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

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

1 Scope

These specifications establish minimum design standards for systems used to control blowout preventers (BOPs) and associated valves that control well pressure during drilling operations. The requirements in this specification apply to the following control system categories:

a) control systems for land based and surface-mounted BOP stacks;

b) discrete hydraulic control systems for subsea BOP stacks;

c) electro-hydraulic/multiplex (MUX) control systems for subsea BOP stacks;

d) emergency control systems for subsea BOP stacks;

e) secondary control systems for subsea BOP stacks; and

f) control systems for diverter equipment.

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.

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 design of control system equipment and circuitry varies in accordance with the application and environment.

See Annex A for information on the API Monogram Program.

2 Normative References

The following documents contain provisions which, though referenced in this text, constitute provisions of this standard. For dated references, only the edition cited applies. For undated references, the latest edition of the reference document (including amendments) applies.

ANSI/ESD S20.20, *Protection of Electrical and Electronic Parts, Assemblies, and Equipment*

API Recommended Practice 17H, *Remotely Operated Tools and Interfaces on Subsea Production Systems*

API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells*

API Recommended Practice 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division I and Division 2*

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

API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*

ASME B31.3, P*rocess Piping; ASME Code for Pressure Piping*

ASME B40.100, *Pressure Gauges and Gauge Attachments*

ASME, *Boiler and Pressure Vessel Code (BPVC)*, *Section VIII, Division 1, Rules for Construction of Pressure Vessels*

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

ASTM A370, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

IEC 60079 (All Parts), *Explosive Atmosphere Standards*

IEC 60529, *Degrees of Protection Provided by Enclosures (IP Code)*

IEC 60617, *Graphical Symbols for Diagrams*

IEC 60812, *Analysis techniques for system reliability—Procedure for failure mode and effects analysis (FMEA)*

IPC J-Std-0001, *Requirements for Soldering Electronic and Electrical Assemblies*

IPC 610, *Acceptability of Electronic Assemblies*

IPC 620, *Requirements and Acceptance of Cable and Wire Harnesses Assemblies*

IPC-7711/7721, *Rework, Repair and modifications of Electronic Assemblies*

ISO 1219, *Fluid Power symbols and components—Graphical symbols and circuit diagrams*

NACE SP0176, *Corrosion Control of Submerged Areas*

NFPA 70, *National Electrical Code*

NFPA 496, *Standard for Purged and Pressurized Enclosures for Electrical Equipment*

NEMA 250, *Enclosures for Electrical Equipment (1000 Volts Maximum)*

United States Department of Transportation (DOT) Specification 3AA2015

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purposes of this specification, the following terms and definitions apply:

3.1.1
absolute pressure
The pressure referenced against a vacuum.

3.1.2
accumulator
Pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

3.1.3
accumulator bank
Assemblage of multiple accumulators sharing a common manifold.

3.1.4
accumulator precharge
precharge
Initial inert gas charge in an accumulator, which is further compressed when the hydraulic fluid is pumped into the accumulator, thereby storing potential energy.

3.1.5
acoustic control system
Subsea control system that uses coded acoustic signals for communications and is normally used as a secondary control system having control of a few selected critical functions.

3.1.6
air pump/air-powered pump
Air driven hydraulic piston pump.

3.1.7
annular BOP
BOP that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or an open hole.

3.1.8
arm
To enable the operation of a critical function or functions.

3.1.9
autoshear system
Emergency control system that automatically activates in the event of a disconnect of the LMRP.

3.1.10
backup
Element or system that is intended to be used only in the event that the primary element or system is non-functional.

3.1.11
blind ram BOP
BOP having rams that seal the open wellbore.

3.1.12
blind shear ram
Closing and sealing component in a ram BOP that first shears the tubular in the wellbore and then seals off the bore; this acts as a blind ram if there is no tubular in the wellbore.

3.1.13
black box test
Test designed to verify the functionality of a software unit by creating a sufficient number of test cases to ensure that the functionality defined in the software design specification is thoroughly exercised and produces the correct set of outputs for a given set of inputs.

3.1.14
block position
Center position of a three-position control valve.

NOTE 1 The position blocks supply pressure, preventing function activation with the valve.

NOTE 2 It may or may not vent control fluid from the function, depending on the valve design.

3.1.15
blowout
Uncontrolled flow of pressurized wellbore fluids.

3.1.16
BOP
Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, or in an open hole during well drilling operations.

NOTE BOPs are not: gate valves, workover/ intervention control packages, subsea shut-in devices, well control components (per API 16ST), intervention control packages, diverters, rotating heads, rotating circulating devices, capping stacks, snubbing or stripping packages, or non-sealing rams.

3.1.17
BOP control system (closing unit)
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.

3.1.18
BOP stack
Complete assembly of well control equipment including BOPs, spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies.

3.1.19
casing shear ram
Closing component in a ram type preventer that is capable of shearing or cutting certain tubulars.

NOTE Casing shear rams are not required to seal.

3.1.20
central control unit
Central control point for control and monitoring system functions and communications.

3.1.21
check valve

Valve that allows flow through it in one direction only.

3.1.22
choke or kill line
High-pressure line that allows fluids to be pumped into or removed from the well with the BOPs closed.

3.1.23
choke and kill valves
Valve(s) connected to and a part of the BOP stack that controls the flow to the choke and kill manifold.

3.1.24
close and seal
Operation of a BOP to close the wellbore and obtain a wellbore pressure seal.

3.1.25
closing ratio (ram BOP)
Effective wetted cross-sectional area of the piston(s) divided by the cross-sectional area of the piston rod.

3.1.26
commodity item
Manufactured product purchased by the control system manufacturer for use in the construction of control systems for drilling well control equipment.

3.1.27
control fluid
Hydraulic oil, water-based fluid, or gas, which under pressure, pilots the operation of control valves or directly operates functions.

3.1.28
control hose bundle
hose bundle
Group of pilot or supply, or both; or control hoses, or a combination thereof, assembled into a bundle covered with an outer protective sheath.

3.1.29
control line
Flexible hose or rigid line that transmits control fluid.

3.1.30
control manifold
Assemblage of valves, regulators, gauges and piping used to regulate pressures and control the flow of hydraulic power fluid to operate system functions.

3.1.31
control pod
Assemblage of valves and pressure regulators which respond to control signals to direct hydraulic power fluid through assigned porting to operate functions.

3.1.32
control station

Array of switches, push buttons, lights, valves, graphical user interface, pressure gauges, meters, or a combination thereof, used to control or monitor functions, pressures, and alarms.

3.1.33 .
control valve
Component that directs power fluid to operate a selected function.

3.1.34
critical
Element or system that deemed by the organization, product specification, or customer as mandatory, indispensable or essential, needed for a stated purpose or task, and requiring specific action.

3.1.35
deadman system
Emergency control system that automatically activates in the event of a main control system failure.

3.1.36
dedicated
Element or system that is exclusively used for a specific purpose, and is precluded for any other purpose.

3.1.37
dedicated accumulator system
Accumulators exclusively used for a specific purpose that are supplied by the main accumulator system or a dedicated pump system, but not affected (e.g. by use of check valves) if the main supply is depleted or lost.

3.1.38
design validation
Process of proving a design by testing and provision of evidence to demonstrate conformity of the product to design requirements.

3.1.39
design verification
Process of examining the result of design and development output to determine conformity with specified requirements.

3.1.40
differential pressure
The difference in pressure between any two points.

3.1.41
disarm
To disable the operation of a critical function or functions.

3.1.42
disconnect
To unlatch and separate the LMRP connector from its mandrel or the BOP stack connector from the wellhead.

3.1.43
discrete hydraulic control system
System using pilot hoses to transmit hydraulic pressure signals to activate pilot-operated valves assigned to functions.

3.1.44
diverter
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.

3.1.45
drift-off
Unintended lateral move of a dynamically positioned vessel off of its intended location relative to the well-head, generally caused by loss of station keeping control or propulsion.

3.1.46
drive-off
Unintended lateral move of a dynamically positioned vessel off its location driven by the vessel's main propulsion or station keeping thrusters.

3.1.47
dunking transducer
Portable device capable of sending and receiving acoustic signals.

3.1.48
dynamic positioning
Computerized means of maintaining a vessel on location by selectively driving thrusters.

3.1.49
electric pump
Electrically driven hydraulic pump, usually a three-plunger (triplex) pump.

3.1.50
electro-hydraulic control system
EH
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.

3.1.51
factory acceptance testing
Testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings.

3.1.52
failure modes and effects analysis
FMEA
Reliability assessment process whereby all possible failure modes of a system are identified, and the probability and effects on the system performance are assessed.

3.1.53
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).

3.1.54
gauge pressure
The differential pressure relative to ambient pressure.

3.1.55
hydraulic conduit
Auxiliary line on a marine drilling riser used for transmission of control fluid between the surface and the subsea BOP stack

3.1.56
hydraulic connector
Hydraulically actuated drill-through equipment that locks and seals on end connections.

3.1.57
interflow
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 ports are temporarily interconnected.

3.1.58
integration test (software)
Test method to ensure the software units (after completing unit testing) work together.

NOTE 1 Usually, the system is built from the bottom-up by performing integration testing on groups of units at the lowest level first and building up the system by adding more units and more groups of units that have already completed their integration testing.

NOTE 2 The goal of integration testing is to ensure that the output from one unit is correct as the input to another unit; and to ensure that the functionality between the units exists and works as expected.

3.1.59
interlock sequencing
Arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another function.

3.1.60
jumper
Segment of hose or cable used to make a connection such as a hose reel junction box to the control manifold.

3.1.61
junction box (electrical)
Enclosure used to house the termination points of electrical cables and components that may also contain electrical components required for system operation.

3.1.62
junction box (hydraulic or pneumatic)
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.

3.1.63
lower marine riser package
LMRP
Remotely disconnectable upper section of a two-section subsea BOP stack that can be quickly disconnected.

NOTE A typical LMRP consists of the hydraulic connector, annular BOP(s), flex/ball joint, riser adapter, flexible choke and kill lines, and subsea control pods.

3.1.64
lowest maintainable subassembly
Lowest level field replaceable component or assembly as defined in a FMEA.

3.1.65
limit switch
Hydraulic, pneumatic or electrical switch that indicates the end of motion or extreme position of a device.

3.1.66
main accumulator system
Equipment that consists of the surface accumulator system and any LMRP mounted accumulators (if applicable) that are part of the main control system (not dedicated accumulators for the diverter, emergency, or secondary systems).

3.1.67
manifold
Assemblage of pipe, valves, and fittings by which fluid from one or more sources is selectively directed to various systems or components.

3.1.68
manipulator valve
Four way three position (typically) control valve where the center position blocks supply and pressure and vents both function ports.

3.1.69
minimum operating pressure
MOP
Minimum pressure differential required for a device to successfully perform its intended function in a particular environment.

3.1.70
Minimum Operator Pressure for Low Pressure Seal
MOPFLPS
BOP operator pressure required to obtain a wellbore seal.

3.1.71
mixing system
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.

3.1.72
multiplex control system
MUX
System utilizing electrical or optical conductors such that on each conductor multiple distinct functions are independently operated by dedicated serialized coded commands.

3.1.73
pilot fluid
Control fluid that is dedicated to the pilot supply system.

3.1.74
pilot line
Line that transmits pilot fluid to operate a control valve.

3.1.75
pipe ram BOP
Ram BOP that seals around the outside diameter of a tubular in the wellbore.

3.1.76
pop-up display
control dialog box
Display or control that appears on a computer screen to allow increased access to a control item or to display auxiliary data, a message, or a supplemental operational request or a system alarm notification.

3.1.77
power fluid
Pressurized fluid dedicated to the direct operation of functions.

3.1.78
pressure
Ratio of force to the area over which that force is distributed.

3.1.79
pressure-biased control system
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.

3.1.80
pressure-containing component
Component whose failure to function as intended results in a release of retained fluid to the environment.

3.1.81
pressure vessel
For BOP control systems, a container for the containment of internal fluid pressure or for the exclusion of external pressure.

3.1.82
qualification test
One-time (prototype) test program performed on a newly designed or significantly redesigned control system or component to validate conformance to design specifications.

3.1.83
ram BOP
BOP that uses rams to seal off pressure in the wellbore.

3.1.84
rated working pressure
RWP
Maximum internal pressure that equipment is designed to contain or control under normal operating conditions.

3.1.85
readback
Indication of a remote condition.

3.1.86
reel (hose or cable)
Reel, usually power driven, that stores, pays-out and takes-up umbilicals, hoses, or electrical cables.

3.1.87
regulator (valve)
Hydraulic device that reduces upstream supply pressure to a desired (regulated) pressure

NOTE It is manually or remotely operated and maintains the regulated output pressure unless reset to a different pressure.

3.1.88
relief valve
Device that is built into a hydraulic or pneumatic system to relieve (dump) any excess pressure.

3.1.89
reservoir
Storage tank for BOP control system fluid.

3.1.90
response time
Time elapsed between activation of a function at any control panel and complete operation of the function.

NOTE For automated functions, the start time is when the conditions are met for the automated response to initiate.

3.1.91
return-to-reservoir circuit
Hydraulic control circuit in which spent fluid is returned to the reservoir.

3.1.92
rigid conduit
Hydraulic supply line from surface to subsea, composed of pipe attached to the riser.

NOTE See hydraulic conduit.

3.1.93
riser connector
LMRP connector
Hydraulically operated connector that joins the LMRP to the top of the lower BOP stack.

3.1.94
risk
Situation or circumstance that has both a likelihood of occurring and a potentially negative consequence.

3.1.95
seal pressure
BOP operator pressure required to effect a wellbore seal.

3.1.96
shared
Element or system that may be used for more than one purpose.

3.1.97
shear and seal
Operation to shear a tubular in the wellbore and obtain a wellbore pressure seal.

NOTE See also MOPFLPS.

3.1.98
shear pressure
Ram BOP operator pressure required to shear.

3.1.99
shear ratio (shear ram BOP)
The effective operator closing area for shearing divided by the ram shaft area.

3.1.100
sheave
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.

3.1.101
shuttle valve
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.

3.1.102
software topology
Schematic representation of the electronic components, network connections, software applications installed and the interfaces between the software applications.

3.1.103
software unit
Smallest amount of software that has a set of inputs, produces a set of outputs, and can be compiled into an executable (or interpreted) code unit (or component or module).

3.1.104
solenoid valve
Electrical coil operated valve which controls a hydraulic or pneumatic function or signal.

3.1.105
spent fluid
Hydraulic control fluid that is vented from a function control port.

3.1.106
stored hydraulic fluid volume
Fluid volume recoverable from the accumulator system between the system rated working pressure and the precharge pressure.

3.1.107
system rated working pressure
Maximum design pressure at which control fluid is stored in the accumulator assembly.

3.1.108
test pressure
Pressure at which the component or system is tested to verify structural and pressure integrity.

3.1.109
umbilical
Control hose bundle or electrical cable that runs from the reel on the surface to the subsea control pod on the LMRP.

3.1.110
unit test
Test method by which software units created by the software developer(s) is verified to function correctly per design specification and that they meet the organizations quality standards.

3.1.111
vent position
Position of a control valve that vents spent fluid to the reservoir or to the environment.

3.1.112
volumetric efficiency (general)
VE
The ratio of the amount of control fluid than can be delivered under certain conditions to the total gas volume of the accumulator.

NOTE Volumetric efficiencies used in accumulator sizing calculations are listed in Annex C.

3.1.113
water-based hydraulic fluid
Control liquid mixture composed mainly of water with additives to provide lubricity, antifoaming, antifreeze, anticorrosion and antibacterial characteristics.

3.1.114
wellhead connector
stack connector
Hydraulically-operated connector that joins the BOP stack to the subsea wellhead.

3.1.115
white box test
Test designed to verify the structure of a software unit by creating a sufficient number of test cases to ensure that every line of code in the software unit and every branch statement (true/false) is executed at least once.

3.1.116
wireless communication
Transfer of information between two or more points that are not connected by an electrical conductor.

3.2 Abbreviations

For the purposes of this document, the following abbreviations and acronyms apply.

ACR Accumulator Capacity Requirement

ANSI American National Standards Institute

ASTM American Society of Testing and Materials

AWS American Welding Society

BOP blowout preventer

BSR blind shear ram

CCU central control unit

CSR casing shear ram

DMAS deadman autoshear

EDS emergency disconnect sequence

ESD emergency shutdown

FAT factory acceptance test

FMEA failure modes and effects analysis

FVR functional volume requirement

HPU hydraulic power unit

IEC International Electrotechnical Commission

IEEE	Institute of Electrical and Electronics Engineers
KSC	Kennedy space center
LMRP	lower marine riser package
MUX	multiplex system
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination (e.g., ultrasonic, radiographic, dye penetrant, etc.)
NIST	National Institute of Standards and Technology
OEM	original equipment manufacturer
P and ID	piping and instrumentation diagram
PQR	procedure qualification record
ROV	remotely operated vehicle
RWP	rated working pressure
UPS	uninterrupted power supply
VE	volumetric efficiency
VEp	pressure-limited volumetric efficiency
VEv	volume-limited volumetric efficiency
WPS	welding procedure specification

4 Control System Descriptions

4.1 Control Systems for Surface BOP Stacks

Control systems for surface BOP stacks are typically 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 manifolds, piping, and control valves for transmission of control fluid to the BOP stack functions and instrumentation for system control.

4.2 Discrete Hydraulic Control Systems for Subsea BOP Stacks

Remote control of a seafloor BOP stack requires specialized equipment. 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 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 redundancy.

4.3 Electro-hydraulic/Multiplex (MUX) 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 (MUX) 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.

4.4 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.

4.5 Auxiliary Equipment Control Systems and Interfaces

For floating drilling operations, various auxiliary functions such as the telescopic joint packer, latch/pin connection, riser annulus gas control equipment, etc., can be operated 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.

4.6 Emergency Control Systems

Emergency control systems are designed to automatically activate when certain conditions are met; two emergency control systems are autoshear and deadman.

4.7 Secondary Control Systems

When the main control system is inaccessible or non-functional, a secondary control system may be used to operate selected well control, disconnect, or recovery functions, or a combination thereof. These include acoustic control systems and ROV operated control systems.

4.8 Emergency Disconnect Sequenced Systems (EDS)

The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack. An EDS is activated by rig personnel 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 the requirements for similar equipment.

5 Control System Design Requirements

5.1 General

Well control systems and equipment identified in Section 4 designed or supplied by control system manufacturers, or both, shall meet or exceed these specifications.

5.2 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. Design verification and validation shall follow the requirements specified in API Q1.

5.3 Operational Conditions

5.3.1 The purchaser shall provide all necessary information for the BOP stack and other equipment to be controlled to ensure that the control system design meets the requirements of this specification.

5.3.2 The following shall be defined for all equipment supplied and be documented as part of the deliverables to the purchaser:

a) Hydraulic capacity requirements.

b) System rated working pressure(s).

c) Environmental conditions—the design of each sub-system or assembly capable of being located in different environments shall account for the following parameters and be documented as part of the deliverables to the purchaser.

   1) Temperature ratings shall be established that provide for operation within the ambient temperatures anticipated or the operational environment must be controlled within the temperature ratings of the equipment.

   2) Enclosure ratings—ingress protection of enclosures shall be rated for the environment in which they are installed in accordance with IEC 60529 or equivalent national or international standard.

   3) Corrosive environment—subsea or splash zone equipment that require special materials or cathodic protection shall be defined.

   4) Humidity ratings shall be established that provide for operation within the anticipated environmental conditions or the operational environment must be controlled to ensure environmental conditions are maintained within the ratings of the equipment.

   5) Hazardous area classifications—equipment shall be designed in accordance with a national or international standard. (Reference NEC 500, NEC 505, IEC 60079).

5.4 Design Data Documentation Requirements

5.4.1 Graphic symbols for fluid power and electrical diagrams shall be in accordance with ISO 1219 or IEC 60617 (or equivalent international or national standard) and documented with a symbols library. The standard being followed shall be clearly identified. If a graphic symbol does not exist, the symbol must be clearly recognized within the library as to its functionality. The manufacturer shall provide this legend to the end user on all hydraulic, pneumatic, and electrical drawings that include symbology.

NOTE This legend can be provided on each drawing that includes symbology or a separate document that is referenced on each drawing.

5.4.2 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.

5.4.3 The design data documentation shall include a table of contents.

5.4.4 Design data deliverable to the purchaser shall include the following.

a) utilities consumption list;

b) general arrangement drawings, factory acceptance test data, sizing calculations, and FMEA to document conformance to standards and specifications;

c) list of applicable standards and specifications.

5.5 Reservoirs and Reservoir Sizing—General

5.5.1 Reservoirs shall be designed to accommodate the fluids to be stored.

5.5.2 Cleanout ports/hatches shall be provided for each reservoir to facilitate cleaning. Cleanout ports shall be minimum 4-in. diameter. At least one inspection port shall be located above the normal maximum fluid level of the reservoir.

5.5.3 To prevent over pressurization, each reservoir shall have air vents that have air flow capacity in excess of the incoming fluid flow capacity (including flow from accumulators into the mixed fluid reservoir). These vents shall not lend themselves to being mechanically sealed.

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

5.5.5 Hydraulic fluid reservoirs shall be cleaned and flushed of all weld slag, machine cuttings, sand and any other contaminants before fluid is introduced.

5.6 Return-to-Reservoir Hydraulic Reservoirs

5.6.1 The hydraulic fluid reservoir usable capacity shall be at least twice the stored hydraulic fluid capacity of the accumulator system(s). Fluid located below the level required for proper pump operation is not considered part of usable capacity. The reservoir design shall ensure that fluid levels can be maintained below any inspection ports that are normally accessed during operations and still meet the usable capacity requirements.

5.6.2 Return-to-reservoir hydraulic systems do not require an automatic mixing system.

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

5.6.4 A pump shutoff level and (low, low-level) alarm may be provided to shut down the pumps before cavitation can occur. If a pump shutoff is installed, there shall be a manual override to operate the pump(s).

5.7 Vent-to-Environment Hydraulic Reservoirs

5.7.1 Main Mixed Fluid Reservoir

5.7.1.1 The control system fluid reservoir usable capacity shall be at least equal to the maximum possible total surface accumulator stored hydraulic fluid volume and have sufficient additional volume in the reservoir to permit draining the largest bank of accumulators back into the reservoir without overflow.

NOTE Fluid located below the level required for proper pump operation is not considered part of usable capacity.

5.7.1.2 The reservoir design shall ensure that fluid levels can be maintained below any inspection ports that are normally accessed during operations and still meet the usable capacity requirements. An automatic hydraulic mixing system is required for this type of system.

5.7.2 Control Fluid Concentrate Reservoir

The control fluid concentrate reservoir shall be sized using the maximum anticipated ratio for mixing the control system's hydraulic fluid. It shall have sufficient capacity to contain at least 10 times the concentrate necessary to mix the power fluid volume of the main accumulator system.

5.7.3 Ethylene Glycol Reservoir

The ethylene glycol reservoir, if installed, shall be sized using the maximum anticipated ethylene glycol/water ratio for the minimum anticipated ambient temperature to which the control fluid is to be exposed. The reservoir shall have sufficient capacity to contain enough ethylene glycol to mix at least 1.5 times the total (surface and subsea) accumulator power fluid volume capacity of the control system fluid.

5.8 Hydraulic Fluid Mixing System

5.8.1 The hydraulic fluid mixing system shall be designed for automatic operation.

5.8.2 The system shall automatically stop (or finish the current batch) when the mixed fluid reaches the designated shut-off level for the reservoir.

5.8.3 The mixing system shall automatically restart before the fluid level decreases not more than 10 % below the shut-off level.

5.8.4 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.

5.8.5 The automatic mixing system should be adjustable by the user over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

5.8.6 A means to override the automatic mixing system shall be provided.

5.9 Hydraulic Fluid Filtration

5.9.1 The hydraulic fluid shall be filtered to ensure proper operation in accordance with the control system manufacturer's requirements. The main system hydraulic power fluid supply shall use a dual filter parallel arrangement with isolation valves (to facilitate online maintenance).

5.9.2 Filters may permit manual or automatic bypassing of clogged elements rather than interrupting system operation. If automatic bypass is utilized, it shall include a bypassing indicator.

5.9.3 Filter housings should be mounted in an accessible location to facilitate maintenance.

5.10 Close, Shear and Seal Operation

5.10.1 Close and seal is the process to close a ram BOP with the operator pressure required to seal the wellbore (MOPFLPS) and lock the rams. MOPFLPS is not a single number, as environmental conditions can include elevated wellbore pressures at different temperatures; thus the highest MOPFLPS shall be used.

5.10.2 Shear and seal is the process to shear the drill pipe, seal the wellbore, and lock the sealing rams.

Depending on the state of operations, there can be elevated wellbore pressure which affects the operating pressure required; the functional requirements for this process shall be dependent on the equipment used.

a) For a BOP stack that uses a blind shear ram, shear and seal is defined as closing the blind shear rams with the operator pressure required to shear the drill pipe used on the rig that has the highest shear pressure, seal the wellbore, and lock the blind shear rams.

b) For a BOP stack that uses casing shear rams and blind shear rams to shear and seal, shear and seal is defined as closing the casing shear rams with the operator pressure required to shear the drill pipe used on the rig that has the highest shear pressure, closing the blind shear rams on open hole with the operator pressure required to seal the wellbore, and lock the blind shear rams.

c) For a BOP stack that has additional functions to shear and seal the wellbore, those functions shall be included in the shear and seal requirement.

5.11 FMEA and Validation Testing

5.11.1 General

A FMEA shall be provided for each control system design in accordance with IEC 60812 or equivalent national or international standards (including emergency and secondary systems) down to the lowest maintainable subassembly. The FMEA is used to identify and control risk associated with the functionality of the control system. The FMEA shall identify the techniques, tools and their application for risk identification, assessment, and mitigation.

NOTE The FMEA can include consideration of severity, detection methods, and probability of occurrence.

5.11.2 BOP Functionality

The FMEA shall include local, system, and global effects. The global effects shall include the loss of BOP system functionality, as defined in API 53 and the following.

a) For surface stacks:

1) close and seal on the drill pipe, tubing, casing, or liner and allow circulation;

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

3) strip the drill string;

4) shear the drill pipe or tubing and seal the wellbore (for surface stacks with shear rams).

b) For subsea stacks:

1) close and seal on the drill pipe, tubing, and on casing or liner and allow circulation;

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

3) strip the drill string;

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

5) shear the drill pipe or tubing and seal the wellbore;

6) disconnect the riser from the BOP stack;

7) circulate the well after drill pipe disconnect;

8) circulate across the BOP stack to remove trapped gas;

9) Deadman autoshear (DMAS);

10) EDS (if applicable).

The subsea control system shall not include a subsea component single-point failure that results in the inability to operate the BOP system; with the exception of the shuttle valve and associated piping that connects directly to the BOP function port.

5.11.3 Test Requirements

5.11.3.1 A validation test or analysis shall be performed for each control system design.

NOTE A control system design is a primary, secondary or emergency control system of a new design or a redesign using components not previously proven.

5.11.3.2 Testing or analysis shall ensure the following:

a) The results for each non-destructive local, system and global failure mode that have identifiable detection methods (i.e. alarms) operate as specified in the FMEA. The failure modes that warrant actual testing shall be ones that have the potential of causing the control system to fail to perform as required by this specification.

b) The functionality meets requirements set forth in this specification.

c) The capability to meet closing times.

d) The equipment is fit for purpose and suitable for the environment to which it is exposed during transportation, handling, installation and operation.

e) For systems 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 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.

f) If an analysis is used as an alternative to testing, the manufacturer shall provide information based on facts that can be proven through analysis, measurement, observation, and other such means of research that the equipment performs as specified.

5.12 Equipment Design Specifications

5.12.1 Control Circuitry

Surface and subsea control function circuitry shall be designed such that a leak or failure in one circuit shall not cause the unintended operation of another function.

5.12.2 Loss of Rig Power

Loss of any rig power services (electricity, compressed air, etc.) shall not immediately cause the loss of control of the well control equipment; see 5.16.2.

5.12.3 Backup Power

Control stations shall have adequate backup power available as specified in this document; see 5.17.2.

5.12.4 Subsequent Operation on Power Loss

The restoration of power to the control system after a power loss shall not result in the automatic operation of a control system function.

5.12.5 Conformance to Specifications

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.

5.12.6 Purchaser-supplied Information

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

a) the equipment to be operated,

b) service conditions,

c) any application details necessary for the manufacturer to design and build a control system that complies with these specifications.

5.13 Main Pumping System

5.13.1 General

The main pumping system provides power fluid for the main control system hydraulic functions. The main pumping unit is used to provide fluid power for the BOP control system, and may be used to provide fluid power to dedicated accumulator systems.

5.13.2 Power Supply Requirements

The main pumping unit shall be comprised of a minimum of two pump systems with at least two independent power systems.

NOTE 1 A pump system consists of one or more pumps.

NOTE 2 An independent power system is a source of power that is not impaired by any fault which disables the power to the other pump system(s).

NOTE 3 Examples of independent power supplies include the following:

— one pump may be powered from the emergency bus on an all-electric power rig;

— on electric drive rigs, separate electric motors and motor controllers fed from separate buses or from buses that can be isolated by means of a bus tie circuit breaker constitute independent power supplies;

— on rigs utilizing compressed air, 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 bus, or if there is sufficient stored air to meet requirements in 5.13.3.

5.13.3 Output Requirements

The main pumping unit shall be comprised of the following.

— The cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 15 minutes.

— With the loss of one pump system or one power system, the remaining pump system(s) shall have the capacity to charge the main accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 30 minutes.

5.13.4 Pump Isolation Requirements

A supply fluid isolation valve and a discharge valve shall be provided on each pump, these valves shall not affect the operation of other pump(s).

5.13.5 Air Pumps

Air pumps, if used, shall be capable of charging the accumulators to 98 % to 100 % of the system RWP with 75 psi (0.52 MPa) air pressure supply.

5.13.6 Over-pressurization

Each pump system shall be protected from over-pressurization by a minimum of two devices designed to limit the pump discharge pressure as follows:

a) One device shall ensure that the pump discharge pressure does not exceed the system RWP.

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

c) 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.

d) Relief devices on main hydraulic surface supplies shall be automatically resetting. Rupture discs or non-resetting relief valves, or both, can cause the complete loss of pressure control and shall not be used.

5.13.7 Primary Pumps

Primary pumps shall automatically start before system pressure has decreased to 90 % of the system RWP, and automatically stop between 98 % and 100 % of the system RWP.

5.13.8 Secondary Pumps

The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system RWP, and automatically stop between 95 % and 100 % of the system RWP.

NOTE This provides operation similar to the primary pumps, except that the set point to start the secondary pump can be adjusted slightly lower so that both pump systems do not start simultaneously.

5.13.9 Manual Operation

Manual operation of each pump system shall be through the use of a switch or button that is spring reset to the 'OFF' state.

EXAMPLE The pump stops if the manual operation button or switch is let go.

5.13.10 Low-level Shutdown

If a low-level shutdown is installed in any reservoir to shut down the pumps before cavitation can occur, an audible and visual alarm shall indicate the condition at the main system and at least two remote locations.

5.14 Pump Systems for Dedicated Accumulator Systems

5.14.1 General

If the main pumping system is NOT used to provide fluid power to dedicated accumulator systems, the pump systems for dedicated accumulator systems shall be comprised of a minimum of two pump systems with at least two independent power systems.

NOTE 1 A pump system consists of one or more pumps.

NOTE 2 An independent power system is a source of power that is not impaired by any fault which disables the power to the other pump system(s).

NOTE 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.

5.14.2 Output Capacity

The cumulative output capacity of the pump systems shall be sufficient to charge the dedicated accumulator system from precharge pressure to 98 % and 100 % of the system RWP within 60 minutes. With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the dedicated accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 120 minutes.

5.14.3 Primary Pump

The primary pump system shall automatically start before system pressure has decreased to 95 % of the system RWP and automatically stop between 98 % and 100 % of the RWP.

5.14.4 Secondary Pump

The secondary pump system shall automatically start before system pressure has decreased to 90 % of the system RWP and automatically stop between 95 % and 100 % of the system RWP.

5.14.5 Pump Isolation Requirements

A supply fluid isolation valve and a discharge valve shall be provided on each pump, these valves shall not affect the operation of other pump(s).

5.14.6 Air Pump

Air pumps, if used, shall be capable of charging the accumulators to 98 % to 100 % of the system RWP with 75 psi (0.52 MPa) air pressure supply.

5.14.7 Over-pressurization

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

a) One device shall ensure that the pump discharge pressure does not exceed the system RWP.

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

c) 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.

d) Relief devices shall be automatically resetting; rupture discs or non-resetting relief valves, or both, can cause the complete loss of pressure control and shall not be used.

5.14.8 Manual Operation

Manual operation of each pump system shall be through the use of a switch or button that is spring reset to the ‘OFF’ state.

5.14.9 Monitoring

5.14.9.1 The dedicated accumulator pressure shall be capable of being monitored by the main control system and at least two control station locations inclusive of the driller’s station.

5.14.9.2 Dedicated subsea accumulators used with a discrete hydraulic control system do not require monitoring by the main control system.

5.15 BOP Control Valves, Fittings, Lines and Manifolds

5.15.1 Pressure Rating

All valves, fittings, piping, flexible lines, hoses and other pressure retaining components such as pressure switches, transducers, transmitters, etc., shall have a RWP at least equal to the RWP of the circuit in which it is installed.

5.15.2 Piping Systems

Pipe and tubing shall conform to specifications of ASME B31.3 or an equivalent recognized national or international standard.

5.15.3 Accumulator Bottles and Manifolds

5.15.3.1 Accumulators shall meet design requirements of and be documented in accordance with applicable normative references listed in 14.2.3 and 14.8.4.

5.15.3.2 The main accumulator system shall be designed such that the loss of an individual accumulator or bank, or both, does not result in more than 25 % loss of the total accumulator system capacity.

5.15.3.3 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.

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

5.15.3.5 The precharge pressure for bladder type accumulators should be greater than 25 % of the system hydraulic pressure, to reduce the risk of damage to the bladder. Absolute pressures should be used for determining minimum precharge pressure when bladder type accumulators are used subsea (i.e. precharge pressure in psia should be greater than 25 % of system hydraulic pressure in psia).

5.15.3.6 Dedicated accumulator systems may be dedicated to a control system (such as the diverter control system), to an emergency system (such as the DMAS), or to a specific function or functions (such as high-pressure shear rams close, which can be operated by different control systems). The dedicated accumulators shall be sized based on the highest capacity requirement.

5.15.3.7 A non-oxidizing (inert) gas with low flammability, such as nitrogen or helium, shall be used for precharging accumulators. Compressed air or oxygen shall not be used to precharge accumulators. If helium is used, special requirements for containment of helium gas shall be addressed. Among these requirements are leakage past seals, permeability through elastomers, and solubility of gas in operating fluid.

5.15.3.8 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. Operation manuals shall state any requirements for precharge pressures required based on design. The temperature conditions (operating range) shall be specified for surface installations.

5.15.3.9 The OEM shall provide to the buyer the minimum operating pressure, ACR, and the accumulator sizing method to be used for calculating volume-sized accumulator precharge pressures for operation.

5.15.4 Hydraulic Pressure Control Circuits

5.15.4.1 The control system shall be capable of providing the required shear pressure. The required shear pressure shall be provided by the purchaser.

5.15.4.2 An isolation valve with nominal bore size at least equal to the control manifold(s) supply piping size shall be provided for supply of control fluid from an alternate source. This valve shall be supplied with a blind flange (or plug) of the correct size and RWP.

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

5.15.5 Pressure Control Manifold(s)

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

5.15.5.2 The circuit(s) shall be provided with a regulator bypass valve or other means to increase the pressure of the circuit to the maximum RWP of the functions being controlled. The circuit shall be designed so that it cannot exceed the RWP of the functions being controlled. Functions on a regulated circuit shall be grouped such that they are not adversely affected by changes in the regulated pressure.

5.15.5.3 The pressure regulators shall provide regulated pressures through the required range 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.

5.15.5.4 The annular BOP Control manifold 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 annular BOP Control 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.

5.15.6 Hydraulic Control Manifold Valves

The valves shall be installed such that 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.

NOTE 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 function 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 labeled as to function and position.

5.15.7 Relief Valves

5.15.7.1 Relief valves shall be separately tested and adjusted using a low-flow rate, dead-weight tester (or comparable method).

5.15.7.2 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

5.15.7.3 Relief valves shall reseat within 25 % of the set pressure.

5.15.7.4 Relief valves shall additionally be type tested to determine the maximum flow rate through the relief valve without exceeding 133 % of the relief valve’s set pressure.

5.16 Remote Operation

5.16.1 Control Stations—General

5.16.1.1 There shall be at least two control station locations.

5.16.1.2 One control station shall be designed for installation in an area accessible by the drill crew which can include the drill floor, the driller’s cabin, or area specified by the purchaser. For onshore installations, either control station may be the hydraulic manifold.

5.16.1.3 For offshore installations there shall be at least two control station locations in addition to the hydraulic manifold (if installed).

5.16.1.4 Each control station location shall have the following capability:

a) Control the BOP stack functions.

b) Control the diverter functions (if installed).

c) Control the pressure regulation of functions that require variable control pressure. Examples include:

- annular BOPs,
- ram BOPs,
- diverter packer,
- connectors.

d) Monitor all system pressures.

e) Monitor status of all alarms.

5.16.1.5 For subsea applications, the pilot pressure for remotely adjustable regulators shall be adjustable on both the online and offline pod.

5.16.2 Loss of Power

5.16.2.1 The loss of rig power services (electricity, compressed air, etc.) shall not immediately cause the loss of control of the well control equipment.

5.16.2.2 An isolated pilot supply (pneumatic or hydraulic) shall be provided for the remote operation of surface manifold-mounted control valves. Loss of pilot supply shall not affect the manual operation of the control valves.

5.16.2.3 The remote control system shall permit operation of the surface function control valves at least two times after the loss of rig air or electric power (excluding regulator controls), or both.

5.16.3 Layout Requirements

5.16.3.1 When Installed, control station lamps (or other means of visual indication) that are 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 station 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. Amber shall indicate that the function is in its “block” or “vent” position. On functions that have three or more positions, red or green shall be on whenever the “block” or “vent” (amber) indication is on, and thereby indicate the function’s last selected position. Other indicator colors may be used for information display on particular functions such as selection of yellow or blue subsea control pods.

5.16.3.2 The remote control panels shall be designed so that the last position of a blocked or vented function shall not be displayed when restoration from an event causing the panel to go offline or otherwise be compromised could result in an incorrect indication.

5.16.3.3 Control station functionality, excluding the hydraulic regulator controls, shall require a two-handed operation (e.g. the use of an “ENABLE” or “PUSH and HOLD” in addition to the function).

5.16.3.4 Physical arrangement of the control station shall be as a graphic representation of the flow path of the BOP stack or diverter, or both.

5.16.3.5 Each control station shall be capable of displaying the operator positions and pressure read backs for the entire BOP stack and diverter if both the BOP and diverter can be in use simultaneously.

5.16.3.6 Control station panel control devices shall be physically spaced to prevent unintended operations.

5.16.4 Pressure Measurement

5.16.4.1 Mechanical Analog Pressure Measurement

Mechanical analog pressure measurement devices shall be selected in accordance with the following:

a) maximum operating pressure is less than or equal to 75 % of full scale;

b) minimum operating pressure (when used as a test gauge) is greater than or equal to 25 % of full scale;

c) normal operating pressure (when used as a control system gauge) is between 25 % and 75 % of full scale (it is acceptable for a control system gauge to measure below 25 % of full scale when the normal operating pressure range exceeds 50 % of full scale0;

d) full scale is displayed over a minimum span of 120°;

e) meets requirements of ASME B40.100 Grade C or better.

5.16.4.2 Electronic Pressure Measurement

Electronic pressure measurement shall include the following:

a) accuracy within ±2.5 % of the circuit(s) operational range;

b) a maximum display range less than or equal to 133 % of maximum operating pressure for scaled displays. (numeric readouts are not subject to this restriction);

c) resolution within 2.5 % of full scale.

5.16.4.3 Units

5.16.4.3.1 Pressure readings shall be displayed in psi; additional units of measure are optional.

5.16.4.3.2 Units of measurement shall be consistent throughout the control system.

5.16.5 Alarms

5.16.5.1 The alarm circuits or software, or both, should be designed so the frequency of false indication(s) is eliminated or reduced to a minimum level without compromising the ability of the system to provide indication of an abnormal condition to the equipment operators.

5.16.5.2 The normal operation of the system should not activate an alarm.

5.16.5.3 The following summary alarms (where equipment/system is installed) shall have immediate visual indication with an audible alarm when the listed event(s) condition is met:

a) Accumulator pressure LOW:

   1) main accumulator pressure LOW (surface, discrete hydraulic, MUX);

   2) dedicated shear accumulator pressure LOW (surface, MUX);

   3) diverter accumulator pressure LOW (surface, discrete hydraulic, MUX);

b) Pod supply pressure LOW (MUX);

c) Pod pilot supply pressure LOW (MUX);

d) Control manifold pressure LOW (surface, discrete hydraulic);

e) Control manifold pilot pressure LOW (surface, discrete hydraulic);

f) Rig air pressure LOW (surface, discrete hydraulic, MUX);

g) Control fluid level LOW (surface, discrete hydraulic, MUX);

h) Mix system FAILURE (discrete hydraulic, MUX):

   1) lubricant fluid level LOW;

   2) glycol level LOW (if applicable);

   3) rig water supply pressure (or level) LOW.

i) Primary power LOSS/standby power IN USE (surface, discrete hydraulic, MUX);

j) Pump system FAULT (surface, discrete hydraulic, MUX):

   1) pump system electric power LOSS;

   2) pump FAULT.

k) Air purge LOSS (surface, discrete hydraulic, MUX);

l) Control station communication FAULT (surface, discrete hydraulic, MUX);

m) Pod communication FAULT (MUX);

n) Slip joint packer AUTO SEQUENCED (discrete hydraulic, MUX);

o) Diverter FAULT (surface, discrete hydraulic, MUX);

   1) diverter manifold pressure LOW;

   2) diverter packer pressure LOW;

   3) flowline seal pressure LOW.

5.16.6 Readout Requirements

The control station shall be equipped for readout of the following (where equipment/system is installed):

a) Main accumulator pressure (surface, discrete hydraulic, MUX);

b) Diverter accumulator pressure (surface, discrete hydraulic, MUX);

c) Dedicated shear accumulator pressure (surface, MUX);

d) Conduit pressure (discrete hydraulic, MUX);

e) Hotline supply pressure (MUX);

f) Pod supply pressure (MUX);

g) Pod pilot supply pressure (MUX);

h) Control unit manifold pressure (surface, discrete hydraulic);

i) Control unit pilot pressure (surface, discrete hydraulic);

j) Regulator readback pressures (surface, MUX);

k) Regulator pilot pressures (discrete hydraulic, MUX);

l) Rig air supply pressure (surface, discrete hydraulic, MUX);

m) Pump running indication (surface, discrete hydraulic, MUX);

n) Resettable surface flow meter (offshore surface, discrete hydraulic, MUX);

o) Resettable subsea flow meters (MUX);

5.16.7 Safety Requirements

5.16.7.1 A safety cover or other lock-out means (e.g. pop-up controls, mechanical restraint) that does not obstruct visibility of function status, shall be installed to avoid unintended operation of critical functions (where installed) including:

a) connector(s) unlock;

b) shear ram(s) close;

c) emergency disconnect sequence activate;

d) deadman/autoshear arm;

e) deadman/autoshear disarm;

f) stabs retract/unlock;

g) diverter packer close.

5.16.7.2 Noncritical functions shall not have the safety cover or lock-out means described above, to prevent operator complacency.

5.16.7.3 Critical functions shall be clearly identified and have a different look to be easily distinguishable from non-critical functions. The LMRP connector unlatch function and wellhead connector unlatch function shall have a different look from other critical functions.

5.16.8 Failure or Disabling

The design shall be configured such that a failure of or disabling of one of the remote control station(s), remote control station components, or conductor/cable shall not:

a) affect the operation of the other control station,

b) result in erroneous indication, or

c) cause another function to be unintentionally operated.

5.16.9 Touchscreens

5.16.9.1 Touchscreens, displays, keyboards, mouse, etc., may be used as a full control and monitoring station.

5.16.9.2 Subsea MUX installations utilizing touchscreens or displays for a control station shall include multiple touchscreens or displays with independent processors, each touchscreen or display shall be capable of providing the BOP stack and diverter function positions and pressure readbacks.

5.16.10 Cabling

Shipboard cabling design shall allow the cables from the control stations to the cable reels to be routed along separate paths to reduce the possibility of both cables being simultaneously damaged.

5.17 Electrical Equipment

5.17.1 General

5.17.1.1 Electrical displays (lamps, meters, etc.) shall be sufficiently luminous to be readily discernible in all conditions of ambient light in which the device can operate.

5.17.1.2 Electrical enclosures that include lamps that can change state during operations shall include lamp test capability to detect lamp failures. Power available lamps that are normally illuminated are excluded from this requirement.

5.17.1.3 No more than 130V RMS shall be connected to any component mounted in an electrical enclosure face or any component requiring routine adjustment.

5.17.1.4 Electrical enclosures with inputs higher than 130V RMS shall:

a) include a warning sign(s) mounted on the enclosure listing all voltages more than 130 V RMS,

b) require tools to gain access.

5.17.1.5 Electrical equipment and enclosures exposed to the environment shall have defined ingress protection (IP) ratings suitable for the application.

5.17.1.6 Hydraulic lines or components containing hydraulic fluid shall not be mounted inside an electrical enclosure.

5.17.1.7 Electro-pneumatic devices mounted inside enclosures with vent lines shall be:

a) vented to the outside of the enclosure,

a) sized and connected such that the back pressure to other components does not cause any function to be unintentionally operated.

5.17.1.8 Wireless communication devices shall not be used for primary controls or end devices. Wireless communication devices may be used for maintenance, monitoring purposes, and secondary control (e.g. acoustic or additional control stations beyond the minimum stated in this specification). This requirement is not intended to prevent the use of pinless or non-contact connectors.

5.17.2 Electrical Power and Uninterruptable Power Supplies

5.17.2.1 The electrical conductors and electrical insulation shall not be used as load bearing components in the cable assembly.

5.17.2.2 Electrical power shall be supplied from one or more UPS system(s). Each UPS system shall have the backup battery capacity to operate the control system for a minimum of two hours (excluding the pump systems).

5.17.2.3 The electrical power supply to electrical equipment shall automatically switch to an alternate source of electric supply when primary power is interrupted (excluding the pump systems).

5.17.2.4 UPS batteries shall be a maintenance free design and sealed.

5.17.2.5 Subsea MUX control systems shall conform to the following:

a) Include two independent UPS systems.

b) Include two independent electrical umbilical cables. Each electrical umbilical cable shall contain all communications or power conductors, or both, required to control all the subsea functions through one pod. The severing, opening, or shorting of one cable assembly shall not disable the surface equipment and the pod connected to the other cable shall remain functional.

c) Include an equipment design that permits cable routing from the electrical control units to the cable reels along separate paths to reduce the possibility of simultaneous failure of both cables.

d) Be designed such that electrical control functions and electrical power required for running, landing and retrieving of the LMRP or the stack, or a combination thereof, can remain fully active.

5.17.3 Hazardous Area Electrical Equipment

5.17.3.1 General

5.17.3.1.1 The purchaser shall specify the hazardous area classification required for electrical equipment in accordance with API 500, API 505, IEC 60079-10-1 or equivalent recognized international standard.

5.17.3.1.2 Hazardous area electrical enclosures shall be certified by a national testing laboratory or notified body as suitable per the purchaser defined hazardous area classification.

5.17.3.1.3 Electrical assemblies and electrical equipment shall be suitable per the purchaser-defined hazardous area classification. The contractual requirements shall define the type of certification required, and the equipment manufacturer is to meet the contractual requirements and those of the authority having jurisdiction.

5.17.3.2 Air Purge Air Systems

5.17.3.2.1 Air purge systems shall only be used to increase the protection of a panel from Class 1 Division 2 to Class 1 Division 1 or from Zone 2 to Zone 1.

5.17.3.2.2 If an air purge system is used, the following apply:

— it shall be manufactured in accordance with NFPA 496, or IEC 60079-2 or another recognized international standard;

— a loss of air purge shall activate an alarm at the affected panel and at least two other control stations;

— a loss of purge shall not cause loss of functionality at any panel.

5.17.3.3 Subsystem Components

5.17.3.3.1 Subsystems (e.g. control stations, HPU, diverter control system, uninterruptable power supplies, hose reels) shall be factory acceptance tested for conformance with these specifications.

5.17.3.3.2 When a subsystem is to be integrated with other equipment which is not supplied by the integrator, 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. Subsystems shall not be marked until after factory testing ensures conformance to these specifications.

5.18 Control System Software

5.18.1 General

The BOP control system software design and development process shall ensure:

— Design verification (e.g. test procedures) is related back to requirements providing evidence that design requirements have been met by the verification process.

— The process that is used for all software development activities whenever appropriate.

— The process is recorded with appropriate revision control providing historical archiving.

— Implementation that does not require unique or previous knowledge, or both (e.g. process is flexible to prevent continual process changes for each design and development).

5.18.2 Software Lifecycle Process

A software lifecycle process shall be documented and utilized for developing software or modifying software. The manufacturer may have multiple software lifecycle processes. Changes to the software lifecycle process shall be documented with revision controls. The software lifecycle process shall include the following:

— software functional specification (see 5.18.3)

— software design and development (see 5.18.4)

— software design validation and software design verification (see 5.18.5)

— software production and maintenance (see 5.18.6)

5.18.3 Software Functional Specification

5.18.3.1 A software functional specification shall be created that details the operational system requirements and includes the necessary information required to address the following (as applicable):

a) user interface (e.g. Human Machine Interface—HMI);

b) redundancy;

c) timing:

- — system software boot up or initialization time;
- — software response time from operator initiation to acknowledgment displayed to operator;
- — recovery time for component/component processes to complete re-initialization;
- — hot standby failover time (if installed);
- — EDS timing;
- — alarm activation delays.

d) sequencing;

e) automation;

f) interlocks;

g) alarm management;

h) error management;

i) event logging and historical archiving;

j) initialization;

k) external interface(s);

l) operator configuration capabilities.

5.18.3.2 The functional specifications shall include additional requirements from the user/purchaser and shall be documented.

5.18.3.3 A technical specification of software capabilities that satisfies the functional specification requirements shall be created and documented. The technical specification should be reviewed with the user/purchaser when applicable.

5.18.3.4 A software functional specification review shall be conducted and include personnel responsible for the system level (e.g. electrical, hydraulic, mechanical) design.

5.18.4 Software Design and Development

5.18.4.1 A software design review(s) shall be conducted and should include personnel responsible for the system level (e.g. electrical, hydraulic, mechanical) design. Software design reviews may be conducted at preliminary, critical and final design stages.

5.18.4.2 Software design architecture drawings shall be included in the design review that identify the hardware/ software interfaces, dependencies, and processes to include the following:

— software topology;

— logic flow diagrams or function block specifications;

— external interfaces.

5.18.4.3 A software FMEA shall be performed down to the Software Unit level.

— The software FMEA shall include local, system and global effects. If the software is a modification of an existing design, a gap analysis of the software can be conducted in order to establish a new FMEA for that design.

— The global effects shall include:

  — loss of ability to secure the well;

  — loss of ability to disconnect from the well;

  — loss of ability to operate the diverter;

  — loss of sequencing, timing, or interlock capability;

  — loss of alarm capability;

  — loss of logging capability.

5.18.4.4 Software development shall use a documented coding standard. The coding standard can be internally or externally produced.

5.18.4.5 A software code review(s) shall be conducted and include other competent software personnel with ability to understand the software changes and its potential impacts.

5.18.4.6 The software build procedure shall be documented (e.g. build tools to be used, revision control process, etc.).

5.18.4.7 The software build results using the software build procedure (e.g. which build tool used, components built, warnings, errors, etc.) shall be documented for future troubleshooting, if needed.

5.18.5 Software Validation and Verification

5.18.5.1 Software validation and verification shall be performed for the BOP control system software to ensure:

a) local, system, and global effects test results are as identified in the software FMEA,

b) functionality meets requirements set forth in the software functional specification.

5.18.5.2 All software specifications/requirements shall have a corresponding validation test. A single software validation test can satisfy multiple software specifications/requirements.

5.18.5.3 Individual software component level testing, also referred to as unit level testing, shall be conducted on software modules that can be tested independent of other software modules.

5.18.5.4 Single unit functionality (inputs vs outputs) shall be tested (black box testing).

5.18.5.5 Every line of code and logic path should be tested (white box testing).

5.18.5.6 Software integration level testing shall be conducted on individual software modules combined as a whole.

5.18.5.7 Testing shall be conducted with the actual control system hardware or equivalent.

5.18.5.8 If the Software FMEA indicates a network storm test should be included, software testing shall be conducted.

5.18.6 Software Production and Maintenance

5.18.6.1 Proposed modifications to existing software shall be reviewed to identify software processes/modules impacted and the level of regression testing required.

5.18.6.2 The software lifecycle processes shall be applied to the change as determined by the control system manufacturer.

5.18.6.3 The software code review as specified in the software design and development process shall be conducted for software changes.

5.18.6.4 The software documentation shall be updated as required to reflect software changes. A configuration management plan shall be followed for software development.

5.18.6.5 Software changes shall be revision controlled and shall document the following:

a) date and time of the software change;

b) reason for the software change;

c) description of differences between revisions (e.g. a detailed description of the code differences between revisions);

d) unique identification;

e) person conducting change.

5.18.6.6 A copy of the software and source code shall be archived to an offsite location to ensure that a secure backup copy is maintained.

5.18.6.7 A software security analysis shall be conducted and made available to the customer that includes:

— a documented risk assessment (e.g. external connections, internet accessibility, removable storage media access, etc.);

— security guidelines to mitigate risks identified by the risk assessment;

— authorized user access control.

5.18.6.8 An obsolescence management plan shall be created. Software should not depend on unsupported or obsolete platforms (e.g. hardware, operating system, third party software, etc.) for operation.

6 Control Systems for Land and Surface BOP Stacks

6.1 General

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 the following:

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.

6.2 Response Time

6.2.1 The control system for a surface BOP stack shall be designed to deliver power fluid at sufficient volume and pressure to operate selected functions within the allowable response times.

6.2.2 Measurement of closing response time begins when the close function is activated, at any control panel, and ends when the BOP or valve is closed affecting a seal. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting.

6.2.3 For surface installations, the BOP control system shall be capable of the following:

a) closing each ram BOP in 30 seconds or less;

b) closing each shear ram in 30 seconds or less;

c) closing each annular BOP in 30 seconds or less for annular preventers smaller than 18 $^3/_4$ in. nominal bore or 45 seconds or less for annular preventers of 18 $^3/_4$ in. nominal bore and larger;

d) a response time for choke and kill valves (either open or close) that shall not exceed the minimum observed ram close response time. If multiple circuits are provided for operation of the above functions (for example regulated and high pressure) each circuit shall be capable of meeting the response time.

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

6.3 Pump Systems

6.3.1 The main pump system shall meet the requirements listed in 5.13.

6.3.2 The dedicated pump system, if installed, shall meet the requirements listed in 5.14.

6.4 Accumulator Bottles and Manifolds

Accumulators shall conform with 5.15.3.

6.5 Accumulator Capacity Requirements for Surface BOP Stacks

6.5.1 Main Accumulator System

6.5.1.1 General

The BOP control system's main accumulator system shall meet the ACR as listed below. The ACR shall be met with pumps inoperative. Accumulator sizing calculations shall follow requirements outlined in Annex B.

6.5.1.2 Surface Stacks without Shear Rams

For surface stacks that do not have shear rams, the ACR (with same precharge pressure) shall be the greater of the following:

a) Provide the power fluid volume and pressure required to perform the accumulator drawdown test as defined in API 53. The accumulator capacity required for this test correlates with the results obtained using calculation Method B.

b) Provide the power fluid volume and pressure required to close the following in functions in sequence;

   1) close the annular (largest by operator volume);

   2) close the pipe ram.

   This is a quick discharge event and the accumulator sizing calculations shall be performed using Annex B, calculated with the beginning pressure at the pump start pressure.

6.5.1.3 Surface Stacks with Shear Rams without Shear Accumulators

For surface stacks that have shear rams, but do not have dedicated shear accumulators, the ACR (with same precharge pressure) shall be the greater of the following:

a) Provide the power fluid volume and pressure required to perform the accumulator drawdown test as defined in API 53. The accumulator capacity required for this test correlates with the results obtained using calculation Method B.

b) Provide the power fluid volume and pressure required to operate the following functions, in sequence:

1) Close the annular (largest by operator volume);

2) Shear and Seal (as defined in 5.10).

This is a quick discharge event and the accumulator sizing calculations shall be performed using Method C, calculated with the beginning pressure at the pump start pressure.

6.5.1.4 Surface Stacks with Shear Rams with Shear Accumulators

For surface stacks that have shear rams with dedicated shear accumulators, the ACR (with same precharge pressure) shall be the greater of the following:

a) Provide the power fluid volume and pressure required to perform the accumulator drawdown test as defined in API 53. The accumulator pressure after the API 53 drawdown test shall equal or exceed the required MOP. The accumulator capacity required for this test correlates with the results obtained using calculation Method B.

b) Provide the power fluid volume and pressure required to close the annular (largest by operator volume).

This is a quick discharge event and the accumulator capacity calculations shall use Method C, calculated with the beginning pressure at the pump start pressure.

6.5.2 Dedicated Shear Accumulator

The dedicated shear accumulators shall meet the pressure and volume requirements to ensure that a shear and seal is obtained (as defined in 5.10). This is a quick discharge event and the accumulator capacity calculations shall use Method C. The beginning pressure used in the calculation shall be:

— the pump stop pressure for systems supplied by the main accumulator system.

— the pump start pressure for dedicated accumulators that are not supplied by the main accumulator system.

6.6 Annular BOP Control Manifold

Direct manual valve and regulator operability shall permit closing the annular BOP or maintaining the set regulated pressure, or both, in the event of loss of the remote control capability.

6.7 Pilot System Accumulator Requirements

6.7.1 If the BOP control system uses hydraulic pilot fluid (this includes pilot systems for remote operation of the control manifold), the accumulator requirements are as follows:

a) the minimum ACR of the pilot accumulator system shall be a minimum of two hundred percent (200 %) of the pilot operating volume at the minimum pilot pressure required to function close all of the BOPs in the BOP stack.

b) the pilot accumulator system shall have a minimum of two accumulator bottles; the loss of any one bottle shall not cause a loss of more than 100 % of the ACR.

c) the sizing calculations shall be performed in accordance with Method B.

d) Precharge pressure for the pilot accumulator 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.

6.7.2 The pilot accumulator system shall be a dedicated accumulator system, isolated from its hydraulic power fluid supply by a check valve. It shall be charged by a dedicated pump or by the main hydraulic supply. If it is charged by a dedicated pump, the main accumulator system shall be available as a selectable backup power source.

7 Control Systems for Subsea BOP Stacks

7.1 Response Time

7.1.1 The subsea control system shall be capable of meeting the following response times:

a) close each ram BOP in 45 seconds or less;

b) close each shear ram in 45 seconds or less;

c) close each annular BOP in 60 seconds or less;

d) unlatch the riser (LMRP) connector in 45 seconds or less;

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

7.1.2 If multiple circuits are provided for operation of the above functions (for example regulated and high pressure) each circuit shall be capable of meeting the response time.

7.1.3 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 initially recovered to its nominal setting or other demonstrated means.

7.1.4 Conformance with response time specifications shall be demonstrated by physical testing with the BOP stack. If it is not possible to test with the BOP stack, testing with similar equipment to verify functional operations is acceptable.

7.2 Subsea Control Pods

7.2.1 General

7.2.1.1 A minimum of two control pods shall be provided, affording redundant control of all subsea functions.

7.2.1.2 Isolation means shall be provided so that if one control pod is disabled, the other control pod and all subsea functions shall remain operable. The disabled pod shall not affect the operation of the other pod/manifold or of the subsea functions.

7.2.1.3 Each control pod shall be capable of the response time requirements specified in 7.1.

7.2.1.4 There shall be two or more means of surface to subsea power fluid supply (e.g. hydraulic conduits, hydraulic umbilical hoses) as follows:

a) at least two power fluid supplies shall satisfy the response time requirements specified in 7.1;

b) at least two (or more) power fluid supplies shall be selectable from each control station.

7.2.1.5 An umbilical (or cable) shall have a strain relief or radius guard at the interface with the control pod or LMRP, or both, to prevent the umbilical (or cable) from being subjected to a bend radius less than the umbilical (or cable) manufacturer's minimum recommended bend radius.

7.2.1.6 The subsea pressure regulators in each pod shall provide regulated pressures through the required range of the designated function(s).

7.2.1.7 Subsea pressure regulators shall maintain set regulated pressure in the event of loss of the remote control capability.

7.2.1.8 The valves and regulators shall be sized to supply the volume required to operate each function within its specified response time.

7.2.1.9 The control pods shall be easily discernible by subsea cameras (color-coded, by location, or otherwise distinguished).

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

7.2.1.11 Stack mounted control valves used to close preventers may be used within the main control system, but there shall be a separate valve for each pod (i.e. there shall not be a single valve with a Blue pilot and a Yellow pilot; there shall be a valve piloted by the 'Blue pod' and a separate valve piloted by the 'Yellow pod', to eliminate the single point failure).

7.2.1.12 Control pods may be retrievable. In such a case, Electro-hydraulic and MUX systems shall use suitable electrical connectors to ensure the integrity of the power supply, signal command and readback circuits through disconnect and reconnect of the pod.

7.2.2 Pressure Regulation for Shear Rams

7.2.2.1 The control system shall supply high-pressure power fluid to close the shear rams, in accordance with BOP manufacturer's recommendations for shearing pipe. This is typically the maximum rated working pressure of the operator.

7.2.2.2 A lower-pressure regulated hydraulic supply may be provided for shear ram closure for pressure testing.

7.2.2.3 The higher and lower pressures may be supplied by adjusting the regulated pressure setting for the shear rams using a subsea regulator but shall not over pressurize other functions.

7.3 Hydraulic Fluid Supply

7.3.1 Accumulators and Manifolds

7.3.1.1 Accumulators and manifolds for hydraulic control systems for subsea BOP stacks shall meet the requirements of 5.15.3.

7.3.1.2 Accumulators mounted subsea shall have a subsea-mounted, surface-controlled valve to charge the accumulators.

7.3.1.3 Accumulators mounted subsea shall have a check valve 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.

7.3.1.4 The OEM shall provide the information needed so that the precharge pressures can be calculated for various water depths.

7.3.1.5 LMRP accumulators may be used to supplement the main hydraulic supply for subsea BOP stacks, but are not specifically required.

7.3.1.6 Dedicated stack mounted accumulators are required for the emergency control systems; additional stack mounted accumulators may be used, but are not specifically required.

7.3.1.7 All dedicated subsea accumulator systems shall have a means to prevent over pressurization during BOP retrieval (pulling of an inoperable control system).

7.3.1.8 All dedicated subsea accumulator systems shall have a ROV readable, isolatable pressure gauge. MUX control systems shall also have a pressure readback of the dedicated subsea accumulator systems.

7.3.2 Pump Systems

7.3.2.1 The main pump system shall meet the requirements listed in 5.13.

7.3.2.2 The dedicated pump system, if used, shall meet the requirements listed in 5.14.

7.3.3 Accumulator Capacity Requirements for Subsea Control Systems

7.3.3.1 General

The BOP control system's main accumulator system shall meet the ACR as listed below. The ACR shall be met with pumps inoperative. Accumulator sizing calculations shall follow requirements outlined in Appendix B.

7.3.3.2 Without Shear Accumulators

For main control systems that do not use the subsea dedicated shear accumulators for high pressure shear ram closure, the ACR (with the same precharge pressure) shall be the greater of the following:

a) The power fluid volume and pressure required to perform the accumulator drawdown test as defined in API 53. The accumulator capacity required for this test correlates with the results obtained using calculation Method B.

b) The power fluid volume and pressure required to operate the following functions, in sequence:

   1) close the annular (largest by operator volume);

   2) close a pipe ram;

   3) shear and seal.

   The accumulator sizing calculations shall be performed using Method C, calculated with the beginning pressure at the pump start pressure.

c) Provide the power fluid volume required to perform an EDS (if installed). If the control system has more than one EDS mode, the EDS that requires the greatest accumulator capacity shall be used.

   This is a quick discharge event and the accumulator sizing calculations shall be performed using Method C, calculated with the beginning pressure at the pump start pressure.

7.3.3.3 With Shear Accumulators

For subsea stacks that have shear rams with dedicated shear accumulators, the ACR (with the same precharge pressure) shall be sized to meet the following requirements:

a) Provide the power fluid volume and pressure required to perform the accumulator drawdown test as defined in API 53. The accumulator pressure after the API 53 drawdown test shall equal or exceed the required MOP. The accumulator capacity required for this test correlates with the results obtained using calculation Method B.

b) Provide the power fluid volume and pressure required to operate the following functions: 1) Close the annular (largest by operator volume); and 2) Close a pipe ram. The accumulator capacity calculations shall use Method C, calculated with the beginning pressure at the pump start pressure.

c) Provide the power fluid volume required to perform an EDS (if installed). If the control system has more than one EDS mode, the EDS that requires the greatest accumulator capacity shall be used. This is a quick discharge event and the accumulator sizing calculations shall be performed using Method C, calculated with the beginning pressure at the pump start pressure.

7.3.3.4 Dedicated Shear Accumulators

The dedicated shear accumulators shall meet the pressure and volume requirements to ensure that a shear and seal is obtained (as defined in 5.10). This is a quick discharge event and the accumulator capacity calculations shall use Method C. The beginning pressure used for the calculations shall be:

— the pump stop pressure for dedicated accumulators that are supplied by the main accumulator system; or

— the pump start pressure for dedicated accumulators that are not supplied by the main accumulator system.

7.3.4 Accumulator Requirements for Dedicated Close Assist Systems

7.3.4.1 A single accumulator may be used for more than one valve of a close assist accumulator system, but a single accumulator shall not be used for the close assist of two valves on the same outlet. For example, a single accumulator shall not be used for the close assist circuit of the lower inner kill valve and the lower outer kill valve.

7.3.4.2 The minimum ACR of each close assist accumulator system shall be the volume and pressure required to close all the valves connected to that close assist accumulator system. Calculations shall be performed in accordance with Method C; starting pressure shall be the hydraulic charge pressure of the dedicated close assist accumulator system.

7.3.5 Pilot System Accumulator Requirements

7.3.5.1 If the BOP control system uses hydraulic pilot fluid (this includes pilot systems for remote operation of the control manifold), the accumulator requirements are as follows:

a) The pilot accumulator ACR shall be sized to supply the greater of the following:

  — two hundred percent (200 %) of the pilot operating volume at the minimum pilot pressure required to function close and open all the BOPs in the BOP stack;

  — for rigs that do have an EDS, two hundred percent (200 %) of the pilot operating volume at the minimum pilot pressure required to function the EDS requiring the most pilot volume.

b) The pilot accumulator system shall have a minimum of two accumulator bottles; the loss of any one bottle shall not cause a loss of more than 100 % of the ACR.

c) The sizing calculations shall be performed in accordance with Method B.

d) Precharge pressure for the pilot accumulator system shall be no lower than the minimum required pilot pressure. The minimum pilot pressure shall be the greater of the following:

— pressure required to function any pilot operated control valve installed in the control manifold at its system rated working pressure.

— pressure required to pilot any pilot operated regulator installed in the control manifold to the minimum safe operating pressure as determined by the OEM and the BOPs to be controlled.

7.3.5.2 The pilot accumulator system shall be a dedicated accumulator system, isolated from its hydraulic power fluid supply by a check valve. It shall be charged by a dedicated pump or by the main hydraulic supply. If it is charged by a dedicated pump, the main accumulator system shall be available as a selectable backup power source.

7.4 Discrete Hydraulic Control Systems

7.4.1 Control Manifold

7.4.1.1 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.

7.4.1.2 Each valve, regulator, and gauge shall be clearly labeled to indicate its function.

7.4.1.3 Each control valve shall indicate its position status.

7.4.1.4 The control manifold shall operate surface-controlled functions, such as the telescopic joint packer, diverter, tension ring, and/or gas handler (if equipped) if these functions are not included in the diverter controls. This subsystem shall employ return-to-reservoir hydraulics. Control manifolds that operate surface-controlled functions (are not included in the diverter controls, such as an overboard valve, diverter, tension ring, or gas handler, or a combination thereof), shall meet the requirements of this specification. These functions can be included on the BOP control system manifold or on separate manifolds. This subsystem shall employ return-to-reservoir hydraulics.

7.4.1.5 The control manifold shall be equipped with a flow meter which measures the volume of flow from the surface-control system that is supplied subsea.

7.4.2 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 for manual intervention and control of the surface regulators at the control manifold.

7.4.3 Hose Reels and Hose Handling Equipment

7.4.3.1 Hose reels are used to store, run, and retrieve the umbilical hose bundles that communicate the main hydraulic power fluid supply and command pilot signals to the subsea mounted BOP control pods.

7.4.3.2 The hose reel assembly shall be prepared and coated to withstand direct exposure to saltwater spray.

7.4.3.3 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.

7.4.3.4 At least two 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.

7.4.3.5 The hose reel shall have pay-out and take-up controls located on the reel; remote controls are optional. If a remote control station is used, the local control shall be capable of locking out the remote controls. If a remote control station is used for more than one reel, the controls shall be clearly marked for which reel they control.

7.4.4 Hose Reel Drum

7.4.4.1 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.

7.4.4.2 The hose reel drum shall be equipped with a brake capable of overriding and stalling the motor.

7.4.4.3 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.

7.4.5 Hose Reel Drive

7.4.5.1 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.

7.4.5.2 The design shall include the fluid weight inside the hose and the effect of buoyancy on any submerged section.

7.4.6 Brakes and Locking Mechanism

7.4.6.1 The hose reel brake shall have sufficient capacity to stall the hose reel at full drive motor torque output.

7.4.6.2 A mechanical locking mechanism shall be available to lock the drum in position.

7.4.6.3 The reel drive mechanism shall be fitted with safety guards to prevent accidental injury to personnel.

7.4.7 Hose Sheaves

7.4.7.1 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.

7.4.7.2 Sheaves shall be designed to 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 times the calculated force required to overcome the rated braking capacity of the reel at the minor wrap diameter of the drum;

b) two times the calculated force required to overcome the maximum motor torque output at the minor wrap diameter of the drum.

7.4.7.3 Sheaves shall be designed for safety slings; the safety sling attachment point shall have the same load capacity as the sheave; the safety sling attachment point shall be different than the primary attachment point.

7.4.7.4 Each sheave assembly shall be qualification tested to 1.5 times the safe working load and meet design acceptance criteria.

7.4.7.5 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.

7.4.8 Hose Reel Manifold

7.4.8.1 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 or the BOP stack, or a combination thereof.

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

7.4.9 Automatic Data Logging

Software controlled discrete hydraulic control systems shall be equipped with automatic data logging as specified in 7.5.3.

7.5 Multiplex Control Systems

7.5.1 Subsea Electrical Equipment

7.5.1.1 Subsea electrical power shall be provided with overcurrent protection (to minimize fault migration).

7.5.1.2 Electrical equipment used subsea is to be temperature rated to be fully operational on a continuous basis while exposed to both subsea ambient and surface ambient conditions for which they were designed.

7.5.1.3 There shall be temperature alarms for the main control system subsea one atmosphere housing(s). Temperature alarms for subsea one atmosphere chambers shall be set to ensure the operational temperature range of the components is not exceeded.

7.5.1.4 Subsea one atmosphere electrical housings shall have sensors that trigger alarms if the components can be damaged by high humidity.

7.5.1.5 Subsea one atmosphere electrical housings shall have sensors that trigger alarms if there is any ingress of fluid, whether control fluid, saltwater, or dielectric fluid.

7.5.1.6 Electrical equipment should not be mounted in those areas of the subsea one atmosphere housing where water initially collects given minor ingress.

7.5.1.7 Plug-in devices shall be mechanically secured.

7.5.1.8 Non-pressure compensated and partially pressure compensated electrical and electronic chambers shall be double sealed at all areas exposed to seawater or hydrostatic pressure and shall have a provision for a test port. Each test port shall include at least one seal and be designed to allow pressure testing to verify seal integrity. A chamber that is pressure compensated to the ambient pressure surrounding the stack may be sealed using a single seal.

7.5.2 Auxiliary Subsea Electronics

7.5.2.1 Auxiliary equipment supports drilling operations, but is not required for the operation of the BOP Control System.

7.5.2.2 The transmission of auxiliary equipment data and power may be through independent conductors in the subsea electronic umbilical or may be integrated into the BOP Control System.

7.5.2.3 When integrated as part of the BOP Control System, auxiliary equipment shall be integrated in such a manner to avoid disabling the BOP control system in the event of a failure in the auxiliary equipment.

7.5.2.4 Typical auxiliary functions 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.

7.5.3 Automatic Data Logging

7.5.3.1 Automated data logging functionality shall be provided that logs or records with a time and date stamp; all operator initiated commands, changes of function states (both operator initiated and non-operator initiated) for all HPU, diverter, and subsea functions, regulated pressures (manifold, annular, wellhead and LMRP connectors), accumulator pressures, wellbore pressures and temperatures (if equipped), and all changes of alarm states such that both the alarm generation and alarm mitigation are logged or recorded.

7.5.3.2 All high-volume analog data such as pressures and temperatures shall be recorded at a resolution to prevent premature over utilization of the data logger's local storage media.

7.5.3.3 The data logging system shall provide at a minimum, three separate local storage media utilization alarms as follows:

a) When local storage media utilization exceeds 50 %;

b) When local storage media utilization exceeds 75 %;

c) When local storage media utilization has been completely (100 %) utilized creating potential loss of locally stored data that have not been externally archived.

7.5.3.4 The data logger system shall provide for one calendar year of local storage in accordance with the manufacturer's defined normal operating conditions.

7.5.3.5 The data logger system shall provide the ability for an operator to retrieve locally stored data as a means to help facilitate trouble shooting exercises.

7.5.3.6 If the data logger's local storage media capacity is reached, the system shall overwrite the oldest data present on the local storage media to prevent loss of current data.

7.5.3.7 The data logger system shall provide the ability to manually or automatically archive data to an external device or remote location. The externally archived data shall be stored in accordance with API 53.

7.5.4 Subsea Electrical Power and Signal Distribution Cables

7.5.4.1 Umbilical cables shall be designed to avoid kinking and twisting.

7.5.4.2 The umbilical 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.

7.5.4.3 The umbilical electrical conductors and electrical insulation shall not be used as load bearing components in the umbilical cable assembly.

7.5.4.4 Each umbilical cable shall contain all communications or power conductors required to control all the subsea functions through one pod.

7.5.4.5 The severing, opening, or shorting of one umbilical assembly should not disable the surface equipment and at least one pod shall remain fully functional.

7.5.5 Subsea Electrical Cables

7.5.5.1 Subsea electrical connections that are not pressure compensated shall have pressure test ports to verify the seal integrity of mated plug-receptacles. These ports shall be capable of being plugged and sealed when not in use for testing.

7.5.5.2 Subsea electrical connectors that can remain powered after disconnection shall have contacts protected to prevent exposure.

7.5.5.3 Subsea electrical 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.

7.5.6 Cable Reels and Cable Handling Equipment

7.5.6.1 Cable reels are used to store, run, and retrieve the cable, which communicate from the surface to the subsea BOP control pods.

7.5.6.2 The cable reel assembly shall be prepared and coated to withstand direct exposure to salt water spray.

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

7.5.6.4 At least two independent cable reels shall be provided. Each reel shall be clearly identified as to the subsea control pod to which it is connected (e.g. color coded yellow and blue).

7.5.6.5 The cable reel shall have pay-out and take up controls located on the reel; remote controls are optional. If a remote control station is used, the local control shall be capable of overriding the remote controls. If a remote control station is used for more than one reel, the controls shall be clearly marked for which reel they control.

7.5.7 Cable Reel Drum

7.5.7.1 The cable 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.

7.5.7.2 The cable reel drum shall be equipped with a brake capable of overriding and stalling the motor.

7.5.8 Cable Reel Drive

7.5.8.1 The cable 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 cable.

7.5.8.2 The design shall include the effect of buoyancy on any submerged section.

7.5.9 Brakes and Locking Mechanism

7.5.9.1 The cable reel brake shall have sufficient capacity to stall the cable reel at full drive motor torque output.

7.5.9.2 A mechanical locking mechanism shall be available to lock the drum in position.

7.5.9.3 The reel drive mechanism shall be fitted with safety guards to prevent accidental injury to personnel.

7.5.10 Cable Reel Electrical Components—Slip Rings

7.5.10.1 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.

7.5.10.2 If slip rings are to be located in a hazardous area, the design shall be certified as suitable for use in the hazardous location.

7.5.11 Cable Sheaves

7.5.11.1 Cable sheaves facilitate running and retrieving the subsea umbilical from the cable 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.

7.5.11.2 Sheaves shall be designed to prohibit damage to the cable 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.

7.5.11.3 Sheaves shall be designed for safety slings; the safety sling attachment point shall have the same load capacity as the sheave; the safety sling attachment point shall be different than the primary attachment point.

7.5.11.4 Each sheave assembly shall be qualification tested to 1.5 times the safe working load and meet design acceptance criteria.

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

8 Emergency Control Systems

8.1 General

8.1.1 Autoshear and deadman systems are safety systems that are designed to automatically secure the wellbore during unplanned emergency events and shall use a dedicated subsea accumulator system.

8.1.2 Control systems for subsea stacks that have an LMRP shall have an autoshear system.

8.1.3 Control systems for subsea stacks that are installed on a floating rig shall have a Deadman system.

8.1.4 The autoshear system and the deadman system shall be manually armed and disarmed.

8.1.5 A single emergency control system may incorporate both the autoshear and the deadman features (DMAS). In some installations, the deadman system (when conditions are met) activates the autoshear system.

8.1.6 The deadman arm valve and autoshear arm valve should have a pressure readback and shall have a ROV readable pressure gauge to verify the system arm valve is opened to the trigger mechanism.

8.2 Autoshear Systems

8.2.1 The autoshear system is a safety system that is designed to automatically shear and seal securing the wellbore in the event of a disconnect of the LMRP.

8.2.2 The autoshear system is a “rapid discharge” system; accumulator calculations shall use Method C.

8.2.3 The autoshear system response time to secure the well shall be 90 seconds or less.

8.3 Deadman Systems

8.3.1 A deadman system is designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply to and control of the main control system’s subsea control pods.

8.3.2 The deadman system is a “rapid discharge” system; accumulator calculations shall use Method C.

8.3.3 The deadman system response time to secure the well shall be 90 seconds or less.

8.4 Battery Powered Emergency System Requirements

8.4.1 Battery powered emergency systems shall have a monitoring system that monitors the subsea electrical power source.

8.4.2 MUX systems shall have an alarm prior to when the subsea power source is not capable of operating the emergency control system.

8.4.3 Discrete systems shall have a means for ROV verification of the subsea power source.

8.5 Emergency Disconnect Sequence (EDS)

8.5.1 An EDS shall be provided for all dynamically positioned drilling rigs; an EDS is optional for a moored rig.

8.5.2 The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack. The number of sequences, timing, and functions of the EDS are specific to the rig, equipment, and location.

8.5.3 The EDS response time shall be 90 seconds or less. The 90 seconds begins when the EDS button is depressed by the user and ends when the LMRP connector is physically released.

8.5.4 A means to actuate the EDS shall be provided from the drill floor and at least one additional non-hazardous area location, such as the toolpusher's panel.

8.5.5 The EDS shall be defined by an auditable document.

9 Secondary Control Systems

9.1 General

9.1.1 A secondary control system is employed in the event the main control system is not functional. Examples of secondary control systems for subsea BOP stacks are ROV intervention control systems and acoustic control systems.

9.1.2 Secondary control systems shall, as a minimum, be capable of operating critical functions. The critical functions are:

a) each shear ram—close,

b) at least one pipe ram—close,

c) ram locks—lock,

d) LMRP connector—unlatch.

9.1.3 The secondary control functions shall be connected to the stack functions by way of shuttle valves (or similar means) to allow secondary control operation of the stack without affecting operability from the main control system.

9.2 ROV Intervention

9.2.1 All subsea BOP stacks shall be equipped with ROV intervention equipment. All ROV stab ports for critical functions (per API 53) shall be fitted with docking receptacles designed in accordance with API 17H. If multiple ROV receptacle types are used, the receptacle types shall be identified. ROV connections shall be locking type to prevent disengaging the connection by pressure reaction forces.

9.2.2 The ROV intervention circuits for critical functions shall meet the same response times as the main control system (see 7.1). Unless it is known that the ROV can meet the power fluid requirements (flow rate and pressure), the ROV shall have access to an accumulator system for the hydraulic power supply in order to meet the response time requirements for critical functions.

NOTE Hydraulic fluid can be supplied by the ROV, stack mounted accumulators (which can be the dedicated shear accumulators), or an external hydraulic power source, such as a SAM (subsea accumulator module).

9.2.3 The ROV accessible accumulator system shall:

a) have an ROV Accumulator Charge port

b) meet the ACR for the ROV critical function with the greatest pressure and volume requirement

c) meet the requirements of 5.15.3.

9.2.4 ROV functions shall be located on a panel mounted to the LMRP or BOP stack in an accessible location; the functions shall be clearly labeled.

NOTE 1 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators (which can be the dedicated shear accumulators), or an external hydraulic power source, such as a SAM (subsea accumulator module).

NOTE 2 Additional ROV functional requirements can be specified by the purchaser.

9.3 Acoustic Control Systems

9.3.1 General

9.3.1.1 An acoustic control system is an optional secondary control system for subsea BOP stacks. The acoustic control system includes a surface electronics package, subsea electronic package and a subsea electro-hydraulic package.

9.3.1.2 The acoustic system shall be designed to meet the testing criteria specified in API 53.

9.3.1.3 The acoustic functions shall be connected to the stack functions by way of shuttle valves (or similar means) to allow acoustic operation of the stack without affecting operability from the main control system.

9.3.2 Acoustic System Accumulator Requirements

9.3.2.1 The acoustic system should have the capability to read and report the subsea accumulator hydraulic pressure.

9.3.2.2 The acoustic accumulator system(s) shall be capable of the greater (by accumulator capacity) of the following operation sequences (note that these operations can include the requirement to shear and seal):

a) operate all critical functions utilizing Method B;

b) operate all functions of the acoustic EDS (in sequence, if installed) utilizing Method C.

9.3.2.3 The acoustic system may achieve the shear and seal function by acoustic operation of the shear functions, which are supplied from a separate dedicated accumulator system. This is considered a shared accumulator system.

9.3.2.4 The acoustic control system shall have a dedicated accumulator system(s) for the functions that are not supplied by a shared accumulator system. A shared accumulator system is not required to provide the hydraulic power of a specific function more than once.

EXAMPLE A dedicated shear accumulator system 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 DMAS circuit and the acoustic system then functions to close the shear ram, the shear ram BOP is already closed, and additional volume for this is not needed. If the DMAS did not close the shear ram prior to the acoustic function, then the required hydraulic volume in the dedicated shear accumulator system is still available to close the shear ram with the acoustic system.

9.3.3 Acoustic Electrical Equipment

9.3.3.1 The acoustic control electronic system shall include command signal coding to prevent operation by other equipment in close proximity.

9.3.3.2 Two actions shall be required to initiate the function(s) (e.g. actuate the acoustic system arm function and actuate the BOP close control function).

9.3.3.3 The design shall include redundant subsea transducers providing parallel sending and receiving capability from opposing sides of the BOP.

9.3.3.4 Electrical power to operate the acoustic control system shall be capable of 100 command functions over a 360-day duration without recharging. A low electrical power alarm shall be provided.

9.3.3.5 If the design includes the ability to charge the batteries within a subsea chamber, the designer shall review the safety aspects of this charging and include the necessary mitigations in the design, monitoring or procedures, or a combination thereof.

9.3.3.6 Subsea electronics and battery pack shall be housed in a container designed for the environment to which it is to be exposed.

9.3.3.7 Subsea acoustic electrical equipment shall meet the applicable requirements of other subsea electrical equipment as defined in 7.5.1.

9.3.3.8 The surface control equipment shall include the following:

a) A portable, battery operated control unit with a portable, cabled, omni-directional (horizontal) beam pattern dunking transducer. This portable control unit shall provide communication capability to meet purchaser specifications.

b) A single surface control unit which shall be used with either a dedicated vessel mounted transducer or a vessel mounted transducer shared with an acoustic Dynamic Positioning system.

c) A battery that can provide 50 transmissions in 4 hours of operation.

d) The capability to perform a minimum of 10 transmissions within the first 10 minutes of operation.

e) A low battery alarm.

f) A test unit or suitable means of testing the full operational circuitry of the portable console unit.

10 Diverter Control Systems

10.1 General

10.1.1 The diverter control system shall be designed to preclude closing-in of the well with the diverter.

10.1.2 Operation to open the vent valve and close the mud line (return) valve shall occur before the diverter packer is closed.

10.2 Response Time

10.2.1 A diverter control system shall be capable of completing the diverting sequence in 45 seconds or less.

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

10.3 Diverter Control Manifold

10.3.1 General

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.

10.3.2 Control Systems

10.3.2.1 The diverter control system shall be designed to prohibit closing the diverter packer unless a vent line has been opened.

10.3.2.2 Normally open mud system valves (if installed) shall be closed prior to closing the diverter packer.

10.3.2.3 If the diverter in use is equipped with an insert packer or pressure energized flow line seals, or both, the control system sequencing circuitry shall additionally prevent closing the diverter packer if the insert packer is unlocked or if the flow line seals or overshot packer, or both, are not energized.

10.3.2.4 When more than one vent line is used, 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.

10.3.2.5 Regulators shall be used to reduce operating pressure to within the manufacturer's limits for the components being operated. The regulators shall be capable of adjustment to within the recommended operating parameters.

10.3.2.6 An air storage or regulated nitrogen back-up system, protected by a check valve, shall be provided with capability to operate all of the pneumatic pilots for the functions at least twice in the event of loss of rig air pressure.

10.3.2.7 An open/close position indication of valve (i.e. a mechanical method) shall be provided for the following functions (when used in the interlock sequence):

a) overboard valves;

b) fill-up valve;

c) trip tank valve;

d) mud gas separator;

e) any mud control valve;

f) any valve to the mud room.

10.3.2.8 The pressurization of the slip joint packer (where installed) to the pressure required for divert mode functions shall be included in the diverter packer close auto-sequence.

10.3.2.9 The diverter control system shall provide a means to operate diverter related functions, such as the telescopic joint packer and gas handler, if equipped. These functions shall be sequenced with the diverter system if their position is essential for diverting operations.

10.3.2.10 For diverter controls systems that operate a gas handler, the diverter accumulator system shall be sized for the larger of the diverter sequence or the gas handler functions. If the diverter system and the gas handler system can be used simultaneously, the accumulator system shall be sized for both systems.

10.3.2.11 The telescopic joint packer control system shall be equipped with an automatic switch over to the secondary system in the event of a leak in the primary system that results in a loss of pressure below that which is required to effect a seal on the packer.

10.3.2.12 The diverter control system can be used to operate other surface functions. The operation of other functions shall not affect the operation of the divert mode functions.

10.3.2.13 The diverter control system is typically a return to tank (closed loop) system; however, there are some functions that have a high probability of control fluid contamination by wellbore fluid ingress. These function circuits (e.g. the slip joint packer, flow lines, diverter operators) should not return control fluid to the tank; spent control fluid from these functions should be directed to the rig's waste treatment system.

10.3.2.14 There shall be a test mode function (manual override), where the diverter can be closed without operating the diverter sequence. The test mode function shall be designed such that the diverter packer can be tested to ensure it is operating correctly when not in test mode.

10.3.3 Diverter Sequencing and Interlocks

10.3.3.1 Actuation of the divert mode sequence shall be the same as a single function, in that one actuation shall initiate the entire sequence.

10.3.3.2 Some automatically sequenced diverter systems require interlocks in the controls to prevent continuation of the sequence should one function fail to operate. Hydraulic valves, pneumatic valves, mechanical linkages, or limit switches, or a combination thereof, can be used as interlock controls in the diverter system sequence.

10.3.3.3 There shall be an alarm if the interlock sequence did not complete. If the interlock sequence did not complete, it shall be possible to operate any failed functions (including diverter packer close) from the control panels.

NOTE There are multiple functions in a divert mode sequence, with the closure of the diverter packer typically occurring last.

10.3.4 Diverters Controlled by the BOP control system

10.3.4.1 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, without a fixed diverter system, 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. Alternatively, either separate controls on the control stations or dedicated hydraulic controls may be provided.

10.3.4.2 Separate panel controls for a common hydraulic manifold shall have a mode select control on the panel.

10.4 Diverter Control Stations

10.4.1 The diverter control stations shall meet the requirements of 5.16.1.

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

10.4.3 A second control station shall be provided for installation in an area remote from the rig floor. The remote control station shall be capable of operating all diverter system functions including any necessary sequencing and control of the direction of the diverted flow.

10.4.4 Loss of remote control capability should not interrupt or alter the automatic sequencing from the main control unit.

10.5 Pump System

10.5.1 If the diverter control system accumulators are charged by the main pump system, the main pump system shall meet the requirements listed in 5.13.

10.5.2 If the diverter control system accumulators are charged by a dedicated pump system, the dedicated pump system shall meet the requirements listed in 5.14.

10.5.3 If a dedicated pump system is used, the diverter control system shall have a control fluid reservoir that meets the requirements of return-to-reservoir systems, as defined in 5.6.

10.6 Diverter Control Accumulator System

10.6.1 The diverter control system shall have a dedicated accumulator system.

10.6.2 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.

10.6.3 The BOP accumulators shall not be depleted by the diverter accumulators.

10.6.4 For diverters controlled by the BOP control system, the accumulator system shall also meet or exceed the requirements listed in 6.1.5.

10.7 Accumulator Volumetric Capacity

10.7.1 The diverter control system shall have an ACR to provide one hundred percent (100 %) of the power fluid volume and pressure (with pumps inoperative) required to operate the divert mode functional sequence. This requires a quick discharge from the accumulator system, accumulator sizing calculations shall be performed in accordance with Annex B, Method C. The beginning pressure used for the calculations shall be one of the following:

a) the pump stop pressure for diverter accumulators that are supplied by the main pump system (where the diverter accumulators are charged everytime the main accumulator system is charged);

b) the pump start pressure for dedicated accumulators that are supplied by a dedicated pump system.

10.7.2 The pressure of the remaining accumulator fluid after operating the required divert mode functions shall exceed the calculated minimum system operating pressure. The calculated minimum system operation pressure shall exceed the greater of the following:

a) the minimum calculated operating pressure required to close and seal the diverter packing element on drill pipe at the maximum rated wellbore pressure of the diverter system;

b) 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.

c) the minimum calculated operating pressure required to close and hold close any flowline valve in the diverter flow line system at the maximum rated wellbore pressure of the diverter system.

10.7.3 Additionally, the accumulator sizing requirements shall include the following (where applicable).

a) The operational temperature range of the diverter control system.

b) The closing volume and pressure of the diverter required to:

- seal on open hole if the diverter is capable of complete shut off (CSO),
- seal on the smallest size drill pipe,
- seal at the minimum closure size of the insert.

c) Provide an allowance for filling control lines (piping allowance).

d) The operator volume of all the valves in the diverter sequence.

e) The control system working pressure.

f) Other functions integral to the diverter system operation, i.e. diverter insert locking dogs, telescopic joint packer activation, etc.

11 Periodic Inspection and Maintenance Procedures

11.1 The manufacturer shall provide the purchaser with information necessary to establish inspection and maintenance procedures for control systems equipment.

11.2 Inspection and Maintenance procedures (where applicable), shall include the following:

a) verification of instrument accuracy;

b) relief valve settings;

c) pressure control switch settings;

d) precharge pressure in accumulators;

e) pump systems;

f) fluid quality requirements;

g) lubrication points;

h) the general condition of piping systems, hoses, electrical conduit/cords, mechanical components, structural components, filters/strainers, safety covers/devices, control system sizing, and battery condition;

i) list of reference documents.

12 Documentation

12.1 General

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

12.2 Quality Control Records

The following records shall be maintained by the manufacturer for a period of not less than five years. Record retention shall also meet any additional requirements of API Q1.

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) Design data documentation

h) Certificate of conformance to API 16D.

i) Contract information including:

   1) purchaser name and purchase order number;

   2) manufacturer's serial number;

   3) EX-works delivery date;

   4) destination/rig name;

   5) API monogram (if applicable);

   6) manufacturer's identification/model numbers.

j) Design data documentation (if applicable).

k) Reference documents

12.3 Manufacturing Documentation

A documented system to ensure that equipment specifications are met during the purchasing and manufacturing processes shall be established and employed by the control system manufacturer. The system shall address the following:

a) purchase control specifications;

b) engineering specifications;

c) manufacturing standards;

d) quality control procedures.

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

12.4 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 a minimum, include the following.

a) Reference documentation list.

b) Test equipment and apparatus list.

c) Pre-test inspection, servicing and assembly requirements.

d) Detailed instructions (as applicable) for the following.

   1) Flushing and fluid cleanliness requirements.

   2) Utilities verification, to include the following:

      — electric motor voltage, frequency, phase balance, amperage and insulation resistance;

      — air supply pressure and flow capacity;

   3) Hydrostatic test requirements.

   4) Operational limit settings.

   5) Functional requirements.

   6) Pass/Fail criteria.

   7) Records and data requirements.

   8) Post test procedures, preservation and protection requirements.

e) Quality witness and acceptance.

f) Special considerations such as

   1) requirements to ensure proper interface of system components permitted when delivery of components precludes availability of all components during factory tests, and

   2) calculations acceptable to ensure design specifications are met where actual measurement of performance is not practical.

13 Manufacturing Processes

13.1 Structural Steel

Structural steel shall conform to ASTM, AISI, or other internationally recognized standard. The minimum strength level, group, and class should be selected by the manufacturer and be appropriate for the given application. Unidentified steel shall not be used.

13.2 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.

13.3 Welding

13.3.1 Welding General Requirements

All welding of external or internal pressure containing components shall comply with the welding requirements of the ASME *BPVC*, Section IX or other pressure vessel codes referenced in Section 2. Verification of conformance shall be established through the implementation of the manufacturer's welding procedure specification (WPS) and the supporting procedure qualification record (PQR).

13.3.2 Welding Procedure Qualifications

When welded, pressure containing (15 psi [103kPa] or greater) components may require impact testing. Verification of conformance shall be established through the implementation of the manufacturer's WPS and supporting PQR.

13.3.3 Pressure-containing Fabrication Weldments

Pressure containing fabrication weldments described here pertain to primary pressure-containing members. Full penetration welds can be used for pressure-containing fabrication. Typical examples are listed in AWS D1.1.

13.3.4 Load-bearing Weldments

13.3.4.1 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.

13.3.4.2 The manufacturer shall define joint design for load bearing weldments.

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

13.3.4.4 Welding and completed welds shall meet the quality control requirements of Section 12 and Section 13.

13.3.5 Weld Surfacing

13.3.5.1 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.

13.3.5.2 As a minimum, the procedure shall include inspection methods and acceptance criteria.

13.3.5.3 Qualification shall be in accordance with Article II and III of ASME *BPVC*, Section IX for corrosion resistant weld metal overlay or hard facing weld metal overlay as applicable.

13.3.6 Welding Controls

13.3.6.1 Welding shall be performed in accordance with the WPS, qualified in accordance with Article II of ASME *BPVC*, Section IX or equivalent recognized international standard.

13.3.6.2 The WPS shall describe all the essential, non-essential and supplementary essential variables (see ASME *BPVC*, Section IX or equivalent recognized international standard).

13.3.6.3 Welders and welding operators shall have access to and shall comply with the welding parameters as defined in the WPS.

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

13.3.7 Design of Welds

13.3.7.1 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.

13.3.7.2 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.

13.3.8 Preheating

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

13.3.9 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.

13.3.10 Welding Consumables

13.3.10.1 Welding consumables shall conform to the American Welding Society or consumable manufacturer's approved specifications.

13.3.10.2 Welding consumables shall only be used within the limitations of ASME *BPVC*, Section 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.

13.3.10.3 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 properties.

13.3.11 Post-weld Heat Treatment

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

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

13.3.11.3 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.

13.3.12 Welding Procedure and Performance Qualifications

13.3.12.1 General

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

13.3.12.2 Base Materials

13.3.12.2.1 The manufacturer shall use ASME *BPVC*, Section IX, P-number materials.

13.3.12.2.2 The manufacturer may establish an equivalent P-number (EP) grouping for carbon and low alloy steels not listed in ASME *BPVC*, Section IX with a carbon equivalent less or equal to 0.43 for ≤1 in. or less and 0.45 for > 1 in. material thickness. See the following.

13.3.12.2.3 Prior to welding of carbon and low alloy steel, all elements in the carbon equivalency formula shall be adequately identified as per ASME *BPVC*, Section IX, QW-403.26.

13.3.12.2.4 Carbon and low alloy steels not listed in ASME *BPVC*, Section IX with a carbon equivalent as identified above and a nominal carbon content greater than 0.23 % (by weight) shall be specifically qualified for the manufacturer's specified base material.

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

13.3.12.3 Heat-treat Condition

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

13.3.12.4 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 12.

13.3.13 Other Requirements—Impact Test Locations for Weld Qualification

13.3.13.1 When impact testing is required by the base material specification, the testing shall be performed in accordance with ASTM A370 using the Charpy V-notch technique. Results of testing in the weld and HAZ shall meet the minimum requirements of the base material, for both average and minimum toughness requirements.

13.3.13.2 If any one of the three specimens falls below the minimum allowed toughness requirement, then two additional Charpy test specimens are required from that area and both shall be at or above the minimum toughness requirement. Records of results shall become part of the PQR.

13.3.13.3 The number and location of Charpy V-notch impact test specimen shall be in accordance with Figure 1 following the sampling requirements in relation with the material thickness and weld type and weld thickness used for the qualification:

a) Less or equal to 19 mm (0.75 in.)—Charpy specimens shall be taken from the external surface (within 2 mm from the surface), subject to the requirements for multi-process and double-sided welds.

b) Greater than 19 mm (0.75 in.) to less than 38 mm (1.5 in.)—Charpy specimens shall be taken from the external and internal surface (within 2 mm from both surfaces), subject to the requirements for multi-process and double sided welds.

c) Greater or equal to 38 mm (1.5 in.)—Charpy specimens shall be taken from the external and internal surfaces within 2 mm (0.1 in.) from both surfaces and from the mid-wall position, subject to the requirements for multi-process and double-sided welds.

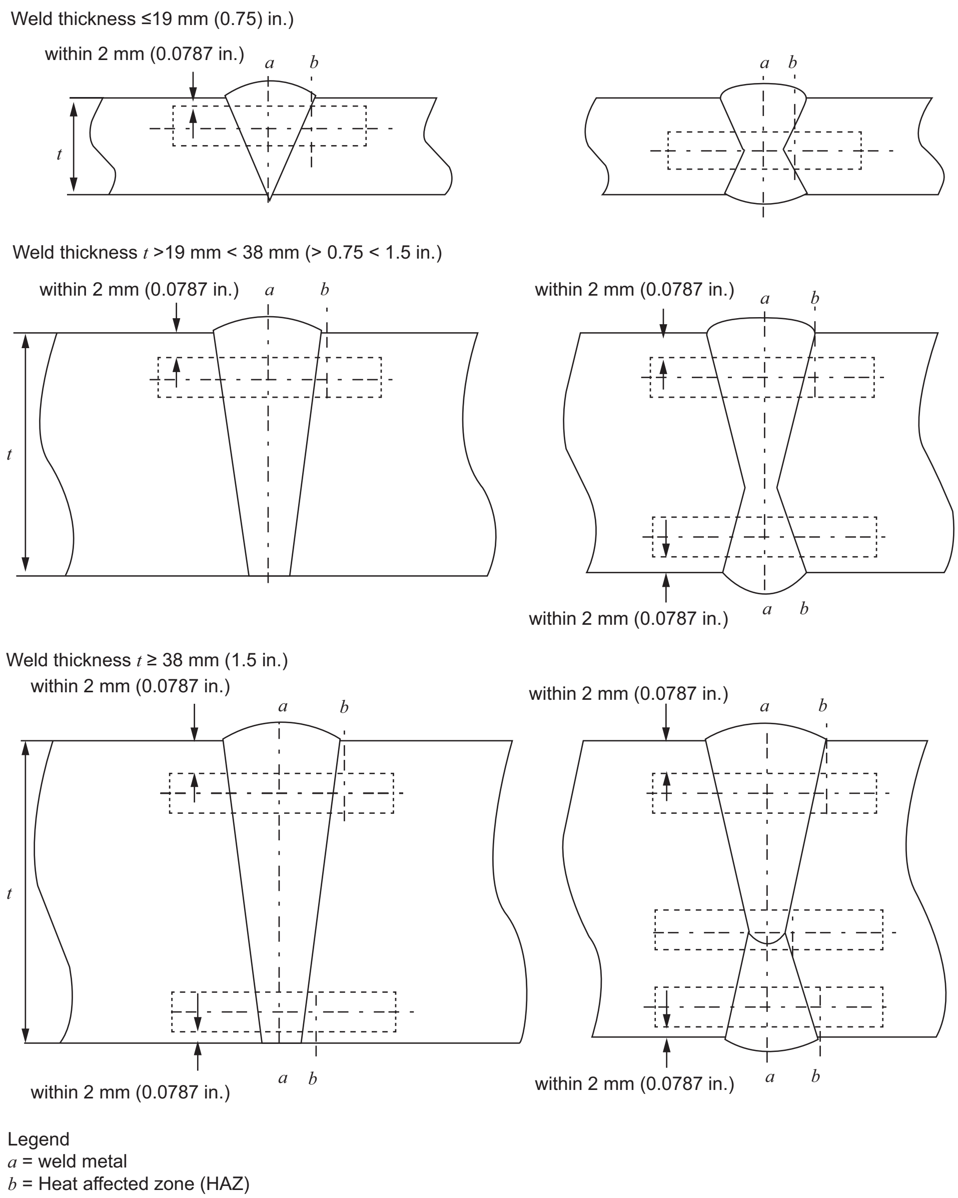


Figure 1—Charpy V-notch Impact Test Specimens

13.3.13.4 When impact testing is required, sets of three test specimens shall be removed from the weld metal and heat-affected zone.

13.3.13.5 If multiple welding processes are used to produce the weldment, the weld metal and appropriate HAZ test specimens shall be removed for each welding process.

13.3.13.6 The manufacturer may take impact specimens from the following locations:

a) the root region containing consumed tack welds made with different weld metal;

b) as near as practical at the midway thickness of the weld for qualification of a single V-groove.

13.3.13.7 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.

13.3.13.8 The allowable range for the post-weld heat treatment on the WPS shall be a nominal temperature ±25 °F.

13.3.13.9 The stress relieving time at the qualified temperature range shall be the minimum time and shall not exceed 120 % of the minimum time that which was used for the test weldment.

13.3.13.10 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.

13.4 Cathodic Protection

Equipment to be deployed subsea shall be cathodically protected in accordance with the applicable provisions of NACE SP0176. The manufacturer shall specify materials, sizes, locations and method of installation of cathodic protectors in accordance with these NACE standards.

13.5 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.

14 Commodity Items

14.1 General

14.1.1 For the purpose of this specification, commodity items are defined as manufactured products used 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 sub-vendors rather than by the control system manufacturer and such items may be commercially available for other industrial applications.

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

14.1.3 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.

14.2 Pressure-containing Components

14.2.1 General

All pressure-containing (15 psi [103 kPa] 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.

14.2.2 Bolting

14.2.2.1 Bolting used (surface and subsea) to contain control system operating pressure shall meet the control system manufacturer's written specifications.

14.2.2.2 Bolting materials (including coatings/platings) used in a seawater environment shall meet the control system manufacturer's written specifications.

14.2.2.3 Bolting used in a seawater environment for containment of control system operating pressure shall have batch traceability.

14.2.2.4 Pressure vessels having internal or external working pressures above 15 psi (103 kPa) shall meet or exceed the mandatory appendices of ASME *BPVC*, Section VIII, Division I, Division 2, or equivalent pressure vessel code.

14.2.2.5 Equipment that must maintain a pressure lower than the hydrostatic sea water head in order to operate as designed, shall have test ports that allow those seals to be tested on surface to the maximum expected differential pressure.

14.2.3 Accumulators

14.2.3.1 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.

14.2.3.2 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.

14.2.3.3 Accumulator shells shall include a permanently affixed serial number.

14.2.3.4 Written test reports certifying acceptance of the accumulator shell test shall be maintained by the control system manufacturer for each serial numbered unit.

14.2.3.5 Traceability to the original accumulator shell manufacturer shall be maintained.

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

14.2.4 Pipe, Tubing, and Connections

14.2.4.1 Pipe, tubing, and connections used in hydraulic or pneumatic circuits subjected to internal pressure exceeding 15 psi (103 kPa) shall meet the piping design requirements (including appropriate material stress level, pressure reduction for joints or attachments, and operational considerations) of ASME B31.3.

14.2.4.2 Pipe and tubing shall be adequately supported and clamped to protect end fittings from failures due to vibration, fatigue, and shock loads. Clamps shall be resistant to loosening from the normal vibration of the system. Clamps and supports shall be in accordance with an industry standard (e.g. ASME B31.3; KSC-SPEC-Z-0008C) or in accordance with the manufacturer's written specifications.

14.2.5 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.

14.2.6 Threaded and Welded Connections

14.2.6.1 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 sealing 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.

14.2.6.2 Design of threaded piping connections shall be in accordance with a published national or international standard which shall be documented by the manufacturer.

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

14.2.6.4 All hydraulic 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.

14.2.6.5 Air supply piping and instrument air systems shall be bubble tested in accordance with ASME *BPVC,* Section 5, Article 10 or equivalent recognized national or international standard. Air receivers shall be built according to ASME pressure vessel code (or equivalent) and shall be protected from over pressurization.

14.2.7 Non-ASME Coded Hydraulic Control System Components

14.2.7.1 Components used in the hydraulic circuits of control systems 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 times the rated working pressure rating of the components.

NOTE 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.

14.2.7.2 Hydraulic and pneumatic components integral with electric/electronic devices are also subject to the electrical and electronic equipment and installation specifications presented in 14.3.

14.2.7.3 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 *BPVC*; 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, or end piece that allows pressure to safely vent while still having sufficient structural capacity to retain the pressure.

14.2.7.4 Nitrogen cylinders used for emergency backup systems (e.g. in case of loss of rig air pressure) 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.

14.2.7.5 All components used in the construction of control systems shall be new equipment. Component selection shall be based on a minimum history of two years of acceptable performance in a similar environment and application, or on simulated cycle testing of a minimum 1000 cycles at the working pressure. Components not normally cycled shall be qualified for an equivalent two years of service. Components used for qualification tests shall not be used in the construction of deliverable equipment.

14.3 Electrical and Electronic Equipment and Installation

14.3.1 All electrical components shall be rated at 100 % duty cycle for use in the full ambient temperature range specified in the design.

14.3.2 Electrical components shall be qualified for use in accordance with a recognized industry standard (e.g. IEC, IEEE, etc.).

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

14.3.4 All electrical conductor insulation shall be rated at 1.5 times the peak operating voltage (for AC voltages use maximum RMS value), or 50 volts, whichever is greater.

14.3.5 Electrical power 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 for power distribution.

14.3.6 The installed bend radius for cables shall be equal to or greater than the cable manufacturers' recommended minimum bend radius.

14.3.7 Electrical equipment shall be designed or packaged for the environment in which they are to be exposed in accordance with a recognized industry standard (e.g. Type 4X construction in accordance with NEMA 250 for deck mounted equipment).

14.3.8 Electrical connectors shall employ a form of restraint. Socket mounted components shall be secured in their sockets; this can be accomplished by means of a restraint or with a vibration resistant socket design.

14.3.9 Soldering shall be in accordance with the following standards or equivalent recognized international standard:

a) IPC J-Std-0001;

b) IPC 610;

c) IPC 620;

d) IPC-7711/7721;

e) Soldering operators are certified to IPC J-Std-0001 by a certified instructor.

14.3.10 Electrostatic discharge control shall be in accordance with ANSI/ESD S20.20.

14.3.11 Control system cabinets, skids, and externally mounted components shall include a provision for electrical bonding to a common ground system.

14.3.11.1 Ground conductors shall be sized in accordance with NFPA 70.

14.3.11.2 Semiconductor devices shall not be used singularly as a means to isolate circuits from electrical energy sources for personnel safety but can be used for equipment protection.

14.3.11.3 Intrinsically safe circuits shall be designed and installed in accordance with NFPA 70—Article 504 or ANSI/ISA/IEC-60079-11 or similar national or international recognized standards.

14.3.11.4 Electrical conductor installation shall be in accordance with NFPA 70 or similar national or international recognized standards.

14.4 Mechanical Equipment

14.4.1 General

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

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

14.4.1.3 Operator guards shall be provided for all rotating equipment that presents a hazard to personnel.

14.4.1.4 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.

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

14.4.1.6 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 that could have been affected by the repair.

14.4.1.7 The control system components shall be assembled in such a manner that repairs can be made in a timely manner.

14.4.1.8 Control panels and valves shall be vented in such a manner to prevent actuation of other functions.

14.4.2 Control Pod Equipment

Control pot equipment shall conform to the following:

a) Normally closed valves should have effective spring closure in the absence of pressure assist closing.

b) Prototype springs shall be tested to 1000 cycles and retain the minimum design spring constant.

c) All pod valve prototypes shall be cycled a minimum of 1000 times at normal operating pressure.

d) All pod valve prototypes shall be pressure and flow tested at conditions that simulate the application environment, including the "vent" port pressure environment.

e) Cap screws holding valves and regulators together shall be corrosion resistant.

14.5 Fluids and Lubricants

NOTE Control fluids and lubricants are user responsibilities.

Manufactures shall provide minimum requirements for their equipment related to water quality, cleanliness, lubricity, testing methods, temperature, and environmental safety. The OEM should provide a list of acceptable commercially available products (e.g. brand/product information and minimum concentration ratios).

14.6 Qualification Testing

14.6.1 Control Systems

14.6.1.1 Qualification testing shall be required for prototype control systems, which are first time systems of a new manufacture or systems using major components of a type not previously proven.

14.6.1.2 An in-plant test shall be performed to demonstrate that the prototype control system meets time requirements set forth in this specification.

14.6.1.3 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.

14.6.2 Fire Tests

14.6.2.1 General

14.6.2.2 The control hose and any component of the control hose to a surface-mounted BOP stack or diverter, located in a division one area, as defined by API 500 or a Zone 1 area defined by API 505, shall be capable of containing the hose rated working pressure in a flame temperature of 1300 °F (704 °C) for a 5-minute period.

14.6.2.3 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 or testing witnessed by a third party 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 to the hose rated working pressure (+3 %/–0 %) before the start of the test. 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 over-pressurization 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.

14.6.2.4 Procedure

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 until the average temperature reading of six thermocouples is at least 1300 °F (704 °C). Temperatures are to be measured at the middle and ends of the test piece by three 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 (704 °C)] for a minimum of 5 minutes.

d) Instrument readings shall be recorded at a minimum of 1-minute intervals. Readings to be recorded are as follows:

— thermocouple average temperature;

— internal hydraulic pressure of test piece;

— volume of water added to maintain the internal hydraulic pressure of the test piece.

e) A test is deemed a failure if within the duration of the test either of the following occurs:

f) the rated working pressure of the hose cannot be maintained;

g) it is necessary to add water to maintain the rated working pressure of the hose.

14.6.2.5 Test Report

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 1300 °F (704 °C), and time at which the test was terminated;

e) a table of the instrument readings recorded in accordance with 14.6.2.2;

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 was 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.

14.7 Factory Acceptance Testing

14.7.1 Accumulator System Test for Bladder Type Accumulators

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

NOTE This test is not required for accumulators that do not have a poppet (or similar) flow-restriction valve.

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 (flow meter reading is an alternate indication).

d) Close the flow path and wait at least 15 minutes for temperature and pressure stabilization.

e) 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.

f) Repeat test for the remaining accumulators.

14.7.2 Subsystem Components

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

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

14.7.2.3 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.

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

14.8 Certifications

14.8.1 Type Certification

14.8.1.1 Type certifications may be used for commodity items, manufactured equipment or components, or a combination thereof, 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.

14.8.1.2 Subsequent units of an accepted type shall be periodically audited to ensure conformance to specifications.

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

14.8.1.3 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.

14.8.2 Hydrostatic Test Certificates

14.8.2.1 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 rated working pressures.

14.8.2.2 Piping and containment devices shall be tested to:

— 1.5 times the rated working pressure for factory acceptance tests, and

— rated working pressure for field tests.

14.8.2.3 Hydrostatic test evaluation periods shall be a minimum of 5 minutes. The test evaluation period shall be adjusted to account for the accuracy, precision and resolution of the test instruments utilized to ensure acceptance criteria are met.

14.8.2.4 Acceptance criteria shall be as follows:

— no visible leaks;

— test pressure shall not drop below the required minimum test pressure;

— the pressure shall be stable or the decay rate shall be decreasing over the evaluation period; the pressure drop during the hydrostatic pressure test shall average less than 5 psig per minute during the evaluation period.

NOTE This means if test equipment with an accurate display is used (e.g. pressure transducers with a digital display), and the test results can be confirmed as meeting the criteria during a 5-minute hold period, then a 5-minute hold time is acceptable. That is less than a 25 psi drop with a measurable decreasing rate of pressure loss.

However, if equipment with a less accurate display is used (e.g. an analog chart recorder), it takes longer to determine if the acceptance criteria are met. The general rule is that if an analog pressure measurement device is used, the hold time is at least 10 minutes to ensure that the acceptance criteria are met.

14.8.2.5 Test recorder charts shall be available, dated, witnessed, and identified to the particular equipment under test.

14.8.3 Hazardous Area/Electrical Certificates

Manufacturer's certificates of conformance to applicable electrical codes shall be required for all electrical equipment and apparatus for installation in explosive environments as defined in API 500 or API 505 or IEC 60079-10-1.

14.8.4 Accumulator Certificates

14.8.4.1 Seamless accumulators shall be furnished with ASME U-1A certificates or equivalent documentation from other pressure vessel codes referenced in Section 2.

14.8.4.2 Welded accumulators shall be furnished with ASME U-1A certificates or equivalent documentation from other pressure vessel codes referenced in Section 2. They shall further be documented with weld and NDE reports.

14.8.4.3 Accumulators shall conform to 14.2.3.

14.8.5 Relief Valve Certificates

A certificate of the relief valve setting and operation shall be provided indicating the set point and the pressure at which the relief valve re-seats in accordance with 5.15.7.

14.8.6 Certificate of Conformance

14.8.6.1 Manufacturer's certificate of conformance 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.

14.8.6.2 All records pertaining to the design, manufacture, and testing shall be retained by the manufacturer for a minimum of 10 years.

15 Marking

15.1 Temporary Marking

15.1.1 Materials received in the manufacturer's facilities for use in products to be manufactured to this specification 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.

15.1.2 Materials that have been found to be nonconforming 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.

15.2 Permanent Marking

Permanent markings shall be affixed in a manner to prevent them from being covered by further assembly.

15.3 Traceability Marking Methods

15.3.1 Temporary marking shall be affixed by tags, adhesive labels, or paint.

15.3.2 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.

15.3.3 Material requiring in-process inspection and non-destructive inspection shall be traceable to the inspection records.

15.3.4 Permanent markings may be engraving, stamping, etching, castings, or metal deposit, however these markings shall be visible after complete assembly.

15.3.5 The method of marking shall take into consideration the integrity of the part in its intended application and the length of time the markings need to be legible.

15.4 Equipment Identification Markings

15.4.1 All control system parts shall be identifiable. Parts that are not marked shall be identifiable by bills of material (parts list) and illustrated in drawings.

15.4.2 Manufacturers shall provide permanent identification marking for the equipment they provide, as listed below. The permanent markings shall be designed to be legible for the expected service life of the equipment. Commodity items such as wiring, cabling, pipe, tube, and hose are not included.

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

a) manufacturer's name or mark;

b) model name or part number, or both;

c) serial number or unique identifier;

d) date of manufacture;

e) API 16D.

15.4.4 Control system subassemblies (e.g. valves, regulators) shall have at least one permanent marking containing, as a minimum, the manufacturer's name or mark and the part number or other suitable unique identification.

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

15.4.6 Manufacturers may affix other markings at their discretion.

16 Storing and Shipping

16.1 Protection and Preservation

16.1.1 Prior to shipment the equipment manufacturer should consult with the purchaser to properly prepare the equipment for shipment and storage. Preparations should take into consideration the intended method of transportation—land, sea, or air—as well as the length of time the equipment is not to be in service. Additionally, an MSDS sheet applicable to any fluid remaining in the equipment shall accompany the shipment.

16.1.2 The painting and color of finished surfaces shall be the option of the manufacturer unless specified on the purchase order.

16.1.3 All reasonable precautions shall be taken to prevent damage in transit to transparent surfaces, threads or service entries, and operating parts.

16.1.4 Exposed ports shall be plugged. If temporary fittings, plugs, or caps are installed in equipment, it is preferred that they be rated to the full rated working pressure of the circuit where they are installed. If this is not practical, covers (not pressure rated) may be used, and shall be of a different color than the pressure rated fittings. The control system shall have warnings posted on the equipment that the temporary fittings shall be removed prior to pressurizing the equipment. The temporary fittings shall be clearly identified with a tag stating that these fittings shall be removed prior to placing the equipment in service. The tag shall be of durable material that can withstand the environment and be securely fastened to the fitting.

16.1.5 If extended storage of units and assemblies is anticipated, the manufacturer shall be consulted for preservation measures to be employed.

16.2 Packing

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

16.2.2 For export shipment, units and assemblies shall be securely crated or mounted on skids so as to prevent damage and facilitate sling handling. This may be performed by the purchaser.

16.2.3 All enclosed electrical and electronic housings shall have desiccant (or alternative) protection for a minimum of four months storage from date of shipment.

16.3 Identification

16.3.1 Unit manufacturer's assembly or serial number shall be displayed on weatherproof material rigidly attached to the system.

16.3.2 If the unit is enclosed in sealed crating, the manufacturer's assembly or serial number shall be permanently painted on the exterior of the crate in addition to attachment on the system.

16.4 Installation, Operation, and Maintenance Documentation

16.4.1 Form of Deliverable Documentation

16.4.1.1 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.

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

16.4.2 Content of Deliverable Documentation

A minimum of two sets of the installation, operation, and maintenance documentation shall be provided.

The following is an example (sequence of presentation is optional):

1) Table of Contents through Index, and location of information.

2) Contract information consisting of the following:

   — purchaser's order number;

   — supplier's identification number;

   — supplier's contract information;

   — calendar year and month of delivery;

   — scope of supply.

3) Technical data (as applicable) consisting of the following:

   — design calculations;

   — temperature ratings;

   — area classification, zone and gas group of electric equipment.

4) Safety precautions.

5) Installation, interface, and testing data.

6) Operating characteristics.

7) General maintenance data consisting of the following:

   — recommended preventive maintenance and schedules;

   — recommended fluids, lubricants and capacities;

   — recommended list of maintenance and critical spare parts;

   — troubleshooting methods.

8) Product specific maintenance data consisting of the following:

- — assembly drawings and Bills of Materials showing identification and general location of replaceable commodity items;
- — electric, hydraulic and pneumatic schematics showing point-to-point connection identifications;
- — interconnect diagrams showing point-to-point interconnections.

9) Appendix/Glossary listing general definitions of terms used in the text and schematic symbols used in the support documentation.

Annex A
(informative)

API Monogram Program

A.1 Scope

A.1.1 Applicability

This annex is normative (mandatory) for products supplied bearing the API Monogram and manufactured at a facility licensed by API; for all other instances it is not applicable.

A.1.2 General

The API Monogram® is a registered certification mark owned by the American Petroleum Institute (API) and authorized for licensing by the API Board of Directors. Through the API Monogram Program, API licenses product manufacturers to apply the API Monogram to products which comply with product specifications and have been manufactured under a quality management system that meets the requirements of API Q1. API maintains a complete, searchable list of all Monogram licensees on the API Composite List website (www.api.org/compositelist).

The application of the API Monogram and license number on products constitutes a representation and warranty by the licensee to API and to purchasers of the products that, as of the date indicated, the products were manufactured under a quality management system conforming to the requirements of API Q1 and that the product conforms in every detail with the applicable standard(s) or product specification(s). API Monogram program licenses are issued only after an on-site audit has verified that an organization has implemented and continually maintained a quality management system that meets the requirements of API Q1 and that the resulting products satisfy the requirements of the applicable API product specification(s) and/or standard(s). Although any manufacturer may claim that its products meet API product requirements without monogramming them, only manufacturers with a license from API can apply the API Monogram to their products.

Together with the requirements of the API Monogram license agreement, this annex establishes the requirements for those organizations who wish to voluntarily obtain an API license to provide API monogrammed products that satisfy the requirements of the applicable API product specification(s) and/or standard(s) and API Monogram Program requirements.

For information on becoming an API Monogram Licensee, please contact API, Certification Programs, 1220 L Street, NW, Washington, DC 20005 or call 202-682-8145 or by email at certification@api.org.

A.2 Normative References

In addition to the referenced standards listed earlier in this document, this annex references the following standard: API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*.

For Licensees under the Monogram Program, the latest version of this document shall be used. The requirements identified therein are mandatory.

A.3 API Monogram Program: Licensee Responsibilities

A.3.1 Monogram Program Requirements

For all organizations desiring to acquire and maintain a license to use the API Monogram, conformance with the following shall be required at all times:

a) the quality management system requirements of API Q1;

b) the API Monogram Program requirements of API Q1, Annex A;

c) the requirements contained in the API product specification(s) to which the organization is licensed; and

d) the requirements contained in the API Monogram Program License Agreement.

A.3.2 Control of the Application and Removal of the API Monogram

Each licensee shall control the application and removal of the API Monogram in accordance with the following:

a) products that do not conform to API specified requirements shall not bear the API Monogram;

b) each licensee shall develop and maintain an API Monogram marking procedure that documents the marking/ monogramming requirements specified by this annex and any applicable API product specification(s) and/or standard(s). The marking procedure shall:

   1) define the authority responsible for application and removal of the API Monogram and license number;

   2) define the method(s) used to apply the Monogram and license number;

   3) identify the location on the product where the API Monogram and license number are to be applied;

   4) require the application of the date of manufacture of the product in conjunction with the use of the API Monogram and license number;

   5) require that the date of manufacture, at a minimum, be two digits representing the month and two digits representing the year (e.g. 05-12 for May 2012) unless otherwise stipulated in the applicable API product specification(s) or standard(s);

   6) define the application of all other required API product specification(s) and/or standard(s) marking requirements.

c) only an API licensee shall apply the API Monogram and its designated license number to API monogrammable products;

d) the API Monogram and license number, when issued, are site-specific and subsequently the API Monogram shall only be applied at that site specific licensed facility location;

e) the API Monogram may be applied at any time appropriate during the production process but shall be removed in accordance with the licensee's API Monogram marking procedure if the product is subsequently found to be out of conformance with any of the requirements of the applicable API product specification(s) and/or standard(s) and API Monogram Program.

For certain manufacturing processes or types of products, alternative API Monogram marking procedures may be acceptable. Requirements for alternative API Monogram marking are detailed in the, API Monogram Program

Alternative Marking of Products License Agreement, available on the API Monogram Program website at http://www.api.org/alternative-marking.

A.3.3 Design and Design Documentation

Each licensee and/or applicant for licensing shall maintain current design documentation as identified in API Q1 for all of the applicable products that fall under the scope of each Monogram license. The design document information shall provide objective evidence that the product design meets the requirements of the applicable and most current API product specification(s) and/or standard(s). The design documentation shall be made available during API audits of the facility.

In specific instances, the exclusion of design activities is allowed under the Monogram Program, as detailed in Advisory #6, available on API Monogram Program website at http://www.api.org/advisories.

A.3.4 Manufacturing Capability

The API Monogram Program is designed to identify facilities that have demonstrated the ability to manufacture equipment that conforms to API specifications and/or standards. API may refuse initial licensing or suspend current licensing based on a facility's level of manufacturing capability. If API determines that an additional review is warranted, API may perform additional audits (at the organization's expense) of any subcontractors to ensure their conformance with the requirements of the applicable API product specification(s) and/or standard(s).

A.3.5 Use of the API Monogram in Advertising

An API Monogram licensee shall not use the API Monogram and/or license number on letterheads, buildings or other structures, websites or in any advertising without an express statement of fact describing the scope of Licensee's authorization (license number and product specification). The Licensee should contact API for guidance on the use of the API Monogram other than on products.

A.4 Product Marking Requirements

A.4.1 General

These marking requirements shall apply only to those API Licensees wishing to mark applicable products in conjunction with the requirements of the API Monogram Program.

A.4.2 Product Specification Identification

Manufacturers shall mark products as specified by the applicable API specifications or standards. Marking shall include reference to the applicable API specification and/or standard. Unless otherwise specified, reference to the API specifications and/or standards shall be, as a minimum, “API [Document Number]” (e.g. API 6A, or API 600). Unless otherwise specified, when space allows, the marking may include use of “Spec” or “Std”, as applicable (e.g. API Spec 6A or API Std 600).

A.4.3 Units

Products shall be marked with units as specified in the API specification and/or standard. If not specified, equipment shall be marked with U.S. customary (USC) units. Use of dual units [USC units and metric (SI) units] may be acceptable, if such units are allowed by the applicable product specification and/or standard.

A.4.4 Nameplates

Nameplates, when applicable, shall be made of a corrosion-resistant material unless otherwise specified by the API specification and/or standard. Nameplate shall be located as specified by the API specification and/or standard. If the location is not specified, then the licensee shall develop and maintain a procedure detailing the location to which the nameplate shall be applied. Nameplates may be attached at any time during the manufacturing process.

The API Monogram and license number shall be marked on the nameplate, in addition to the other product marking requirements specified by the applicable product specification and/or standard.

A.4.5 License Number

The API Monogram license number shall not be used unless it is marked in conjunction with the API Monogram. The license number shall be used in close proximity to the API Monogram.

A.5 API Monogram Program: Nonconformance Reporting

API solicits information on products that are found to be nonconforming with API specified requirements, as well as field failures (or malfunctions), which are judged to be caused by either specification and/or standard deficiencies or nonconformities against API specified requirements. Customers are requested to report to API all problems with API monogrammed products. A nonconformance may be reported using the API Nonconformance Reporting System available at http://compositelist.api.org/ncr.aspx.

Annex B
(normative)

Accumulator Sizing Calculation Methods

B.1 Accumulator Capacity Requirement (ACR)

The ACR of an accumulator system is the accumulator volume necessary (for a given precharge pressure and temperature) to provide functional volume requirement (FVR) (required hydraulic fluid volume to actuate the specified well control equipment). The sizing calculation methods specified within this document are conservative sizing guides, and shall not be used as a basis for field performance. The accumulator minimum required capacity design factors, $\mathrm{F_v}$ and $\mathrm{F_p}$, vary for each sizing method. Normal control system valve interflow is taken into account as part of the method correction factors, and is not required to be accounted for separately. See Annex C for the derivation of the accumulator sizing calculations.

The FVR_S identified in this document may be satisfied by bottle volume (BV) from surface or subsea stack-mounted accumulators, or both, as determined by design of the system.

Accumulator sizing parameters:

For general accumulator systems:

$$ACR = FVR/\min(VE_V, VE_P) \tag{B.1}$$

For main accumulator systems with both surface and stack-mounted accumulators:

$$ACR_{surf} = (FVR - BV_{SM} \times \min(VE_{VSM}, VE_{PSM}))/\min(VE_{Vsurf}, VE_{Psurf})$$

$$ACR_{SM} = (FVR - BV_{surf} \times \min(VE_{Vsurf}, VE_{Psurf}))/\min(VE_{VSM}VE_{PSM}) \tag{B.2}$$

where

ACR is the accumulator capacity required

FVR is the required hydraulic fluid volume to actuate the specified equipment

BV is the bottle gas volume

VE is the volumetric efficiency

VE_v is the volumetric efficiency for volume-limited case

VE_p is the volumetric efficiency for pressure-limited case.

The accumulator sizing calculation methods have four conditions of interest: precharged (Condition 0), charged (Condition 1), discharged to MOP (Condition 2), and totally discharged (Condition 3). As the sizing methods of this document require the use of real gas data, gas density is the measure of the conditions.

NOTE The NIST gas table data (http://webbook.nist.gov/chemistry/fluid) is a source for gas density, entropy, pressure, and temperature.

B.2 Condition 0: Precharged

For the condition state of the accumulator gas before the accumulator is charged with hydraulic supply pressure:

When specifying a precharge pressure, the appropriate temperature shall be included that achieves the chosen gas density. The chosen precharge shall be verified not to exceed the pressure rating of the accumulator at the maximum ambient temperature.

A chart (or similar means) shall be provided that specifies the precharge pressure at other temperatures.

B.3 Condition 1: Charged

For the condition state of the accumulator gas when the accumulator is charged with hydraulic supply pressure:

Accumulator systems where the charged pressure fluctuates with the pump cycling shall be calculated utilizing pump start pressure. Dedicated accumulator systems supplied by the main accumulator system where the charged pressure does not fluctuate with the pump cycling may be calculated utilizing pump stop pressure.

When a maximum fluid volume mechanical limit can limit the charge of the accumulator gas, the charged fluid volume shall be calculated to determine if the mechanical limit has been reached. If the mechanical limit has been reached, the charged gas state shall be based on the hydraulic volume at the mechanical limit.

B.4 Condition 2: Minimum Operating Pressure

For the condition state of the accumulator gas when the accumulator hydraulic pressure is the minimum allowable to properly actuate the required function(s):

This is designated as the pressure-limited case. The design factor for this condition is the pressure-limited factor, $\mathrm{F_P}$.

The design factor shall be applied to the hydraulic volume, not the gas volume. As such, accumulator designs that include an area ratio between the gas volume and the fluid volume shall modify the pressure-limited volumetric efficiency calculations appropriately.

All conditions that affect the MOP must be included in the MOP calculation, such as shearing pressure, pressure required for sealing (MOPFLPS), wellbore pressure effects, shearing/closing ratios, effective vent pressure, etc.

The rated working pressure of the ram BOPs shall be an absolute pressure. There are two exceptions to this requirement:

— When sizing the main accumulator system for a subsea BOP stack, the rated working pressure shall be calculated as a gauge pressure, which calculates the worst case design scenario when the stack is at maximum water depth.

— If the subsea BOP designs are properly evaluated and validated using the design assessment procedures proposed in API 17TR12 and will be used above the absolute pressure ratings as described in API 17TR04, then the rated working pressure of the ram BOPs shall be calculated as a gauge pressure when sizing subsea accumulators.

B.5 Condition 3: Total Discharge

For the condition state of the accumulator gas when the accumulator hydraulic volume has been discharged:

This is designated as the volume-limited condition. The volume design factor for this condition is the volume-limited factor, F_{V}.

The design factor shall be applied to the hydraulic volume, not the gas volume. As such, accumulator designs that include an area ratio between the gas volume and the fluid volume shall modify the volume-limited volumetric efficiency calculations appropriately.

The volume-limited factor, F_V, may be insufficient for some system designs (small BOP systems, systems with MOPs that approach accumulator charge pressure, systems that do not maintain fluid in the control lines, etc.). The equipment manufacturer shall include a higher design factor or additional considerations to achieve the accumulator system requirements based on their design.

B.6 Accumulator Sizing Methods

NOTE Method A has been withdrawn effective with the third edition of API 16D, and shall not be used for accumulator calculations in control system design.

Method B calculations shall utilize real gas properties (not ideal gas properties) as an isothermal discharge, with a 1.4 volume correction factor for volume-limited discharge and a 1.0 volume correction factor for pressure-limited discharge.

Method C calculations shall utilize real gas properties as an adiabatic discharge, with a 1.1 volume correction factor for volume-limited discharge and a 1.1 volume correction factor for pressure-limited discharge.

For a given accumulator volume, precharge conditions, and full-charge conditions, Methods B and Method C provide the same stored hydraulic fluid. The difference between Method B and Method C is how the discharge is calculated, isothermal vs adiabatic. The adiabatic discharge assumes no heat transfer into the gas; so as the gas cools significantly, the pressure is reduced. Method C calculation results are conservative with regard to the remaining pressure available, as heat transfer occurs over a period of time.

For systems where the calculation method has not been defined, evaluation of environmental conditions, functional requirements, and operational data requires sound engineering evaluation.

B.7 Less-than-ambient Pressure Chambers

Effective vent pressure is the pressure at the fluid discharge port to sea or other environment, as altered by any de-boosting equipment on the exhaust side of an operator. In most systems, the effective vent pressure (EVP) is the static pressure of the sea (or 1 atm for surface systems). Utilizing a system that changes effective vent pressure decreases the MOP. When utilized in a circuit that includes an accumulator calculation, the effective vent pressure reduces the appropriate function MOP and require modification of the formulas for calculation of VE_V.

Systems that use less-than-ambient pressure chambers to either reduce the hydraulic pressure required or to increase the efficiency of a gas chamber shall include a method of monitoring the less-than-ambient chamber(s) pressure.

B.8 Temperature Range Effects on Volumetric Efficiency

As temperature has an effect on the volume of usable fluid and pressure the accumulator system can provide, the sizing calculations shall include the effects of temperature variation when large operating temperature ranges are expected (see Figure B.1). Pressure-limited volumetric efficiency decreases during operations as temperature drops. In contrast, the volume-limited volumetric efficiency decreases during operations as temperature rises.

— The low temperature shall be used with the pressure-limited volumetric efficiency calculations.

— The high temperature shall be used with the volume-limited volumetric efficiency calculations.

For example, to account for a ±30 °F temperature range for an accumulator precharged at 70 °F, the calculations for the pressure-limited volumetric efficiency shall use gas densities at 40 °F. The volume-limited volumetric efficiency shall use gas densities at 100 °F.

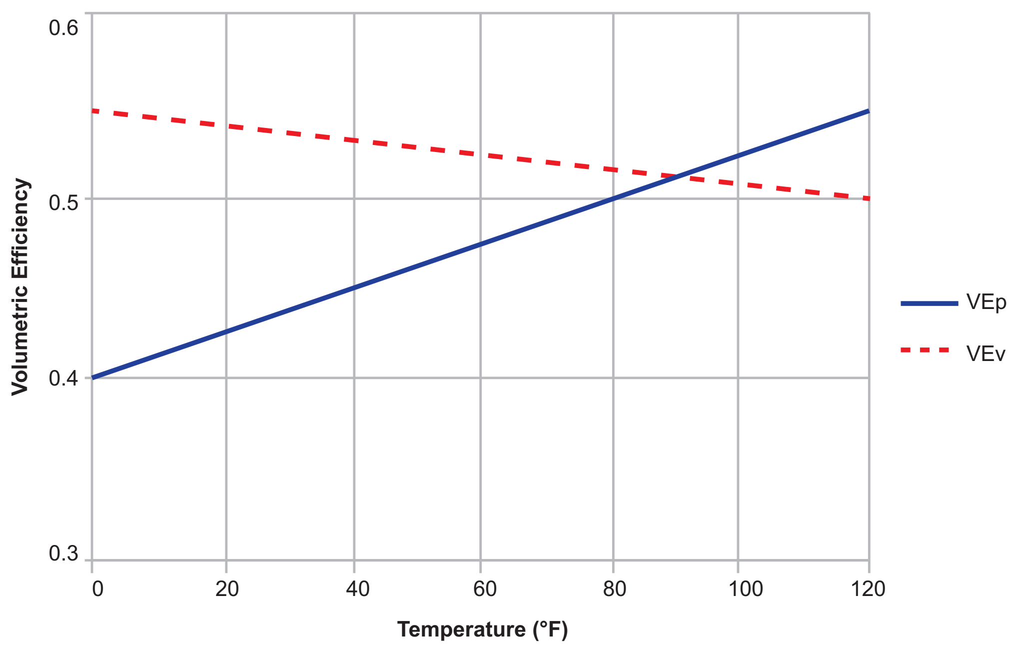


Figure B.1—Effect of Temperature Range on Volumetric Efficiencies

Annex C
(informative)

Accumulator Sizing Calculation Derivations

C.1 Terminology used for Accumulator Sizing Calculations

C.1.1 Minimum Operating Pressure

Minimum pressure differential required for a device to successfully perform its intended function in a particular environment.

C.1.2 Pressure

The ratio of force to the area over which that force is distributed [i.e. pound-force applied to an area (square inches), measured in “psi’, etc.]:

— absolute pressure—the pressure referenced against a vacuum, (e.g. psia, MPa [abs]);

— differential pressure—the difference in pressure between any two points (p1 and p2), (e.g. psid)

— gauge pressure—differential pressure relative to ambient pressure (e.g. atmospheric for surface application, hydrostatic for subsea application), (e.g. psig, MPa [gauge]).

If pressure is used with units other than those defined, the reference pressure shall be clearly stated.

C.1.3 Pressure-limited Volumetric Efficiency (VE_p)

The ratio of the deliverable control fluid above MOP to the total gas volume of the accumulator, based on design conditions and calculation method.

C.1.4 Volume-limited Volumetric Efficiency (VE_v)

The ratio of deliverable control fluid above local ambient pressure to the total gas volume of the accumulator, based on design conditions and calculation method.

NOTE If the local ambient pressure is less than the precharge pressure, then the deliverable fluid is all of the stored control fluid.

C.1.5 Volumetric Efficiency (VE)

For calculations in accordance with 16D, this is the overall volumetric efficiency of the accumulator system and is the minimum of the pressure-limited (VE_p) and volume-limited (VE_v) volumetric efficiencies.

C.2 Volumetric Efficiency Calculations

The following equations listed in this and following sections apply to conventional piston or bladder accumulators only. Accumulator designs that include an area ratio between the gas volume and the fluid volume (such as depth compensated accumulators) shall modify the volumetric efficiency calculations appropriately.

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

$$VE_n = \frac{(V_n - V_1)}{(V_0)F} \tag{C.1}$$

where

V_0 is the gas volume at Condition 0 (precharge);

V_1 is the gas volume at Condition 1 (charged);

V_n is the gas volume at withdrawal condition of interest:

Condition 2 (minimum operating pressure), or

Condition 3 (total discharge);

F is the 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 be expressed by the following:

$$V_n = \frac{m}{\rho_n} \tag{C.2}$$

where

m is the mass of the gas;

ρ_n is the gas density at Condition *n*.

Therefore,

$$VE_n = \frac{\left(\frac{m}{\rho_n} - \frac{m}{\rho_1}\right)}{\left(\frac{m}{\rho_0}\right)F}$$

$$VE_n = \frac{\left(\frac{1}{\rho_n} - \frac{1}{\rho_1}\right)}{\left(\frac{1}{\rho_0}\right)F}$$

$$VE_n = \frac{\left(\frac{\rho_0}{\rho_n} - \frac{\rho_0}{\rho_1}\right)}{F} \tag{C.3}$$

where

ρ_0 is the gas density at precharge;

ρ_1 is the gas density when fully charged at the hydraulic supply pressure plus hydrostatic pressure of control fluid column (usually fresh water at 0.433 psi/ft).

For the Condition 2 pressure-limited case:

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_2} - \frac{\rho_0}{\rho_1}\right)}{F_p}, \qquad (\rho_2 \text{ shall be} \geq \rho_0) \tag{C.4}$$

where

ρ_2 is the gas density when the accumulator fluid pressure is at the minimum operating pressure

For the Condition 3 volume-limited case:

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_3} - \frac{\rho_0}{\rho_1}\right)}{F_V}$$

For the total discharge case, $\rho_3 = \rho_0$, therefore:

$$VE_V = \frac{\left(1 - \frac{\rho_0}{\rho_1}\right)}{F_V}$$

For systems that modify effective vent pressure (EVP):

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_{EVP}} - \frac{\rho_0}{\rho_1}\right)}{F_V}$$

For optimum precharge:

$$VE_P = VE_V$$

$$\frac{\left(\frac{\rho_0}{\rho_2} - \frac{\rho_0}{\rho_1}\right)}{F_P} = \frac{\left(1 - \frac{\rho_0}{\rho_1}\right)}{F_v}$$

Rearranged for optimum precharge density:

$$\rho_0 = \frac{F_p}{\left[\frac{F_V}{\rho_2} - \frac{(F_V - F_P)}{\rho_1}\right]}$$

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

C.3 Method A

Method A has been withdrawn effective with the third edition of 16D, and shall not be used for accumulator calculations in control system design.

C.4 Method B

For Method B, the general equations become:

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_2} - \frac{\rho_0}{\rho_1}\right)}{1.0}, \qquad (\rho_2 \text{ shall be} \geq \rho_0)$$

$$VE_V = \frac{\left(1 - \frac{\rho_0}{\rho_1}\right)}{1.4}$$

If P_0 is less than ambient and hydraulic fluid is vented to ambient, then P_3 = ambient hydrostatic absolute pressure (does not equal P_0):

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_3} - \frac{\rho_0}{\rho_1}\right)}{1.4}$$

If P_2 is less than ambient pressure and hydraulic fluid is not vented to ambient, then P_2 = effective vent absolute pressure.

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_{EVP}} - \frac{\rho_0}{\rho_1}\right)}{1.4}$$

Optimum precharge density becomes:

$$\rho_0 = \frac{1.0}{\left(\frac{1.4}{\rho_2} - \frac{0.4}{\rho_1}\right)}$$

See Annex D for accumulator sizing calculation examples.

C.5 Method C

For Method C, the general equations become:

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_2} - \frac{\rho_0}{\rho_1}\right)}{1.1}, \qquad (\rho_2 \text{ shall be} \geq \rho_0)$$

$$VE_V = \frac{\left(1 - \frac{\rho_0}{\rho_1}\right)}{1.1}$$

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 (if hydraulic fluid is vented to the seawater environment). Calculate ρ_3 for this new pressure, and:

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_3} - \frac{\rho_0}{\rho_1}\right)}{1.1}$$

If P_2 is less than ambient pressure and hydraulic fluid is not vented to ambient, then P_2 = effective vent absolute pressure.

$$VE_V = \frac{\left(\frac{\rho_0}{\rho_{EVP}} - \frac{\rho_0}{\rho_1}\right)}{1.1}$$

Optimum precharge density becomes:

$$\rho_0 = \rho_2$$

Optimum precharge pressure P_0 is the 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 expansion from Condition 1 to the pressure condition of interest.

See Annex D for accumulator sizing calculation examples.

C.6 Combined Method B and C Optimization

The following details calculations derived to determine the optimal precharge for a set of accumulators that are required to satisfy both a Method B requirement and a Method C requirement. This is useful when sizing the main accumulator system to have enough capacity to pass a Method B drawdown test or to perform a Method C well control sequence (does not account for operating both without recharging accumulators).

It is useful to view the curves generated by plotting the results from both a Method B and Method C calculation on a graph showing required accumulator volume vs precharge pressure (see Figures C.1, C.2, and C.3).

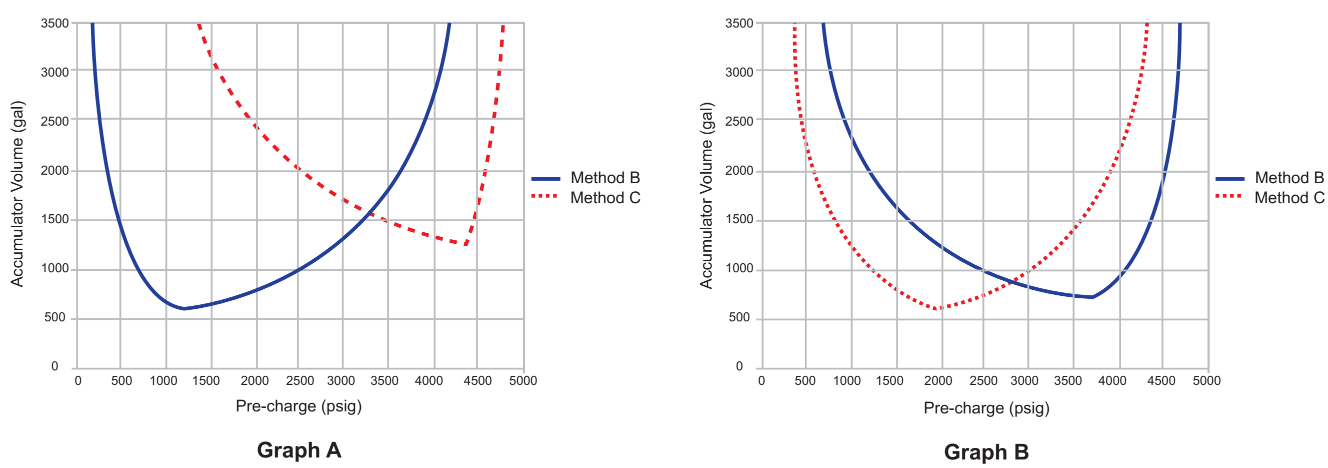


Figure C.1—Intersection of the Method B (Solid Line) and Method C (Dotted Line) Curves

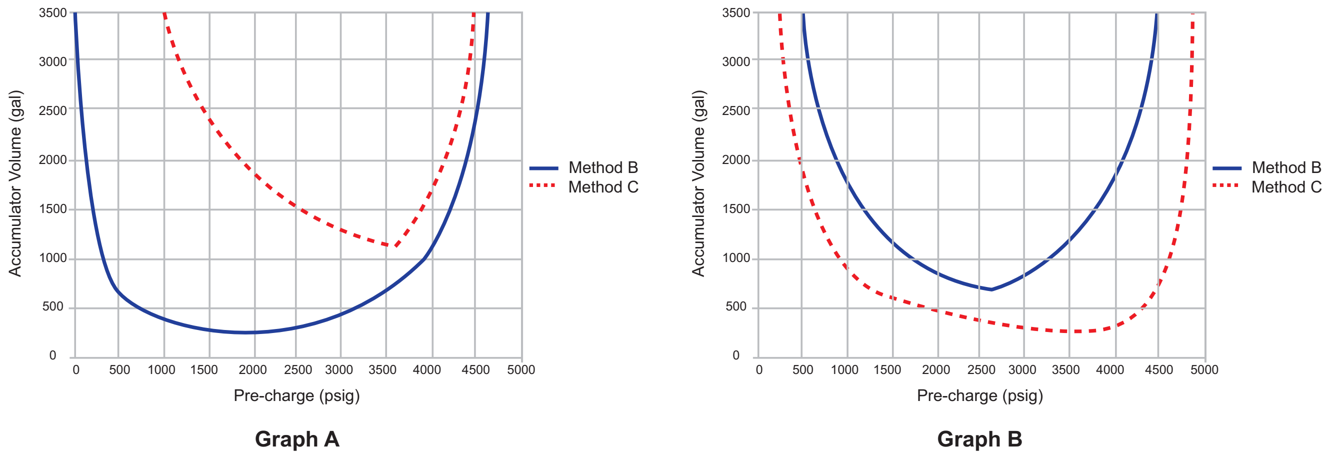


Figure C.2—Nonintersecting Curves When the Method C Curve (Dotted Line) Has a Larger Optimum Precharge Pressure than the Method B Curve (Solid Line)

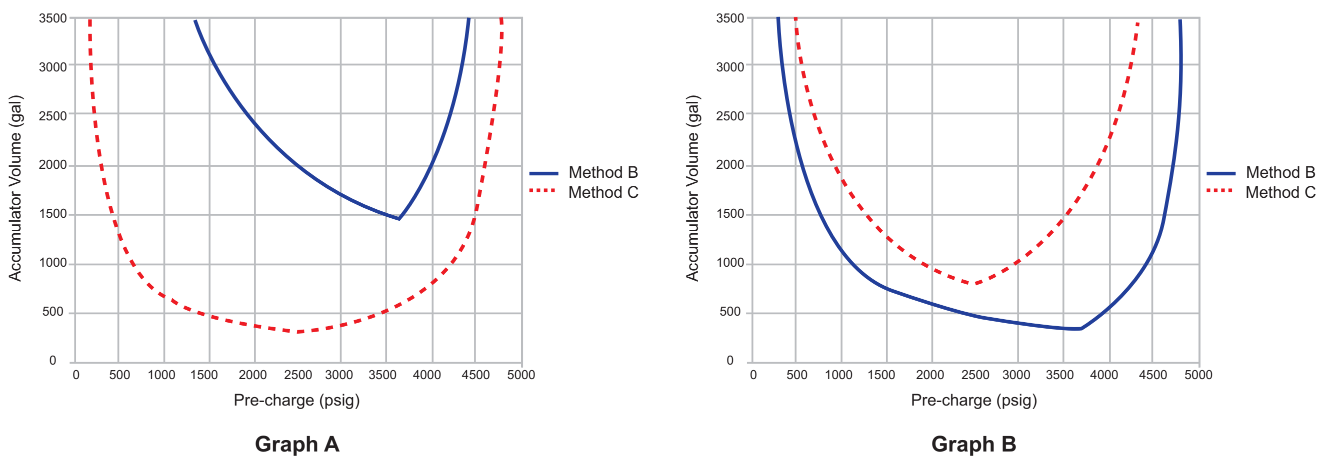


Figure C.3—Nonintersecting Curves When the Method B (Solid Line) Has a Larger Optimum Precharge Pressure than the Method C Curve (Dotted Line)

As shown, there are six possible scenarios for the orientation of the Method B and Method C curves relative to each other. The particular form of each chart is dependent upon the functional volume requirements and MOPs of the two sequences.

The equation to determine the optimal precharge for all six possible curve forms is as follows:

if $\rho_{0B} < \rho_{XBC} < \rho_{0C}$,

then $\rho_0 = \rho_{XBC}$

else if $\rho_{0C} < \rho_{XCB} < \rho_{0B}$,

then $\rho_0 = \rho_{XCB}$

else if $V_{0B} < V_{0C}$

then $\rho_0 = \rho_{0C}$

else $\rho_0 = \rho_{0B}$

where

ρ_{0B} is the optimum precharge density for the Method B sequence as defined in C4.

$$\rho_{0B} = \frac{1.0}{\left(\frac{1.4}{\rho_2} - \frac{0.4}{\rho_1}\right)}$$

ρ_{0C} is the optimum precharge density for the Method C sequence as defined in C.5.

$$\rho_{0C} = \rho_2$$

ρ_{XBC} is the optimum precharge density defined by the precharge pressure at the intersection of the volume-limited curve of Method B and the pressure-limited curve for Method C. This can be seen in Graph A in Figure C.1.

$$\rho_{XBC} = \frac{1.1FVR_C}{\left[1.4FVR_B\left(\frac{1.0}{\rho_{2C}} - \frac{1.0}{\rho_{1C}}\right) + 1.1FVR_C\left(\frac{1.0}{\rho_{1B}}\right)\right]}$$

ρ_{XCB} is the optimum precharge density defined by the precharge pressure at the intersection of the pressure-limited curve of Method B and the volume-limited curve for the Method C. This can be seen in Graph B in Figure C.1.

$$\rho_{XCB} = \frac{FVR_B}{\left[1.1FVR_C\left(\frac{1.0}{\rho_{2B}} - \frac{1.0}{\rho_{1B}}\right) + FVR_B\left(\frac{1.0}{\rho_{1C}}\right)\right]}$$

V_{0B} is the accumulator volume required at the optimum precharge pressure for Method B.

$$V_{0B} = \frac{FVR_B}{\left(\frac{\rho_{1B} - \rho_{2B}}{1.4\rho_{1B} - 0.4\rho_{2B}}\right)}$$

V_{0C} is the accumulator volume required at the optimum precharge pressure for Method C.

$$V_{0C} = \frac{1.1FVR_C}{\left(1.0 - \frac{\rho_{2C}}{\rho_{1C}}\right)}$$

FVR_B is the functional volume requirement for the Method B sequence.

FVR_C is the functional volume requirement for the Method C sequence.

ρ_{1B} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method B sequence.

ρ_{1C} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method C sequence.

NOTE The charged condition for the Method B sequence is the pump stop pressure, while the Method C sequence uses the pump start pressure.

ρ_{2B} is the density of the gas in the accumulator as described by ρ_2 in C.2 for a Method B sequence.

ρ_{2C} is the density of the gas in the accumulator as described by ρ_2 in C.2 for a Method C sequence.

Derivation of ρ_{XBC}

When the volume-limited curve of Method B intersects the pressure-limited curve of Method B (Figure C.1, Graph A), the optimal precharge pressure occurs at the intersection and requires the least amount of accumulator volume to satisfy both sequences. The density of the gas at this point is defined as ρ_{XBC}. At this precharge density the required accumulator volume for each method is equal:

$$V_B = V_C$$

This can be rewritten in terms of the FVR_B and the VE_V for Method B and FVR_C and VE_P for Method C:

$$\frac{FVR_B}{VE_V(\text{Method B})} = \frac{FVR_C}{VE_P(\text{Method C})}$$

$$FVR_B \times VE_P(\text{Method C}) = FVR_C \times VE_V(\text{Method B})$$

Substitute the formulas for volumetric efficiency as defined in C.4 and C.5:

$$FVR_B\frac{\left(\frac{\rho_0}{\rho_{2C}} - \frac{\rho_0}{\rho_{1C}}\right)}{1.1} = FVR_C\frac{\left(1.0 - \frac{\rho_0}{\rho_{1B}}\right)}{1.4}$$

$$1.4\rho_0 FVR_B\left(\frac{1.0}{\rho_{2C}} - \frac{1.0}{\rho_{1C}}\right) = 1.1FVR_C - 1.1\rho_0 FVR_C\left(\frac{1.0}{\rho_{1B}}\right)$$

Collect all optimum precharge density terms:

$$\rho_0\left[1.4FVR_B\left(\frac{1.0}{\rho_{2C}} - \frac{1.0}{\rho_{1C}}\right) + 1.1FVR_C\left(\frac{1.0}{\rho_{1B}}\right)\right] = 1.1FVR_C$$

Rearrange for optimum precharge density:

$$\rho_{XBC} = \frac{1.1FVR_C}{\left[1.4FVR_B\left(\frac{1.0}{\rho_{2C}} - \frac{1.0}{\rho_{1C}}\right) + 1.1FVR_C\left(\frac{1.0}{\rho_{1B}}\right)\right]}$$

Derivation of ρ_{XCB}

When the pressure-limited curve of Method B intersects the volume-limited curve of Method B (Figure C.1, Graph B), the optimal precharge pressure occurs at the intersection and requires the least amount of accumulator volume to satisfy both sequences. The density of the gas at this point is defined as ρ_{XCB}. At this precharge density, the required accumulator volume for each method is equal:

$$V_B = V_C$$

This can be rewritten in terms of the FVR_B and the VE_P for Method B and FVR_C and VE_V for Method C:

$$\frac{FVR_B}{VE_P(\text{Method B})} = \frac{FVR_c}{VE_V(\text{Method C})}$$

$$FVR_B{*}VE_V(\text{Method C}) = FVR_C{*}VE_P(\text{Method B})$$

Substitute the formulas for volumetric efficiency as defined in C.4 and C.5:

$$FVR_B\frac{\left(1.0-\frac{\rho_0}{\rho_{1C}}\right)}{1.1} = FVR_C\frac{\left(\frac{\rho_0}{\rho_{2B}}-\frac{\rho_0}{\rho_{1B}}\right)}{1.0}$$

$$FVR_B\left(1.0-\frac{\rho_0}{\rho_{1C}}\right) = 1.1FVR_C\left(\frac{\rho_0}{\rho_{2B}}-\frac{\rho_0}{\rho_{1B}}\right)$$

$$FVR_B = 1.1\rho_0FVR_C\left(\frac{1.0}{\rho_{2B}}-\frac{1.0}{\rho_{1B}}\right)+\rho_0FVR_B\left(\frac{1.0}{\rho_{1C}}\right)$$

Collect all optimum precharge density terms:

$$\rho_0\left[1.1FVR_C\left(\frac{1.0}{\rho_{2B}}-\frac{1.0}{\rho_{1B}}\right)+FVR_B\left(\frac{1.0}{\rho_{1C}}\right)\right] = FVR_B$$

Rearrange for optimum precharge density:

$$\rho_{XCB} = \frac{FVR_B}{\left[1.1FVR_C\left(\frac{1.0}{\rho_{2B}}-\frac{1.0}{\rho_{1B}}\right)+FVR_B\left(\frac{1.0}{\rho_{1C}}\right)\right]}$$

When the curves do not intersect, such as in Figures C.2 and C.3, then the optimal precharges for the individual Method B and C sequences must be compared. The sequence that requires the largest amount of accumulator volume at its optimal precharge pressure drives the optimal precharge pressure for the accumulator system.

Derivation of V_{0B}

To determine the accumulator volume required at the optimum precharge pressure for Method B, substitute the optimum precharge pressure into the equation for volumetric efficiency (does not matter if the pressure-limited or volume-limited volumetric efficiency is used since they are equal at the optimal precharge pressure. The pressure-limited equation was used for ease of calculations).

$$\rho_0 = \frac{1.0}{\left(\frac{1.4}{\rho_{2B}}-\frac{0.4}{\rho_{1B}}\right)}$$

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_{2B}}-\frac{\rho_0}{\rho_{1B}}\right)}{1.0} = \rho_0\left(\frac{1}{\rho_{2B}}-\frac{1}{\rho_{1B}}\right) = \frac{\left(\frac{1}{\rho_{2B}}-\frac{1}{\rho_{1B}}\right)}{\left(\frac{1.4}{\rho_{2B}}-\frac{0.4}{\rho_{1B}}\right)}$$

The equation can be simplified by multiplying by 1:

$$VE_P = \frac{\left(\frac{1}{\rho_{2B}}-\frac{1}{\rho_{1B}}\right)}{\left(\frac{1.4}{\rho_{2B}}-\frac{0.4}{\rho_{1B}}\right)} * \left(\frac{\rho_{1B}\rho_{2B}}{\rho_{1B}\rho_{2B}}\right) = \frac{(\rho_{1B}-\rho_{2B})}{(1.4_{1B}-1.4_{2B})}$$

Substitute into the equation for volume:

$$V_{0B} = \frac{FVR_B}{VE_P} = \frac{FVR_B}{\left(\frac{\rho_{1B} - \rho_{2B}}{1.4\rho_{1B} - 0.4\rho_{2B}}\right)}$$

Derivation of V_{0C}

To determine the accumulator volume required at the optimum precharge pressure for Method C, substitute the optimum precharge pressure into the equation for volumetric efficiency (does not matter if the pressure-limited or volume-limited volumetric efficiency is used since they are equal at the optimal precharge pressure. The volume-limited equation was used for ease of calculations.)

$$\rho_0 = \rho_{2C}$$

$$VE_V = \frac{\left(1 - \frac{\rho_0}{\rho_{1C}}\right)}{1.1} = \frac{\left(1 - \frac{\rho_{2C}}{\rho_{1C}}\right)}{1.1}$$

Substitute into the equation for volume:

$$V_{0C} = \frac{FVR_C}{VE_V} = \frac{1.1FVR_C}{\left(1.0 - \frac{\rho_{2C}}{\rho_{1C}}\right)}$$

C.7 Method C Two-function Sequence Optimization

The following details calculations derived to determine the optimal precharge for a set of accumulators that must satisfy a Method C calculation for two functions that are operated consecutively in sequence without recharging, such as with a deadman sequence that closes a casing shear ram followed by a blind shear ram.

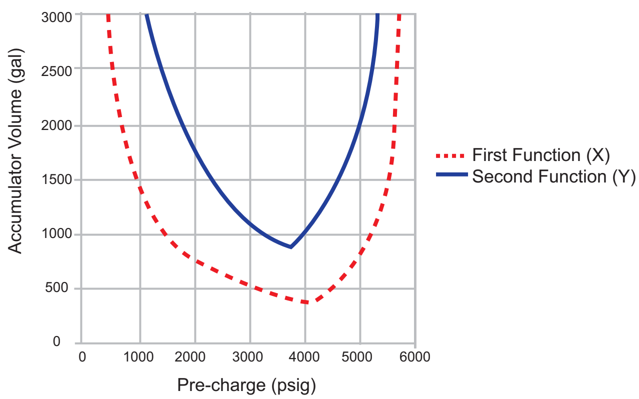
Figure C.4 shows two graphs that plot precharge pressure versus required accumulator volume. Function X is the first function to occur in the sequence while function Y is the second function in the sequence. The volume-limited curve of the second function always show a larger required accumulator volume than for the first function since the dispensed volume for the second function must include the volume of the first function. However, the pressure-limited curve of either function may require a larger accumulator volume depending on the MOP of that function. When the pressure-limited curve of the second function requires less volume than for the first function, an intersection of the two curves occurs. Therefore, for a two-function sequence Method C calculation there are two curve forms possible. The first is depicted in the left graph and shows that the second function (Y) drives the required accumulator volume. The other possible curve form exists when the volume-limited curve for the second function (Y) intersects the pressure-limited curve of the first function (X). In this scenario, the optimal precharge pressure for the overall sequence is found at the intersection of the two curves.

The following formula was derived to calculate the optimal precharge density that requires the least amount of accumulator volume for a two-function Method C sequence:

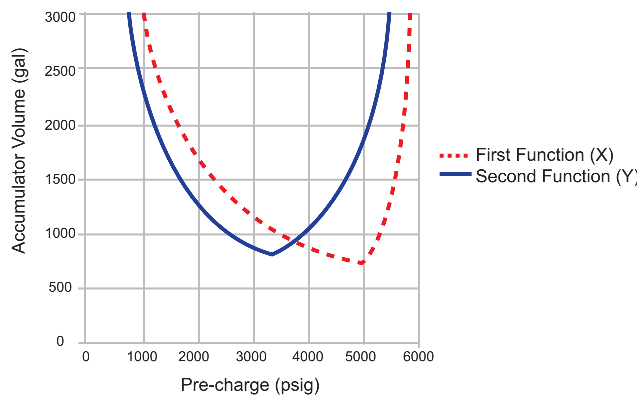
If $\rho_{0X} > \rho_{0XY} > \rho_{0Y}$

then $\rho_0 = \rho_{0XY}$

else $\rho_0 = \rho_{0Y}$



Graph A



Graph B

Figure C.4—Graphs for a Two-function Method C Sequence

where

ρ_{0X} is the optimum precharge density of the gas in the accumulator as described by ρ_0 in C.5 for the first function in a Method C sequence.

ρ_{0Y} is the optimum precharge density of the gas in the accumulator as described by ρ_0 in C.5 for the second function in a Method C sequence.

ρ_{0XY} is the density of the gas in the accumulator at the precharge pressure at the intersection of the pressure-limited curve of the first function and the volume-limited curve of the second function for a Method C sequence. This can be seen in Graph B in Figure C.4.

$$\rho_{0XY} = \frac{FVR_X}{\left[(FVR_X + FVR_Y)\left(\frac{1.0}{\rho_{2X}} - \frac{1.0}{\rho_1}\right) + FVR_X\left(\frac{1.0}{\rho_1}\right)\right]}$$

Derivation of ρ_{0XY}

At the intersection of the pressure-limited curve of the first function and the volume-limited curve of the second function, the required accumulator volumes are equal.

$$V_X = V_Y$$

The volume for the second function must include the volume of the first function since it must be dispensed first.

$$\frac{FVR_X}{VE_{PX}} = \frac{(FVR_X + FVR_Y)}{VE_{VY}}$$

$$FVR_X VE_{VY} = (FVR_X + FVR_Y) VE_{PX}$$

Substitute the formulas for volumetric efficiency from C.5.

$$FVR_X\frac{\left(1.0-\frac{\rho_0}{\rho_1}\right)}{1.1} = (FVR_X+FVR_Y)\frac{\rho_0\left(\frac{1.0}{\rho_{2X}}-\frac{1.0}{\rho_1}\right)}{1.1}$$

$$FVR_X-\rho_0 FVR_X\left(\frac{1.0}{\rho_1}\right)= \rho_0(FVR_X+FVR_Y)\left(\frac{1.0}{\rho_{2X}}-\frac{1.0}{\rho_1}\right)$$

$$\rho_0\left[(FVR_X+FVR_Y)\left(\frac{1.0}{\rho_{2X}}-\frac{1.0}{\rho_1}\right)+FVR_X\left(\frac{1.0}{\rho_1}\right)\right]= FVR_X$$

Rearrange for optimum precharge density:

$$\rho_{0XY} = \frac{FVR_X}{\left[(FVR_X+FVR_Y)\left(\frac{1.0}{\rho_{2X}}-\frac{1.0}{\rho_1}\right)+FVR_X\left(\frac{1.0}{\rho_1}\right)\right]}$$

C.8 Method B with Temperature Range

The volumetric efficiencies for the pressure- and volume-limited cases can be rewritten to account for the temperature range as follows:

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_{2L}}-\frac{\rho_0}{\rho_{1L}}\right)}{1.0}, (\rho_2 \text{ shall be } \geq \rho_0)$$

$$VE_V = \frac{\left(1-\frac{\rho_0}{\rho_{1H}}\right)}{1.4}$$

where

ρ_{1L} is the density of the gas in the accumulator at the charged condition for the low end of the temperature range.

ρ_{1H} is the density of the gas in the accumulator at the charged condition for the high end of the temperature range.

ρ_{2L} is the density of the gas in the accumulator at the MOP of the function for the high end of the temperature range.

For optimum precharge density:

$$VE_P = VE_V$$

$$\frac{\left(\frac{\rho_0}{\rho_{2L}}-\frac{\rho_0}{\rho_{1L}}\right)}{1.0} = \frac{\left(1-\frac{\rho_0}{\rho_{1H}}\right)}{1.4}$$

$$1.4_{\rho 0}\left(\frac{1.0}{\rho_{2L}}-\frac{1.0}{\rho_{1L}}\right)+\rho_0\left(\frac{1.0}{\rho_{1H}}\right)= 1.0$$

Rearranged for optimum precharge density:

$$\rho_0 = \frac{1.0}{\left(\frac{1.4}{\rho_{2L}} - \frac{1.4}{\rho_{1L}} + \frac{1.0}{\rho_{1H}}\right)}$$

See Annex D for accumulator sizing calculation examples.

C.9 Method C with Temperature Range

The volumetric efficiencies for the pressure- and volume-limited cases can be rewritten to account for the temperature range as follows:

$$VE_P = \frac{\left(\frac{\rho_0}{\rho_{2L}} - \frac{\rho_0}{\rho_{1L}}\right)}{1.1}, (\rho_2 \text{ shall be } \geq \rho_0)$$

$$VE_V = \frac{\left(1 - \frac{\rho_0}{\rho_{1H}}\right)}{1.1}$$

For optimum precharge:

$$VE_P = VE_V$$

$$\frac{\left(\frac{\rho_0}{\rho_{2L}} - \frac{\rho_0}{\rho_{1L}}\right)}{1.1} = \frac{\left(1 - \frac{\rho_0}{\rho_{1H}}\right)}{1.1}$$

$$\rho_0\left(\frac{1.0}{\rho_{2L}} - \frac{1.0}{\rho_{1L}} + \frac{1.0}{\rho_{1H}}\right) = 1.0$$

Rearranged for optimum precharge density:

$$\rho_0 = \frac{1.0}{\left(\frac{1.0}{\rho_{2L}} - \frac{1.0}{\rho_{1L}} + \frac{1.0}{\rho_{1H}}\right)}$$

See Annex D for accumulator sizing calculation examples.

C.10 Combined Method B and C Optimization with Temperature Range

To use the Method B and Method C optimization while including the effects of a temperature range into the equation, the following adjusted equation should be used

if $\rho_{0B} < \rho_{XBC} < \rho_{0C}$,

then $\rho_0 = \rho_{XBC}$

else if $\rho_{0C} < \rho_{XCB} < \rho_{0B}$

then $\rho_0 = \rho_{XCB}$

else if $V_{0B} < V_{0C}$

then $\rho_0 = \rho_{0C}$

else $\rho_0 = \rho_{0B}$

where

ρ_{0B} is the optimum precharge density for the Method B sequence adjusted for temperature range effects as defined in C.8.

$$\rho_{0B} = \frac{1.0}{\left(\frac{1.4}{\rho_{2L}} - \frac{1.4}{\rho_{1L}} + \frac{1.0}{\rho_{1H}}\right)}$$

ρ_{0C} is the optimum precharge density for the Method C sequence adjusted for temperature range effects as defined in C.9.

$$\rho_0 = \frac{1.0}{\left(\frac{1.0}{\rho_{2L}} - \frac{1.0}{\rho_{1L}} + \frac{1.0}{\rho_{1H}}\right)}$$

ρ_{XBC} is the optimum precharge density defined by the precharge pressure at the intersection of the volume-limited curve of Method B and the pressure-limited curve for the Method C and modified for temperature range effects as defined in B.8. This can be seen in Graph A in Figure C.1.

$$\rho_{XBC} = \frac{1.1FVR_C}{\left[1.4FVR_B\left(\frac{1.0}{\rho_{2CL}} - \frac{1.0}{\rho_{1CL}}\right) + 1.1FVR_C\left(\frac{1.0}{\rho_{1BH}}\right)\right]}$$

ρ_{XCB} is the optimum precharge density defined by the precharge pressure at the intersection of the pressure-limited curve of Method B and the volume-limited curve for the Method C and modified for temperature range effects as defined in B.8. This can be seen in Graph B in Figure C.1.

$$\rho_{XCB} = \frac{FVR_B}{\left[1.1FVR_C\left(\frac{1.0}{\rho_{2BL}} - \frac{1.0}{\rho_{1BL}}\right) + FVR_B\left(\frac{1.0}{\rho_{1CH}}\right)\right]}$$

V_{0B} is the accumulator volume required at the optimum precharge pressure for Method B modified for temperature range effects.

$$V_{0B} = FVR_B\frac{\left(\frac{1.4}{\rho_{2BL}} - \frac{1.4}{\rho_{1BL}} + \frac{1}{\rho_{1BH}}\right)}{\left(\frac{1.0}{\rho_{2BL}} - \frac{1.0}{\rho_{1BL}}\right)}$$

V_{0C} is the accumulator volume required at the optimum precharge pressure for Method C modified for temperature range effects.

$$V_{0C} = 1.1FVR_C\frac{\left(\frac{1.0}{\rho_{2CL}} - \frac{1.0}{\rho_{1CL}} + \frac{1.0}{\rho_{1CH}}\right)}{\left(\frac{1.0}{\rho_{2CL}} - \frac{1.0}{\rho_{1CL}}\right)}$$

ρ_{1BL} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method B sequence at the low end of the temperature range.

ρ_{1CL} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method C sequence at the low end of the temperature range.

ρ_{1BH} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method B sequence at the high end of the temperature range.

ρ_{1CH} is the density of the gas in the accumulator as described by ρ_1 in C.2 for a Method C sequence at the high end of the temperature range.

ρ_{2BL} is the density of the gas in the accumulator as described by ρ_2 in C.2 for a Method B sequence at the low end of the temperature range.

ρ_{2CL} is the density of the gas in the accumulator as described by ρ_2 in C.2 for a Method C sequence at the low end of the temperature range.

The derivations for ρ_{XBC}, ρ_{XCB}, V_{0B}, and V_{0C} are very similar to those shown in C.6, and is therefore not shown.

C.11 Method C, Two-function Optimization with Temperature Range Effects

To utilize the Two-function Method C optimization while including the effects of a temperature range into the equation, the following adjusted equation should be used

If $\rho_{0X} > \rho_{0XY} > \rho_{0Y}$

then $\rho_0 = \rho_{0XY}$

else $\rho_0 = \rho_{0Y}$

where

ρ_{0X} is the optimum precharge density of the gas in the accumulator as described by ρ_0 in C.9 for the first function in a Method C sequence. Temperature range effects are included in the calculations.

ρ_{0Y} is the optimum precharge density of the gas in the accumulator as described by ρ_0 in C.9 for the second function in a Method C sequence. Temperature range effects are included in the calculations.

ρ_{0XY} is the density of the gas in the accumulator at the precharge pressure at the intersection of the pressure-limited curve of the first function and the volume-limited curve of the second function for a Method C sequence. This can be seen in Graph B in Figure C.4. Temperature range effects are included in the calculation.

$$\rho_{0XY} = \frac{FVR_X}{\left[(FVR_X + FVR_Y)\left(\frac{1.0}{\rho_{2XL}} - \frac{1.0}{\rho_{1L}}\right) + FVR_X\left(\frac{1.0}{\rho_{1H}}\right)\right]}$$

ρ_{1L} is the density of the gas in the accumulator at the charged condition at the low end of the temperature range.

ρ_{1H} is the density of the gas in the accumulator at the charged condition at the high end of the temperature range.

ρ_{2XL} is the density of the gas in the accumulator at the MOP of the second function for the low end of the temperature range.

Annex D
(informative)

Accumulator Sizing Examples

D.1 Summary of Examples

Annex D features a summary of examples that have been divided into tables and also include figures so that the reader can comprehend the information more easily.

Table D.1—Summary of Examples

Example	System Case	Equipment Case	Design Method	Circuit Pressure [a]	Notes	Minimum Required Accumulator Volume (gal)
1	Land Rig	Main Accumulators	B (drawdown) C (well control)	3000 2700	±50 °F temperature range considered	79.5
2	Offshore Surface Sack with dedicated shear accumulator	Main Accumulators	B (drawdown) C (well control)	3000 2700	±30 °F temperature range considered	336.5
3		Pilot Accumulators	B (open and close all BOPS)	3000	±30 °F temperature range considered	0.097
4		Detailed Shear Accumulators (not supplied by main accumulators)	C	4500	±30 °F temperature range considered	90.7
5		Diverter Accumulators	C	3000	±30 °F temperature range considered	140.1
6	Offshore Surface Sack without dedicated shear accumulator	Main Accumulators	B (drawdown) C (well control)	3000 2700	±30 °F temperature range considered	655.9
7	Subsea Stack	Main Accumulators	C (well control)	5000 4500	—	975.5
8		Pilot Accumulators	B (open and close all BOPS C (EDS)	3000	—	1.449
9		DMAS/Shear Accumulators	C	5000	—	1576.9
10		Acoustic Accumulators	B	5000	—	530.0
11		Diverter Accumulators	C	5000	—	90.5
12	Special Purpose	Depth Compensated Accumulators	C	5000	—	687.9
13		Choke and Kill Valve Closure Assist Accumulators	C	3000	—	58.4

[a] Based on pump start and stop pressures or regulated pressures.

Table D.2—Example 1: BOP Stack Configuration and Parameters for Land Rigs

Example 1: BOP Stack Configuration and Parameters for *Land Rig*

The following example sizes the main accumulator system for a BOP on a land rig. This example will take a 50°F temperature range into consideration.

Stack	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Opening Volume (gal)	Closing Ratio
Annular BOP, 9"	5,000	1,500	10.20	9.60	-
Blind Ram, 9"	5,000	600	5.15	3.50	7.25
Pipe Ram, 9"	5,000	750	3.60	2.25	6.23
Choke & Kill Valve	5,000	780	0.65	0.65	-

System Parameters		
System Pressure	3,000	psig

Environmental Conditions		
Surface Temperature at Precharge	70	°F
Temperature Range (+/- °F)	50	°F
Minimum Surface Temperature	20	°F
Maximum Surface Temperature	120	°F
Atmospheric Pressure	14.7	psia

Relevant References

Main Pump System

- Primary pump start at 90% of system RWP
- Primary pump stop between 98%-100% of system RWP

Ex. 1 Main Accumulator System

- Example rig does not have shear rams installed

Drawdown Test
- Close all rams, open valve, close annular
- Use pump stop pressure
- Method B

Well Control Sequence
- Close annular and pipe ram
- Use pump start pressure
- Method C

Table D.3—Example 1: Land Rig—Main Accumulator Sizing

Example 1: Land Rig - Main Accumulator Sizing

Main Accumulator

This worksheet details the sizing calculations for the Main Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s) - Accumulator Drawdown (Method B)	Rated Working Pressure (psia)	Opening Volume (gal)	Closing Volume (gal)	Closing Ratio	Pressure to Close Against RWP (psig)
Annular BOP, 9"	5,000	9.60	10.20	-	1,500
Blind Ram, 9"	5,000	3.50	5.15	7.25	690
Pipe Ram, 9"	5,000	2.25	3.60	6.23	803
Choke & Kill Valve	5,000	0.65	0.65	-	780

Pressure Required (psig) to Close Blind Ram against Rated Working Pressure = Rated Working Pressure / Closing Ratio = 5000 / 7.25 = 689.7

Total Functional Volume Requirement (FVR_B)	19.60	gal
Pressure Required	1,500	psig

Operator Function(s) - Well Control Sequence (Method C)	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Closing Ratio	Adjusted Pressure Required (psig)
Annular BOP, 9"	5,000	1,500	10.20	-	1,500
Pipe Ram, 9"	5,000	750	3.60	6.23	1,553

Minimum Pressure Required (psig) to Seal with Pipe Ram = MOPFLPS + Rated Working Pressure / Closing Ratio = 750 + 5000 / 6.23 = 1552.6

Total Functional Volume Requirement (FVR_C)	13.80	gal
Pressure Required	1,553	psig

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	70	°F
Temperature Range (+/-)	50	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	3,000	psig
Pump Stop Pressure (Method B - 100%)	3,000	psig
Pump Start Pressure (Method C - 90%)	2,700	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Atmospheric Pressure = 3000 + 14.7 = 3014.7

Condition 1 - Charged Accumulator Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - High Temp (Method B)	3,000	3,015	120	12.623	
Charged Condition - Normal (Method B)	3,000	3,015	70	14.037	
Charged Condition - Low Temp (Method B)	3,000	3,015	20	15.883	
Charged Condition - High Temp (Method C)	2,700	2,715	120	11.518	1.2614603
Charged Condition - Normal (Method C)	2,700	2,715	70	12.819	1.2339407
Charged Condition - Low Temp (Method C)	2,700	2,715	20	14.528	1.2021216

2. Calculate minimum operating pressures

Calculate the minimum operating pressure (psia) for each case.

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1500 + 14.7 = 1514.7

Calculate MOPs	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - (Method B)	1,500	1,515
Minimum Operating Pressure - (Method C)	1,553	1,568

3. Calculate minimum operating densities

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature (for Method B) or Condition 1 entropy (for Method C).

Condition 2 - MOP Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density - High Temp (Method B)	1,500	1,515	120	6.698
Minimum Operating Density - Normal (Method B)	1,500	1,515	70	7.444
Minimum Operating Density - Low Temp (Method B)	1,500	1,515	20	8.420
Minimum Operating Density - High Temp (Method C)	1,553	1,568	34	8.401
Minimum Operating Density - Normal (Method C)	1,553	1,568	-9	9.451
Minimum Operating Density - Low Temp (Method C)	1,553	1,568	-50	10.877

4. Calculate optimum precharge density

Optimum precharge density

- *Method B: $\rho_0 = 1.0/(1.4/\rho_{2BL} - 1.4/\rho_{1BL} + 1.0/\rho_{1BH})$*
- *Method C: $\rho_0 = 1.0/(1.0/\rho_{2CL} - 1.0/\rho_{1CL} + 1.0/\rho_{1CH})$*
- *See Annex C for Derivation*

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-charge Pressure (psig)	Accumulator Pre-charge Pressure (psia)
Optimum Precharge Pressure - (Method B)	6.356	70	1,273	1,288
Optimum Precharge Pressure - (Method C)	9.097	70	1,852	1,867

Calculate the overall optimum precharge that satisfies requirements for both Method B and Method C. See Annex C for explanation.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-charge Pressure (psig)	Accumulator Pre-charge Pressure (psia)
Overall Optimum Precharge Pressure	8.266	70	1,674	1,689

Table D.3—Example 1: Land Rig—Main Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:
- maintaining precharge pressure below the maximum rated working pressure
- maintaining precharge pressure above 25% of system working pressure
- permitting a range of precharge pressures during operations
- following manufacturer's recommendations.

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-charge Pressure (psig)	Accumulator Pre-charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		1,674	1,689	70	8.266
Selected Precharge Pressure at Minimum Temperature		1,472	1,487	20	8.266
Selected Precharge Pressure at Maximum Temperature		1,875	1,889	120	8.266

Precharge Verification	
Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (1487 psia) is greater than 25% of charged accumulator pressure (754 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (1875 psig) is less than accumulator rated working pressure (3000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	70	1,674	1,689	8.266
Condition 1: Charged accumulators @ 3000 psi	70	3,000	3,015	14.037
Condition 1: Charged accumulators @ 2700 psi	70	2,700	2,715	12.819
Condition 2: Minimum Operating Pressure - (Method B)	70	1,500	1,515	7.444
Condition 2: Minimum Operating Pressure - (Method C)	-9	1,553	1,568	9.451

Method B Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2BL} - \rho_0/\rho_{1BL})/1.0$	0.461
Volume Limited $VE_{VH} = (1.0 - \rho_0/\rho_{1BH})/1.4$	0.247
Volumetric Efficiency $VE_B = \min(VE_{PL}, VE_{VH})$	0.247
Accumulator Volume Required (gal) $ACR_B = FVR_B/VE_B$	79.5

Method C Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2CL} - \rho_0/\rho_{1CL})/1.1$	0.174
Volume Limited $VE_{VH} = (1.0 - \rho_0/\rho_{1CH})/1.1$	0.257
Volumetric Efficiency $VE_C = \min(VE_{PL}, VE_{VH})$	0.174
Accumulator Volume Required (gal) $ACR_C = FVR_C/VE_C$	79.5

Minimum Accumulator Volume Required (gal)=$\max(ACR_B, ACR_C)$	79.5

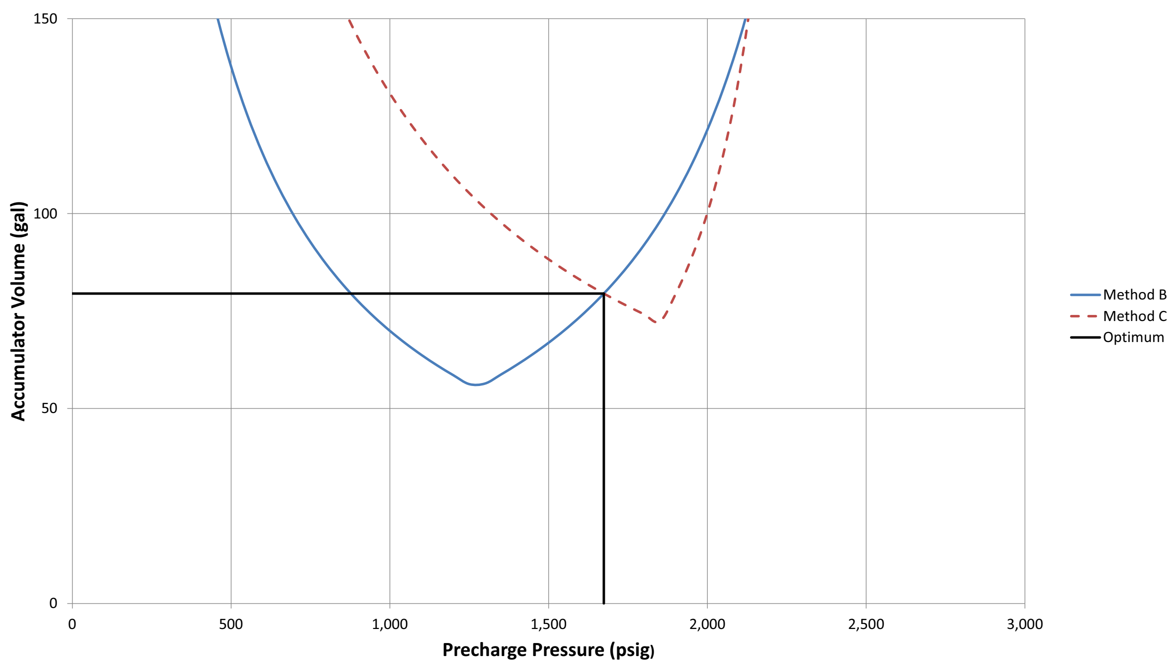


Figure D.1—Example 1: Land Rig—Main Accumulator Sizing

Table D.4—Examples 2, 3, 4 and 5: BOP Stack Configuration and Parameters for Offshore Surface Stack

Examples 2, 3, 4, & 5: BOP Stack Configuration and Parameters for *Offshore Surface Stack*

The following examples size accumulator systems for a surface BOP. The main, pilot, dedicated shear and diverter accumulators will be sized. This example will take a 30° F temperature range into consideration.

Stack	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Opening Volume (gal)	Closing/Shearing Ratio	
Annular BOP, 13"	10,000	1,500	26.50	24.30	-	
Blind Shear Ram, 13"	10,000	1,600	21.50	16.00	18.20	Shearing
		520			6.20	Sealing
Upper Pipe Ram, 13"	10,000	600	12.30	10.80	7.65	
Middle Pipe Ram, 13"	10,000	600	12.30	10.80	7.65	
Lower Pipe Ram, 13"	10,000	600	12.30	10.80	7.65	
Choke & Kill Valve	10,000	780	0.65	0.65	-	

Pilot - Volume to pilot all BOPs closed			
Functions	QTY	Size	Total Volume (gal)
1X Annular	1	1.5" SPM	0.0059
4X Rams	4	1.0" SPM	0.0105
		Total	0.0164
		200%	0.0329

Diverter System		
Function	Pressure (psig)	Volume (gal)
Sequence	1,500	11
Diverter	1,500	25
	Total	36

System Parameters		
System Pressure	3,000	psig
System Pressure (HP shear circuit)	5,000	psig

Environmental Conditions		
Surface Temperature at Precharge	90	°F
Temperature Range (+/- °F)	30	°F
Minimum Surface Temperature	60	°F
Maximum Surface Temperature	120	°F
Atmospheric Pressure	14.7	psia

Relevant References

Pump System

- Primary pump start at 90% of system RWP
- Primary pump stop between 98%-100% of system RWP

Ex. 2 Main Accumulator System

- Example rig uses dedicated shear accumulators for high pressure shear ram closure

Drawdown Test
- Close all rams, open valve, close annular
- Use pump stop pressure
- Method B

Well Control Sequence
- Close annular and pipe ram
- Use pump start pressure
- Method C
* Volume for shear rams provided by dedicated shear accumulators

Ex. 3 Pilot Accumulators

- 200% of volume to close all BOPs
- Method B

Ex. 4 Dedicated Shear Accumulators

- Example rig's dedicated shear accumulators are not supplied by the main accumulator system and, therefore, pump start pressure is used
- Method C

Ex. 5 Diverter Accumulators

- Example rig's diverter accumulators are supplied by the main accumulator system and are checked in, therefore, pump stop pressure is used
- Method C

Table D.5—Example 2: Main Accumulator Sizing

Example 2: Surface Stack - Main Accumulator Sizing

Main Accumulator

This worksheet details the sizing calculations for the Main Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s) - Accumulator Drawdown (Method B)	Rated Working Pressure (psia)	Opening Volume (gal)	Closing Volume (gal)	Closing Ratio*	Pressure to Close Against RWP (psig)
Annular BOP, 13"	10,000	24.30	26.50	-	1,500
Blind Shear Ram, 13"	10,000	16.00	21.50	6.20	1,613
Upper Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Middle Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Lower Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Choke & Kill Valve	10,000	0.65	0.65	-	780

Pressure Required (psig) to Close Blind Shear Ram against Rated Working Pressure = Rated Working Pressure / Closing Ratio = 10000 / 6.2 = 1613

Total Functional Volume Requirement (FVR_B)	85.55	gal
Pressure Required	1,613	psig

*Use the sealing ratio for the drawdown test calculations when a shear ram has a different closing ratio for shearing and sealing.

Operator Function(s) - Well Control Sequence (Method C)**	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Closing Ratio	Adjusted Pressure Required (psig)
Annular BOP, 13"	10,000	1,500	26.50	-	1,500
Middle Pipe Ram, 13"	10,000	600	12.30	7.65	1,907

Minimum Pressure Required (psig) to Seal with Pipe Ram = MOPFLPS + Rated Working Pressure / Closing Ratio = 600 + 10000 / 7.65 = 1907.2

**Rig has dedicated shear accumulators that will supply shear and seal functions.

Total Functional Volume Requirement (FVR_C)	38.30	gal
Pressure Required	1,907	psig

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Temperature Range (+/-)	30	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	3,000	psig
Pump Stop Pressure (Method B - 100%)	3,000	psig
Pump Start Pressure (Method C - 90%)	2,700	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Atmospheric Pressure = 3000 + 14.7 = 3014.7

Condition 1 - Charged Accumulator Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - High Temp (Method B)	3,000	3,015	120	12.623	
Charged Condition - Normal (Method B)	3,000	3,015	90	13.429	
Charged Condition - Low Temp (Method B)	3,000	3,015	60	14.365	
Charged Condition - High Temp (Method C)	2,700	2,715	120	11.518	1.2614603
Charged Condition - Normal (Method C)	2,700	2,715	90	12.259	1.2453902
Charged Condition - Low Temp (Method C)	2,700	2,715	60	13.122	1.2279664

2. Calculate minimum operating pressures

Calculate the minimum operating pressure (psia)for each case.

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1613 + 14.7 = 1627.7

Calculate MOPs	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - (Method B)	1,613	1,628
Minimum Operating Pressure - (Method C)	1,907	1,922

3. Calculate minimum operating densities

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature (for Method B) or Condition 1 entropy (for Method C).

Condition 2 - MOP Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density - High Temp (Method B)	1,613	1,628	120	7.176
Minimum Operating Density - Normal (Method B)	1,613	1,628	90	7.634
Minimum Operating Density - Low Temp (Method B)	1,613	1,628	60	8.167
Minimum Operating Density - High Temp (Method C)	1,907	1,922	64	9.476
Minimum Operating Density - Normal (Method C)	1,907	1,922	37	10.126
Minimum Operating Density - Low Temp (Method C)	1,907	1,922	10	10.892

4. Calculate optimum precharge density

Optimum precharge density

- Method B: $\rho_0 = 1.0/(1.4/\rho_{2BL} - 1.4/\rho_{1BL} + 1.0/\rho_{1BH})$

- Method C: $\rho_0 = 1.0/(1.0/\rho_{2CL} - 1.0/\rho_{1CL} + 1.0/\rho_{1CH})$

- See Annex C for Derivation

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - (Method B)	6.528	90	1,369	1,384
Optimum Precharge Pressure - (Method C)	9.763	90	2,097	2,112

Calculate the overall optimum precharge that satisfies requirements for both Method B and Method C. See Annex C for explanation.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Overall Optimum Precharge Pressure	8.130	90	1,723	1,738

Table D.5—Example 2: Main Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		1,723	1,738	90	6.526
Selected Precharge Pressure at Minimum Temperature		1,605	1,293	60	6.526
Selected Precharge Pressure at Maximum Temperature		1,841	1,474	120	6.526

Precharge Verification

Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (1293 psia) is greater than 25% of charged accumulator pressure (754 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (1460 psig) is less than accumulator rated working pressure (3000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	1,723	1,738	8.129
Condition 1: Charged accumulators @ 3000 psi	90	3,000	3,015	13.429
Condition 1: Charged accumulators @ 2700 psi	90	2,700	2,715	12.259
Condition 2: Minimum Operating Pressure - (Method B)	90	1,613	1,628	7.634
Condition 2: Minimum Operating Pressure - (Method C)	37	1,907	1,922	10.126

Method B Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2BL} - \rho_0/\rho_{1BL})/1.0$	0.430
Volume Limited $VE_{VH} = (1.0 - \rho_0/\rho_{1BH})/1.4$	0.254
Volumetric Efficiency $VE_B = \min(VE_{PL}, VE_{VH})$	0.254
Accumulator Volume Required (gal) $ACR_B = FVR_B/VE_B$	336.4

Method C Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2CL} - \rho_0/\rho_{1CL})/1.1$	0.115
Volume Limited $VE_{VH} = (1.0 - \rho_0/\rho_{1CH})/1.1$	0.268
Volumetric Efficiency $VE_C = \min(VE_{PL}, VE_{VH})$	0.115
Accumulator Volume Required (gal) $ACR_C = FVR_C/VE_C$	336.5

Minimum Accumulator Volume Required (gal) = $\max(ACR_B, ACR_C)$	336.5

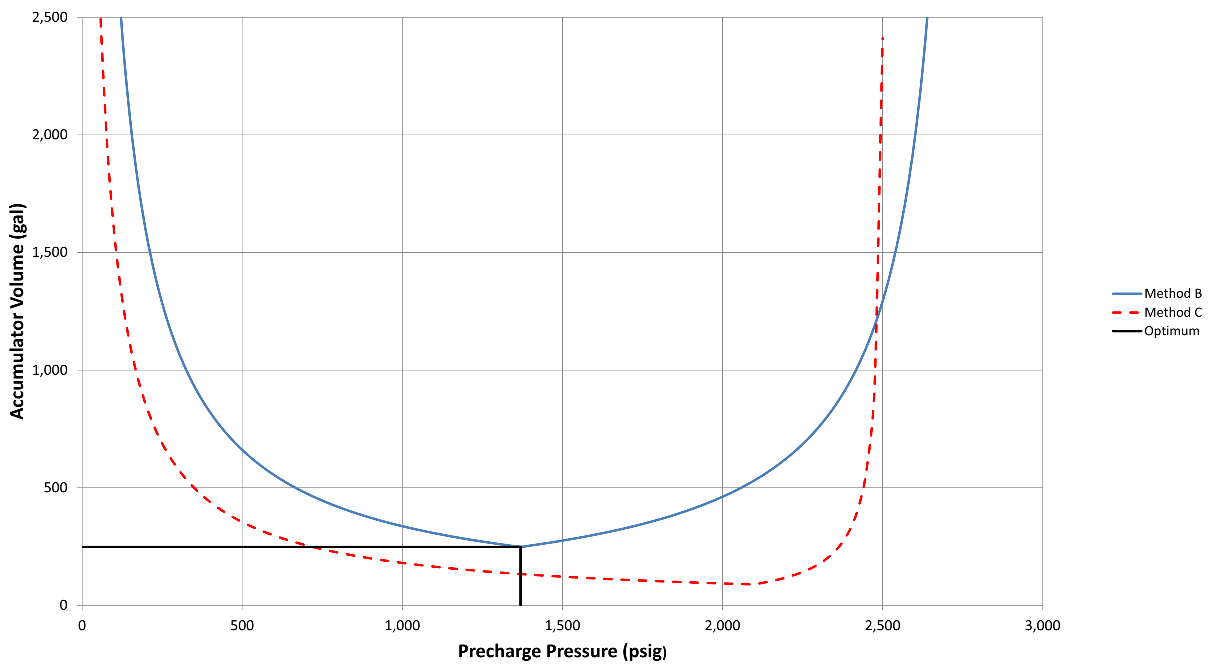


Figure D.2—Example 2: Main Accumulator Sizing

Table D.6—Example 3: Surface Stack—Pilot System Accumulator Sizing

Example 3: Surface Stack - Pilot System Accumulator Sizing

Pilot Accumulator

This worksheet details the sizing calculations for the Pilot Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Valve Size (in.)	Pilot Open Volume (gal)	Pilot Close Volume (gal)	Pilot Pressure Required (psig)
Annular BOP, 13"	1.5	0.006	0.006	1,500
Blind Shear Ram, 13"	1.0	0.003	0.003	1,500
Upper Pipe Ram, 13"	1.0	0.003	0.003	1,500
Middle Pipe Ram, 13"	1.0	0.003	0.003	1,500
Lower Pipe Ram, 13"	1.0	0.003	0.003	1,500

Volume to close all BOPs	0.0180	gal
200% of volume to open and close all BOPs (FVR)	0.036	
Pressure Required	1,500	psig

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Temperature Range (+/-)	30	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	3,000	psig
Regulated Supply Pressure	3,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Regulated Supply Pressure + Atmospheric Pressure = 3000 + 14.7 = 3014.7

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1
Charged Condition - High Temp	3,000	3,015	120	12.623
Charged Condition - Normal	3,000	3,015	90	13.429
Charged Condition - Low Temp	3,000	3,015	60	14.365

2. Calculate minimum operating pressure

Calculate the minimum operating pressure (psia)

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1500 + 14.7 = 1514.7

Calculate MOP	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	1,500	1,515

3. Calculate minimum operating density

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature.

Condition 2 - MOP Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density - High Temp	1,500	1,515	120	6.698
Minimum Operating Density - Normal	1,500	1,515	90	7.123
Minimum Operating Density - Low Temp	1,500	1,515	60	7.618

4. Calculate optimum precharge density

Optimum precharge density

- $\rho_0 = 1.0/(1.4/\rho_{2L} - 1.4/\rho_{1L} + 1.0/\rho_{1H})$
- See Annex C for derivation

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	6.041	90	1,264	1,278

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		1,264	1,278	90	6.041
Selected Precharge Pressure at Minimum Temperature		1,181	1,195	60	6.041
Selected Precharge Pressure at Maximum Temperature		1,346	1,361	120	6.041

Precharge Verification	
Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (1195 psia) is greater than 25% of charged accumulator pressure (754 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (1346 psig) is less than accumulator rated working pressure (3000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	1,264	1,278	6.041
Condition 1: Charged accumulators	90	3,000	3,015	13.429
Condition 2: Minimum Operating Pressure	90	1,500	1,515	7.123

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2L} - \rho_0/\rho_{1L})/1.0$	0.372
Volume Limited $VE_{VH} = (1.0-\rho_0/\rho_{1H})/1.4$	0.372
Volumetric Efficiency $VE = \min(VE_{PL}, VE_{VH})$	0.372
Minimum Accumulator Volume Required (gal) ACR = FVR/VE	0.097

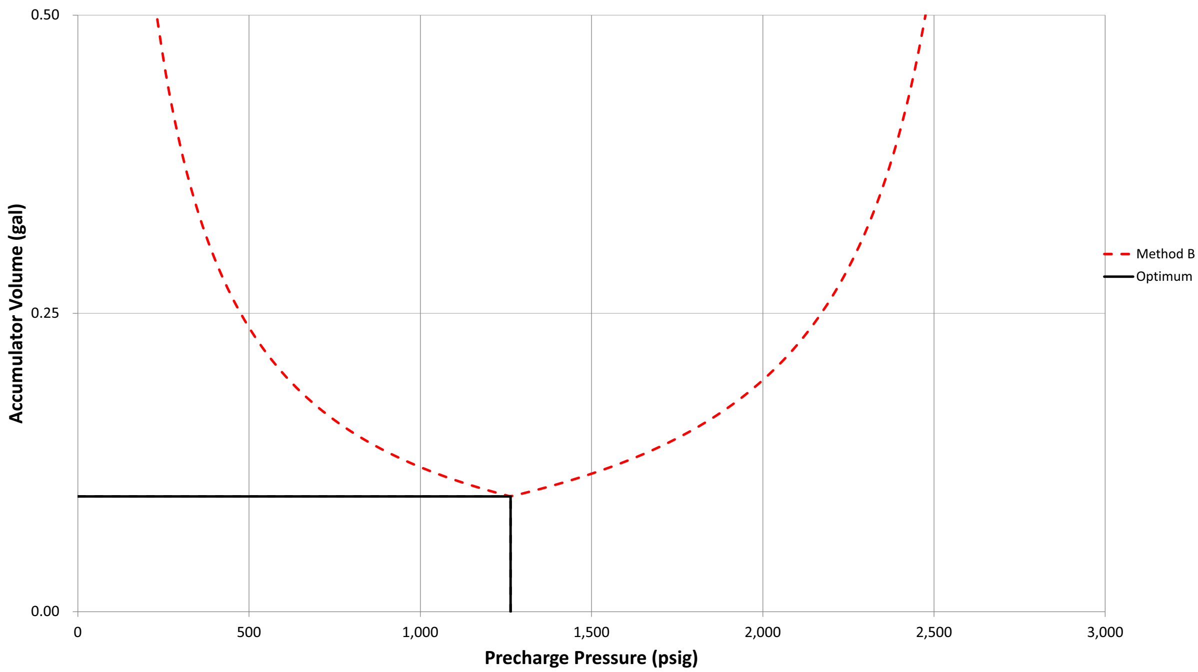


Figure D.3—Example 3: Surface Stack—Pilot System Accumulator Sizing

Table D.7—Example 4: Surface Stack—Dedicated Shear Accumulator

Example 4: Surface Stack - Dedicated Shear Accumulator Sizing

Dedicated Shear Accumulator

This worksheet details the sizing calculations for the Dedicated Shear Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Rated Working Pressure (psia)	Pressure Required (psig)		Function Volume (gal)	Closing or Shearing Ratio	Adjusted Pressure (psig)
Blind Shear Ram, 13"	10,000	1,600	Shear	21.50	18.20	2,149
		520	MOPFLPS		6.20	2,133

Pressure Required (psig) to Shear with Blind Shear Ram = Shear Pressure + Rated Working Pressure / Shearing Ratio = 1600 + 10000 / 18.2 = 2149.5

Minimum Pressure Required (psig) to Seal with Blind Shear Ram = MOPFLPS + Rated Working Pressure / Closing Ratio = 520 + 10000 / 6.2 = 2133

Use the greater of the required shearing or sealing pressure

Total Functional Volume Requirement (FVR)	21.50	gal
Pressure Required	2,149	psig

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Temperature Range (+/-)	30	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	5,000	psig
Pump Start Pressure (90%)	4,500	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Atmospheric Pressure = 4500 + 14.7 = 4514.7

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - High Temp	4,500	4,515	120	17.515	1.2167643
Charged Condition - Normal	4,500	4,515	90	18.547	1.1999016
Charged Condition - Low Temp	4,500	4,515	60	19.724	1.1816246

2. Calculate minimum operating pressure

Calculate the minimum operating pressure (psia).

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 2149 + 14.7 = 2163.7

Calculate MOP	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	2,149	2,164

3. Calculate minimum operating density

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density - High Temp	2,149	2,164	1.2167643	12.180	10
Minimum Operating Density - Normal	2,149	2,164	1.1999016	13.067	-13
Minimum Operating Density - Low Temp	2,149	2,164	1.1816246	14.115	-36

4. Calculate optimum precharge density

Optimum precharge density

- $\rho_0 = 1.0/(1.0/\rho_{2L} - 1.0/\rho_{1L} + 1.0/\rho_{1H})$
- See Annex C for derivation

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	12.946	90	2,875	2,889

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		2,875	2,889	90	12.946
Selected Precharge Pressure at Minimum Temperature		2,659	2,673	60	12.946
Selected Precharge Pressure at Maximum Temperature		3,090	3,105	120	12.946

Precharge Verification	
Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (2673 psia) is greater than 25% of charged accumulator pressure (1129 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (3090 psig) is less than accumulator rated working pressure (5000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	2,875	2,889	12.946
Condition 1: Charged accumulators	90	4,500	4,515	18.547
Condition 2: Minimum Operating Pressure	-13	2,149	2,164	13.067

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2L} - \rho_0/\rho_{1L})/1.1$	0.237
Volume Limited $VE_{VH} = (1.0-\rho_0/\rho_{1H})/1.1$	0.237
Volumetric Efficiency $VE = \min(VE_{PL}, VE_{VH})$	0.237
Minimum Accumulator Volume Required (gal) ACR = FVR/VE	90.7

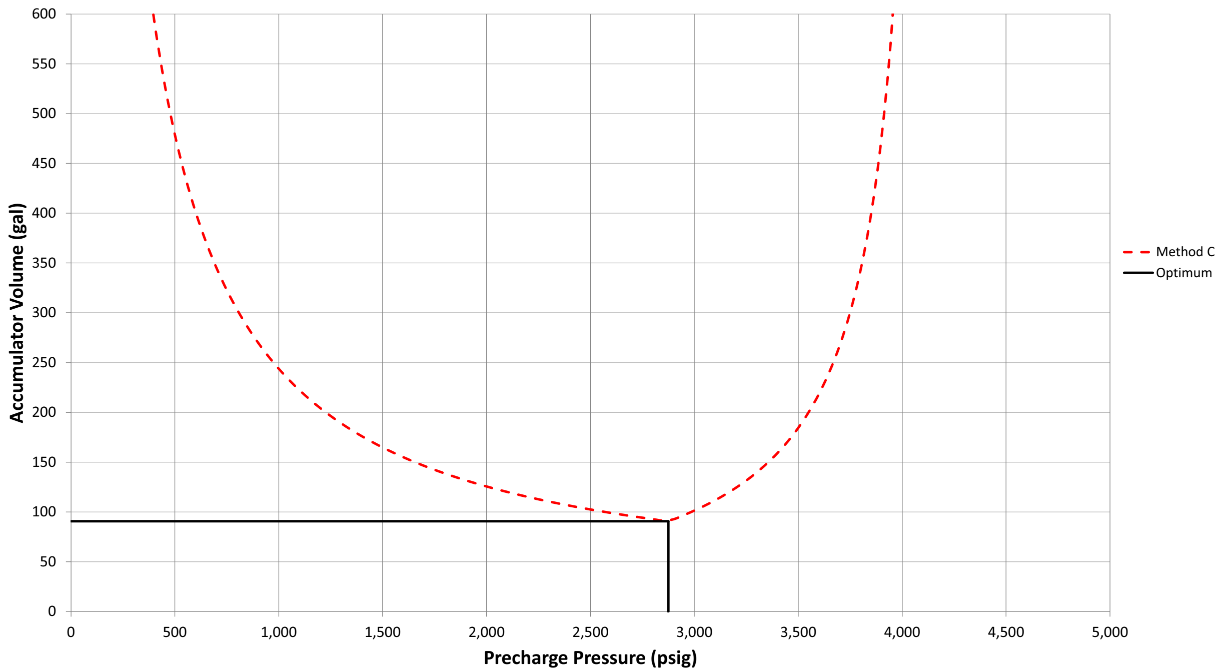


Figure D.4—Example 4: Surface Stack—Dedicated Shear Accumulator

Table D.8—Example 5: Surface Stack—Diverter Accumulator Sizing

Example 5: Surface Stack - Diverter Accumulator Sizing

Diverter Accumulator

This worksheet details the sizing calculations for the Diverter Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Rated Working Pressure (psig)	Pressure Required (psig)	Function Volume (gal)
Divert Mode Functional Sequence	1,500	1,500	11.00
Diverter	500	1,500	25.00

Sequence

Total Functional Volume Requirement (FVR)	36.00
Pressure Required	1,500

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Temperature Range (+/-)	30	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	3,000	psig
Pump Stop Pressure (100%)	3,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia)= Surface Supply Pressure + Atmospheric Pressure = 3000 + 14.7 = 3014.7

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - High Temp	3,000	3,015	120	12.623	1.2523076
Charged Condition - Normal	3,000	3,015	90	13.429	1.2360478
Charged Condition - Low Temp	3,000	3,015	60	14.365	1.2184071

2. Calculate minimum operating pressure(s)

Calculate the minimum operating pressures for each step within the sequence and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1500 + 14.7 = 1514.7

Calculate MOP(s)	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	1,500	1,515

3. Calculate minimum operating density(s)

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density(s)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density - High Temp	1,500	1,515	1.2523076	8.557	14
Minimum Operating Density - Normal	1,500	1,515	1.2360478	9.179	-10
Minimum Operating Density - Low Temp	1,500	1,515	1.2184071	9.919	-34

4. Calculate optimum precharge density

Optimum precharge density

- $\rho 0 = 1.0/(1.0/\rho_{2L} - 1.0/\rho_{1L} + 1.0/\rho_{1H})$

- See Annex C for derivation

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - Sequence 1	9.056	90	1,934	1,948

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		1,934	1,948	90	9.056
Selected Precharge Pressure at Minimum Temperature		1,798	1,813	60	9.056
Selected Precharge Pressure at Maximum Temperature		2,068	2,083	120	9.056

Precharge Verification

Greater than 25% of Accumulator Charged Pressure	Precharge pressure (1948 psia) is greater than 25% of charged accumulator pressure (754 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (2068 psig) is less than accumulator rated working pressure (3000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	1,934	1,948	9.056
Condition 1: Charged accumulators	90	3,000	3,015	13.429
Condition 2: Minimum Operating Pressure	-10	1,500	1,515	9.179

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2L} - \rho_0/\rho_{1L})/1.1$	0.257
Volume Limited $VE_{VH} = (1.0-\rho_0/\rho_{1H})/1.1$	0.257
Volumetric Efficiency $VE = \min(VE_P, VE_V)$	0.257

Minimum Accumulator Volume Required (gal) ACR = FVR/VE	140.1

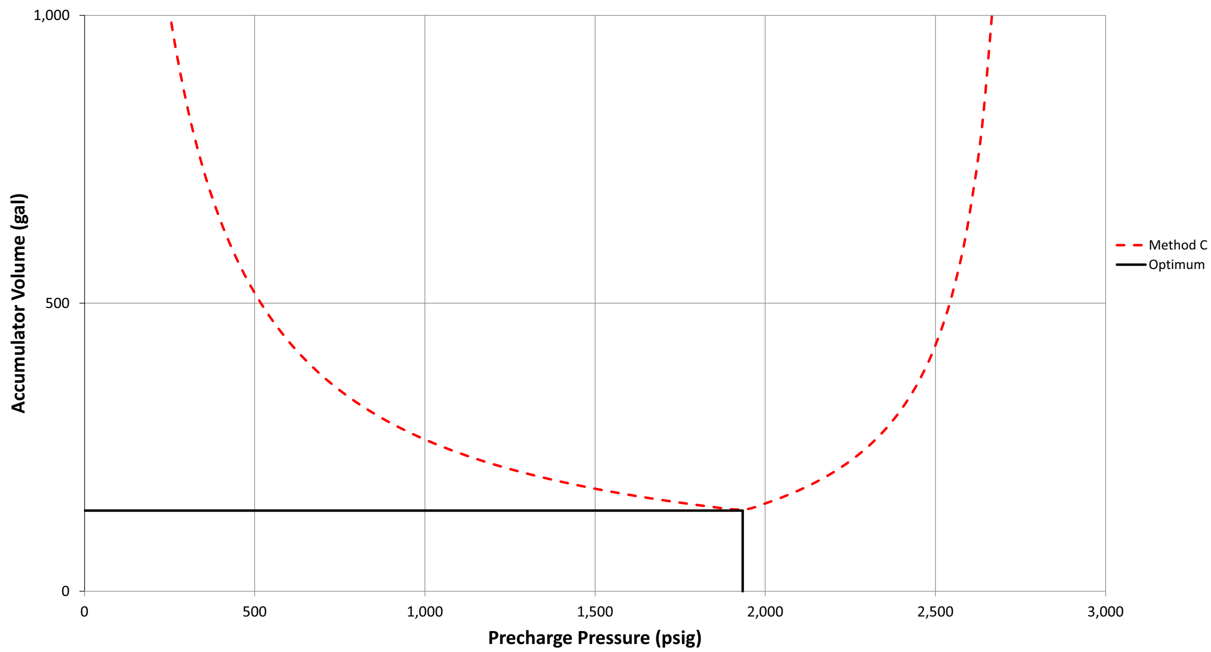


Figure D.5—Example 5: Surface Stack—Diverter Accumulator Sizing

Table D.9—Example 6: BOP Stack Configuration and Parameters for Offshore Surface Stack

Example 6: BOP Stack Configuration and Parameters for *Offshore Surface Stack*

The following example sizes accumulators for a surface BOP. The main accumulators will be sized. This example will take a 30°F temperature range into consideration. Rig does not have dedicated shear accumulators.

Stack	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Opening Volume (gal)	Closing/Shearing Ratio	
Annular BOP, 13"	10,000	1,500	26.50	24.30	-	
Blind Shear Ram, 13"	10,000	1,600	21.50	16.00	18.20	Shearing
		520			6.20	Sealing
Upper Pipe Ram, 13"	10,000	750	12.30	10.80	7.65	
Middle Pipe Ram, 13"	10,000	750	12.30	10.80	7.65	
Lower Pipe Ram, 13"	10,000	750	12.30	10.80	7.65	
Choke & Kill Valve	10,000	780	0.65	0.65	-	

System Parameters		
System Pressure	3,000	psig

Environmental Conditions		
Surface Temperature at Precharge	90	°F
Temperature Range (+/- °F)	30	°F
Minimum Surface Temperature	60	°F
Maximum Surface Temperature	120	°F
Atmospheric Pressure	14.7	psia

Relevant References

Pump System

- Primary pump start at 90% of system RWP
- Primary pump stop between 98%-100% of system RWP

Ex. 6 Main Accumulator System

- Example rig does *not* use dedicated shear accumulators for high pressure shear ram closure

Drawdown Test
- Close all rams, open valve, close annular
- Use pump stop pressure
- Method B

Well Control Sequence
- Close annular, pipe ram, and blind shear ram
- Use pump start pressure
- Method C

Example 6: Surface Stack - Main Accumulator Sizing

Main Accumulator

This worksheet details the sizing calculations for the Main Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s) - Accumulator Drawdown (Method B)	Rated Working Pressure (psia)	Opening Volume (gal)	Closing Volume (gal)	Closing Ratio*	Pressure to Close Against RWP (psig)
Annular BOP, 13"	10,000	24.30	26.50		1,500
Blind Shear Ram, 13"	10,000	16.00	21.50	6.20	1,613
Upper Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Middle Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Lower Pipe Ram, 13"	10,000	10.80	12.30	7.65	1,307
Choke & Kill Valve	10,000	0.65	0.65		780

Pressure Required (psig) to Close against Rated Working Pressure = Rated Working Pressure / Closing Ratio = 10000 / 6.2 = 1613

Total Functional Volume Requirement (FVR_B)	85.55	gal
Pressure Required	1,613	psig

*Use the sealing ratio for the drawdown test calculations when a shear ram has a different closing ratio for shearing and sealing.

Operator Function(s) - Well Control Sequence (Method C)	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)		Closing Volume (gal)	Closing or Shearing Ratio	Adjusted Pressure Required (psig)
Annular BOP, 13"	10,000	1,500		26.50		1,500
Middle Pipe Ram, 13"	10,000	750		12.30	7.65	2,057
Blind Shear Ram, 13"	10,000	1,600	Shear	21.50	18.20	2,149
		520	MOPFLPS		6.20	2,131

Minimum Pressure Required (psig) to Seal with Pipe Ram = MOPFLPS + Rated Working Pressure / Closing Ratio = 750 + 10000 / 7.65 = 2057.2
Pressure Required (psig) to Shear with Blind Shear Ram = Shear Pressure + Rated Working Pressure/Shearing Ratio = 1600 + 10000 / 18.2 = 2148.7
Minimum Pressure Required (psig) to Seal with Blind Shear Ram = MOPFLPS + Rated Working Pressure / Closing Ratio = 520 + 10000 / 6.2 = 2130.6

Total Functional Volume Requirement (FVR_C)	60.30	gal
Pressure Required	2,149	psig

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Temperature Range (+/-)	30	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	3,000	psig
Pump Stop Pressure (Method B - 100%)	3,000	psig
Pump Start Pressure (Method C - 90%)	2,700	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

Table D.9—Example 6: Surface Stack—Main Accumulator Sizing (Continued)

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Atmospheric Pressure = 3000 + 14.7 = 3014.7

Condition 1 - Charged Accumulator Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - High Temp (Method B)	3,000	3,015	120	12.623	
Charged Condition - Normal (Method B)	3,000	3,015	90	13.429	
Charged Condition - Low Temp (Method B)	3,000	3,015	60	14.365	
Charged Condition - High Temp (Method C)	2,700	2,715	120	11.518	1.2614603
Charged Condition - Normal (Method C)	2,700	2,715	90	12.259	1.2453902
Charged Condition - Low Temp (Method C)	2,700	2,715	60	13.122	1.2279664

2. Calculate minimum operating pressures

Calculate the minimum operating pressure (psia)for each case.

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1612.90322580645 + 14.7 = 1627.60322580645

Calculate MOPs	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - (Method B)	1,613	1,628
Minimum Operating Pressure - (Method C)	2,149	2,163

3. Calculate minimum operating densities

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature (for Method B) or Condition 1 entropy (for Method C).

Condition 2 - MOP Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density - High Temp (Method B)	1,613	1,628	120	7.176
Minimum Operating Density - Normal (Method B)	1,613	1,628	90	7.634
Minimum Operating Density - Low Temp (Method B)	1,613	1,628	60	8.167
Minimum Operating Density - High Temp (Method C)	2,149	2,163	83	10.144
Minimum Operating Density - Normal (Method C)	2,149	2,163	55	10.826
Minimum Operating Density - Low Temp (Method C)	2,149	2,163	27	11.627

4. Calculate optimum precharge density

Optimum precharge density

- *Method B: $\rho_0 = 1.0/(1.4/\rho_{2BL} - 1.4/\rho_{1BL} + 1.0/\rho_{1BH})$*
- *Method C: $\rho_0 = 1.0/(1.0/\rho_{2CL} - 1.0/\rho_{1CL} + 1.0/\rho_{1CH})$*
- *See Annex C for Derivation*

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - Method B	6.528	90	1,369	1,384
Optimum Precharge Pressure - Method C	10.350	90	2,235	2,249

Calculate the overall optimum precharge that satisfies requirements for both Method B and Method C. See Annex C for explanation.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Overall Optimum Precharge Pressure	10.318	90	2,227	2,242

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		2,227	2,242	90	10.318
Selected Precharge Pressure at Minimum Temperature		2,068	2,082	60	10.318
Selected Precharge Pressure at Maximum Temperature		2,387	2,401	120	10.318

Precharge Verification	
Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (2083 psia) is greater than 25% of charged accumulator pressure (754 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (2387 psig) is less than accumulator rated working pressure (3000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	2,227	2,242	10.318
Condition 1: Charged accumulators @ 3000 psi	90	3,000	3,015	13.429
Condition 1: Charged accumulators @ 2700 psi	90	2,700	2,715	12.259
Condition 2: Minimum Operating Pressure - (Method B)	90	1,613	1,628	7.634
Condition 2: Minimum Operating Pressure - (Method C)	55	2,149	2,163	10.826

Method B Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2BL} - \rho_0/\rho_{1BL})/1.0$	0.545
Volume Limited $VE_{VH} = (1.0-\rho_0/\rho_{1BH})/1.4$	0.130
Volumetric Efficiency $VE_B = \min(VE_{PL}, VE_{VH})$	0.130
Accumulator Volume Required (gal) $ACR_B = FVR_B/VE_B$	655.9

Method C Volumetric Efficiencies

Pressure Limited $VE_{PL} = (\rho_0/\rho_{2CL} - \rho_0/\rho_{1CL})/1.1$	0.092
Volume Limited $VE_{VH} = (1.0-\rho_0/\rho_{1CH})/1.1$	0.095
Volumetric Efficiency $VE_C = \min(VE_{PL}, VE_{VH})$	0.092
Accumulator Volume Required (gal) $ACR_C = FVR_C/VE_C$	655.9

Minimum Accumulator Volume Required (gal) = $\max(ACR_B, ACR_C)$	655.9

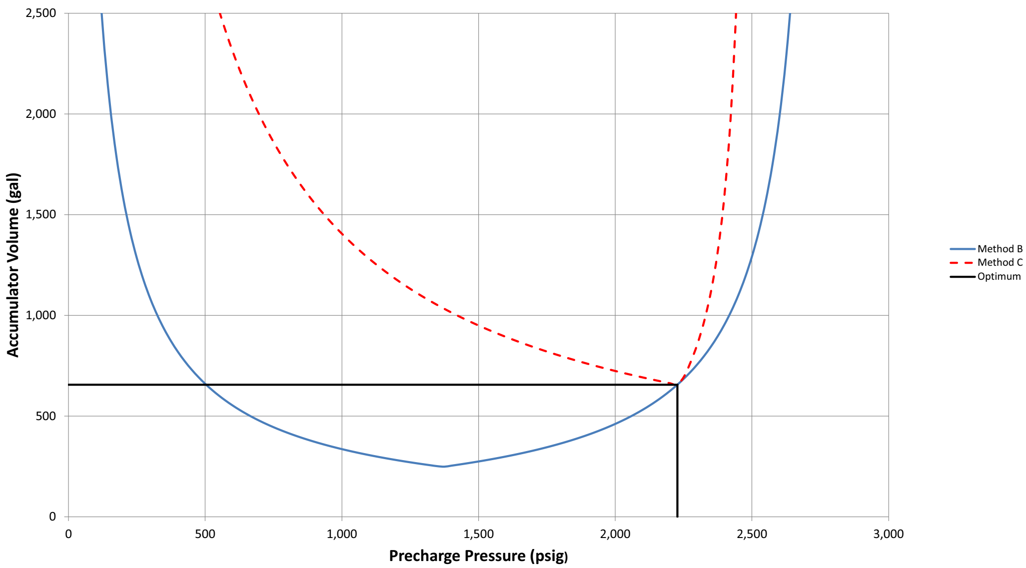


Figure D.6—Example 6: Surface Stack—Main Accumulator Sizing

Table D.10—Example 7, 8, 9, 10, and 11: BOP Stack Configuration for Subsea BOP Stack

Example 7, 8, 9, 10 & 11: BOP Stack Configuration for *Subsea BOP Stack*

The following examples size accumulators for a subsea MUX BOP. The main surface, pod pilot, deadman/autoshear, acoustic and diverter accumulators will be sized.

Stack	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Opening Volume (gal)	Closing/Shearing Ratio	
Upper Annular BOP, 18-3/4"	10,000	1,500	85.30	64.80	-	
Lower Annular BOP, 18-3/4"	10,000	1,500	85.30	64.80	-	
Upper Blind Shear Ram, 18-3/4"	15,000	1,710	40.30	35.00	15.24	Shearing
		520			6.40	Sealing
Casing Shear Ram, 18-3/4"	15,000	2,035	40.30	35.00	15.24	
Lower Blind Shear Ram, 18-3/4"	15,000	1,710	40.30	35.00	15.24	Shearing
		520			6.40	Sealing
Upper Pipe Ram, 18-3/4"	15,000	750	20.75	17.30	7.20	
Middle Pipe Ram, 18-3/4"	15,000	750	20.75	17.30	7.20	
Lower Pipe Ram, 18-3/4"	15,000	750	20.75	17.30	7.20	

Pod Pilot System - Volume to pilot EDS with Largest Volume Demand		
QTY	Size	Total Volume (gal)
0	1.5" SPM	0.0000
4	1.0" SPM	0.0105
4	0.5" SPM	0.0065
	Total	0.0170
	200%	0.0341

Pod Pilot System - Volume to pilot all BOPs closed and open		
QTY	Size	Total Volume (gal)
2	1.5" SPM	0.0237
6	1.0" SPM	0.0315
0	0.5" SPM	0.0000
	Total	0.0552
	200%	0.1104

Acoustic Functions	Volume (gal)
Upper Blind Shear Ram*	40.30
Casing Shear Ram*	40.30
Upper Pipe Ram	20.75
Middle Pipe Ram	20.75
All Stabs Retract	5.00
Riser Connector Primary + SecondaryUnlatch	25.00
Total	152.10
Total*	71.50

**Volume to operate UBSR and CSR not included in sizing of acoustic accumulators. Volume for shear rams will be shared with the deadman/autoshear accumulators.*

System Parameters		
System Pressure	5,000	psig
Regulated Supply Pressure	3,000	psig
Riser Air Gap	75	ft
Control Fluid Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Sea Water Weight	8.54	ppg
Water Depth	12,500	ft

5,463	psia
5,560	psia

Environmental Conditions		
Surface Temperature at Precharge	90	°F
Maximum Surface Temperature	120	°F
Subsea Operating Temperature	35	°F
Atmospheric Pressure	14.7	psia

Diverter System		
Function	Pressure (psig)	Volume (gal)
Sequence	1,500	11.00
Diverter	2,000	25.00
	Total	36.00

Relevant References

Pump System

API 16D 3rd Edition Section 5.11.6
- Primary pump stop between 98%-100% of system RWP

Ex. 7 Main Accumulator System

API 16D 3rd Edition Section 7.3.4.3

Drawdown Test
- Close and open largest annular and 4 smallest ram BOPs
- Use pump stop pressure
- Method B

Well Control Sequence.
- Close annular and pipe ram
- Use pump start pressure
- Method C

*Volume for shear rams provided by dedicated shear accumulators

Ex. 8 Pod Pilot Accumulators

API 16D 3rd Edition Section 7.3.6
- 200% of volume to operate most demanding EDS sequence. (Method C)

Ex. 9 DMAS Accumulators

API 16D 3rd Edition Section 8.2 & 8.3

- Method C

Ex. 10 Acoustic Accumulators

API 16D 3rd Edition Section 9.3
- Example rig's acoustic accumulators are supplied by the main accumulator system and are checked in, therefore, pump stop pressure

- Acoustic EDS not utilized by example rig.
- Method B

Ex. 11 Diverter Accumulators

API 16D 3rd Edition 10.8

- Method C

Table D.11—Example 7: Subsea Stack—Main Accumulator

Example 7: Subsea Stack - Main Accumulator Sizing

Main Accumulator

This worksheet details the sizing calculations for the Main Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s) - Accumulator Drawdown (Method B)	Rated Working Pressure (psig)*	Opening Volume (gal)	Closing Volume (gal)	Closing Ratio**	Pressure to Close Against RWP (psig)
Upper Annular BOP, 18-3/4"	10,000	64.80	85.30		1,500
Upper Blind Shear Ram, 18-3/4"	15,000	35.00	40.30	6.40	2,344
Upper Pipe Ram, 18-3/4"	15,000	17.30	20.75	7.20	2,083
Middle Pipe Ram, 18-3/4"	15,000	17.30	20.75	7.20	2,083
Lower Pipe Ram, 18-3/4"	15,000	17.30	20.75	7.20	2,083

Pressure Required (psig) to Close Blind Shear Ram against Rated Working Pressure = Rated Working Pressure / Closing Ratio = 15000 / 6.4 = 2343.8

Total Functional Volume Requirement (FVR_B)	339.55	gal
Pressure Required	2,344	psig

* Rated working pressure for the main accumulators on a subsea stack is taken as a gauge pressure. See annex section B4.

**Use the sealing ratio for the drawdown test calculations when a shear ram has a different closing ratio for shearing and sealing.

Operator Function(s) - Well Control Sequence (Method C)***	Rated Working Pressure (psig)*	Pressure Required / MOPFLPS (psig)	Closing Volume (gal)	Closing Ratio	Adjusted Pressure Required (psig)
Upper Annular BOP, 18-3/4"	10,000	1,500	85.30		1,500
Middle Pipe Ram, 18-3/4"	15,000	750	20.75	7.20	2,833

Minimum Pressure Required (psig) to Seal with Pipe Ram = MOPFLPS + (Rated Working Pressure - Seawater Static Pressure) / Closing Ratio = 750 + (15000 - 5560) / 7.2 = 2833.4

***Volume for shear rams provided by dedicated emergency accumulators.

Total Functional Volume Requirement (FVR_C)	106.05	gal
Pressure Required	2,833	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Riser Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,560	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	5,000	psig
Pump Stop Pressure (Method B - 100%)	5,000	psig
Pump Start Pressure (Method C - 90%)	4,500	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Atmospheric Pressure = 5000 + 14.7 = 5014.7

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - (Method B)	5,000	5,015	90	20.001	
Charged Condition - (Method C)	4,500	4,515	90	18.547	1.1999016

2. Calculate minimum operating pressures

Calculate the minimum operating pressures for each case and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Surface Pressure Required + Seawater Hydrostatic Absolute Pressure = 2834 + 5560 = 8393.4

Minimum Operating Pressure (psig) = Minimum Operating Pressure (psia) - Control Fluid Head = 8394 - 5463 = 2930.4

Calculate MOPs	Pressure Required (psig)***	Minimum Operating Pressure (psig)****	Minimum Operating Pressure (psia)****
Minimum Operating Pressure - (Method B)	2,344	2,441	7,904
Minimum Operating Pressure - (Method C)	2,833	2,930	8,393

*** When stack is on surface

****When stack is subsea

3. Calculate minimum operating densities

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature (for Method B) or Condition 1 entropy (for Method C).

Condition 2 - MOP Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density - (Method B)	2,441	2,455	90	11.209
Minimum Operating Density - (Method C)	2,930	2,945	28	15.249

4. Calculate optimum precharge density

Optimum precharge density

- Method B: $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$

- Method C: $\rho_0 = \rho_2$

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - (Method B)	9.533	90	2,043	2,058
Optimum Precharge Pressure - (Method C)	15.249	90	3,494	3,509

Calculate the overall optimum precharge that satisfies requirements for both Method B and Method C. See Annex C for explanation.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Overall Optimum Precharge Pressure	10.255	90	2,212	2,227

Table D.11—Example 7: Subsea Stack—Main Accumulator (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		2,212	2,227	90	10.255
Selected Precharge Pressure at Maximum Temperature		2,370	2,385	120	10.255

Precharge Verification	
Greater than 25% of Accumulator Charged Pressure	Precharge pressure (2227 psia) is greater than 25% of charged accumulator pressure (1254 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (2370 psig) is less than accumulator rated working pressure (5000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	2,212	2,227	10.255
Condition 1: Charged accumulators @ 5000 psi	90	5,000	5,015	20.001
Condition 1: Charged accumulators @ 4500 psi	90	4,500	4,515	18.547
Condition 2: Minimum Operating Pressure (Method B)	90	2,441	2,455	11.209
Condition 2: Minimum Operating Pressure (Method C)	28	2,930	2,945	15.249

Method B Volumetric Efficiencies

Pressure Limited $VE_P = (\rho_0/\rho_{2B} - \rho_0/\rho_{1B})/1.0$	0.402
Volume Limited $VE_V = (1.0 - \rho_0/\rho_{1B})/1.4$	0.348
Volumetric Efficiency $VE_B = \min(VE_P, VE_V)$	0.348
Minimum Accumulator Volume Required (gal) $ACR_B = FVR_B/VE_B$	975.5

Method C Volumetric Efficiencies

Pressure Limited $VE_P = (\rho_0/\rho_{2C} - \rho_0/\rho_{1C})/1.1$	0.109
Volume Limited $VE_V = (1.0 - \rho_0/\rho_{1C})/1.1$	0.406
Volumetric Efficiency $VE_C = \min(VE_P, VE_V)$	0.109
Min. Accumulator Volume Required (gal) $ACR_C = FVR_C/VE_C$	975.5

Overall Min. Accumulator Volume Required (gal) = $\max(ACR_B, ACR_C)$	975.5

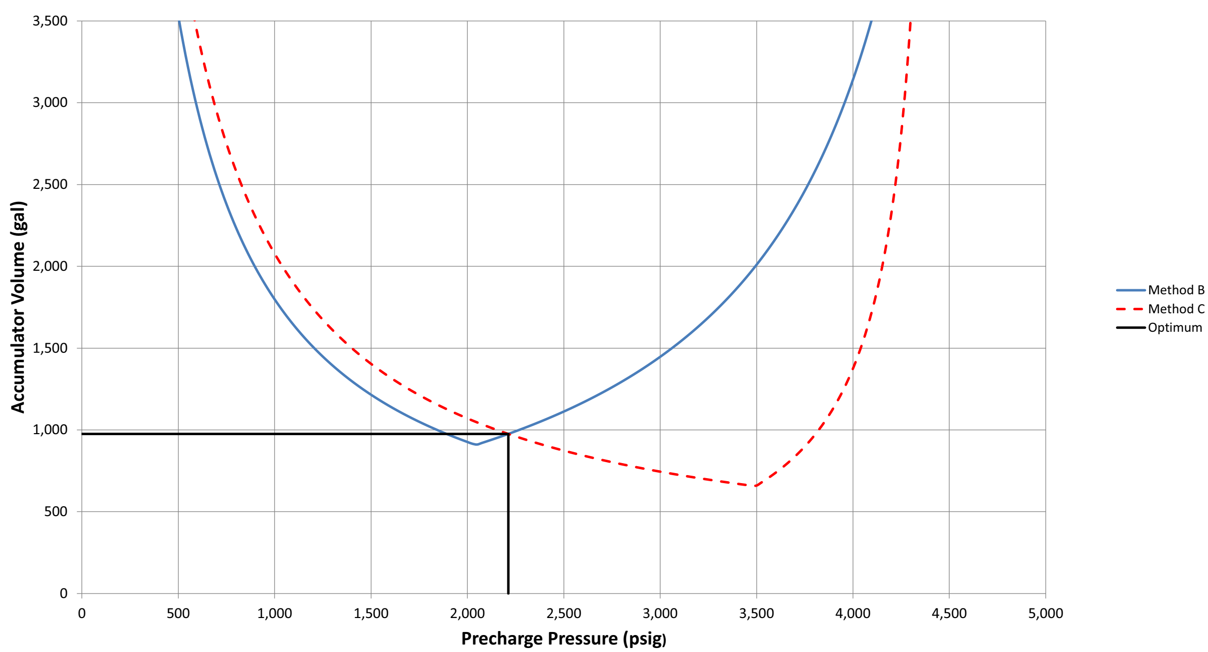


Figure D.7—Example 7: Subsea Stack—Main Accumulator

Table D.12—Example 8: Subsea Stack—Pilot System Accumulator Sizing

Example 8: Subsea Stack - Pilot System Accumulator Sizing

Pilot Accumulator

This worksheet details the sizing calculations for the Pilot Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s) - Open & Close all BOPs (Method B)	Valve Size (in.)	Pilot Open Volume (gal)	Pilot Close Volume (gal)	Pilot Pressure Required (psig)
Upper Annular BOP, 18-3/4"	1.5	0.006	0.006	1,500
Lower Annular BOP, 18-3/4"	1.5	0.006	0.006	1,500
Upper Blind Shear Ram, 18-3/4"	1.0	0.003	0.003	1,500
Casing Shear Ram, 18-3/4"	1.0	0.003	0.003	1,500
Lower Blind Shear Ram, 18-3/4"	1.0	0.003	0.003	1,500
Upper Pipe Ram, 18-3/4"	1.0	0.003	0.003	1,500
Middle Pipe Ram, 18-3/4"	1.0	0.003	0.003	1,500
Lower Pipe Ram, 18-3/4"	1.0	0.003	0.003	1,500

Volume to open and close all BOPs	0.060	gal
200% of volume to open and close all BOPs (FVR_B)	0.120	gal
Pressure Required	1,500	psig

Operator Function(s) - Emergency Disconnect Sequence (Method C)	Valve Size (in.)	Pilot Volume Required (gal)	Pilot Pressure Required (psig)
DMAS system Arm	0.5	0.002	1,500
Casing Shear Ram Close	1.0	0.003	1,500
Choke & Kill Stabs Retract	0.5	0.002	1,500
Wetmate Connector Retract	0.5	0.002	1,500
Acoustic Stabs Retract	0.5	0.002	1,500
Blind Shear Rams Close	1.0	0.003	1,500
Riser Connector Unlock - Primary	1.0	0.003	1,500
Riser Connector Unlock - Secondary	1.0	0.003	1,500

Volume to pilot largest demand EDS	0.020	gal
200% of volume to pilot largest demand EDS (FVR_C)	0.040	gal
Pressure Required	1,500	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Riser Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,560	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	7,500	psig
Subsea Regulated?	Yes	
Regulated Supply Pressure	3,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Regulated Supply Pressure + Seawater Head = 3000 + 5560 = 8560

Charged Accumulator Pressure (psig) = Charged Accumulator Pressure (psia) - Seawater Head = 8560 - 5560 = 3000

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - (Method B)	3,000	8,560	35	30.148	
Charged Condition - (Method C)	3,000	8,560	35	30.148	1.1094044

2. Calculate minimum operating pressures

Calculate the minimum operating pressures for each case and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Seawater Hydrostatic Absolute Pressure = 1500 + 5560 = 7060

Calculate MOPs	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - (Method B)	1,500	7,060
Minimum Operating Pressure - (Method C)	1,500	7,060

3. Calculate minimum operating densities

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 temperature (for Method B) or Condition 1 entropy (for Method C).

Condition 2 - MOP Densities	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2	Entropy S_2
Minimum Operating Density - (Method B)	1,500	7,060	35	27.372	
Minimum Operating Density - (Method C)	1,500	7,060	12	28.541	1.1094044

4. Calculate optimum precharge density

Optimum precharge density

- *Method B: $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$*
- *Method C: $\rho_0 = \rho_2$*

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - (Method B)	26.399	90	7,804	7,819
Optimum Precharge Pressure - (Method C)	28.541	90	9,044	9,059

Calculate the overall optimum precharge that satisfies requirements for both Method B and Method C. See Annex C for explanation.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Overall Optimum Precharge Pressure	26.399	90	7,804	7,819

Table D.12—Example 8: Subsea Stack—Pilot System Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:
- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature	6900	6,900	6,915	90	24.609
Selected Precharge Pressure at Operating Temperature		284	5,844	35	24.609
Selected Precharge Pressure at Maximum Temperature		7,478	7,493	120	24.609

NOTE: The optimum precharge exceeds the accumulator RWP at maximum temperature. Therefore, a lower precharge has been selected.

Precharge Verification

Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (5844 psia) is greater than 25% of charged accumulator pressure (2140 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (7478 psig) is less than accumulator rated working pressure (7500 psig).

6. Determine volumetric efficiencies

Use the NIST fluid property references to determine accumulator absolute pressure using the Condition 0 density and Condition 1 entropy or temperature

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Total Discharge - (Method B)	24.609		284	5,844	35
Total Discharge - (Method C)	24.609	1.1094044	-1,219	4,341	-41

Use the NIST fluid property references to determine gas density using Condition 1 entropy or temperature and the Seawater Head for accumulator pressure

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Seawater Hydrostatic Limit - (Method B)	23.878		0	5,560	35
Seawater Hydrostatic Limit - (Method C)	26.590	1.1094044	0	5,560	-15

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	6,900	6,915	24.609
Condition 1: Charged accumulators - (Method B)	35	3,000	8,560	30.148
Condition 1: Charged accumulators - (Method C)	35	3,000	8,560	30.148
Condition 2: Minimum Operating Pressure (Method B)	35	1,500	7,060	27.372
Condition 2: Minimum Operating Pressure (Method C)	12	1,500	7,060	28.541
Condition 3: Total Discharge - (Method B)	35	284	5,844	24.609
Condition 3: Seawater Hydrostatic Limit - (Method C)	-15	0	5,560	26.590

Method B Volumetric Efficiencies

Pressure Limited $VE_P = (\rho_0/\rho_{2B} - \rho_0/\rho_{1B})/1.0$	0.083
Volume Limited $VE_V = (1.0-\rho_0/\rho_{1B})/1.4$	0.131
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_0/\rho_{3B} - \rho_{0B}/\rho_{1B})/1.4$	NR
Volumetric Efficiency $VE_B = \min(VE_P, VE_V)$	0.083
Minimum Accumulator Volume Required (gal) $ACR_B = FVR_B/VE_B$	1.449

Method C Volumetric Efficiencies

Pressure Limited $VE_P = (\rho_0/\rho_{2C} - \rho_0/\rho_{1C})/1.1$	0.042
Volume Limited $VE_V = (1.0-\rho_0/\rho_{1C})/1.1$	NR
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_{0C}/\rho_{3C} - \rho_{0C}/\rho_{1C})/1.1$	0.099
Volumetric Efficiency $VE_C = \min(VE_P, VE_V)$	0.042
Minimum Accumulator Volume Required (gal) $ACR_C = FVR_C/VE_C$	0.479

Overall Min. Accumulator Volume Required (gal) = max (ACR_B, ACR_C)	1.449

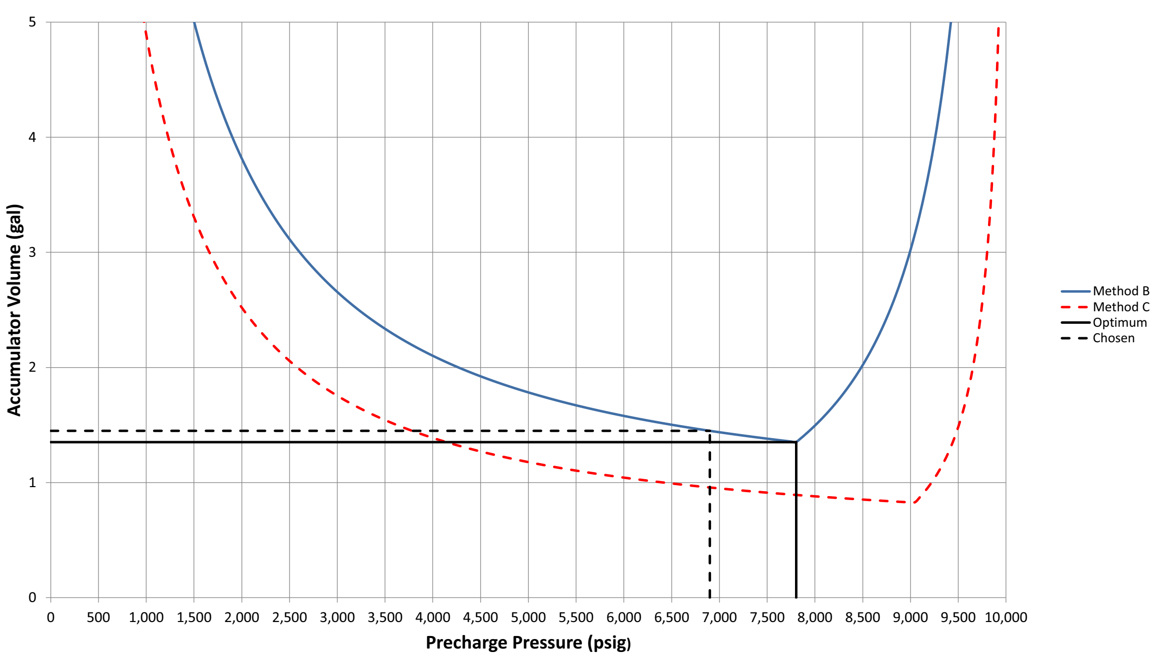


Figure D.8—Example 8: Subsea Stack—Pilot System Accumulator Sizing

Table D.13—Example 9: Subsea Stack—DMAS Accumulator Sizing

Example 9: Subsea Stack - DMAS Accumulator Sizing

Shear Accumulator

This worksheet details the sizing calculations for the Shear Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Sequence	Rated Working Pressure (psia)	Pressure Required (psig)		Function Volume (gal)	Closing or Shearing Ratio	Adjusted Pressure (psig)
Casing Shear Ram, 18-3/4"	1	15,000	2,035	Shear	40.30	15.24	2,654
Timing Circuit	2	3,000 psig	1,500		1.00	-	1,500
Upper Blind Shear Ram, 18-3/4"	2	15,000	1,710	Shear	40.30	15.24	2,329
			520	MOPFLPS		6.40	1,995

Pressure Required (psig) to Shear with Casing Shear Ram = Shear Pressure + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 2035 + (15000 - 5560) / 15.24 = 2654.4
Pressure Required (psig) to Shear with Blind Shear Ram = Shear Pressure + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 1710 + (15000 - 5560) / 15.24 = 2329.5
Minimum Pressure Required (psig) to Seal with Blind Shear Ram = MOPFLPS + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 520 + (15000 - 5560) / 6.4 = 1995

Sequence	1	2	
Total Functional Volume Requirement (FVR)	40.30	41.30	gal
Pressure Required	2,654	2,329	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Riser Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,560	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	7,500	psig
Subsea Regulated	No	
Pump Stop Pressure (100%)	5,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state
Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.
Charged Accumulator Pressure (psia)= Surface Supply Pressure + Control Fluid Hydrostatic Absolute Pressure = 5000 + 5463 = 10463
Charged Accumulator Pressure (psig)= Charged Accumulator Pressure (psia) - Seawater Hydrostatic Absolute Pressure = 10463 - 5560 = 4903

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition	4,903	10,463	35	32.981	1.0928525

2. Calculate minimum operating pressure(s)
Calculate the minimum operating pressures for each step within the sequence and adjust for hydrostatic effects.
Minimum Operating Pressure (psia) = Pressure Required + Seawater Hydrostatic Absolute Pressure = 2654 + 5560 = 8214.4

Calculate MOP(s)	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - Sequence 1	2,654	8,214
Minimum Operating Pressure - Sequence 2	2,329	7,889

3. Calculate minimum operating density(s)
Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density(s)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density - Sequence 1	2,654	8,214	1.0928525	30.973	7
Minimum Operating Density - Sequence 2	2,329	7,889	1.0928525	30.643	2

4. Calculate optimum precharge density
Optimum precharge density $\rho_0 = \rho_2$.
Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - Sequence 1	30.973	90	10,705	10,720
Optimum Precharge Pressure - Sequence 2	30.643	90	10,462	10,477

If sequence consists of 2 functions, then calculate the optimum precharge that satisfies both functions, otherwise use the optimum precharge for the single function. See Annex C for explanation of two function optimum precharge.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	30.643	90	10,462	10,477

Table D.13—Example 9: Subsea Stack—DMAS Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *maintaining total discharge pressure above seawater hydrostatic pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature	6900	6,900	6,915	90	24.609
Selected Precharge Pressure at Operating Temperature		284	5,844	35	24.609
Selected Precharge Pressure at Maximum Temperature		7,478	7,493	120	24.609

NOTE: The optimum precharge exceeds the accumulator RWP at maximum temperature. Therefore a lower precharge has been selected.

Precharge Verification

Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (5844 psia) is greater than 25% of charged accumulator pressure (2616 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (7478 psig) is less than accumulator rated working pressure (7500 psig).

6. Determine volumetric efficiencies

Use the NIST fluid property references to determine accumulator absolute pressure using the Condition 0 density and Condition 1 entropy

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Total Discharge	24.609	1.0928525	-1,894	3,666	-75

Use the NIST fluid property references to determine gas density using Condition 1 entropy and the Seawater Head for accumulator pressure

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Seawater Hydrostatic Limit	27.840	1.0928525	0	5,560	-35

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators - Surface	90	6,900	6,915	24.609
Condition 0: Precharged Accumulators - Subsea	35	284	5,844	24.609
Condition 1: Charged accumulators	35	4,903	10,463	32.981
Condition 2: Minimum Operating Pressure - Sequence 1	7	2,654	8,214	30.973
Condition 2: Minimum Operating Pressure - Sequence 2	2	2,329	7,889	30.643
Condition 3: Seawater Hydrostatic Limit	-35	0	5,560	27.840

Sequence 1

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$	0.044
Volume Limited $VE_V = (1.0-\rho_0/\rho_1)/1.1$	NR
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$	0.125
Volumetric Efficiency $VE_1 = \min(VE_P, VE_V)$	0.044
Minimum Accumulator Volume Required (gal) $ACR_1 = FVR_1/VE_1$	916.4

Sequence 2

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$	0.052
Volume Limited $VE_V = (1.0-\rho_0/\rho_1)/1.1$	NR
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$	0.125
Volumetric Efficiency $VE_2 = \min(VE_P, VE_V)$	0.052
Minimum Accumulator Volume Required (gal) $ACR_2 = FVR_2/VE_2$	1,576.9

Overall Min. Accumulator Volume Required (gal) = $\max(ACR_1, ACR_2)$	1,576.9

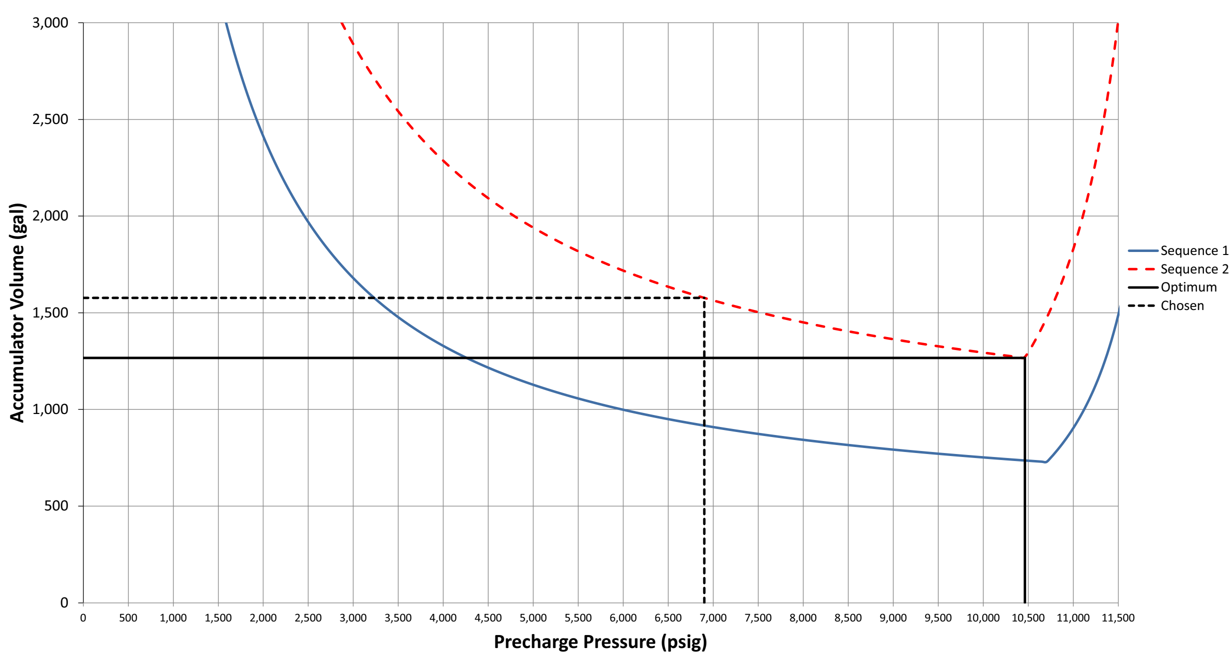


Figure D.9—Example 9: Subsea Stack—DMAS Accumulator Sizing

Table D.14—Example 10: Subsea Stack—Acoustic Accumulator Sizing

Example 10: Subsea Stack - Acoustic Accumulator Sizing

Acoustic Accumulators

This worksheet details the sizing calculations for the Acoustic Accumulators utilizing API 16D 3rd. Edition calculations.

Operator Function(s)*	Rated Working Pressure (psia)	Pressure Required / MOPFLPS (psig)	Function Volume (gal)	Closing Ratio	Adjusted Pressure Required (psig)
Upper Pipe Ram	15,000	750	20.75	7.20	2,061
Middle Pipe Ram	15,000	750	20.75	7.20	2,061
All Stabs Retract	3,000 psig	1,500	5.00		1,500
Riser Connector Primary + Secondary Unlatch	3,000 psig	1,500	16.00		1,500

Minimum Pressure Required (psig) to Seal with Pipe Ram = MOPFLPS + (Rated Working Pressure - Seawater Static Pressure) / Closing Ratio = 750 + 15000 / 7.2 = 2061.2

*Volume for shear rams supplied from dedicated shear accumulators

Total Functional Volume Requirement (FVR)	62.50	gal
Pressure Required	2,061	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Riser Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,560	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	7,500	psig
Subsea Regulated	No	
Pump Stop Pressure (100%)	5,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Control Fluid Absolute Pressure = 5000 + 5463 = 10463

Charged Accumulator Pressure (psig) = Charged Accumulator Pressure (psia) - Seawater Hydrostatic Absolute Pressure = 10463 - 5560 = 4903

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1
Charged Condition	4,903	10,463	35	32.981

2. Calculate minimum operating pressure

Calculate the minimum operating pressure and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Seawater Hydrostatic Absolute Pressure = 2061.2 + 5560 = 7621.2

Calculate MOP	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	2,061	7,621

3. Calculate minimum operating density

Use NIST fluid property references to determine gas density at MOP based upon and absolute pressure and Condition 1 temperature.

Condition 2 - MOP Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_2
Minimum Operating Density	2,061	7,621	35	28.480

4. Calculate optimum precharge density

Optimum precharge density $\rho_0 = 1.0/(1.4/\rho_2 - 0.4/\rho_1)$.

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	27.006	90	8,137	8,151

Table D.14—Example 10: Subsea Stack—Acoustic Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface Precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature	6900	6,900	6,915	90	24.609
Selected Precharge Pressure at Operating Temperature		284	5,844	35	24.609
Selected Precharge Pressure at Maximum Temperature		7,478	7,493	120	24.609

NOTE: The optimum precharge exceeds the accumulator RWP at maximum temperature. Therefore a lower precharge has been selected.

Precharge Verification

Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (5844 psia) is greater than 25% of charged accumulator pressure (2616 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (7478 psig) is less than accumulator rated working pressure (7500 psig).

6. Determine volumetric efficiencies

Use NIST fluid property references to determine gas absolute pressure based upon precharge density and Condition 1 temperature.

Condition 3	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Total Discharge	35	284	5,844	24.609

Use NIST fluid property references to determine gas density at seawater hydrostatic pressure and Condition 1 temperature.

Condition 3	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Hydrostatic Limit	35	0	5,560	23.878

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators - Surface	90	6,900	6,915	24.609
Condition 0: Precharged Accumulators - Subsea	35	284	5,844	24.609
Condition 1: Charged accumulators	35	4,903	10,463	32.981
Condition 2: Minimum Operating Pressure	35	2,061	7,621	28.480
Condition 3: Total Discharge	35	284	5,844	24.609

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.0$	0.118
Volume Limited $VE_V = (1.0 - \rho_0/\rho_1)/1.4$	0.181
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.4$	NR
Volumetric Efficiency VE = min(VE_P, VE_V)	0.118
Minimum Accumulator Volume Required (gal) = FVR/VE	530.0

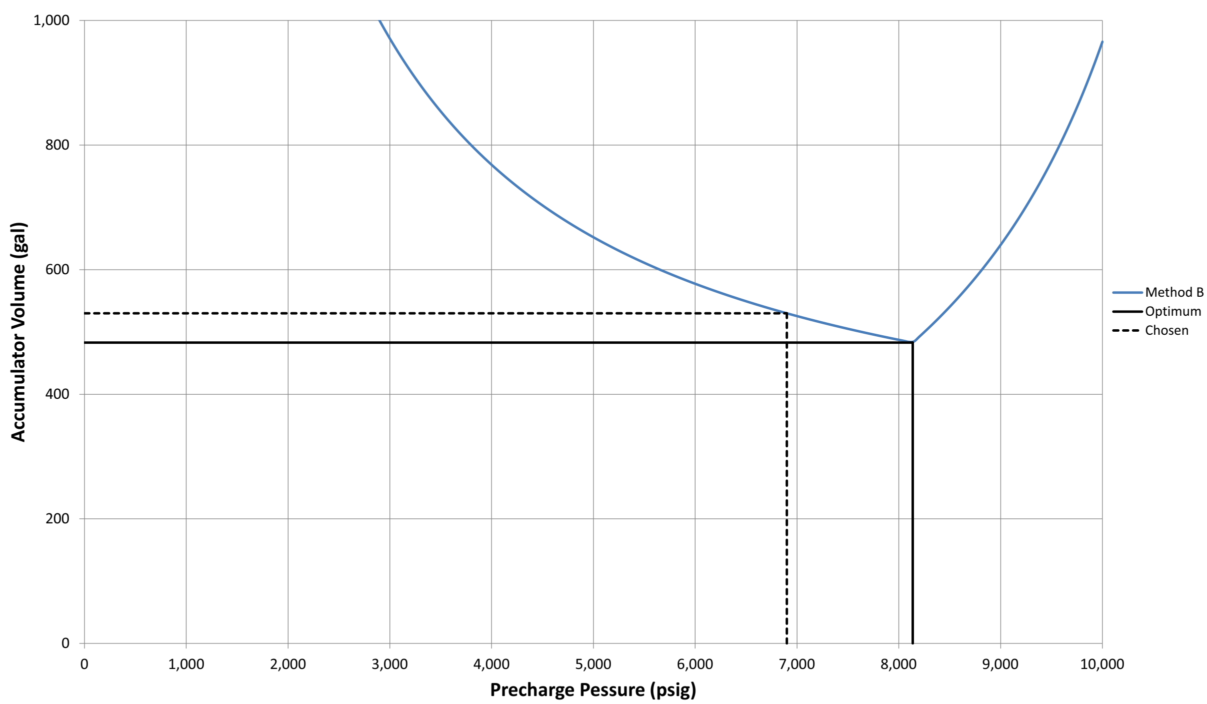


Figure D.10—Example 10: Subsea Stack—Acoustic Accumulator Sizing

Table D.15—Example 11: Subsea Stack—Diverter Accumulator Sizing

Example 11: Subsea Stack - Diverter Accumulator Sizing

Diverter Accumulator

This worksheet details the sizing calculations for the Diverter Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Rated Working Pressure (psig)	Pressure Required (psig)	Function Volume (gal)
Divert Mode Functional Sequence	1,500	1,500	11.00
Diverter	500	1,500	25.00

Sequence

Total Functional Volume Requirement (FVR)	36.00
Pressure Required	1,500

Environmental Conditions		
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	5,000	psig
Pump Stop Pressure (100%)	5,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia)= Surface Supply Pressure + Atmospheric Pressure = 5000 + 14.7 = 5014.7

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition	5,000	5,015	90	20.001	1.191

2. Calculate minimum operating pressure(s)

Calculate the minimum operating pressures for each step within the sequence and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Atmospheric Pressure = 1500 + 14.7 = 1514.7

Calculate MOP(s)	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	1,500	1,515

3. Calculate minimum operating density(s)

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density(s)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density	1,500	1,515	1.191	11.247	-68

4. Calculate optimum precharge density

Optimum precharge density $\rho_0 = \rho_2$.

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - Sequence 1	11.247	90	2,450	2,465

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *maintaining total discharge pressure above seawater hydrostatic pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		2,450	2,465	90	11.247
Selected Precharge Pressure at Maximum Temperature		2,628	2,643	120	11.247

Precharge Verification

Greater than 25% of Accumulator Charged Pressure	Precharge pressure (2465 psia) is greater than 25% of charged accumulator pressure (1254 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (2628 psig) is less than accumulator rated working pressure (5000 psig).

6. Determine volumetric efficiencies

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators	90	2,450	2,465	11.247
Condition 1: Charged accumulators	90	5,000	5,015	20.001
Condition 2: Minimum Operating Pressure	-68	1,500	1,515	11.247

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$	0.398
Volume Limited $VE_V = (1.0-\rho_0/\rho_1)/1.1$	0.398
Volumetric Efficiency $VE = \min(VE_P, VE_V)$	0.398
Minimum Accumulator Volume Required (gal) = FVR/VE	90.5

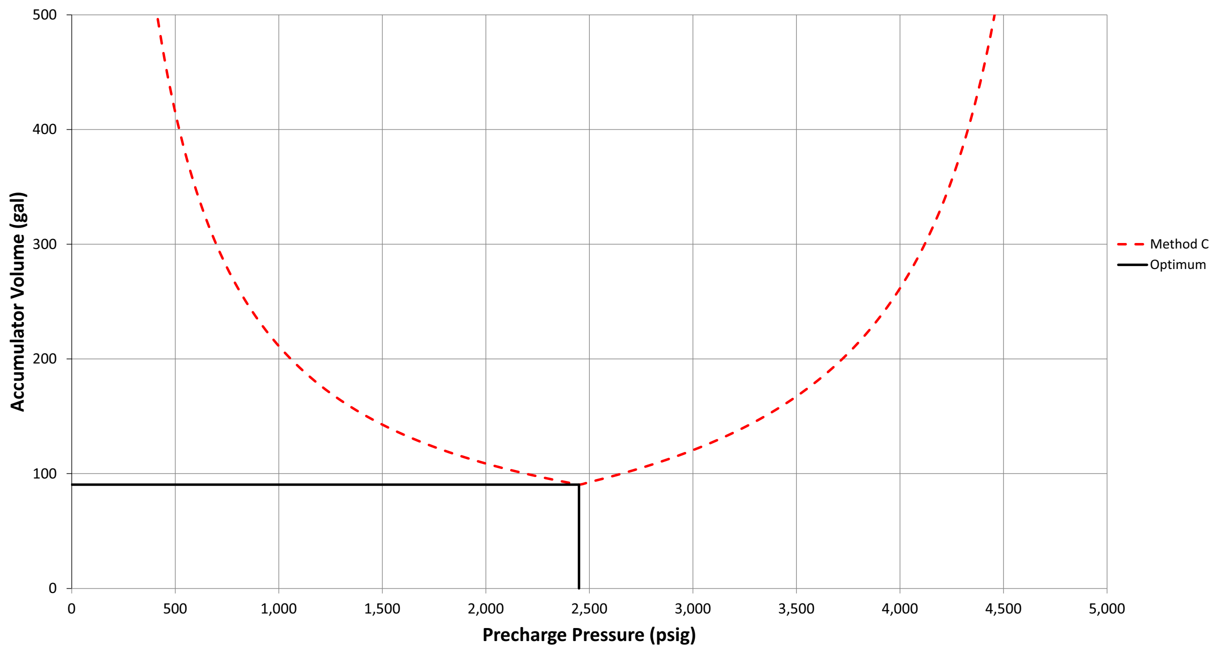


Figure D.11—Example 11: Subsea Stack—Diverter Accumulator Sizing

Table D.16—Example 12 and 13: BOP Stack Configuration for Special Purpose Accumulators

Example 12 & 13: BOP Stack Configuration for *Special Purpose Accumulators*

The following examples size accumulators for special purpose functions. The deadman/autoshear (with Depth Compensated Bottles) and choke & kill valve closure assist accumulators will be sized.

<table>
<tr><th>Stack</th><th>Rated Working Pressure (psia)</th><th>Pressure Required / MOPFLPS (psig)</th><th>Closing Volume (gal)</th><th>Opening Volume (gal)</th><th colspan="2">Closing/Shearing Ratio</th></tr>
<tr><td>Upper Annular BOP, 18-3/4"</td><td>10,000</td><td>1,500</td><td>85.30</td><td>64.80</td><td colspan="2">-</td></tr>
<tr><td>Lower Annular BOP, 18-3/4"</td><td>10,000</td><td>1,500</td><td>85.30</td><td>64.80</td><td colspan="2">-</td></tr>
<tr><td rowspan="2">Upper Blind Shear Ram, 18-3/4"</td><td rowspan="2">15,000</td><td>1,710</td><td rowspan="2">40.30</td><td rowspan="2">35.00</td><td>15.24</td><td>Shearing</td></tr>
<tr><td>520</td><td>6.40</td><td>Sealing</td></tr>
<tr><td>Casing Shear Ram, 18-3/4"</td><td>15,000</td><td>2,035</td><td>40.30</td><td>35.00</td><td colspan="2">15.24</td></tr>
<tr><td rowspan="2">Lower Blind Shear Ram, 18-3/4"</td><td rowspan="2">15,000</td><td>1,710</td><td rowspan="2">40.30</td><td rowspan="2">35.00</td><td>15.24</td><td>Shearing</td></tr>
<tr><td>520</td><td>6.40</td><td>Sealing</td></tr>
<tr><td>Upper Pipe Ram, 18-3/4"</td><td>15,000</td><td>750</td><td>20.75</td><td>17.30</td><td colspan="2">7.20</td></tr>
<tr><td>Middle Pipe Ram, 18-3/4"</td><td>15,000</td><td>750</td><td>20.75</td><td>17.30</td><td colspan="2">7.20</td></tr>
<tr><td>Lower Pipe Ram, 18-3/4"</td><td>15,000</td><td>750</td><td>20.75</td><td>17.30</td><td colspan="2">7.20</td></tr>
<tr><td>Choke & Kill Valve</td><td>15,000</td><td>780</td><td>0.65</td><td>0.65</td><td colspan="2">-</td></tr>
</table>

System Parameters		
System Pressure*	5,000	psig
Regulated Pressure**	3,000	psig
Riser Air Gap	75	ft
Control Fluid Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Sea Water Weight	8.54	ppg
Water Depth	12,500	ft

*For Example 12
**For Example 13

5,463	psia
5,561	psia

Environmental Conditions		
Surface Temperature at Precharge	90	°F
Maximum Surface Temperature	120	°F
Subsea Operating Temperature	35	°F
Atmospheric Pressure	14.7	psia

Relevant References

Pump System

- Primary pump start at 90% of system RWP
- Primary pump stop between 98%-100% of system RWP

Ex. 12 DMAS Accumulators

- Example rig's emergency accumulators are supplied by the main accumulator system and are checked in, therefore, pump stop pressure is used
- Method C

Ex. 13 Choke & Kill Closure Assist Accumulators

- Hydraulic charge pressure (regulated 3 KSI)
- Method C
- accumulator system to close all inner choke & kill valves (qty 6)

Table D.17—Example 12:Special Purpose—Subsea Depth Compensated Bladder Accumulator Sizing

Example 12: Special Purpose - Subsea Depth Compensated Bladder Accumulator Sizing

Depth Compensated Bladder Accumulator

This worksheet details the sizing calculations for the Depth Compensated Bladder Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Sequence	Rated Working Pressure (psia)	Pressure Required (psig)		Function Volume (gal)	Closing or Shearing Ratio	Adjusted Pressure (psig)
Casing Shear Ram, 18-3/4"	1	15,000	2,035	Shear	40.30	15.24	2,654
Timing Circuit	2	3,000 psig	1,500		1.00	-	1,500
Upper Blind Shear Ram, 18-3/4"	2	15,000	1,710	Shear	40.30	15.24	2,329
			520	MOPFLPS		6.20	2,042

Pressure Required (psig) to Shear with Casing Shear Ram = Shear Pressure + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 2035 + (15000 - 5561) / 15.24 = 2654.4

Pressure Required (psig) to Shear with Blind Shear Ram = Shear Pressure + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 1710 + (15000 - 5561) / 15.24 = 2329.4

Minimum Pressure Required (psig) to Seal with Blind Shear Ram = MOPFLPS + (Rated Working Pressure - Seawater Static Pressure) / closing ratio = 520 + (15000 - 5561) / 6.2 = 2042.5

Sequence	1	2	
Total Functional Volume Requirement (FVR)	40.30	41.30	gal
Pressure Required	2,654	2,329	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Riser Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,561	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	10,000	psig
Area Ratio (AR)	1.1738	
Gas Volume (per accumulator)	158.3330	gal
Hydraulic Volume (per accumulator)	20.6600	gal
Quantity of accumulators	5	
Subsea Regulated	no	
Pump Start Pressure (100%)	5,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Hydraulic Accumulator Pressure (psia) = Surface Supply Pressure + Control Fluid Hydrostatic Absolute Pressure = 5000 + 5463 = 10463

Charged Hydraulic Accumulator Pressure (psig) = Charged Hydraulic Accumulator Pressure (psia) - Seawater Hydrostatic Absolute Pressure = 10463 - 5561 = 4902

Charged Gas Accumulator Pressure (psia) = (Charged Hydraulic Accumulator Pressure (psia) - Seawater Head) / Area Ratio = (10463 - 5561) / 1.1738 = 4176.2

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition - Gas	NR	4,176	35	19.717	1.1722480
Charged Condition - Hydraulic	4,902	10,463	NR	NR	NR

2. Calculate minimum operating pressure(s)

Calculate the minimum operating pressures for each step within the sequence and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Seawater Hydrostatic Absolute Pressure = 2655 + 5561 = 8215.4

Calculate MOP(s)	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure - Sequence 1	2,654	8,215
Minimum Operating Pressure - Sequence 2	2,329	7,890

3. Calculate minimum operating density(s)

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density(s)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density - Sequence 1 Gas	NR	2,261	1.1722480	15.007	-42
Minimum Operating Density - Sequence 1 Hydraulic	2,654	8,215	NR	NR	NR
Minimum Operating Density - Sequence 2 Gas	NR	1,984	1.1722480	14.076	-57
Minimum Operating Density - Sequence 2 Hydraulic	2,329	7,890	NR	NR	NR

4. Calculate optimum precharge density

Optimum precharge density $\rho_0 = \rho_2$.

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure - Sequence 1	15.007	90	3,426	3,441
Optimum Precharge Pressure - Sequence 2	14.076	90	3,172	3,186

If sequence consists of 2 functions, then calculate the optimum precharge that satisfies both functions, otherwise use the optimum precharge for the single function. See Annex C for explanation of two function optimum precharge.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	14.076	90	3,172	3,186

Table D.17—Example 12:Special Purpose—Subsea Depth Compensated Bladder Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:

- *maintaining precharge pressure below the maximum rated working pressure*
- *preventing accumulator piston from stroking out.*
- *maintaining total discharge pressure above seawater hydrostatic pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

NOTE: Depth Compensated accumulators are intended for use in deeper depths. If a system designed for deeper depth is used at shallower depths, calculations should be performed to verify they are sufficient for the application.

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature		3,916	3,931	90	16.697
Selected Precharge Pressure at Maximum Temperature		4,226	4,241	120	16.697
Selected Precharge Pressure at Operating Temperature		3,346	3,360	35	16.697
Precharge Pressure at full stroke of piston*		3,916	3,931	90	16.697

** A check is done to ensure that piston does not reach the mechanical stop in the charged state. If it does, the pre-charge is adjusted to prevent this from occurring.*

Precharge Verification

Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (4226 psig) is less than accumulator rated working pressure (10000 psig).
Hydraulic Stroke Verification Check	Precharge pressure does not cause piston to reach full stroke.

6. Determine volumetric efficiencies

Use the NIST fluid property references to determine accumulator absolute pressure using the Condition 0 density and Condition 1 entropy

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Total Discharge - Gas	16.697	1.1722480	NR	2,841	-15
Total Discharge - Hydraulic	NR	NR	3,335	8,896	NR

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators - Gas	90	NR	3,931	16.697
Condition 0: Precharged Accumulators - Gas (Subsea)	35	NR	3,360	16.697
Condition 1: Charged accumulators - Gas	35	NR	4,176	19.717
Condition 1: Charged accumulators - Hydraulic	NR	4,902	10,463	NR
Condition 2: Minimum Operating Pressure - Sequence 1 Gas	-42	NR	2,261	15.007
Condition 2: Minimum Operating Pressure - Sequence 1 Hyd	NR	2,654	8,215	NR
Condition 2: Minimum Operating Pressure - Sequence 2 Gas	-57	NR	1,984	14.076
Condition 2: Minimum Operating Pressure - Sequence 2 Hyd	NR	2,329	7,890	NR
Condition 3: Total Discharge - Gas	-15	NR	2,841	16.697
Condition 3: Total Discharge - Hydraulic	NR	3,335	8,896	NR

Sequence 1

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/(1.1^*AR)$ **	0.206
Volume Limited $VE_V = (1.0-\rho_0/\rho_1)/(1.1^*AR)$ **	0.119
Volumetric Efficiency $VE_1 = \min(VE_P, VE_V)$	0.119
Gas Volume Required (gal) $ACR_1 = FVR_1/VE_1$	339.7

Sequence 2

Pressure Limited $VEP = (\rho 0/\rho 2 - \rho 0/\rho 1)/(1.1^*AR)$ **	0.263
Volume Limited $VEV= (1.0-\rho 0/\rho 1)/(1.1^*AR)$ **	0.119
Volumetric Efficiency $VE_2 = \min(VE_P, VE_V)$	0.119
Gas Volume Required (gal) $ACR_2 = FVR_2/VE_2$	687.9

** The area ratio of the accumulator must be included in the efficiency calculation as shown.

Min. Accumulator Gas Volume Required (gal) = max (ACR_1, ACR_2)	687.9
Minimum Quantity of accumulators required	5

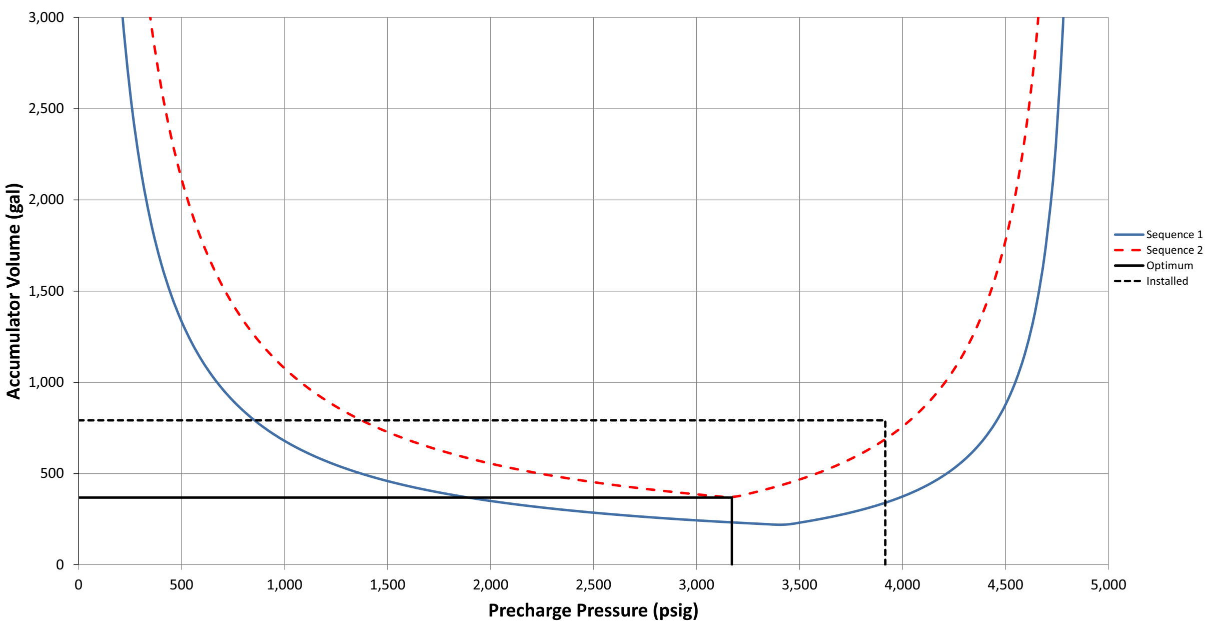


Figure D.12—Example 12:Special Purpose—Subsea Depth Compensated Bladder Accumulator Sizing

Table D.18—Example 13: Subsea Stack—Choke and Kill Valve Closure Assist Accumulator Sizing

Example 13: Subsea Stack - Choke & Kill Valve Closure Assist Accumulator Sizing

Choke & Kill Valve Close Assist Accumulator

This worksheet details the sizing calculations for the Choke & Kill Valve Close Assist Accumulator utilizing API 16D 3rd. Edition calculations.

Operator Function(s)	Rated Working Pressure (psia)	Pressure Required (psig)	Function Volume (gal)
All Inner Choke and Kill Valves (QTY 6)	15,000	780	3.90

Total Functional Volume Requirement (FVR)	3.90	gal
Pressure Required	780	psig

Environmental Conditions		
Water Depth	12,500	ft
Control Fluid Air Gap	75	ft
Control Fluid Weight	8.34	ppg
Seawater Weight	8.54	ppg
Control Fluid Static Pressure	5,463	psia
Seawater Static Pressure	5,561	psia
Atmospheric Pressure	14.7	psia
Surface Temperature at Precharge	90	°F
Subsea Operating Temperature	35	°F
Maximum Surface Temperature	120	°F

Accumulators		
Precharge Gas	Nitrogen	
Accumulator RWP	7,500	psig
Subsea Regulated	yes	
Regulated Pressure	3,000	psig

Input	Rig specific data
Transfer	Transferred within worksheet
Calculated	Calculated from table data
NIST	Data from NIST reference program

1. Calculate accumulator conditions at charged state

Use NIST fluid property references to determine gas density and entropy based upon gas temperature and absolute pressure.

Charged Accumulator Pressure (psia) = Surface Supply Pressure + Seawater Hydrostatic Absolute Pressure = 3000 + 5561 = 8561

Condition 1 - Charged Accumulator Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_1	Entropy S_1
Charged Condition	3,000	8,561	35	30.150	1.1093947

2. Calculate minimum operating pressure

Calculate the minimum operating pressure and adjust for hydrostatic effects.

Minimum Operating Pressure (psia) = Pressure Required + Seawater Hydrostatic Absolute Pressure = 780 + 5561 = 6341

Calculate MOP	Pressure Required (psig)	Minimum Operating Pressure (psia)
Minimum Operating Pressure	780	6,341

3. Calculate minimum operating density

Use NIST fluid property references to determine gas density at MOP based upon absolute pressure and Condition 1 entropy.

Condition 2 - MOP Density	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Entropy S_2	Density (lbm/ft^3) ρ_2	Temperature (°F)
Minimum Operating Density	780	6,341	1.1093947	27.659	0

4. Calculate optimum precharge density

Optimum precharge density $\rho_0 = \rho_2$.

Use NIST fluid property references to determine gas absolute pressure based upon gas temperature and density.

Condition 0	Optimum Precharge Density (lbm/ft^3)	Temperature (°F)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)
Optimum Precharge Pressure	27.659	90	8,511	8,526

Table D.18—Example 13: Subsea Stack—Choke and Kill Valve Closure Assist Accumulator Sizing (Continued)

5. Determine precharge density

Actual precharge pressure can vary from optimal precharge pressure for reasons such as:
- *maintaining precharge pressure below the maximum rated working pressure*
- *maintaining precharge pressure above 25% of system working pressure*
- *maintaining total discharge pressure above seawater hydrostatic pressure*
- *permitting a range of precharge pressures during operations*
- *following manufacturer's recommendations.*

Surface precharge pressure should equal Optimum Precharge Pressure unless the volume of the accumulator supports a range of precharges

Precharge Gas Properties	User-Selected Precharge (psig)	Accumulator Pre-Charge Pressure (psig)	Accumulator Pre-Charge Pressure (psia)	Temperature (°F)	Density (lbm/ft^3) ρ_0
Selected Precharge Pressure at Precharge Temperature	6900	6,900	6,915	90	24.609
Selected Precharge Pressure at Operating Temperature		283	5,844	35	24.609
Selected Precharge Pressure at Maximum Temperature		7,478	7,493	120	24.609

NOTE: The optimum precharge exceeds the accumulator RWP at maximum temperature. Therefore, a lower precharge has been selected.

Precharge Verification

Accumulator Precharge Pressure at Minimum Temperature	Precharge pressure (5845 psia) is greater than 25% of charged accumulator pressure (2141 psia).
Accumulator Precharge Pressure at Maximum Temperature	Precharge pressure (7479 psig) is less than accumulator rated working pressure (7500 psig).

6. Determine volumetric efficiencies

Use the NIST fluid property references to determine accumulator pressure using the Condition 0 density and Condition 1 entropy

Condition 3	Density (lbm/ft^3) ρ_3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Temperature (°F)
Total Discharge	24.609	1.1093947	-1,221	4,340	-41

Use the NIST fluid property references to determine gas density using Condition 1 entropy and the Seawater Head for accumulator pressure

Condition 3	Entropy S_3	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3) ρ_3	Temperature (°F)
Seawater Hydrostatic Limit	1.1093947	0	5,561	26.592	-15

Condition Summary	Temperature (°F)	Accumulator Pressure (psig)	Accumulator Pressure (psia)	Density (lbm/ft^3)
Condition 0: Precharged Accumulators - Surface	90	6,900	6,915	24.609
Condition 0: Precharged Accumulators - Subsea	35	283	5,844	24.609
Condition 1: Charged accumulators	35	3,000	8,561	30.150
Condition 2: Minimum Operating Pressure	0	780	6,341	27.659
Condition 3: Seawater Hydrostatic Limit	-15	0	5,561	26.592

Pressure Limited $VE_P = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$	0.067
Volume Limited $VE_V = (1.0-\rho_0/\rho_1)/1.1$	NR
Cond. 3 - Hydrostatic Limited $VE_V = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$	0.120
Volumetric Efficiency VE= min(VE_P, VE_V)	0.067
Minimum Accumulator Volume Required (gal) = FVR/VE	58.4

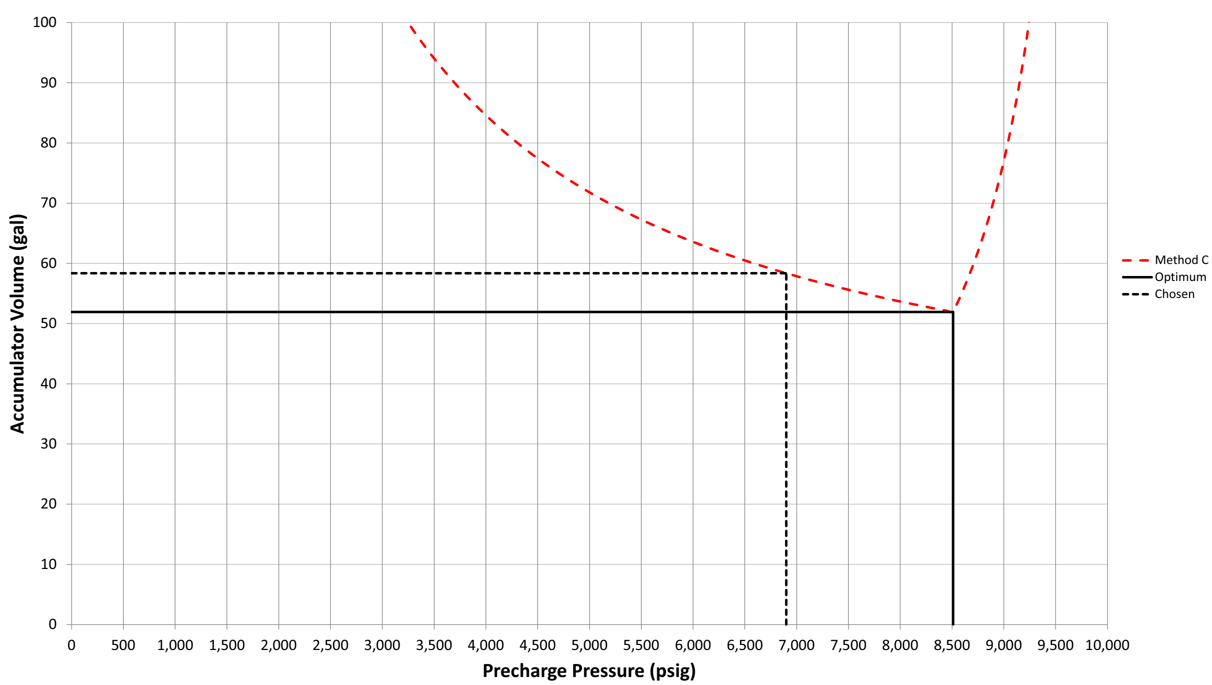


Figure D.13—Example 13: Subsea Stack—Choke and Kill Valve Closure Assist Accumulator Sizing

Bibliography

[1] AWS D1.1, *Structural Welding Code-Steel*

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