Specification for Control Systems for Drilling Well Control Equipment

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FOREWORD

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f. These specifications were formulated to serve as an aid to procurement of standardized equipment and materials as well as to provide instructions to manufacturers of control systems for well control equipment. They identify requirements for the design, materials, processing and testing of standardized equipment.

g. These specifications were prepared by the Subcommittee on Control Systems for Well Control Equipment. They represent a composite of industry accepted practices and standard specifications employed by various equipment manufacturing companies. In some instances, reconciled composites of these practices are included in this publication. This publication is under jurisdiction of the API Exploration & Production Department's Committee on Standardization of Drill Through Equipment.

h. The goal of these specifications is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling rig and associated equipment, and preservation of the environment for land and marine drilling operations.

i. Individuals and organizations using these specifications are cautioned that operations and equipment must comply with requirements of federal, state, and/or local laws and regulations. Users should review these legal requirements to ensure compliance therewith.

j. Users of specifications set forth herein are reminded that constantly developing technology and specialized or limited operations do not permit complete coverage of all operations and/or alternatives. Specifications presented herein are not intended to inhibit developing technology and equipment improvements or improved operational procedures. These specifications are not intended to obviate the need for qualified engineering and operations analyses and sound judgements as to where and when these specifications should be used to fit a specific manufacturing application.

k. This publication includes use of the verbs "shall" and "should" whichever is deemed most applicable for the specific situation. For the purposes of this publication, the following definitions are applicable:

Shall. Indicates that the specification is a minimum requirement that has universal applicability to that specific activity.

Should. Denotes a specification (1) where an alternative specification that is equally safe and/or effective is available; (2) that may be impractical under certain circumstances; or (3) that may be unnecessary under certain circumstances or applications.

Changes in the uses of these verbs are not to be effected without risk of changing intent of specifications set forth herein.

l. Suggested revisions or additions are invited and should be submitted to: Director, Exploration & Production Department, API, 1201 Main Street, Suite 2535, Dallas, TX 75202–3994.

SECTION 1
SCOPE

1.0 These specifications establish design standards for systems, subsystems and components used to control BOP's (blowout preventers) and associated valves that control well pressure during drilling operations. Although diverters are not considered well control devices, their controls are often incorporated as part of the BOP control system. Control systems for drilling well control equipment typically use 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 control component is referred to as a control function. The control system equipment and circuitry varies generally in accordance with the application and envirornnent. Thus, the specifications provided herein are applicable to six control system categories.

These include:

1.1 CONTROL SYSTEMS FOR SURFACE MOUNTED BOP STACKS. These systems are typically simple closed hydraulic control systems consisting of a reservoir for storing hydraulic fluid, pump equipment for pressurizing the hydraulic fluid, accumulator banks for storing power fluid, manifolding, piping and control valves for transmission of control fluid to the BOP stack functions.

1.2 HYDRAULIC CONTROL SYSTEMS FOR SUBSEA BOP STACKS. In addition to the equipment required for surface mounted BOP stacks, subsea control systems use umbilical hose bundles for transmission of hydraulic pilot signals subsea. Also used are dual subsea control pods mounted on the LMRP (lower marine riser package), 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 afford backup security.

1.3 ELECTRO-HYDRAULIC/MULTIPLEX CONTROL SYSTEMS FOR SUBSEA BOP STACKS. For deepwater operations, transmission subsea of electric (rather than hydraulic) signals permits short response times. Electro-hydraulic systems employ multi conductor cables, having an individual wire dedicated to each function to operate subsea solenoid valves which send hydraulic pilot signals to the valves that operate the BOP stack functions. Multiplex control systems employ serialized electronically coded messages transmitted over shared conductors. Electronic 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.

1.4 DIVERTER CONTROL SYSTEMS. Direct hydraulic controls are commonly used for operation of the surface mounted diverter unit and any associated valves.

1.5 EMERGENCY BACKUP BOP CONTROL SYSTEMS. When the subsea control system is inaccessible or nonfunctional, an independent control system may be used to operate critical well control and/or disconnect functions. These systems have their own supply of power fluid. They include acoustic control systems, ROV (Remotely Operated Vehicle) operated control systems and LMRP recovery systems. For surface control systems, a reserve supply of pressurized nitrogen gas can serve as a backup means to operate functions in the event that the pump system power supply is lost.

1.6 AUXILIARY EQUIPMENT CONTROL SYSTEMS AND INTERFACES. For floating drilling operations, various auxiliary functions such as the telescopic joint packer, 30" latch, etc., require operation by the control system. These auxiliary equipment controls, though not specifically described herein, shall be subject to the relevant specifications and requirements for similar equipment.

SECTION 2
DESIGN

2.0 Well control systems and equipment identified in paragraph 1.0 and related auxiliary equipment which may be designed and/or supplied by control system manufacturers for the intended use on oil well drilling rigs shall meet or exceed these specifications.

These specifications do not exempt such systems from federal, state, or local laws, or from prudent engineering practices and industry accepted standards.

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

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

2.1.1 Service Conditions

1. Sizing and capacity requirements.

2. Rated Working Pressure – The pressure at which the system, subsystem or component is designed to operate.

3. Temperature Ratings – The control system shall be designed to be operational within the ambient temperatures anticipated or the operational environment must be controlled to within the temperature ratings of the equipment.

AMBIENT TEMPERATURE CLASSIFICATION CHART

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

NOTE – *The preceding table represents the minimum acceptable ranges for operating the equipment.*

4. Location.

a. Land

b. Offshore

1. Subsea

2. Surface

5. Well Controll Equipment Specifications — Appendices I and II are check lists for use by the purchaser to provide information describing the BOP stack and other well control equipment such that the control system may be properly designed.

2.1.2 Design Documentation Requirements. A design data book shall be retained for each system design type by the manufacturer for a minimum of ten years after delivery of the last unit of the subject design.

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

Example of Design Data Book Constitution:

1. Title Page
2. Foreword
3. Table of Contents
4. Typical Sizing/Capacity Calculations
5. Rated Design Working Pressure
6. Rated Design Operating Temperature
7. Drawings/Calculations to document compliance to specifications
8. Utilities Consumption List
9. List of Applicable Standards and Specifications
10. Equipment Location Designations

2.2 EQUIPMENT SPECIFICATIONS. The purchaser shall provide complete description and specification of the equipment to be operated, service conditions and any application details necessary for the control system manufacturer to design and build a control system that complies with these specifications.

Appendix I is a form to be used by the purchaser to specify the operating and interface requirements of a surface control system. Appendix II is a form to be used by the purchaser to specify the operating and interface requirements of a subsea control system.

Appendices I and II serve as checklists for the purchaser to specify which functions are to be controlled.

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

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

2.2.1 Control System for Surface Mounted BOP Stacks.

2.2.1.1 Response Time. Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For surface installations, the BOP control system should be capable of closing each ram BOP within 30 seconds. Closing time should not exceed 30 seconds for annular BOP's smaller than 18-3/4 inches nominal bore and 45 seconds for annular preventers of 18-3/4 inches and larger. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time. Measurement of closing response time begins when the close function is activated at any control panel and ends when the BOP or valve is closed effecting a seal. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

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

2.2.1.2 Hydraulic Fluid and Reservoir Equipment. A suitable control fluid should be selected in accordance with paragraph 4.3.4.

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

The hydraulic fluid reservoir capacity shall be at least twice the usable hydraulic fluid capacity of the accumulator system. Air vents shall be installed of sufficient size to avoid pressurization of the tank during hydraulic fluid transfers or nitrogen transfers if a nitrogen backup system is installed.

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

2.2.1.3 Pump Requirements. At least two pump systems, each having independent dedicated power sources shall be provided. Each pump system shall have sufficient quantity and pump capacity to satisfactorily perform the following:

With the accumulators isolated from service, the pump system shall have the capacity to close one annular BOP (excluding the diverter) on open hole and open the hydraulically operated choke valve(s) and provide the minimum system operating pressure within two (2) minutes.

The combined output of all pumps shall be capable of charging the entire accumulator system from precharge pressure to the maximum rated control system working pressure within 15 minutes.

The same pump system(s) may be used to produce power fluid for control of both the BOP stack and the diverter system.

Each pump system shall provide a discharge pressure at least equivalent to the system working pressure. Air driven pump systems shall require no more than 75 psig air supply pressure to reach rated working pressure.

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

One device shall limit the pump discharge pressure so that it will not exceed the design working pressure of the BOP control system.

The second device, normally a relief valve, shall be sized to relieve at a flow rate at least equal to the design flow rate of the pump systems and set to relieve at not more than ten percent over the design working pressure.

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.

Electrical and/or air (pneumatic) supply for powering pumps shall be available at all times such that the pumps will automatically start when the system pressure has decreased to approximately ninety percent of the system working pressure and automatically stop within plus zero or minus 100 psi of the system design working pressure.

2.2.1.4 Accumulator Bottles and Manifolds. Accumulators shall meet ASME Section VIII Division 1 design requirements and be documented with ASME U1A certificates.

The accumulator system shall be designed such that the loss of an individual accumulator and/or bank will not result in more than twenty-five percent loss of the total accumulator system capacity.

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.

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

The recommended precharge pressures for the BOP components and conditions specified shall be stated on a tag permanently attached to the accumulator or the accumulator banks. Precharge pressure shall not exceed working pressure of the accumulator.

2.2.1.5 Accumulator Volumetric Requirements. The BOP control system shall have a minimum stored hydraulic fluid volume (VR), with pumps inoperative, to satisfy the greater of the two following requirements:

1. Close from a full open position at zero wellbore pressure, all of the BOP's in the BOP stack, plus fifty percent reserve.

2. The pressure of the remaining stored accumulator volume after closing all of the BOP's shall exceed the minimum calculated (using the BOP closing ratio) operating pressure required to close any ram BOP (excluding the shear rams) at the maximum rated wellbore pressure of the stack.

2.2.1.6 Hydraulic Control Manifold. A valve with porting sized at least equal to the control manifold supply piping size shall be provided for supply of control fluid from an alternate source. This valve should be plugged when not in use.

A minimum of two independent hydraulic pressure control circuits shall be provided which includes the following:

2.2.1.6.1 Hydraulic Control Manifold Annular BOP Circuit. A dedicated control circuit on the hydraulic control manifold shall operate the annular BOP(s). The components in this circuit shall include a pressure regulator to reduce upstream manifold pressure to the power fluid pressure level that meets the BOP manufacturer's recommendations. The regulator shall respond to pressure changes on the downstream side with sensitivity sufficient to maintain the set pressure within plus or minus one hundred and fifty psi.

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

2.2.1.6.2 Hydraulic Manifold Circuit for Common Pressure Functions. The hydraulic control manifold includes a common power fluid circuit with pressure regulation and control valves for operation of the ram type BOP's and choke and kill valves. This circuit shall be provided with a manifold regulator bypass valve or other means to override the manifold regulator to permit switching from regulated pressure to direct accumulator pressure for operating functions. The manifold shall be designed to function at full system rated working pressure in an emergency.

2.2.1.7 Remote Control Panels. A minimum of one remote control panel shall be furnished. This is to ensure that there are at least two locations from which all of the system functions can be operated. The remote panel shall be accessible to the driller. The driller's remote control panel display must be physically arranged as a graphic representation of the BOP stack. Its capability shall include the following:

1. Control all the hydraulic functions which operate the BOP's and choke and kill valves.

2. For offshore installations, display the position of the control valves and indicate when the electric pump is running.

3. Provide control of the annular BOP regulator pressure setting.

4. Provide control of the manifold regulator bypass or override valve or alternately provide remote control of the manifold regulator pressure setting.

5. The driller's panel shall be equipped with displays for readout of:

1. Accumulator pressure
2. Manifold regulated pressure
3. Annular BOP regulated pressure
4. Rig air pressure (air operated panels only) or low air supply warning (electric panels)

6. Driller's panels for offshore rigs shall additionally have audible and visual alarms to indicate:

1. Low accumulator pressure
2. Low rig air pressure
3. Low hydraulic fluid reservoir level
4. Panel on stand by power (if applicable)

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

2.2.2 Hydraulic Control Systems for Subsea BOP Stacks.

2.2.2.1 Response Time. The control system for a subsea BOP stack shall be capable of closing each ram BOP in 45 seconds or less. Closing response time shall not exceed 60 seconds for annular BOP's. Operating response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time. The response time to unlatch the LMRP shall not exceed 45 seconds. Conventional measurement of response time begins when the function is activated at any control panel and ends when the readback pressure gage recovers to its nominal setting.

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

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

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

The ethylene glycol reservoir if required, shall be sized using the maximum anticipated ethylene glycol/water ratio for the minimum anticipated ambient temperature to which the control fluid will be exposed. The reservoir shall contain sufficient ethylene glycol to mix at least one and one half times the total accumulator stored hydraulic fluid volume of control system fluid.

An audible and visible alarm shall be provided to indicate low fluid level in each of the individual reservoirs. The alarm control should be set to activate after 75% of the reservoir usable volume has been drained. The alarm shall sound and illuminate at the master, driller's and auxiliary remote panels.

Cleanout ports/hatches shall be provided for each reservoir to facilitate cleaning. To prevent overpressurization, each reservoir shall have suitable vents that have flow capacity in excess of the incoming flow capacity (including flow from accumulators for the mixed fluid reservoir). These vents shall not lend themselves to being mechanically plugged, or capped. Cleanout ports shall be a minimum four inch diameter.

The hydraulic fluid mixing system shall be designed for automatic operation. The system must automatically stop when the mixed fluid reservoir reaches the upper hydraulic fluid fill valve shut off level. The mixing system must automatically restart when the fluid level decreases not more than ten percent (10%) below the fill valve shut off level.

The mixing system shall be capable of mixing the fluids at a mixture ratio suitable to combat freezing at anticipated ambient temperature and supply an output flow rate at least equal to the combined discharge flow rate of the pump systems.

Reservoirs shall be cleaned of all weld slag, machine cuttings, sand or any other contaminants before fluid is introduced.

2.2.2.3 Pump Systems. The subsea BOP control system shall have a minimum of two independent pump systems (primary and secondary). The combination of all pumps shall be capable of charging the entire accumulator system volume from precharge pressure to the maximum rated system working pressure within fifteen minutes.

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

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

The pump systems shall have controls for automatic operation.

The primary pump system's controls shall be set so that the pump(s) will automatically stop at the maximum design working pressure of the BOP control system. The primary pump system control must start the pump(s) automatically if the control system accumulator pressure decreases to ninety percent of the design working pressure.

The secondary pump system's controls must provide operation similar to the primary system except that the set point to start the pump may be adjusted slightly lower so that both pump systems do not start simultaneously. The secondary pump control shall not stop the pump at less than ninety-five percent of the BOP control system design working pressure and must start the pump automatically prior to the system pressure decreasing below eighty-five percent of the design working pressure.

See Section 2.2.1.3 for information regarding overpressurization protection.

2.2.2.4 Accumulators and Manifolds. Accumulators and manifolds for hydraulic control systems for subsea BOP stacks should meet the guidelines of Section 2.2.1.4.

2.2.2.5 Calculated Accumulator Volumetric Capacity Requirements. The hydraulic control system for a subsea BOP stack shall have a minimum total stored hydraulic fluid volume, with the pumps inoperative, to satisfy the greater of the following requirements:

1. Open and close, at zero wellbore pressure, all of the ram type BOP's and one annular BOP in the BOP stack, with a fifty percent reserve.

2. The pressure of the remaining stored accumulator volume after opening and closing all of the ram BOP's and one annular BOP, shall exceed the calculated minimum system operating pressure. The calculated minimum system operating pressure shall exceed the greater of the following minimum stack component operating pressures:

   1. The minimum calculated operating pressure required (using the closing ratio) to close any ram BOP (excluding shearing pipe) at the maximum rated wellbore pressure of the stack.

   2. The minimum calculated operating pressure required to open and hold open any choke or kill valve in the stack at the maximum rated wellbore pressure of the stack.

Accumulators may be mounted on the subsea BOP stack to reduce response time and/or to serve as a backup supply of power fluid.

Means shall be provided to prevent 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) should be severed. The subsea accumulator capacity calculations shall compensate for subsea hydrostatic pressure gradient at the rate of .445 psi per foot of true vertical water depth. The compensated nitrogen precharge pressure shall not exceed the rated working pressure of the accumulator.

Accumulators mounted subsea shall have a subsea mounted, surface controlled valve to allow blocking the supply pressure to the accumulators so that the pump system pressure may be directed straight through to a selected BOP stack function.

2.2.2.6 Control Manifold. The control manifold is an assemblage of valves, gages, 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 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.

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

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

The remote control system shall permit operation of all the surface control valves at least two times after the loss of rig air and electric power. This backup equipment may be provided at the rig site by the user.

The pilot system shall include components to indicate the selected position of the BOP's at the remote panels by sensing pilot signals.

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

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

All functions on the hydraulic control manifold shall be remotely operable from the driller's panel (see paragraph 2.2.2.7.1).

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

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

2.2.2.7 Hydraulic Manifold Electric Remote Panel Interfaces. The control manifold functions as described in 2.2.2.6 shall be operable from and/or indicated at one of more additional remote panels connected in parallel to the driller's panel.

All panels shall be designed and connected in such a way that a component failure in one panel should not affect the operation or indication at the other panel(s) or the manifold. To prevent inadvertent operation of any function, each panel shall have a dedicated "push and hold" switch such that to operate a critical function, it is necessary to depress the "push and hold" button and the specific button for that function.

To confirm the integrity of all pilot lights, a lamp test switch shall be provided.

Switches controlling critical functions, such as shear rams, stack (wellhead connector, riser connector, connector secondaries and pod latches) shall have protective hinged covers or other means to prevent inadvertent operation.

2.2.2.7.1 Driller's Panel. The driller's panel display shall be physically arranged as a graphic representation of the BOP stack/LMRP. Its capability shall include at least the following:

1. Control all functions associated with BOP stack and LMRP including stack/LMRP mounted choke and kill line valves.

2. Display the current position status of all functions and last position status when functions are placed in the center (block) position.

3. Provide control of annular BOP regulator and manifold regulator remotely. This control shall be capable of being overridden at the control manifold described in 2.2.2.6. As specified in 2.2.2.6, any failure of remote operation shall not cause the loss of subsea regulator pressure setting.

4. The following pressure readout displays shall be provided:

   1. Accumulator Pressure
   2. Surface manifold pilot pressure
   3. Subsea Annular BOP regulator pilot pressure
   4. Subsea Annular BOP regulated (readback) pressure
   5. Subsea manifold regulator pilot pressure
   6. Subsea manifold regulated (readback) pressure
   7. Rig air supply pressure

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

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

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

2.2.2.7.2 Secondary Remote or Tool Pusher's Panel. The secondary-remote panel shall be located at a place away from the drill floor. The preferred location for the panel shall be either at the tool pusher's office or at a location close to the life boat station. This panel shall be physically arranged as a graphic representation of the BOP stack/LMRP.

Its capability shall include at least the following:

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

2. Display the position status of all functions.

3. The following indicating or alarm lights shall be provided:

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

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

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

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

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

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

2.2.2.8 Hose Reels. The hose reel drum radius shall be equal to or greater than the minimum bend radius recommended by the manufacturer of the subsea umbilical.

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

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

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

The hose reel drum shall have a mechanical locking device that positions the hose reel manifold and junction box in an accessible position when parked.

The hose reel assembly shall be prepared and coated to withstand direct exposure to salt water spray (see paragraph 4.3.5.2).

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.

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

2.2.2.10 Subsea Control Pods. Two control pods shall be used to provide redundant control of all subsea functions. The surface control manifold directs pilot command signals to operate the pressure regulators, control valves, and straight-through functions in the pod.

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

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

Isolation means shall be provided so that, if one pod or umbilical is disabled, it shall not affect the operation of the other pod or the subsea functions.

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

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

2.2.3 Electro Hydraulic and Multiplex Electro Hydraulic Control Systems for Subsea BOP Stacks. Electro hydraulic and multiplex control systems for subsea BOP stacks must meet the same response time, mixing and storage, pump requirements and accumulator manifolding and capacity requirements listed in 2.2.2 for subsea control systems.

Electrical power for these control systems (excluding the pump systems) shall be supplied from one or more uninterruptible power supplies with battery capacities to operate the controls for at least two hours.

2.2.3.1 Electrical Control Unit. One electrical control unit shall be located in a safe dry area.

All control functions and readbacks shall be operable and monitored at the panel on the drill floor.

The electrical control unit(s) shall maintain a non-violative function memory in the event of a power interruption to the unit. Upon restoration of power, the unit will automatically re-configure all subsea functions as they were prior to loss of power.

2.2.3.2 Electrical Cables. Two complete independent subsea cables shall be used. The severing, opening, or shorting of one cable assembly should not disable the surface equipment and the pod connected to the other cable should remain fully functional.

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

Each electrical cable shall contain all communications and/or power conductors required to control all the subsea functions through one pod.

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

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

Underwater connectors shall be provided with pressure test ports to verify the seal integrity of mated plug-receptacles.

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

All electrical control functions and electrical power required to run, land and retrieve the LMRP and/or the stack shall remain fully active during running, landing and retrieval.

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

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

All cable reel components shall have an environmental rating suitable for the area classification related to explosion hazard in which the reel is installed.

All electrical terminations, slip rings, etc. shall be protected against moisture and shall be suitable for the classification of the areas where installed. These items and their installation shall have the approvals, where required, of the certifying agencies specified.

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 the formation of resulting conductive dust which could cause signal degradation and short circuits.

2.2.3.4 Subsea Control Pods/Manifolds and Electrical Equipment. Two sets of electronic and or electro hydraulic control pods and manifolds shall be provided for the redundant control of all subsea functions.

A cable strain relief/radius guard shall be employed at the cable/pod interface.

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

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

2.2.3.5 Subsea Electrical Equipment. All electrical connections which may be inadvertantly exposed to seawater shall be protected from excessive electrical current to prevent overloading the subsea electrical supply system in the event of water intrusion into the connection.

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

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

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

All subsea electrical equipment shall be insulated from any surface exposed to seawater.

All electrical and electronic chambers shall be double sealed at all areas exposed to seawater or hydrostatic pressure and should have a provision for a test port. A chamber containing electrical components which is filled with dielectric fluid and pressure compensated to the ambient pressure surrounding the stack may be sealed using a single seal.

2.2.4 Diverter Control Systems.

General — The diverter control system shall be designed to preclude closing-in of the well with the diverter. This requires opening one or more vent lines prior to closing the diverter annular sealing device as well as closing normally open mud system valves. Operation to open the vent valve and close the mud line (return) valve shall occur before the diverter packer is closed. The pumps and/or accumulators used to operate the diverter system shall either be common to the BOP control system or dedicated to the diverter system.

An alternate means (back-up fluid supply) shall be employed to permit sequencing the diverter system should the primary closing system become inoperative. This can be accomplished by alternative pump system capacity, separate isolated accumulator capacity, nitrogen backup capacity or other means. The back-up system shall be capable of meeting the recommendations of Section 2.2.4.1.The back-up system shall be automatically or selectively available on demand.

2.2.4.1 Response Time. A diverter control system shall be capable of operating the vent line and flow line valves (if any) and closing the annular packing element on pipe or open hole within thirty seconds of actuation if the packing element has a nominal bore of twenty inches or less. For elements of more than twenty inches nominal bore, the diverter control system must be capable of operating the vent line and flow line valves (if any) and closing on pipe in use within forty-five seconds.

2.2.4.2 Control Fluid Reservoir. A diverter control system shall have a control fluid reservoir sized to hold a minimum of two times the usable hydraulic fluid of the accumulator system capacity required to operate the diverter equipment.

2.2.4.3 Pump Requirements. The pump system(s) for diverter system control systems shall be designed to automatically stop the pump(s) when the full design accumulator charging pressure is reached and to automatically re-start the pump(s) when the pressure decreases to not more than 90 percent of the charging pressure. The automatic pressure control system should additionally include a secondary overpressurization protection device such as a relief valve. The relief valve shall be set to relieve overpressurization at not more than 110 percent of the design accumulator charging pressure. Relief valves must be designed to automatically reseat and shut off within twenty five percent below the pressure setting.

The pump system(s) must be capable of recharging the diverter control system accumulators to full system within five minutes after one complete divert mode operation of the diverter control system.

2.2.4.4 Accumulator Volumetric Capacity. The diverter control system shall have sufficient accumulator capacity to provide the usable hydraulic fluid volume (with pumps inoperative) required to operate all of the divert mode functions plus fifty percent reserve.

2.2.4.5 Diverter Control Manifold. The diverter control manifold consists of control valves, regulators and gages. The control valves shall be arranged so that they represent the actual diverter equipment arrangement and be clearly identified as to their purpose and functional position.

The diverter control system shall be designed to prohibit closing the diverter packer unless a vent line has been opened. If the diverter in use is equipped with an insert packer and/or pressure energized flow line seals, the control system sequencing circuitry shall additionally prevent closing the diverter packer if the insert packer is unlocked or if the flow line seals and/or overshot packer are not energized.

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

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

2.2.4.6 Control Panels. All of the diverter control functions shall be remotely operable from the rig floor. The main hydraulic control panel shall be provided in an area remote from the rig floor. Loss of remote control capability should not interrupt or alter the automatic sequencing from the main control unit.

2.2.5 Manufacturing Documentation. A system to assemble and keep documentation to ensure that equipment specifications are met during the purchasing and manufacturing processes shall be established and employed by the control system manufacturer. The documentation shall include:

1. Purchase control specifications.
2. Engineering specifications.
3. Manufacturing standards.
4. Quality control procedures.

SECTION 3
INDIVIDUAL SYSTEM DESIGN VERIFICATION

3.0 Documentation and testing required to verify the design of each control system to these specifications shall include:

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

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

1. Reference documentation list.

2. Test equipment and apparatus list.

3. Personnel safety instructions.

4. Pre-test inspection, servicing and assembly requirements.

5. Detailed instructions (as applicable) for:

5.1 Flushing and Fluid cleanliness requirements.

5.2 Utilities verification.

5.2.1 Electric motor voltage, frequency, phase balance, amperage and insulation resistance.

5.2.2 Air supply pressure and operational pressure drop.

5.3 Hydrostatic test requirements.

5.4 Operational limit settings.

5.5 Functional requirements.

5.6 Records and data requirements.

5.7 Post test procedures, preservation and protection requirements.

6. Quality witness and acceptance.

7. Special considerations.

7.1 Requirements to ensure proper interface of system components permitted when delivery of components precludes availability of all components during factory tests.

7.2 Calculations acceptable to ensure design specifications are met where actual measurement of performance is not practical.

3.1.2 Certifications. The following certificates shall be available:

3.1.2.1 Hydrostatic Test Certificates. Hydrostatic test certificates shall be provided by the control system manufacturer for piping and component systems subjected to internal pressure of 250 psi or more. Pressure measurement and transmitting devices shall be tested to full design working pressure. Piping and containment devices shall be tested to 1-1/2 times the design working pressure in plant tests or to full design working pressure in the field. Holding time for test pressure shall be 5 minutes after stabilization. Test recorder charts shall be available, dated, witnessed, and identified to the particular equipment to accredit manufacturer's certifications.

3.1.2.2 Hazardous Area/Electrical Certificates. Manufacturer's certificates of compliance to applicable electrical codes shall be required for all electrical equipment and apparatus for installation in explosive environments as defined in API RP500.

3.1.2.3 Accumulator Certificates. Seamless accumulators furnished with ASME-U-1A reports are acceptable. Welded accumulators shall be documented with weld and NDE reports as well as hydrostatic test reports and manufacturer's certification to acceptable design and manufacturer requirements meeting ASME Section VIII Division I design criteria.

3.1.2.4 Relief Valve Certificates. Relief valves shall be separately tested and adjusted using a low flow rate tester comparable to a dead weight tester. A certificate of the relief valve setting and operation shall be provided by the valve manufacturer indicating the accuracy of the set point and the pressure at which the relief valve reseats. Relief valves for use in accumulator systems shall reseat within twenty five percent of the set pressure. Relief valves shall additionally be tested to determine the maximum flow rate through the relief valve without exceeding the relief valve's set pressure. The system shall be verified to have sufficient relief valves to meet 2.2.1.3 flow capability.

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

3.2 CONTROL SYSTEM QUALIFICATION TESTS. Qualification testing shall be required for prototype control systems. A prototype control system is a first time system of a new manufacturer or a system using major components of a type not previously proven. An in-plant test shall be performed to demonstrate that the prototype control system meets closing time requirements set forth in this specification (see 2.2). For units that are to be used subsea, calculated volumes for stack mounted accumlulators (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.

Warning accumulators shall not be precharged to pressures exceeding the design working pressure of the vessel when compensating for subsea hydrostatic pressure gradient.

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

1. With a least fifty percent (50%) of the accumulators isolated from service and the remainder fully charged, shut the pump systems off.

2. 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.

3. The accumulator pressure should decline steadily to the approximate precharge pressure, then drop to zero psi. (Flowmeter reading is an alternate indication).

4. Close the flow path then check precharge pressure of each accumulator to ensure no loss of precharge pressure or trapped pressure has occurred caused by improper operation of an accumulator discharge valve. Close the flow path and wait at least 15 minutes for temperature stabilization.

5. Repeat test for the remaining accumulators.

SECTION 4
MATERIAL REQUIREMENTS

4.1 PRESSURE CONTAINING COMPONENTS. All pressure containing (15 psi or greater) or pressure controlling components shall require a documented standard material specification (i.e., AISI or SAE specification) or the manufacturer's written requirements for the metallic materials to be used.

4.2 FABRICATION MATERIALS.

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

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

a. Group I designates mild steels with specified minimum yield strengths of 40 ksi (280 MPa) or less. Carbon equivalent is generally 0.40% or less, and these steels may be welded by any of the welding processes as described in AWS D1.1.

b. Group II designates intermediate strength steels with specified minimum yield strengths of over 40 ksi (280 MPa) through 52 ksi (360 MPa). Carbon equivalent ranges up to 0.45% and higher, and these steels require the use of low hydrogen welding processes.

c. Group III designates high strength steels with specified minimum yield strengths in excess of 52 ksi (360 MPa). Such steels may be used, provided that each application is investigated with regard to:

(1) Weldability and special welding procedures which may be required.

(2) Fatigue problems which may result from the use of higher working stresses.

(3) Notch toughness in relation to other elements of fracture control, such as fabrication, inspection procedures, service stress, and temperature environment.

4.2.3 Structural Shape and Plate Specifications. Unless otherwise specified by the designer, structural shapes and plates should conform to one of the specifications listed in ASTM standards.

4.3 COMMODITY ITEMS.

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

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

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

1. Pressure containing components.
2. Electrical and electronic equipment and installations.
3. Mechanical equipment.
4. Fluids and Lubricants.
5. Protective Finishes.

4.3.1 Pressure Containing Components.

4.3.1.1 Pressure Vessels.

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

4.3.1.1.1 Accumulators. Accumulator shells shall be hydrostatically tested to one and one-half (1-1/2) times their maximum intended working pressure. Certification of hydrostatic test witnessed by the ASME inspector shall be evident by the appropriate code inspection stamp permanently affixed to each accumulator shell. Accumulator shells shall include a permanently affixed serial number. Written test reports certifying acceptance of the accumulator shell test shall be maintained by the control system manufacturer for each serial numbered unit. Traceability to the original accumulator shell manufacturer shall be maintained.

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

The control system manufacturer shall maintain a Quality History File including Hydrostatic Test Charts to insure proof that each serial numbered unit successfully held the test pressure (within 1.5%) for a minimum of five minutes after stabilization (see 3.1.2.1). Sufficient time for pressure stabilization should be allowed to compensate for the temperature effect on the nitrogen precharge.

4.3.1.1.2 Non pressure compensated vessels subjected to external pressure above 15 psi and vessels (housing) for use subsea and subjected to subsea hydrostatic pressure externally where internal pressure is not compensated in a manner to prevent a differential pressure less than 15 psi shall be designed in accordance with ASME Section VIII, Division I rules.

Such vessels shall be permanently marked in a conspicuous manner to indicate the maximum water depth the vessel is designed for.

The vessel shall be tested and certified to ensure seal and structural integrity at the simulated design water depth identified on the vessel.

4.3.1.1.3 Nitrogen cylinders used in conjunction with blowout preventer and diverter control systems for emergency backup systems shall meet the Department of transportation Specification's 3AA2015 as a minimum. Nitrogen cylinders shall physically bear the D.O.T. inspector's mark, registered identifying symbol, test date and supplier's mark.

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

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

4.3.1.2.1 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 design working pressure.

4.3.1.2.2 Flame Tests. The control lines, and any component of the control lines to a surface mounted BOP stack or diverter located in a division (1) one area, as defined by API 500 (area classification) shall be capable of containing the normal operating pressure in a flame temperature of 2000 degrees F for a period of three minutes without a leakage (includes end connections).

Where hoses are used to connect the control system to the well control equipment, flame resistance tests shall be conducted on a typical specimen in the following manner:

1. The test specimen shall be fitted with pressure end couplings and installed in a test facility capable of maintaining a 2,000 degrees F (+/-100) flame temperature over at least 180 angle degrees of the test specimen inclusive of approximately 12 inches of the specimen length, including one end connection.

2. The specimen is to be connected to a regulated water pressure source equal to normal operating pressure.

3. Thermocouples shall be located within the flame area to ensure that the test temperature is maintained at the end coupling, the coupling to hose transition and at a point along the hose at least six inches from the hose to coupling transition.

4. Deliverable hoses typical of successful test specimens shall be permanently identified in a manner to permit tracing of the test specimen and test facility. The control system manufacturers shall be responsible for maintaining hose compliance certifications on hoses which they supply in accordance with this specification.

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

Design of threaded piping connections shall be in accordance with ANSI B31.3 latest edition.

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

All piping and tubing installations shall be hydrostatically tested to one and one-half (1-1/2) times design working pressure by the control system manufacturer during factory acceptance testing. Air supply piping and instrument air systems shall be bubble tested (soap solution on each connection). Air receivers shall be ASME coded, where applicable, and shall be protected from overpressurization.

4.3.1.3 Non ASME Coded Hydraulic Control System Components. Components in this category include control valves, check valves, pressure reducing/regulating valves, solenoid valves, pressure switches, pressure transducers, gages, relief valves, pump fluid ends and other components in the hydraulic system.

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

All components in this group shall be hydrostatically tested during factory acceptance testing to system design working pressure. Additionally, hydraulic and pneumatic components integral with electric/electronic devices are also subject to the electrical and electronic equipment and installation specifications presented in Section 4.3.2 of this specification.

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 1,000 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.

4.3.2 Electrical and Electronic Equipment and Installation.

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

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

4.3.2.3 All electrical components shall be capable of operating within specifications at a voltage range of + or -10% nominal rated voltage.

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

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

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

4.3.2.7 Electrical components should be designed or packaged in such a manner so as to prevent corrosion caused by condensation and exposure to a salt laden atmosphere. All electrical apparatus exposed to uncontrolled atmospheric conditions (i.e. deck-mounted equipment) should be of NEMA 4X construction.

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

4.3.2.9 All socket mounted components shall be mechanically restrained in their sockets.

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

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

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

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

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

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

4.3.2.15 Aluminum wire shall not be used.

4.3.3 Mechanical Equipment.

Pod Valves — Pod valves shall be designed to minimize interflow. Consideration should be given to effective spring closure in the absence of pressure assist closing. Prototype springs should be tested to 1,000 cycles and retain the minimum design spring constant. All pod valve prototypes shall be cycled a minimum of 1,000 times at normal operating pressure. Cap screws holding valves and regulators together should be corrosion resistant.

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

Clamps for control hoses and cables shall be designed and tested to hold maximum loads induced by hose or cable weight, current and wave action. Materials of construction should be corrosion resistant.

Operator guards shall be provided for all rotating equipment.

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.

All check valves and shuttle valves shall be cycled and pressure and flow tested to ensure proper function under all anticipated conditions.

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

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

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

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

4.3.5 Cathodic Protection and Painting.

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

4.3.5.2 Painting. Abrasive blast cleaning methods, painting materials and standards of measurement shall meet the applicable recommendations of SSPC (Steel Structures Painting Council) guidelines for the intended environment of installation. Manufacturer shall specify materials, application and verification in written procedures.

SECTION 5
WELDING REQUIREMENTS

5.1 GENERAL.

5.1.1 All welding of external or internal pressure containing components shall comply with the welding requirements of the ASME Boiler and Pressure Vessel Code Section IX. (Ref. 4.3.1.) Verification of compliance shall be established through the implementation of the manufacturer's Welding Procedure Specification (WPS) and the supporting Procedure Qualification Record (PQR).

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

5.2 WELDMENT DESIGN AND CONFIGURATION.

5.2.1 Pressure Containing Fabrication Weldments. Pressure containing fabrication weldments described here pertain to primary pressure containing members.

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

5.2.2 Load Bearing Weldments. Load bearing weldments are essential to the operation or installation of equipment and which are not in contact with the contained fluid. These include, but are not limited to, lifting points and equipment mounting supports.

Joint design for load bearing weldmounts shall be defined by the manufacturer. Welding and completed welds shall meet the quality control requirements of Section 6 of this specification.

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

Welding and completed welds shall meet the requirement of Section 6 of this specification.

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

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

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

5.4 DESIGN OF WELDS.

5.4.1 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.

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

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

5.6 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.

5.7 WELDING CONSUMABLES. Welding consumables shall conform to American Welding Society or consumable manufacturer's approved specifications.

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.

5.8 POST WELD HEAT TREATMENT.

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

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

5.8.3 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.

5.9 WELDING PROCEDURE AND PERFORMANCE QUALIFICATIONS. All weld procedures, welders and welding operators shall be qualified in accordance with the qualification and test methods of Section IX, ASME Boiler and Pressure Vessel Code as amended below.

5.9.1 Base Materials.

5.9.1.1 The manufacturer may use ASME Section IX P number materials.

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

5.9.1.3 Low alloy steels not listed in ASME Section IX with a nominal carbon content greater than 0.35%

shall be specifically qualified for the manufacturer's specified base material.

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

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

5.9.3 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 6 of this specification.

5.10 OTHER REQUIREMENTS. Article I of ASME Section IX applies with an optional addition in this section for impact testing.

5.10.1 Impact Testing.

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

5.10.1.2 When impact testing is required of the base material, one set of three (3) test specimens each shall be removed at the 1/4 thickness location of the test weldment for each of the weld metal and base material Heat Affected Zone (HAZ). The root of the notch shall be oriented normal to the surface of the test weldment and located as follows:

5.10.1.2.1 Weld Metal Specimens (3 each) shall be 100% weld metal.

5.10.1.2.2 HAZ Specimens (3 each) shall include as much HAZ material as possible.

5.10.1.2.3 When weld thickness of the product is equal to or greater than 2 inches, impact testing as defined in 1.2.2 shall be performed on weld metal and HAZ material removed within 1/4 thickness from the root.

5.10.2 ASME Section IX, Article II. Article II of ASME Section IX applies with additions shown in this section.

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

5.10.2.2 Chemical Analysis. 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.

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

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

SECTION 6
QUALITY CONTROL

6.1 GENERAL. This specification covers the control systems for drilling well control equipment.

6.1.1 Measurement and Testing Equipment. Measurement and testing equipment shall be identified with the date of calibration name, number of identification of calibrator, and the expiration date of calibration or calibration cycle.

Personnel using measurement and testing equipment must be qualified to properly use such equipment and must apply its use in accordance with written procedures that require recording of the test results against predetermined standards.

Damaged, defective and/or equipment which does not meet the calibration requirements shall not be used for verification of the quality requirements.

6.1.2 Personnel Qualifications. Quality assurance/control personnel shall be qualified by relevant training and experience. Verification of qualification in written record shall be maintained and available as audit may demand.

Quality assurance/control personnel shall have additionally received training and shall have demonstrated a thorough understanding of the requirements and specifications of the equipment, processes, and functions under their jurisdiction.

6.1.3 Quality Control Requirements.

6.1.3.1 Organization/Procedures. The quality program shall adhere to procedures and guidelines which shall be available in written form to all quality personnel. The quality program shall include a quality manual approved by a responsible officer of the manufacturing company.

6.1.3.2 Quality Engineering. Quality assurance shall be involved with reviewing the design, material selection, specification and documentation requirement prior to issuance of engineering releases to manufacturing.

Quality assurance shall be on distribution list for engineering releases and change orders issued to manufacturing.

Quality assurance shall be on the distribution list for request for engineering changes.

Quality assurance shall approve all standards, shop procedures or processes which are stated and/or implied as applicable to products being manufactured.

6.1.3.3 In-Process Inspection. Hold points shall be established for various stages of fabrication and assembly during the manufacturing process, where further fabrication/assembly would preclude adequate inspection. In-process inspection hold points shall not be waived or violated.

Disassembly for inspection shall be considered rework and subject to non-conformance reporting as a process/procedure violation which shall be reported to a responsible officer of the manufacturing company.

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

Quality control personnel shall witness all aspects of the testing process. The test shall be conducted in accordance with written procedures and shall verify compliance to applicable API RP 16E Recommended Practices.

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 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 may be marked only if factory testing ensures conformance to these specifications.

NOTE: *Integrated "on site" tests shall be the responsibility of the purchaser and/or user and shall ensure performance complying with API 16E Recommended Practices.*

6.1.3.5 Receiving Inspection. Materials received into the manufacturing facility shall be inspected by quality control personnel to ensure conformance to appropriate receiving documents and specifications.

Non-conforming materials shall be dispositioned in accordance with the manufacturer's quality manual.

6.1.3.6 Shipping Inspection. Prior to any preservation, protection, or packing for storage or shipment, the equipment shall be final inspected to ensure completeness and conformance to the requirements of the purchase specification. Particular attention shall ensure:

1. Correct finish
2. Installation of tags, markings and/or instruction plates
3. Record of all serial numbered units
4. Correct configuration
5. Installation dimensions and specifications
6. Weight

6.1.3.7 Vendor Surveys, Critical Components. Suppliers of critical materials shall be evaluated, selected and controlled in accordance with the manufacturer's quality manual.

6.1.3.8 Reporting. Quality Assurance shall internally audit the manufacturers engineering and manufacturing process, procedures and activities to ensure compliance with the requirements of the manufacturer's quality manual.

6.2 QUALITY CONTROL RECORDS.

6.2.1 Records Maintained by the Manufacturer. The following lists the minimum requirements for applicable records to be maintained for a period of not less than five years.

1. Material specifications and certifications
2. Hazardous area certifications
3. Hydrostatic test charts
4. Performance test and measurements
5. Materials/components list
6. Certificate of compliance to API 16D Specifications
7. Contract information including:

   Customer name and purchase order number

   Manufacturers serial number

   Ex-works delivery date

   Destination/Rig name

   API monogram (if applicable)

   Manufacturers identification/model numbers
8. Design Data Book (if applicable)

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

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

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

SECTION 7
MARKING

7.1 TEMPORARY MARKING. Materials received in the manufacturer's facilities for use in products to be manufactured to AP1 16D specifications shall be temporarily marked to identify them to traceable documents when required. These markings shall be removed only after a level of manufacturing has been reached whereby a permanent identification can be affixed. A manufacturing record shall be maintained by the permanent identification listing all temporary markings that have been removed.

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

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

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

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

7.4 MANUFACTURER'S IDENTIFICATION MARKINGS. Manufacturers shall affix at least one permanent marking on each final assembly. Manufacturers may affix other markings at their discretion.

7.5. EQUIPMENT NAME PLATE DATA. The name plate shall include information as to model no., name, and volume requirements that the equipment is designed to provide.

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

SECTION 8
STORING AND SHIPPING

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

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

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

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

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

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

8.4.2 Content of Deliverable Documentation. A minimum of two sets of the installation, operation and maintenance documentation shall be provided. One set shall be maintained by the manufacturer for a minimum of one year after delivery.

Content — (Sequence of presentation is optional.)

1. Index — Table of Contents and location of information.

2. Contract information consisting of:

— Buyer's purchase order number

— Supplier's identification number

— Supplier's contract information

— Calendar month of delivery

— Warranty information

— Scope of supply

3. Technical data (as applicable) consisting of:

— Design calculations in accordance with Paragraph 2.2.

— Temperature ratings in accordance with Paragraph 2.1.1.3.

— Area classification, zone and gas group of electric equipment in accordance with Paragraph 3.1.4.3.

4. Safety precautions

5. Installation, interface and testing data.

6. Operating characteristics.

7. General maintenance data consisting of:

— Recommended preventive maintenance and schedules.

— Recomended fluids, lubricants and capacities.

— Recommended list of maintenance and critical spare parts.

— Trouble shooting methods.

8. Product specific maintenance data consisting of:

— 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. Glossary/Appendix listing general definitions of terms used in the text and schematic symbols used in the support documentation.

SECTION 9
REFERENCE DOCUMENTS

1. API RP16E Recommended Practice for Design of Control Systems for Well Control Equipment, October 1, 1990.

2. API RP14F Design and Installation of Electrical Systems for Offshore Production Platforms, July 1, 1985.

3. API RP 500 Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, June 1, 1991.

4. AWS (American Welding Society) A2.4-86 Welding Symbols Chart.

5. ABS Standard.

6. ANSI Y32.10.

GLOSSARY

Accumulator. A pressure vessel charged with nitrogen gas and used to store hydraulic fluid under pressure for operation of blowout preventers.

Accumulator Bank. An assemblage of multiple accumulators sharing a common manifold.

Accumulator Precharge. An initial nitrogen charge in an accumulator which is further compressed when the hydraulic fluid is pumped into the accumulator storing potential energy.

Acoustic Control System. A subsea control system that uses coded acoustic signals for communications. An acoustic control system is normally used as an emergency backup having control of a few selected critical functions.

Air Pump/Air Powered Pump. Air driven hydraulic piston pump.

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

Blind Ram BOP (Blowout Preventer). A BOP having rams which seal against each other to close the wellbore in the absence of any pipe.

Block Position. The center position of a three-position control valve

Blowout. An uncontrolled flow of pressurized wellbore fluids.

BOP (Blowout Preventer). A device attached to the casing head that allows the well to be sealed to confine the well fluids in the wellbore.

BOP Closing Ratio (Ram BOP). A dimensionless factor equal to the area of the piston operator divided by area of the ram shaft.

BOP Control System. The system of pumps, valves, lines, accumulators, fluid storage and mixing equipment, manifold, piping, control panels and other items necessary to hydraulically operated the BOP equipment.

BOP Stack. The assembly of well control equipment including BOP's, spools, valves, and nipples connected to the top of the casing head.

BOP Stack Maximum Rated Working Pressure. The pressure containment rating of the ram BOP's in a stack. In the event that the rams are rated at different pressures, the BOP Stack Maximum Rated Working Pressure is considered equal to the lowest rated ram BOP pressure. In stacks which do not contain any ram BOP, the BOP stack maximum rated wellbore pressure is considered equal to the lowest rated BOP pressure.

Bumpless Transfer. The transfer from main electrical supply power to an alternate electrical power supply without losing signal and/or memory circuit normally associated with power interruption.

Check Valve. A valve that allows flow through it in one direction only.

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

Choke and Kill Valves. BOP stack mounted valves which are connected below the BOP's to allow access to the wellbore to either choke or kill the well.

Closed Loop Circuit. A hydraulic control circuit in which spent fluid is returned to the reservoir.

Closing Unit (Closing System). See BOP Control System.

Commodity Item. A manufactured product purchased by the control system manufacturer for use in the construction of control systems for drilling well control equipment.

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

Control Hose Bundle. A group of pilot and/or supply and/or control hoses assembled into a bundle usually covered with an outer protective sheath.

Control Line. A flexible hose or rigid line that transmits the hydraulic power fluid to a function.

Control Manifold. The assemblage of valves, regulators, gages and piping used to regulate pressures and control the flow of hydraulic power fluid to operate system functions.

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

(a) Diverter Panel – A panel that is dedicated to the diverter and flowline system functions.

(b) Driller's Panel – The BOP control panel mounted near the driller's position on the rig floor.

(c) Master Panel (Hydraulic or Electric) – The panel mounted in close proximity to the main accumulator unit. All control functions are operable from this panel including all regulators and gages.

(d) Mini or Auxiliary Remote Panel – A limited function panel mounted in a remote location for use as an emergency backup. On an offshore rig it is normally located in the tool pusher's office, and on a land rig, at least 100 feet from the well center on the leeward side of the prevailing wind.

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

Control Valve (Surface Control System). A valve mounted on the hydraulic manifold which directs hydraulic power fluid to the selected function (such as annular BOP close) while simultaneously venting the opposite function (annular BOP open).

Control Valve (Subsea Control System). A pilot operated valve in the subsea control pod that directs power fluid to operate a function.

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

Electric Pump. An electrically driven hydraulic pump, usually a 3 piston (triplex) pump.

Electro Hydraulic (EH) System. A control system that uses an electrical signal to activate a solenoid piloted hydraulic valve to operate a function or to operate a control valve which in turn operates a function.

Factory Acceptance Testing. Testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings.

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).

HAZ. Heat Affected Zone (pertains to welding).

Hose Bundle. See control hose bundle.

Hydraulic Connector. A mechanical connector that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack.

Hydraulic Supply Line. An auxiliary line on a marine drilling riser used for supply of control system operating fluid from the surface to the subsea BOP stack.

Hydrophone. An underwater listening device that converts acoustic energy to electric signals.

Interflow. The power control fluid lost (vented to the sea) during the travel of the piston in a control pod valve.

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

Junction Box (J-Box) (Electrical). An enclosure used to house the termination points of electrical cables and components. May also contain electrical components required for system operation.

Junction Box (J-Box) (Hydraulic or Pneumatic). A bolt-on plate having multiple stab-type terminal fittings used for quick connection of the multi-hose bundle to a pod, hose reel or manifold.

Kill Line. A high pressure line between the mud pumps to a connection below a BOP. This line allows fluid to be pumped into the well or annulus with the BOP closed during well control operations.

LMRP (Lower Marine Riser Package). The upper section of a two-section subsea BOP stack consisting of the hydraulic connector, annular BOP, flex/ball joint, riser adapter, flexible choke and kill lines, and subsea control pods. This interfaces with the lower subsea BOP stack.

Limit Switch. A hydraulic pneumatic or electrical switch that indicates the motion or position of a device.

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

Manipulator Valve. A three position directional control valve that has the pressure inlet port blocked and the operator ports vented in the center position.

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

Multiplex. A system that uses electronic signals that are coded and transmitted through a conductor pair. This eliminates the requirement of a dedicated conductor pair for each required signal.

Non-Retrievable Control Pod. A pod that is fixed in place on the LMRP and not retrievable.

Pilot Fluid. Hydraulic control fluid that is dedicated to the pilot supply system.

Pilot Line. A hydraulic line that transmits pilot fluid to a control valve. Pilot lines are normally grouped in a common bundle or umbilical.

Pilot Response Time. The time required to transmit a step pressure change from one end of a pilot line to the other.

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

Pipe Rams. Rams whose ends are contoured to seal around pipe to close the annular space.

Pod. See Control Pod.

Potable Water. A water supply that is acceptably pure for human consumption. On an offshore rig, it is usually produced by watermakers and used as supply water for mixing control fluid for a subsea control system.

Power Fluid. Pressurized fluid dedicated to the direct operation of functions.

PQR. Procedure Qualification Record (pertains to welding).

Precharge. See Accumulator Precharge.

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

Ram BOP. A blowout preventer that uses rams to seal off pressure in the wellbore.

Readback. An indication of a remote condition.

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

Regulator (Pressure). A hydraulic device that reduces upstream supply pressure to a desired (regulated) pressure. It may be manual or remotely operated and, once set, will automatically maintain the regulated output pressure unless reset to a different pressure.

Relief Valve. A device that is built into a hydraulic or pneumatic system to relieve (dump) any excess pressure.

Remote Panel. See Control Panel.

Reservoir. A storage tank for the BOP control system fluid.

Response Time. The time elapsed between activation of a function at any control panel and complete operation of the function. For subsea BOP stacks, a function is considered completed when the readback pressure gage recovers to its nominal setting.

Retrievable Control Pod. A subsea pod that is retrievable remotely on a wire line.

Riser Connector (LMRP Connector). A hydraulically operated connector that joins the LMRP to the top of the lower BOP stack.

Selector Valve. A three position directional control valve that has the pressure inlet port blocked and the operator ports blocked in the center position.

Shear Ram BOP (Blowout Preventer) (Blind/Shear Rams). Rams having cutting blades that will shear tubulars that may be in the wellbore, while the rams close and seal against the pressure below.

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

Shutoff Valve. A valve with two or more supply pressure ports and only one outlet port. When fluid is flowing through one of the supply ports the internal shuttle seals off the other inlet port and allows flow to the outlet port only.

Solenoid Valve. An electrical coil operated valve which controls a hydraulic or pneumatic function or signal.

Spent Fluid. Hydraulic control fluid that is vented from a function control port when the opposite function is operated.

Stored Hydraulic Fluid Volume. The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.

Straight-Through Function. A subsea function that is directly operated by a pilot signal without interface with a pod mounted pilot operated control valve. Straight-through functions typically require a low fluid volume to operate and its response time is not critical.

Type Certification Testing. Testing by a manufacturer of a representative specimen (or prototype) of a product which qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture.

Umbilical. A control hose bundle or electrical cable used to control subsea functions.

Usable Hydraulic Fluid. The hydraulic fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the minimum operating pressure.

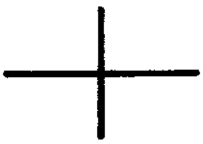
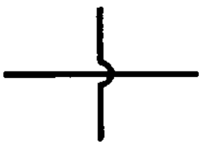
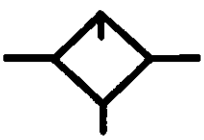
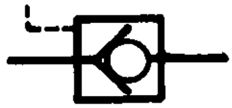
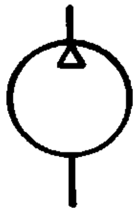
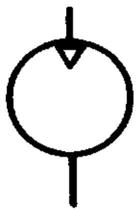
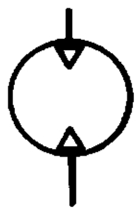
Water Based Hydraulic fluid. A control liquid mixture composed mainly of water with additives to provide lubricity, anti-foaming, anti-freeze, anti-corrosion and anti-bacterial characteristics.

Wellhead Connector (Stack Connector). A hydraulically operated connector that joins the BOP stack to the subsea wellhead.

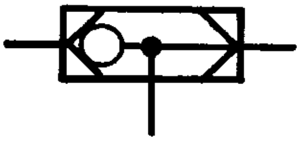
WPS. Welding Procedure Specification (pertains to welding)

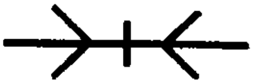
SCHEMATIC SYMBOLS

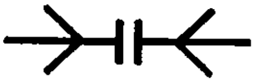
NOTE: GRAPHIC SYMBOLS FOR FLUID POWER DIAGRAMS BASED ON ANSI Y. 32.10

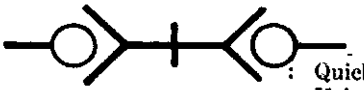
	: Main Lines
	: Hydraulic Lines
	: Pneumatic Lines
	: Pilot Lines (dashes)
	: Drain Lines (dotted)
	: Lines Crossing (not Connected)
	: Lines Crossing (alternate)
	: Lines Connected
	: Connected to Reservoir (above fluid level)
	: Connected to Reservoir (below fluid level)
	: Plugged Port
	: Filter or Strainer
	: Lubricator Without Drain
	: Lubricator With Drain
	: Check Valve (free flow is from left to right)
	: Pilot Operated Check Valve (pilot to open)
	: Pilot Operated Check Valve (pilot to close)
	: Compressor, Fixed Displacement, Pneumatic
	: Motor, Uni-Directional, Pneumatic
	: Motor, Bi-Directional, Pneumatic
	: Internal Combustion Engine
	: Pressure Gauge
	: Temperature Gauge
	: Flow Rate Flowmeter


: Totalizing Flow Meter


: Shuttle Valve


: Quick Disconnect, Connected


: Quick Disconnect, Disconnected


: Quick Disconnect, with Check Valve, Connected


: Quick Disconnect, with Check Valve, Disconnected


: Manual Shut Off Valve, Normally Open


: Manual Shut Off Valve, Normally Closed

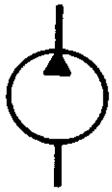

: Orifice, Fixed

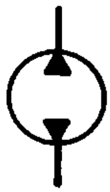

: Adjustable Orifice

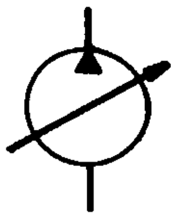

: Accumulator, Spring Loaded

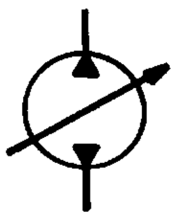

: Accumulator, Gas Charged


: Receiver, Air or Gas

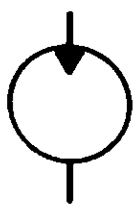

: Pump, Hydraulic, Uni-Directional, Fixed Displacement

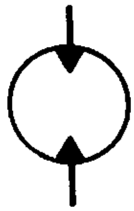

: Pump, Hydraulic, Bi-Directional, Fixed Displacement


: Variable Displacement Hydraulic Pump, Uni-Directional

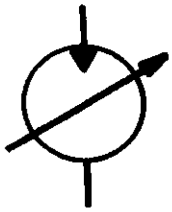

: Variable Displacement, Bi-Directional Hydraulic Pump


: Electric Motor

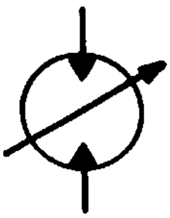

: Hydraulic Motor Fixed Displacement, Uni-Directional



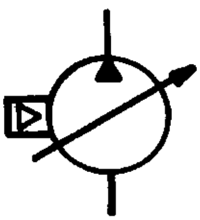
: Hydraulic Motor, Fixed Displacement Bi-Directional



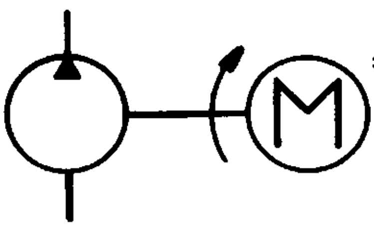
: Hydraulic Motor Variable Displacement, Uni-Directional



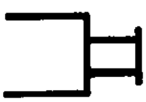
: Hydraulic Motor, Variable Displacement, Bi-Directional



: Air Operated Variable Displacement Uni-Directional Hydraulic Pump

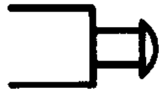


: Electric Motor Driven, Fixed Displacement Uni-Directional Hydraulic Pump



: Manual Operator

: Lever Operator

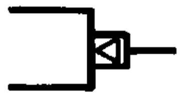


: Push Button Operator

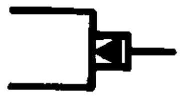
: Foot Pedal Operator

: Mechanical Operator

: Two Position Detent



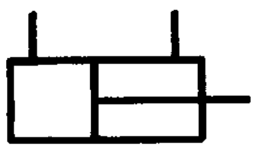
: Pneumatic Pilot



: Hydraulic Pilot

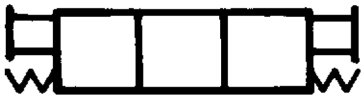
: Solenoid Operator

: Spring



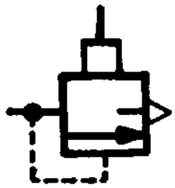
: Cylinder, Double Acting

: 3 Position, Double Air Pilot Operated, Spring Centered

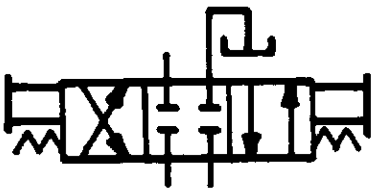


: 3 Position, Manual Operated, Spring Centered

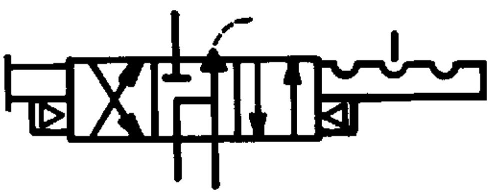
: 3 Position, Double Air Pilot Operated, with Manual Override, Detented, Valve



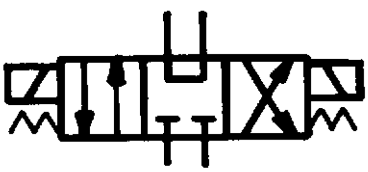
: Relief Valve, Remote Pilot Set, Vented to Atmosphere



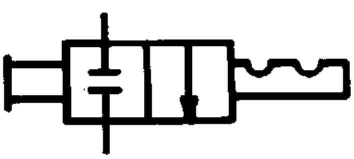
: 4 Way, 3 Position, Manual Operated, Spring Centered, Center Position, All ports Blocked



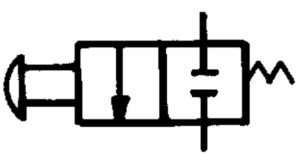
: 4 Way, 3 Position, Pilot Cylinder Operated with Manual Override, Detented, Pressure Blocked, Cylinders Vented to Ambient In The Center Position, Valve



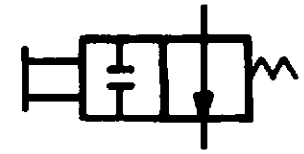
: 4 Way, 3 Position, Solenoid Operated, Spring Centered, Pressure Connected To Return, Cylinder Ports Blocked, Valve



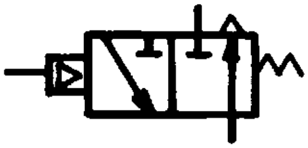
: Two Way Manual Operated, Detented Valve (shown in the closed position)



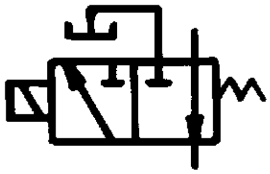
: Two Way, Push Button Operated, Spring Return, Normally Close Valve



: Two Way, Manual Operated, Spring Return Normally Open Valve

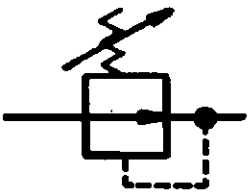


: 3 Way, Pneumatic Pilot Operated, Spring Return, Normally Closed Valve (fluid vents to ambient)

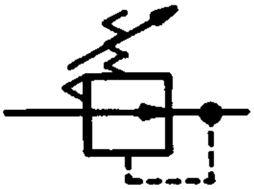


: 3 Way Solenoid Operated, Spring Return, Normally Open Valve (fluid vent is connected to reservoir)

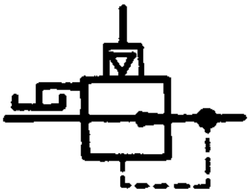
: 4 Way, Two Position, Hydraulic Pilot Operated with Manual Override, Detented Valve (fluid vent is connected to reservoir)



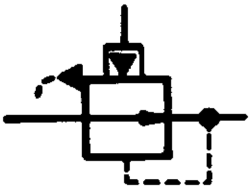
: Regulator, Manual Set, Non-Relieving



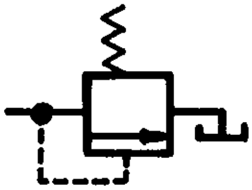
: Regulator, Manual Set, Relieving Type (fluid vented to ambient



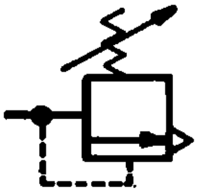
: Regulator, Air Pilot Operated, Relieving (fluid vent connected to reservoir)



: Regulator, Hydraulic Pilot Operated, Relieving (fluid vented to ambient)



: Relief Valve, Non Adjustable, (vent connected to reservoir)



: Relief Valve, Adjustable (vented to ambient)

APPENDIX I

CONTROL SYSTEM OPERATING AND INTERFACE REQUIREMENTS FOR SURFACE BOP STACK

REGULATORY AGENCY COMPLIANCE REQUIRED YES__________ NO__________

REGULATORY AGENCY(S) MMS_____ DEN_____ NPD _____ OTHER __________

BOP STACK – SIZE __________ WORKING PRESSURE __________

BOP STACK – RAMS __________ ANNULARS __________ VALVES __________

– VALVES FAILSAFE OPEN __________ FAILSAFE CLOSE __________

ANNULAR BOI _____ QUANTITY_____ SIZE _____ WORKING PRESSURE __________

MANUFACTURER __________ MODEL __________

RAM BOP'S QUANTITY_____ SIZE _____ WORKING PRESSURE __________

RAM LOCKS YES_____ NO_____ TYPE __________

CLOSING RATIO __________

SHEAR RAM OPERATING PRESSURE __________ SIZE, TYPE, GRADE

PIPE TO SHEAR __________

MANUFACTURER __________ MODEL __________

CHOKE VALVE(S) REQUIRED_____ SIZE _____ WORKING PRESSURE __________

OPERATING PRESSURE (AGAINST WORKING PRESSURE): OPEN_____ CLOSE __________

MANUFACTURER __________ MODEL __________

KILL VALVE(S) QUANTITY_____ SIZE _____ WORKING PRESSURE __________

MANUFACTURER __________ MODEL __________

HYDRAULIC PUMP SYSTEMS

ELECTRIC POWERED QUANTITY_____ SIZE _____ WORKING PRESSURE __________

AIR POWERED QUANTITY_____ SIZE _____ WORKING PRESSURE __________

REMOTE PANEL(S) QUANTITY__________ AREA CLASSIFICATION __________

LOCATION OF CHOKE CONNECTION(S) (To Show on Panel Graphic)

LOCATION OF KILL CONNECTION(S) (To Show on Panel Graphic)

SURFACE STACK HYDRAULIC CONTROL SYSTEM CONTROL FUNCTION LIST (SELECT AS APPLICABLE)

NO.	CONTROL FUNCTION			2 POS. GALLONS REQUIRED	
1	ANNULAR BOP	OPEN	CLOSE	______	______
2	UPPER PIPE RAMS	OPEN	CLOSE	______	______
3	MIDDLE PIPE RAMS	OPEN	CLOSE	______	______
4	LOWER PIPE RAMS	OPEN	CLOSE	______	______
5	CHOKE VALVE	OPEN	CLOSE	______	______
6	KILL VALVE	OPEN	CLOSE	______	______

DIVERTER SYSTEM HYDRAULIC CONTROL SYSTEM CONTROL FUNCTION LIST (SELECT AS APPLICABLE)

DIVERTER MODEL ____________________ SIZE ________ WORKING PRESSURE ______

NO.	CONTROL FUNCTION			2 POS. GALLONS REQUIRED	
1	DIVERTER UNIT	OPEN	CLOSE	______	______
2	FLOW SELECTOR	PORT	STARBOARD	______	______
3	VENT VALVE	OPEN	CLOSE	______	______
4	PORT OVERBOARD VALVE	OPEN	CLOSE	______	______
5	STARBOARD OVERBOARD VALVE	OPEN	CLOSE	______	______
6	FLOWLINE VALVE	OPEN	CLOSE	______	______
7	DIVERTER LOCKDOWN DOGS	LATCH	UNLATCH	______	______
8	INSERT PACKER LOCKDOWN DOGS	LATCH	UNLATCH	______	______
9	FLOWLINE SEAL	ENERGIZE	VENT	______	______
10	FILLING LINE VALVE	OPEN	CLOSE	______	______
11	OVERSHOT PACKER SEAL	ENERGIZE	VENT	______	______
12	OTHER (SPECIFY)	(SPECIFY)	(SPECIFY)	______	______

NOTE WHICH FUNCTIONS (IF ANY) ARE TO BE INTERCONNECTED FOR SEQUENCING.

APPENDIX II

CONTROL OPERATING AND INTERFACE REQUIREMENTS SUBSEA BOP STACK

REGULATORY AGENCY COMPLIANCE REQUIRED YES ________ NO ________
REGULATORY AGENCY(S) MMS ________ DEN ________ NPD ________ OTHER ________

CONTROL SYSTEM TYPE – HYDRAULIC ________ EH ________ MUX ________
MAXIMUM WATER DEPTH ________ HYDRAULIC OPERATING PRESSURE ________

BOP STACK – SIZE ________ WORKING PRESSURE ________
– RAM BOP'S ________ ANNULAR BOP'S ________ FAILSAFE VALVES ________
– VALVES ARE FSO ________, FSC ________, FAO ________, FAC ________
SUBSEA UMBILICALS
MANUFACTURER ________ MODEL ________ LENGTH ________

SUBSEA HYDRAULIC SUPPLY LINES
UMBILICAL HOSE QUANTITY ____ SIZE ________ WORKING PRESSURE ________
SUPPLY HOSE QUANTITY ____ SIZE ________ WORKING PRESSURE ________
RIGID CONDUIT QUANTITY ____ SIZE ________ WORKING PRESSURE ________

ANNULAR BOP(S) QUANTITY ____ SIZE ________ WORKING PRESSURE ________
MANUFACTURER ________ MODEL ________
RAM BOP'S QUANTITY ____ SIZE ________ WORKING PRESSURE ________
RAM LOCKS YES ________ NO ________ TYPE ________
CLOSING RATIO ________
MANUFACTURER ________ MODEL ________

RISER CONNECTOR SIZE ________ WORKING PRESSURE ________
MANUFACTURER ________ MODEL ________
WELLHEAD CONNECTOR SIZE ________ WORKING PRESSURE ________
MANUFACTURER ________ MODEL ________

CHOKE VALVE(S) QUANTITY ____ SIZE ________ WORKING PRESSURE ________
MANUFACTURER ________ MODEL ________
CHOKE OUTLET LOCATION(S) ________

KILL VALVE(S) QUANTITY ____ SIZE ________ WORKING PRESSURE ________
MANUFACTURER ________ MODEL ________
KILL OUTLET LOCATION(S) ________
LMRP ACCUMULATORS
QUANTITY ________ SIZE ________ WORKING PRESSURE ________ BANKS ________

BOP ACCUMULATORS
QUANTITY ________ SIZE ________ WORKING PRESSURE ________ BANKS ________
HYDRAULIC PUMP SYSTEMS
ELECTRIC POWERED QUANTITY ____ SIZE ________ WORKING PRESSURE ________
AIR POWERED QUANTITY ____ SIZE ________ WORKING PRESSURE ________

REMOTE PANELS
HAZARDOUS LOCATION QUANTITY ________ AREA CLASSIFICATION ________
SAFE LOCATION QUANTITY ________

SUBSEA STACK HYDRAULIC CONTROL SYSTEM CONTROL FUNCTION LIST (SELECT AS APPLICABLE)

NO.	CONTROL FUNCTION			GALLONS		POS
1	POD SELECT	BLUE	YELLOW	______	______	3
2	UPPER ANNULAR BOP	OPEN	CLOSE	______	______	3
3	LOWER ANNULAR BOP	OPEN	CLOSE	______	______	3
4	RISER CONNECTOR	UNLOCK	LOCK	______	______	3
5	RISER CONNECTOR SECONDARY	UNLOCK	VENT	______	______	2
6	UPPER PIPE RAMS	OPEN	CLOSE	______	______	3
7	SHEAR RAMS	OPEN	CLOSE	______	______	3
8	HIGH PRESSURE SHEAR RAMS	CLOSE		______	______	1
9	UPPER MIDDLE PIPE RAMS	OPEN	CLOSE	______	______	3
10	LOWER MIDDLE PIPE RAMS	OPEN	CLOSE	______	______	3
11	BOTTOM PIPE RAMS	OPEN	CLOSE	______	______	3
12	WELLHEAD CONNECTOR	UNLOCK	LOCK	______	______	3
13	WELLHEAD CONNECTOR SECONDARY	UNLOCK	VENT	______	______	2
14	POD LATCH	LATCH	UNLATCH	______	______	2
15	BLUE HYDRAULIC STABS	EXTEND	RETRACT	______	______	3
16	YELLOW HYDRAULIC STABS	EXTEND	RETRACT	______	______	3
17	CHOKE & KILL STABS	EXTEND	RETRACT	______	______	3
18	ANNULAR BOP OUTER CHOKE	OPEN	CLOSE	______	______	2
19	ANNULAR BOP INNER CHOKE	OPEN	CLOSE	______	______	2
20	LMRP CHOKE & KILL TEST VALVE	CLOSE	OPEN	______	______	2
21	UPPER OUTER CHOKE	OPEN	CLOSE	______	______	2
22	UPPER INNER CHOKE	OPEN	CLOSE	______	______	2
23	LOWER OUTER CHOKE	OPEN	CLOSE	______	______	2
24	LOWER INNER CHOKE	OPEN	CLOSE	______	______	2
25	UPPER OUTER KILL	OPEN	CLOSE	______	______	2
26	UPPER INNER KILL	OPEN	CLOSE	______	______	2
27	LOWER OUTER KILL	OPEN	CLOSE	______	______	2
28	LOWER INNER KILL	OPEN	CLOSE	______	______	2

SUBSEA STACK HYDRAULIC CONTROL SYSTEM CONTROL FUNCTION LIST (SELECT AS APPLICABLE)

NO.	CONTROL FUNCTION			GALLONS		POS
29	SHEAR RAMS WEDGELOCKS	LOCK	UNLOCK	______	______	2
30	UPPER RAMS WEDGELOCKS	LOCK	UNLOCK	______	______	2
31	UPPER MIDDLE RAMS WEDGELOCKS	LOCK	UNLOCK	______	______	2
32	LOWER MIDDLE RAMS WEDGELOCKS	LOCK	UNLOCK	______	______	2
33	BOTTOM RAMS WEDGELOCKS	LOCK	UNLOCK	______	______	2
34	BLUE SUPPLY PILOT CHECK	VENT	CHECK	______	______	2
35	YELLOW SUPPLY PILOT CHECK	VENT	CHECK	______	______	2
36	LMRP ACCUM ISOLATOR	OPEN	CLOSE	______	______	2
37	LOWER STACK ACCUM ISOLATOR	OPEN	CLOSE	______	______	2
38	LMRP FAILSAFE SUPPLY	OPEN	CLOSE	______	______	2
39	LOWER STACK FAILSAFE SUPPLY	OPEN	CLOSE	______	______	2
40	ACOUSTIC ACCUM ISOLATOR	OPEN	CLOSE	______	______	2
41	SUBSEA MANIFOLD REGULATOR	INCR	DECR	______	______	2
42	FAILSAFE ASSIST REGULATOR	INCR	DECR	______	______	2
43	UPPER ANNULAR BOP REGULATOR	INCR	DECR	______	______	2
44	LOWER ANNULAR BOP REGULATOR	INCR	DECR	______	______	2

HOSE REEL "LIVE" FUNCTIONS

1 ____

2 ____

3 ____

ACOUSTIC FUNCTIONS

1 ____

2 ____

3 ____

4 ____

SUBSEA STACK HYDRAULIC CONTROL SYSTEM READBACK FUNCTION LIST (SELECT AS APPLICABLE)

NO.	READBACK FUNCTION	REQUIRED
1	SURFACE ACCUMULATOR SUPPLY PRESSURE	______
2	SURFACE PILOT SUPPLY PRESSURE	______
3	RIG AIR SUPPLY PRESSURE	______
4	SUBSEA MANIFOLD REGULATOR PILOT PRESS	______
5	SUBSEA MANIFOLD REGULATED PRESSURE	______
6	FAILSAFE ASSIST REGULATOR PILOT PRESS	______
7	FAILSAFE ASSIST REGULATED PRESSURE	______
8	UPPER ANNULAR BOP REGULATOR PILOT PRESS	______
9	UPPER ANNULAR BOP REGULATED PRESSURE	______
10	LOWER ANNULAR BOP REGULATOR PILOT PRESS	______
11	LOWER ANNULAR BOP REGULATED PRESSURE	______

SURFACE DIVERTER HYDRAULIC CONTROL SYSTEM CONTROL FUNCTION LIST (SELECT AS APPLICABLE)

NO.	CONTROL FUNCTION				2 POS.
1	DIVERTER UNIT	OPEN	CLOSE		______
2	FLOW SELECTOR	PORT	STARBOARD	______	______
3	DIVERTER LOCKDOWN	LATCH	UNLATCH	______	______
4	VENT VALVE	OPEN	CLOSE	______	______
5	PORT OVERBOARD VALVE	OPEN	CLOSE	______	______
6	STARBOARD OVERBOARD VALVE	OPEN	CLOSE	______	______
7	FLOWLINE VALVE	OPEN	CLOSE	______	______
8	INSERT PACKER LOCKDOWN DOGS	LATCH	UNLATCH	______	______
9	FLOWLINE SEAL	ENERGIZE	VENT	______	______
10	FILLING LINE VALVE	OPEN	CLOSE	______	______
11	BALL JOINT PRESSURE		RANGE	______	______
12	OVERSHOP PACKER	ENERGIZE	VENT	______	______
13	TRIP TANK	OPEN	CLOSE	______	______
14	SUPPORT RING	OPEN	CLOSE	______	______
15	OTHER (SPECIFY)				

NOTE WHICH FUNCTIONS (IF ANY) ARE TO BE INTERCONNECTED FOR SEQUENCING.

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