, psig
30
40
50
60
70
80
90
100
110
120
Temperature, Deg. °F

Example 5: Subsea BOP Stack—Method B (Surface) and Method B (Stack-mounted)

C.6 Example 5—Subsea API BOP With Surface Accumulators and Stack Mounted Designed With Method B

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define stack configuration and operating parameters
2. Specify minimum volume desired from stack mounted bottles
3. Select desired precharge pressure (and temperatures)
4. Calculate required number of surface bottles

Total Functional Volume Requirement (FVR) = 394.0 gallons (from BOP Configuration for Subsea BOP Examples)

Condition 1 Data	Surface psig	Bottle psia	density, ρ_1	
Using the NIST tables determine the charged gas density, ρ_1, based upon gas temperature and pressure.				
Surface Accumulator	5,000	*5,015*	***20.798***	lb/ft^3 @ 70°F
Stack Mounted Accumulator	5,000	*8,282*	***29.676***	lb/ft^3 @ 35°F

Condition 2 Data	MOP (surface) = 2,143 psig		
Using NIST tables determine the MOP gas density, ρ_2, based upon gas temperature & pressure.			Density, ρ_2
MOP + SW head + 14.7	*5,485* psia at BOP		***23.678*** lb/ft^3 @ 35°F
For surface accumulator, - control fluid head	*2,218* psia	*2,203* psig	***10.686*** lb/ft^3 @ 70°F

Surface Accumulator Condition 0 Data - Method B								
Optimum Precharge density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$			*8.946* lb/ft^3 @		70°F			
1. Using the NIST tables determine the optimum precharge gas pressure based upon gas density and temperature.								
Optimum Precharge Pressure	***1836***	psia	1,821	psig				
Input Precharge pressure @ surface	**70**	°F	**1,821**	psig	*1,836*	psia	***8.946***	lb/ft^3
Pressure at maximum temperature	**120**	°F	*2042*	psig	***2,057***	psia	8.946	lb/ft^3
2. Using the NIST tables determine the precharge gas density, ρ_0, based upon gas temperature and pressure.								
3. Using the NIST tables determine the gas pressure at maximum temperature based upon the gas density and temperature.								
Stack-mounted Accumulator Condition 0 Data - Method B								
Optimum Precharge density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$			*21.907*	lb/ft^3				
1. Using the NIST tables determine the optimum precharge gas pressure based upon gas density and temperature.								
Optimum Precharge Pressure	***4,860***	psia	4,845	psig @	35	°F		
@ Surface Temperature	***5,419***	psia	5,404	psig @	70	°F		
Input Precharge pressure at surface	**70**	°F	**5,404**	psig	*5,419*	psia	***21.908***	lb/ft^3
Pressure @ maximum temperature	120	°F	*6,195*	psig	***6,210***	psia	21.908	lb/ft^3
Pressure @ subsea temperature, Cond. 0	35	°F	*4,845*	psig	***4,860***	psia	21.908	lb/ft^3
Pressure @ Sea water head, Cond. 3 limit	35	°F	*3,327*	psig	*3,342*	psia	***16.625***	lb/ft^3
2. Using the NIST tables determine precharge gas densities at ρ_0 and ρ_3 limit, based upon gas temperature and pressure.								
3. Using the NIST tables determine the gas pressure at maximum temperature based upon the gas density and temperature.								

Design factors per Table 2	Volume Limited	Pressure Limited
Method B	1.4	1.0

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic data	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia	Gas Density, lb/ft³	
Surface accumulator	**Method B**				
1. Tabulate ambient air temperature, pressures psig and psia					
Condition 0: Precharged accumulators	70	1,821	1,836	8.946	
Condition 1: Accumulators charged	70	5,000	*5,015*	20.798	
Condition 2: Pressure Requirement (MOP)	70	2,203	*2,218*	10.686	
2. Use Method B density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.0$		**VE_p**	*0.407*		
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.4$		**VE_v**	*0.407*		
3. Volumetric Efficiency $VE_{surf} = \min(VE_p, VE_v)$.		**Min. = VE_{surf}**	*0.407*		
Stack Mounted accumulator	**Method B**				
1. Tabulate temperature & pressures, psig & psia, and gas densities for each Condition from above					
Condition 0: Precharged accumulators	35	1,578	*4,860*	21.908	
Condition 1: Charged accumulators	35	5,000	*8,282*	29.676	
Condition 2: Pressure Requirement (MOP)	35	2,203	*5,485*	23.678	
Condition 3: Discharged	35	1,578	4,860	21.908	To precharge pressure
2. Use Method B density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.0$		**VE_p**	*0.187*		
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.4$					
If P0 is less than hydrostatic sea pressure, $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.4$		**VE_v**	*0.187*		
3. Volumetric Efficiency $VE_{sm} = \min(VE_p, VE_v)$.		**Min. = VE_{sm}**	*0.187*		

Calculate Number of Bottles, Stack Mounted and Surface

1. Minimum required stack accumulator volume = subsea FVR / VE_{sm}
2. Calculate resulting SM usable Pressure Limited and Volume Limited with subsea FVR/$VE_{p\text{-}sm}$ and subsea FVR/$VE_{v\text{-}sm}$
3. Minimum required surface accumulator volume = (FVR - V_{sm} * VE_{sm}) / VE_{surf}

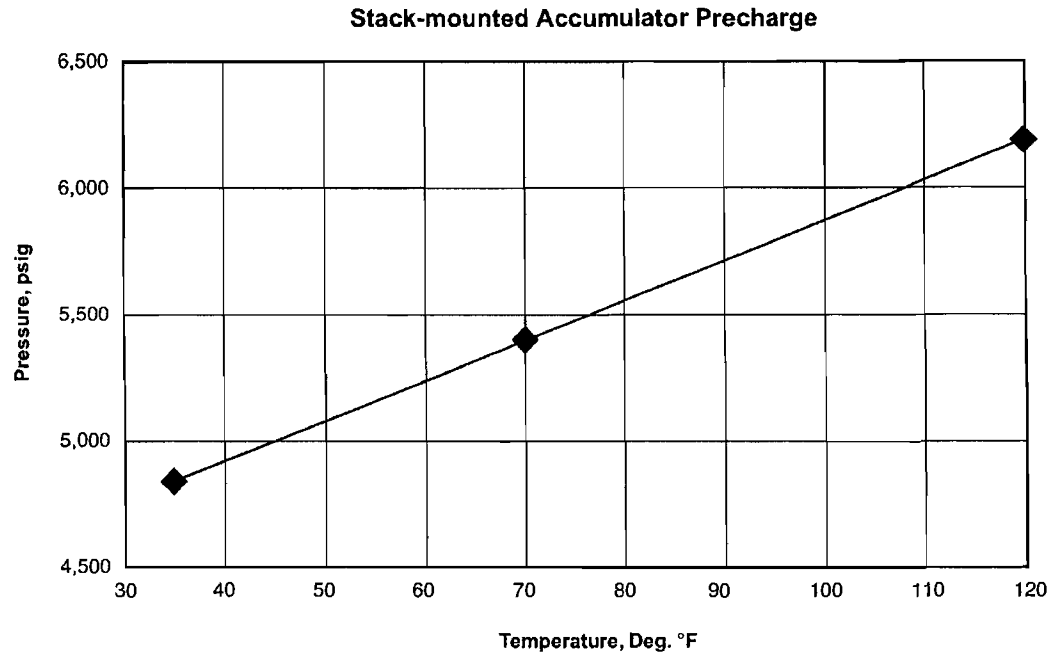
	# of bottles		Bottle Volume		Usable volume	
Stack Mounted bottles required	*27.1*	Bottles	*374.4*	gals		
Round up to desired integer	*28*	Bottles	*386.4*	gals	72.2	gals
Surface bottles required, Vol. Ltd.	*57.3*	Bottles	*790.5*	gals		
Surface bottles required, Press. Ltd.	*57.3*	Bottles	*737.9*	gals		
Select higher number	*57.3*	Bottles				
Round up to desired integer	*58*	Bottles	*800.4*	gals	*325.8*	gals

Performance Table	Temp °F	Pressure, Surf. Equiv. psig	Bottle Pressure psia	Volume, gals Gas	Volume, gals Liquid	Gas Density lb/ft³
1. Tabulate surface temperature and pressures						
2. Enter Surface Bottle Volume as the Condition 0 Initial Gas Volume						
3. (Method A) Use Ratio of absolute pressures to calculate Gas Volumes for Conditions 1 to 3						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume.						
Functional Steps - Surface Bottles						
Condition 0: Precharge	70	1,821	1,836	800.4	0.0	8.946
Condition 1: Charged	70	5,000	5,015	*344.3*	*456.1*	20.798
Condition 2: MOP	70	2,203	2,218	670.1	130.3	10.686
Condition 3: Fully discharged	70	1,821	1,836	800.4	0.0	8.946
1. Tabulate stack mounted bottle temperatures, pressures, and densities						
2. Enter Stack Mounted Bottle Volume as the Condition 0 Initial Gas Volume						
3. (Method B) Use Ratio of gas densities to calculate Gas Volumes for Conditions 1 to 3						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume						
Functional Steps - Stack Mounted Bottles						
Precharged accumulators @ surface	70	5,404	5,419	386.4	0.0	21.908
Condition 0: Precharged accumulators	35	*1,578*	4,860	386.4	0.0	21.908
Condition 1: Charged	35	5,000	8,282	285.3	*101.1*	29.676
Condition 2: MOP	35	2,203	5,485	*357.5*	*28.9*	23.678
Condition 3: Fully discharged	35	1,578	4,860	386.4	0.0	21.908

Summary

Accumulator Location	# of bottles	Precharge Pressure, psig	Precharge Temperature, °F
Surface	58	1,821	70
Stack mounted	28	5,404	70

Liquid Volumes, gal	Actual Surface	Actual Stack Mtd.	With Volume Factor Surface	With Volume Factor Stack Mtd.	With Volume Factor Total	FVR	Meets req'ts?
Condition 1: Charged	456.1	101.1					
Condition 2: MOP	130.3	28.9					
From Condition 1 to 2: Pressure Design	*325.8*	*72.2*	*325.8*	*72.2*	*398.0*	394.0	**YES**
Condition 3: Fully discharged	0.0	0.0					
From Condition 1 to 3: Volume Design	*456.1*	*101.1*	*325.8*	*72.2*	*557.3*	394.0	**YES**
Condition 2: MOP (Stack Mounted)				72.3		70	**YES**
Condition 3: Discharged (Stack Mounted)				72.2		70	**YES**


Stack-mounted Accumulator Precharge
6,500
6,000
5,500
5,000
4,500
Pressure, psig
30
40
50
60
70
80
90
100
110
120
Temperature, Deg. °F

Example 6: Surface Rapid Discharge System—Method C

C.7 Example 6–Surface Rapid Discharge System Designed with Method C

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define BOP configuration, operating sequence, and operating parameters
2. Select desired precharge pressure (and temperatures)
4. Calculate required number of surface bottles

Total Functional Volume Requirement (FVR) = 97.0 gallons (from BOP Configuration for Rapid Discharge System Examples)

Precharge gas type:	**Nitrogen**	
Surface temperature at precharge	**70**	°F

Condition 1 Data	psig	psia	density, ρ_1				Base Entropy	
Using the NIST tables determine the charged gas density, ρ_1, and base entropy based upon gas temperature and pressure.								
Accumulator	4,700	4,715	***19.923***	lb/ft^3 @	70	°F	***0.50661***	BTU/lb °F

Final Minimum Operating Pressure (MOP)		
3. Choke Valve	1,500	psig
User specified MOP, if any	**1,000**	psig
Maximum	1,500	psig

Condition 2 Data							
Using NIST tables determine the MOP gas density, ρ_2, based upon gas pressure and Base Entropy (held constant)							
MOP requirement @ accumulator	1,515	psia	Density, ρ_2=	***11.592***	lb/ft^3 @	***–75***	°F

Accumulator Condition 0 Data—Method C								
Optimum Precharge density $\rho_0 = \rho_2$	11.597	lb/ft^3						
1. Using NIST tables determine the Optimum Precharge pressure based upon Optimum Precharge Density and Surface Temperature								
Optimum Precharge Pressure @ Surf. Temp.	70	°F	2,410	psig @	***2,426***	psia		
Input Precharge pressure	**70**	°F	**2,200**	psig	*2,215*	psia	***10.673***	lb/ft^3
2. Using the NIST tables determine the gas pressure for the maximum surface temperature and precharge gas density.								
Pressure @ maximum temperature	**120**	°F	*2,478*	psig	***2,493***	psia	10.673	lb/ft^3

Design Factors per Table 2	**Volume Limited**	**Pressure Limited**
Method C	**1.1**	**1.1**

Calculation of volumetric efficiency based upon specified precharge pressure

Calculate Basic data	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia	Gas Density, ρ lb/ft^3	
Method C					
1. Tabulate temperatures & pressures psig & psia, and gas densities for each Condition from above					
Condition 0: Precharged accumulators	70	2,200	*2,215*	10.673	
Condition 1: Charged accumulators	70	4,700	*4,715*	19.923	
Condition 2: Pressure Requirement (MOP)	– 75	1,500	1,515	11.592	
2. Using the NIST tables determine gas temperature & pressure for density = precharge density & constant entropy.					
Condition 3: Discharge all liquid	***– 91***	1,290	***1,305***	10.673	To precharge density
3. Use Method C density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$			**VE_p**	*0.350*	
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.1$			**VE_v**	*0.422*	
4. Volumetric Efficiency $VE = \min(VE_p, VE_v)$			**min. = VE**	*0.350*	

Calculate Number of Bottles

1. Minimum required accumulator volume = FVR/VE FVR = 99.0 gals.

	# of bottles	Bottle Volume	Usable volume
Bottles required	*20.5* bottles	*282.8* gals	
Round up to desired integer	*21* bottles	*289.8* gals	*101.4* gals

Performance Table	Temp °F	Pressure, psig	Pressure, psia	Volume, gals Gas	Volume, gals Liquid	Gas Density lb/ft^3
1. Tabulate temperatures, pressures, densities, and Base Entropy for Conditions 0, 1, and 3						
2. Set up each Condition 2 MOP functional step with required bottle pressure						
3. For each Cond. 2 MOP step, use NIST tables determine the gas temperatures & density based on gas pressure & entropy.						
4. Enter Bottle Volume as the Condition 0 initial gas volume						
5. Use ratios of densities to calculate gas volumes for remaining steps						
6. Liquid volume for each Condition = Bottle Volume minus Gas Volume			Base Entropy =		0.50661	BTU/lb°F
Functional Steps						
Condition 0: Precharged accumulators	70	2,200	2,215	289.8	0.0	10.673
Condition 1: Charged	70	4,700	4,715	*155.2*	*134.6*	19.923
Condition 2 MOP: Casing Shear Ram BOP	***– 31***	2,200	2,215	*218.8*	*71.0*	***14.138***
Condition 2 MOP: Blind Shear Ram BOP	***– 85***	1,374	1,389	*279.9*	*9.9*	***11.050***
Condition 2 MOP: Choke Valve	– *75*	1,500	1,515	*266.8*	*23.0*	***11.592***
Condition 3: Fully discharged	– 91	1,290	1,305	*289.8*	0.0	10.673

Summary

# of bottles	21	Precharge pressure	2,200 psig @	70	°F

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	134.6			
Condition 2 MOP: Casing Shear Ram BOP	71.0			
Delta from Condition 1	*63.5*	*57.7*	54.0	**YES**
Condition 2 MOP: Blind Shear Ram BOP	*9.9*			
Delta from Condition 1	*124.7*	*113.3*	*82.0*	**YES**
Condition 2 MOP: Choke Valve	*23.0*			
Delta from Condition 1	*111.6*	*101.4*	*99.0*	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	*134.6*	*122.3*	99.0	**YES**

Example 7: Subsea Rapid Discharge System—Method C

C.8 Example 7—Subsea Rapid Discharge System Designed with Method C

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define BOPE configuration, operating sequence, and operating parameters
2. Select desired precharge pressure (and temperature)
4. Calculate required number of stack mounted bottles

Precharge gas type: Nitrogen

Total Functional Volume Requirement (FVR) = 97.0 gallons (from BOP Configuration for Rapid Discharge System Examples)

Condition 1 Data	Surface, psig	Subsea, psia	density, ρ_1				Base Entropy (B.P. Conv.)	
Using the NIST tables determine the charged gas density, ρ_1, and base entropy based upon gas temperature and pressure.								
Accumulator	4,700	*7,982*	***29.146***	lb/ft^3 @	35	°F	***0.43785***	BTU/lb °F

Minimum Operating Pressures (MOP)	Surface basis, psig	Adj. for (Riser head - SW head) / Closing Ratio + Sea Water head =			
3. LMRP Connector	1,500	NR		*4,842*	psia
User specified MOP, if any	1,000	NR		*4,342*	psia
Final MOP = maximum =				*4,842*	psia
Intermediate sequence step MOPs					
1. Casing Shear Ram BOP	2,200	*421*	psi	*5,963*	psia (adj. for riser head)
2. Blind Shear Ram BOP	1,374	*421*	psi	*5,137*	psia (adj. for riser head)

Condition 2 Data							
Using NIST tables determine the MOP gas density, ρ_2, based upon gas pressure and Base Entropy (held constant)							
MOP requirement @ accumulator	4,842	psia	Density, ρ_2 =	***25.033***	lb/ft^3 @	**– 22.7**	°F

Stack Mounted Accumulator Condition 0 Data - Method C								
Optimum Precharge density $\rho_0 = \rho_2$	25.033	lb/ft^3	if P3 is not seahead limited					
1. Using NIST tables determine the Optimum Precharge pressure based upon Optimum Precharge Density and Surface Temperature								
Optimum Precharge Pressure @ Surf. Temp.	70	°F	6,665	psig	***6,680***	psia		
Input Precharge pressure at surface	70	°F	5,000	psig	*5,015*	psia	***20.798***	lb/ft^3
2. Using the NIST tables determine the gas pressure for the maximum surface temperature and precharge gas density.								
Pressure @ maximum temperature	120	°F	*5,727*	psig	***5,742***	psia	20.798	lb/ t^3
3. Using the NIST tables determine the gas pressure for the subsea temperature and precharge gas density ρ_0								
Pressure @ subsea temperature, Cond. 0	35	°F	*4,487*	psig	***4,502***	psia	20.798	lb/ft^3
4. Using the NIST tables determine gas temperature & density at ρ_3 limit, based upon Cond. 3 Sea water head pressure and constant Base Entropy.								
Temp. & ρ @ Cond. 3 Limit	– 61	°F	*3,327*	psig	*3,342*	psia	***22.094***	lb/ft^3

Design factors per Table 2	Volume Limited	Pressure Limited
Method C	1.1	1.1

Calculation of volumetric efficiency based on specified precharge pressure

Calculate Basic data	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia	Gas Density, ρ lb/ft^3	
Method C					
1. Tabulate temperatures & pressures, psig & psia, and gas densities for each Condition from above.					
Condition 0: Precharged accumulators	35	*1,220*	4,502	20.798	
Condition 1: Charged accumulators	35	4,700	*7,982*	29.146	
Condition 2: Pressure Requirement (MOP)	– 22.7	*1,560*	4,842	25.033	
2. Using the NIST tables determine gas temperature & pressure for density = precharge density & constant entropy.					
Trial Condition 3 case: Discharge all liquid	**– 78**		***2,829***	20.798	To precharge density
3. Compare pressure to minimum limit of sea water hydrostatic:			3,342	**Low—Use Limited Case**	
Cond. 3 Case Used: SW pressure limit	– 61		3,342	22.094	
4. Use Method C density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$			**VE_p**	*0.1066*	
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.1$					
Except if Condition 3 is sea water pressure limited, then $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$			**VE_v**	*0.207*	
5. Volumetric Efficiency VE = min(VE_p, VE_v)			**min. = VE**	*0.1066*	

Calculate Number of Bottles

1. Minimum required accumulator volume = FVR/VE FVR = 99.0 gals

	# of bottles	Bottle Volume	Usable volume
Stack-mounted bottles required	*67.3* bottles	*928.7* gals	
Round up to desired integer	*68* bottles	*938.4* gals	*100.0* gals

Performance Table	Temp °F	Pressure, Surf. Equiv. psig	Bottle Pressure psia	Volume, gals Gas	Volume, gals Liquid	Gas Density lb/ft^3
1. Tabulate bottle temperatures, pressures, densities, and Base Entropy for Conditions 0, 1, and 3.						
2. Set up each Condition 2 MOP functional step with required bottle pressure.						
3. For each Cond. 2 MOP step, use NIST tables determine the gas temperatures & density based on gas pressure & entropy.						
4. Enter Bottle Volume as the Condition 0 Initial Gas Volume.						
5. Use ratios of densities to calculate gas volumes for remaining steps.						
6. Liquid volume for each Condition = Bottle Volume minus Gas Volume.				Base Entropy =	0.43785	BTU/lb°F
Functional Steps						
Precharged accumulators @ surface	70	5,000	5,015	924.6	0.0	20.798
Condition 0: Precharged accumulators	35	*1,220*	4,502	924.6	0.0	20.798
Condition 1: Charged	35	4,700	7,982	*659.8*	*264.8*	29.146
Condition 2 MOP: Casing Shear Ram BOP	***0***	*2,681*	5,963	*719.5*	*205.1*	***26.725***
Condition 2 MOP: Blind Shear Ram BOP	***-16***	*1,855*	5,137	*753.8*	*170.8*	***25.510***
Condition 2 MOP: LMRP Connector	***-23***	*1,560*	4,842	*768.2*	*156.4*	***25.033***
Condition 3: Fully discharged	-61	60	3,342	*870.3*	*54.3*	22.094

Summary

# of bottles	68	Precharge pressure	5,000	psig @	70	°F

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	268.8			
Condition 2 MOP: Casing Shear Ram BOP	208.1			
Delta from Condition 1	*60.7*	*55.1*	54.0	**YES**
Condition 2 MOP: Blind Shear Ram BOP	*173.3*			
Delta from Condition 1	*95.5*	*86.8*	82.0	**YES**
Condition 2 MOP: LMRP Connector	*158.8*			
Delta from Condition 1	*110.0*	*100.0*	*99.0*	**YES**
Condition 3: Fully discharged	55.1			
From Condition 1 to 3: Volume Design	*213.7*	*194.3*	*99.0*	**YES**

Example 8: Subsea Rapid Discharge System with Helium Precharge—Method C

C.9 Example 8—Surface Rapid Discharge System Designed with Method C and Using Helium Precharge Gas

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define BOP configuration, operating sequence, and operating parameters
2. Select desired precharge pressure (and temperatures)
4. Calculate required number of surface bottles

Precharge gas type: Helium

Total Functional Volume Requirement (FVR) = 97.0 gallons (from BOP Configuration for Rapid Discharge System Examples)

Condition 1 Data	psig	psia	density, ρ_1				Base Entropy (B.P. Conv.)	
Using the NIST tables determine the charged gas density, rho1, and base entropy based upon gas temperature and pressure.								
Accumulator	4,700	*7,982*	***4.715***	lb/ft^3 @	35	°F	***3.46905***	BTU/lb °F

Minimum Operating Pressures (MOP)	Surface basis, psig	Adj. for (Riser Head – SW Head) / Closing Ratio		+ Sea Water Head =	
3. LMRP Connector	1,500	NR		*4,842*	psia
User specified MOP, if any	1,000	NR		*4,342*	psia
Final MOP = maximum =				*4,842*	psia
Intermediate sequence step MOPs					
1. Casing Shear Ram BOP	2,200	*421*	psi	*5,963*	psia (adj. for riser head)
2. Blind Shear Ram BOP	1,374	*421*	psi	*5,137*	psia (adj. for riser head)

Condition 2 Data							
Using NIST tables determine the MOP gas density, ρ_2, based upon gas pressure and Base Entropy (held constant)							
MOP requirement @ accumulator	4,842	psia	Density, ρ_2=	***3.676***	lb/ft^3 @	***– 53***	°F

Stack Mounted Accumulator Condition 0 Data - Method C								
Optimum Precharge density $\rho_0 = \rho_2$	3.676	lb/ft^3						
1. Using NIST tables determine the Optimum Precharge pressure based upon Optimum Precharge Density and Surface Temperature								
Optimum Precharge Pressure @ Surf. Temp.	70	°F	6,267	psig	**6,282**	psia		
Input Precharge pressure at surface	70	°F	5,000	psig	*5,015*	psia	***3.037***	lb/ft^3
2. Using the NIST tables determine the gas pressure for the maximum surface temperature and precharge gas density.								
Pressure @ maximum temperature	120	°F	*5,466*	psig	***5,481***	psia	3.037	lb/ft^3
3. Using the NIST tables determine the gas pressure for the subsea temperature and precharge gas density ρ_0								
Pressure @ subsea temperature, Cond. 0	35	°F	*4,674*	psig	***4,689***	psia	3.037	lb/ft^3
4. Using the NIST tables determine gas temperature & density at p3 limit, based upon Cond. 3 Sea water head pressure and constant Base Entropy.								
Temp. & ρ @ Cond. 3 Limit	***– 109***	°F	*3,327*	psig	*3,342*	psia	***3.037***	lb/ft^3

Design factors per Table 2	**Volume Limited**	**Pressure Limited**
Method C	**1.1**	**1.1**

Calculation of volumetric efficiency based on specified precharge pressure

Calculate Basic data	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia		Gas Density, ρ lb/ft^3	
Method C						
1. Tabulate temperatures & pressures psig & psia, and gas densities for each Condition from above						
Condition 0: Precharged accumulators	35	*1,407*	4,689		3.037	
Condition 1: Charged accumulators	35	4,700	*7,982*		4.715	
Condition 2: Pressure Requirement (MOP)	– 55	*1,560*	4,842		3.653	
2. Using the NIST tables determine gas temperature & pressure for density = precharge density & constant entropy.						
Trial Condition 3 case: Discharge all liquid	***– 109***		***3,342***		3.037	To precharge density
3. Compare pressure to minimum limit of sea water hydrostatic:			3,342	**Okay—use Trial Condition 3 Case**		
Cond. 3 Case Used: Discharge all liquid	– 109		3,342		3.037	
4. Use Method C density-based Volumetric Efficiency formulas:						
Pressure limited VEp = $(\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$				**VE$_p$**	*0.165*	
Volume limited VEv = $(1.0 - \rho_0/\rho_1)/1.1$						
Except if Condition 3 is sea water pressure limited, then VEv = $(\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$				**VE$_v$**	*0.323*	
5. Volumetric Efficiency VE = min(VE$_p$, VE$_v$)				**min. = VE**	*0.165*	

Calculate Number of Bottles

1. Minimum required accumulator volume = FVR/VE FVR = 99.0 gals

	# of bottles	**Bottle Volume**	**Usable Volume**
Stack Mounted bottles required	*43.4* Bottles	*598.6* gals	
Round up to desired integer	*44* Bottles	*607.2* gals	*100.4* gals

Performance Table	Temp °F	Pressure, Surf. Equiv. psig	Bottle Pressure psia	Volume, gals Gas	Volume, gals Liquid	Gas Density lb/ft^3
1. Tabulate bottle temperatures, pressures, densities, and Base Entropy for Conditions 0, 1, and 3						
2. Set up each Condition 2 MOP functional step with required bottle pressure						
3. For each Cond. 2 MOP step, use NIST tables determine the gas temperatures & density based on gas pressure & entropy.						
4. Enter Bottle Volume as the Condition 0 Initial Gas Volume						
5. Use ratios of densities to calculate gas volumes for remaining steps						
6. Liquid volume for each Condition = Bottle Volume minus Gas Volume				Base Entropy =	3.46905	BTU/lb°F
Functional Steps						
Precharged accumulators @ surface	70	5,000	5,015	593.4	0.0	3.037
Condition 0: Precharged accumulators	35	*1,407*	4,689	593.4	0.0	3.037
Condition 1: Charged	35	4,700	7,982	*382.2*	*211.2*	4.715
Condition 2 MOP: Casing Shear Ram BOP	***– 19***	*2,681*	5,963	*441.3*	*152.1*	***4.083***
Condition 2 MOP: Blind Shear Ram BOP	***– 44***	*1,855*	5,137	*475.7*	*117.1*	***3.788***
Condition 2 MOP: LMRP Connector	***– 53***	*1,560*	4,842	*490.2*	*103.2*	***3.676***
Condition 3: Fully discharged	– 109	60	3,342	*593.4*	0.0	3.037

Summary

# of bottles	44	Precharge pressure	5,000	psig @	70	°F

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Condition 1: Charged	216.1			
Condition 2 MOP: Casing Shear Ram BOP	155.6			
Delta from Condition 1	*60.5*	*55.5*	54.0	**YES**
Condition 2 MOP: Blind Shear Ram BOP	*120.4*			
Delta from Condition 1	*95.6*	*86.9*	82.0	**YES**
Condition 2 MOP: LMRP Connector	*105.6*			
Delta from Condition 1	*110.5*	*100.4*	99.0	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	*216.1*	*196.4*	99.0	**YES**

C.10 Example 9—Special Purpose Accumulator Circuit with Method C

C.10.1 Description Circuit

This circuit is fitted to a subsea stack with controls to a choke and kill valve consisting of a single control line from each pod to pressure the valve open. The example circuit described below is used to illustrate a general approach to this type of rapid discharge accumulator application.

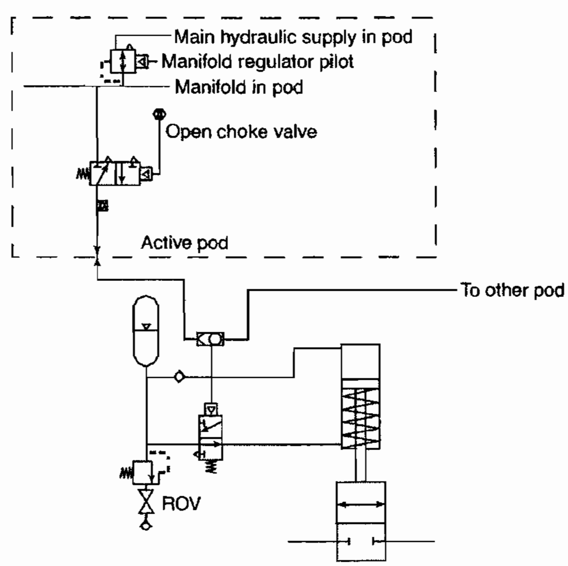
There is the usual shuttle valve allowing fluid pressure from either blue or yellow pod. Circuit is designed to pressure to open the valve and vent to close the valve. When the choke and kill valve is commanded open, pressure is applied to the shuttle from the active pod. The discharge of the shuttle valve is directs the regulated pressure (typically 1500 psig) to three branches:

- To the open side of the operator to open the valve.
- To the accumulator through a check valve. This ultimately provides the close choke valve energy charged with fluid from the regulated source.
- To the pilot of a two position spring offset stack mounted valve. Due to the applied pilot pressure, this piloted valve shifts, venting the close side of the valve operator.

Choke and kill valve close command is generated by removing the pod valve open signal. When the open signal is removed and vented at the pod, the pressure to the shuttle dissipates:

- The check valve to the accumulator checks off, trapping charge pressure in the accumulator.
- The pilot on the stack mounted control valve is removed, allowing the spring to shift this pilot valve, which now directs the accumulator pressure to the close side of the choke and kill valve. Pressure remaining after discharge shall be greater than the minimum required operating pressure of the valve after discharging the valve closing volume (plus volume design factor).
- The choke and kill valve operator now displaces open side fluid back to the vented pod valves through the shuttle as the valve closes.

This accumulator is to meet the required pressure and volume requirements both immediately after charging and after long periods of being charged. For special purpose accumulators, the designer and user should determine the sensitivity of the solutions to various parameters. Just as a range of precharge pressures is acceptable for a particular water depth, a given precharge will have a range of acceptable water depths, other factors held constant.



Choke Valve with Spring Close Assist

C.10.2 Design Example 9—Subsea Hydraulic Assist Circuit For Normally Closed Valve—Method C

Legend
Input
NIST (11/2003) lookup
Calculated
Transferred

Design sequence: 1. Define BOPE configuration and operating parameters
2. Select desired precharge pressure (and temperature)
4. Calculate required bottle number/size

Configuration

Valve Description	Bore Size in.	Rated Working Pressure psig	Closing Volume gal	Minimum Operating Pressure psig
Valve, spring close, accumulator assist	$3\ ^{1}/_{16}$	15,000	0.75	750
Total Functional Volume Requirement (FVR)			*0.75*	
For a rapid discharge system, the minimum FVR is as specified by the user.				
Environmental Conditions				
Water depth		7,500 ft		
Air gap		50 ft		
Surface temperature at precharge		70°F		
Subsea (mudline) water temperature		35°F		

Fluid Densities and Head Pressures						
Sea water	8.54	lb/gal	*0.444*	psi/ft	*3327*	psig
Control fluid	8.33	lb/gal	*0.433*	psi/ft	*3267*	psig including air gap

Stack-mounted Accumulator bottles				
Gas volume per bottle	13.8	gal	Gas type	nitrogen
Pressure rating of bottles	7,000	psig		

Charged Pressure (Condition 1)	1,500	psig (surf. equiv.)	Closing accumulator is charged by regulated opening fluid pressure.

Condition 1 Data (cooled to subsea temperature)	psig	psia	density, ρ_1				Entropy (Normal B.P. Conv.)	
Using the NIST tables determine the charged gas density, ρ_1, and entropy based upon gas temperature and pressure.								
Accumulator pressure—add control fluid head	1,500	*4,782*	***21.672***	lb/ft^3 @	35	°F	***0.48251***	BTU/lb °F

Minimum Operating Pressure (MOP)	Surface basis, psig	+ Sea water head =		
Valve, spring close, accumulator assist	750	*4,092*	psia	= MOP

Condition 2 Data (for case of charged accumulator cooled to subsea temperature—Isothermal)						
Using NIST tables determine the MOP gas density, ρ_2, based upon gas pressure and entropy (held constant from charged condition)						
MOP requirement @ accumulator	4,092 psia	Density, ρ_2=	***20.399***	lb/ft^3 @	***15***	°F

Precharge, at surface conditions		**Cooling charging (isothermal)**		**Adiabatically heated charging**	
Optimum Precharge density $\rho_0 = \rho_2$		20.399 lb/ft^3		19.613 lb/ft^3 from below	
1. Using NIST tables determine the Optimum Precharge pressures based upon Optimum Precharge Densities					
Optimum Precharge Pressure @ Surf. Temp.	70 °F	4,862 psig		***4,877*** psia	
Select an input precharge pressure at surface	70 °F	<u>**4,676**</u> psig		(using adiabatic)	
1. Using the NIST tables determine the precharge gas density ρ_0, based upon gas temperature and pressure.					
2. Using the NIST tables determine the gas pressure for the maximum surface temperature and precharge gas density.					
Precharge at surface condition	70 °F	4,676 psig	4,691 psia	**19.851**	lb/ft^3
Precharge at maximum temperature	120 °F	5,350 psig	**5,365** psia	**same**	lb/ft^3

	Pressure		Gas		Gas		Gas	
Calculate Basic data	psig	psia	Density, ρ		Temperature		Entropy	
1. Using NIST, determine the precharge gas pressure and its initial entropy based on its density and subsea temperature.								
Condition 0 @ subsea temperature	934	***4,216***	19.851	lb/ft^3 @	35	°F	***0.49397***	BTU/lb °F
Condition 1 to 3 Data—for adiabatic compressional heating during charging								
2. Using NIST, determine adiabatically charged gas density ρ_1, & temperature based on the charged pressure and initial entropy								
3. Using NIST, determine the MOP gas density ρ_2, based on gas pressure and base entropy (held constant)								
4. Using NIST, determine gas density & temperature @ ρ_3 limit, based on Cond. 3 Sea water head pressure and constant entropy								
5. Condition 3 @ fully discharged = Condition 0 for this case (reversible adiabatic compression, then expansion)								
6. Select Condition 3 as Fully Discharged unless its pressure is below Sea Water head limit								
Condition 1 @ adiabatic heated temperature	1,500	*4,782*	***20.884***	lb/ft^3 @	***52***	°F	0.49397	BTU/lb °F
Condition 2 MOP requirement	810	4,092	***19.613***	lb/ft^3 @	***31***	°F	same	BTU/lb °F
Condition 2 after limit check	934	*4,216*	***19.581***		***35***	°F	**(is empty)**	
Condition 3 limit at sea water head	60	*3,342*	***18.005***	lb/ft^3 @	***5***	°F	same	BTU/lb °F
Condition 3 fully discharged to ρ_0	934	4,216	19.581	lb/ft^3 @	35	°F	same	BTU/lb °F
Condition 3: is fully Discharged Case	934	4,216	19.581	lb/ft^3 @	35	°F		
Condition 1 to 3 Data—for charged accumulator cooled down to subsea temperature								
7. Tabulate the Conditions 1 and 2 Data from above								
8. Perform steps 4, 5, and 6 above for this case.								
Condition 1 @ subsea temperature	1,500	*4,782*	21.672	lb/ft^3 @	35	°F	0.48251	BTU/lb °F
Condition 2 MOP requirement	810	4,092	20.399	lb/ft^3 @	15	°F	same	BTU/lb °F

Condition 2 after limit check	810	*4,092*	***20.399*** lb/ft³ @	***15***	°F	(has liquid remaining)	
Condition 3 limit at sea water head	60	*3,342*	***18.785*** lb/ft³ @	***– 10***	°F	same	BTU/lb °F
Condition 3 fully discharged to ρ_0	541	***3,823***	19.851 lb/ft³ @	***6***	°F	same	BTU/lb °F
Condition 3 is fully Discharged Case	541	3,823	19.851 lb/ft³ @	6	°F		

Design Factors per Table 2	**Volume Limited**	**Pressure Limited**
Method C	**1.1**	**1.1**

Calculation of volumetric efficiency based upon specified precharge pressure

	Temp °F	Pressure Surf Equiv. psig	Pressure in Bottle psia	Gas Density, ρ lb/ft³	Entropy BTU/lb °F
Condition 0: Precharged accumulators	35	*934*	4,216	19.851	0.48251
Method C—for adiabatically heated accumulator					
1. Tabulate temperatures and pressures psig and psia, and gas densities for each Condition from above					
Condition 1: Charged accumulators	52	1,500	4,782	20.884	0.49047
Condition 2: Pressure Requirement (MOP)	35	*934*	4,216	19.851	
Condition 3: Is fully Discharged Case	35	*934*	4,216	19.851	
2. Use Method C density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$				**VE_p**	*0.045*
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.1$					
Except if Condition 3 is sea water pressure limited, then $VEv = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$				**VE_v**	*0.045*
3. Volumetric Efficiency VE = min(VE_p, VE_v)				**min. = VE**	*0.045*
Method C—for charged accumulator cooled to sea water temperature					
4. Tabulate temperatures and pressures psig and psia, and gas densities for each Condition from above					
Condition 1: Charged accumulators	35	1,500	4,782	21.672	0.48251
Condition 2: Pressure Requirement (MOP)	15	*810*	4,092	20.399	
Condition 3: Is fully Discharged Case	6	*541*	3,823	19.851	
5. Use Method C density-based Volumetric Efficiency formulas:					
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$				**VE_p**	*0.052*
Volume limited $VE_v = (1.0 - \rho_0/\rho_1)/1.1$					
Except if Condition 3 is sea water pressure limited, then $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$				**VE_v**	*0.076*
6. Volumetric Efficiency VE = min(VE_p, VE_v)				**min. = VE**	*0.052*
7. **Compare adiabatically heated and cooled cases and use minimum VE =**					*0.045*
minimum is the Adiabatically Heated Case					

Calculate Number of Bottles			
Minimum required accumulator volume = FVR/VE			
	# of bottles	**Bottle Volume**	**Usable volume**
Bottles required	1.2 bottles	16.7 gals	
Round up to desired integer	2 bottles	27.6 gals	1.2 gals

Performance Table	Temp °F	Pressure, Surf. Equiv. psig	Bottle Pressure psia	Volume, gals Gas	Volume, gals Liquid	Gas Density lb/ft^3
1. Tabulate bottle temperatures, pressures, and densities for each Condition						
2. Enter Bottle Volume as the Condition 0 Initial Gas Volume						
3. Use ratios of densities to calculate gas volumes for remaining steps						
4. Liquid volume for each Condition = Bottle Volume minus Gas Volume						
Precharged accumulators @ surface	70	4,676	4,691	27.6	0.0	19.851
Condition 0: Precharged accumulators	35	934	4,216	27.6	0.0	19.851
Accumulator Adiabatically Heated–Functional Steps						
Condition 1: Charged	52	1,500	4,782	26.2	1.4	20.884
Condition 2: MOP	35	934	4,216	27.6	0.0	19.851
Condition 3: Fully discharged	35	934	4,216	27.6	0.0	19.851
Accumulator Cooled–Functional Steps						
Condition 1: Charged	35	1,500	4,782	25.3	2.3	21.672
Condition 2: MOP	15	810	4,092	26.9	0.7	20.399
Condition 3: Fully discharged	6	541	3,823	27.6	0.0	19.851

Summary

# of bottles	2	Precharge pressure	4,676	psig @	70	°F

Liquid Volumes, gal	Actual	With Volume Factor	FVR	**Meets req'ts?**
Accumulator Adiabatically Heated during Charging				
Condition 1: Charged	1.4			
Condition 2: MOP	0.0			
Delta from Condition 1	1.4	1.2	0.8	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	1.4	1.2	0.8	**YES**
Accumulator Cooled during Charging				
Condition 1: Charged	2.3			
Condition 2: MOP	0.7			
Delta from Condition 1	1.6	1.4	0.8	**YES**
Condition 3: Fully discharged	0.0			
From Condition 1 to 3: Volume Design	2.3	2.1	0.8	**YES**

Annex D—API Monogram Systems and Marking Requirements

D.1 Eligible Systems

Control systems eligible for the API Monogram Program are as follows:

a) Control systems for surface-mounted BOP stacks
b) Control systems for subsea BOP stacks
c) Discrete hydraulic control systems for subsea BOP stacks
d) Electro-hydraulic/multiplex control systems for subsea BOP stacks
e) Control systems for diverter equipment
f) Auxiliary equipment control systems and interfaces
g) Emergency disconnect sequence, if separate from main control system
h) Backup systems
i) Special deepwater/harsh environments systems described herein

D.2 Marking Requirements

The following marking requirements apply only to those API Monogram licensees wishing to mark their products with the API Monogram and are to be used in place of those found in 11.5:

The master control panel (and other major assemblies) of control systems supplied in accordance with this specification shall be affixed with a name plate. The name plate information shall include, as a minimum, the following:

a) Manufacturer's name or mark
b) API Monogram (including API license number)
c) Model name and/or number
d) Date of manufacture
e) Power fluid volumetric capacity that the system is designed to provide
f) System rated working pressure

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