

Guide for the

Classification of Drilling Systems



February 2021



GUIDE FOR THE

...
CLASSIFICATION OF DRILLING SYSTEMS
FEBRUARY 2021

American Bureau of Shipping
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the State of New York 1862

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Foreword (1 February 2021)

This Guide describes criteria to be used for drilling systems, which are approved by the American Bureau of Shipping (ABS) and built to requirements of recognized codes and standards.

This Guide is to be used in conjunction with other applicable ABS Rules and Guides, codes and standards as referenced therein, and applicable national regulations.

ABS Classification continues to provide the offshore industry with a pathway toward agreement with Regulatory Authorities. Any Owner/Operator's specific request for compliance with applicable requirements of flag or Coastal State Authorities affecting the drilling systems is to be filed as an addendum to the Request for Classification.

The first edition of the *CDS Guide* was published in 1986 to support the drilling regulations developed for rigs operating in the UK sector of the North Sea. As part of ABS's commitment to promoting the security of life and property and preserving the natural environment, ABS has endeavored to continuously update the Guide by applying the latest industry standards and trends in risk abatement.

The July 2020 edition of the Guide provides clarification on stock/spare equipment and components when not installed on a drilling unit and gives a process to incorporating them into the drilling unit. This update also provides clarification on maintenance and overhaul of equipment and components.

The February 2021 edition of the Guide adds a requirement for technical review of the Riser Operations, Maintenance, and Inspection Manual. It also modifies 3-2/Table 3 to change Tier level from 5 to 4/5 for the Auxiliary Well Control Equipment [IBOP, Drill Pipe Safety Valves, Drill String Float Valves, Non-return (NR), Valves in Drill String (IBO)], thus allowing the product quality assurance (PQA) program.

This Guide becomes effective on the first day of the month of publication.

Users are advised to check periodically on the ABS website www.eagle.org to verify that this version of this Guide is the most current.

We welcome your feedback. Comments or suggestions can be sent electronically by email to rsd@eagle.org.



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CLASSIFICATION OF DRILLING SYSTEMS

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CHAPTER 1

Scope and Conditions of Classification

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CHAPTER 1 **Scope and Conditions of Classification**

SECTION 1 **Classification**

The requirements for conditions of classification are contained in the separate, generic ABS *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Additional requirements specific to drilling systems are contained in this Chapter.

CHAPTER 1

Scope and Conditions of Classification

SECTION 2

Classification Symbols and Notations

1 ABS Class Notation

Drilling systems, related subsystems, equipment, and/or components that have been built, installed and commissioned to the satisfaction of the Surveyors to the full requirements of this Guide, where approved by the Committee for service for the specified design environmental conditions, may be classed and distinguished in the *ABS Record* by the notation ⌘ **CDS**. For new construction or for existing systems being brought in **CDS** class, the full requirements of this Guide apply.

3 Sub Class Notations (1 October 2019)

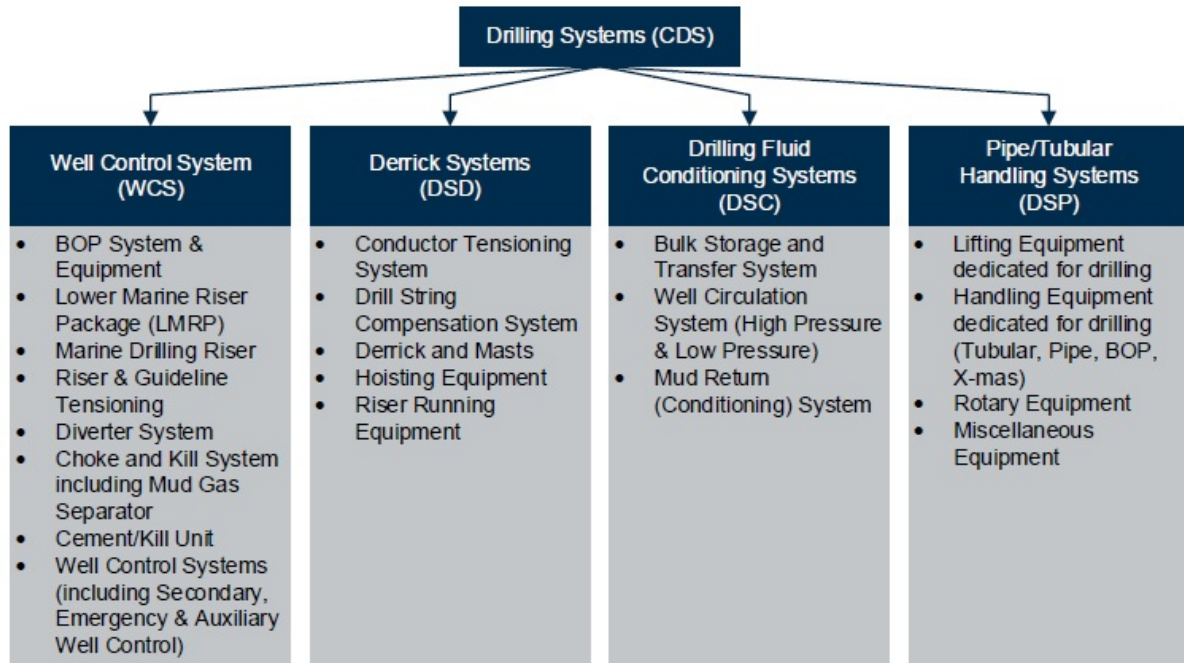
Upon completion of 1-2/1 above and at the Owner's request, ⌘ **CDS** can be limited in scope. Following completion of the requirements to change the class scope, the existing ⌘ **CDS** may be exchanged for one or more of the following sub-class designations (See also 1-2/Figure 1):

- ⌘ **CDS(WCS)** applies to the classification of the well control system including well control equipment and associated control systems
- ⌘ **CDS(DSD)** applies to the classification of the derrick systems including drawworks, hoisting and drilling and motion compensating systems and associated control systems
- ⌘ **CDS(DSC)** applies to the classification of the drilling fluid circulating system and associated control systems
- ⌘ **CDS(DSP)** applies to the classification of the specialized pipe and tubular handling systems and associated control systems

Note:

⌘ **CDS(WCS+DSD)** class designation would apply where the Well Control and Derrick systems were classed and ⌘ **CDS(DSC)** and ⌘ **CDS(DSP)** were not selected.

FIGURE 1
Notations Application



5 Systems Not Built Under Survey

The symbol "✕" (Maltese-Cross) signifies that the drilling system, subsystems, equipment, and/or components were built, installed and commissioned to the satisfaction of the Surveyors. Drilling systems, subsystems, equipment, and/or components that have not been built under ABS survey, but which are submitted for Classification, will be subjected to special consideration. Where found satisfactory and thereafter approved by the Committee, they may be classed and distinguished in the *Record* by the notation described above, but the symbol "✕" signifying survey during construction will be omitted.

A listing of Classification Symbols and Notations available to the Owners of vessels, offshore drilling and production units and other marine structures and systems, "List of ABS Notations and Symbols" is available from the ABS website "<http://www.eagle.org>".

7 Managed Pressure Drilling (MPD) Systems

For managed pressure drilling (MPD) systems and associated optional notations refer to the ABS *Guide for Classification and Certification of Managed Pressure Drilling Systems*.

CHAPTER 1

Scope and Conditions of Classification

SECTION 3

Rules for Classification

1 General

This Guide is applicable to optional classification of drilling systems and associated equipment used to construct wells or support such activities on mobile offshore drilling units, offshore installations, tendering vessels and other units that are classed with ABS. This Guide is intended for use in conjunction with the

- *ABS Rules for Building and Classing Mobile Offshore Units (MOU Rules)*
- *ABS Rules for Building and Classing Offshore Installations (Offshore Installations/FOI Rules)*
- *ABS Rules for Building and Classing Floating Production Installations (FPI Rules)*
- *ABS Rules for Building and Classing Marine Vessel (Marine Vessel Rules)*
- *ABS Rules for Building and Classing Facilities on Offshore Installations (Facilities Rules)*
- or other applicable ABS Rules and Guides.

If requested by the Owner, this Guide can also be used as a basis for acceptance or certification under the requirements of other Administrations. An Owner who requires a drilling system to be evaluated for compliance with other national regulations should contact ABS.

If requested by the manufacturers, Owner, or designers, ABS can provide approval of individual equipment or component associated with drilling systems or subsystems in accordance with the requirements of this Guide where the installation unit may not be classed with ABS.

3 Application

Application of the Rules and Guides is, in general, based on the contract date for construction between the shipbuilder and the prospective owner. (e.g., Rules which became effective on 1 January 2017 are not applicable to a drilling unit for which the contract for construction was signed on 30 June 2016.) See also 1-1-4/3 of the *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. For application of codes and standards, see 2-2/1.1 of this Guide.

CHAPTER 1

Scope and Conditions of Classification

SECTION 4

Plans and Design Data to be Submitted for Review

1 Submission of Plans

Typical documentation that is required to be submitted for review for drilling systems, subsystems, equipment, and/or components for the ABS Classification process is provided in Appendix 7 of this Guide.

The ABS approval process for drilling systems, subsystems, equipment, and/or components is provided in Chapter 3, Section 2. Subsequently, 3-2/Tables 1 through 10 identify the typical drilling systems, subsystems, equipment, and/or components that are part of the ABS Classification process.

Drilling systems, subsystems, equipment and/or component-related drawings, calculations and documentation are required to be submitted to ABS for review by the contracting party or the party assigned by the contracting party to substantiate that the design of the systems, subsystems, equipment and/or components are in compliance with this Guide and applicable codes or standards as listed in this Guide.

Upon satisfactory completion of ABS review of the submitted design plans and data, ABS will issue an approval letter and/or an Independent Review Certificate (IRC), as specified in 3-2/7.1. This letter or certificate, in conjunction with ABS-approved documentation, will be used and referenced during surveys. Subsequently, the Surveyor will issue appropriate survey reports and Certificate of Conformity (COC) as specified in 3-2/7.1.

Upon satisfactory completion of all of the required engineering design review and survey processes (inspection, testing, installation and commissioning), ABS may issue the Classification Certificate to the operating unit, including the Class notation **✱ CDS** (abbreviation for Classed Drilling System).

CHAPTER 1

Scope and Conditions of Classification

SECTION 5

Alternatives

1 General

The Committee is willing to consider alternative arrangements and designs which can be shown, through either satisfactory service experience or a systematic analysis based on sound engineering principles, to meet the overall safety, serviceability and design standards of the applicable Rules and Guides.

3 National Standards

The Committee will consider special arrangements or design of drilling systems and their equipment which can be shown to comply with standards recognized in the country provided that the proposed standards are not less effective.

When alternate standards are proposed, comparative analyses are to be provided to demonstrate equivalent level of safety to the recognized standards as listed in this Guide and to be performed in accordance with this Chapter.

5 New Technologies and Novel Concepts

Drilling systems which involve new technologies or contain novel design features to which the provisions of this Guide are not directly applicable may be classed, when approved by the Committee, on the basis that this Guide, insofar as applicable, has been complied with and that special consideration has been given to these aspects, based on the best information available at that time. The *ABS Guidance Notes on Qualifying New Technologies* and the *ABS Guidance Notes on Review and Approval of Novel Concepts* provide a methodology for approval of such designs and their incorporation on an asset.

CHAPTER 1

Scope and Conditions of Classification

SECTION 6

Recognition of Risk Based Techniques to Justify Alternatives and Novel Features

1 General

ABS will consider the application of risk evaluations for alternative arrangements and novel features in the design of the drilling system, subsystems, equipment or components. Risk evaluations for the justification of alternative arrangements or novel features may be applicable either to the drilling system as a whole, or to individual systems, subsystems, equipment or components. Any alternatives to the requirements of this Guide may be specially considered by ABS on the basis of a risk assessment submitted for review.

- i) In case of such alternatives, ABS approval will be contingent upon a demonstration of fitness for purpose and equivalent level of safety in accordance with the principles of ABS Guides and Rules, as well as recognized codes and standards.
- ii) Risk acceptance criteria are to be developed in line with the principles of the ABS Rules and will be subject to ABS approval. In instances where a direct alternative recognized code or standard is used, ABS verification of compliance with the standard will be considered to demonstrate equivalent level of safety.
- iii) The *ABS Guidance Notes on Risk Assessment Applications for the Marine and Offshore Industries* provides an overview of risk assessment techniques and additional information.
- iv) For risk based inspection techniques refer to 8-4/5 of this Guide.

3 Application

When this optional risk assessment is applied at the specific request of the contracting party, designer or manufacturer, all hazards that may affect the drilling system or any of its subsystems, equipment or components are to be identified.

- i) A systematic process is to be applied to identify situations where a combination or sequence of events could lead to undesirable consequences (property damage, personnel safety and environmental damage), with consideration given to all reasonably foreseeable causes.
- ii) As appropriate, account must be given to hazards outside the bounds of the system under consideration. Such account is to include incidents relating to remote hazards impacting on or being influenced by the system under consideration.
- iii) Portions of the installation not included in the risk assessment are to comply with the applicable parts of the ABS Rules and Guides.

- iv) The objective of the hazard identification is to identify areas of the design that may require the implementation of further risk control options in order to reduce the risk to an acceptable level.
- v) The identified risk control options (prevention and mitigation measures) deemed necessary to be implemented are to be considered part of the design basis of the drilling system.
- vi) At minimum, HAZID workshop is to identify potential hazardous situations and verify that adequate risk control measures are provided to address the following:

- Dropped objects/loads
- Release of hydrocarbons
- Release of H₂S, CO₂, etc.
- Release of toxic chemicals
- Fire and explosion
- Pollution to the sea
- Loss of well control/blowouts
- Release of pressurized fluids
- Loss of system function
- Loss of station-keeping
- Loss of stability/buoyancy
- Structural damage
- Damage of subsea equipment
- Collisions
- Injury due to interface with machinery
- Blackout
- Environmental events
- Mechanical Failure
- Electrical Failure
- Domino effects or impairment of emergency response equipment and/or activities (Not to be considered on its own, but in conjunction with each hazardous event)
- Loss of purged air
- Loss/failure at mooring
- Helicopter crash

The following design principals are to be verified for the integrated drilling plant HAZID study:

- Safety of personnel and operation
- Separation of nonhazardous areas from classified hazardous areas
- Separation of fuel and ignition source as far as practical
- Minimizing probability of ignition
- Minimizing likelihood of uncontrollable releases of hydrocarbon
- Minimizing spread of flammable liquids and gases

- Minimizing consequences of fire and explosions
- Preventing fire escalation and equipment damage
- Providing for adequate arrangements for escape and evacuation
- Facilitating effective emergency response
- Minimizing dropped object hazards to personnel, equipment (on installation and subsea) and structure
- Protection of critical systems, subsystems, equipment and/or components from damage during drilling operation, (such as: electrical cables, well control equipment, control and shutdown systems, fire/gas detection and fire-fighting equipment arrangement, exhaust ducting and air intake system)
- Equipment arrangements provide access for inspection and servicing and safe means of egress from all machinery spaces

The ABS *Guidance Notes on Risk Assessment Applications for the Marine and Offshore Industries* contain detailed procedures for the Risk Evaluation Process for classification of Alternative Arrangements and Novel Features. Section 2 of those Guidance Notes contains a description of the most common hazard identification techniques. In addition, 3/1.5 of those Guidance Notes provides an overview of how to assemble an appropriate risk assessment team.

When the risk assessment technique is considered, ABS' participation in the hazard identification meeting(s) is recommended. Tangible benefits can be derived by the participation of an ABS representative who will later be directly involved in reviewing the designs for ABS Classification.

5 Other Requirements

Where it is intended that risk-based techniques are used as a basis for compliance with flag and coastal State requirements, the contracting party is directed to contact the Administration, either directly or through ABS, to obtain an understanding as to the extent to which the Administration is prepared to consider alternatives to such requirements. The Administration may require additional hazards to be considered and safety functions.

CHAPTER 1 Scope and Conditions of Classification

SECTION 7 Definitions

The following definitions are provided to clarify the use of certain terms in the context of this Guide:

Accumulator: A pressure vessel charged with high pressure gas and used to store hydraulic energy under pressure.

Acoustic Control Systems: Acoustic signal transmission may be used as an emergency backup means for controlling critical BOP stack functions, such as pipe ram preventers, shear ram preventer and marine drilling riser connector including LMRP. The acoustic control system includes a surface electronics package, acoustic pod transponder, subsea electronic package and a subsea electro-hydraulic package.

Acoustic Pod Transponder: Device which receives acoustic signals from the surface and provides command signals to the subsea BOP control system.

Actuator: A mechanical component that is responsible for moving or controlling a mechanism such as for the remote or automatic operation of a valve or choke.

Annular Blowout Preventer: Blowout preventer that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or an open hole.

Autoshear System: A system that is designed to automatically shut-in the wellbore in the event of a disconnection of the LMRP. When the autoshear is armed, disconnect of the LMRP closes the shear ram on BOP stack.

Auxiliary Line: A conduit (excluding choke and kill lines) attached to the outside of the drilling riser main tube (e.g., hydraulic supply line, buoyancy control line, mud boost line).

Backup: An element or system that is intended to be used only in the event that the primary element or system is nonfunctional.

Backup Power: Secondary power source equal to or greater than the power required for operation from the primary power source.

Bell Nipple: A piece of pipe, with inside diameter equal to or greater than the blowout preventer bore, connected to the top of the blowout preventer or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker pit.

Blind Rams: See "Rams"

Blind-shear Rams: See "Rams"

Blowout: An uncontrolled flow of well fluids/gas and/or formation fluids/gas from the wellbore to the surface or into lower pressured subsurface zones (underground blowout).

Blowout Preventer Equipment:

Blow Out Preventer: The equipment installed at the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and tubulars or in an open hole during drilling, completion and testing operations.

BOP Handling Crane: Typically a bridge or gantry-type crane used to move BOP from storage location to BOP transporter/skidder location.

BOP Operating and Control System: System of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, electrical systems, software and control panels and other items necessary to hydraulically operate the BOP equipment.

BOP Stack Assembly: The complete assembly of well control equipment, including preventers, spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies and related structural stack frames.

BOP Seafixing: Mechanism to secure the BOP onboard the drilling unit.

BOP Stack Frame: Steel frame to which the lower stack is mounted for handling and mating with LMRP. Also serves as a support structure to mount various subsea equipment, such as subsea accumulators and control pods.

BOP Transporter/Skidder: Mechanism to position the BOP for deployment, retrieval or storage.

Bolting: Threaded fasteners including all-thread studs, tap-end studs, double-ended studs, headed bolts, cap screws, screws, and nuts.

Buffer Chamber: A targeted, horizontal or vertical, cylindrical tank that changes the direction of fluid flow downstream of the choke and serves as a flow director to the flare line, gas buster or mud-gas separator.

Bulk Storage: Tanks that are designed for storage of bulk materials for drilling fluid and cement mixing (barite, bentonite, cement, etc.).

Buoyancy Equipment: Devices added to riser joints to reduce their weight, thereby reducing riser top tension requirements.

Burner Boom: Boom which extends over the deck edge to flare hydrocarbon from kick circulation or well test operations.

Casing Pressure: The pressure existing at the surface on the casing side of the drill string/annulus flow system.

Casing Stabbing Board: Folding platform located in the derrick which positions the stabbing hand (pipe stabber) while running casing.

Catwalk: Elongated platform adjacent to the rig floor where pipe is laid out and lifted into the derrick. The catwalk is connected to the rig floor by a pipe ramp.

Cementing Manifold: Used to direct high pressure cement through the cement standpipe.

Cement Pump: High pressure positive-displacement-type pump used for cementing operations, often connected to the kill line for emergency kill operations, usually smaller capacity than mud pump.

Choke: A device with either a fixed or variable orifice used to control the rate of flow of liquids and/or gas.

Choke/Kill Line: The high-pressure piping (flexible lines, rigid piping, valves, connectors, fittings, etc.) that allows fluids to be pumped into or removed from the well with the BOPs closed.

Choke/Kill Line Valve: The valve(s) connected to and a part of the BOP stack that allows fluids flow to the choke manifold.

Choke/Kill Manifold: An assembly of valves, chokes, gauges, and piping components through which drilling fluid is circulated when the blowout preventer is closed to control the pressure encountered during a kick.

Circulation Head: Accessory attached to the top of the tubulars to form a connection with the mud system to permit circulation of drilling mud.

Clamp Connection: A pressure sealing device used to join two items without using conventional bolted flange joints. The two items to be sealed are prepared with clamp hubs. These hubs are held together by a clamp containing a minimum of four bolts.

Classified Area: A location in which flammable gases or vapors are or may be present in the air in quantities sufficient to produce explosive or ignitable mixtures (see the *ABS MOU Rules*, API 500 or API 505 for additional details).

Closure Bolting: Threaded fasteners used to assemble or join well-bore pressure-containing parts including end and outlet connections. Examples include flange bolting, bonnet bolting, bolting on end connections on BOPs, bolting on hub clamps and ram door bolting.

Certificate of Conformity (COC): A Certificate of Conformity issued by the attending Surveyor in accordance with the provisions of this Guide.

Collision Avoidance Systems: Systems and/or devices that prevent the collision of power actuated equipment with personnel, equipment and fixed structures during drilling operations.

Computer-Based System: A system of one or more microprocessors, associated software, peripherals and interfaces.

Contracting Party: The commercial entity that enters into a Classification agreement with ABS.

Control Panel/Console: An enclosure displaying an array of switches, push buttons, lights and/or valves and various pressure gauges or meters to control or monitor functions. These panels can be pneumatic, electric or hydraulic powered.

Control Manifold: An assembly of valves and piping to control the flow of hydraulic fluid to operate the various components of systems, equipment or components.

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

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

Control Stations: Spaces containing the following, as applicable:

- Radio or main navigation equipment

- Central process control rooms
- Drilling and hoisting control systems
- Dynamically positioning control system
- Centralized ballast control
- Fire control equipment and fire recording
- Fire extinguishing system serving various locations
- Emergency source of power
- CO₂ bottle room

Control Signal: The signal (hydraulic, pneumatic, electrical, etc.) applied to the device that makes corrective changes in a controlled process or machine.

Control Systems: An assembly of devices interconnected or coordinated to generate or convey the command(s) and maintain a desired output. A control system may be comprised of hydraulic, pneumatic, electrical sources, or combinations thereof with control signals.

Critical Component: Any structural/mechanical component in a Critical Load Path.

Critical Load Path: A path in an assembly of mechanical components, along which force/load is transferred from one component to its connected component(s), failure of any of which will compromise the load carrying capacity of the assembly under intended operational conditions.

Critical Well Control Equipment: Equipment items that are issued IRCs and COCs per 3-2/Table 3.

Criticality Analysis: provides relative measures of significance of the effects of a failure mode as well as the significance of an entire piece of equipment or system, on defined performance requirements. It is a tool used to prioritize and minimize the effects of critical failures early in the design.

Criticality Ranking: Criticality rankings based on risk use a combination of the consequence (severity) of the failure and the anticipated likelihood of the consequence occurring. When used as part of a risk analysis study (e.g., FMECA) will highlight failure modes with high probability of occurrence and severity of consequences, allowing corrective actions to be implemented where they will produce the greatest impact.

Crown: Upper section of the derrick.

Crown Block: Assembly of sheaves mounted at the derrick top (crown) through which the drilling line is reeved.

Deadline Anchor: Device to securely fasten one end of drill line to the drill floor or derrick structure.

Deadman System: A system that is designed to automatically close the wellbore in the event of a simultaneous absence of hydraulic supply and signal (control and communication) transmission capacity in both subsea control pods.

Degasser: Device used to remove entrained gas from a drilling fluid in normal well circulation.

Desander: Centrifugal device for removing sand from drilling fluid.

Desilter: Centrifugal device used for removing silt from drilling fluid.

Derrick (Mast): Main load-bearing structure in drilling unit used as support structure for various equipment associated with hoisting, lifting, handling, etc.

Designer/Integrator: The group responsible for the design and integration of the overall functional system which includes components and interconnecting piping and controls as applicable.

Design Pressure: The pressure used in the design of pressure-retaining equipment or piping systems for the purpose of determining the minimum permissible thickness or physical characteristics of the different parts of the pressure-retaining equipment or piping systems. When applicable, static head and other external loads (e.g., bending, torsional, tension, compression, temperature gradient, etc.) are to be added to the design pressure to determine the thickness of any specific part of the pressure-retaining equipment or piping systems.

Design Validation, Testing: Process of proving a design by testing to demonstrate conformity of the product to design requirements. Design validation includes one or more of the following:

- Prototype tests;
- Functional and/or operational tests of production products;
- Tests specified by industry standards and/or regulatory requirements;
- Field performance tests and reviews.

Diverter Equipment:

Diverter: A device attached to the wellhead or marine drilling riser to control the upward flow of well fluids and direct flow into a line away from the rig floor.

Diverter Control System: The assemblage of pumps, accumulator bottles, manifolds, control panel, valves, lines, etc., used to operate the diverter system.

Diverter System: The assemblage of an annular sealing device, flow control means, vent system components, and control system that facilitates closure of the upward flow path of well fluids and opening of the vent to atmosphere.

Diverter Vent Line/Diverter Piping: The conduit which directs the flow of gas and wellbore fluids away from the drill floor to the atmosphere.

Drape Hoses: A flexible line connecting a choke, kill, and auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure.

Drawworks: Large winch typically located on the drill floor used to raise and lower the drill string, top drive assembly by taking in or paying out the drilling line through the crown block and traveling block.

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

Drill Floor Substructure: The foundation structure(s) on which the derrick, rotary table, drawworks, and other drilling equipment are supported.

Drill Pipe Safety Valve: A full-opening valve located on the rig floor with threads to match the drill pipe connections or other tubulars. The valve is used to close off the drill pipe to prevent flow.

Driller's Cabin: An enclosed space on the drill floor that provides clear view for the driller to monitor and control drilling activities.

Drilling Spool: Pressure containing piece of equipment having end connections, and outlets used below or between drill-through equipment.

Dual Gradient Drilling (DGD): A drilling process that creates multiple pressure gradients to manage the annular pressure profile by either increasing or decreasing annular pressure.

Dump Tank: Calibrated tank used to measure the volume of a liquid, may be drilling mud or reservoir fluids.

Elevator, Drilling: Manually or hydraulically/pneumatically operated hinged clamp-type device used to grasp drill pipe or casing for lifting.

Engineering Changes:

Major Engineering Change: A change that affects form, fit, or function of the component or system that could include, but not necessarily be limited to, a change in items in the load path (main or operational load path), pressure boundary, a change in materials, testing requirements, operational characteristics, or updates of the rules that requires further engineering evaluation.

Minor Engineering Change: A change that does not have an impact on the design, validation, and/or testing requirements with no effect on the form, fit, or function of a component or system that can be accepted by attending Surveyor.

Equipment Skids: Structural support assemblies used for different purposes and segregated as follows:

Permanently installed: Skid assemblies supporting drilling equipment permanently installed on the rig.

Portable: Skid assemblies supporting drilling equipment that are not permanently affixed and are moved (together with the associated installed equipment) for use during drilling operations.

Shipping: Skid assemblies used solely for the purpose of the one way transfer of the equipment for permanent installation on board.

Escape Routes: Designated path used by personnel to evade an immediate danger and ultimately leads to a temporary refuge or muster station.

Fail-safe: An engineering design principle wherein a system, equipment or component is designed to inherently respond to a specific type of failure or malfunction in such a manner that there is no or minimal impact on the safety of people, asset and the environment.

Finger Board: A rack located in the derrick that supports the top of the stands of pipe stacked in the derrick.

Flammable Fluid: Any fluid, regardless of its flash point, capable of fueling a fire. Examples are diesel fuel, hydraulic oil (oil-based), lubricating oil, crude oil, or hydrocarbons.

Flash Point: The minimum temperature at which a combustible liquid gives off vapor in sufficient concentration to form an ignitable mixture with air near the surface of the liquid or within the vessel used, as determined by the test procedure and apparatus specified in NFPA 30.

Flex/Ball Joint: A steel and elastomer assembly installed directly above the subsea BOP stack and at the top of the telescopic riser joint (slip joint) having central through-passage equal to or greater in diameter than the riser bore, positioned to permit relative angular movement of the riser string to reduce local bending stresses due to vessel motions and environmental forces.

Flexible Lines/Hydraulic Hoses: Conduits that can accommodate the relative motion and/or vibration encountered on the drilling facility and are used to transfer fluids (mud, cement, hydraulic fluids, etc.). Typical uses for flexible lines and/or hydraulic hoses within the drilling facility are:

- Rotary and vibratory hoses

- Cementing hoses
- Choke and kill flexible lines, and auxiliary lines (drapes and jumpers)
- Hydraulic hoses for control functions and operations

Fluid Cushion: A provision to dampen the effects of high pressure fluid flow by use of a blind flanged machined with a fluid cushion bore.

FMEA (Failure Modes and Effects Analysis): A systematic process to identify potential failures to fulfill the intended function, to identify possible failure causes so the causes can be eliminated or minimized, and to locate the failure impacts so the impacts can be reduced to acceptable levels.

FMECA (Failure Modes, Effects and Criticality Analysis): An extension of the FMEA that includes a criticality assessment - an explicit estimation of the severity of the consequences of the failure or a combination of the likelihood of the failure and severity of the consequences.

FMEA/FMECA Validation: Validation program developed to test when necessary the conclusions of the FMEA or to establish conclusively the effects of failure modes that the FMEA desktop exercise had a high degree of uncertainty about.

FMEA Critical Results: Critical Results are defined as those areas of a mechanical or control system identified from the FMEA as having mitigating barrier(s) to prevent the occurrence of a hazardous situation. These are considered as part of the FMEA Validation program to validate that upon the specified failure, a minimum of one mitigating barrier performs as intended in order to prevent occurrence of a hazardous situation. Examples of such mitigating barriers are hydraulic load holding valves, alarms, sensors, etc.

FMEA Selected Results: Those results for which there is reasonable uncertainty or disagreement of the FMEA assumptions. During the FMEA, uncertain assessments results are to be identified and discussed with the designer at time of Design Review for resolution. If a resolution is not achieved, these items require testing in the Validation program. Examples of areas where inadequate data may be available to perform definitive analysis include the behavior of interlocks that may inhibit operation of essential systems.

Form, Fit and Function:

Form: The shape, size, dimensions, material, design specification parameters that uniquely distinguish a part.

Fit: The ability of a part to physically interface with, connect to, or become an integral part of another part.

Function: The action or actions that a part is designed to perform per the applicable design specifications.

Gimbal: Support for the riser spider which allows some angular movement of the spider and riser relative to the rig support structure.

Gooseneck: Curved connection between the rotary hose and the swivel or top drive.

Hazardous Area: See "Classified Areas".

HAZID (Hazard Identification study): A process to find, list and characterize hazards. This is the first step to risk assessments.

HAZOP (Hazard and Operability study): A method of identifying hazards that might affect the safety and operability of a system process using process performance metrics (example: flow/no flow, high/low pressure, rotation/no rotation). A HAZOP can be considered a HAZID tool.

Heave: Vessel motion in the vertical direction due to marine environment.

High-Pressure High-Temperature (HPHT): Wells with a potential pressure greater than 103.43 MPa (15,000 psi) at the wellhead, and/or with a potential reservoir temperature of greater than 177°C (350°F).

Hook, Drilling: Hook-shaped lifting device attached to the traveling block from which the swivel (or top drive) is suspended.

Horizontal to Vertical Equipment: Equipment to move tubulars from/to horizontal position to/from vertical position for stand building or breaking, and tubulars operations.

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 Cylinder: Mechanical device used to convert hydraulic fluid pressure to linear action.

Hydraulic Hoses: Conduits that can accommodate the relative motion, and/or vibration encountered on a drilling facility and are used to transfer fluid for hydraulic system functions.

Hydraulic Power Unit (HPU): Skid-mounted systems used to provide hydraulic power, usually comprised of a hydraulic fluid reservoir, filters, hydraulic pump, motor and control.

Hydrocarbon: A compound of hydrogen and carbon, such as any of those that are the chief components of petroleum and natural gas.

Hydrogen Sulfide (H_2S): A highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon-bearing formations.

Hydrogen Sulfide (Sour) Service: Refers to equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide.

Ignitable Mixture: A mixture that is within the flammable range (between the upper and lower limits) and is therefore capable of propagation of flame away from the source of ignition.

Inside Blowout Preventer (IBOP): A valve installed in drill string to prevent a blowout inside the drill string. Flow is possible only downward, allowing mud to be pumped in but preventing any flow back up the drill string.

Integrated Drilling System: Collective set of systems, subsystems and equipment related to Well Control Systems (WCS), Derrick Systems (DSD), Drilling Fluid Conditioning Systems (DSC) and Pipe/Tubular Handling Systems (DSP) including associated interfaces with drilling support systems, utilities and marine systems.

Iron Roughneck/ Power Tongs: Tool with automated combination of spinning and torquing for make-up or break-down of drill string pipes during drilling operation.

Jumper Line: A flexible section of choke, kill, or auxiliary line that provides a continuous flow around a flex/ball joint while accommodating the angular motion at the flex/ball joint.

Kelly Equipment: The uppermost component of the drill string; the kelly is an extra-heavy joint of pipe with flat or fluted sides that is free to move vertically through a "kelly bushing" in the rotary table; the kelly bushing imparts torque to the kelly and thereby the drill string is rotated.

Kelly Bushing: Device which imparts torque to the kelly from the master bushing and permits vertical movement of the kelly.

Kelly Cock: A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

Kelly Spinner: Pneumatically-operated device mounted to the top of the kelly used to spin up the kelly for making and breaking connections on a rotary table-type rig.

Kelly Valve, Lower: A full-opening/full-closing valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter.

Kick: Influx of water, gas, oil or other formation fluid into wellbore.

Kick Out: Terminal fittings on the lower riser adapter that serve to connect the riser choke, kill and auxiliary lines to the corresponding flexible hoses or flex loops on the BOP stack.

Kill: In drilling/well servicing, to prevent a threatened blowout by taking suitable preventative measures (e.g., to shut in well with blowout preventer, circulate kick out, and increase weight of drilling/completion/workover fluid).

Kill Line: The high-pressure piping (flexible lines, rigid piping, valves, connectors, fittings, etc.) between the pumps (cement or mud pumps) and BOP outlets or wellhead outlets.

Kill Unit: A unit to pump kill mud to kill the well.

Links, Drilling: Strong rods which connect the drilling elevators to the hook and allow movement for the elevator to be pushed out of the way when not in use.

Loose Gear: Off-the-shelf equipment including, but not limited to, shackles, chain, hooks, connecting links, turnbuckles, binders, sheave blocks, and swivels used in an assembly to suspend, secure, or lift a load.

Lower Marine Riser Package (LMRP) equipment:

LMRP: Part of the blowout preventer stack assembly; usually contains LMRP connector, one or more annular-type preventers, lower flex joint, riser adapter, and MUX control pods.

LMRP Connector: Hydraulic connector used to securely latch the LMRP to the BOP stack.

LMRP Frame: Structural frame which is used for handling of the LMRP and integration with the BOP stack. It also serves as a support structure to mount various subsea equipment such as subsea accumulators and control pods.

MAC (Manufacturer's Affidavit of Compliance): A document certified by the manufacturer that the specified product meets the required specifications. Also referred to as a Manufacturers Certificate of Compliance (MCOC).

Machinery Spaces of Category A: All spaces which contain internal combustion-type machinery used either:

- For main propulsion; or
- For other purposes where such machinery has in the aggregate a total power of not less than 375 kW; or
- Which contain any oil-fired boiler or oil fuel unit; and trunks to such spaces.

Machinery Spaces (other than Category A): Other Machinery Spaces: Spaces, including trunks to such spaces, containing propulsion machinery, boilers, oil fuel units, steam and internal combustion engines, generators and major electrical machinery (SCR, MCC and switchgear); oil filling station; refrigerating,

ventilation and air-conditioning machinery with motors having an aggregate capacity greater than 7.5 kW (10 hp); and similar spaces, but are not machinery spaces of Category A.

Manifold: An accessory system of piping to a main piping system (or another conductor) that serves to divide a flow into several parts, to combine several flows into one, or to reroute a flow to any one of several possible destinations.

Manipulator Arm: Mechanism to guide tubulars from/to well center to/from the V-door.

Marine Drilling Riser System: The extension of the well bore from the subsea BOP stack to the floating drilling vessel which provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, booster lines, auxiliary lines (for specialized needs including riser boost, mud return for a dual gradient drilling program and glycol injection to control hydrate formation), guides tools into the well, and serves as a running string for the BOP stack.

Master Bushing: Device which imparts torque from the rotary table to the kelly bushing and accepts the slips.

Maximum Allowable Working (Operating) Pressure (MAWP) or Rated Working Pressure (RWP): The maximum internal pressure equipment or system is designed to operate or work and to contain and/or control the pressure.

MCOC: See MAC.

Mechanical Load-bearing Component: Components transmitting, resisting, or converting loads.

Primary Mechanical Load-bearing Component: A path in an assembly of mechanical components, along which force/load is transferred from one component to its connected component(s), failure of any of which will compromise the load carrying capacity of the assembly under operational conditions.

Minimum Design Service Temperature (MDST): The lowest predictable metal temperature occurring during normal operation including start-up, shut-down and ambient situation is to be used.

Mitigating Barriers: Those areas of a mechanical or control system which have barrier(s) to prevent the occurrence of a hazardous situation. The FMEA/FMECA Validation testing is to validate that upon the specified failure, a minimum of one mitigating barrier performs as intended in order to prevent occurrence of a hazardous situation. Examples of such mitigating barriers are hydraulic load holding valves, alarms, sensors, etc.

Monkey Board: Elevated platform on the derrick structure for the support of the derrickman to place and/or withdraw tubulars into the finger board.

Mud Agitator: Device to mix, or maintain mixture of, drilling mud in the mud pits.

Mud Boost Line: An auxiliary line which provides supplementary fluid supply from the surface and injects it into the riser at the LMRP to assist in the circulation of drill cuttings up the marine drilling riser, when required.

Mud-Gas Separator (Poor Boy Degasser): A vessel for removing free gas from the drilling fluid returns, generally used when circulating a gas kick out of the well.

Mud Pit Level Indicator: An indicator system that monitors and reports the level of mud in the pits. Serves as an indicator of losses and well kicks. Sometimes referred to a PVT (Pit Volume Totalizer).

Mud Pump: Large high-pressure pump used to circulate drilling fluid, usually positive-displacement type.

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

New Technology: Any design (material, component, equipment or system), process or procedure which does not have prior in-service experience, and/or any Classification Rules, Statutory Regulations or industry standards that are directly applicable. It is possible to categorize the type of "novelty" in one of four categories:

- i) Existing design/process/procedures challenging the present boundaries/envelope of current offshore or marine applications
- ii) Existing design/process/procedures in new or novel applications
- iii) New or novel design/process/procedures in existing applications
- iv) New or novel design/process/procedures in new or novel applications.

Non-conformance:

Major Non-conformance: A condition that affects form, fit or function.

Minor Non-conformance: A condition that does not affect form, fit or function.

Nonhazardous Areas (Unclassified Locations): Locations determined to be neither "hazardous areas" nor "classified areas" (see Classified Area" for definition).

Novel Concept: An offshore drilling unit that with the inclusion of new technologies, the service scope, functional capability, and/or risk profile is appreciably altered.

Operating Conditions: A set of conditions (e.g., pressure, temperature, flow rates, composition, loads, etc.) chosen for normal operation of a system, subsystem, equipment or component.

Pin: Male member of a riser coupling or a choke, kill, or auxiliary line stab assembly

Pipe Rams: See "Rams"

Pipe Racking Mechanism: Automated equipment to place and/or withdraw tubular strands to/from the setback are

Power Slips: Automated slips typically controlled by the driller, usually hydraulically or pneumatically operated.

Power Subs: A power sub is a device which moves with a hoisting system and is designed to provide rotary power to the top of the tubular/string. It attaches to the bottom of the rotary swivel, but does not include a rotary seal or bearing for supporting the tubular/string.

Power Swivels: A power swivel is a device which moves with a hoisting system and is designed to provide rotary power to the top of the tubular/string. It replaces the rotary swivel and includes a rotary seal and bearing for supporting the tubular/string weight.

Pressure Containing Equipment: Equipment/parts exposed to wellbore fluid/pressurized fluid whose failure to function as intended would result in a release of wellbore fluid/pressurized fluid to the environment.

Pressure Controlling Equipment: Equipment/parts intended to regulate the movement of wellbore/pressurized fluids.

Pressure Retaining Equipment: Equipment/parts not exposed to the wellbore/pressurized fluids whose failure to function as intended will result in a release of wellbore fluid to the environment.

Primary Load Bearing: Load bearing components in the critical load path.

Primary Structural Weld: Primary structure welds which are single point failure, with no redundancy, and are considered critical by the designer, will require 100% Volumetric NDE plus 100% Surface NDE

Product Design Assessment (PDA): A certificate issued by ABS upon completion of ABS Engineering plan review (to the manufacturer's requested standards and/or ABS Rules and Guides) and survey of prototype testing (as applicable to the product).

Programmable Logic Controller (PLC): An industrial computer control system that continuously monitors the state of input devices and makes decisions based upon a custom program to control the state of output devices.

Prototype Testing: Design validation testing of equipment designs in accordance with the applicable design standard.

Pulsation Dampeners: Chambered device used to dampen pressure pulsations in a fluid flow.

Pup Joint: A shorter-than-standard-length riser joint, tool joint, or drill pipe.

Rams: Mechanical device used for closing, shearing and sealing component of a blowout preventer. One of three types – blind, shear, or pipe – may be installed in several preventers mounted in a stack on top of the wellbore.

Blind Rams: Blind ram ends are not intended to seal against any drill pipe or casing. The rams seal against each other to effectively close the hole.

Shear Rams:

Shear Rams (non-sealing): Closing component in a ram blowout preventer that is capable of shearing or cutting certain tubulars but, does not seal

Blind-shear Rams: Closing and sealing component in a ram blowout preventer that first shears the tubular in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore

Pipe Ram is a sealing component with an indentation and packing for drill pipe, drill collars or casing that closes the annular space between the pipe and the blowout preventer or wellhead. Separate rams are necessary for each size (outside diameter) pipe in use. Pipe rams can include:

Fixed Bore Pipe Ram: Closing and sealing component in a ram blowout preventer that is capable of sealing only specified tubular size.

Variable Bore Pipe Ram: Closing and sealing component in a ram blowout preventer that is capable of sealing on a range of tubular sizes.

Rated Load: The load specified by the manufacturer that the machine/structure is rated to carry. Maximum operating load, both static and dynamic, to be applied to the equipment

Rated Setback Load: The maximum weight of tubular goods which can be supported by the substructure in the setback area.

Rated Working Pressure (RWP) or Maximum Allowable Working (Operating) Pressure (MAWP): The maximum internal pressure the equipment or system is designed to operate or work and to contain and/or control the pressure.

Remotely Operated Vehicle (ROV): An unmanned vehicle for offshore subsea use.

Reels (MUX, Hotline): Large spool and winch system used to store, deploy, and retrieve flexible lines.

Riser Adapter: Crossover between riser and flex/ball joint.

Riser Chute: To guide risers from vertical position at set back area to drill-floor.

Riser Feeding Machine: A machine designed for horizontal transportation of casing, riser/slip joint and material from pipe deck to drill floor and vice versa.

Riser Flood Valve Joint: A special riser joint having a valve which allows the riser annulus to be opened to the sea based on differential pressure.

Riser Joint: A section of riser main tube having flanged connector (or equivalent) ends fitted with a box and pin and including choke, kill and (optional) auxiliary lines, booster lines, and their support brackets.

Riser Recoil System: A means of limiting the upward acceleration of the riser for unplanned disconnect (EDS).

Riser Running/Handling Tool: A device that joins to the upper end of a riser joint to permit the lifting and lowering of the joint and the assembled riser string in the derrick by the elevators.

Riser Spider – Fixed: A device having retractable jaws or dogs used to support the riser string on the uppermost coupling support shoulder during deployment and retrieval of the riser.

Riser Spider – Elevator: Riser spider that is capable of being used as elevators.

Riser Tensioners: Systems for providing and maintaining top tension on the deployed riser string to prevent buckling.

Riser Tensioner Ring: The structural interface of the telescopic joint outer barrel and the riser tensioners. The tensioner ring may be an integral part of the telescopic joint (slip joint).

Rotary Hose (also known as Kelly Hose): Flexible hose which conducts high-pressure drilling fluids from the standpipe to the gooseneck/swivel and kelly or top drive.

Rotary Swivel: A device hanging on the traveling hook that allows the drill string to rotate while hanging and provide path for fluids flow.

Rotary Table: A device through which passes the bit and drill string and that transmits rotational action to the kelly.

Rupture (or Bursting) Disc: A device designed to rupture or burst and relieve pressure at a defined pressure and rate. The device will not close after being activated.

Safe Working Load (SWL): The maximum rated load within the equipment rated capacity for the given operating conditions.

Safety Factor: The relationship between maximum allowable stress level and a defined material property, normally specified minimum yield strength.

Safety System – Equipment: A system designed to automatically lead equipment being controlled to a predetermined less critical condition in response to a fault which may endanger the equipment or the safety of personnel and which may develop too fast to allow manual intervention.

Service Temperature (the ABS MOU Rules): The service temperature of the unit refers to the minimum temperature of the steel in all modes of operation and is to be taken as the lowest mean daily average air temperature based on available meteorological data for anticipated areas of operation.

Shale Shaker: Any of several mechanical devices utilizing screens and vibration that remove cuttings and other large solids from drilling fluid.

Shear Rams: See "Rams".

Sheaves: Grooved pulley for use with wire rope.

Shut-in: A condition resulting from a shutting-in of the wellbore caused by the occurrence of one or more undesirable events and/or actions of the safety shutdown.

Shutdown: A system action that will be initiated upon signal or failure and is to result in shutdown of systems, subsystems, equipment, component, or part of the facility.

Skid: A steel frame on which equipment is mounted to facilitate handling.

Slip Critical Connection: A bolted structural steel connection which relies on friction between the two connected elements rather than bolt shear or bolt bearing to join two structural elements.

Sour Service: Exposure to environments that contain H₂S and can cause cracking of materials by the mechanisms addressed in NACE MR0175/ISO 15156.

Structural Load-bearing Component: Components supporting loads due to hoisting, lifting, handling, or self/assembled weight, etc.

Primary Structural Load-bearing Component: Component that is necessary to maintain stability of a structure and that resides within the primary load path of the structure when the structure is loaded. Failure of primary structural load bearing components may cause significant structural damage to the unit.

Subsystem: An assembly of interconnected or interrelated parts that performs tasks as a component as a subset of a system.

System: An assembly of various subsystems and equipment, including all associated hardware and software, combined into a unified whole.

Supplier: Manufacturer of components and subsystems that form part of a complete system.

Surveyor: ABS's representative on location to perform examination or inspection activities.

Survival Condition: Condition during which a unit may be subjected to the most severe environmental loading for which the unit is designed. Drilling or similar operations may have been discontinued due to the severity of the environmental loading. The unit may be either afloat or supported on the sea bed, as applicable.

Telescopic Joint (Slip Joint): A riser joint having an inner barrel and an outer barrel with sealing means between. The inner and outer barrels of the telescopic joint move relative to each other to compensate for the required change in the length of the riser string as the vessel moves due to marine environment.

Tensioning System: Systems for providing and maintaining tension on the deployed equipment.

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

Test Stump: Stump with wellhead profile used to support the BOP during surface pressure test operations. Also used during BOP storage.

Threaded Fasteners: Includes all-thread studs, tap-end studs, double-ended studs, headed bolts, cap screws, screws, and nuts.

Tongs (Power or Manual): Automated or manual tongs used to torque drill pipe to final torque or to break out pipe connections.

Top Drive: A top drive is either a power swivel or a power sub, typically with integrated pipe handling and hoisting capabilities below the drive. The pipe handler may comprise an elevator, elevator links, link tilt system and a pipe gripper mechanism to assist in making and breaking connections.

Transit Conditions: All unit movements from one geographical location to another.

Traveling Block: Set of sheaves which move up and down in the derrick as drilling line is paid out or taken in.

Trip: The operation of hoisting the drill string from and returning it to the wellbore.

Trip Tank: Small mud tank used to keep track of the volume of mud displaced by the drill string during "trip in" and "trip out".

Tubulars: Tubular goods can be tubing, casing, drill pipe, and line pipe.

Tubular Horizontal Transporter/Tubular chute: A machine designed for horizontal transportation of tubulars and materials from pipe deck to drill floor and vice versa.

Type Approval: See Appendix 1-1-A2 of the *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*.

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

Uninterruptible Power Supply (UPS): Device supplying output power in some limited time period after loss of input power with no interruption of the output power.

Unit Certification: Unit certification includes a technical review and survey during fabrication of individual systems, subsystems, equipment, components, and materials for compliance with ABS Rules, Guides, or other recognized codes and standards. This allows these items to be placed on a vessel, marine structure or system to become eligible for classification

Unsafe Situation: An event or situation that would cause damage to Life, Property, or Natural Environment.

Upset Condition: A condition that occurs in a system, subsystem, equipment or component when an operating variable deviates substantially from its normal operating limits. If left unchecked, this condition will result in a threat to safety, or undesirable events, and may cause shutting-in of system, subsystems, equipment or component.

Utility Systems: Various systems providing the supporting functions to the drilling operations. Typical utility systems are cooling water, hot oil for heating, chemical systems for injection, hydraulic, potable water, nitrogen generation and system, instrument air and power generation system, etc.

Vibratory Hose: A flexible hose assembly used to convey high-pressure drilling liquids between two piping systems or between the mud-pump discharge outlet and the high-pressure mud piping system for the purpose of attenuating noise and/or vibration, or compensating for misalignment and/or thermal expansion.

Wellhead Connector: Hydraulic connector used to securely latch the lower BOP stack to the wellhead.

Wire Rope: Cable composed of steel wires twisted around a central core of wire or fiber.

Wireline Spoolers: System consisting of a drum, motor and control system used for running or retrieving wireline. Often skid-mounted, may be electrically, pneumatically or hydraulically operated.

CHAPTER 1

Scope and Conditions of Classification

SECTION 8

Acronyms and Abbreviations

The following acronyms and abbreviations are used in this Guide

AHC	Active Heave Compensation
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
COC	Certificate of Conformity
CTOD	Crack-tip Opening Displacement
CTU	Conductor Tensioning Unit
CVN	Charpy V-Notch
DCS	Distributed Control System
DN	Diameter Nominal
DSC	Drilling System- Conditioning
DSD	Drilling System- Derrick
DSP	Drilling System- Pipe handling
EDS	Emergency Disconnect System
ESD	Emergency Shutdown
FAT	Factory Acceptance Testing
FMEA	Failure Modes and Effects Analysis
FMECA	Failure Modes, Effects and Criticality Analysis
GA	General Arrangement
H ₂ S	Hydrogen Sulfide
HAZ	Heat-Affected Zone
HAZID	Hazard Identification
HAZOP	Hazard and Operability

HP	High Pressure
HPHT	High-Pressure High-Temperature
I/O	Input/Output
IBOP	Inside Blowout Preventer
IRC	Independent Review Certificate
ITP	Inspection and Test Plans
LEL	Lower Explosive Limits
LMRP	Lower Marine Riser Package
LP	Liquid Penetrant Examination
MAC	Manufacturer's Affidavit of Compliance
MASP	Maximum Anticipated Surface Pressure
MAWP	Maximum Allowable Working (Operating) Pressure
MCOC	A Certificate of Compliance issued by the Manufacturer
MDST	Minimum Design Service Temperature
MGS	Mud-Gas Separator
MLP	Mud Lift Pumps
MRL	Mud Return Line
MRN	Maintenance Release Note
MT	Magnetic Particle Examination
MTR	Material Test Report
MUX	Multiplex Systems
NCR	Non-Conformance Report
NDE	Nondestructive Examination
NDT	Nil Ductility Transition
NPS	Nominal Pipe Size
NPT	National Pipe Thread Tapered Thread
NRV	Non-Return Valve
OEM	Original Equipment Manufacturer
P&ID	Piping and Instrumentation Diagram
PDA	Product Design Assessment
PFA	Process Hazards Analysis
PHC	Passive Heave Compensation
PLC	Programmable Logic Controller
PM	Preventive Maintenance
PO	Purchase Order
PoC	Point of Contact

PPM	Parts per Million
PQR	Procedure Qualification Record
PT	Dye Penetrant Examination
PVT	Pit Volume totalizer
ROV	Remotely Operated Vehicles
RQS	Recognized Quality Systems
RT	Radiographic Examination
RWP	Rated Working Pressure
SBP	Surface-applied Back Pressure
SG	Specific Gravity
SIT	System Integration Test
SMYS	Specified Minimum Yield Strength
SR	Survey Report
SSL	Structural Safety Level
SWL	Safe Working Load
TA	Type Approval
UPS	Uninterruptible Power Supply
UT	Ultrasonic Examination
UTS	Ultimate Tensile Strength
VIV	Vortex-Induced Vibration
WCS	Well Control System
WP	Working Pressure
WPS	Weld Procedure Specification

CHAPTER 2 Drilling Systems

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CHAPTER 2 Drilling Systems

SECTION 1 General

1 General

The designer of a drilling system is to evaluate the system as a whole, considering the interfacing and interdependence of subsystem equipment and controls. The required design plans and data to be submitted for ABS design review and approval related to the drilling systems, subsystems, equipment, and/or components are listed in 3-2/Tables 1, 3, 5, 7, 9 and Appendix 7 of this Guide.

Well Test systems are not covered under this Guide. For Well Test system requirements, refer to 8-2-1/6.5 of the ABS *MOU Rules* and Part 5D, Chapter 12 of the ABS *Marine Vessel Rules*. Drilling systems consist of multiple subsystems designed for well construction operations.

This Guide provides detailed procedures for ABS approval of drilling systems, subsystems, equipment, and/or components for Classification of a drilling system.

The following general items are required to be addressed in the Drilling Systems Classification process:

- i)* The drilling system, subsystems, equipment, and/or components are to be designed and manufactured in compliance with the applicable recognized codes and standards, as listed in Appendix 1, and the additional requirements specified in this Guide.
- ii)* Where a certain aspect of the design is not in compliance with the recognized code, standard or the requirements of this Guide, the specific variations are to be advised and justified and will be specially considered by ABS in accordance with Chapter 1, Section 5 of this Guide, on a case-by-case basis.
- iii)* ABS approval requirements for typical drilling systems, subsystems, equipment, and/or components are outlined in Chapter 3, Section 1 and 3-2/Tables 1 through 10 of this Guide.
- iv)* Pressure vessels, piping, valves, fittings, electrical systems, control systems, material, welding and NDE associated with equipment and systems for CDS Class are required to be in accordance with the applicable sections of this Guide unless alternate requirements are provided.

3 Equipment Layout

Equipment layout and work areas associated with the drilling activities are to be arranged with the following objectives:

- i)* Safety of personnel

- ii) Separation of nonhazardous areas from those classified as hazardous areas
- iii) Separation of fuel and ignition source as far as practical
- iv) Prevention and mitigation of uncontrollable releases of hydrocarbons
- v) Prevention and mitigation of spills and the spread of flammable liquids and gases which may result in a hazardous event
- vi) Control of potential sources of ignition
- vii) Prevention and mitigation of fire and explosions
- viii) Providing for adequate arrangements for escape and evacuation
- ix) Facilitating effective emergency response
- x) Prevention of dropped object hazards to personnel and assets
- xi) Protection of equipment and components from physical damages, such as:
 - Electrical cables and cableways
 - Well control equipment
 - Exhaust ducting and air intake ducting
 - Control and shutdown systems
 - Fire/gas detection, and fire-fighting equipment
- xii) Provisions for safe access for maintenance and inspection
- xiii) Hazardous areas and associated electrical installations are to be in compliance with the *ABS MOU Rules*. Combustion equipment and combustion engines are not to be located in hazardous areas unless the equipment and engines are designed and rated to operate in hazardous areas.
- xiv) Arrangement drawings are to show the location of all equipment in hazardous areas and systems, controls and equipment relative to the location of living quarters, all machinery spaces, tanks, derrick, wellheads/moon pool, flare and vents, escape route, evacuation equipment, air intake, opening to close spaces, and any fire and barrier walls.
- xv) Prevention of collision between equipment, structures and personnel. Layout of equipment is to consider the static and operating footprints for potential collisions between equipment, personnel and structures. Collision avoidance systems and/or devices are to be incorporated into designs, as applicable.

5 Over Pressurization Protection

Systems, subsystems, equipment, and/or components that may have the potential of exposure to pressure greater than for which they are designed are to be protected by suitable pressure protection devices. Pressure regulators are not to be used as a substitute for pressure relief devices.

It is to be the responsibility of the systems and equipment designers to specify and consider the most severe combination of pressure sources, such as formation pressure, pumps, flow restriction, static heads, hammer effects, fire and/or thermally-induced pressures, in the design and selection of suitable overpressure protection devices. Pressure relief devices will be reviewed for the applicable design parameters, as specified in this Guide.

7 Materials

The materials for each equipment or component are to be selected with consideration of their fitness for the intended service and in accordance with the applicable codes and standards as referenced in Appendix 1, in addition to the material requirements of Chapter 5 of this Guide.

Engineering design material specifications that demonstrate compliance with the applicable design standards are to be submitted with the design package for each system/component in both structure and pressure related systems.

9 Welding and Nondestructive Examination

General requirements for welding and nondestructive examination (NDE) are to be in accordance with Chapter 6 of this Guide.

11 Platforms and Railings

It is to be noted that various national and international regulatory bodies have requirements for the loading, arrangement and construction of local structures such as walking/working platforms, guardrails, handrails, ladders, stairs and walkways. It is the designer's responsibility to be in compliance with the applicable regulatory requirements and the design loads as given below, as applicable. Drawings are to be submitted for working platforms and storage areas. For general traffic areas, manufacturer's affidavit of compliance is sufficient for submittal.

The following are the minimum vertical live loads that are to be considered in the design of walkways:

- General Traffic Areas – 4,500 N/m² (94 psf)
- Working Platforms – 9,000 N/m² (188 psf)
- Storage Areas – 13,000 N/m² (272 psf)

CHAPTER 2 Drilling Systems

SECTION 2 Design Specifications

1 Design Specification

The design specification for drilling systems, subsystems, equipment and/or components is to consider as a minimum, but not limited to, the most adverse combination of applicable loads listed in 2-2/3.3 and consisting of design plans, drawings, data, and calculations, as outlined in Appendix 7 of this Guide, to substantiate the design. The design specifications are to include material specifications, welding specifications, NDE procedures, and testing procedures/specifications utilized in the manufacturing, installation, and commissioning of each system, subsystem, equipment, and/or component and are to comply with the applicable section of this Guide, in addition to the codes or standards used.

1.1 Recognized Standards

The submitted design is to be in accordance with the requirements of this Guide and the latest edition of the specified codes and standards, as referenced herein and in Appendix 1 of this Guide, from contract date (see 1-1-4/1.3 of the *ABS Rules for Conditions of Classification - Offshore Unit and Structures (Part 1)*).

- i) Design complying with other international or national standards not listed in Appendix 1 will be subject to special consideration in accordance with Chapter 1, Section 5 of this Guide.
- ii) ABS advises the designer/manufacturer to contact the ABS Technical office early in the design phase for acceptance of alternate design codes and standards.
- iii) When alternate design codes and standards are proposed, justifications can be achieved through equivalency, gap analysis or appropriate risk analysis/philosophy to demonstrate that the proposed alternate design code and standard will provide an equivalent level of safety to the recognized standards as listed in this Guide, and are required to be performed in accordance with Chapter 1, Section 5 of this Guide.

1.3 Alternative Basis of Design

Designs based on manufacturers' standards may also be accepted. In such cases, complete details of the manufacturer's standard and engineering justification are to be submitted for review.

- i) The manufacturer will be required to demonstrate by way of testing or analysis that the design criteria employed results in a level of safety consistent with that of a recognized standard or code of practice.
- ii) Where strain gauge testing, fracture analysis, proof testing or similar procedures form a part of the manufacturer's design criteria, the procedure and results are to be submitted for ABS review.

- iii)* Historical performance data for drilling systems, subsystems, equipment or components is to be submitted for justification of designs based on manufacturers' standards.
- iv)* ABS will consider the application of risk evaluations for alternative or novel features for the basis of design in accordance with Chapter 1, Section 5 of this Guide, as applicable.

3 Design Considerations

In addition to the codes and standards listed in 2-2/1.1 the following additional requirement are to be complied with:

3.1 Corrosion/Erosion Allowance

Where drilling systems (including piping systems), subsystems, equipment, and/or components are subjected to a corrosive, erosive or abrasive environment, the design is to include allowances for such extra material as applicable in accordance with the requirements as specified below:

- i)* Corrosion/erosion allowance is to be defined as specified by the applicable design codes and standards.
- ii)* Alternative allowances will be considered when supplemented with technical justifications for the life-cycle of the equipment, such as:
 - a)* Previous documented service experience
 - b)* Active corrosion protection and maintenance, such as galvanizing, anodes, etc.
 - c)* Passive corrosion protection and maintenance, such as special coating, etc.
- iii)* In the absence of 2-2/3.1i) through 2-2/3.1iii) above, a minimum corrosion/erosion allowance of 1.6 mm (0.0625 in.) is to be utilized.

3.3 Design Conditions

The drilling systems, subsystems, equipment, and/or components are to be designed to account for all applicable environmental, operational, test loads, or combination thereof. These include, but are not limited to, the following:

- i)* Environmental Conditions, as applicable
 - a)* Earthquake
 - b)* Ice
 - c)* Current, waves
 - d)* Wind
 - e)* Temperature
 - f)* Storm events as per the ABS *MOU Rules* for operating, standby and survival conditions
- ii)* Operational
 - a)* Static pressure
 - b)* Transient pressure excursion
 - c)* Temperature excursion
 - d)* Tension
 - e)* Bending
 - f)* Vibration
 - g)* Acceleration loads due to movement of the drilling unit

- h) Deployment and retrieval
- iii) Hang off and Drifting
- iv) Transportation
- v) Installation
- vi) Commissioning
- vii) Storage and Maintenance
- viii) Test Loads
- ix) MODU inclination

3.5 Risk Assessments for Drilling System Design

A risk assessment for the integrated drilling system and individual systems, subsystems, and equipment is to be performed as listed below. These assessments are to be performed sequentially, starting with the identification of hazards for the overall design, and focusing to detailed risk studies driven by the findings of the previous studies, as necessary

3.5.1 Levels of Risk Assessment

Three (3) levels of risk assessments are to be performed, as applicable:

- Integrated Drilling System Risk Assessment
- Functional FMEA/FMECA
- Component level FMEA/FMECA (Only if required by the results of functional FMEA)

3.5.1(a) Integrated Drilling System Risk Assessment.

An integrated drilling system risk assessment is to be conducted using a qualitative hazard identification technique such as HAZID, HAZOP, What-If or similar and submitted for review. The purpose of the risk assessment is to identify the major hazards to people, environment and equipment associated with the drilling systems/drilling plant and its integration to verify the adequacy of the risk control measures for various modes of operations. The most commonly applied technique is the HAZID and the study involves systems designers, systems integrators and equipment manufacturers/vendors. It is the responsibility of the contracting party to coordinate the process and the submittal of the required information.

The HAZID study is to focus on identifying hazardous situations originating from:

- i) Arrangement, location and general layout of different drilling systems, subsystem and equipment.
- ii) Integration and interactions between the different drilling systems, subsystems and equipment.
- iii) Interfaces with drilling support systems, utilities and marine systems.
- iv) Various operating modes.

7/1.12 of the *ABS Guidance Notes on Failure Mode and Effect Analysis (FMEA) for Classification (FMEA Guidance Notes)* provides detailed steps for carrying out the integrated drilling system risk assessment.

3.5.1(b) *Functional and Component-level Failure Mode and Effect Analysis/Failure Modes, Effects and Criticality (FMEA/FMECA)*. The purpose of an FMEA is to verify that the individual drilling systems, subsystems and equipment comply with the following design philosophy:

- No single failure will lead to a hazardous situation to people, environment or equipment, and

- That there are at least two means of protection in place to prevent the hazardous event.

A functional FMEA/FMECA is to be conducted for individual systems, subsystems and their associated control systems and submitted for review. Based on the results of functional FMEA/FMECA, a component level FMEA/FMECA may be deemed necessary to be performed for the critical components as identified during the functional FMEA/FMECA.

If component level FMEA/FMECA is required, the results of the component level FMEA/FMECA is to correlate to the functional FMEA/FMECA to provide an overall understanding of the local effects of the equipment failure mode and ‘global’ effects of the failure of the control/safety function and other equipment/interfaces in the system.

For certain simple systems, standard engineering methods may suffice to demonstrate compliance with the stated design philosophy. Such simple systems may be exempt from a FMEA study and typically refer to those systems for which the following statements hold true:

- Manual control only – could be hydraulic, pneumatic, electrical, etc. (e.g., on/off switches, manual lever)
- Do not have any PLC or computerized control system
- Control function cannot be altered by operator
- Go mechanically to safe state in all failure modes
- Failure of control will not impact other systems
- System will not be impacted by other system failure

A FMEA/FMECA Validation Program and related test procedures are to be developed and submitted for review. The purpose of the FMEA/FMECA Validation Program is to verify critical and selected results (that are not already covered by FAT and SIT procedures) from the FMEA.

The specific goals of the tests are to validate the:

- Effectiveness of system to identify failures
- Effect of identified failures on system/equipment
- Response of safety controls
- Other measures to protect against failure

Validation tests are to be carried out during factory acceptance testing and/or as part of the on board commissioning of the integrated systems in accordance with the approved program and verified by the attending Surveyor.

When final testing requires assembly and installation on-board the facility, it may not be possible to perform all required testing at vendor’s plant. In this case, FMEA/FMECA Validation testing is to be carried out as part of the system integration testing (SIT) during commissioning. Any modifications made to the Validation test plan are to be submitted for review.

7/1.11 of the *FMEA Guidance Notes* provides detailed steps for the FMEA/FMECA and FMEA Validation Program.

3.5.2 Maintenance of Risk Assessment

Risk study results are to be maintained by the Owner of the drilling unit. If any subsequent modifications to the classed drilling system, subsystems, equipment or components are carried out, relevant risk studies are to be updated to incorporate the modifications; and to demonstrate that any hazards derived from the modifications have been mitigated, as applicable.

CHAPTER 2 Drilling Systems

SECTION 3 Well Control Systems (WCS)

1 General

The **WCS** notation comprises classification of the following systems including their subsystems, equipment, components, and associated control system:

- i)* Sub-sea BOP stack:
 - Lower BOP stack
 - Lower Marine Riser (LMRP)
 - Blowout Preventers (BOPs)
- ii)* Surface BOP stack (only for surface installations)
- iii)* Marine Drilling Risers including Riser Tensioning
- iv)* Diverter System
- v)* Choke & Kill System including Mud Gas Separator
- vi)* Kill/Cement Unit
- vii)* Secondary Well Control Systems:
 - Acoustic
 - ROV Interface
- viii)* Emergency Well Control Systems:
 - Deadman
 - Autoshear
 - Emergency Disconnect System (EDS)
- ix)* Auxiliary Well Control System

The well control systems, equipment, and/or components are to be in compliance with the API standards indicated in 2-3/Table 1, and the additional requirements of this Guide.

TABLE 1
Well Control System (WCS)

<i>Description</i>	<i>Standards (as applicable)</i>
Blowout Preventer (BOP) System and Equipment	API 16A, 16D, 53, 59
Lower Marine Riser Package (LMRP)	API 16A, 16D, 16F, 16R, 16Q
Choke and Kill System and Equipment	API 16C, 6A, 16F, 53
Diverter System and Equipment	API 16D, 53, 64
Marine Drilling Riser System	API 16F, 16R, 16Q
Auxiliary Well Control Equipment	API 53, 7-1, 7G

3 Blowout Prevent System and Equipment

Typical components of the BOP system and equipment would include ram and annular type BOPs, BOP stack structural frame, accumulators, connectors, clamps, drilling spools, spacer spools, control systems/ consoles/panels, control pods, umbilical, flexible/jumper lines (choke, kill, mud booster and hydraulic), hydraulic hoses, MUX (multiplex), cable reels, rigid piping, hydraulic power units, manifold, ROV interface, test stump and testing equipment.

3.1 Blowout Prevent Stack Configuration

BOP stack configurations are to be in accordance with API 53, and the additional requirements as listed below.

- i)* For Subsea BOP Systems Two (2) shear rams are to be provided for moored or dynamically positioned units, of which at least one shall be capable of sealing.
- ii)* All rams capable of sealing are to have a positive locking device to prevent opening in the event of loss of closing pressure.
- iii)* The BOP stack configuration is to be able to close BOPs on all sizes of drill pipe, drill collars and casing that may be used within a drilling program.
- iv)* The ram-type BOP positions and outlet arrangements on subsea BOP stacks are to provide reliable means to handle potential well control events and provide means to:
 - a)* Close in on the drill string, casing or liner and allow circulation
 - b)* Close and seal on open hole and allow volumetric well control operations
 - c)* Strip the drill string using the annular BOP(s)
 - d)* Hang off the drill pipe on a ram-type BOP and control the wellbore
 - e)* Shear logging cable or the drill pipe and seal the wellbore
 - f)* Disconnect the riser from the BOP stack
 - g)* Circulate across the BOP stack to remove trapped gas
- v)* Systems of valves complying with the requirements of 2-3/7 are to be provided.
- vi)* Spacer spools can be used to provide separation between two (2) drill-through components. If installed, spacer spools for BOP stacks are to meet the following minimum specifications:
 - a)* Have a vertical bore diameter the same internal diameter as the mating equipment
 - b)* Have a rated working pressure equal to the rated working pressure of the mating equipment

- c) Are not to have any penetrations capable of exposing the wellbore to the environment, without dual isolation capabilities
- vii) The BOP equipment is to be designed for a specified operating envelope, and suitable for the intended application. The BOP manufacturer is to specify and to attest to BOP stack minimum and maximum capability with regard to its operating envelope such as:
 - Pressure
 - Temperature
 - Shearing capabilities
 - Water Depth
- viii) The BOP structural frame and lifting attachments are to be designed considering applicable loads as specified in 2-3/3.3 of this Guide and in accordance with the design criteria and procedures requirements of API 2A-WSD applicable to movable structures or other recognized standard. Allowable stresses are to be in accordance with design standards and/or AISC.

3.3 Control Systems for Blowout Preventers- Surface and Subsea

- i) The control systems and components (hydraulic, pneumatic, electric, electro-hydraulic, etc.) are to comply with 2-7/3 and are to be in compliance with API 16D and API 53 as applicable.
- ii) Calculations are to demonstrate compliance with the standards referenced above for the hydraulic fluids volumetric capacity of the accumulator system, pump system and reservoir capacity, including the rapid discharge systems.
- iii) Well control systems and components are to comply with the functional requirements of API 53, and include response time, pump system sizing, arrangements, and charging of accumulator systems.
- iv) As a minimum, two (2) full-functioning well control panels are to be provided:
 - a) One (1) well control panel is to be at the driller's station or cabin.
 - b) A second well control panel is to be located in a nonhazardous area, as defined in 4-3-5/7.1 of the *ABS MOU Rules*, API 500 or API 505, without having to cross the drill floor or cellar deck, and is to be arranged for easy access in case of emergency.
- v) Well control panels are to be accessible and functional at all times.
- vi) Well control panels are to be mutually independent (i.e., directly connected to the control system, and not connected in series).
- vii) For the subsea BOP stack, adequate measures are to be provided to prevent accidental unlatching of the wellhead connector until the well is secure, such as two-hand function, two-step action, protective cover or equivalent.
- viii) Shear ram functions are to be two-hand function, two-step action, protective cover or equivalent.
- ix) The well control panels are to include controls for at least, but not limited to:
 - a) Control pressure regulators or means of controlling pressure regulation.
 - b) Close or open of all rams, annular preventers, and choke and kill valves on BOP stack
 - c) Diverter operations
 - d) Disconnect of riser connector (floating installations)
 - e) Emergency disconnect (floating installations)
 - f) Positive means of locking of rams in the closed position, as applicable
- x) With pumps inoperative, the BOP control system's accumulator systems(including hydraulic power fluid, hydraulic pilot fluid, and pneumatic pilot) shall meet the accumulator capacity

requirements of API 16D, API 53, and the additional requirements of this Guide. It shall also be sufficient to perform all testing required therein, including drawdown tests. Calculations are to be in accordance with API 16D. The system shall be able to demonstrate compliance with these requirements.

- xi)* The accumulator capacity for the BOP system (BOP stack configuration and minimum required operator pressure) is to be determined based on the following, in accordance with API 16D and API 53, as applicable:
 - a)* MASP and BOP rated working pressure
 - b)* Water depth
 - c)* Hydraulic fluid properties
 - d)* Local regulations
 - e)* Operational sequence
 - f)* Shearing pressure
- xii)* The required hydraulic fluid capacity is to be calculated in accordance with API 16D to perform the following functions:
 - a)* Subsea BOP stack:
 - 1)* To close and open one (1) largest volume annular-type preventer from full-open position
 - 2)* To close and open four (4) largest ram-type preventers from full-open position
 - 3)* To open valve(s) on BOP stack for one (1) flow path
 - 4)* To close all ram locking devices, as applicable
 - b)* Surface BOP stack:
 - 1)* To close one (1) largest volume annular-type preventer from full-open position
 - 2)* To close four (4) largest ram-type preventers from full-open position
 - 3)* To open valve(s) on BOP stack for one (1) flow path
 - 4)* To close all ram locking devices, as applicable

Note: Variations to the surface stack arrangement per API 53 will be specially considered.
- xiii)* The calculations for the pre charge pressure and hydraulic fluid capacity are to consider the operational sequence during well control to provide sufficient hydraulic pressure and fluids for the shearing operation for the specified operational sequence and wellbore pressure, and with the pumps inoperative.
- xiv)* When stripping accumulators are installed on BOP stack, subsea or surface, additional hydraulic fluids volumes are to be provided in addition to 2-3/3.3xii). The additional hydraulic fluids required are to be based on the BOP hydraulic operator rated working pressure, and the minimum specified pre-charge pressure of the stripping accumulators.
- xv)* For hydraulic fluid drawdown tests, the system is to have sufficient usable fluid volume as required by API 53 to demonstrate the following:
 - a)* To perform all functions specified in 2-3/3.3xii) for subsea or surface BOP stack, respectively, against zero wellbore pressure while pumps are inoperative.
 - b)* The remaining pressure after completion of 2-3/3.3xii) for subsea or surface BOP stack, respectively, is to be 1.38 MPa (200 psi) or greater, above the minimum pre-charge pressure.

- xvi)* Secondary and emergency well control systems, such as Emergency Disconnect Systems, acoustic (if installed), deadman and autoshear systems, are to be provided for DP or moored units with dedicated rapid discharge system with dedicated subsea accumulator unit. The main hydraulic supply for the secondary and emergency well control systems can be powered by a shared dedicated subsea accumulator unit.

The accumulator capacity, volume and pressure, is to be calculated in accordance with API 16D and is to consider all applicable closing sequences to shut in the well.

Floating installations or dynamically-positioned units require the following independent emergency well control systems and safety features. These systems are to be designed in accordance with API 16D and API 53, as applicable:

- a)* Emergency Disconnect System
- b)* Deadman System
- c)* Autoshear System
- xvii)* Acoustic control system, if provided on drilling unit, is to be in accordance with API 16D.
- xviii)* Subsea BOP stack is to be equipped with ROV intervention equipment and control systems, and is to be provided with the following provisions:
 - a)* ROV intervention equipment which at a minimum allows the closing of one set of pipe ram, closing of one each blind-shear rams, and unlatching of the LMRP. These functions are to operate independently of the primary BOP control system.
 - b)* ROV interface and/or receptacles are to be in accordance with ANSI/API 17H.

3.5 Blowout Preventer Equipment

3.5.1 Design Requirements

- i)* Surface and subsea, ram and annular blowout preventers, including workover and well servicing BOPs, ram blocks, annular packing units, valves, wellhead connectors, drilling spools, adapter spools and clamps are to be designed, fabricated and tested by the respective manufacturers for compliance with API 6A, API 16A, API 53 and the additional requirements of this Guide.
- ii)* Hydraulically-operated wellhead, riser and choke and kill line connectors are to have redundant mechanisms for unlock and disconnect.
- iii)* The secondary unlock and disconnect mechanism may be hydraulic or mechanical, but must operate independently of the primary unlocking and disconnect mechanism.
- iv)* In addition to the design conditions/loads listed in 2-2/3.3, the design of preventers is to consider the following loads, as applicable:
 - a)* The weight of a specified length of drill string suspended in the pipe ram preventer
 - b)* Loads induced from the marine drilling riser
 - c)* Designers specified ratings of pipe centering capabilities and ability to shear with pipe in defined positions
- v)* The blind-shear rams are to be capable to seal after shearing operations.
- vi)* The shear rams are to be capable of shearing the largest section and highest-grade of tubulars (drill pipe, casing, wireline, etc.), as applicable, in accordance with API 16A and API 53, as applicable, or the specified drilling program.

- vii)* The shearing capacity calculations for the shear rams are to consider the following, simultaneously, as applicable:
 - a)* MASP (surface) and/or well head pressure (subsea)
 - b)* Forces to shear highest-grade of Tubulars
 - c)* Rated working pressure of BOP
 - d)* Frictional force
 - e)* Shearing ratio
 - f)* Shear test data to validate shear capacity calculation are to be submitted.
- viii)* The annular, pipe and blind ram BOP operator design pressure is to consider the following, simultaneously, as applicable:
 - a)* MASP (surface) and/or well head pressure (subsea)
 - b)* Rated working pressure of BOP
 - c)* Frictional force
- ix)* Procedures to test preventers during manufacturing and “on-site” are to be developed and submitted for ABS review.
- x)* For subsea BOP and associated components such as valves, control system components, sealing components, elastomeric components, etc., are to be designed with consideration to marine conditions and external pressure gradient due to rated water depth.
- xi)* All nonmetallic materials are to be suitable for the intended service conditions, such as temperature and fluid compatibility.
- xii)* Materials are to be in accordance with Chapter 5.
- xiii)* Welding and NDE are to be in accordance with Chapter 6, as applicable.

3.5.2 Operations/Maintenance Manuals

- i)* Manufacturers are to provide the Owner with product operations and maintenance manuals to assist in the safe operation of each assembly on each installation.
- ii)* The manufacturer’s recommended maintenance schedules are to be available for each component of the BOP assembly. These schedules are to be used by the equipment Owner to prescribe maintenance routines.

5 Lower Marine Riser Package (LMRP)

Typical components of the lower marine riser package, including connectors, flex joints, and adapter spools are to be designed, fabricated, and tested by the respective manufacturers for compliance with API 16A, API 16F, API 16R as applicable and the additional requirements of this Guide.

The LMRP package typically includes annular BOPs that are to be designed, fabricated, and tested in accordance with 2-3/3 of this Guide, API 16A, API 16D and API 53.

- i)* Lower marine riser package disconnect arrangements are to be designed for all possible operating and loading conditions. The loading conditions of the LMRP are to consider, but not limited to, the following:
 - a)* Riser angle – min/max
 - b)* Side loads
 - c)* Bending loads

- d)* Currents
 - e)* External pressure due to static head
 - f)* Internal pressure
 - g)* Top tension – min/max
- ii)* The LMRP design is to consider the induced loads as defined in API 16F and API 16Q, as a minimum, for the following modes:
 - a)* Installation
 - b)* Drilling
 - c)* Retrieval
 - d)* Storage and maintenance
 - e)* Hang-off
 - f)* Drifting
- iii)* For dynamically-positioned floating units, an emergency disconnect system (EDS) is to be provided
- iv)* The emergency disconnect is to initiate and complete disconnection in correct sequence. A typical emergency disconnect sequence may be:
 - a)* Blind-shear
 - b)* Close well
 - c)* Disconnect LMRP
- v)* LMRP and associated components, such as valves, control system components, sealing components, elastomeric components, etc., are to be designed with consideration to marine conditions and external pressure gradient due to rated water depth.
- vi)* Adapter spools for BOP stacks are to meet the following minimum specifications:
 - a)* Have a minimum vertical bore diameter equal to the internal diameter of the mating equipment
 - b)* Have a rated working pressure equal to the lowest rated end connection of the mating equipment
- vii)* LMRP structural frame and lifting attachments are to be designed with consideration to all applicable loading conditions. The applicable structural design code and standard, including loading conditions, are provided in 2-3/3.1viii) of this Guide.
- viii)* The LMRP and lower stack frames are to be analyzed together as a unit.

7 Choke and Kill Systems and Equipment

Typical components of the choke and kill system and equipment would include the choke and kill manifolds, including their chokes, spools, flanges and valves; choke and kill lines; connectors and flexible lines (drape hoses at Moonpool area and jumper lines at LMRP); BOP stack fail-close valves; Mud-Gas Separator; kill/Cement unit; connecting piping from the kill unit and/or cementing unit and drilling fluid manifold to the choke manifold, buffer tanks and control systems.

Choke and kill systems, manifolds, arrangements, and associated components are to be in compliance with the applicable codes and standards (API 6A, API 16C, API 53) and the additional requirements of this Guide.

Piping, flexible lines and hydraulic hoses are to be in accordance with Chapter 4 of this Guide, and the standards listed above.

Materials are to be in accordance with Chapter 5 of this Guide, and the standards listed above.

Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable, and the standards listed above.

7.1 Choke and Kill Lines and Flexibles

- i)* Design and arrangements of choke and kill lines and flexibles are to be in accordance with API 16C and API 53.
- ii)* Choke and kill lines from the BOP stack to the choke manifold are to be equipped with two (2) valves each installed on the BOP stack. For surface BOP stacks, at least one of these two valves is to be arranged for remote hydraulic operation.
- iii)* For subsea BOP stacks, these two valves are to be arranged for remote hydraulic operation.
- iv)* Hydraulically-operated valves on subsea units are to be fail-close valves to seal upon failure of the control system pressure. Fail-close can be achieved by a dedicated pressure accumulator back up, by a spring close mechanism or other acceptable fail-close mechanisms.
- v)* Stack mounted valves are to meet the applicable requirements of API 16C, API 53, and API 6A.
- vi)* Hydraulically operated choke and kill isolation valves used for testing purposes are to be fail safe open type.
- vii)* The design pressure of the pipes, valves, flexible lines, connectors, fittings, and the choke manifolds from the BOP stack to the isolation valve downstream of the choke is to be the same as that of the ram-type BOPs or greater.
- viii)* Choke and Kill connections to the BOP are to be in accordance with the provisions of API 16A, 16C, and 53. Connections are to be shown on the design drawings and submitted for review.
- ix)* The choke lines that connect the BOP stack to the choke manifold and lines downstream of the choke are to:
 - a)* Be as straight as practicable; turns, if required, are to be targeted (see API 53)
 - b)* Be firmly anchored to prevent excessive dynamic effect of fluid flow and the impact of drilling solids and/or vibration
 - c)* Supports and fasteners located at points where piping changes direction are to be capable of restraining pipe deflection in all operating conditions
 - d)* Refer to 2-2/3.1 for guidance on corrosion/erosion allowances.
- x)* For flexible lines, the requirements contained in 4-2/7 of this Guide are applicable. End Connections are to be in accordance with applicable parts of Chapter 4.

7.3 Components of Choke and Kill

- i)* For surface BOP choke and kill manifolds with a rated working pressure of 20.7 MPa (3000 psi) and above, only flanged, welded or clamped connections, and rated hammer unions are to be used.
- ii)* For subsea BOP choke and kill manifolds, end connections only, to be flanged, welded or clamped connections, and rated hammer unions are to be used, regardless of rated working pressure.
- iii)* For Surface BOP systems with rated working pressure less than 69 MPa (10000 psi), the minimum size for the choke lines is to be 50.8 mm (2.0 in.) nominal diameter.
- iv)* For Surface BOP systems with rated working pressure of 69 MPa (10000 psi) and higher and all Subsea BOP systems, the minimum size for the choke lines is to be 76.2 mm (3.0 in.) nominal diameter.
- v)* HPHT well equipment is to be designed as per Chapter 1, Section 5 of this Guide.

- vi)* Minimum size for vent lines downstream of the choke is to be at least the same internal diameter as for the chokes end connections.
- vii)* When buffer tanks are utilized, provisions are to be made to isolate a failure or malfunction without interrupting flow control.
- viii)* All choke manifold valves subject to erosion from well control are to be full-opening and designed to operate in high pressure gas and abrasive fluid service.
- ix)* All manual chokes and valves are to be provided with local marking or indicators to enable the operator to determine the valve positions, “open” or “closed”. Placards on the valve can be used for this purpose.

7.5 Arrangement of Choke Manifold

- i)* The choke and kill manifold assembly is to include the following:
 - a)* The choke manifold is to be designed for a minimum of three (3) chokes, of which at least one (1) is remotely controlled and one (1) is manual. The chokes are to be arranged to permit control through either the choke or kill line.
 - b)* Each of the chokes is to be capable of being isolated and replaced while the manifold is in use.
 - c)* Choke and kill manifold is to permit pumping or flowing through either choke or kill line.
 - d)* For subsea BOP, the arrangement is to allow for simultaneous choke and kill operation.
 - e)* The manifold arrangement is to permit the rerouting of flow through an alternative choke without interrupting the well control operation or interfering with pumping through the other line.
 - f)* RWP connection to both drilling fluid and cement unit pump systems
- ii)* The manifolds downstream of the choke are to be designed to minimize erosion or abrasion from high velocity flow, by avoiding sharp bends. If 90 degree cannot be avoided, these are to be buffered by targeted flanges or fluid cushions.
- iii)* Each of the manifolds’ inlet and outlet lines is to be fitted with an isolation valve with the pressure-temperature rating as the choke inlet and outlet accordingly. Temperature rating shall meet the design temperature of the manifold.
- iv)* The choke manifold is to have an alternate discharge outlet:
 - a)* To avoid a single failure, blockage or washout impairing the manifold operation
 - b)* To permit flow to a mud-gas separator, to a flare boom and emergency discharge overboard
- v)* The routing downstream of the chokes to mud-gas separator or discharge overboard are to be provided with an alternate path for redundancy so that eroded, plugged, or malfunctioning parts can be isolated without interrupting flow.
- vi)* In the event the capacity of the mud-gas separator is exceeded, the choke manifold is to have the capability to divert flow to alternate locations for emergency discharge, such as vent lines, flare or discharge overboard as applicable.
- vii)* The bleed line (bypassing the primary three chokes), if installed, is to be at least equal to or greater than the maximum internal diameter to the upstream choke line.
- viii)* Overboard lines are to be arrange so that discharges can be directed in downwind directions and away from the drilling facility. Routing along the diverter lines is recommended.
- ix)* The Joule-Thompson effects are to be considered in the design and material selections of choke and kill manifold and downstream piping and associated components.

7.7 Mud-Gas Separator (Poor Boy)

- i)* Mud-gas separator is to be designed and manufactured in accordance with ASME Section VIII Boiler and Pressure Vessel Code and 2-7/5 of this Guide.
- ii)* The mud-gas separator is to be vented to the atmosphere through the vent line.
- iii)* The pressure relief valve or rupture disc is not considered necessary as the mud-gas separator is vented to the atmosphere.
- iv)* The vent line is to be provided without any restriction.
- v)* Precautions are to be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the vessel wall.
- vi)* Design pressure of the mud-gas separator is to be determined by the vent line being filled with mud at 2.2 SG, or the specified maximum mud weight.
- vii)* The vent line is to be as straight as possible, free from obstructions and is to be sized and arranged to minimize backpressure. If the vent line is not straight, suitable backpressure calculations are to be provided
- viii)* The maximum design backpressure in the vent line is to allow for the maximum specified gas flow without gas breaking through the mud outlet liquid seal with the design mud/condensate weight of 0.6SG .
- ix)* The mud-gas separator is to be provided with a high level sensor or equivalent for notification of re-routing of flow from choke to overboard or alternate route.
- x)* The mud-gas separator is to be equipped with provisions to prevent gas blow-by to the mud condition equipment downstream of the mud-gas separator and for the notification of manual or automatic re-routing of flow from choke for overboard discharge or to stop the flow. These provisions are to be achieved by:
 - a)* Pressure and temperature monitoring, and
 - b)* Passive liquid seal, which is to be a minimum of 3 meters (9.84 feet) for general purpose drilling operations
- xi)* Provisions are to be provided for monitoring of liquid seals by:
 - a)* Measuring the differential pressure at the liquid seal, or
 - b)* Monitoring the liquid seal with a low-level sensor system arranged to provide notification to rig personnel to take corrective action to prevent gas blow-by.
- xii)* The mud-gas separator and liquid seal is to be equipped for easy clean out and drain at lowest point. Drain line is to slope downward to prevent backflow.
- xiii)* The mud-gas separator is to have sufficient capacity for the intended use in accordance with established sizing procedure, details of the sizing calculations are to be documented on board. The sizing of the mud-gas separator is to be performed in accordance with SPE Paper No. 20430: Mud-Gas Separator Sizing and Evaluation.
- xiv)* Piping is to be in accordance with the requirements of Chapter 4 of this Guide.
- xv)* Materials are to be in accordance with Chapter 5 of this Guide.
- xvi)* Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

7.9 Gas Vents

- i)* Vent lines from mud-gas separator (poor boy) are to extend a minimum of 4 m (13 ft) above the crown block and to have a minimum nominal diameter of 250 DN (10 in. NPS).
- ii)* For HPHT drilling operations, the vent lines are to have a minimum nominal diameter of 300 DN (12 in. NPS).

- iii)* The vent line is to be as straight as possible, free of obstructions, and is to be sized and arranged to minimize backpressure in the upstream equipment of the vent line. Minimum line diameters are noted in 2-3/7.9i) above.
- iv)* The vent line from the mud-gas separator is not to be interconnected to any other vent lines.
- v)* Vent lines are to be routed to avoid low point and to be self-draining to avoid accumulation of mud and to be sloped toward the mud-gas separator.
- vi)* Vent line from liquid seal siphon breaker of the mud-gas separator is:
 - a)* To be elevated at a minimum 10 meters (32.8 ft) above the mud-gas separator
 - b)* To have a minimum internal diameter of 100 mm (4.0 in.)
 - c)* To be as straight as possible, free of obstructions
 - d)* Not to be interconnected to other vent lines
- vii)* Bypass lines to alternate locations from choke manifold, such as vent lines, flare or overboard, as applicable, must be provided in case of malfunction or in the event the capacity of the mud-gas separator is exceeded. These lines are not to be interconnected to the diverter lines.
- viii)* Overboard lines are to be directed for discharge in downwind directions and away from the drilling facility. Routing along the diverter lines is preferred.
- ix)* Vent lines from degassers are to be:
 - a)* Individual lines
 - b)* As straight as possible
 - c)* Free of obstructions
 - d)* Free of “water traps”
 - e)* Sized and arranged to minimize backpressure
 - f)* Arranged to accommodate possible precipitation of fluid in the vent line
- x)* The vent lines from the degasser must not be interconnected to any other vent lines.

7.11 Control Systems for Choke and Kill Equipment

- i)* The control systems and components (hydraulic, pneumatic, electric, electro-hydraulic, etc.) are to comply with 2-7/3 and are to be in compliance with applicable codes and standards such as API 16C and API 53, and the additional requirements of this Guide.
- ii)* A minimum of one remote control station is to be away from the choke manifold and protected to avoid hazards caused by leakage from the manifold, valves or chokes.
- iii)* Any remotely operated valve and choke is to be equipped with emergency operation provisions as required by API 16C. Alternative power sources other than specified in API 16C can be utilized as long as the availability and redundancy of the system is equivalent or better.
- iv)* All remotely operated valves are to be provided with “open” and “close” indicators on the control panels at all locations.
- v)* Remotely operated valves that have alternative means of local control in an emergency are to be provided with local markings to enable the operator to determine the valve position.
- vi)* A choke position indicator showing the relative position of the choke trim or relative orifice size as a percent of fully open is to be provided at the control panel.
- vii)* Electronic pressure and temperature transmitters and analog gauges are to comply with the requirements of API 16C, as a minimum.
- viii)* The instrumentation gauges and/or transmitter on the choke manifold are to be at a minimum:

- a)* Analog test pressure measurements are to be made at not less than 25% and not more than 75% of the full pressure span.
- b)* Electronic pressure gauges and chart recorders, or data acquisition systems are to be utilized within the manufacturer's specified range.
- ix)* Electrical systems are to be in accordance with 2-7/7.

7.13 Cement/Kill System

Typical components of the cement/kill system would include pumps, connecting piping, pulsation dampeners and safety valves. The following requirements are to be complied with:

- i)* If the cement pumps are to be arranged to be capable of emergency well kill circulation, using the drilling fluid transferred from the mud pits, then compliance with the following is required:

High-pressure kill unit (pump system) is to comply with the following requirements:
 - a)* It is to be capable of pumping kill fluids at a pressure at least equal to the maximum rating of the BOP.
 - b)* Means of pumping are to be powered by either:
 - Dedicated internal combustion engine, or
 - Electrically powered – to be connected to a back-up power supply, independent of the main power supply
 - c)* Pumps required to transfer drilling fluid from the mud pits to the high pressure kill pumping system should also be connected to a back-up power supply, independent of the main power supply.
 - d)* It is to be equipped to allow the equipment operator to monitor the pressure, flow rate, and volume of the fluid being pumped.
- ii)* Cement pump installations or modifications to existing installations are to be subjected to ABS review and approval.
- iii)* Cement pumps are to be in accordance with 2-5/7.1.
- iv)* The interconnect lines between systems that are used only for emergency well kill circulation are to be fitted with blind or spectacle flanges, lockable valves or similar devices that can be opened as needed, but positively isolate the systems during normal operations. These flanges are to be clearly identified and labeled on the P&ID, and corresponding flanges or valves are to be appropriately identified and their function indicated.
- v)* The cement manifold is to be rated to the ram-type BOPs pressure rating.
- vi)* The control systems are to be in accordance with 2-7/3.
- vii)* Pressure-retaining equipment associated with cementing equipment is to be in accordance with the requirements of 2-7/5.
- viii)* Electrical systems are to be in accordance with 2-7/7.
- ix)* Piping systems and their components are to be in accordance with Chapter 4 of this Guide.
- x)* Materials used for cementing system and equipment are to be in accordance with Chapter 5 of this Guide.
- xi)* Welding and NDE are to be in accordance with Chapter 6 of this Guide.

9 Diverter System and Equipment

Typical components of the diverter system and equipment would include annular sealing device (packer, housing), accumulators, diverter flex joint, overshot mandrel, overshot packers, overshot spool, diverter test tool, vent outlets, valves, power unit and piping, control systems/panels/panels.

The diverter equipment and arrangements are to be in compliance with the requirements of API 64, API 53, API 16D, or other recognized standards and the additional requirements of this Guide. The allowable stresses for the diverter equipment are to be in accordance with API 64.

9.1 Diverters

- i) A diverter with a securing element for closing around the drill string in the wellbore or open hole is to be provided when it is desired to divert wellbore fluids away from the rig floor.
- ii) The diverter is to be equipped with two (2) overboard/vent lines sized in accordance with API 64 and lines are to be routed overboard to opposite sides of the rig floor.

9.3 Diverter Valve Assembly

- i) Valves in the discharge piping are to be of the full opening and full bore type.
- ii) Valves are to be designed per API 6D and to the rated working pressure of the diverter.
- iii) Valve actuators are to be sized to be capable of operating the diverter valve under full differential pressure.

9.5 Control Systems for Diverters

- i) The diverter control systems and components (hydraulic, pneumatic, electric, electro-hydraulic, etc.) are to comply with 2-7/3 and are to be in compliance with API 64, API 53 and API 16D. This also includes response time, volumetric capacity of the accumulator system, hydraulic reservoir, pump system sizing and arrangements.
- ii) Any remotely operated valve is to be equipped with a backup power source.
- iii) The diverter system is to be controlled from two (2) locations; one is to be located near the driller's console/workstation and the other is to be located at an accessible location away from the well activity area and reasonably protected from physical damage from drilling activities on the drill floor. Both controls are to be arranged for ready operation by the driller.
- iv) The control systems are to have interlocks so that the diverter valve opens before the annular element closes around the drill string. An interlock override function is to be provided to enable valve operation and closure of the diverter packer in case of interlock failure.
- v) When the diverter element close function is activated, the return flow to the mud system is to be isolated.
- vi) The range of diverter elements is to be suitable to seal on all sizes of drill string elements on which the diverter is required to operate.
- vii) A relief valve is required to prevent over pressurization of the diverter packer. If applicable, the diverter system is to have an interlock system to prevent insert packer closure unless the insert packer is installed and the insert packer lock-down dogs are energized.
- viii) Local and remote controls are to be provided that are visible and specify which valve is operated with the open/closed position of each valve clearly indicated.
- ix) Electrical Systems are to be in accordance with 2-7/7.

9.7 Diverter Piping

- i) Pipe size, arrangement and support is to be determined with due consideration given to maximum pressure and maximum reaction loads, erosion resistance and the range of temperatures likely to be encountered in service.

- ii)* Piping is to be run in accordance with the pipe routing requirements of API 64.
- iii)* Flexible lines are to be avoided where possible. When this is not practicable, data is to be submitted substantiating their suitability for the maximum pressure, maximum reaction loads, fire-resistance, erosion resistance, expected range of temperatures, and their compatibility to associated piping provided it is adequately supported and connected.
- iv)* Suitable pipe supports in accordance with ASME B31.3.
- v)* Piping systems are to be in accordance with Chapter 4 of this Guide.
- vi)* Materials are to be in accordance with Chapter 5 of this Guide.
- vii)* Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

11 Auxiliary Well Control Equipment

Typical auxiliary well control equipment includes flare booms and related piping, kelly cocks, drill pipe safety valves, IBOP, drill string float valves, etc. Submit the following documentation, as applicable:

- i)* Design details for valves, and fittings
- ii)* Manufacturing specifications, as applicable
- iii)* Manufacturer's affidavit of compliance
- iv)* Details of flare boom(s) fitted for well control operations are to be submitted in accordance with 2-3/11.9.

Auxiliary well control equipment are to be used in a rotary drilling system. For drilling installation using a top drive system, an automated or manual drill pipe safety valve must be installed. Auxiliary well control equipment is to be in compliance with API 7-1, and API 53, and Chapter 4 of this Guide.

11.1 Kelly Cock

- i)* The drill string is to be equipped with two (2) kelly cocks, one of which is to be mounted below the swivel (upper kelly cock valve), and the other at the bottom of the power swivel or kelly (lower kelly cock).
- ii)* The lower kelly cock is a full-opening valve that backs up the upper kelly cock. For surface BOP stack, the lower kelly cock is to be sized so that it can be run through the blowout preventer stack.
- iii)* Testing of kelly cocks is to be performed bi-directionally and at a low and high pressure, with the low pressure tests first.

11.3 Drill Pipe Safety Valves

- i)* A full-opening manual safety valve is to be available on the rig floor to be installed into the drill string immediately in the event of a kick occurring during a trip.
- ii)* The wrench to operate the valve is to be readily accessible to the crew to perform this operation.

11.5 Internal Blowout Prevent (IBOP)

- i)* An internal blowout preventer or IBOP is a back pressure or check valve that is to be provided in the drill string.
- ii)* IBOP is spring-operated and is locked in the open position with a removable rod lock screw.

11.7 Drill String Float Valve

- i)* A float valve is to be installed just above the drill bit to protect the drill string from back flow or inside blowouts.
- ii)* The two (2) most common types of floats are spring-operated piston (plunger) and flapper types.

11.9 Permanently Installed Burner/Flare Booms (If used for Well Control Purposes)

11.9.1 Design

- i) The use of the flare boom is to extend and support the burner/flare at a safe distance away from the drilling area. This is to limit exposure of personnel, equipment, and helicopter traffic to vent gas, flare exhaust, or flare radiation.
- ii) In addition to this Guide, flare and vent analysis is to be in compliance with 3-3/15.5 of the *ABS Rules for Building and Classing Facilities on Offshore Installations (Facilities Rules)*.

11.9.2 Design Loads

- i) The loads to be considered in the design of a boom structure are to include, as applicable:
 - a) Dead weight of structure, piping, fittings, rigging, snow and ice, walkways, guard rails, etc.
 - b) Wind loads
 - c) Thermal and impulsive loads resulting from the use of the flare
 - d) Vessel motion-induced loads
- ii) The values of all design loads are to be listed in the submitted design documentation.
- iii) Loads resulting from vessel motions and wind loads can be established using the procedures given in API 4F.
- iv) The derivation of loading conditions to be used in the design is to give due account of the operational requirements of the Owner, and are to reflect both the operational and stowed modes of the boom.

13 Marine Drilling Riser System

13.1 General

Typical marine drilling riser subsystems and components include the following:

- Riser tensioning system and equipment
- Riser spider, gimbal and shock absorber equipment
- Riser running equipment
- Riser recoil system
- Riser joints and riser pup joints
- Telescopic joints (slip joints)
- Buoyancy equipment
- Ball and flex joints
- Riser couplings (connectors): mechanical, hydraulic, etc.
- Special equipment, including fill-up valves, mud boost system, riser VIV suppression devices

13.3 Riser Tensioning System

Typical components of the riser tensioning system would include accumulators, air/nitrogen compressors, air/nitrogen dryers, control systems/panels, hydraulic cylinders, HPU, piping, pressure vessels, tensioners, guideline, podline, wireline, sheaves for tensioners, telescopic arms, wire ropes, etc. The design of these components is to be in accordance with the applicable requirements of this Guide.

13.3.1 Component Specific Requirements

- i) The riser tensioning system and associated components listed above are to be designed manufactured and tested in accordance with the applicable sections of API 2RD, API 16F, and API 16R, and the additional requirements of this Guide.
- ii) Design analysis and results, boundary conditions and loading conditions are to be submitted for review, showing that the drilling riser tensioning system components will not be overstressed at the maximum tension capacity, either in axial loading, lateral loading or bending and overpressure.
- iii) Load-carrying parts are to be in accordance with API 16F, as applicable.
- iv) Locking mechanism is to be in accordance with design codes and standards and 2-4/9.7.
- v) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- vi) Piping and hoses are to be in accordance with Chapter 4 of this Guide.
- vii) Materials are to be in accordance with Chapter 5 of this Guide.
- viii) Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

13.3.2 Riser Recoil System

Riser recoil system is to be provided to protect personnel and prevent damage to the drilling unit and to various equipment in the load path of the marine drilling riser system.

The riser recoil system is typically integrated with the riser tensioning system and its control system by incorporating various control valves, sensors, hydraulic/pneumatic energy sources, and computer-based control systems, etc.

The riser recoil system is to control the released energy in the event of an emergency disconnect (EDS) event or upon failure of the marine drilling riser. The riser recoil system is required to be activated as part of the emergency disconnect sequence. This is to be achieved through the following:

- i) Design of the marine drilling riser recoil system is to consider emergency situations, such as EDS event, failure of marine drilling riser, during all phases of drilling operations.
- ii) Riser recoil system is to complete an orderly and controlled shutdown of the riser tensioning system to a predetermined safe position, regardless of the sea state.

13.3.3 Control Systems for Riser Tensioning System

- i) Provisions for load monitoring are to be provided for the riser tensioning system.
- ii) Any remotely-operated valve is to be equipped with a backup power source.
- iii) The control systems are to be in accordance with 2-7/3.
- iv) Electrical systems are to be in accordance with 2-7/7.

13.5 Marine Drilling Riser Global Analysis

The global riser analysis is to be performed and documented for the drilling site specific conditions. The analysis and operation procedure are to be maintained by the owner and to be submitted to ABS if required by Administration. The marine drilling riser system design is to be in compliance with the global analysis results using site-specific loading conditions and API 16Q requirements during the operation. In addition, local jurisdiction requirements may apply.

The analysis report is to demonstrate the parameters applied to and methodology including assumptions made, and operation envelop. Refer to the ABS *Guidance Notes on Drilling Riser Analysis* for details.

13.7 Riser Operations Manual

Riser is required to be on an approved maintenance system (Refer to 8-1/11). In association with the submitted maintenance program, an Operations, Maintenance and Inspection manual is required to be submitted for review. The following items are to be included in the manual (API 16Q):

- i)* Manufacturer's drawings of the riser system components
- ii)* Load ratings of the components
- iii)* Internal and collapse pressure ratings of the riser and integral lines
- iv)* Operation limits including emergency operation limits
- v)* Operation procedure for each mode
- vi)* Load monitoring and control
- vii)* Vessel motion and offset control
- viii)* Address safety and risk for operation
- ix)* Emergency response plan
- x)* Inspection and maintenance procedures for each component including method, frequency, criteria, and timing
- xi)* Maintenance method and procedure
- xii)* Procedures for verification when removing from storage
- xiii)* Riser joint operation tracking method and requirement
- xiv)* Log for each joint including its position along the riser system and its operation history shall be available for audit or review when requested

CHAPTER 2 Drilling Systems

SECTION 4 Derrick Systems (DSD)

1 General

The **DSD** notation comprises classification of the following systems, including their subsystems, equipment, components, and associated control system:

- Conductor Tensioning System
- Drill String Compensation System
- Derricks/Mast
- Hoisting Equipment
- Riser Running Equipment

The DSD systems, equipment, and/or components are to be in compliance with the API standards shown in 2-4/Table 1, and the additional requirements of this Guide.

TABLE 1
Derrick System (DSD)

<i>Description</i>	<i>Standards (as applicable)</i>
Conductor Tensioning System and Equipment	CDS 2-4/3
Drill String Compensation System	CDS 2-4/5
Derricks/Masts	API 4F, 2INT-MET, 2 MET, ISO 19901-1
Hoisting Equipment	API 8C, 7K, 7F, 9A
Riser Running Equipment	API 16F

3 Conductor Tensioning System

Typical components of the conductor tensioning system equipment would include accumulators, control systems/panels, hydraulic cylinders, HPU, piping, pressure vessels, sheaves, wire ropes, chains, etc.

3.1 Conductor Tensioning System Equipment

The design of conductor tensioning system equipment and/or components is to be in accordance with the applicable sections of this Guide.

- i) Load-carrying parts are to be in accordance with design codes and standards as referenced in 2-4/9.7, as applicable
- ii) Pressure vessels are to be in accordance with ASME Section VIII Boiler and Pressure Vessel Code and 2-7/5 of this Guide.
- iii) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- iv) Piping, flexible lines and hydraulic hoses are to be in accordance with Chapter 4.
- v) Materials are to be in accordance with Chapter 5.
- vi) Welding and NDE are to be in accordance with Chapter 6.

3.3 Control Systems for Conductor Tensioning System

- i) The control systems are to be in accordance with 2-7/3.
- ii) Electrical systems are to be in accordance with 2-7/7.

5 Drill String Compensation System

Drill string compensation systems can be categorized as follows:

- Active heave compensation (AHC)
- Passive heave compensation (PHC)

5.1 Drill String Compensation Equipment

Typical components of the drill string compensation equipment, AHC and PHC, would include accumulators, air/nitrogen compressors, air/nitrogen dryers, compensators, control systems/consoles/panels, hydraulic cylinders, HPU, piping, pressure vessels, sheaves, wire ropes, etc.

Design plans and data are to include, but are not limited to, as applicable:

- i) Theory of operation is to be included in design plans and data
- ii) The backup braking system
- iii) Computer/control redundancy studies
- iv) Fast and dead line compensation
- v) Traveling hose integrity

The design of these equipment and/or components is to be in accordance with the applicable sections of this Guide.

5.1.1 Component Specific Requirements

- i) Load-carrying parts are to be in accordance with design codes and standards as referenced with 2-4/9.7, as applicable
- ii) Locking mechanism is to be in accordance with design codes and standards as referenced with 2-4/9.7
- iii) If the locking mechanism is in the load path, it is to be in accordance with 2-4/9.7, as applicable.
- iv) Pressure vessels are to be in accordance with ASME Section VIII Boiler and Pressure Vessel Code and 2-7/5 of this Guide.

- v) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- vi) Piping, flexible lines and hydraulic hoses are to be in accordance with Chapter 4.
- vii) Materials are to be in accordance with Chapter 5.
- viii) Welding and NDE are to be in accordance with Chapter 6.

5.3 Control Systems for Drill String Compensation

- i) The control systems are to be in accordance with 2-7/3.
- ii) Electrical systems are to be in accordance with 2-7/7.
- iii) Any remotely-operated valve is to be equipped with a backup power source.

7 Derricks/Masts

7.1 Recognized Codes and Standards

Except as provided below, the design and fabrication of drilling derricks/masts are to be in accordance with API 4F and the additional requirements of this Guide.

The following derrick/mast structural components are considered to be primary load-bearing structures:

- i) Upper section: crown shaft, main crown beam, main top beams/water table beams.
- ii) Lower section: legs, "V" door beams, shoes, and girths above and attached to the "V" door beams.
- iii) Main load path structural components.

Materials are to be in accordance with Chapter 5 of this Guide. Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

7.3 Design Loads

For structural design of the derrick/mast, design loads, definition of forces and loads, and applicable loading conditions are to be in accordance with API 4F, and as specified below:

- i) Structure failure consequences are to be categorized as medium or higher, as defined in API 4F for the Structural Safety Level (SSL).
- ii) The derrick design is to consider both fixed and pinned boundary conditions. The use of the actual support stiffness (e.g., rotational and/or translational spring supports) based on results from analysis of the supporting structure will be considered. However, when a complete model of the derrick and drillfloor/substructure is generated to reflect the actual stiffness, then appropriate boundary conditions applied at the drillfloor/substructures are to be considered. If the supports are designed to release any degrees of freedom, this shall be reflected in the analysis.
- iii) The Owner is required to specify the geographic region of operation, the static loads (dead weight, hook load, static rotary load, fluid load, setback loads, etc.) and dynamic loads (inertial, dynamic amplification, erection, transportation, wind, transit, motion, acceleration, seismic, etc.) on the derrick/ mast, as required in API 4F. Additionally, the following loads are also to be given consideration, where applicable:
 - a) The increase in dead load due to the accumulation of ice and snow
 - b) The wind-induced load is to be included in the design analysis of the derrick/mast structure and is to consider the following, as applicable:
 - 1) The use of wind speeds higher than those provided in API 4F, where required by the Owner, for regions not specified within API 4F, ISO 19901-1, API 2INT, or API 2 MET.

- 2) The minimum wind velocity for unrestricted offshore service for all normal drilling and transit conditions is not to be less than 36 m/s (70 knots), as specified in 3-1-3/1.3 of the *ABS MOU Rules*. It should be noted that wind velocities in the *ABS MOU Rules* are 1 minute average velocities, and therefore these are to be converted to 3 second gust velocities for use in the structural analysis of the derrick.

For host structures other than mobile offshore drilling units, such as production unit or fixed structure, the transit conditions are to be in compliance with the *ABS FPI Rules* and *ABS Facilities Rules*.

- 3) For the *ABS MOU Rules* unrestricted service, the wind speed to be considered in the Survival Case (no hook load or setback loads) is not to be taken less than 51.4 m/sec (100 knots). It should be noted that wind velocities in the *ABS MOU Rules* are 1 minute average velocities and therefore these are to be converted to 3 second gust velocities for use in the structural analysis of the derrick.
- 4) If only the **CDS** notation is required, it is not mandatory to use wind velocity higher than 51.4 m/sec (100 knots) for regional requirements as specified in API 4F, ISO 19901-1, API 2INT, or API 2 MET, unless required by the Owner.

When requested by Owner, higher wind velocity is to be used in accordance with regional requirements as specified in API 4F, ISO 19901-1, API 2INT, or API 2 MET.

- c) The use of a higher rated setback, where required by the operational demands of the Owner.
- d) Dynamic loading due to motion of the hull are to be provided, as specified below, by the Owner as specified in API 4F for installation, transit, operation, survival condition of the floating units, as applicable. The above conditions are not to be less than those specified in the *ABS MOU Rules*, *ABS Marine Vessel Rules*, *ABS Facilities Rules*, *ABS Barge Rules*, and *ABS FPI Rules*.

If information on the motion of the self-elevating hull is unavailable, the following are to be used.

- *Field Transit*: 70 knots wind plus 6-degree single amplitude roll or pitch at the natural period of the unit.
- *Ocean Tow*: 70 knot wind plus 15-degree single amplitude roll or pitch at a 10-second period.

It should be noted that wind velocities mentioned above are 1 minute average velocities and they are to be converted to 3 second gust velocities for use in the structural analysis of the derrick.

- 1) For the calculation of dynamic loading induced by floating hull motion, the vertical distance and the horizontal distance, where applicable, between the center of flotation of the host drilling unit and the center of gravity of the derrick are to be provided by the Owner to the derrick designer and are to be used in the calculations.
- 2) The horizontal distance is to be considered in addition to the vertical distance in the transit condition for self-elevating drilling units.
- 3) If motion analysis for floating structure is performed, the appropriate acceleration data from the analysis are to be provided for ABS review.

7.5 Live Loads for Local Structure and Arrangements

- i) The arrangement of members is to allow the free drainage of water from the structure.
- ii) The following are the minimum vertical live loads that are to be considered in the design of walkways:
 - General Traffic Areas – 4,500 N/m² (94 psf)
 - Working Platforms – 9,000 N/m² (188 psf)
 - Storage Areas – 13,000 N/m² (272 psf)
- iii) Refer to 2-1/11 for guidance concerning regulatory body requirements.

7.7 Allowable Stresses

- i) To prevent excessive stresses in structural members and connections, or buckling, reference is to be made to the allowable stress limits given in the API 4F or other recognized industry standard.
- ii) The extent to which fatigue has been considered in design is to be indicated in submitted design documentation.
- iii) For allowable stresses in plate structures, refer to 2-4/7.9.
- iv) Consideration is to be given in stress calculations to confirm that maximum stress loads include "Jarring Procedures".

7.9 Equivalent Stress Criteria for Plate Structures

- i) For plate structures, members may be designed according to the Von Mises equivalent stress criterion, where the equivalent stress, σ_{eqv} , defined as follows, is not to exceed $F_y/F.S.$
- ii) The Factor of Safety ($F.S.$) will be specially considered when the stress components account for surface stress due to lateral pressures.

$$\sigma_{eqv} = \sqrt{\sigma_x^2 + \sigma_y^2 - \sigma_x\sigma_y + 3\tau_{xy}^2}$$

where

σ_x	=	calculated in-plane stress in the x direction
σ_y	=	calculated in-plane stress in the y direction
τ_{xy}	=	calculated in-plane shear stress
F_y	=	manufacturer's guaranteed minimum yield point
$F.S.$	=	1.43 for static loading 1.11 for combined loading (includes dynamic loading)

7.11 Bolted Connections

- i) Where bolted connections are used in the derrick, the design documentation, including torquing procedures, is to be submitted for ABS review.
- ii) Bolted connections in the main load path such as on upper mast, foundation, and crown, etc. are to be provided with a locking mechanism and bolted connections which can cause dropped object hazards are to be provided with secondary retention or other mechanical means to mitigate drop hazards.
- iii) Bolted connection designs are to consider the following:
 - a) Fatigue assessment for derrick structures installed on Mobile Offshore Drilling Units performed for welded connections only requires that all bolted connections are designed as slip-critical connections. For Derrick bolted connections designed as bearing

- connections only, fatigue assessment for both bolted and welded connections as applicable is required.
- b)* All bolted connections should be designed as slip-critical connections. However, when designed as bearing connections only, fatigue is required to be considered.
 - c)* Design loading in accordance with 2-4/7.3.
 - d)* Allowable stress in accordance with AISC.
 - e)* Potential for dropped objects.
 - iv)* Bolt tensioning procedures are to include, but not limited to, sequencing, torque loads, etc., depending on the bolt tightening procedure (e.g., Turn-of-Nut, Calibrated Wrench, etc.) as applicable.
 - v)* Bolt materials are to be selected with consideration to stress corrosion cracking, fatigue, marine environment, etc., to recognized industry standards. Non-standard bolt materials will be subject to special consideration.
 - vi)* Regarding bolted connection designs, fatigue is to be considered as follows:
 - a)* Bolted connections designed as slip critical
 - 1)* Fatigue assessment is only required for the welded connections as applicable (e.g., brackets welded at the lower part of the legs, leg foundation welds, etc.) where cyclic loading will occur.
 - 2)* Design of bolts in Slip-Critical Connections is to be carried out in accordance with American Institute of Steel Constructions (AISC) or recognized industry Standards
 - b)* Bolted connections designed as bearing connections only:
 - 1)* Fatigue assessment for both bolted and welded connections as applicable is required where cyclic loading will occur.
 - 2)* Design of bolts as bearing connections is to be carried out in accordance with the American Institute of Steel Construction (AISC) or recognized industry Standards

9 Hoisting Equipment

Typical components of the hoisting system would include the crown block with its support beams, traveling block with its guide track and dolly, sheaves for the crown block and traveling block, deadline anchors, drawworks, drilling hook, top drive, drilling line and sand line, drilling elevators and links, hydraulic cylinders for overhead hoisting power swivel, power subs, adapters, bells, and rotary swivel, wire rope and hoisting equipment gears.

9.1 Drawworks

- i)* Drawworks are to be provided with a minimum of two independent braking systems. Each of the independent braking systems is to be designed for full-rated load at rated speed.
- ii)* At least one of the independent braking systems is to be of the mechanical type and of a fail-safe design.
- iii)* The control systems including collision avoidance provisions are to be in accordance with 2-7/3.
- iv)* Drawworks control is to be provided with deceleration parameters for upper and lower limits for the traveling block/top drive to assist in stopping the load.
- v)* Drawworks construction is to comply with API 7F for chains and sprockets.
- vi)* All mechanical load-bearing components are to be in compliance with API 7K.

- vii) The mechanical coupling between the drawworks drum and the electromagnetic brake is to be provided with a system to prevent unintentional disengagement.
- viii) Drawworks brakes and all other electrical power and control systems are to be suitable for the intended hazardous area.
- ix) The diameter of brake shafts is to be determined by the following equation:

$$d = \sqrt[6]{(bT)^2 + (mM)^2}$$

$$b = 0.073 + \frac{n}{Y}$$

$$m = \frac{c_1}{c_2 + Y}$$

where (in SI (MKS and US units), respectively):

d = shaft diameter at section under consideration, mm (in.)

Y = yield strength (offset = 0.2%, ASTM E-8), kg/mm² (psi)

T = torsional moment at rated speed, kg-cm (lb-in)

M = bending moment at section under consideration; N-m (kgf-cm, lbf-in)

k , n , c_1 , and c_2 are constants given in the following table:

	<i>SI units</i>	<i>MKS units</i>	<i>US units</i>
k	5.25	2.42	0.10
n	191.7	19.5	27800
c_1	1186	121	172000
c_2	413.7	42.2	60000

- x) For hydrodynamic brake systems, detailed drawings and supporting calculations proving that the proposed braking system is as effective as other drawworks braking systems are to be submitted for review.
- xi) Electromagnetic dynamic brake systems are to be arranged to prevent inadvertent failure of the drawworks to suspend the derrick overhead load.
- xii) Electromagnetic systems are to include the following provisions:
 - a) The system is to be provided with a backup power supply.
 - b) Cooling medium temperature and flow indicators and alarms for out of range conditions.
 - c) An automatically activated emergency stop system capable of applying full braking torque to stop and provide a means for a controlled decent of the full rated load.
 - d) The Emergency Stop system is to be designed to automatically engage upon reduction of, or loss of power, or when operation of the drawworks system is detected to be outside of normal operating parameters.
 - e) A fault monitoring system that monitors either electrical faults within the system or the kinetic energy of the traveling block is to be provided and provisions are to include the following:
 - 1) The system must be provided with a backup power source
 - 2) Brake coil current

- 3) Monitors that initiate an emergency stop upon detection of a preset brake coil current or a brake coil current varying in proportion to the driller's control lever position
- 4) Brake coil leakage current detector
- 5) Audible and visual alarms at the driller's control panel to indicate when the limiting parameters of the brake have been reached or when the emergency stop system has been activated
- 6) In the case of AC motors using variable frequency drives for braking, an abnormality in any of the connected drives is to alarm to the driller's control station
- 7) A manual emergency stop button is to be installed within reach of the driller
- xiii) Drawwork designs, including drums and wire ropes, are to comply with the applicable part of 2-6/3.3.
- xiv) The control systems are to be in accordance with 2-7/3.
- xv) Electrical systems are to be in accordance with 2-7/7.
- xvi) Gears and couplings are to be in accordance with 2-7/9.7 and are to be suitable for their intended service in terms of maximum power rating, service life and minimum operating temperature.
- xvii) Piping systems are to be in accordance with Chapter 4 of this Guide.
- xviii) Materials are to be in accordance with Chapter 5 of this Guide.
- xix) Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

9.3 Power Swivels, Rotary Swivel, and Top Drives

- i) Power swivels, rotary swivel and top drives are devices used to rotate the drill string other than by means of the rotary table.
- ii) Power swivels, rotary swivel and top drives are to be designed in compliance with API 8C and the additional requirements of this Guide.
- iii) Major mechanical load-bearing components are to be in accordance with the requirements of 2-4/9.7.
- iv) The control systems including collision avoidance provisions are to be in accordance with 2-7/3.
- v) Pressure-retaining equipment is to be in accordance with the applicable requirements of 2-7/5.
- vi) Electrical equipment is to be in accordance with the requirements of 2-7/7.
- vii) Gears and couplings are to be in accordance with 2-7/9.7 and are to be suitable for their intended service in terms of maximum power rating, service life and minimum operating temperature.
- viii) Piping systems are to be in accordance with Chapter 4.
- ix) Materials for mechanical load-bearing or pressure-retaining equipment are to be in accordance with the material traceability and toughness requirements of Chapter 5.
- x) Welding and NDE are to be carried out in accordance with Chapter 6, as applicable.

9.5 Safety Devices and Instrumentation

- i) The hoisting systems are to have weight indicators installed and the display is to be easily read from the driller's console.

- ii) Anti-crown collision/upper limits and lower limit safety devices are to be installed to prevent the traveling block from contacting the crown block. These safety devices are to be designed to be fail-safe.
- iii) Testing intervals for the safety devices are to be agreed upon by the Owner, but is not to be less frequent than as specified by the drawworks manufacturer.
- iv) If override to the uppermost limit of travel is provided, it is to be part of the testing, accordingly.
- v) Safety devices to prevent dropping of the load due to motor/shaft coupling slippage or functional failure are to be provided.
- vi) For minimum degrees of protection required for electrical equipment, refer to the requirements of 4-3-3/Table 1 of the *ABS MOU Rules*.
- vii) Lighting fixtures and other equipment installed in the derrick are to be designed and suitably secured against vibration and environmental design conditions to prevent dropped objects.

9.7 Hoisting Equipment Specific Requirements

- i) Crown block, sheaves, traveling block, hook, tubular goods elevators and other overhead hoisting equipment are to be designed in compliance with API 8C, API 4F as applicable, and the additional requirements of this Guide.
- ii) The results of the design verification testing if required in API 8C along with design calculations for the component tested are to be submitted for ABS review with the design specification.
- iii) Wire rope is to be designed in compliance with API 9A or equivalent.
- iv) Main load-bearing weld connections are to be full penetration. Where partial-penetration or fillet welds are utilized, validation through design and fatigue analyses, manufacturing process and procedure qualifications (WPS and PQR) are required.
- v) Gears, shafting and couplings are to be in accordance with 2-7/9.7 and are to be suitable for their intended service in terms of maximum power rating, service life and minimum operating temperature.
- vi) Bearings are to be suitable for the intended application. Bearings installed in the main hoisting load path and/or intended for continuous service are to be designed to a recognized industry standard. The design including the load spectrum and bearing life calculations are to be submitted for review.
- vii) Materials for mechanical load-bearing or pressure-retaining equipment are to be in accordance with the material traceability and toughness requirements of Chapter 5.
- viii) Welding and NDE are to be carried out in accordance with Chapter 6, as applicable.

11 Riser Running Equipment

This Subsection provides the requirements for the following riser running and handling equipment:

- Manual riser running tools.
- Hydraulic riser running tools.
- Riser spiders.
- Riser gimbals.
- Equipment used to lift, run, retrieve, or support the riser string and BOP stack.

11.1 Design Loads

- i) Riser hang-off spiders shall be rated to support the riser system and BOP stack at the drill floor level.
- ii) Equipment are to be designed for the loads and requirements as specified in API 16F

- iii)* The Running tool design shall be in accordance with the requirements of API 16F
- iv)* Pressure containing components shall be design in accordance with Chapter 4
- v)* Testing of the riser running and handling tools shall follow the requirements of API 16F
- vi)* Materials are to be in accordance with Chapter 5 of this Guide.
- vii)* Welding and NDE are to be in accordance with Chapter 6 of this Guide, as applicable.

CHAPTER 2 Drilling Systems

SECTION 5 Drilling Fluid Conditioning Systems (DSC)

1 General

The **DSC** notation comprises classification of the following systems, including their subsystems, equipment, components, and associated control system.

- Bulk Storage and Transfer System
- Mud Return (Conditioning) System
- Well Circulation System

The Drilling Fluid Conditioning Systems (DSC), equipment, and/or components are to be in compliance with the standards shown in 2-5/Table 1 and the additional requirements of this Guide.

TABLE 1
Drilling Fluid Conditioning Systems (DSC)

<i>Description</i>	<i>Standards (as applicable)</i>
Bulk Storage and Transfer systems and Equipment	CDS 2-5/3
Mud Return (Conditioning) System	API 13C, ASME Section VIII Boiler and Pressure Vessel Code
Well Circulation System (High Pressure & Low Pressure)	CDS 2-5/9, API 7K, ASME B31.3

3 Bulk Storage and Transfer Equipment

Typical components of the bulk (mud, cement, etc.) storage and transfer equipment would include bulk storage vessels, utility/bulk air system, mixing station and transport or transfer piping.

- i) All utility air piping is to be designed to be purged with dry air prior to transfer operations.
- ii) The utility air transfer piping is to be fitted with relief valves set at a pressure not greater than the working pressure of the bulk storage tanks.
- iii) Bulk storage vessels are to be fitted with safety relief valves or rupture disks piped to a safe relief area. Unless they are fitted with a relief line to an open area, the use of rupture disks is to be limited to tanks installed in open areas.

- iv)* A P&ID or equivalent schematic of the bulk transfer system is to be clearly posted at the operator station to facilitate operation of the system during various bulk transfer operations.
- v)* The control systems are to be in accordance with 2-7/3, as applicable.
- vi)* Electrical systems are to be in accordance with 2-7/7.
- vii)* Piping systems and their components are to be in accordance with Chapter 4.
- viii)* Materials used for bulk storage and transfer equipment are to be in accordance with Chapter 5.
- ix)* Welding and NDE are to be in accordance with Chapter 6, as applicable.

5 Mud Return System and Equipment

Typical components of the mud return equipment would include agitators, chemical mixers, degassers, desanders, desilters, centrifuges, mud pits, dump tanks, piping from degassers to burners or vents, piping of mud return, shale shakers and trip tanks.

- i)* The mud circulating piping system is to be arranged so that the mud reconditioning system may be run in series with the degasser, desander, desilter and centrifuge so as to prevent mud from entering other piping systems.
- ii)* The control systems are to be in accordance with 2-7/3.
- iii)* Pressure-retaining equipment associated with mud return equipment is to be in accordance with the requirements of 2-7/5.
- iv)* Electrical systems are to be in accordance with 2-7/7.
- v)* Piping systems and their components are to be in accordance with Chapter 4.
- vi)* Materials used for mud return system and equipment are to be in accordance with Chapter 5.
- vii)* Welding and NDE are to be in accordance with Chapter 6, as applicable.

5.1 Degasser

Degasser design and arrangements are to comply with the requirements of API 13C and the additional requirements of this Guide.

- i)* The degasser is to be designed and manufactured in accordance with ASME Section VIII Boiler and Pressure Vessel Code and 2-7/5 of this Guide.
- ii)* Typically, the degasser is to be designed so that it can be operated under partial vacuum to assist in removing the entrained gas.
- iii)* Provisions are to be incorporated to vent gas to a safe location.
- iv)* The degasser is to be placed as the first stage in the mud conditioning system to reduce the possibility of gas breaking out of the drilling fluid in the mud treatment pits.

5.3 Mud Returns and Processing

The mud return system includes flowline, degasser, gumbo box, shale shaker, agitators, mud pit, mud tanks, pumps, mixing tanks, hoppers, volume measuring systems, and if installed, desilter, desander and cuttings handling equipment.

Mud return and processing systems, and associated equipment design and arrangements are to comply with the requirements of API 13C and the additional requirements of this Guide.

- i)* The piping system design is to allow the returns from the flowlines to installed mud conditioning equipment as listed above to the mud pit.

- ii) The mud return system, associated equipment and piping systems are to be designed in accordance with 2-7/5 and Chapter 4 of this Guide.

7 Well Circulation System and Equipment (Mud Circulation – HP & LP)

Typical components of the well circulation (including high pressure and low pressure) equipment would include mud tank, mud pumps, charge pumps to pipe, pipe to kelly (rotary hose), vibratory hoses, mud booster hoses, standpipe manifold, standpipe, standpipe to kelly hose, gooseneck, top drive/kelly, bottom-hole assembly (BHA), BHA to flowline, flowline to shale shaker, degasser, desilter, desander.

The High pressure mud circulation would include Circulation Head, Gooseneck, Swivel, Mud Pump – Power end, Fluid Ends – High Pressure, Pulsation Dampeners, HP Piping system, Standpipe Manifold, Mud/Cement Hoses, Mud Pump Relief Valve, and associated control system.

The Low Pressure mud circulation would include – Bulk Tanks, Mud Tanks, Agitators, Mixing Hopper, Low Pressure Piping, Mixing/Charging Pump, Degasser, Desander, Desilter, Gumbo Box, Mud Cleaner, Shale Shaker, Trip Tank, and associated control system.

High-pressure mud pumps are to be fitted with safety relief valves whose maximum setting is no higher than the maximum allowable pressure of the system.

- i) Relief lines from the mud system are to be self-draining.
- ii) Where rupture disk type pressure relief devices are installed, rupture disks are to be certified to meet a recognized standard and the disk assembly is to be subjected to survey in accordance with the manufacturer's specifications.
- iii) Rotary hoses in the well circulation system are to be designed and constructed in accordance with 4-2/7 of this Guide and API 7K.
- iv) Piping systems and their components, and flexible lines are to be in accordance with Chapter 4.
- v) Materials used for well circulation systems and equipment are to be in accordance with Chapter 5.
- vi) Welding and NDE are to be in accordance with Chapter 6, as applicable.

7.1 Mud Pumps

The mud pumps specified in this Chapter are to comply with the following requirements:

- i) Fluid ends, pressure-retaining components, and mechanical load-bearing components including, but not limited to, gears, shafting, clevis linkages, gears of all types, keyways, splines, etc., are to be in compliance with API 7K or equivalent recognized standard, and the additional requirements of this Guide.
- ii) Materials and Welding/NDE used for major pressure-retaining equipment of the fluid ends and mechanical load-bearing components are to be in accordance with Chapters 5 and 6 of this Guide, respectively.
- iii) The fluid end and associated manifolds (suction and discharge) are to be hydrostatically tested as required by 3-2/Table 8.
- iv) Motor couplings and shafting are to comply with a recognized standard and be suitable for intended service in terms of maximum power and minimum operating temperature.
- v) The pumps are to be equipped with suitable vibration (pulsation) dampening devices.
- vi) Installation of pulsation dampeners is not mandatory for cement pumps, when all of the following conditions are met:
 - Where cement can potentially plug the dampening devices,

- Fluid-ends, discharge piping, and supports are designed and installed to withstand pressure pulsation and they are to be in accordance with recognized codes and standards, and
 - Intermittent duty.
- vii)* Discharge high pressure piping to comply with ASME B31.3, or equivalent recognized standard, and Chapter 4 of this Guide.
- viii)* Prime movers (electric motor or diesel) are to be in accordance with 2-7/9.
- ix)* Gears and couplings are to be in accordance with 2-7/9.7.

7.3 Control System for Well Circulation Equipment

- i)* The control systems are to be in accordance with 2-7/3.
- ii)* Electrical systems are to be in accordance with 2-7/7.
- iii)* All valves are to be provided with position indicators. See also 2-3/7.3ix).

CHAPTER 2 Drilling Systems

SECTION 6 Handling Systems (DSP)

1 General

The **DSP** notation comprises classification of the following systems including their subsystems, equipment, components and associated control systems dedicated for drilling operations as follows:

- Lifting Equipment
- Handling Equipment
- Rotary Equipment
- Miscellaneous Equipment (e.g., power slips, tongs, catwalk, mechanical mousehole and any other handling devices used to aid in the transfer of drilling tubulars and marine drilling riser between the rotary table and storage areas).

The DSP systems, equipment, and/or components are to be in compliance with the API standards shown in 2-6/Table 1 and the additional requirements of this Guide:

TABLE 1
Handling Systems (DSP)

<i>Description</i>	<i>Standards (as applicable)</i>
Dedicated Lifting Equipment	API 2C, API 9A, API 9B, BS EN 12385 or equivalent
Handling Equipment	API 7K
Rotary Equipment	API 7K
Miscellaneous Equipment	CDS 2-6/9

3 Lifting Equipment dedicated to Drilling Operations

Typical lifting equipment are cranes (gantry, king post, knuckle boom, bridge racker), base-mounted winches, specialized automated handling equipment for lifting purpose, etc., that are used for pipe handling, riser handling, LMRP handling, BOP handling, and for other lifting activities associated with drilling operations.

3.1 Cranes

- i) Cranes are to be designed, constructed, and tested in accordance with the requirements of API 2C or the ABS *Lifting Appliance Guide* or other recognized industry standards. When alternate codes or standards are proposed, comparative analyses are to be provided to demonstrate an equivalent level of safety to the recognized standards as listed in this Guide and to be performed in accordance with Chapter 1, Section 6 of this Guide, on a case-by-case basis.
- ii) Design loads of the crane winches are to be the maximum line pull based on the design loading or the load created by dynamic braking, in accordance with the above design code. In either case, the distribution of loading from the reeving system is to be taken into account.
- iii) Drums and brakes are to be in accordance with API 2C or the ABS *Lifting Appliance Guide*.
- iv) Wire ropes are to be in accordance with API 9A, API 9B, BS EN 12385, or equivalent.
- v) Design loads of the crane cylinders are to be the loads applied by the crane boom(s), in accordance with the design code. Allowable stresses or minimum scantlings are to be in accordance with ABS Rules or other recognized standard.
- vi) Design loading for crane accumulators and crane piping systems is the resultant pressure as a result of the design loadings from the design code.
- vii) Emergency brakes are to be of a fail-safe design.
- viii) The control systems including collision avoidance provisions are to be in accordance with 2-7/3.
- ix) Where integrated software control systems are installed, collision avoidance provisions are to be integrated into the design to provide safety to personnel and prevent collision damage to equipment during drilling activities.
- x) Hydraulic cylinder/Pressure vessels are to be in accordance with 2-7/5.
- xi) Electrical systems are to be in accordance with 2-7/7.
- xii) Gears and couplings are to be in accordance with 2-7/9.7 and are to be suitable for their intended service in terms of maximum power rating, service life and minimum operating temperature.
- xiii) Piping systems are to be in accordance with Chapter 4.
- xiv) Materials are to be in accordance with Chapter 5.
- xv) Welding and NDE are to be in accordance with Chapter 6, as applicable.

3.3 Base-mounted Winches and other Lifting Devices

- i) Design loads considered in the design analyses are to include, as appropriate, the following:
 - a) Recommended single line pull at specified speed, drum size and layers of wire rope
 - b) Maximum load created by dynamic braking
 - c) Dynamics created by accelerations due to hoisting motion and drilling unit motion (where applicable)
- ii) Design Standards and Factors of Safety are to include the following:
 - a) Bases and other structural steel components are to be designed in accordance with AISC or other recognized standard. Allowable stress for bending, tension, shear and buckling are to comply with specifications contained herein.
 - b) Factors of safety and critical ratios for wire rope, drums, shafts and other parts are as follows:

Load-carrying member allowable stress is to be no greater than the following:

$$\begin{aligned}
 F &= F_{cr}/1.25 && \text{for flat members} \\
 &= F_{cr}/1.55 && \text{for curved members} \\
 F_a &= F_y/1.33 && F_y/F_u < 0.7 \\
 &= (F_y + F_u)/3.25 && F_y/F_u > 0.7 \\
 F_s &= 0.577F_a
 \end{aligned}$$

where

$$\begin{aligned}
 F &= \text{allowable stress for buckling} \\
 F_a &= \text{allowable stress in tension or compression} \\
 F_s &= \text{allowable shear stress} \\
 F_y &= \text{material yield stress} \\
 F_u &= \text{material ultimate stress} \\
 F_{cr} &= \text{critical buckling stress}
 \end{aligned}$$

- c) Wire rope for lifting application is to be rated in accordance with the ABS *Lifting Appliance Guide*, API 9A, API 9B, BS EN 12385, or equivalent, as applicable.
- d) In addition, any combined stresses are not to exceed F_a .

iii) Materials and Fabrication:

- a) All mechanical parts where failure could terminate the load-carrying capabilities of the systems are to be made of steel.
- b) Use of ductile iron for gears and drums, and the use of aluminum for fabrication will be specially considered.

iv) Winch drum design and capacity:

- a) The drum capacity is to accommodate the recommended rope size and length necessary to perform the function required for the load-handling equipment.
- b) Plain or grooved drums will normally be considered acceptable, provided no less than five (5) full wraps of rope remain on the drum with the load in its lowest possible position. Other design specifications/standards will be subject to special consideration based on calculations submitted to ABS.
- c) Each drum end of the rope is to be anchored by a clamp attached to the drum, or by a socket arrangement approved by the hoist or rope manufacturer, providing for attachment of rope to the drum.
- d) The drum flange is to extend a minimum distance of 2.5 times the diameter of the rope over the outermost layer, unless additional means of keeping the rope on the drum are provided (keeper plates, rope guards, etc.).
- e) The diameter of the drum is to provide first layer rope pitch diameter of not less than 18 times the nominal diameter of the rope used.
- f) Gears and couplings are to be in accordance with 2-7/9.7 and are to be suitable for their intended service in terms of maximum power rating, service life and minimum operating temperature.
- g) Piping systems are to be in accordance with Chapter 4.
- h) Materials are to be in accordance with Chapter 5, as applicable.

- i)* Welding, heat treatment and NDE are to be in accordance with Chapter 6, as applicable.
- v)* Wire ropes are to be constructed in accordance with a recognized standard applicable to the intended service, such as API 9A, API 9B, BS EN 12385 or equivalent.
- vi)* Brake design:
 - a)* A power control braking means such as regenerative, dynamic, counter torque braking, controlled lowering or a mechanically-controlled braking means are to be provided and are to be capable of maintaining controlled lowering speeds.
 - b)* Brakes are to activate automatically upon loss of power or when the winch lever is returned to neutral.
 - c)* Brakes are to have the ability to stop and hold 100% of the design load with the outermost layer of wire on the drum.
 - d)* Thermal capacity of the brakes as outlined in the manufacturer's ratings or charts is to be suitable for the intended services.
 - e)* Brake linings containing asbestos material are not to be used.
 - f)* Documentation and calculations for the braking effect of the AC motors are to be submitted when they are the only backup system to the disc brakes.

3.5 Lifting Attachments and Pad Eyes

The provisions of this Paragraph are applicable to lifting attachments and pad eyes that are permanently mounted on to drilling equipment and are used for transfer of equipment onboard, and pad eyes that serve as equipment foundations. For skid mounted equipment, refer to 2.7/11 for additional requirements.

- i)* Design loads and allowable stresses for lifting attachments and pad eyes are to be in accordance with the applicable design criteria and procedures requirements of API 2A WSD or specified design code and standard. The Safe Working Load is to be shown on the drawings and permanently marked on lifting attachments that are subject to technical review.
- ii)* As far as practicable, lifting attachments are to be free from stress concentration points (e.g., geometric discontinuities, sharp weld edges, cuts and notches, etc.).
- iii)* Pad eyes used as permanent equipment foundations are to be reviewed.
- iv)* Lifting attachments used solely for the purposes of shop transfer, load out, transport, installation and maintenance of equipment are not subject to these requirements.
- v)* Pad eyes installed on permanent structures for temporary use are not subject to these requirements.
- vi)* Load testing of lifting attachments is to be carried out in accordance with 3-2/Tables 1 and 2.

3.7 Safety Devices and Instrumentation

- i)* All winches are to be marked with the maximum permissible load allowed for the winch and its system components.
- ii)* Where pneumatic winches are provided:
 - a)* Air supply lines are to be sized to operate the winch at safe working loads (SWL).
 - b)* Isolation provisions are to be provided for each winch at the flexible connection.
 - c)* Motor exhaust is to be vented to a point where it will not present a hazard to personnel, and noise reduction measures are to be utilized.
- iii)* Air regulators and pressure relief valves, located upstream of the non-return valves, are to be provided to limit air supply pressure to the winch, and the supply lines serving the winches are to be fitted with appropriate non-return valves and water separators/filters before the operating valves.

5 Handling Equipment

5.1 BOP Handling Equipment

Typical components of the BOP handling equipment would include horizontal BOP/Christmas tree transporter/skidders, seafixing, bulkhead guiding, handling cranes, etc.

- i) BOP handling equipment is to be designed with consideration of loads, inertia, stability, pulling requirements, etc.
- ii) Emergency brakes are to be of a fail-safe design.
- iii) The control systems including collision avoidance provisions are to be in accordance with 2-7/3.
- iv) Major load-bearing components including sheaves and bearings located in the primary load path are to be in accordance with API 7K or other recognized industry standards. Refer to 2-4/9.7 of this Guide.
- v) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- vi) Electrical systems are to be in accordance with 2-7/7 of this Guide and the *ABS MOU Rules*.
- vii) Piping systems are to be in accordance with Chapter 4.
- viii) Materials are to be in accordance with Chapter 5 of this Guide and the *ABS MOU Rules*.
- ix) Welding and NDE are to be in accordance with Chapter 6, as applicable.

5.3 Tubular Handling Equipment

Typical components of the tubular handling equipment would include finger boards, pipe racking, racking arms, stabbing boards, iron roughnecks, cranes, winches, and wire ropes, or any other handling devices used to aid in the transfer of drilling tubulars and marine drilling riser between the rotary table and storage areas.

- i) The drilling rig is to be equipped with hydraulic, pneumatic or mechanical equipment capable of lifting, transporting, and suspending the drill pipe in the pipe rack, and making up or breaking out the drilling pipe.
- ii) Brakes are to be of a fail-safe design.
- iii) The control systems including collision avoidance provisions are to be in accordance with 2-7/3.
- iv) All drill pipes, collars, tubing and casing that may be racked in the derrick are to have provisions to remain secured in place.
- v) All storage racks are to be designed to prevent drill collars, pipe and other tubulars from being unintentionally released from the rack.
- vi) Foundations and storage racks are to be designed to withstand the maximum anticipated setback load of the racked pipe, drill collars and other intended loads.
- vii) Storage racks are to be provided with appropriate drip pans and drains to direct mud and other liquids to appropriate drain system.
- viii) Major load-bearing components including sheaves and bearings located in the primary load path are to be in accordance with API 2C, ISO, AISC or other recognized industry standards. Refer to 2-6/3.1 of this Guide for cranes.
- ix) The control systems are to be in accordance with 2-7/3.
- x) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- xi) Electrical systems are to be in accordance with chapter 2-7/7.

5.5 Casing Stabbing Boards

5.5.1 Rails, Masts, Guides and Runners:

- i) The rails and masts supporting the casing stabbing board are to be securely attached to their supports, designed so that they are unable to open under operating conditions and capable of supporting the casing stabbing board in the event of the operation of the safety gear.
- ii) The guides and runners are to be designed so that in the event of a roller or wheel failure, the platform cannot become detached from the mast.
- iii) Plates that are capable of supporting the weight of the fully loaded platform are to be fitted at the bottom of the rail.
- iv) Upper and lower limits are to be provided and tested before use.
- v) A minimum of two safety harness attachment points must be provided.

5.5.2 Controls and Safety Provisions

- i) The controls are to be arranged to stop the platform if the raising and lowering handle is released.
- ii) Two independent locking devices are to be provided. One locking device is to be engaged when the lifting handle is in neutral and the second is to engage upon failure of the hoisting system.
- iii) Fail-safe upper and lower limit switches are to be provided, as applicable.
- iv) All platforms are to be fitted with sufficient anchoring points for safety harnesses.
- v) A non-slip surface is to be provided on the platform, and adequate handrails, midrails and toe-plates are to be provided in accordance with Section 5-3-1 of the *ABS MOU Rules*.
- vi) The platform is to be fitted with a lock latch mechanism that secures it when it is not in motion.
- vii) Additionally, adequate safety provisions are to be provided for the equipment. Safety provisions are to be of the progressive type designed to be fully engaged within free fall conditions.
- viii) Where two-point operation is used, the operator station in the basket is to override the remote.
- ix) A safety override at the remote station is to be installed for use in the event that the work-performing personnel are incapacitated

5.5.3 Raising and Lowering:

- i) Lifting is to be arranged for both raising and lowering of the platform. The arrangement is not to be such that it is possible to lower the platform by brake only.
- ii) Means of lowering a person to the drill floor must be provided that will function in case of failure of the normal lifting mechanism.
- iii) A speed-controlling device is to be provided which is designed to prevent the raising and lowering of the platform at speeds in excess of the tripping speed.
- iv) The factor of safety for rope or chain is not to be less than 10:1.
- v) If rack and pinion systems are used, they are to be designed so that the failure of either a rack or pinion will not cause the platform to fall.
- vi) The lifting system is to incorporate sufficient rope so that there are at least five (5) full turns of rope remaining on the winding drum when the platform is at its maximum level.
- vii) The equipment associated with the operation of the casing stabbing board is to be securely anchored to the derrick structure.

- viii) The anchorages for rope or chain are to be designed such that they will not be adversely affected by corrosion.

7 Rotary Equipment

Typical components of rotary equipment include master bushing and the rotary table, including its skid adapters and driving unit. The rotary table and its components are to comply with the following requirements, as applicable:

- i) All mechanical load-bearing components are to be in compliance with API 7K.
- ii) Load-bearing beams are to be in accordance with 8-2-1/3.1 of the *ABS MOU Rules* and the requirements for structural materials in Chapter 5 of this Guide.
- iii) The rotary table transmission and associated motor couplings, shafting and brakes are to comply with a recognized standard and be suitable for the intended service in terms of maximum power and minimum operating temperature.
- iv) The control systems are to be in accordance with 2-7/3.
- v) Electrical systems are to be in accordance with 2-7/7.
- vi) Piping systems are to be in accordance with Chapter 4.
- vii) Materials are to be in accordance with Chapter 5.
- viii) Welding and NDE are to be in accordance with Chapter 6, as applicable.

9 Miscellaneous Equipment

Typical components that can be categorized under miscellaneous equipment in the drilling system could include power slips, mechanical mouseholes and any other handling devices used to aid in the transfer of drilling tubulars and marine drilling risers between the rotary table and storage areas.

- i) All tongs are to be capable of being securely attached to the derrick mast or back-up post and anchored by appropriate means such as a wire rope line or stiff arm that will have a breaking strength greater than the force exerted by the tongs.
- ii) Safety lines on tongs are to be positioned in such a manner that the tongs cannot rotate beyond anticipated limits.
- iii) Power tong pressure systems are to be equipped with safety relief valves that are to be set no higher than the maximum working pressure of the system.
- iv) Safety cables attached to kelly hose, tongs and other suspended equipment are to be properly secured to prevent their breaking loose in the event of a connection failure.
- v) Major mechanical load-bearing components are to be in accordance with 2-4/9.7, as applicable.
- vi) The control systems are to be in accordance with 2-7/3.
- vii) Hydraulic and pneumatic cylinders are to be in accordance with 2-7/5.3.
- viii) Electrical systems are to be in accordance with 2-7/7 and the *ABS MOU Rules*.
- ix) Piping systems are to be in accordance with Chapter 4.
- x) Materials are to be in accordance with Chapter 5 and the *ABS MOU Rules*.
- xi) Welding and NDE are to be in accordance with Chapter 6, as applicable.

CHAPTER 2 Drilling Systems

SECTION 7 Common Requirements for WCS, DSD, DSC, and DSP Notations

1 General

This Section contains general requirements for Control Systems, Pressure-Retaining Equipment, Electrical Systems and Equipment, Rotating Machinery, and Skid Mounted Equipment that form part of the drilling system.

The contents of this Section are applicable to and are to be complied with for Well Control Systems (**WCS**), Derrick Systems (**DSD**), Drilling Fluid Conditioning Systems (**DSC**), and Handling Systems (**DSP**) notation requirements.

3 Control Systems

3.1 General

A control system is an assembly of devices interconnected or otherwise coordinated to convey command or orders. Control system can be computer based, hydraulic, pneumatic, electric, electro-hydraulic, acoustic, etc., or combination thereof. This section covers control systems for the drilling systems subject to class in accordance with this Guide. Arrangements for housing the control systems (Driller Cabin, Dog House or other enclosed control stations) are outside the scope of this Guide and are covered in the ABS *MOU Rules*. For hazardous area consideration, refer to Section 4-3-6 of the ABS *MOU Rules*.

The requirements below apply to control systems for equipment and systems covered by this Guide.

- i) The control system (hydraulic, pneumatic, electric, electro-hydraulic, acoustic, etc.) is to be designed where no single point control system failure is to lead to an unsafe situation.
- ii) FMEA, FMECA or similar analysis is to be conducted in accordance with a recognized standard in order to demonstrate compliance with the above design principles. See 2-2/3.5.
 - a) *Failure Modes and Effects Analysis* (FMEA). An FMEA is to be used to determine that any component failure will not result in an unsafe situation through loss of control or shutdown of the system or equipment being controlled, unless the shutdown process is designed into the system in order to prevent an unsafe condition.
 - b) *Failure Mode, Effects and Criticality Analysis* (FMECA). An FMECA is an extension of the FMEA to include a criticality analysis that is used to identify the probability of failure modes against the severity of their consequences.

- c) FMEA/FMECA Validation testing procedures are to be developed and submitted for review for testing the mitigating barriers of critical results and selected results identified in the FMEA/FMECA process to demonstrate the ability of the controls to preclude an unsafe situation. Validation tests are required to be carried out at the plant of manufacture and/or as part of the on board commissioning and verified by the attending Surveyor. See 2-2/3.5 and Chapter 1, Section 7 for explanation of the terms “critical results”, “selected results” and “unsafe situation”.
- iii) Transfer between control stations is to comply with the following requirements:
 (Not applicable to BOP, EDS, choke and kill, and diverter control systems)
 - a) When control of the system or equipment is possible from more than one control location, control is to be possible only from one control location at a time.
 - b) Clear method to transfer control between stations is to be provided.
 - c) At each control location, there is to be an indicator showing which location is in control.
- iv) Maximum control system voltages: 250 VAC 50 Hz or 60 Hz or 250 VDC is to be the highest voltage in any of the control system panels.
- v) Visual and audible alarms are to be provided to indicate an alarm indicating an abnormal condition of an electronically monitored parameter.
- vi) Control panels are to be clearly labeled.

3.1.1 Logic Circuit Features

Logic circuits are to comply with the following principles:

- i) When logic circuits are used for sequential startup or for operating individual components, indicators are to be provided at the control console to show the successful completion of the sequence of operations by the logic circuit and start-up and operation of the component. If some particular step is not carried out during the sequence, the sequence is to stop at this point.
- ii) Manual override is to be fitted in vital functions to permit control in the case of failure of a logic circuit.

3.1.2 Collision Avoidance

- i) Collision Avoidance Systems are to maintain safety of personnel and prevent collision between the equipment and personnel, fixed structures and other equipment during drilling activities. Effective measures to achieve this objective are to be engineered for operating in areas where such collision would be otherwise possible. The measures should include but not limited to sensors, alarms, time-stamped command signals, automated shutdowns and safety interlocks.
- ii) Power actuating functions which are not fully manual operator control are to incorporate Collision Avoidance Systems as applicable to satisfy the requirement of 2-7/3.1i) for all operating modes.
Note: : Equipment designs can utilize combinations of manual and automated controlled functions.
- iii) Computer automated control functions are to manage collision avoidance. Software automated functions are to incorporate collision avoidance systems to satisfy requirement 2-7/3.1i) as applicable (i.e., when software automates a function and or coordinates multiple movements.).
- iv) Design details of collision avoidance systems are to be submitted by the designer/integrator of the equipment package for review. The effectiveness of the collision avoidance measures used is to be verified during commissioning of the equipment.

- v) It is the operators' sole responsibility to manage collision avoidance with manually controlled functions and equipment.

3.3 Control Systems for Well control Equipment

Control systems for well control include the BOP, EDS, choke and kill and diverter control systems, as applicable. These control systems are to comply with the following requirements:

- i) The control system (hydraulic, pneumatic, electric, electro-hydraulic, acoustic, etc.) is to be designed where no single control system component failure is to lead to a failure of the controlled system, loss of control or loss of well control.

Shutdown of control systems for well control equipment is not permitted. With any single point of failure, well control systems are to be sufficiently operational to prevent a loss of control, a loss of well control, or any otherwise unsafe event. This at minimum applies to BOP, Diverter, and Choke and Kill systems, and further applies to any additional control systems directly responsible for maintaining well control.

- ii) The control system and components are to be in compliance with API 16C, API 16D, API 53 and with applicable recommended practices such as API 59 and API 64.
- iii) See 2-3/3.3, 2-3/7.11, and 2-3/9.5 for control system requirements for individual well control systems and/or equipment.
- iv) Computer-based control systems for well control are to comply with the applicable requirements in 2-7/3.
- v) Computer-based control systems for BOPs are to also comply with the following additional requirements:
 - a) Redundant processor, memory, and networks
 - b) Local and remote I/O modules are to fail in a predetermined fashion when there is loss of communications with the processor.
 - c) Input and Output channels are to be diagnostic type, where the program will read the diagnostic status of the I/O and perform safe actions. The program is to notify the operator if a channel fails

- vi) Alternative arrangements can be specially considered for surface BOPs, instead of redundant components, provided it can be demonstrated that the computer-based control system complies with the single control system component failure principle denoted in 2-7/3.3i).

For example, an arrangement with a single processor does not comply. However, an arrangement with a single processor along with additional arrangements that address the possible single control system component failure concept can be specially considered. This special consideration is subject to ABS review of the supporting documentation.

- vii) FMEA, FMECA or similar analysis is to be conducted in accordance with a recognized standard in order to determine compliance with the design principles of Chapter 2, Section 3, 2-7/3.1 and 2-7/3.2. The FMEA Guidance Notes provides guidance on applicable industry standards and the FMEA process.
- viii) The control systems are to be provided with additional measures to prevent accidental disconnection of the wellhead connector, the LMRP connector or the riser connector, such as two-hand function, two-step action, protective cover or equivalent.
- ix) For BOP control systems where functions are executed manually, only visual indicators are required.
- x) With any single point of failure, BOP control systems are to be capable of performing safe actions to secure the well and disconnect, as applicable, using primary methods of control, without

resorting to secondary or emergency control systems (i.e., deadman/autoshear, ROV intervention, etc.).

3.5 Electrical Control Systems and Computer-Based Systems

3.5.1 Electrical Control Systems

Electrical control systems are to comply with 4-9-2/3.1 and 4-9-2/7 (except 4-9-2/3.1.5) of the *ABS Marine Vessel Rules*. For general definitions, 4-9-1/5 of the *ABS Marine Vessel Rules* may be used, as applicable.

3.5.2 Computer-based Systems

A computer-based system is a system of one or more microprocessors, associated software, peripherals and interfaces. Programmable Logic Controllers (PLC), Distributed Control Systems (DCS), PC or server-based computation systems are examples of computer-based systems.

Computer-based systems are to comply with the requirements of this Guide and 4-9-3/5 (except 4-9-3/5.1.4 and 4-9-3/5.1.8) of the *ABS Marine Vessel Rules*.

In addition, computer-based systems are to comply with the following:

- i) *Fail Safe*: Computer-based systems are to be designed such that failure of any of the system's components will not cause unsafe operation of the system or equipment being controlled.
- ii) *FMEA/FMECA*: Additional detailed FMEA, FMECA or similar analysis is to be conducted in accordance with a recognized standard in order for the computer-based systems covering all components to determine compliance with the design principles of this section.
- iii) *Safety Integrity*:
 - a) When computer-based systems have safety-related control functions and the associated failure modes identified in the FMEA/FMECA result in an unsafe situation, special consideration may be given, provided the appropriate level of safety integrity has been provided.
 - b) The appropriate level is to be determined by the application of a recognized industry standard, such as the IEC 61508 Series or the ANSI/ISA 84 Series.
 - c) Documentation in accordance with the relevant industry standard is to be submitted for review to justify the appropriate safety integrity levels.
 - d) Means are to be provided to record and track revisions and document any subsequent changes to the FMEA content. Any significant modification to the software or hardware which influences the safety and/or functionality of the system is to be submitted for approval.
- iv) *System Security*: Computer-based systems are to be protected against unintentional or unauthorized modification of software. System Securities are to be identified and (performance & requirement) specifications are to be defined.

3.7 Safety Functions – Equipment

All control systems are to comply with the following requirements:

- i) Means are to be provided to indicate the cause of the safety action.
- ii) Alarms are to be given at each control location, including any local manual control positions when the system performs a safety action.
- iii) Drilling systems or equipment shut down by a safety action is to be designed not to restart automatically, unless first actuated by a manual reset.

- iv) All shutdowns are to be executed in a predetermined logical manner, as specified in the “shutdown logic” and/or “shutdown cause and effect charts”, and are to:
 - a) Limit the severity of the incident
 - b) Protect personnel
 - c) Limit environmental impact
- v) Shutdown systems are not to result in adverse cascading effects.
- vi) The shutdown systems are to be designed such that when a shutdown is activated, any ongoing operations can be terminated without leading to an unsafe situation.

5 Pressure-Retaining Equipment

5.1 Pressure Vessels

Pressure vessels are considered to be accumulators, heat exchangers, pulsation dampeners, separators (oil/gas), mud-gas separators, and degassers.

- i) Pressure vessels are to be designed, constructed, and tested in accordance with ASME Boiler and Pressure Vessel Code Section VIII Div. 1 or Div. 2. Alternative design codes and standards will be specially considered by ABS with justifications in accordance with Chapter 1, Section 5 of this Guide.
- ii) Pressure vessels utilized in drilling systems are to be submitted for ABS approval in accordance with 6-1-5/1.1 of the ABS *MOU Rules*.
- iii) For the purpose of specifying the degree of survey and testing during the ABS approval process, pressure vessels are to be categorized in accordance with 3-2/Tables 1 and 2.
- iv) The design is also to be such that stresses due to acceleration forces arising out of the motion of the installation, stresses due to external nozzle loads and moments, and stresses due to any other applicable external forces, such as winds, are within the limits allowed by the design code.
- v) All pressure vessels, accumulators, heat exchangers, and separators are to be suitably supported and properly secured to skid structure or rig floor.
- vi) Materials of manufacturing for pressure vessels are to be in accordance with the specified design code and Chapter 5, and appropriately selected for the intended service.
- vii) Welding and NDE for pressure vessels are to be in accordance with the specified design code and Chapter 6.

5.3 Hydraulic Cylinders

Hydraulic cylinders are to comply with the following requirements:

- i) Design and manufacturing are to be based upon the strength criteria of the ASME Boiler and Pressure Vessel Code Section VIII Div. 1 or Div. 2, National Fluid Power Association or other recognized standards.
- ii) Hydraulic cylinders in critical load path and/or applications are to be submitted for ABS approval in accordance with 3-2/Tables 1 and 2.
- iii) Hydraulic cylinders that are in service as load bearing components on overhead lifting or hoisting equipment are to comply with 2-4/9 and 2-6/3, as applicable.

7 Electrical Systems and Equipment

7.1 References

Electrical systems and equipment are to comply with Part 4, Chapter 3 of the *ABS MOU Rules* and are to comply with API 14F, API 14FZ or IEC 61892, as applicable.

- i) Compliance with industry standards, such as the following, will be specially considered:
 - API 500
 - API 505
 - API 2003
 - IEC 61892
 - IEEE C37.06.1
 - IEEE C37.20.6
 - IEEE Std. 45
 - IEEE Std. 142
 - IEEE Std. 242
 - NFPA Std. No. 70
 - NFPA Std. No. 496
- ii) All electrical components are to be designed to meet safe operating conditions by accounting for maximum and minimum temperatures and vibrations expected during service.
- iii) Electrical equipment installed in a hazardous area is to be certified by an independent testing laboratory as suitable for the intended hazard.

9 Rotating Machinery

9.1 Internal Combustion Engines

Internal combustion engines are to comply with the following requirements:

- i) Engines are to be in accordance with the requirements for engines intended for essential services as required in 4-1-2/1.1 and Section 6-1-3 of the *ABS MOU Rules*.
- ii) Engines' installations are to be in accordance with NFPA Std. No. 37.
- iii) The recommended service applications together with curves showing the recommended maximum standard brake horsepower within the recommended speed range for each service are to be submitted.

9.3 Rotating Electrical Machinery

Electrical machinery (rotating) are to comply with the following requirements:

- i) All rotating machines (if any) 100 kW (135 hp) and above are to be of an ABS-approved design in accordance with the *ABS MOU Rules*, tested in the presence of and inspected by the Surveyor, preferably at the plant of the manufacturer.
- ii) All rotating machines having a rated power of less than 100 kW (135 hp) and used in the critical load path are to be designed, constructed and tested in accordance with established industrial practices and manufacturer's specifications. ABS is to review the design and acceptance will be based on manufacturer's affidavit stating compliance with a recognized standard. The test certificates are to be made available when requested by the Surveyor. Acceptance of machines will be based on satisfactory performance after installation.

- iii) For machines of less than 100 kW (135 hp), are to be designed, constructed and tested in accordance with established industrial practices and manufacturer's specifications. Acceptance will be based on manufacturer's affidavit stating compliance with a recognized standard. The test certificates are to be made available when requested by the Surveyor. Acceptance of machines will be based on satisfactory performance after installation.

9.5 Hydraulic motors

Hydraulic motors are to comply with the following:

- i) Hydraulic motors located in the critical load path are to meet recognized industry standards and submitted for review. The test certificates are to be made available when requested by the Surveyor. Acceptance of machines will be based on satisfactory performance after installation.
- ii) Hydraulic motors located in a non-critical load path are to meet recognized industry standards. Acceptance of such hydraulic motors will be based on manufacturer's affidavit stating compliance with a recognized industry standard. The test certificates are to be made available when requested by the Surveyor. Acceptance of machines will be based on satisfactory performance after installation.

9.7 Gears, Shafts and Couplings

Gears shafts and couplings are to comply with the following requirements:

- i) All gears, shafts and couplings in the critical load path having a rated power of 100 kW (135 hp) and over are to be designed, constructed, certified and installed in accordance with AGMA, ISO or equivalent. ABS is to review the design and the parts are to be constructed under the attendance of the Surveyor.
- ii) All gears, shafts and couplings having a rated power of less than 100 kW (135 hp) and used in the critical load path are to be designed, constructed and equipped in accordance with good commercial and marine practice. ABS is to review the design and acceptance of such gears will be based on the manufacturer's affidavit, verification of gear nameplate data and subject to a satisfactory performance test after installation conducted in the presence of the Surveyor.
- iii) All gears, shafts and couplings regardless of rated power and not in the critical load path are to be designed, constructed and equipped in accordance with good commercial and marine practice. Acceptance will be based on manufacturer's affidavit stating compliance with a recognized standard, verification of gear nameplate data and subject to a satisfactory performance test after installation conducted in the presence of the Surveyor.

11 Skid mounted Equipment

11.1 General (1 July 2018)

A typical list of skid-mounted equipment associated with drilling systems operation includes, but is not limited to, the following:

- Utilities and instrument air
- Chemical injection
- Nitrogen generation and charging
- Hydraulics/Pneumatic power units (HPU)
- Sea water
- BOP test pumps
- BOP and/or Diverter control test units
- Portable skids

- Cementing skid

Skid-mounted equipment for drilling operations is to comply with the applicable sections of this Guide covering electrical systems and controls, pressure retaining equipment, Piping, materials and NDE.

Note: Containers and associated lifting sets used solely for shipping or transferring equipment to the unit are not subject to the requirements of this Section. The ABS *Guide for the Certification of Offshore Containers* may be applied for these items outside the scope of these Rules.

11.3 Skid Structures

Skid structures used as permanent foundations for fixed equipment and for use in portable applications on board in the course of drilling operations including the lifting attachments are to comply with the following requirements:

- i) Skid structures for drilling system equipment packaged units are to be sufficiently rigid to support any mounted equipment and piping and, as required, to permit lifting during shipment without damage to the equipment or piping.
- ii) Structural design calculations for skid units with a center of gravity height of more than 1.5 m (5 ft), or a maximum operating weight in excess of 10 MT (metric tons) or 22.05 Kips, calculated in dry conditions, are to be submitted for review.
- iii) Permanently installed lifting attachments on the skid structures subject to design review, which are designed to lift only the skid unit with associated installed equipment, are to be designed in accordance with the requirements of a recognized industry standard. Lifting attachments are subject to design review and fabrication inspection, testing and marking. Load testing of lifting attachments is to be carried out in accordance with 3-2/Tables 1 and 2.
- iv) Lifting attachments installed only to facilitate handling for transport and permanent installation are not subject to these requirements.

Skid structures that do not require ABS review will be accepted based on Manufacturer's Affidavit of Compliance (MAC).

11.5 Drip Pans

Drip pans on permanently installed skids and portable skids are to comply with the following requirements:

- i) Drip pans are to be able to contain liquid spills and leaks from skid-mounted equipment and piping, and to drain the liquid with adequate slope of 1 cm per meter (0.125 inch per foot) into open drain systems.
- ii) A minimum 150 mm (6 in.) coaming around the entire perimeter of a skid is to be provided.
- iii) Spill containment with less than 150 mm (6 in.) coaming arrangement is subject to special consideration (see Chapter 1, Section 5, "Alternatives").
- iv) Calculations of spillage containment capacity for the skid are to be submitted for consideration.
- v) Skid beams that extend above the drip pan may be considered as meeting the coaming requirement, provided that the drip pan is seal-welded to the skid beams.
- vi) Where shipyard installed coamings will be provided to meet these requirements for permanently installed skids, same is to be noted on the skid drawings submitted for review.

CHAPTER 3

Scope of Drilling System and Equipment Approval

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CHAPTER 3 Scope of Drilling System and Equipment Approval

SECTION 1 General

1 General

This Section provides detailed procedures for ABS approval of typical drilling systems, subsystems, equipment, and/or components for Classification of drilling system, that require design approval and survey in accordance with Chapter 3, Section 2, Tables 1 through 10.

- i)* 3-2/Tables 1 through 10 are provided as a general reference listing, and are not to be considered as the complete drilling system, subsystem, equipment or component listing.
- ii)* For drilling systems, subsystems, equipment or components not listed, the designer/manufacturer is to contact the appropriate ABS Technical office for guidance on the approval process.
- iii)* ABS is prepared to consider alternative design methodology and industry practice for drilling system, subsystems, equipment, and/or component designs, on a case-by-case basis, with justifications through novel features as indicated in Chapter 1, Section 5 of this Guide.
- iv)* It is recommended to schedule a kick-off meeting at beginning of each project between the manufacturer/fabricator and ABS Engineering office engineer/project manager in order to:
 - Confirm and/or establish the main point of contacts (PoC) for the design review.
 - Confirm submission requirement for design review and manufacturing and testing including specifications, drawings and/or documentation associated with the design manufacturing and testing processes.
 - Review project design, manufacturing and delivery schedules.
 - Review sub-contractors and their role in the classification process associated with the system or components.

The above list is not all inclusive and the kick off meeting is not limited to the above.

CHAPTER 3

Scope of Drilling System and Equipment Approval

SECTION 2

Approval Process

1 General

ABS approval of drilling systems, equipment, and/or components is to be in accordance with the applicable codes and/or standards regarding design, fabrication, and testing, and is also to comply with the additional requirements of this Guide.

- i)* Drilling systems, subsystems, equipment, and/or components, including drilling support systems, are to be approved according to the following general procedures:
 - a)* Design plans and data are to be submitted in accordance with this Section and Appendix 7.
 - b)* ABS design review for issuance of the following documents (see 3-2/3):
 - 1)* ABS Design Review/Approval Letter or PDA (optional) (see 3-2/7.1 and 3-2/Tables 1, 3, 5, 7 and 9)
 - 2)* Independent Review Certificate (IRC) (see 3-2/7.3, 3-2/Table 3, and Appendix 3), as applicable
 - c)* ABS survey at plant (see 3-2/5.1), and at installation and commissioning (see 3-2/5.3), as applicable, for issuance of the following documents:
 - 1)* Survey Report (see 3-2/7.1, 3-2/Tables 1 through 10, and Appendix 5)
 - 2)* Certificate of Conformance (CoC) (see 3-2/7.3, 3-2/Table 3, and Appendix 4), as applicable
- ii)* The issuance of reports and certificates by ABS is to be in accordance with 3-2/7 and Appendices 3, 4 and 5.
- iii)* Approval of individual or unit equipment and/or components are typically combined toward the approval of complete systems or subsystems.
- iv)* ABS design review, survey, and the issuance of applicable reports or certificates constitute the ABS Classification of the drilling system inclusive of the subsystems, equipment and components.

3 Design Review

Drilling systems, subsystems, equipment, and/or components that require ABS design review and subsequently an ABS approval letter, and an IRC, as required for ABS Classification, are listed in 3-2/Tables 1, 3, 5, 7, and 9, and are detailed throughout this Guide.

- i)* ABS design review verifies that the design of systems, subsystems, equipment, and/or components meets the requirements of this Guide and the specified design codes, standards, or specifications, as applicable.
- ii)* For vessel-specific design review, a submitted design is to be in accordance with the requirements of this Guide and the latest edition(s) of the specified codes and standards, as referenced herein and in Appendix 1, in effect on the vessel contract date (see 1-3/3).
- iii)* For the purposes of non-vessel-specific equipment design reviews, the submitted design is to be in accordance with the requirements of the latest Guide and the latest edition(s) of the specified codes and standards, as referenced herein and in Appendix 1 of this Guide, in effect on the date of submission to ABS.
- iv)* In cases where the contracting party intends to issue a purchase order to, or otherwise contracts the equipment manufacturer for supply of the equipment specifying earlier edition(s) of the specified codes and standards, the designer/manufacturer needs to contact the ABS Technical office for clarification as these will be assessed on a case-by-case basis. Information on the applicable vessel contract dates and/or intended destination will be needed.
- v)* Stock/spare replacement components manufactured for equipment covered under pre-existing design approvals will not require resubmittal to the ABS Technical office, provided the design of the replacement components is unchanged. ABS Survey is to be contacted regarding stock/spare parts as certain components and integrations require tracking and testing to maintain ABS Certification.
- vi)* Vessel-specific design reviews must be performed for systems which are non-transferrable, customized to the rig and/or are permanently installed on the rig.
- vii)* System-level and equipment design reviews in which subsystems and equipment have individual ABS approval requirements defined by 3-2/Tables 1, 3, 5, 7, and 9, will ensure that manufactured and/or purchased subsystems and equipment under the overall system scope of supply are ABS-Approved according to 3-2/Tables 1, 3, 5, 7, and 9, and the additional requirements of this Guide during the top-level design review.
- viii)* Top-level approval letters, IRCs, and/or PDAs will list all subsystem and equipment approvals under the scope of supply, together with their associated ABS Reference numbers. Therefore, it is the responsibility of the contracting party to ensure that manufactured and/or purchased subsystems and equipment are ABS-approved according to 3-2/Tables 1, 3, 5, 7, and 9, and the additional requirements of this Guide. Evidence of ABS approval is to be provided with the top-level design review submission.
- ix)* The manufacturer is to provide manufacturer's affidavit of compliance in accordance with 3-2/3.3.
- x)* Upon satisfactory completion of the design review process, ABS will issue an ABS Approval Letter/PDA, and an IRC, as applicable in accordance with 3-2/7 and 3-2/Tables 1, 3, 5, 7, and 9.
- xi)* ABS is prepared to consider manufacturer's exception(s) to part(s) or section(s) of this Guide and/or the specified codes, and standards for drilling equipment and/or components, on a case-by-case basis, with justifications through:
 - Stress calculations/analysis
 - Finite element modeling/analysis testing
 - Historical performance/experience data
 - Novel features, as indicated in Chapter 1, Section 5

In this case, the manufacturer must provide details of the exception(s) to part(s) or section(s) of recognized design standards in the “Design Basis” submittal, as referenced in Appendix 7 and clearly stated in detail on the manufacturer’s affidavit of compliance as specified in 3-2/3.

3.1 Product Design Assessment (PDA) (Optional)

- i)* For equipment or components listed in 3-2/Tables 1, 3, 5, 7, and 9, which have PDAs available, the ABS design review and ABS approval letter are not required.
- ii)* It is to be noted that no changes can be made to the design details on the PDA from the date of issuance. Any design changes will require a revision to the PDA.
- iii)* Manufacturer/designers with existing PDAs for other equipment or components, not specified in 3-2/Tables 1, 3, 5, 7, and 9, will be specially considered.

3.3 Manufacturer’s Affidavit of Compliance (MAC)

- i)* Manufacturers are required to provide a written affidavit of compliance stating that their products are designed, manufactured, assembled and tested in accordance with specified codes, standards, or specifications, and the additional requirements of this Guide, as applicable. The codes, standards or specifications must be stated in the manufacturer’s affidavit of compliance.
- ii)* The manufacturer’s affidavits of compliance are to accompany the systems, subsystems or equipment placed onboard drilling units and are to be verified by Surveyors prior to final Classification of the drilling system.
- iii)* See Appendix 2 for an example of manufacturer’s affidavit of compliance and its contents.

3.5 Extension of Approval

- i)* If drilling systems and equipment have been previously approved by ABS, the manufacturer can request extension of approval for a new project (vessel specific), clearly stating that no changes have been made to the equipment and/or components from the previous approval. If the new vessel(s) are contracted to later versions of the ABS Rules, Guides, and/or standards referenced therein, documentation justifying compliance with the new requirements will need to be submitted, as applicable. If changes are made to the previously approved design, refer to 3-2/3 of this Guide.

Upon completion of the review of the requested extension, an approval letter will be issued for the new vessel specific project.

- ii)* If changes are made from previously approved systems and equipment, documentation identifying and justifying the changes, as well as any documentation that supersedes or replaces previously approved documentation is required to be submitted for ABS review and approval.

5 ABS Survey

5.1 Survey at Vendor’s Plant

- i)* Surveyor’s attendance is required at the plant of manufacturing for drilling system, subsystems, equipment, and/or components approval, as indicated in 3-2/Tables 1, 3, 5, 7, and 9, and in accordance with Chapter 7, Section 2.
- ii)* In 3-2/Tables 2, 4, 6, 8, and 10, and Appendix 7, Table 1, “Factory Acceptance Testing” is to be performed for the system/subsystem/equipment/component level as required by the design codes and standards, and as specified in this Guide. This is to include, but not limited to, as applicable:
 - a)* Prototype testing, as required by the design codes or manufacturer specifications
 - b)* Hydrostatic pressure test
 - c)* Load testing

- d) Post-test NDE
 - e) FMECA verification trials
 - f) Function testing
- iii) Test procedures are required for testing of CDS systems and equipment as required by this Guide, and are to be submitted to the ABS technical office in association with the design review. Test procedures are to include procedures for design validation testing per the design specification and the testing to be carried out both during and at completion of manufacturing and for installation/commissioning on board, where applicable. All testing is required to be completed prior to issuance of the CDS Classification. Test procedures requiring submittal include, but are not limited to the following:
 - a) Factory Acceptance Tests (FATs)
 - b) Factory Integration Tests (FITs)
 - c) System Integration Tests (SITs)
 - d) Commissioning Procedures
 - e) FMECA Verification test Procedures
 - f) Any additional test procedures as identified during the design review.
- iv) Where final testing requires assembly and installation on-board a facility, a partial survey report will be issued by the attending Surveyor for the work and partial testing completed at the manufacturing facility. After final testing on board, the attending Surveyor will issue the final survey reports or CoC as applicable.

5.2 ABS Marking on Finished Components and Equipment (2021)

All finished component/equipment issued with unit certificates are to be permanently marked at an accessible location for identification and traceability. The identification shall include but not limited to the model number or part number, serial number and other data that may be necessary to comply with any other ABS Rule requirements.

At the request of the manufacturer, an ABS Marking may be applied. The marking shall include the ABS mark (⌘) and a unique identification number generated by ABS.

An example of ABS marking: ⌘ 123456.

Markings are to be permanently marked (i.e. steel-die-stamped, laser etched, etc.) at an accessible location by the manufacturer on each finished component or equipment.

ABS Certificates for the components and equipment are to be provided to the responsible party (e.g. owner or shipyard) and Surveyor at installation.

5.3 Survey during Installation and at Commissioning

- i) ABS Survey for the installation and commissioning of drilling systems is to be performed in accordance with Chapter 7, Sections 3 and 5 and in accordance with the approved test plans.
- ii) In 3-2/Tables 2, 4, 6, 8, and 10, “On Board Testing” typically covers the testing of the assembled or integrated systems/subsystems/equipment/component. This is to include, but not limited to, as applicable:
 - a) Hydrostatic pressure test to rated working pressure
 - b) Functional testing
 - c) Load test to the rated load of the assembled unit
 - d) FMEA/FMECA trials

7 Issuance of Certificates and Reports

7.1 ABS Approval Letter and Survey Reports

- i)* Upon satisfactory completion of the ABS design review process, based on design plans and data as specified in Appendix 7, an ABS approval letter will be issued for the components indicated in 3-2/Tables 1, 3, 5, 7 and 9.
- ii)* The ABS approval letter will describe the scope and results, including any applicable comments and correspondences for the design review performed of the submitted design plans and data, and the specified engineering criteria. The approved rating and/or capacity will be indicated for each system, subsystem, equipment or component in the ABS approval letter.
- iii)* Upon satisfactory completion of fabrication, testing and commissioning as applicable, the attending Surveyor will issue appropriate survey report(s) (SR) for all survey activities as specified in 3-2/Tables 1 through 10, and Chapter 7.

7.3 IRC and CoC

- i)* Upon satisfactory completion of the ABS design review process and issuance of the ABS approval letter, based on the design plans and data as specified in Appendix 7 for critical well control equipment or components, an Independent Review Certificate (IRC) will be issued when indicated in 3-2/Table 3, in conjunction with the ABS approval letter.
- ii)* The IRC will describe the scope and results of the design review performed by ABS for the submitted design plans and data, and the specified engineering criteria. The approved rating and/or capacity will be indicated for each system, subsystem, equipment or component covered by the certificate. IRCs are issued for equipment model/part number.
- iii)* At the discretion of the ABS Technical office, an IRC may be issued for equipment not requiring an IRC if specifically requested by the manufacturer, the owner or the purchaser. For this purpose, IRCs apply to equipment reviews and are not issued for assemblies (example: BOP stack) made up of equipment requiring dedicated approvals.
- iv)* Upon issuance of an ABS approval letter, an IRC, and satisfactory completion of the required testing and survey, a Certificate of Conformity (CoC) will be issued when indicated in 3-2/Table 3.
- v)* The CoC will affirm that, at the time of assessment and/or survey, the systems, subsystems, equipment, and/or components met the applicable codes and standards, and the requirements of this Guide with respect to design, manufacturing and testing.
 - a)* CoCs are issued for each individual equipment manufactured/fabricated, based on equipment serial number, and
 - b)* CoCs are to be correlated to the IRC for the specific equipment model/part number.
- vi)* Appendix 3 and Appendix 4 provide examples of IRC and CoC, respectively.
- vii)* The contents of the IRC and CoC are to be specific to the equipment and its respective design parameters.

7.5 Individual Equipment Approval: Non-Class Installation

If specifically requested by the manufacturers, Owner, or designers, ABS can provide approval of individual equipment or components associated with drilling systems or subsystems in accordance with the requirements of this Guide, and where the installation unit may not be classed with ABS.

- i)* The individual equipment approval processes are outlined in 3-2/3.
- ii)* The final installation and commissioning surveys, as outlined in this are the responsibility of the requesting party.

9 Project Management and Vendor Coordination Program

CDS Classification projects are to be coordinated through the ABS Project Management and Vendor Coordination Program in order to facilitate the efficient progression of the ABS technical and survey approval processes. The contracting party is required to contact the respective ABS division office where project coordination will take place for guidance on the process, primary contacts and role responsibilities.

- i)* At the initiation of the project, the contracting party (Builder/ Shipyard/ Owner) is to provide a list of equipment that will make up the CDS Class project using this Guide for reference.
- ii)* The suppliers and associated expected delivery dates are to be provided by the contracting party upon issuance of the purchase orders for the listed equipment.
- iii)* The listing of CDS equipment will be made available to the key personnel associated with the project.
- iv)* Milestone tasks in the coordination project will be developed by the ABS Division office lead and contracting party together with roles and responsibilities to assure each milestone is achieved and communications are maintained. Upon completion of each task the responsible team member is to update the Division Office lead for updating the program data. Deviations from the plan are to be advised to the ABS Division office and communicated to all stakeholders in order to minimize disruption to the process.
- v)* Periodic status reports will be provided as agreed between the ABS Division Office and the contracting party.

TABLE 1
Common Equipment and Components (Design Review/Survey)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Pressure Vessels	Pressure Vessels and Heat exchangers etc. ID > 150 mm (6 in.)	X	X		Material testing witness not required by Surveyor, Compliance with 6-1-1/1 of the <i>ABS MOU Rules</i> required		4/5
	Pressure Vessels and Heat exchangers etc. ID ≤ 150 mm (6 in.)				MAC		1
	Non-cylindrical pressure vessels and heat exchangers	X	X		Consult ABS Engineering on actual design requirements	662	4/5
	Seamless accumulators	X	X		Compliance with 6-1-5/1.1 of the <i>ABS MOU Rules</i> required		4/5
	Seamless accumulators ID ≤ 150 mm (6 in.) or design pressure < 6.9 bar				MAC		1
	Weld fabricated accumulators	X	X		Material testing witness not required by Surveyor, Compliance with 6-1-5/1.1 of the <i>ABS MOU Rules</i> required		5
Hydraulic Cylinders	Hydraulic Cylinders (critical component in the load path) including piston rods	X	X		Example: Used in luffing, folding and telescoping in load handling. Refer to 2-6/25 of the <i>Lifting Appliance Guide</i>		4/5
	Hydraulic Cylinders (non-critical component)				MAC		1

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Skid Structures	Skid Support Structure and integrated lift attachments	X	X		If required by 2-7/11		5
Lifting Attachment	Lift Attachments per 2-6/3.5i), ii), ii), and vi)	X	X		Safe Working Load Proof Load < 20 tons 25% in excess 20-50 tons 5 tons in excess > 50 tons 10% in excess		5
	Lift Attachments per 2-6/3.5iv), v)				No requirements for CDS		
Control Systems	Defined separately in the table for each system/equipment						
Hydraulic Power Unit (HPU)	Hydraulic Power Unit (HPU)	X	X				5
	Pressure Relief Valve				MAC		1
Loose Gear, Sheaves, Hooks, Hook Blocks, Wire Rope, and Pulleys	Drilling Line				MAC	9A, 9B	1
	Wire Rope				MAC	9A, 9B	1
	Sand Line				MAC	9A, 9B	1
	Loose Gear, Hooks, Hook Blocks, and Pulleys				Refer to Chapter 2, Section 5 of <i>Lifting Appliance Guide</i>		
Base Mounted Winches	Base Mounted Winches	X	X		Non-manriding		4/5
Electrical Systems	Electrical Systems and Components				See Chapter 2, Section 7		
Piping and Conduit (Rigid and Flexible)	Piping System Components				MAC See Chapter 4, Section 1		1
	Expansion Joints	X			See Chapter 4, Section 1		2
	Interconnecting Piping	Design review and testing to be in accordance with 6-1-6/Table 1 (except for “Material tests to be witness by Surveyor”) of the ABS <i>MOU Rules</i>					
Internal Combustion Engines	Internal Combustion Engines				Refer to Part 6 and Part 8 of the ABS <i>MOU Rules</i> (Drilling Service)		

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Gears, Shafts and Couplings	Rated power \geq 100 kW and used in the critical load path	X	X				4/5
	Rated power < 100 kW and used in the critical load path	X			MAC		2
	Rated power < 100 kW and not used in the critical load path				MAC		1
Rotating Electric Motors and Rotating Electrical Machines	Rated power < 100 kW and used in the critical load path	X			MAC		2
	Rated power < 100 kW and not used in the critical load path				MAC		1
	Rated power of \geq 100 kW (all applications)	X	X		Refer to Part 6 of the ABS <i>MOU Rules</i>		4/5
Hydraulic Motors	Located in the critical load path	X			MAC		2
	Located in a non-critical load path				MAC		1
Pumps	Support systems for hydraulic pumps				MAC		1

Notes:

- "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. A COC is also required where indicated. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For optional ABS Type Approval Tiers see Appendices 1-1-A2 and 1-1-A3 of the *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Refer to Chapter 8 of this Guide for quality system requirements.
- Safety clamps capable of being used as hoisting equipment require proof testing for each production unit, reference API 8C.
- MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. An MAC is required for all equipment listed in these tables.
- Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- Common equipment tables apply to all CDS equipment tables (WCS, DSD, DSC, and DSP systems).

TABLE 2
Common Equipment and Components (Testing)

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Pressure Vessels	Pressure Vessels and Heat exchangers, etc. ID > 150 mm (6 in.)	HPT	RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
	Pressure Vessels and Heat exchangers, etc. ID ≤ 150 mm (6 in.)		RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
	Non-cylindrical pressure vessels and heat exchangers	HPT	RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
	Seamless Accumulators	HPT	RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
	Seamless Accumulators ID ≤ 150 mm (6 in.) or design pressure < 6.9 bar		RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
	Weld Fabricated Accumulators	HPT	RWP/FT		Function testing with assembled systems. See Section 6-1-5 of the <i>ABS MOU Rules</i>	
Hydraulic Cylinders	Hydraulic Cylinders (critical component in the load path)	HPT	RWP/FT			
	Hydraulic Cylinders (non-critical component)		FT			
Skid Structures	Skid Support Structure and integrated lift attachments	LT			If required under 2-7/11.3	
Lifting Attachments	Lift Attachments per 2-6/3.5i), ii), ii), and vi)	LT	LT		LT at applicable location. SWL to be marked. Safe Working Load Proof Load < 20 tons 25% in excess 20-50 tons 5 tons in excess > 50 tons 10% in excess	
	Lift Attachments per 2-6/3.5iv), v)				No requirements for CDS	
Control Systems	Defined separately in the table for each system/equipment					

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Hydraulic Power Unit (HPU)	Hydraulic Power Unit	HPT/FT	RWP/FT			
	Pressure Relief Valve				Function testing with assembled systems	
Loose Gear, Sheaves, Hooks, Hook Blocks, Wire Rope, and Pulleys	Drilling Line		FT		FT with associated system	9A, 9B
	Wire Rope		FT		FT with associated system	9A, 9B
	Sand Line		FT		FT with associated system	9A, 9B
	Loose Gear, Hooks, Hook Blocks, and Pulleys		FT		FT with associated system	
Base Mounted Winches	Base Mounted Winches	LT/FT	LT/FT		Non-manriding; see 7-3/3 for additional testing requirements	
Electrical Systems	Electrical Systems and Components				Design review and testing in accordance with 6-1-7/Table 1 of the <i>ABS MOU Rules</i>	
Piping and Conduit (Rigid and Flexible)	Piping System Components		FT		Per applicable standard	
	Expansion Joints		FT		Per applicable standard	
	Interconnecting Piping (welded)	Design review and testing to be in accordance with 6-1-6/Table 1 (except for “Material tests to be witness by Surveyor”) of the <i>ABS MOU Rules</i>				
Internal Combustion Engines	Internal Combustion Engines				Refer to Part 6 of the <i>ABS MOU Rules</i>	
Gears, Shafts and Couplings	Rated power ≥ 100 kW and used in the critical load path	FT	FT		Function testing with assembled systems	
	Rated power < 100 kW and used in the critical load path		FT		Function testing with assembled systems	
	Regardless of rated power and not used in the critical load path		FT		Function testing with assembled systems	
Rotating Electric Motors and Rotating Electrical Machines	Rated power < 100 kW and used in the critical load path		FT		Function testing with assembled systems	
	Rated power < 100 kW and not used in the critical load path		FT		Function testing with assembled systems	
	Rated power of ≥ 100 kW (all applications)	FT	FT		Refer to Part 6 of the <i>ABS MOU Rules</i>	

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Hydraulic Motors	Located in the critical load path		FT			
	Located in a non-critical load path		FT		Function testing with assembled systems	
Pumps	Support systems for hydraulic pumps		FT		Function testing with assembled systems	

Notes:

- 1 Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can only be completed at installation due to the nature of the system, same is to be noted in the test plans. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- 2 For design validation, design validation testing may be required per the applicable design code. DVT on critical items per API 16A require Surveyor witness.
- 3 Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.

Types of Test

HPT	Hydrostatic Proof Test per design specification
RWP	Design Rated Working Pressure
FT	Function Test (operational tests without load/pressure applied)
HT	Hydrostatic Test to over flow or vent height
LT	Load Test as specified in the approved test plan.
MAC	Manufacturers Affidavit of Compliance
VT	FMEA/FMECA Validation testing

TABLE 3
Well Control Systems (CDS-WCS notation) (Design Review /Survey)
(1 February 2021)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Blowout Preventer Equipment	BOP System (including LMRP)	X	X	X			
	Blowout Preventer Stack	X	X			16A, S53 for assembly	5
	BOP Stack and LMRP Structural Frame	X	X		See 2-3/3.1viii) for applicable standards		5
	Ram BOP Assembly	IRC	COC			16A, S53	5
	• Ram BOP Body	IRC	COC			16A, S53	5
	• Bonnet/Door Assembly	IRC	COC			16A, S53	5
	• Ram Blocks	X	X			16A, S53	5
	Annular BOP	IRC	COC			16A, S53	5
	BOP Stack Mounted Choke & Kill Valves	IRC	COC		Including gas bleed, test, outlet	6A, 16C, S53	5
	Loose Flanges/ End Fittings	X	X			6A/16A, S53	4/5
	Clamps	IRC	COC			16A, 6A, 16C, S53	5
	Drilling and Adapter Spools	IRC	COC			16A, 6A, 16C, S53	5
	Wellhead and LMRP/BOP Connector	IRC	COC			16A, 6AF2, S53	5
	LMRP Mandrel (connector spool)	IRC	COC			16A, S53, 6AF2	5
Lower Marine Riser Package – LMRP may include Annular BOP and Connector as addressed in BOP Equipment	LMRP System	X	X	X			
	Jumper Lines for Flex/ Ball Joints	X	X			16F, 16C, 16D, 7K	4/5
	Riser Adapter	X	X			16A, 16F, 16R, 6AF2	5

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Diverter System	Diverter System	X	X	X			
	Diverter Assembly (Housing + Insert)	X	X			16F, 64	5
	Overshot Mandrel, Spool and Packers	X	X			16F, 64	4/5
	Piping and Pipe Fittings	X	X			6A, 64	5
	Valves	X	X			6D, 64	5
Auxiliary Well Control Equipment	IBOP	X	X			7, 7G	4/5
	Drill Pipe Safety Valves, Drill String Float Valves, Non-return (NR) Valve in drill String (IBO)	X	X			7, 7G	4/5
	Burner/Flare Boom	X	X			7, 7G	5
	Burner/Flare Piping				MAC		1
	Burner/Flare Control Panel	X	X	X			5
Marine Drilling Riser	Riser System	X	X				
	Flex/Ball Joint	X	X			16F	4/5
	Riser Joints	X	X			16F	4/5
	• Couplings	X	X			16R	4/5
	• Riser Components	X	X			16F, 16Q, 16R	4/5
	Special Equipment/ Components/ Joints as defined per API 16F	X	X			16F, 16Q, 16R	4/5
	Buoyancy Equipment				MAC	16F, 16Q	1
	Riser Joint Lift Attachments	X	X			16F	4/5
	Telescopic Joint (Slip Joint)	X	X			16F	4/5

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Riser and Guideline Tensioning	Tensioning Systems	X	X				
	Pod Line & Guideline Tensioners	X	X			16F, 16Q	5
	Riser Recoil System	X	X			16F, 16Q	5
	Tensioner Ring	X	X			16F	5
	Riser Tensioning Unit	X	X			16F	5
	Telescopic Arms	X	X				5
	Sheaves	X	X			8C	4/5
	Nitrogen Generator	X	X				5
	Compressor Skid	X	X			617	5
	Dryer Skid	X	X				5
	Control Systems	X	X	X		16F, 16Q	5

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Choke and Kill System including MGS	Choke and Kill System	X	X	X			
	Cement Pump (Power End: Prime Mover)				MAC: See 2-5/7.1viii) of this Guide and 8-2-1/5.1 of the ABS <i>MOU Rules</i>		1
	Cement Pump (Power End: Gears/Couplings)				MAC: See 2-5/7.1ix)	7K	1
	Cement Pump (Fluid End)	X	X			7K	5
	Cement Pump Relief Valve	X	X			7K	5
	Choke and Kill Connectors	X	X			16C	5
	Choke and Kill Flexible Lines	X	X			16C	5
	Choke and Kill Articulated Lines	X	X			16C	5
	Union Connections and Swivel Connections	X	X			16C	5
	Choke and Kill Rigid Lines	X	X			16C	5
	Choke and Kill Drape Hoses	X	X			16C,16F,53	5
	Choke and Kill Manifold	X	X			16C	5
	Spools, Crosses and Tees	X	X			16C	5
	Buffer Chamber	X	X			16C	5
	Drilling Choke and Operator	X	X			16C	5
	Choke and Kill Valves	X	X			6A	5
	Mud-Gas Separator (Poor Boy)	X	X			16C,53	5

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Well Control Systems Controls	BOP and Diverter Control System including Emergency Disconnect for Subsea Applications	X	X	X		16D, 53, 64	5
	Choke and Kill Control System	X	X	X	Refer to Part 4 of the ABS <i>MOU Rules</i>	16C, 53	5
	Hoses: Surface hydraulic/ pneumatic				MAC	16D, 53, 64	1
	Hoses: Subsea	X	X			16D, 53	4/5
	Hoses: Moonpool Hotline Drape	X	X			16D, 53, 64	4/5
	Pressure Compensating Accumulators	X	X			16D	4/5
	Mux Reel	X	X			16D, 53, 64	4/5
	Hose Reels	X	X			16D, 53, 64	4/5
	Umbilical Sheave	X	X			16D, 53, 64	4/5
	BOP stack control system equipment and system level testing	X	X		System Integration Testing (SIT)	16D, 53, 64	5
Secondary Controls	Acoustic Control System	X	X	X		16D, 53	5
	ROV Panel	X	X	X	Full documentation must be submitted with BOP/Diverter control system review even if separately approved	16D, 17H, 53	5

Notes:

- "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. A COC is also required where indicated. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For optional ABS Type Approval Tiers see Appendices 1-1-A2 and 1-1-A3 of the ABS *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Refer to Chapter 8 of this Guide for quality system requirements.
- IRCs and COCs are issued for the listed equipment only. IRCs are issued part number specific. COCs are issued part number and serial number specific.
- For equipment common to all systems, see 3-2/Table 1.
- Tabular listing of API references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. An MAC is required for all equipment listed in these tables.
- For a description of CDS sub class notations see 1-2/3.

TABLE 4
Well Control System (CDS-WCS notation) (Testing)

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Blowout Preventer Equipment	BOP System (including LMRP)	NA	FT	VT		16D and 53
	Blow Out Preventer Stack	RWP/FT	RWP/FT			53 and 16A
	BOP Stack and LMRP Structural Frame	LT			Load Test padeyes to be used for routine lifting and handling at 1.25 times padeye SWL	
	Ram BOP Assembly	HPT/ RWP/FT	RWP/FT			16A, 53
	• Ram BOP Body	HPT	RWP			16A, 53
	• Door Assembly	HPT	RWP			
	• Ram Blocks	NA	RWP/FT		Test with assembly per API 16A	
	Annular BOP	HPT/ RWP/FT	RWP/FT		HPT is shell test only without elastomers	6A, 53
	BOP Stack Mounted Choke & Kill Valves	HPT/FT	RWP/FT			6A, 16C, 53
	Loose Flanges/End Fittings	NA	RWP		Tested with the Equipment installed upon in accordance with appropriate standard	6A, 16A, 53
	Clamps	HPT	RWP			6A, 16A
	Drilling and Adapter Spools	HPT	RWP		Load/Capacity to be documented in accordance with API 6AF. RWP performed with assembled Stack	16A
	Wellhead and LMRP/BOP Connector	HPT/ RWP/FT	RWP/FT		HPT is shell test only without elastomers	16A
	LMRP Mandrel (connector spool)	HPT	RWP		Testing per design standard	16A, 53

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Lower Marine Riser PackageL MRP may include Annular BOP and Connector as addressed in BOP Equipment	LMRP System	FT	FT	VT		
	Jumper Lines for Flex/Ball Joints	HPT	RWP			16F
	Riser Adapter	HPT/ RWP	RWP		Kick outs tested separately. Testing to design standard or approved procedure. On board testing is in conjunction with slip joint, drape hoses, on board rigid choke lines and manifold.	16A, 16F, 16Q
Diverter System	Diverter System	FT	FT	VT		
	Diverter Assembly (Housing + Insert)	HPT/ RWP/FT	RWP/FT		HPT is shell test only without elastomers	64
	Overshot Mandrel, Spool, and Packers	HPT	RWP		Test in Accordance with approved procedures. HPT is shell test only without elastomers	
	Piping and Pipe Fitting	NA	FT			64
	Valves	FT/HPT	FT/RWP			64
Auxiliary Well Control Equipment	IBOP	HPT/ RWP/FT	FT		HPT is shell test only without elastomers	7-1
	Drill pipe safety valves, Drill string float valves, Non-return (NR) valve in drill strings (IBO)	HPT/ RWP/FT	FT		HPT is shell test only without elastomers	7-1
	Burner/Flare Boom	RWP/FT	FT			
	Burner/Flare Piping		FT			
	Burner/Flare Control Panel	FT	FT	VT		

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Marine Drilling Riser	Riser System	NA	FT			
	Flex/Ball Joint	HPT	FT			16F
	Riser Joints	HPT	RWP		“HPT” – Auxiliary, choke and kill lines.C&K lines, Mud Booster, Hydraulic Lines – See applicable sections.	16F, 16R, 16Q
	• Couplings	NA			Design Testing	16R
	• Riser Components	HPT			Auxiliary line only	16F, 16Q, 16R
	Special Equipment/ Components/ Joints as defined per API 16F				Testing per design specification	16F, 16Q, 16R
	Buoyancy Equipment					16F, 16Q,
	Riser Joint Lift Attachments	LT				16F
	Telescopic Joint (Slip Joint)	HPT	FT		Prototype load test of locking mechanism at 1.25 x maximum design loads. HPT is shell test only without elastomers	16F, 16Q
Riser & Guide Line Tensioning	Tensioning Systems	NA	FT			
	Pod Line & Guideline Tensioners	HPT/FT	RWP/FT			16F, 16Q
	Riser Recoil System	FT	FT			
	Tensioner Ring	LT	FT		LT pad eyes at 1.25 x padeye design SWLProduction load Test as follows: 1) Each diametrically opposed pair of pad eyes and to include bearing shoulder 2) See “Lifting Attachments” for test loads	16F
	Riser Tensioning Unit	HPT/FT	RWP/FT			16F
	Telescopic Arms	HPT/FT	RWP/FT			
	Sheaves	FT	FT		Load Test and NDE	8C
	Nitrogen Generator	HPT/FT	RWP/FT			
	Compressor Skid	HPT/FT	RWP/FT			617
	Dryer Skid	HPT/FT	RWP/FT			16F, 16Q

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Choke and Kill System including MGS	Choke and Kill System	NA	FT	VT		
	Cement Pump (Power End: Prime Movers and Gears)				See 8-2-1/5.1 of the ABS <i>MOU Rules</i>	
	Cement Pump (Fluid End)	HPT	RWP/FT			7K
	Cement Pump Relief Valve	HPT/FT	FT			7K
	Choke and Kill – Connectors	HPT	RWP			16C, 53
	Choke, Kill Flexible Lines	HPT	RWP			16F, 53
	Choke & Kill Articulated Lines	HPT	RWP			16C, 53
	Union Connections and Swivel Connections	HPT	RWP			16C, 53
	Choke and Kill Rigid Lines	HPT	RWP			16C, 53
	Choke and Kill Drape Hoses	HPT	RWP			16C, 16F, 53
	Choke and Kill – Manifolds	HPT	RWP			16C, 53
	Spools, Crosses, Tees	HPT	RWP		On Board Test with Manifold (See Manifold comment)	16C, 53
	Buffer Chamber	HPT	RWP		On Board Test with Manifold (See Manifold comment)	16C, 53
	Drilling Choke and Operator	HPT/FT	RWP/FT			16C, 53
	Choke and Kill Valves	HPT/FT	RWP/FT			6A, 53
	Mud-Gas Separator (Poor Boy)	HPT/FT	FT			16C, 53

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Well Control Systems Controls	BOP and Diverter Control System including Emergency Disconnect for Subsea	HPT/FT	Function Test as Assembly	VT		16D, 64
	Choke and Kill Control System	FT	Function Test as Assembly	VT		16C
	Hoses: Surface hydraulic/pneumatic		Function Test as Assembly			16D
	Hoses: Subsea	HPT	Function Test as Assembly			16D
	Hoses: Moonpool Hotline Drape	HPT	Function Test as Assembly			16D
	Pressure Compensating Accumulators	HPT	Function Test as Assembly			16D
	Mux Reel	FT	Function Test as Assembly			16D
	Hose Reels	HPT/FT	Function Test as Assembly			16D
	Umbilical Sheave	FT	Function Test as Assembly			16D
	BOP stack control system equipment and system level testing	HPT/FT	HPT/FT			16D, S53, S64
Secondary Control Systems	Acoustic Control System	FT	FT	VT		16D
	ROV Panel	HPT	RWP/FT	VT		16D, 53, 17H

Notes:

- 1 Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can only be completed at installation due to the nature of the system, same is to be noted in the test plans. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- 2 Well Control Components are to be tested in accordance with tests specified by the Manufacturer and this Guide. Low pressure and rated working pressure tests are required at Installation/Commissioning testing on board. Refer to API 53 for low pressure testing criteria.
- 3 For design validation, design validation testing may be required per the applicable design code. DVT on critical items per API 16A require Surveyor witness.
- 4 For equipment common to all systems, see the 3-2/Table 2.
- 5 Tabular listing of API references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- 6 Where multiple tests are indicated (e.g., HPT/RWP/FT), all tests are required
Types of Tests

HPT	Hydrostatic Proof Test per design specification
RWP	Design Rated Working Pressure
FT	Function Test (Operational Tests without load/pressure applied)
LT	Load Test as specified in the approved test plan.
VT	FMEA/FMECA Validation Testing
- 7 For a description of CDS sub class notations, see 1-2/3.

TABLE 5
Derrick Systems (CDS-DSD notation) (Design Review/Survey)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Riser Running Equipment	Riser Handling System	X	X				
	Gimbal (or Shock Absorber) assembly	X	X			16F	5
	Gimbal (fixed) assembly	X	X			16F	5
	Riser Spider (For use as elevators/lifting)	X	X			8C	4/5
	Riser Spider (fixed)	X	X			16F	5
	Riser Hang Off unit (Not capable of lifting)	X	X			16F	5
	Riser Test/Running Tool	X	X		(If used to handle or land BOP)	16F	5
	Diverter Test/Running Tool	X	X		(If used to land BOP)	16F	5
	Control Systems	X	X	X			5

Compensation Support Equipment	Compensation Systems	X	X				
	Nitrogen Generator	X	X				5
	Compressor Skid	X	X				5
	Dryer Skid	X	X				5
	Sheaves	X	X			8C	4/5
In-Line Heave Compensator	Heave Compensation Systems	X	X				
	Compensator Assembly	X	X			8C	5
	Hose Bundle				MAC		1
	Control Systems	X	X	X			5
Crown Mounted Compensator	Traveling Frame and Guides	X	X			4F,8C	5
	Drill Line Compensation	X	X			8C, 9B	5
	Control Systems	X	X	X			5
Derrick and Masts	Structure with Guide Tracks	X	X			4F	5
	Support Beams	X	X			4F	5

Hoisting	Hoisting Systems	X	X				
	Crown Block	X	X			4F	5
	Crown Block Sheaves	X	X			4F	5
	Deadline Anchors	X	X			8C	5
	Dolly for Traveling Assembly	X	X			8C	5
	Drawworks	X	X			7K	5
	Drawworks Control Systems	X	X	X			5
	Drill and Wire Line Spoolers				MAC		1
	Elevators	X	X			8C	4/5
	Kelly Spinner (If used as lifting or hoisting equipment)	X	X			8C	4/5
	Links	X	X			8C	5
	Power Swivel/Top Drive	X	X		MAC on Gears and Couplings	8C	5
	Top Drive Control System	X	X	X			5
	Rotary Swivel	X	X		MAC on Gears and Couplings	8C	5
	Sheaves	X	X			8C, 7K, 9B	4/5
	Traveling Block	X	X			8C	5
	Hook Block	X	X			8C	5

Notes:

- "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For optional ABS Type Approval Tiers see Appendices 1-1-A2 and 1-1-A3 of the *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Refer to Chapter 8 of this Guide for quality system requirements.
- Safety clamps capable of being used as hoisting equipment require proof testing for each production unit, Reference API 8C.
- For equipment common to all systems, see 3-2/Table 1.
- Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. An MAC is required for all equipment listed in these tables.
- For shafts gears and couplings associated with hoisting equipment subject to design review, refer to 2-9/9.7.
- For a description of CDS sub class notations, see 1-2/3.

TABLE 6
Derrick Systems (CDS-DSD notation) (Testing)

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Riser Running Equipment	Riser Handling System	NA	FT			
	Gimbal (or Shock Absorber) assembly	FT/LT	FT		1.5x rated load in axial direction	16F
	Gimbal (fixed) assembly	FT/LT	FT		1.5x rated load in axial direction	16F
	Riser Spider (For use as elevators/lifting)	FT/LT	FT		1.5x rated load in axial direction	16F
	Riser Spider (fixed)	FT/LT	FT		1.5x rated load in axial direction	16F
	Riser Hang Off unit (Not capable of lifting)	FT/LT	FT		1.5x rated load in axial direction unless waived by technical qualification	16F
	Riser Test/Running Tool	HPT/FT/LT	FT		As per design approval and standards	16F
	Diverter Test/Running Tool	HPT/FT/LT	FT		As per design approval and standards	16F
	Control Systems	FT	FT	VT	A function test at the manufacturer plant to the extent possible	
Compensation Support Equipment	Compensation Systems	NA	FT			
	Nitrogen Generator	HPT/FT	RWP/FT			
	Compressor Skid	HPT/FT	RWP/FT			617
	Dryer Skid	HPT/FT	RWP/FT			
	Sheaves	LT	FT			8C
Conductor Tensioning Unit	Conductor Tensioning System	NA	FT			
	Conductor Tensioning Unit	HPT/FT	RWP/FT			16F
	Control System	FT	FT	VT		16F
In-Line Heave Compensator	Heave Compensation Systems	NA	FT			
	Compensator Assembly	HPT/FT	RWP/FT			8C
	Hose Bundle					
	Control System	FT	FT	VT		16F

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Crown Mounted Compensator	Traveling Frame and Guides	FT	FT			4F, 8C
	Drill Line Compensation	FT	FT			8C, 9B
	Control System	FT	FT	VT		16F
Derrick and Masts	Structure with Guide Tracks	FT	FT		FT per vendor facility capability	4F
	Support Beams	FT	FT		Design verification testing per design standard	4F
Hoisting	Hoisting Systems	NA	FT			
	Crown Block	FT	FT		Design verification testing per design standard	8C
	Crown Block Sheaves	NA	FT			8C
	Deadline Anchors	FT	FT			8C
	Dolly for Traveling Assembly	FT	FT			4F, 8C

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Hoisting (continued)	Drawworks	FT/LT	FT/LT		<p>1) Caliper brake (Mechanical) tests at 100% of rated motor torque or static single line load test – 1.25 x rated load of the fast line pull rating, one time.</p> <p>2) Other testing per Chapter 7</p> <p>3) On board testing to approved commissioning procedures.</p>	7K
	Drawworks Control Systems	FT	FT	VT		
	Drill and Wire Line Spoolers		FT			
	Elevators	LT	FT			8C
	Kelly Spinner (if used as lifting or hoisting equipment)	FT/LT	FT			8C
	Links	LT				8C
	Power Swivel/Top Drive	HPT/FT	RWP/FT		HPT 2X RWP where RWP is 5000 psi or less. Otherwise 1.5	8C
	Top Drive Control Systems	FT	FT	VT	FMEA validation tests required	
	Rotary Swivel	HPT/FT	RWP/FT		HPT 2X RWP where RWP is 5000 psi or less. Otherwise 1.5	8C
	Sheaves	NA	FT		As part of system	8C, 9B
	Traveling Block	FT			Design verification testing per design specification. Unit LT when specified in approved procedures	8C
	Hook Block	FT	FT		Design verification testing per design specification. Unit LT when specified in approved procedures	8C

Notes:

- 1 Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can only be completed at installation due to the nature of the system, same is to be noted in the test plans. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- 2 For design validation, design validation testing may be required per the applicable design code. DVT on critical items per API 16A require Surveyor witness.
- 3 For equipment common to all systems, see 3-2/Table 2.
- 4 Where multiple tests are indicated (e.g., FT/HPT/RWP), all tests are required.
- 5 Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
Types of Test

HPT	Hydrostatic Proof Test per design specification
RWP	Design Rated Working Pressure
FT	Function Test (Operational tests without load/pressure applied)
HT	Hydrostatic Test to over flow or vent height
LT	Load Test as specified in the approved test plan.
VT	Verification Testing
- 6 For a description of **CDS** sub class notations, see 1-2/3.

Table 7
Drilling Fluid Conditioning Systems (CDS-DSC notation) (Design Review/ Survey)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Mud Circulation (LP)	LP Mud System	X	X		Refer to Part 6 of the ABS <i>MOU Rules</i>		
	Bulk Tanks	X	X			13C	5
	Independent Mud Tanks	X	X			13C	5
	Agitators for Drilling Fluid				MAC	682, 13C	1
	Mixing Hopper				MAC	682, 13C	1
	LP piping	X			On board assembly		5
	Mixing/transfer/ charging pumps				MAC		1
	Degasser	X	X			13C	5
	Desander/Desilter				MAC	13C	1
	Gumbo Box				MAC		1
	Mud Cleaner				MAC	13C	1
	Shale Shakers				MAC	13C	1
	Trip Tank	X	X			13C	5
	Control Systems	X	X	X	Refer to Part 4 of the ABS <i>MOU Rules</i>		5

Mud Circulation (HP)	HP Mud System	X	X				
	Circulation Head	X	X			7K	5
	Gooseneck, Swivel	X	X			8C	5
	Mud Pumps – Power End	X	X		See 3-2/Table 1 and Part 6 of the ABS <i>MOU Rules</i>	7K	5
	Fluid Ends – High Pressure	X	X			7K	5
	Pulsation Dampeners	X	X		See ASME Code		5
	HP Piping	X	X		ASME B31.3 or equivalent standard		
	Standpipe Manifold	X	X			6A	5
	Mud/Cement Hoses	X	X			6A	5
	Mud Pump Relief Valve	X	X			7K	5
	Control Systems	X	X	X	Refer to Part 4 of the ABS <i>MOU Rules</i>		5

Notes:

- "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For optional ABS Type Approval Tiers see Appendices 1-1-A2 and 1-1-A3 of the ABS *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*. Refer to Chapter 8 of this Guide for quality system requirements.
- For equipment common to all systems, see 3-2/Table 1.
- MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. An MAC is required for all equipment listed in these tables.
- Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- For a description of CDS sub class notations, see 1-2/3.

TABLE 8
Drilling Fluid Conditioning Systems (CDS-DSC notation) (Testing)

<i>System</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Mud Circulation (LP)	LP Mud System	NA	FT			
	Bulk Tanks	HPT	FT		Refer to Part 6 of the ABS MOU Rules	
	Independent Mud Tanks	HT	FT			13C
	Agitators for Drilling Fluid		FT			13C
	Mixing Hopper		FT			
	Degasser	HPT/FT	RWP/FT			13C
	Desander/Desilter		FT			13C
	Gumbo Box		FT			
	Mud Cleaner		FT			
	Shale Shakers		FT			13C
	Trip Tank	HT	FT			13C
	Control Systems	FT	FT	VT	Refer to Part 6 of the ABS MOU Rules	
Mud Circulation (HP)	HP Mud System	NA	FT			
	Circulation Head	HPT	RWP			7K
	Gooseneck, Swivel	HPT/FT	RWP			8C
	Mud Pumps – Power End	RWP/ FT	RWP/ FT			7K
	Mud Pump Fluid Ends	HPT	RWP/ FT			7K
	Pulsation Dampeners	HPT	RWP/ FT		Pre-charge verification/FT in system	
	HP piping system	HPT	HPT/FT		ASME B31.3 or equivalent standard	
	Standpipe Manifold	HPT	RWP/ FT			6A
	Mud/Cement Hoses	HPT	RWP			6A
	Mud Pump Relief Valve	HPT/FT	FT			
	Control Systems	FT	FT	VT	Refer to Part 6 of the ABS MOU Rules	

Notes:

- 1 Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can only be completed at installation due to the nature of the system, same is to be noted in the test plans. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- 2 For design validation, design validation testing may be required per the applicable design code. DVT on critical items per API 16A require Surveyor witness.
- 3 For equipment common to all systems, see 3-2/Table 2.
- 4 Where multiple tests are indicated (e.g., FT/HPT/RWP), all tests are required.

Types of Test

HPT	Hydrostatic Proof Test per design specification
RWP	Design Rated Working Pressure
FT	Function Test (Operational tests without load/pressure applied)
HT	Hydrostatic Test to over flow or vent height
LT	Load Test as specified in the approved test plan
VT	Verification Testing

- 5 Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- 6 For a description of **CDS** sub class notations, see 1-2/3.

TABLE 9
Handling Systems (CDS-DSP notation) (Design Review/Survey)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
Tubular Handling	Tubular Handling Systems	X	X				
	Bridge Crane	X	X				5
	Casing Stabbing Board	X	X				5
	Crane Type Lifting Equipment	X	X			2C	5
	Finger Board	X	X				5
	Horizontal to Vertical Lifting Equipment	X	X				5
	Hydraulic Cathead				MAC		1
	Iron Roughneck/Power Tongs				MAC	7K	1
	Pipe Racking Equipment	X	X				4/5
	Manipulator Arms	X	X				4/5
	Monkey Board	X	X				4/5
	Mousehole- Powered	X	X				5
	Mousehole - Fixed				MAC		1
	Tubular Chute	X	X				5
	Tubular Horizontal Transporter				MAC		1
	Tubular Horizontal Transporter Support Structure	X	X				5
	Power Slips (Hydraulic or Pneumatic)				MAC		1
	Tail-In Arm				MAC		1
	Tong Suspension				MAC		1
	Tong-Manual, for Tubular Handling				MAC		1
	Control Systems	X	X	X			5
Rotary	Rotary Table	X	X			7K	5
	Control Systems	X	X	X			5

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Design Review</i>	<i>Survey (at vendor)</i>	<i>FMEA</i>	<i>Comments</i>	<i>General API Reference (Informative)</i>	<i>Approval Tier Level See Note 2</i>
BOP Handling	BOP Handling System	X	X				
	Vertical Transporter	X	X				5
	Horizontal Transporter/ Skidder	X	X				5
	BOP Handling Crane	X	X				5
	Lifting attachments/ Padeyes serving as equipment foundations	X	X			2A WSD	5
	Control Systems	X	X	X			5

Notes:

- "Survey" requires the Surveyor attendance during fabrication, witness inspections and testing per rule requirements and design codes/standards in accordance with the agreed Inspection/Test Plan (ITP), verification to approved plans and issuance of a survey report. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For optional ABS Type Approval Tiers see Appendices 1-1-A2 and 1-1-A3 of the *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part I)*. Refer to Chapter 8 of this Guide for quality system requirements.
- Safety clamps capable of being used as hoisting equipment require proof testing for each production unit, reference API 8C.
- For equipment common to all systems, see 3-2/Table 1.
- Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- MAC (Manufacturer's Affidavit of Compliance) is a document certified by a competent authority of the manufacturer that the specified product meets the required specifications. An MAC is required for all equipment listed in these tables.
- For a description of CDS sub class notations, see 1-2/3.

TABLE 10
Tubular Handling Systems (CDS-DSP notation) (Testing)

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
Tubular Handling	Tubular Handling Systems	NA	FT			
	Bridge Crane	FT/LT	FT/LT			
	Casing Stabbing Board	FT	FT/LT			
	Crane Type Lifting Equipment	FT/LT	FT/LT			2C
	Finger Board	FT	FT			
	Horizontal to Vertical Lifting Equipment	FT/LT	FT/LT			
	Hydraulic Cathead		FT			
	Iron Roughneck/Power Tongs		FT			
	Pipe Racking Equipment	FT/LT	FT/LT			
	Manipulator Arms	FT	FT			
	Monkey Board	FT	FT			
	Mousehole - Powered	FT/LT	FT/LT		RWP of hydraulic Systems	
	Mousehole - Fixed		FT			
	Tubular Chute	FT	FT			
	Tubular Horizontal Transporter		FT		RWP of hydraulic Systems	
	Tubular Horizontal Transporter Support Structure	FT	FT		FT with transporter as unit	
	Power Slips (Hydraulic or Pneumatic)		FT			
	Tail-In Arm		FT			
	Tong Suspension		FT			
	Tong- Manual, for Tubular Handling		FT			
	Control Systems	FT	FT	VT		
Rotary	Rotary Table	FT	FT			7K
	Control Systems	FT	FT	VT		

<i>Systems</i>	<i>Components (All Notes apply)</i>	<i>Factory Testing</i>	<i>On Board Testing</i>	<i>FMEA Testing</i>	<i>Testing Remarks</i>	<i>General API Reference (Informative)</i>
BOP Handling	BOP Handling System	NA	FT			
	Vertical Transporter	FT/LT	FT		Functional LT with SWL or according to approved procedure	
	Horizontal Transporter/Skidder	FT/LT	FT		Functional LT with SWL or according to approved procedure	
	BOP Handling Crane	FT/LT	FT/LT		For LT see 2-7/5 of <i>Lifting Appliance Guide</i> or API 2C	
	Lifting Attachments/Padeyes serving as equipment foundations	LT	LT		LT at applicable location. SWL to be marked.Safe Working Load Proof Load< 20 tons25% in excess20-50 tons5 tons in excess>50 tons10% in excess	2A WSD
	Control Systems	FT	FT	VT		

Notes:

- Testing is required per the design specification and the applicable sections of this Guide and test plans are to be submitted to the Surveyor for review. At the discretion of the attending Surveyor, test plans may be required to be submitted for technical review. When specified, "Factory Acceptance Testing" can only be completed at installation due to the nature of the system, same is to be noted in the test plans. Chapter 7 details surveys at vendor's plant, during installation and commissioning.
- For design validation, design validation testing may be required per the applicable design code. DVT on critical items per API 16A require Surveyor witness.
- For equipment common to all systems, see 3-2/Table 2.
- Where multiple tests are indicated (e.g., FT/HPT/RWP), all tests are required.
Types of Test

HPT	Hydrostatic Proof Test per design specification
RWP	Design Rated Working Pressure
FT	Function Test (Operational tests without load/pressure applied)
HT	Hydrostatic Test to over flow or vent height
LT	Load Test as specified in the approved test plan.
VT	Verification Testing
- Tabular listing of API and Industry references are provided for general reference purposes only (informative). Other industry standards may provide an equal or better basis for design.
- For a description of CDS sub class notations, see 1-2/3.

CHAPTER 4 Drilling System Piping

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CHAPTER 4

Drilling System Piping

SECTION 1

General

1 General

This Section contains general requirements for piping systems and/or associated components that form part of the drilling systems.

- i)* Piping systems that are used for both marine and drilling services such as hydraulic piping, air piping, seawater service, potable water, power generation, etc., are to be in accordance with Part 4, Chapter 2 of the *ABS MOU Rules*.
- ii)* The manufacturer is to submit to ABS for approval P&IDs, piping specifications and material data, design plans and calculations for each piping system associated with the drilling systems and equipment listed in 3-2/Tables 1 through 10.
- iii)* Piping systems and components are to be designed and tested in compliance with ASME B31.3 and the applicable recognized codes and standards as specified in Chapter 2, Section 2.
- iv)* The above requirements are to be used for all drilling system piping and in conjunction with the specific requirements contained in Chapter 2 for individual subsystems used for drilling systems.
- v)* For requirements for over pressurization protection refer to 2-1/5

CHAPTER 4 Drilling System Piping

SECTION 2 Design Criteria

1 Piping Systems and Components

1.1 Design

- i) Piping and piping components are to be designed to withstand the maximum stress that could arise from the most severe combination of pressure, temperature, and other loads or service conditions as referenced in 4-2/1.3 below, and to be in accordance with codes and standards referenced in Chapter 4, Section 1.
- ii) For high-pressure ratings that are not within the scope of the referenced codes in Chapter 4, Section 1 above, pipe wall thickness calculations demonstrating suitability for the intended service are to be submitted for ABS review.
- iii) Pipe stress and flexibility analysis are to be performed in accordance with ASME B31.3 or other recognized design code for all applicable service and loading conditions for the following systems (including all associated piping, connection, manifolds, etc.):
 - a) Choke and kill systems
 - b) High-pressure mud and cement systems
 - c) Main Hoisting System (Hydraulic)
 - d) Burner/Flare piping system (permanent)
- iv) Expansion joints are to be in accordance with ASME B31.3 and the applicable recognized codes and standards as required by this Guide for the specific application. When used, non-metallic expansion joints or bellows in piping systems are to be provided with shields to prevent mechanical damage; are to be properly aligned and secured and are to comply with the requirements of 4-6-2/5.8 of the *ABS Marine Vessel Rules*.
- v) Piping Systems that may have the potential of exposure to pressure greater than for which they are designed are to be protected by suitable pressure protection devices. Pressure regulators are not to be used as a substitute for pressure relief devices.

1.3 Service Considerations

- i) The piping design is to account for, relative to the fluid being transported, internal and external pressures, transient vibrational stresses, fluid velocity and associated erosional effects, hydraulic hammer, transient temperature excursions, outside imposed impact forces and pressure pulsations, and low temperature service considerations, as applicable.

- ii) For surface BOP stack, all rigid lines between the control system and BOP stack are to comply with the following:
 - a) Fire test requirements of API 16D, including end connections
 - b) To have RWP equal to the RWP of the BOP control system, as applicable
- iii) For subsea BOP stack:
 - a) For fire resistance requirements refer to 4-2/7.3iii).
 - b) All rigid lines between the control system and BOP are to have RWP equal to the RWP of the BOP control system, as applicable.

1.5 Allowances

The design wall thickness of all piping is to account for, as applicable:

- i) Mill under-tolerances (12.5% of nominal piping thickness, unless otherwise stated in the material specification)
- ii) Allowances for threads
- iii) Corrosion/erosion allowance (unless an effective coating system is applied) is to be in accordance with specified design code/standard and 2-3/3.1, as applicable.
- iv) Fabrication tolerances

1.7 Alternative Criteria

- i) ABS is prepared to consider other applicable design references, alternative design methodology and industry practice for piping system and piping component designs, on a case-by-case basis, with justifications through novel features as indicated in Chapter 1, Section 5 of this Guide.
- ii) Piping components whose dimensions are not specified by recognized codes/standards, design details including dimensional drawings, stress calculations and material data are to be submitted for ABS review and approval.
- iii) The extent of NDE, service temperatures, material ductility and special fabrication methods are also to be considered for alternative design criteria.

3 Fitting and Valves

All piping components are to meet the applicable piping code and the additional requirements in this Section.

5 Piping Joints and Connections

5.1 General

- i) Piping joints and connections greater than 50 DN (2 in. NPS) are to be made by butt-weld, flanged or screwed union where the threads are not part of the sealing.
- ii) Box and pin joints for the choke and kill lines on drilling risers are acceptable.
- iii) SAE Code 61 and 62 (ISO 6162-1/ISO 6162-2) split flanges may be used, subject to the following minimum criteria:
 - a) The location of each split flange is to be identified, and catalogue cut sheets/manufacturers' specifications for each split flange shall be provided.
 - b) Split-flanges shall be installed internally only, shall not be subjected to external mechanical loading, and shall be an integral part of the system design (i.e., they shall be used only within skids/piping systems, in properly supported locations, and shall be protected from damage during drilling operations and day-to-day equipment movement).

They shall not be used in interconnection piping between skids and/or independent units subject to vibration or relative movement, or in any other unprotected or unsupported location in which external mechanical loads may be encountered.

- c) Split flanges, associated O-ring seals and connecting bolts shall be in accordance with standard SAE J518.
- d) The burst pressure of the split flanges shall be at least four times the rated working pressure (RWP) or Maximum allowable working pressure (MAWP) of the system. The test report shall be submitted for review for each type.
- e) A reliability study/service experience record shall be submitted for each split flange type for ABS review and approval. The reliability study shall make mention of the failure rate of split flanges when used in the critical locations based on service experience of X number of years and any related failures observed.
- iv) Piping joints and connections not in accordance with design codes and standards will be specially considered by ABS on a case-by-case basis.

5.3 Threaded Joints and Connections

- i) Threaded joints and connections are not to be used in systems subjected to bending or vibrational loads.
- ii) All screwed joints or connections are to be evaluated, considering the following:
 - a) Pipe outer diameter and thread allowance
 - b) Fluid type, corrosion and fluid leakage risk
 - c) Transient excursions of vibration, pulsation and pressure
- iii) Threaded joints and connections can be utilized on BOP and Diverter Control Systems provided they are demonstrated to meet the requirements of the applicable API Specifications per Chapter 2 of this Guide and ASME B31.3.

5.5 Socket Welds

- i) All socket-welding connections are to be identified and specially approved by ABS.
- ii) Socket-welding of piping connections intended for corrosive, particularly sour services is not to be used.

<i>Type</i>	<i>Size</i>	<i>Pressure</i>	
Socket welds	≤ 50 DN (2 in. NPS)	≤ 34.47 MPa (5000psi)	As permitted by, and to be in compliance with, design code
	> 50 DN (2 in. NPS)	All	Not permitted

5.7 Quick Connect Fittings

Hammer lock, hammer union or other quick connect type specialty fittings are to have a rated pressure not less than the pipe system design pressure and are to conform to applicable piping codes or meet the alternative standards requirements of this Guide.

7 Flexible Lines/Hydraulic Hoses

Typical uses for flexible lines and hydraulic hoses and their applicable design codes and standards are as follows:

<i>Typical Use</i>	<i>Applicable Code/Standard</i>
Choke and kill system flexible lines (surface/subsea) <ul style="list-style-type: none"> • Jumper lines (at subsea BOP stack) • Choke and kill in moon pool for subsea • Choke and kill for surface BOP stack. 	API 16C
Auxiliary lines and drape hoses <ul style="list-style-type: none"> • Mud boost lines • Hydraulic conduits/"Hot-line" hoses (to BOP) • Buoyancy control line • Jumper lines (at subsea BOP stack) 	API 16D, 16F
Hydraulic hoses for control functions, fluid power and hydraulic fluid transfers associated with well control	API 16D
Hydraulic hoses for control functions, fluid power and hydraulic fluid transfers associated with choke control	API 16C
Rotary and vibratory hoses	API 7K
Cementing hoses	API 7K
Hydraulic hoses for control functions, fluid power and hydraulic fluid transfers for drilling systems such as topdrive, drawworks, riser tensioning, tubular handling, etc.	the ABS <i>MOU Rules</i>

Flexible lines and hydraulic hoses are to comply with the following general requirements:

- i) The hose body is to be secured to prevent falling or whipping in the event of a rupture or failure.
- ii) Hose assemblies which can pose risk to personnel upon end failure are to be properly restrained. High pressure hoses are to be secured and fastened per AP 54 requirements 9.7.7, 9.13.3.

7.1 Design

- i) Choke and Kill flexible lines and auxiliary lines are to comply with the design, material, quality control, and prototype testing, including burst testing requirements specified in API 16C, API 16F, and the additional requirements specified in this Guide.
- ii) Drape hoses (moonpool lines) at the telescopic joint are to be able to accommodate the relative movement between the riser and the drilling unit.
- iii) For subsea BOP stack, jumper lines at the flex/ball joints are to be able to accommodate the relative movement between the riser and the BOP stack.
- iv) Flexible lines for subsea services are to be designed to withstand the external pressure for the operational depth without deforming.
- v) Hydraulic hoses/assembly utilized for well control functions are to comply with the requirements of applicable sections of the ABS *MOU Rules* (for surface hydraulic control hoses only), API 16D and recognized industry standards, such as SAE, National Fluid Power Association, as applicable.
- vi) Flexible lines that are exposed to wellbore fluids are to consider gas permeation and decompression in their designs.
- vii) For end connections using split flanges refer to 4-2/5
- viii) Hydraulic hoses/assembly utilized for drilling system control and hydraulic fluid transfer are to comply with the requirements of applicable sections of the ABS *MOU Rules*, recognized industry standards, such as SAE, National Fluid Power Association, as applicable.

- ix) Flexible lines or hydraulic hoses that are to be used in pneumatic service are to be designed with consideration to decompression and permeation.
- x) Rotary and vibratory hoses/assembly for drilling services are to comply with the design, and be manufactured to API 7K, and the additional requirements specified in this Guide, and be suitable for their intended service (temperature, fluid compatibility, etc.).

7.3 Fire Resistance

- i) General:
 - a) Flexible lines/hydraulic hoses carrying flammable fluids, as defined in Chapter 1, Section 7, are to be fire-resistant for well control operations in accordance with API 16C, unless 4-2/7.3i)e) and/or 4-2/7.3iii)a) are applicable.
 - b) Riser choke, kill and auxiliary lines used for well control applications within Zone 0 or Zone 1 hazardous areas, irrespective of fluid category, are to be fire-resistant except as indicated in 4-2/7.3iii)a) as applicable. The fire resistance test is to be in accordance with API 16C and API 16D and ISO 15540/15541, as applicable.
 - c) Hydraulic hoses carrying flammable oil for applications other than well control are to be in compliance with the applicable requirements of 4-2-1/11.29 of the *ABS MOU Rules* and Appendix 2 of the *Facilities Rules*, except for hydraulic hoses in 4-2/7.3 of this Guide.
 - d) Hydraulic hoses and flexible lines carrying non-flammable fluids [other than those under 4-2/7.3i)b)] are not required to be fire-resistant.
 - e) Hydraulic hoses and flexible lines located subsea are not required to be fire-resistant.
- ii) For surface BOP stack, all flexible lines hydraulic hoses between the control system and BOP stack are to comply with the following:
 - a) Fire test requirements of API 16D, including end connections.
 - b) To have RWP equal to the RWP of the BOP control system, as applicable.
- iii) For a subsea BOP stack, all flexible lines hydraulic hoses connected to the BOP stack are to comply with the following:
 - a) All discrete and multiplex lines between the BOP and control system on units with autoshear and deadman systems (except for the choke and kill lines) shall not meet the fire resistance requirement of API 16D, as the use of fire retardant hoses can delay or prevent activation of the autoshear and deadman systems.
 - b) All flexible lines/hydraulic hoses between the control system and BOP are to have RWP greater than or equal to the RWP of the BOP control system, as applicable.
 - c) Moonpool choke and kill hoses or flexible lines and their end connections installed that permit entry of gas or hydrocarbons, are to meet the design requirements, performance verification and fire-resistance requirements in accordance with API 16C.

7.5 End Connections

- i) End connections for flexible lines/hydraulic hoses are to be designed and fabricated to the requirements of this Guide and applicable recognized codes and standards.
- ii) End connections are to be considered as an integral part of the flexible line/hydraulic hose assembly.

7.7 Isolation Valves

Isolation valves are to be provided to prevent potential uncontrolled release of flowing medium from flexible lines to minimize the hazard.

7.9 Materials

- i) Material requirements for flexible lines and hydraulic hoses, including end fittings when exposed to wellbore fluids or a corrosive/erosive environment, are to be in accordance with Chapter 4 and Chapter 5 of this Guide and applicable design codes and standards.
- ii) Nonmetallic materials used in the manufacturing of flexible line and/or hydraulic hose assemblies are to be suitable for the intended service conditions such as temperature and fluid compatibility.

9 Materials

9.1 General

Materials are to be in accordance with the applicable design codes and standards referenced in this section, and the requirements of Chapter 5 of this Guide.

9.3 Toughness

Piping component toughness requirements are to be in accordance with Chapter 5 of this Guide.

9.5 Composite Materials

Composite materials where used in drilling piping system applications are to be of fire-resistant construction and are to be designed and tested to ASME Boiler and Pressure Vessel Code, Section X, and Appendix 1 of the *ABS Facilities Rules*.

11 Welding and NDE

11.1 General

Welding and NDE are to be in accordance with the applicable design codes and standards referenced in this Section, and the requirements of Chapter 6 of this Guide.

CHAPTER 5

Materials for Drilling Systems and Equipment

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CHAPTER 5 Materials for Drilling Systems and Equipment

SECTION 1 General

1 General

This Section specifies requirements for selection of materials intended for drilling system equipment and/or components, including production testing and documentation.

All materials are to be suitable for their intended service conditions and as defined by a recognized standard and/or manufacturer's material specifications.

3 Material Specifications

Material specifications for primary structural load bearing components in the critical load path and pressure retaining, containing and controlling components are to be submitted to ABS for review by ABS Materials Engineering Department. Specifications that fully comply with recognized industry standards such as EN, API and ASTM need not be submitted. Submitted specifications shall include the applicable information from the below list, as a minimum:

- *Material* – Grade, including chemical composition (limits and tolerance), any limitation on grain size, and identification of secondary phases.
- Allowable porosity, segregation level and steel cleanliness controls of inclusions, porosity, etc., as applicable to the process.

For the Material Test Reports (MTR) refer to 5-7/1. Materials indicated in drawings compliant with recognized customary standards need not be incorporated in the materials specification.

5 Manufacturing Specifications

Manufacturing Specifications for raw materials for critical well control equipment and ram blocks, including threaded fasteners per 5-1/11 are to be submitted to ABS Materials Engineering Department for review. It is the responsibility of the critical equipment designer to identify the critical components, and this is to be agreed upon by ABS.

The manufacturing specification shall include but is not limited to:

- i)* Materials identification traceable to materials test reports (MTR) from manufacturer's mill
- ii)* *Processing* – Melting, refining, casting, ingot/billet cropping, hot working, forming (reduction ratio), hydrogen controls etc.

- iii) *Heat Treatment Procedure* – Furnace loading diagram and spacing of components, temperature, time, heating and cooling rate, quenching medium and type of agitation, monitoring of quench medium start and finish temperature, transfer times to quench and furnace, re-heat treatment etc.

Heat treatment procedures per the design specification is to include provisions for loading diagrams and any required photographic records of the heat treat process.

Note: Unless required by the design specification, photographic evidence of furnace loading is not mandatory, however it is the preferred method of furnace loading verification.

- iv) *Surface Treatment* – Surface hardening
- v) *Mechanical Testing* – Requirements, test coupon locations, testing frequency
- vi) *NDE Inspection* – Personnel qualification, requirements, acceptance criteria
- vii) Non-conformance handling procedure, acceptable repairs methods including weld repair
- viii) Marking and traceability
- ix) *Metal Surfacing Specifications* – Reference ASME IX for essential variables

Manufacturing process changes are to be documented and submitted.

- i) Refer to 5-4/1 for requirements of material manufacturers
- ii) Refer to Chapter 5, Section 6 for requirements of non-metallic materials

If the manufacturing facility has an existing ABS approval for the above listed products, the above documentation requirement may be waived upon discretion of the technical review office.

7 Material Selection

The material is to be suitable for the design criteria.

Applicable CVN testing is based on the following drilling system equipment/component category,

- i) Structural and mechanical load-bearing members and components are:
 - a) Members supporting loads or components transmitting, resisting and converting loads, due to hoisting, lifting, handling, drilling or self/assembled weight, etc.
 - b) And are to comply with the requirements of Chapter 5, Section 2.
- ii) Pressure-retaining/containing/controlling equipment and piping components are:
 - a) Equipment/component subjected to pressure
 - b) And are to comply with the requirements of Chapter 5, Section 3.

9 Corrosion

9.1 General

Consideration is to be given to the breakdown of materials by corrosion in the design environment. Refer to 2-2/3.5 for details on corrosion/erosion design allowances.

9.3 Sour Service

Materials used in drilling system equipment/components designed for sour service are to comply with the applicable part of NACE MR0175/ISO 15156: *Materials for use in H₂S containing environment in oil and gas production*.

11 Threaded Fasteners- Well-bore Fluid Service

When selecting materials for the fabrication of threaded fasteners for closure, pressure controlling and pressure retaining equipment, consideration is to be given to minimizing galvanic effects (corrosion and cracking) between components being joined in the anticipated environment. Threaded fasteners, including all fasteners potentially exposed to hydrogen rich environments, such as ram blade to block attachment bolts, are to be manufactured and tested in accordance with applicable recognized material standards such as NACE MR0175, API 20E, API 20F, API 16A, API 6A, API 16C, ASTM, and any other applicable standard. Threaded fasteners manufactured from alloy steel or carbon steel shall be limited to 34 HRC maximum due to concerns with hydrogen embrittlement and environmentally assisted cracking.

In case of plated/coated threaded fasteners used for closure, pressure controlling and pressure retaining equipment including all fasteners potentially exposed to hydrogen rich environments such as the ram blade to block attachment bolts, the application of API 20E is to be followed. In addition to API 20E, ASTM B849 is applicable for pre-heat treatment depending upon the coating process being applied, and ASTM B850 is applicable as a post coating heat treatment for further reducing the risk of hydrogen embrittlement. Zinc electroplating is not permitted for splash zone or subsea service.

Hydrogen embrittlement and cracking can be introduced during the acid cleaning process. Measures such as baking before and after surface coating are to be required to prevent Hydrogen induced failure. Some surface treatments are more susceptible to hydrogen problems than others and careful consideration is to be made of the anticipated environment, (for example levels of cathodic protection in seawater, or interaction between dissimilar materials) when selecting the surface treatment process.

13 Additional Requirements for Critical Well Control Equipment

Equipment/Component/Material manufacturers and subcontractors are to submit documentation indicating certification under an International Scheme such as ISO 9001, API Q1 or equivalent.

Manufacturers of threaded fasteners per 5-1/11 of this Guide are to be qualified to API 20E or 20F and are to certify that the products meet the requirements of API 20E or 20F.

CHAPTER 5

Materials for Drilling Systems and Equipment

SECTION 2

Materials for Structural and Mechanical Load-Bearing Components

1 General

Materials for structural and mechanical load-bearing components are to be selected in accordance to the applicable design codes with consideration to toughness, corrosion resistance, and weldability, and be suitable for their intended service conditions.

Structural and mechanical load-bearing components that are in the load path are to be considered as “primary”. Structural load-bearing materials are to comply with the following requirements:

- i)* For hoisting and handling structures:
 - a)* Hoisting structures. Refer to 2-4/9 for primary load-bearing structural members
 - b)* Handling structures – Refer to 2-6/5
- ii)* For lifting structures. Refer to 2-6/3:
- iii)* Materials for structural and mechanical load-bearing components not covered by, or not in full compliance with EN, API, ASME or applicable recognized standards, the following Charpy V-Notch criteria in 5-2/Table 1, applies.

3 Toughness

- i)* Structural materials are to exhibit impact toughness which is satisfactory for the intended applications (hoisting, handling, lifting), as evidenced by appropriate Charpy V-notch (CVN) longitudinal impact testing results, and are to be based on the specified minimum design service temperature (MDST) and material’s specified minimum yield strength (SMYS), as specified in 5-2/Table 1. CVN values shall be determined from the average of three tests, Refer to 2-1-1/11.11 of the *ABS Rules for Materials and Welding* (Part 2).
- ii)* Other CVN criteria or alternative test data, such as crack-tip opening displacement (CTOD), nil ductility transition (NDT) temperature, or related service experience will be considered if submitted to ABS prior to manufacturing.
- iii)* It should be noted that other national and international regulatory bodies may have additional requirements for toughness. Any additional toughness requirements in the scope of the design review and fabrication inspection, is to be performed, as applicable, and/or as requested.

Table 1
Toughness (Structural Materials)

Item	Material Category	Design Service Temperature (DST) °C (°F)	Yield Stregnth N/mm ² (ksi)	Minimum CVN avg. Value ⁽¹⁾ , J (ft-lb)	CVN Test Temperature ⁽⁶⁾
1	Primary Structural members	-20 (-4) and above	≤ 270 (39)	27 (20)	DST
			> 270 (39) to ≤ 420 (61)	SMYS/10 (SMYS/1.97)	
			> 420 (61) to ≤ 690 ⁽⁵⁾ (100)	42 (31)	
			> 690 (100) to ≤ 800 (116)	50 (37)	
		Lower than -20 (-4)	≤ 270 (39)	27(20)	10°C (18°F) below DST
			> 270 (39) to ≤ 420 (61)	SMYS/10 (SMYS/1.97)	
			> 420 (61) to ≤ 690 ⁽⁵⁾ (100)	42 (31)	
			> 690 (100) to ≤ 800 (116)	50 (37)	
2	Non-Primary structural members ⁽²⁾	-20 (-4) and above	≤ 270 (39) to 800 (116)	27 (20)	DST
		Lower than -20 (-4)	> 270 (39)	27 (20)	DST
			> 270 (39) to ≤ 420 (61)	SMYS/10 (SMYS/1.97)	
			> 420 (61) to ≤ 690 ⁽⁵⁾ (100)	42 (31)	
			> 690 (100) to ≤ 800 (116)	50 (37)	
3	Miscellaneous ⁽³⁾	Lower than -20 (-4)	≤ 270 (39) to 800 (116)	As required for applications	
4	Primary bolts ⁽⁴⁾	All temperatures	All yields	As required by material specifications at MDST	

Notes:

- Individual value for each of the (3) test specimens cannot be less than $\frac{2}{3}$ of the specified minimum average.
- Structure which is not classified as primary load bearing is termed "non-primary".
- For miscellaneous structures, under the scope of this Guide, refer to items such as ladders, supports, walkways, handrails, cable trays, and other ancillary structures. In general, materials for these structures are low in thickness and are to be suitable for their intended application, as evidenced by previous satisfactory services.
- Primary Bolts: Primary load-bearing structural bolts are to be produced to a material specification that requires Charpy impact tests at, or below, the specified minimum design service temperature, in accordance with recognized standards. In addition, bolts are to comply with applicable standards such as API 20E and 20F.
- For a specified minimum design service temperature (MDST) above 0°C (32°F), Charpy V-Notch impact testing is to be performed at 0°C (32°F).
- Non-primary steel below 12.5 mm thickness, supplied in killed or semi killed condition, is exempted from Charpy impact testing.

- 7 CVN for thicknesses for materials less than 6 mm (0.25 in.) is not required unless specifically required by the design specification.
- 8 Refer to 5-5/3iv) for cold forming.

CHAPTER 5

Materials for Drilling Systems and Equipment

SECTION 3

Materials for Pressure-Retaining/Containing/ Controlling Equipment and Piping Components

1 General

Materials for pressure-retaining/containing/controlling equipment or piping components are to be selected in accordance to the applicable design codes with consideration to toughness, corrosion resistance, and weldability, and to be suitable for their intended service conditions.

3 Toughness

Toughness testing for pressure-retaining/containing/controlling equipment or piping components is to be performed in accordance with the relevant EN, API, ASME or applicable recognized standard.

- i) Toughness testing procedures, size, locations and retesting (as applicable) are to be in accordance with the applicable recognized standard.
- ii) The absorbed energy requirement and test temperature is to be in accordance with the relevant EN, API, ASME or applicable recognized standard.
- iii) Materials for pressure-retaining/containing/controlling equipment or piping components not covered by, or not in full compliance with EN, API, ASME or applicable recognized standards, the Charpy V-Notch criteria shown in 5-3/Table 1 apply:

<i>Material Category</i>	<i>Yield Strength N/mm² (ksi)</i>	<i>Minimum CVN avg. Value⁽¹⁾, J (ft-lb)</i>	<i>CVN Test Temperature⁽³⁾</i>
Pressure Containing/ Retaining/ Controlling ⁽²⁾	≤ 450 (65)	SMYS/10 (SMYS/1.97) Minimum 27 (20)	DST
	> 450 (65) to ≤ 690 (100)	50 (37) Lateral expansion of ≥ 0.38 mm (0.015 in.) ⁽⁴⁾	
	> 690 (100) ⁽⁵⁾	Note 5 Lateral expansion of ≥ 0.38 mm (0.015 in.) ⁽⁴⁾	

Notes:

- 1 Individual value for each of the (3) test specimens cannot be less than 2/3 of the specified minimum average. Tested in the longitudinal direction

- 2 Charpy V-Notch (CVN) impact testing is to be performed at the required temperature in the relevant API, ASME or applicable standard or the minimum design service temperature (MDST), whichever is lower.
 - 3 For a specified MDST above 0°C (32°F), Charpy V Notch impact testing is to be performed at 0°C (32°F)
 - 4 Lateral expansion opposite the notch
 - 5 CVN properties are to be submitted for consideration.
 - 6 Refer to 5-5/3 for cold forming.
- iv)* Other CVN criteria or alternative test data, such as crack-tip opening displacement (CTOD), nil ductility transition (NDT) temperature, or related service experience will be considered if submitted to ABS prior to manufacturing.
- v)* It should be noted that other national and international regulatory bodies may have additional requirements for toughness. ABS will include these additional toughness requirements in the scope of the design review and fabrication inspection, as applicable, and/or as requested.

CHAPTER 5 Materials for Drilling Systems and Equipment

SECTION 4 Material Manufacturing Considerations

1 General

All materials are to be manufactured in accordance with requirements indicated in the material specifications (See Chapter 5, Section 1).

Test coupons are required for each final heat treatment for verification of mechanical properties to the material specification and/or industry standards.

It is the equipment or component manufacturers' responsibility to ensure the material manufacturers and/or their sub-suppliers/vendors comply with the following requirements:

- i) Material Manufacturers or sub-suppliers/vendors have an accredited and effective quality control system to meet the materials specifications and manufacturing requirements in accordance with requirements as referenced in the design codes and standards.
- ii) Material test facilities shall maintain a quality process for equipment calibration and record controls and must be certified by international or national recognized authorities.
- iii) Material testing is performed in accordance with the requirements of the applicable material specifications and in accordance with the design codes and standards.
- iv) Materials certificates are valid for the materials they represent.
- v) NDE is carried out by qualified personnel in accordance with requirements as referenced in the design codes and standards, such as ISO 9712, ASNT, EN 473, etc. See Chapter 6, Section 4. Specific nondestructive examination requirements may be required for some product forms.

3 Rolled Products

Plates, shapes and bars may be supplied in the as-rolled, thermo-mechanically processed, normalized, or quenched and tempered condition, and shall conform to recognized standards.

Where the design requires through thickness properties, materials shall be tested for reduction of area in the through-thickness direction in accordance with EN 10164, ASTM A770, 2-1-1/17 of the *ABS Rules Materials and Welding (Part 2)*, or any other recognized standard. The minimum reduction is to be 25%.

5 Forging

Forged products are to comply with the following requirements:

- i)* To be supplied in a worked condition. The forging reduction ratio from an ingot is not to be less than 3 to 1. The microstructure is to be fully wrought and meet specification requirements for internal soundness.
- ii)* Samples for testing are to be taken from integrally forged coupons, or from appropriately designed separately forged coupons or a sacrificial forging.
- iii)* Unless otherwise approved by ABS, these coupons are to be subjected to the same heat treatment as the forging in the same furnace batch. Subject to approval, alternative practices for coupon selection/representation of heats/melts such as those specified in API 16 series standards may be used provided the heat treatment provisions of the standards are applied in full.
- iv)* Weld repairs on raw material forgings and rolled products is not permitted unless specified by the equipment manufacturer using documented approved procedures.

7 Castings

Cast products are to comply with the following requirements:

- i)* Cast products are to be supplied in a heat-treated condition. Samples for testing are to be taken from integrally cast coupons or appropriately designed separately cast coupons.
- ii)* Test coupons are to be subjected to the same heat treatment as the casting, in the same furnace batch. Subject to approval, alternative practices for coupon selection/representation of heats/melts such as those specified in API 16 series standards may be used provided the heat treatment provisions of the standards are applied in full.
- iii)* Weld repairs of defects and unacceptable indications on raw material castings are to be carried out in accordance with recognized codes and standards. In general repairs are to be carried out before final heat treatment.

CHAPTER 5 Materials for Drilling Systems and Equipment

SECTION 5 Material Fabrication Considerations

1 Welding

Welding of materials used in the fabrication of drilling equipment and/or components is to comply with the following requirements:

- i) Welding is to be in accordance with the specified design/manufacturing code and Chapter 6 of this Guide.
- ii) Weldments, weld metal and/or heat-affected zone (HAZ), subject to sour (H₂S) service are to be in compliance with NACE MR0175/ISO 15156 as applicable.

3 Forming

If the structural steel is formed, the forming of materials utilized in drilling equipment and/or components are to comply with the following requirements:

- i) In general, for steel components, forming at temperatures between 205°C (400°F) and 425°C (800°F) is to be avoided.
- ii) Where degradation of properties is unavoidable, complete post forming heat treatment may be required.
- iii) Suitable supporting data is to be provided to indicate compliance with the specified properties.
- iv) For materials with specified toughness properties that are to be cold formed beyond 3% strain* on the outer fiber, data are to be provided indicating that the toughness properties meet the minimum requirements after forming.
- v) After straining, specimens used in toughness tests are to be subjected to an artificial aging treatment of 288°C (550°F) for one hour.

Note: * For details, see 2-4-1/3.13 of the *ABS Rules for Materials and Welding (Part 2)*.

5 Galvanizing

Materials for galvanized structures are to be fabricated and designed in accordance with industry-recommended practices. Welds on galvanized structures may require suitable alternative inspection techniques and inspection at specific stages of fabrication.

Galvanizing procedures and/or process are to be in accordance with ASTM A143, A153, A384, A385, BCSA 40/05, and/or other hot-dip galvanizing standards, and are to be submitted for ABS records. The following are to be considered in the development of galvanizing procedures and processes

- i)* High-strength steels with yields above 355 MPa (51 ksi)
- ii)* Adequate venting and draining
- iii)* Double-dipping practices are not permitted, except in case of galvanizing tank size limitations
- iv)* Pre-heating/warming prior to dipping
- v)* Trace elements in base metal and low Silicon weld consumables
- vi)* Grinding of flame cut edges to remove sharp discontinuities and carbon deposits
- vii)* Weld surface appearance free from undercuts, notches, etc.
- viii)* Inspection before and after hot-dip galvanizing
- ix)* Strain age embrittlement of cold-formed sections
- x)* Abrupt changes in cross section
- xi)* Maximum CE of 0.44% (See CEZ calculation below) based upon the Product Analysis or if Ladle Analysis then maximum specified chemistry values should be applied in the calculation. Steel which is produced from scrap may contain trace elements that influence the susceptibility to hot dip galvanizing cracking. See CEZ calculation below.
- xii)* $CEZ = C + Si/17 + Mn/7.5 + Cu/13 + Ni/17 + Cr/4.5 + Mo/3 + V/1.5 + Nb/2 + Ti/4.5 + 420B$

CHAPTER 5

Materials for Drilling Systems and Equipment

SECTION 6

Sealing (Metallic and Non-metallic) Materials

1 General

The manufacturer's specifications for pressure-containing or pressure-controlling seals shall include the following:

- i)* Metallic – Grade, chemistry; Non-Metallic - Generic base polymer (refer ASTM D1418)
- ii)* Mechanical properties requirements
- iii)* Storage and age control requirements;
- iv)* Testing and NDE requirements; acceptance and/or rejection criteria per applicable standards.

3 Elastomeric Sealants

- i)* Materials used for sealing are to be suitable for the intended operating pressures, temperatures, and operating mediums.
- ii)* Age-sensitive materials for critical components are to have a defined storage life and be identified in storage as to month and year of manufacture.

5 Ring Joint Gaskets

- i)* Metal (such as Ring joint) gaskets are to be of soft iron, low carbon steel or stainless steel, as required by the design standard.
- ii)* Gaskets that are coated with a protective coating material such as fluorocarbon or rubber for shipment and storage are to have the coatings removed prior to installation.

CHAPTER 5

Materials for Drilling Systems and Equipment

SECTION 7

Documentation and Traceability

1 Material Documentation

Materials used for primary structural load-bearing, mechanical load-bearing components, pressure-retaining, pressure containing and pressure controlling parts/components, and piping are to be furnished with material manufacturer/mill's documentation (e.g., material test reports (MTR), etc.) stating, as a minimum, the following, as applicable:

- i)* Material specification, grade
- ii)* Product heat number/batch number
- iii)* Process of manufacture, including melting practices, reduction ratio (if applicable)
- iv)* Chemical analysis, with tolerance ranges and testing standard(s) as required by the material standard.
- v)* Mechanical properties – including acceptance, rejection criteria and testing standard(s).
- vi)* Heat treatment records (showing heat treatment times at temperatures, heating and cooling rate, quenching media, transfer time, and any required photographic evidence of components in furnace showing compliance to the furnace loading diagram, heat treating equipment)
- vii)* Re-heat treatment information, if applicable
- viii)* Surface treatment information – surface hardening, plating, thermal spraying, cladding etc.
- ix)* Charpy impact values and temperatures, including testing standard.
- x)* Hardness test readings (as applicable to NACE MR0175/ISO 15156), including testing standard
- xi)* Certification by the material manufacturer/mill of compliance with the applicable recognized material specification or manufacturer's written specification. For example: 3.1 certification per EN 10204.
- xii)* Repair-welding requirements
- xiii)* NDE results including acceptance and rejection criteria
- xiv)* Corrective actions and disposition of major non-conformances during the material manufacturing or forming process

CHAPTER 5 Materials for Drilling Systems and Equipment

SECTION 8 Nondestructive Testing (NDE)

1 General

Surface and/or volumetric examination is to be performed on materials (castings, forgings and rolled products) used for primary load bearing and mechanical components; pressure retaining/containing/controlling equipment and piping systems, as per applicable standard and specification. The NDE methods outlined in Chapter 6, are to be applied, to the satisfaction of the Surveyor.

3 Specifications, Procedures and Material Documentation

NDE procedures are to be verified by the attending Surveyor as required in Chapter 7 and 3-2/Tables 1 through 10. Refer to Chapter 6 for detailed requirements.

In case of advanced NDE inspection techniques such as phased array UT, at the discretion of the attending Surveyor, the NDE procedures may be submitted to ABS Materials Engineering Department for review.

5 Qualification of NDE Technicians:

Refer to Chapter 6, Section 4 for requirements

7 Extent of Examination of Cast and Wrought Materials and Repair Welds

The extent of NDE for materials, repair welds to materials and on locations where temporary attachments have been removed is to comply with the following requirements:

- i)* Materials (castings, forgings and rolled product) are to be examined in accordance with a recognized standard or design code, by nondestructive methods capable of detecting and sizing significant surface and internal defects.
- ii)* Stress concentrations, sharp edges/corners, etc., of materials (casting, forgings and rolled product) are to be examined for flaws by methods capable of detecting and sizing significant internal defects.
- iii)* Repair welds are to be subjected to 100% surface NDE, and volumetric NDE if applicable or if required by the design code.
- iv)* Locations where welds for temporary attachments have been removed are to be subject to 100% surface NDE.

NDE reports are to be verified by the attending Surveyor. The Surveyor may require additional testing in order to verify product quality or quality of weld repairs. Weld related examinations are to be carried out after any post weld heat treatment.

9 Methods and Acceptance Criteria

Refer to Chapter 6 for applicable design codes and standards.

CHAPTER 6

Welding and Nondestructive Examination

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CHAPTER 6

Welding and Nondestructive Examination

SECTION 1

General

1 General

Welding related to processes of fabrication and repair and associated nondestructive examination (NDE) are to be performed in accordance with the equipment or component design codes and standards. 134 ABS

CHAPTER 6 Welding and Nondestructive Examination

SECTION 2 Welding

1 General

All welds, including overlay welds, tack welds and weld repairs of pressure-retaining/containing/controlling equipment, piping systems, mechanical load-bearing and structural components are to be fabricated using qualified welding procedures in accordance with the recognized and applicable codes and standards, by qualified welders.

3 Welding Procedure Specification

A written welding procedure specification (WPS) is to be prepared in accordance with the applicable Code, such as Section IX of the ASME Boiler and Pressure Vessel Code, or ANSI/AWS D1.1 Structural Welding Code, or an alternative recognized standard. The WPS and the supporting procedure qualification record (PQR) are to be verified by the attending Surveyor.

- i)* The WPS is to describe in detail all essential and nonessential variables, and when applicable, supplementary essential variables to the welding processes employed in the procedure.
- ii)* Welding procedure specifications are to be qualified by testing and the supporting PQR is to include the following test data, which is to be made available to the attending Surveyors:
 - a)* Maximum hardness values (for well bore fluid service)
 - b)* Minimum and average CVN toughness values for weld heat-affected zone and weld metal ((including lateral expansion if required), where the base metal is required to be impact-tested in accordance with Chapters 2 or 5 of this Guide)
 - c)* Minimum tensile strength
 - d)* Results from other tests required by the applicable code or standard
 - e)* Mechanical tests are to be carried out after any post weld heat treatment.
- iii)* Where welding is outside of the essential variable limits or, when applicable, supplementary essential variable limits defined in the existing WPS, the PQR is to be re-qualified.
- iv)* Except as indicated in 6-2/3vi), the Surveyor can accept, at his discretion, welding procedures and welder qualifications at shipyard or manufacturing plant where it is established to his satisfaction that they have been qualified and effectively used for similar work in accordance with this Guide and recognized standards.

- v) The qualification process may require the submittal of relative WPS and supporting PQRs to the ABS Materials Engineering Department for review and agreement, at the discretion of the attending Surveyor.
- vi) In the case of high pressure piping designed in accordance with ANSI/ASME B31.3 Section IX and required to comply with NACE MR0175/ISO 15156, the WPS and supporting PQR for welding shall be submitted to the ABS Materials Engineering Department for review and agreement.
- vii) Weld procedures can be qualified at a designated facility and may be used at other locations under the same quality management system, provided it is agreed to by the purchaser and ABS.

5 Filler Materials

The strength, toughness and chemical composition of filler materials is to be comparable to that of the base material. Selection shall be based on requirements of applicable recognized codes and standards. Filler materials not listed in any recognized codes or standards may be considered and approved upon performing applicable mechanical tests in the presence of attending surveyor.

Storage conditions of filler materials shall be strictly followed. Storage instructions shall be provided to the attending surveyor upon request for verification.

7 Welder/Welding Operator Qualification

The Surveyor is to be satisfied that all welders and welding operators are qualified in accordance with the applicable code for each welding process and for each position used in production welding of systems, subsystems, equipment or components and structures.

Welder/welding operator qualification and continuity records are to be made available to the Surveyor.

CHAPTER 6 Welding and Nondestructive Examination

SECTION 3 Post Weld Heat Treatment (PWHT)

1 General

Accurate records of all heat treatments during fabrication, including rates of heating and cooling, hold time and soaking temperature are to be made available to the Surveyor.

PWHT shall as a minimum be performed in the following cases:

- i)* When required by the design code,
- ii)* When necessary to meet the specific mechanical properties (such as NACE hardness requirements),
- iii)* When specified by the designer for dimensional stability of machined components,
- iv)* When PWHT is an essential variable in the WPS

Alternative methods of stress relief will be subject to special consideration by ABS where post-weld heat treatment is not a requirement of the applicable manufacturing code.

In the case of weld repair, the cumulative PWHT time shall be in accordance with the limits specified in the qualified WPS and supporting PQR and are to be recorded in the weld maps.

Note: The requirements for PWHT will depend upon the materials used, thickness and application. PWHT may not be applicable in all cases.

CHAPTER 6

Welding and Nondestructive Examination

SECTION 4

Nondestructive Examination (NDE)

1 General

Fabrication and repair welds, and welds in locations where temporary attachments have been removed (in pressure-retaining/containing/controlling equipment, piping systems, mechanical load-bearing and structural components), are to be examined for surface and volumetric flaws to the extent specified in the applicable design and/or fabrication code, but not to a lesser extent than that specified in this chapter.

Weld inspection is to be carried out to the satisfaction of the Surveyor.

3 NDE Procedures

NDE procedures and the requirements and extent of NDE are to be developed in accordance with the requirements of the selected design and/or fabrication codes for the drilling systems, subsystems, equipment and/or components for the intended service.

NDE procedures specifying testing parameters, extent of examination and acceptance criteria, are to be verified by the attending Surveyor.

At the discretion of the attending Surveyor, the NDE procedures may be required to be submitted to the ABS Materials Engineering Department for review. Advanced NDE inspection techniques are to be in accordance to the *ABS Guide for Nondestructive Inspection*.

5 Qualification of NDE Technicians

The Surveyor is to be satisfied that personnel responsible for conducting nondestructive tests are trained and qualified to operate the equipment being used and that the technique used is suitable for the intended application. For each inspection method, personnel are to be qualified by training, with appropriate experience and certified to perform the necessary calibrations and tests and to interpret and evaluate indications in accordance with the terms of the specification. Personnel are to be certified in accordance with the International Standard ISO 9712 – *Non-destructive testing – Qualification and certification of personnel* or other internationally/nationally recognized certifying programs (e.g., ASNT Central Certification Program (ACCP) CP-106, EN-473 etc.).

American Society for Nondestructive Testing (ASNT) Recommended Practice No. SNT-TC-1A or equivalent can be used as a guideline for employers to establish their written practice for qualification and certification of their personnel. Manufacturers adopting this practice are to have an appropriately qualified level 3 NDE operator on their own staff or on appointment.

Certification documents of NDE technicians are to be made available to the Surveyor.

CHAPTER 6

Welding and Nondestructive Examination

SECTION 5

Extent of Nondestructive Examination on Welds

1 General

All weldments and other critical sections covered in 6-5/Table 1 are to be subjected to 100% visual examination, surface nondestructive examination, and volumetric nondestructive examination in accordance with the relevant design code, the *ABS Guide for Nondestructive Inspection*, and this Guide.

Examinations are to be carried out after any post weld heat treatment.

3 Extent of NDE

Furthermore, the extent of NDE on welds is to comply with the following requirements:

- i) Welds of structural members are to be inspected in accordance with 6-5/Table 1. In addition changes in geometry, sharp edges/corners, etc., are to be examined for flaws by methods capable of detecting and sizing significant internal defects.
- ii) Repair welds are to be subject to 100% surface NDE. Repairs to complete joint penetration welds (CJP) are to be subject to 100% volumetric NDE, where accessible.
- iii) Welds for mechanical load-bearing components or pressure-retaining/containing/controlling equipment are to be examined, in accordance with the relevant design code, by nondestructive methods capable of detecting and sizing significant surface and internal defects.
- iv) NDE Reports are to be verified by the attending ABS Surveyor.
- v) Weld considered suspect by the attending Surveyor, may require additional testing in order to verify product or weld quality.

TABLE 1
Nondestructive Testing (NDT) of Steel Structural Welds

<i>Structural Member</i>	<i>Extent and Type of NDT</i>
Welds in primary Structure ^(1,2)	20% volumetric NDT and 20% surface NDT for all complete joint penetration (CJP) welds, where welded plate thickness is ≥ 8 mm (5/16 inch) and 20% volumetric NDT and 20% surface NDT for all partial joint penetration (PJP) welds, where the design weld penetration is ≥ 19 mm (3/4 inch) 20% surface NDT of all fillet and other partial joint penetration welds, where welded plate thickness is ≥ 8 mm (5/16 inch)
Welds in non-primary Structure	Random volumetric NDT of complete joint penetration (CJP) welds and surface NDT of fillet and partial penetration joint (PJP) welds, only if considered suspect by the attending Surveyor during construction

Notes:

- 1** Primary structure welds which are single point failure, with no redundancy, and are considered critical by the designer, will require 100% Volumetric NDT plus 100% Surface NDT
- 2** Volumetric NDT of partial joint penetration (PJP) welds is to be carried out using Ultrasonic testing methods to verify the design penetration depth and integrity of the weld. UT scan indications at the weld root are not necessarily considered defects.

CHAPTER 6

Welding and Nondestructive Examination

SECTION 6

Inspection for Delayed (Hydrogen-Induced) Cracking

1 Time of Inspection

- i)* Nondestructive testing of weldments in steels of 415 N/mm² (60,000 psi) specified minimum yield strength (SMYS) or greater is to be conducted at a suitable interval after welds have been completed and cooled to ambient temperature. The following guidance of interval is to be used, unless specially approved otherwise:
 - Minimum 48 hours of interval time for steels of 415 MPa (60,000 psi) SMYS or greater but less than 620 MPa (90,000 psi) SMYS
 - Minimum 72 hours of interval time for steel greater than or equal to 620 MPa (90,000 psi) SMYS
- ii)* At the discretion of the Surveyor, a longer interval and/or additional random inspection at a later period may be required. The 72 hour interval may be reduced to 48 hours for radiographic inspection or ultrasonic inspection, provided a complete visual and random magnetic particle or dye-penetrant inspection to the satisfaction of the Surveyor is conducted 72 hours after welds have been completed and cooled to ambient temperature.
- iii)* The delay period for steels less than 450 MPa (65,000 psi) and less than 12 mm (0.47 in.) thick may be decreased to 24 hours if the heat input applied during welding is less than 3.5 kJ/mm and there is satisfactory evidence that there is no hydrogen cracking occurring after 48 hours.

3 Delayed Cracking Occurrences

- i)* When delayed cracking is encountered in production, previously completed welds are to be inspected for delayed cracking to the satisfaction of the Surveyor.
- ii)* At the discretion of the Surveyor, re-qualification of procedures or additional production control procedures may be required to minimize the potential for delayed cracking.
- iii)* Interval time (prior to non-destructive testing) begins once the weldment has cooled to ambient temperature. Time used for post weld heat treatment for hydrogen outgassing is considered as “interval” time and where a documented PWHT stress relief is applied, NDE may be carried out following completion of the documented PWHT without further delay provided the attending Surveyor is satisfied with the PWHT process and subsequent weld cracking is not evident.

CHAPTER 6

Welding and Nondestructive Examination

SECTION 7

NDT Methods and Acceptance Criteria

1 General

The techniques and methods for performing the nondestructive examination and the acceptance standards to be used for each type of examination, in general, are to be in accordance with the design and applicable construction codes and standards. Acceptance and/or rejection criteria are to be as per applicable standards or specification.

Examples of applicable Standards and Codes are given below.

3 Magnetic Particle Examination

i) Methods:

- ASME Boiler and Pressure Vessel Code, Section V Article 7: “Magnetic Particle Examination”
- ASTM E709: “Standard Recommended Practice for Magnetic Particle Examination”

ii) Acceptance Criteria:

- ASME Boiler and Pressure Vessel Code, Section VIII, Div. 1, Appendix 6: “Methods for Magnetic Particle Examination (MT)”
- ANSI/AWS D1.1: “Structural Welding Code – Steel” – Clause 6 Part C

5 Liquid Penetrant Examination

i) Methods:

- ASME Boiler and Pressure Vessel Code, Section V Article 6: “Liquid Penetrant Examination”
- ASTM E165: “Standard Practice for Liquid Penetrant Inspection”

ii) Acceptance Criteria:

- ASME Boiler and Pressure Vessel Code, Section VIII, Div. 1, Appendix 8: “Methods for Liquid Penetrant Examination (PT)”
- ANSI/AWS D1.1: “Structural Welding Code – Steel” – Clause 6 Part C

7 Radiographic Examination

i) Methods:

- ASME Boiler and Pressure Vessel Code, Section V Article 2: “Radiographic Examination”
- ASTM E94: “Standard Guide for Radiographic Examination”
- ASTM E446: “Standard Reference Radiographs for Steel Castings up to 2 in. in Thickness”
- ASTM E186: “Standard Reference Radiographs for Heavy Walled (2 to 4.5 in.) (51 to 114 mm) Steel Castings”
- ASTM E280: “Standard Reference Radiographs for (4.5 to 12 in.) (114 to 305 mm) Steel Castings”

ii) Acceptance Criteria:

- ASME Boiler and Pressure Vessel Code, Section VIII, Div. 1, Appendix 4: “Rounded Indications Charts Acceptance Standard for Radio graphically Determined Rounded Indications in Welds.”
- ANSI/AWS D1.1: “Structural Welding Code – Steel” – Clause 6 Part C

9 Ultrasonic Examination

i) Methods:

- ASME Boiler and Pressure Vessel Code Section V, Article 4 “UT Examination Methods for Materials and Fabrication”
- ASTM A388: “Standard Practice for Ultrasonic Examination of Heavy Steel Forgings”
- ASTM E428: “Standard Practice for Fabrication and Control of Steel Reference Blocks Used in Ultrasonic Inspection”
- ASTM E587: “Standard Practice for Ultrasonic Angle-Beam Contact Testing”
- ASTM A609: “Standard Practice for Casting, Carbon, Low-Alloy, and Martensitic Stainless Steel, Ultrasonic Examination Thereof”

ii) Acceptance Criteria:

- ASME Boiler and Pressure Vessel Code, Section VIII, Div. 1, Appendix 12: “Ultrasonic Examination of Welds (UT)”
- ANSI/AWS D1.1: “Structural Welding Code – Steel” – Clause 6 Part C
- API 2X: “Ultrasonic Examination of Offshore Structural Fabrication and Guidelines for Qualification of Ultrasonic Technicians”

11 Hardness Testing

i) Methods:

- ASTM E10: “Standard Test Methods for Brinell Hardness of Metallic Materials”
- ASTM E110: “The Standard Test Method for Rockwell and Brinell Hardness of Metallic Materials by Portable Hardness Testers”
- ASTM E18: “Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials”
- ASTM E92: “Standard Test Method for Vickers Hardness of Metallic Materials”

ii) Acceptance Criteria:

- NACE MR0175/ISO 1515: “Materials for use in H₂S containing environments in oil and gas production”

CHAPTER 6

Welding and Nondestructive Examination

SECTION 8

Record Retention

1 General

In addition to the requirements of the applicable Codes and Standards (i.e., API specs, etc.), the manufacturer is to maintain the following records for a period of 10 years, and these records are to be made available to the ABS upon request:

- i)* Weld Procedure Specification (WPS). As specified in applicable recognized code or standard.
- ii)* Procedure Qualification Records (PQR). As specified in applicable recognized code or standard
- iii)* Welder/welding operator qualification test records including the date and test results and subsequent production records for qualification continuity.
- iv)* The manufacturer should have a system in place to record welders work. If weld repairs are required records of the repair locations associated with the welder identification are to be available to the Surveyor.
- v)* Qualification records for all personnel performing nondestructive examinations and evaluating results of examination
- vi)* Nondestructive Examination reports, location of inspection, including radiographs (the manufacturer is to provide a suitable viewer to properly illuminate radiographs). The examination report shall include but is not limited to the following:
 - Date of testing
 - Name and qualification level of personnel
 - Testing technique
 - Identification of material/product to be tested
 - Heat treatment
 - Surface condition
 - Test standards used
 - Testing conditions
 - Results
 - Statement of acceptance/non acceptance
 - Details of weld repair (if applicable) including sketch

- vii)* Manufacturing records (refer to 5-7/1)

CHAPTER 7

Surveys at Vendor's Plant During Installation and Commissioning

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CHAPTER 7

Surveys at Vendor's Plant During Installation and Commissioning

SECTION 1

General

1 General

This Chapter pertains to surveys of drilling systems, related subsystems, equipment, and/or components at the vendor's manufacturing plant and subsequent installation onboard for system assembly and completion of trials prior to issuance of Class Certificates.

CHAPTER 7

Surveys at Vendor's Plant During Installation and Commissioning

SECTION 2

Surveys at Manufacture and During Assembly

1 General Survey Requirements

When the Surveyor's attendance at the manufacturer's plant and at the assembly site is required for classification of the drilling system, the manufactured/assembled system, equipment and/or component will be verified for satisfactory compliance with the ABS approved drawings, applicable codes and/or standards, material supply requirements and the additional requirements of this Guide. See 3-2/Tables 1 through 10 for drilling system, subsystem, equipment, and/or component design review, fabrication survey and testing requirements. Test procedures are to be to the satisfaction of the attending Surveyor in accordance with the applicable design standards and the requirements of this Guide.

The classed drilling system consists of many sub parts from different worldwide locations. The vendor coordination system required by 3-2/9 is applied to confirm that all equipment requirements are met and coordinated through to installation and testing. The following is required for equipment requiring "unit certification".

- i)* A prefabrication or kick-off meeting/discussion between the manufacturer/fabricator and ABS-designated Surveyor(s) is to be carried out and documented in order, but not limited to:
 - a)* Confirm and/or establish the main point of contacts (PoC) for the manufacturer and ABS
 - b)* Review the project quality plans including nondestructive testing.
 - c)* Review proposed manufacturing specification
 - d)* Review project manufacturing and delivery schedules
 - e)* Review and confirm Surveyor examination requirements including but not limited to monitoring, hold points and documents review
 - f)* Confirm sub-contractor qualifications to the vendor's quality assurance plan.
 - g)* Confirm manufacturing specifications per item ii) of this section, access to ABS approved drawings and/or documentation associated with the design and manufacturing process
 - h)* Confirm Vendor Coordination and related functional responsibilities
 - i)* Confirm plans for testing during and after fabrication and testing to be carried out after installation.
 - j)* Confirm FMEA/FMECA Validation testing plans and location of testing.

- k)* Confirm the process for handling major non-conformances and major engineering changes
- l)* Where applicable, confirm, by review of quality control documentation of the manufacturers product control management system, that threaded fasteners used for closure bolting, pressure controlling applications, pressure retaining bolting for hydraulic connectors including bolts potentially exposed to wellbore fluids supplied by subcontractors complies with 5-1/11 and 5-1/13.

Threaded fasteners used for closure, pressure controlling and pressure retaining for hydraulic connectors and bolts potentially exposed to wellbore fluids as identified in 5-1/11 and 5-1/13 are to be visually examined for surface flaws, out of roundness, straightness, and dimensional tolerances. The surveyor, in case of doubt, may require additional nondestructive testing. Surveyor is to confirm and witness the process for installation as identified in 7-2/1ii)j), 7-2/5v), and 7-2/3ii)k).
- ii)* Manufacturing plans, specifications and/or fabrication details are to include, but not limited to, as applicable:
 - a)* Quality plan and specifications
 - b)* WPS and PQR, WPQ and weld maps
 - c)* NDE procedures and NDE reports
 - d)* Detailed Inspection and Test Plans (ITPs), including associated test procedures for system, subsystem, equipment or component, as outlined in 3-2/Tables 1 through 10, as applicable during:
 - Manufacturing (Factory acceptance testing)
 - Installation
 - Commissioning
 - In-service (Recommended periodic testing)
 - e)* Surface treatment (electroplating, galvanizing, etc.) plans and specifications as applicable
 - f)* Installation, and Commissioning plans and procedures
 - g)* Maintenance and Operating manuals
 - h)* FMEA and FMECA requirements and Validation testing to be included in the FAT procedures
 - i)* Procedures for the disposition of major manufacturing non-conformances and major engineering changes
 - j)* Procedures for the installation and testing of threaded fasteners used for closure, pressure controlling and pressure retaining bolting for hydraulic connectors and bolts potentially exposed to wellbore fluids.
- iii)* FMEA Validation test procedures are to be submitted for ABS Technical review.
- iv)* Design validation tests required by the design standard, factory acceptance and commissioning tests are to be carried out to the satisfaction of the attending Surveyor. At the discretion of the Surveyor, test procedures may be required to be submitted for technical review.
- v)* Surveyor's attendance is typically (but not limited) for the following purposes:
 - a)* To confirm that the facilities to manufacture, fabricate or repair drilling system, subsystem, equipment, and/or components have an accredited and maintain an effective quality assurance program (API Q1, ISO 9001 or equivalent) covering design,

procurement, manufacturing and testing, as applicable, and meeting the requirements of a recognized standard applied to their product.

- b)* To qualify or verify welder's qualifications to the extent deemed necessary by the attending Surveyor.
- c)* To qualify or verify welding procedure specifications and corresponding weld procedure qualification records to the extent deemed necessary by the attending Surveyor.
- d)* To verify material certificates/documentation [see 7-2/1vi) below].
- e)* To monitor in process welding, survey fit-up prior to major weldments and witness weld startup operations.
- f)* To survey final weldments and witness repair welding.
- g)* To verify the non-destructive testing program and personnel qualifications in accordance with Chapter 6 and witness, as far as deemed necessary, nondestructive examination tests of welds and to review records of nondestructive examinations.
- h)* To review records of post-weld heat treatment, in particular for piping subjected to pressurized sour service and subject to NACE MR0175/ISO 15156 requirements.
- i)* To review major non-conformances and major engineering changes.
- j)* To verify dimensions are as shown on approved drawings or engineering drawing and design specifications submitted for review.
- k)* To check dimensional tolerances and alignment of mating surfaces.
- l)* To witness design validation testing of drilling equipment or components in accordance with the applicable design specification. For drilling equipment of an existing design, documentation of design validation testing is to be submitted for review together with the design package submittal. Submittals to be verified by the attending Surveyor.
- m)* To witness pressure and/or proof-load testing of equipment and as a unit, as applicable and as specified in the fabrication procedures.
- n)* To witness final testing and functional testing of subassemblies and completed units, as specified in the fabrication procedures.
- o)* To verify all purged and pressurized systems, motor controllers, SCR banks, consoles and instrumentation and control panels are in compliance with approved drawings.
- p)* To carry out other examinations as agreed upon during prefabrication meeting.
- q)* To confirm compliance with associated ABS approval letter or IRC.
- r)* To review final manufacturing Data Book and issue final survey report and CoC, as applicable.
- s)* To verify the installation and testing of hydraulic, electrical and pneumatic control systems together with associated software in accordance with manufacturers testing procedures.
- t)* To verify electrical installations are in accordance with the approved design and meet hazardous zone requirements.
- u)* To verify FMEA testing in accordance with the ABS approved FMEA Validation testing procedures. FMEA Validation testing procedures require ABS technical review.
- vi)* Materials test reports (MTRs) are to be made available to the attending Surveyor during the manufacturing process. In general, materials associated with equipment and/or components that require Surveyor's attendance in accordance with 3-2/Tables 1 through 10, are to have complete

traceability with MTRs. As a minimum, MTRs are to be provided for the following materials as defined in Chapter 5 of this Guide:

- a)* Materials for primary structural-load bearing components
- b)* Materials for primary mechanical-load bearing components
- c)* Materials for primary pressure-retaining equipment/components
- d)* All piping, valves and fittings with an ANSI B16.5 Class 150 or greater
- e)* Bolts and nuts for fastening and/or connections used in pressure retaining, pressure containing, pressure controlling applications (closure bolting per API 6A, 16A and 20E). See also 5-1/11 of this Guide.
- vii)* The Surveyor is to be notified of any major non-conformances and major engineering changes that affect form, fit or function during the manufacturing, installation and commissioning processes. If the major non-conformance and associated corrective actions affect form, fit or function or require rectification processes, such as weld build-up of miss-machined parts, the non-conformance and proposed corrective action is to be documented and submitted to ABS together with the Manufacturers Affidavit of Compliance (MAC) stating compliance with the applicable design specifications.

3 Documentation for Surveyor Review

Traceability through the fabrication process is to be documented on primary structural load-bearing, mechanical load-bearing components and pressure-retaining/containing/controlling equipment including threaded fasteners per 5-1/11 and 5-1/13. The manufacturers are responsible for maintaining this documentation on file and, upon request, are to provide this information to the Surveyor's satisfaction.

The traceability documentation is to include, but not limited to:

- i)* Certified Materials Test Report
 - a)* Chemical and mechanical properties for each heat
 - b)* Heat treatment temperatures and time at temperature
 - c)* Charpy impact values and temperatures
 - d)* Hardness test readings (as applicable to NACE MR0175)
 - e)* Hazardous area certification
- ii)* Manufacturing Processes
 - a)* Welding records with all approved qualifications
 - b)* Post weld heat treatment
 - c)* NDT results
 - d)* Hardness test results (as applied to NACE MR0175)
 - e)* Dimensional check results
 - f)* Hydrostatic pressure tests
 - g)* Low pressure tests and rated pressure tests
 - h)* Load tests
 - i)* Electrical tests
 - j)* Function tests

- k)* Required tension results in accordance with installation procedures for closure bolts, pressure controlling applications, pressure retaining bolting for hydraulic connectors and bolts potentially exposed to well bore fluids as identified in 5-1/11 and 5-1/13. See also 7-2/1ii)j), 7-2/5v), and 7-2/1i).

5 Testing of Well Control Equipment and BOPs

The testing conducted at the manufacturer's plant and witnessed by the Surveyor for all well control equipment including choke and kill equipment, diverters, blow out preventers, and auxiliary well control equipment are to be carried out in accordance with written and/or approved procedures which include the following:

- i)* Design validation testing in accordance with API 16A of each new design is to be performed in the presence of the Surveyor.
- ii)* A hydrostatic body or shell test, hydraulic operating system test and closed preventer test in accordance with 3-2/Tables 2 and 4, and the applicable API standards. All tests for drill through equipment are to be documented by a chart recorder in accordance with API 16A requirements.
- iii)* A shear ram test to verify shear capacity in accordance with API 16A is required in accordance with 2-3/3.5 of this Guide.
- iv)* The manufacturer is to test well control equipment that incorporates a dynamic mode of sealing for low-pressure integrity at a pressure between 250 and 350 psi per API 53.
- v)* Verification of installation pre-tension values for closure bolts, pressure controlling applications, pressure retaining bolting for hydraulic connectors and bolts potentially exposed to well bore fluids. Pretension is to be carried out by controlled means or alternative means, e.g. prototype testing, electronic measuring, etc. Pre-tensioning by bolt torque or by hydraulic tensioning device, is to be in accordance with the equipment manufacturer's instructions, which are to be submitted for review. Elongation of the bolts is to be measured to verify pre-tensioning. At least 10 percent of the bolts, randomly selected, are to be measured to the satisfaction of the attending Surveyor. See also 7-2/1ii)j), 7-2/5v), and 7-2/3ii)k).
- vi)* During the operational tests at the manufacturer's plant, a full design differential pressure opening test is to be carried out for each valve and actuator combination.

Additional testing requirements are to be in accordance with 3-2/Tables 1, 2, 3 and 4.

7 Testing of Marine Drilling Riser System and Associated Components

- i)* Components of the marine drilling riser system such as the connectors, tensioning unit, riser recoil system, telescopic joint (slip joint), service lines, etc., (except risers) are to be thoroughly tested to ascertain their compliance with design requirements and their compatibility in forming the complete system.
- ii)* Hydrostatic testing of components is to be carried out at the manufacturer's plant or rebuilding facility.
- iii)* The number of riser joints tested will be as specified in the approved design of the manufacturer, as required in this Guide. See 3-2 Tables 1, 2, 3 and 4 for additional testing requirements.

9 Testing of Drill String Compensation System

Individual equipment and/or components of the drill string compensation system are to be tested in accordance with the applicable codes and standards, and 3-2/Tables 1, 2, 5 and 6 of this Guide.

11 Testing of Bulk Storage, Circulating and Transfer Systems

Pressurized components of the bulk storage, circulating, and transfer systems are to be tested in accordance with the applicable codes and standards, and 3-2/Tables 1, 2, 7 and 8 of this Guide.

13 Testing of Hoisting, Lifting, Rotating, and Handling Systems

Individual equipment and/or components of the hoisting, lifting, rotating, and handling systems are to be tested (load test, functional test) in accordance with the applicable codes and standards and 3-2/Tables 1, 2, 5, 6, 9 and 10 of this Guide, as applicable.

For tubular handling systems, the following additional testing is to be performed:

- i)* Mechanized tubular handling systems must have their safety controls verified on computer-based systems.
- ii)* Indexing of all mechanical movement must be verified by operational testing. This procedure is to be carried out in all available fingerboard configurations, and system safety verified.

15 Testing of Skid Structures

Refer to 2-7/11 for technical requirements. Where classed drilling system equipment/components are permanently mounted on a skid structure, a Surveyor's attendance is required to verify that the skid structure is in compliance with ABS reviewed structural design calculations, and to carry out the following to the satisfaction of the attending Surveyor:

- i)* Verify material test reports (MTRs) of skid materials.
- ii)* Visual examination of final weldments of skid structure.
- iii)* Witness load testing of the skid structure and associated lifting attachments. Verify SWL markings on lift attachments.
- iv)* Witness surface NDE of weldments of the lifting attachments/lugs or pad eyes.
- v)* Examination of drip pan arrangements (see 2-7/11.5).

CHAPTER 7

Surveys at Vendor's Plant During Installation and Commissioning

SECTION 3

Onboard Surveys During Installation

1 General

Onboard installation tests of all drilling systems are to be verified by a Surveyor and are to be in accordance with manufacturer's test procedures to the satisfaction of the attending Surveyor. The following surveys are to be carried out by Surveyors on systems during installation and testing in accordance with 3-2/Tables 2, 4, 6, 8 and 10. At the discretion of the attending Surveyor, test procedures may be required to be submitted for technical review.

- i)* Piping systems are to be visually examined, nondestructively examined and pressure-tested, as required by the ABS *MOU Rules* or applicable design standards.
- ii)* Pressure tests conducted on Group I piping systems (refer to 4-2-1/5 of the ABS *MOU Rules*) are to be recorded on test charts to the satisfaction of the attending Surveyor for the duration of their tests. Minimum time for holding pressure is to be 15 minutes.
- iii)* All pressure relief and safety valves ratings are to be verified and tested, as applicable per procedure agreed to by the attending Surveyor.
- iv)* Installed choke and kill systems are to be subjected to a low-pressure test between 250 and 350 psi and pressure-tested at rated working pressure in accordance with API 53. Applicable performance tests are to be carried out.
- v)* When final testing of drilling systems requires assembly and installation on-board the facility, it may not be possible to perform all required testing at vendor's plant. In this case, FMEA/FMECA validation testing is to be carried out as part of the system integration testing (SIT) during commissioning. Any modifications made to the validation test plan are to be submitted for review.
- vi)* FMEA validation testing remaining for equipment certification is to be completed if not previously completed at the vendor's plant.
- vii)* The well kill function of the cementing unit (or independent kill unit if provided) is to be tested and verified as being capable of flowing through the choke or kill lines provided. (Including multiple line configurations).
- viii)* Derrick:
 - a)* Assembled and installed derrick is to be visually examined, including welding and bolting, torqueing, water table, crown block and turnover sheave assembly, guide rails for hoisting equipment, derrick-mounted equipment, and outfitting items.

- b) Derrick dimensional control, final alignment and bolting on the drill floor/substructure foundations are to comply with manufacturer's specifications and tolerances.
 - c) Testing of the derrick is not mandatory, however, when testing is specified by the contracting party or purchaser of the derrick, load testing is required to be carried out per Appendix A- SR2 of API 4F with particulars marked on the nameplate.
 - ix) Mud pump operational test at rated working pressure and rated maximum flow is to be carried out in accordance with a test procedure agreed by the attending Surveyor.
 - x) Drawworks: As a minimum, the following tests are to be performed to verify the capacity of the independent braking systems (as defined in 2-4/9.1) of all drawworks in accordance with the ABS-approved OEM's test specifications.
 - a) Drawwork static brake test, at vendor or onboard installation:
 - 1) See 3-2/Tables 5 and 6 for test load requirements.
 - 2) On self-elevating units, deflection testing of the cantilever may also qualify as the static and structural testing of drawworks.
 - 3) On column-stabilized or surface type units, where a full rated load test may constitute increased risk or a safety concern to the unit or personnel, alternative testing methods such as load testing at a reduced number of lines with corresponding rated load may be considered on a case-by-case basis. Request for such consideration is to be submitted to ABS and approved by the Assistant Chief Surveyor – Offshore, prior to commencement of the test.
 - b) Other brake test, at vendor or onboard installation:
 - 1) *Brake Burnishing Test.* Burnishing test is to be performed for the caliper brake with consideration to brake's clamping force, drum speed, RPM, or motor speed. The following tasks are to be performed:
 - Temperature at calipers and motor are to be monitored and recorded.
 - The burnishing results such as percentage of lining contact, bright surface, etc., are to be monitored and recorded.
 - Verification of "gapping", the distance between the brakes and the brake discs, is to be performed and recorded.
 - 2) *Brake Verification.* After the brake burnishing test, individual verification of each caliper is to be performed, as applicable, under drum/motor load.
 - Motor amperage and voltage, hydraulic pressure, and loads, as applicable, associated with caliper slippage are to be monitored and recorded.
 - Each caliper must demonstrate adequate capacity as designed.
 - 3) *Electromagnetic/Regenerative Brake Test:*
 - Electromagnetic/regenerative braking system tests are to be performed for compliance with approved OEM's specifications.
 - Additional provisions of the drawworks electromagnetic braking system are provided in 2-4/9.1.
 - c) Functional test, at vendor or onboard installation:
 - 1) *Rotational Check:*
 - Verify rotation for both directions.
 - 2) *Rotational Test.* Rotational test is to be performed at 100% rated drum/motor speed in both directions for a period of at least five minutes. Repeat this step

three (3) times or in accordance with OEM specifications. The following are to be monitored and recorded for each test:

- Bearing temperature for motor, gearbox and drum
- Gearbox temperature
- Drum temperature

- d)* Functional testing of all safety devices including anti-2 blocking and motor pinion slippage detection on active heave drawworks systems
- xi)* Systems, subsystems, equipment and component associated with tensioning system and compensation system are to be tested in accordance with 3-2/Table 6.
- xii)* Systems, subsystems, equipment and component associated with all hoisting, lifting, handling and rotating systems are to be tested in accordance with 3-2/Tables 6 and 10
- Note:* Riser hang off tools are to be tested in accordance with API 16F.
- xiii)* All drilling systems and associated subsystems and equipment are to be checked for proper operation.
- xiv)* Control system and shutdowns are to be tested to the satisfaction of the Surveyor.
- xv)* All wiring and electrical connections are to be checked for continuity and proper workmanship in accordance with the
- xvi)* The supply, control, use, installation and non-destructive testing of threaded fasteners including closure bolts, pressure controlling applications and pressure retaining bolts used on hydraulic connectors and threaded fasteners subject to wellbore fluids per 5-1/11 is to be verified. See also 7-2/1i), 7-2/1ii)j), 7-2/3k) and 7-2/5iv).
- xvii)* The CDS equipment listing developed and completed by the attending Surveyor(s) after manufacturing, installation and commissioning of the drilling system is to be provided to the contracting party. Upon Classing of the drilling system, the equipment list will be duplicated on the unit's ABS records.

3 Testing of Base-mounted Winches and Other Lifting Appliances Dedicated to Drilling Operations

Testing of base-mounted winches and other lifting appliances are to comply with the following requirements and procedures:

- i)* *Load Test* – After installation, the system is to be tested with a load as per the *Lifting Appliance Guide* (equal to 1.1 to 1.25 times the rated capacity) in the presence of the Surveyor. Satisfactory operation of power drives and brakes is to be demonstrated. After being tested, the system with all its components is to be visually examined for permanent deformation and failure.
- ii)* *Performance Test* – Testing in the presence of the Surveyor is to demonstrate that rated line pull can be achieved at rated speed with the outermost layer of wire on the drum.
- iii)* *Brake Holding Test* – It is to be demonstrated that the brakes have the ability to stop and hold 100% of the design load. Confirmatory testing to demonstrate the braking effect of variable frequency drive AC motors is to be carried out upon installation onboard.

Base mounted winches used for personnel lifting are not part of the **CDS** notation. Refer to the optional requirements contained in the *Lifting Appliance Guide*.

5 Testing of Burner/Flare Boom

The adequacy of the boom's slewing and topping gear is to be demonstrated by testing after the boom's installation on the drilling unit. The details of the test procedure are to be agreed upon with ABS and witnessed by a Surveyor.

Functional testing of the completed assembly is to be carried out by pressure testing from the flexible line connection flange to the burner head.

CHAPTER 7

Surveys at Vendor's Plant During Installation and Commissioning

SECTION 4

Commissioning Surveys of the Drilling Systems

1 General

Commissioning surveys are to be in accordance with this Guide and approved test procedures and at a minimum to include verification of the following items by the attending Surveyor during the drilling system trials:

- i)* Proper hook-up and testing of the entire drilling system equipment and components is completed prior to commissioning. This is to include all tests outlined in Chapter 7, Section 3.
- ii)* Necessary safety precautions are taken during commissioning, which are to include checks of operational readiness of the fire and gas detection system, fire extinguishing system, ESD systems, unobstructed escape routes, etc.
- iii)* Necessary communication procedures are established prior to commissioning.
- iv)* Necessary emergency procedures are readily available to deal with any contingencies such as spillage, fire, and other hazards. Drills prior to commencement of commissioning may be carried out to the satisfaction of the attending Surveyor to confirm readiness of these procedures.
- v)* Readiness of all utility support systems, including main and auxiliary sources for the drilling system, prior to commissioning. Random start-up and testing of the utility support systems to extent deemed necessary by the attending Surveyor.
- vi)* Readiness of the purged drilling system equipment/components, and associated alarms and shutdowns, prior to commissioning, and random testing of the purged alarms systems during commissioning, to the satisfaction of the attending Surveyor.
- vii)* Proper operation of the mud level alarms while the drilling system is running, including random simulation of associated alarms.
- viii)* Proper operation of the hazardous area access and ventilation system while the drilling system is running, including random simulation of associated alarms and shutdowns.
- ix)* Satisfactory functioning of all drilling systems installed onboard and covered under this Guide for a minimum duration of 12 hours. This will include witnessing proper function of the following systems, as applicable, while simulating actual drilling operations to the extent possible and practicable, and to the satisfaction of the attending Surveyor:
 - a)* Well control system including function testing of BOP control line support and tensioning on subsea systems

- b)* Derrick handling systems: Riser running, compensation/tensioning, hoisting and BOP handling
 - c)* HP and LP mud circulation systems
 - d)* Dedicated pipe and tubular handling systems
 - e)* Controls and collision avoidance management systems
 - x)* Complete function testing, pressure testing, and control system testing of the well control system to the satisfaction of the Surveyor. Tests are to be in accordance with API 53 and to include at least the following:
 - a)* Complete function test of all well control components with the BOP on deck:
 - All control stations
 - All pods
 - All ROV panels and acoustic controls
 - All components and preventers of BOP stack
 - Latching components
 - Deadman and autoshear capabilities
 - Emergency disconnect systems
 - Remote controls for Choke and kill manifold
 - Diverter
 - b)* Pressure testing of the BOP stack:
 - Low pressure test
 - High pressure test to rated working pressure
 - Hydraulic chamber test
- xi)* Satisfactory functioning of all systems on the backup power source(s) to confirm proper operation.

CHAPTER 8

Surveys After Construction and Maintenance of Class

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CHAPTER 8

Surveys After Construction and Maintenance of Class

SECTION 1

General

1 General (1 February 2021)

The provisions of this Chapter are requirements for the maintenance of Classification of the drilling systems. These requirements are in addition to the provisions noted in other ABS Rules such as Part 7 of the ABS *MOU Rules*.

For purposes of this Section, the commissioning date of the drilling system will be the date on which a Surveyor issues an Interim Class Certificate for the drilling unit with the applicable **CDS** notation.

Surveys of classed systems are based on the classification designation and the listing of the equipment on the unit's survey status. All requirements apply where all drilling systems covered in this Guide are classed. Where class has been adjusted to one or more sub notations per 1-2/3, periodic surveys of the applicable systems will apply.

Chapter 8 Surveys After Construction and Maintenance of Class is applied to all existing vessels on the effective date of the Rule Change Notice unless explicitly stated otherwise in this Guide.

3 Survey Intervals (1 July 2020)

All Annual and Special Periodical Surveys of Drilling Systems/Equipment, as defined in Chapter 8, Section 3, are to be carried out at the same time and interval as the periodical Classification survey of the drilling unit so that they are recorded with the same crediting date.

- i)* An Annual Survey of the drilling systems is to be carried out by a Surveyor within three months before or after of each annual anniversary date of the initial Classification survey.
- ii)* A Special Periodical Survey of the drilling system is to be carried out within five years of the initial Classification certification survey and at five-year intervals thereafter.
- iii)* Required surveys are to be completed within three (3) months of their due dates.
- iv)* Annual and Special Periodical Surveys may be carried out during a scheduled overhaul period of the drilling system within the allowable time frames
 - a)* Annual Surveys are to be scheduled to coincide with the planned or routine maintenance of the BOP stack and/or spare BOP stack as applicable.
 - b)* Special Periodical Surveys are to be scheduled to coincide with the Owner's planned major maintenance, inspection and testing of the BOP stack and/or spare BOP stack as applicable.

- c) Stock/Spare equipment and components on board the drilling unit are to be surveyed during Annual and Special Periodical Surveys. Any spare components dedicated to the unit, such as a spare BOP Stack, are to be included in the survey status of the drilling unit for periodic surveys.

At the request of the Owner, and upon approval of the proposed arrangements, a system of Continuous Surveys may be undertaken whereby the Special Periodical Survey requirements are carried out in regular rotations to complete all requirements of the particular Special Periodical Survey within a five-year period.

- i) The completion date of a continuous survey will be recorded to agree with the original due date of the special periodical cycle.
- ii) If the Continuous Survey is completed within three months prior to the due date, the Special Continuous Survey will be credited to agree with the effective due date.
- iii) Each part (item) surveyed becomes due again for survey five years from the date of the survey.
- iv) For Continuous Surveys, a suitable notation will be entered in the *Record* and the date of completion of the cycle published.
- v) If any defects are found during the survey, they are to be dealt with to the satisfaction of the Surveyor prior to crediting the survey.
- vi) ABS reserves the right to authorize extensions of Rule-required Special Continuous Surveys under extreme circumstances.

3.1 Survey of Stock/Spare Equipment and Components (1 July 2020)

When a stock/spare equipment or component certified by ABS is maintained at an onshore facility and is not on board a drilling unit, the following requirements are to apply when the item is installed on a drilling unit with **CDS** notation more than 12 months after the ABS survey report date:

- i) The attending ABS Surveyor at the onshore facility is to issue a Maintenance Release Note (MRN) as outlined in Chapter 8, Section 2 once the equipment has been deemed satisfactory.
- ii) Equipment and/or component is to be examined by an ABS Surveyor before installation in accordance with Chapter 8, Section 2.

Surveys during installation and commissioning are to be carried out as outlined in Chapter 7, Sections 3 and 4, as applicable.

5 Drilling Equipment Maintenance Records

- i) Maintenance plans, and records with repair and replacement history will be reviewed by the attending Surveyor to establish the scope and content of the required Annual and Special Periodical Surveys.
- ii) Records of changes or additions made to CDS equipment are to be available to the attending Surveyor for review and verification.
- iii) The Surveyor may determine during the periodic survey if the changes are sufficient to warrant review by ABS Engineering.
- iv) Wire rope is to be replaced in accordance with the manufacturer's recommended maintenance procedures.
- v) Wire ropes are to be replaced if damage exceeds manufacturer's specifications for their rated capacity or if damage could affect smooth passage through sheaves.

7 Use of Temporary Equipment

Where non-classed equipment is required to be substituted for equipment items subject to the applicable class requirements in accordance with this Guide, the Owner is to notify ABS and the following conditions apply:

- i) Details of the equipment and equipment certifications and changes in associated control systems are to be submitted to ABS for technical review.
- ii) A risk assessment is to be performed to assess any impact on the classed systems and the FMEAs carried out on the control systems are to be updated to accommodate changes due to the installation of temporary equipment.
- iii) The time period for use of the temporary equipment is to be agreed upon by ABS and the limits of class are to be established for the agreed period.
- iv) A Surveyor's attendance on board will be required to carry out system testing and Validation of changes to the FMEA for the control systems

9 Leased Drilling Equipment

When drilling equipment supplied to an ABS classed drilling unit is owned by a company other than the unit's owner, ABS can maintain class on the leased equipment at the request of the equipment owner. The unit will be eligible to receive any sub notation the leased equipment satisfies.

The equipment owner will receive reports detailing the surveys conducted on the equipment. The unit owner will receive notification of any recommendations that may affect the unit's sub-notation that the leased equipment satisfies.

11 Marine Drilling Riser (1 February 2021)

For systems contracted on or after 01 October 2017, the requirements below apply:

Marine drilling riser is frequently stored on locations other than the drilling unit, and can even be shared between multiple drilling units. In many cases, the riser may be maintained in a storage area for several years without being used. ABS recognizes that this equipment is not in continual use, and that maintenance periods for the equipment may be usage based instead of calendar based. To accommodate this operational profile, ABS requires the owner of the unit to maintain an approved maintenance program.

- i) The riser maintenance program is to be submitted for technical review and maintained on board for verification by the attending Surveyor.
- ii) Riser Operations, Maintenance and Inspection manual is to be **submitted for technical review and maintained on board for verification by the attending Surveyor**. See 2-3/13.7 for details.
- iii) The program is to include requirements for an annual survey by the Owner with an annual report. The Owner's annual report is to include a complete listing of all the riser joints included in the unit's complement. Each riser is to have the following information available:
 - a) History of usage
 - b) Maintenance schedules
 - c) Maintenance conducted
 - d) Overhauls completed
 - e) MRN certificates and reports
 - f) Current location

CHAPTER 8

Surveys After Construction and Maintenance of Class

SECTION 2

Surveys Onshore and Issuance of Maintenance Release Notes

1 General (1 July 2020)

During operation of the drilling unit when parts of the classed drilling system equipment are returned ashore for maintenance, repair or modification purposes, it is the responsibility of the Owner to inform Surveyors of the scope of work at the shore facility/plant.

- i)* The maintenance of drilling systems, subsystems, equipment or component is to be in accordance with the Manufacturer's and Owner's specifications.
 - a)* Non-Original Equipment Manufacturer (OEM) personnel are to have demonstrated competence to perform maintenance and/or overhaul activities.
 - b)* Maintenance and overhaul are to be carried out in accordance with the OEM Manual, product bulletins, service bulletins, as applicable.
 - c)* Repairs, modifications, and replacement parts are to be in accordance with ABS approved design where design review is required by this Guide. For further information, see 3-2/ Tables 1 through 10.
- ii)* A kick-off meeting between the manufacturer/fabricator and ABS-designated Surveyor(s) is to be scheduled for the maintenance, repair or modification purposes prior to commencement of the work in order to:
 - a)* Confirm availability of approved drawings and documents for maintenance or repair of equipment
 - b)* Assess the need for ABS technical review of proposed repairs or modifications
 - c)* Confirm and/or establish the main point of contacts (PoC) for the manufacturer and ABS
 - d)* Review the project and/or manufacturer's quality plans
 - e)* Review test procedures
 - f)* Review manufacturing specifications
 - g)* Review project manufacturing and delivery schedules
 - h)* Review and confirm project "hold-points"
 - i)* Review sub-contractor lists and/or qualifications

The above list is not all inclusive and the kick off meeting is not limited to the above.

- iii)* Surveyors are to attend the facility/plant for the required function, load and/or pressure testing carried out on the drilling system equipment prior to their release. Tests conducted are to follow guidelines outlined in 3-2/Tables 1 through 10, as applicable.
- iv)* Upon completion of approved repairs/modifications, review of applicable documentation and satisfactory completion of tests, a “Maintenance Release Note” (MRN) will be issued by the attending Surveyor. See Appendix 6 for an example of the “Maintenance Release Note” (MRN).
- v)* All MRNs are to be maintained onboard the drilling unit as part of the Owner maintenance record and for verification by the attending Surveyor during Classification surveys of the unit.

CHAPTER 8

Surveys After Construction and Maintenance of Class

SECTION 3

Survey of Drilling Systems

1 Annual Surveys

At each Annual Survey, the Surveyor is to verify the satisfactory condition of the applicable classed drilling systems and equipment by visual examination and testing, as appropriate. As a minimum, the following is to be carried out to the satisfaction of the attending Surveyor:

- i)* Review of Owner maintenance system and relevant logs/records to confirm that:
 - a)* A suitable maintenance program is in place and in use.
 - b)* Periodical testing requirements have been carried out, as applicable.
 - c)* Any repairs, replacements, reconditioning or renewals of applicable well control systems and equipment, drilling support systems/equipment or support systems and equipment, as defined in the scope of this Guide, were carried out according to the applicable codes and standards and the requirements of this Guide.
- ii)* Review of ABS-issued MRNs and/or CoCs since initial or last Annual Survey, and examination of this equipment to extent deemed necessary by the attending Surveyor.
- iii)* Review of applicable lists of classed equipment and systems for approved changes made to the drilling system equipment components and controls systems and examination and testing to the extent deemed necessary by the attending Surveyor.
- iv)* Where applicable to the equipment and systems associated with the CDS class designation, exposed surfaces of the derrick, ladders, working/service platforms, drilling hoisting systems, lifting devices, burner booms, stabbing boards, racking boards/platforms and drilling equipment foundations are to be examined and placed in satisfactory condition, as found necessary.
- v)* The inspection of the derrick and related structural members will include the following:
 - a)* The general condition of the structure, especially bent, missing or abraded parts and lost corrosion protection coatings.
 - b)* Tightness of bolts and verification of maintenance records for periodic checking of bolt torque in accordance with the manufacturer's recommendations.
 - c)* For in-service inspection, cracks are generally identified by visual examination, and the interval of inspection may need to be appropriately determined specifically for galvanized structures.

- vi)* Where well control systems (WCS) are included in the CDS class of the unit, maintenance and service records (including tracking of replacements) of threaded fasteners including closure bolts, pressure controlling applications, pressure retaining bolts used on hydraulic connectors and bolts potentially exposed to well bore fluids are to be verified. Records of installation and testing per manufacturers recommended practice are to be available to the attending Surveyor. See 5-1/11 and 5-1/13.
- vii)* Condition of wire ropes and fittings.
- viii)* Examination of all mounting hardware and the structure of base-mounted winches and other lifting devices.
- ix)* General external examination so far as accessible of the drilling systems, subsystems, equipment and components as noted in the scope of Chapter 1, Section 2 of this Guide for structural or mechanical damage, excess corrosion, or malfunctions, etc.
- x)* Protective covers, insulation, shrouds and protective guards around moving parts are to be generally examined as far as practicable and found or placed in satisfactory condition.
- xi)* Derrick walkways and ladders, drill floor and drill system machinery spaces to be surveyed with particular attention to fire and explosion hazards, continued compliance with the hazardous area plan and confirmation that emergency escape routes are not blocked.
- xii)* External examination of pressure vessels and their appurtenances, including safety devices, foundations, controls, relieving gear, piping systems, flexible lines/hydraulic hoses, insulation and gauges.
- xiii)* Examination of safety shutdown devices with functional testing as deemed necessary by the attending Surveyor.
- xiv)* General examination of electrical and instrumentation systems, including protective devices and cable supports.
- xv)* For software controlled systems: Validation of satisfactory operating history and testing and testing of software control systems is to be carried out to the satisfaction of the attending Surveyor. Where software code and functionality has changed, the FMEA may be required to be updated and submitted for ABS Technical approval.
- xvi)* External examination of mud and cement systems.
- xvii)* External examination of the BOP stack, to the extent as practical, inclusive of choke and kill manifold, test log and maintenance records.
- xviii)* Review of NDE records for shear rams.

Blind shear ram blades and bodies with hardness properties in excess of 26 HRC require special controls to avoid sulfide stress cracking (SSC). Compliance to NACE is achieved by management of the environment as recommended in NACE 17025:2015 Section A.2.3.2.3 and additional nondestructive evaluation. These controls are to be incorporated into the service manuals for the equipment.

The Surveyor is to refer to the ABS issued blind shear ram design review letter for details on whether the rams require special examination, and verify that the following items are completed for rams of this type:

- a)* For rams that have been exposed to H₂S, the attending Surveyor is to verify that the inspection plan has been conducted during each between well period, and is to review records of the examination.
- b)* For all affected blind shear rams, the attending Surveyor is to verify the manufacturer's annual inspection requirements have been completed (in accordance with API 53 and the Surveyor is to review records of the examination.

- c) When the NDE is conducted on through hardened rams, special attention is to be paid to any areas with stress concentrations.
- xix) Testing of the BOP equipment in accordance with API 53, and/or as required by local regulations:
 - a) Pressure and functional testing
 - b) Control system testing
- xx) Review BOP inspections and maintenance records in accordance with Section 6 (surface BOPs) and/or Section 7 (subsea BOPs) of API 53.
- xxi) Collision avoidance systems are to be function tested.
- xxii) Marine Riser Maintenance Program:

When the riser system is part of the **CDS** class (full **CDS** or **CDS (WCS)**), an annual confirmation of the riser maintenance program is to be carried out by the attending Surveyor. This survey is to be carried out simultaneously with each Annual Survey of the classed drilling systems. The purpose of this survey is to verify that the program is being correctly operated and that the riser is maintained and has been functioning satisfactorily since the previous survey. The survey is to at least include the following:

- a) A general examination of the available riser joints.
- b) The Surveyor is to review the Owner's annual report, and the required onboard documentation required by the Riser Operations Manual. See 2-3/13.7.
- c) The performance and maintenance records are to be examined to verify that the riser has functioned satisfactorily since the previous survey or action has been taken in response to riser operating parameters which are outside acceptable tolerances and the overhaul intervals have been maintained.
- d) Written details of breakdowns or malfunctions of the equipment is to be made available.
- e) At the discretion of the Surveyor, riser sections may be subject to a close visual examination including removal of floatation where required and nondestructive testing of suspect areas.

3 Special Periodical Surveys

The Special Periodical Survey is to include all items listed under the Annual Survey, and, in addition, the following is to be carried out to the satisfaction of the attending Surveyor:

- i) Review of Owner maintenance records to review and confirm that:
 - a) Periodical testing requirements have been carried out, as applicable.
 - b) Any repairs, replacements, reconditioning or renewals of well control systems/equipment, drilling support systems/equipment or support systems and equipment, as defined in the scope of this Guide, were carried out according to the applicable codes and standards and the requirements of this Guide.
- ii) Internal examination and/or thickness gauging of pressure vessels and pressure-retaining components, testing of relief valves and pressure piping systems, as considered necessary by the Surveyor.
- iii) Hydrostatic testing of pressure vessels and other pressure-retaining components related to the drilling system to their maximum allowable working pressure (MAWP) as documented by the manufacturer's operation manual or ABS approved plans.
- iv) Hydrostatic testing of drilling system piping systems and flexible lines/hydraulic hoses to their MAWP.

- v) Verification of insulation resistance testing of motors that are part of the drilling system.
- vi) Examination of rotating drilling machinery to verify suitable operation and free from excessive vibration.
- vii) The blowout preventer is to be subjected to a complete performance test and pressure-tested to its MAWP.
- viii) Examination of mud and cement pump fluid ends. System testing to be carried to the satisfaction of the attending Surveyor.
- ix) Functional testing of derrick gear, drilling hoisting systems and derrick floor lifting devices with available load.
- x) Close visual examination of the condition of welded joints on the derrick and associated structure, including nondestructive testing (including thickness gauging if required) of any suspect areas noted by the attending Surveyor.
- xi) Internal Examination of the critical equipment associated with the well control system and their maintenance records. Continued compliance with the manufacturer's specifications is to be confirmed.
- xii) Satisfactory functioning of the emergency power equipment.
- xiii) Retesting of lifting appliances dedicated to drilling in accordance with the load testing requirements of the applicable design codes and standards, such as API 2C, ABS *Lifting Appliance Guide*, etc.

5 Well Control Event Survey

Surveyor's attendance is required if the blind-shear or casing shear ram was activated in a well control situation. The Owner is to inform ABS of the well control event and plans for servicing the BOP. Surveyor is to be in attendance for the Owner inspection and testing of the BOP.

CHAPTER 8

Surveys After Construction and Maintenance of Class

SECTION 4

Alternatives to Periodical Survey

1 General

Alternative survey programs, as outlined below, can be implemented to achieve and complete the survey objectives as specified in Chapter 8, Section 3.

The alternative survey program is to be submitted by the Owner to ABS for review and approval.

3 Survey Based on Preventative Maintenance Techniques

A properly conducted preventative maintenance/condition-monitoring plan may be credited as satisfying the requirements of Special Survey.

This plan must be in accordance with Appendix 7-2-4, “Preventive Maintenance Program” of the ABS *MOU Rules*.

5 Surveys Using Risk-based Techniques

A properly conducted Risk-based Inspection plan or Reliability-centered Maintenance Plan may be credited as satisfying requirements of Special Survey.

The plan must be in accordance with the ABS *Guide for Surveys Using Risk-based Inspection for the Offshore Industry* or the ABS *Guide for Surveys Based on Reliability-Centered Maintenance*.

Components comprising the BOP are not eligible to be enrolled in a Risk-based PM plan for survey crediting purposes. 166

CHAPTER 8**Surveys After Construction and Maintenance of Class****SECTION 5****Modifications, Damage and Repairs****1 General**

When it is intended to perform any modifications to machinery, piping, equipment, etc., which may affect Classification, the details of such modifications are to be submitted for approval and the work is to be carried out to the satisfaction of the Surveyor.

- i)* When a system certified with ABS has suffered any damage to machinery, piping or equipment, etc., which may affect Classification, ABS is to be notified and the damage examined by a Surveyor.
- ii)* Details of intended repairs are to be submitted to the Surveyor and the work is to be carried out to the satisfaction of the attending Surveyor. Repair details may be required to be submitted for technical review at the discretion of the Surveyor.
- iii)* Where component parts suffer a premature or unexpected failure, and are subsequently repaired or replaced without Surveyor attendance, details of the failure, including the damaged parts where practicable, are to be retained onboard for examination by the Surveyor during the next scheduled survey/visit.
- iv)* Alternatively, the component(s) may be taken ashore for examination and testing, as required. If failures are deemed to be a result of inadequate or inappropriate maintenance, the onboard maintenance plan is to be amended and the changes noted for verification by the Surveyor.

APPENDIX 1

Typical Codes and Standards Related to ABS Classification of Drilling Systems

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APPENDIX 1

Typical Codes and Standards Related to ABS Classification of Drilling Systems

SECTION 1

Typical Codes and Standards Related to ABS Classification of Drilling Systems

The latest edition of the following codes and standards are applicable and referenced in this Guide.

ABS is prepared to consider other appropriate alternative methods and recognized codes and standards. When alternate codes and/or standards are proposed, comparative analyses are to be provided to demonstrate equivalent level of safety to the recognized standards as listed in this Guide and are to be performed in accordance with Chapter 1, Section 5 of this Guide.

API

2INT-MET	Hurricane Conditions in the Gulf of Mexico
16J	Comparison of Marine Drilling Riser Analysis
2MET	Deviation of Metocean Design and Operating Conditions
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14B	Design, Installation, Operation and Redress of Subsea Safety Valve Systems RP 14C Analysis, Design, Installation and Testing of Basic Surface Systems on Offshore Production Platforms
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505	Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2
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521	Pressure Relieving and Depressuring Systems
610	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries
2000	Venting Atmospheric and Low-Pressure Storage Tanks
2003	Protection Against Ignitions Arising Out of Static, Lightning and Stray Contents

ASME

B31.3 Process Piping

Boiler and Pressure Vessel Code:

- Section V Nondestructive Examination
- Section VIII, Div. 1 Rules for Construction of Pressure Vessels
- Section VIII, Div. 2 Alternative Rules for Construction of Pressure Vessels
- Section IX Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators
- Section X Fiber-Reinforced Plastic Pressure Vessels

ASNT

SNT-TC-1A	Personnel Qualification and Certification of Nondestructive Testing
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ASTM

A143	Standard Practice for Safeguarding Against Embrittlement of Hot-Dip Galvanized Structural Steel Products and Procedure for Detecting Embrittlement
A153	Standard Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware
A384	Standard Practice for Safeguarding Against Warpage and Distortion During Hot-Dip Galvanizing of Steel Assemblies
A385	Standard Practice for Providing High-Quality Zinc Coating (Hot-Dip)
A388	Standard Practice for Ultrasonic Examination of Heavy Steel Forgings

A609	Standard Practice for Casting, Carbon, Low-Alloy, and Martensitic Stainless Steel, Ultrasonic Examination Thereof
A770	Standard Specification for Through-Thickness Tension Testing of Steel Plates for Special Applications
B849	Standard Specification for Pre-Treatments of Iron or Steel for Reducing Risk of Hydrogen Embrittlement
B850	Standard Guide for Post-Coating Treatments of Steel for Reducing the Risk of Hydrogen Embrittlement
D1418	Standard Practice for Rubber and Rubber Latices-Nomenclature
E8	Standard Test Methods for Tension Testing of Metallic Materials
E10	Standard Test Methods for Brinell Hardness of Metallic Materials
E18	Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials
E92	Standard Test Method for Vickers Hardness of Metallic Materials
E94	Standard Guide for Radiographic Testing
E110	The Standard Test Method for Rockwell and Brinell Hardness of Metallic Materials by Portable Hardness Testers
E165	Standard Practice for Liquid Penetrant Inspection
E186	Standard Reference Radiographs for Heavy Walled (2 to 4.5 in.) (51 to 114 mm) Steel Castings
E280	Standard Reference Radiographs for (4.5 to 12 in.) (114 to 305 mm) Steel Castings
E428	Standard Practice for Fabrication and Control of Steel Reference Blocks Used in Ultrasonic Inspection
E446	Standard Reference Radiographs for Steel Castings up to 2 in. in Thickness
E587	Standard Practice for Ultrasonic Angle-Beam Contact Testing
E609	Standard Practice for Casting, Carbon, Low-Alloy, and Martensitic Stainless Steel, Ultrasonic Examination Thereof
E709	Standard Recommended Practice for Magnetic Particle Examination
AWS	
D1.1	Structural Welding Code – Steel
BCSA	
Publication No. 40/05	Galvanizing Structural Steelwork – An Approach to the Management of Liquid Metal Assisted Cracking
EN	
473 / ISO 9712	Non-destructive testing – Qualifications and certification of NDT personnel – General principles
12385	Steel Wire Ropes. Safety. General Requirements
IEC	
61508	Functional Safety of Electrical/Electronic/Programmable Electronic Safety-Related Systems, Part 1 - 6
IEEE	

C37.06.1	Guide for High Voltage Circuit Breakers Rated on Symmetrical Current Basis Designated “Definite Purpose for Fast Transient Recovery Voltage Rise Times”
C37.20.6	4.76 kV to 38 kV Rated Ground and Test Devices Used in Enclosures
Std.45	Recommended Practice for Electrical Installations on Shipboard
Std.142	Recommended Practice for Grounding of Industrial and Commercial Power Systems
Std.242	Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

ISO

9712	Non-destructive testing – Qualifications and certification of NDT personnel – General principles
19901-1	Petroleum and Natural Gas Industries – Specific requirements for offshore structures – Part 1: Metocean design and operating considerations-First Edition

NACE

MR 0175/ISO 15156	Materials for use in H ₂ S containing environment in oil and gas production
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NFPA

37	Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines
70	National Electrical Code
496	Standard for Purged and Pressurized Enclosures for Electrical Equipment

SAE

J517	Hydraulic Hoses
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APPENDIX 2

Typical Example of Manufacturer's Affidavit of Compliance (MAC)

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APPENDIX 2

Typical Example of Manufacturer's Affidavit of Compliance (MAC)

SECTION 1

Typical Example of Manufacturer's Affidavit of Compliance (MAC)

The following is an example of Manufacturer's Affidavit of Compliance (MAC), issued in accordance with 3-2/3.3 and 3-2/Tables 1, 3, 5, 7 and 9.

The contents of the MAC are to be specific to the manufacturer's equipment or components and the respective design and manufacturing parameters.

ABC Manufacturing Company

12345 Street Avenue
 City, State, [Zip Code/Postal Code]
 Country

Date: Jan 01, 2017

MANUFACTURER'S AFFIDAVIT OF COMPLIANCE

Manufacturer & Address : ABC Manufacturing Company
 : 12345 Street Avenue
 : City, State (Zip Code)

Customer & Address : XYZ Drilling Corporation
 : 12345 Street Avenue
 : City, State (Zip Code)

Customer PO# : AAA-12345

Description of Equipment : Ram Assembly 5 ½" 18-15M

Equipment Model Number :

Equipment Part/Serial Number : XXX-YYY

Date of Manufacturing :

Equipment Pressure Rating or Load Rating : Temperature Rating: (min / max) °C

Equipment Test Pressure or Test Load :

Date of Pressure Test or Load Test :

Code(s), Standard(s) or Specification(s) Applied : (list all applicable)

This affidavit is prepared by the undersigned, authorized representative of the manufacturer, to certify that the equipment described above and supplied for this order is in full compliance with respect to the design, assembly, manufacture, and testing of the equipment in accordance with the referenced code(s), standard(s) or specification(s), and is suitable for the intended use in accordance with the referenced design parameters.

This affidavit is prepared by the undersigned, authorized representative of the manufacturer, to certify that the equipment described above is in compliance with the requirements of the ABS "Guide for the Classification of Drilling Systems", and is enclosed as part of the equipment delivery/shipment documents.

Signature _____
 Name :
 Title :
 Date :

APPENDIX 3

Typical Example of Independent Review Certificate (IRC)

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APPENDIX 3

Typical Example of Independent Review Certificate (IRC)

SECTION 1

Typical Example of Independent Review Certificate (IRC)

The following is an example of ABS Independent Review Certificate (IRC), issued in accordance with 3-2/7.3 and 7-3/Table 3.

The contents of the IRC and associated CoC are to be specific to the equipment and its respective design parameters and approval.

AMERICAN BUREAU OF SHIPPING INDEPENDENT REVIEW CERTIFICATE

IRC No.: _____

Issuance Date: _____

ABS OPN/PID: _____

This is to certify that the design plans and data for the manufacture of the equipment listed below have been reviewed and found to be in compliance with the specified codes, standards, or specifications, and the ABS 2017 Guide for the Classification of Drilling Systems.

Manufacturer & Address : ABC Manufacturing Company
 12345 Street Avenue
 City, State (Zip Code)

Description of Equipment : RAM BOP ASSEMBLY
Equipment Model : 18-15K DUAL CAVITY
Equipment Part Number : XXXXXXX Rev. XX
Equipment Design Conditions :

Maximum Rated Working Pressure	:	15,000 psi
Hydrostatic Test Pressure	:	22,500 psi
Operator Working Pressure	:	3,000 psi
Design Temperature	:	(-20 / 250) °F, (-29 / 121) °C
Service Condition	:	H ₂ S Service

Codes, Standards, or Specifications : API Specification 16A, 3rd Edition; NACE MR-0175, 2009 Edition; API Standard 53, 4th Edition

Drawings and documentation as per attached list.

Roy H. Bleiberg
 Vice President of Engineering
 ABS Americas

By _____
 ABS Engineer
 Principal Engineer
 Offshore Engineering Department – Machinery Group

This certificate is a representation that the structure, item of material, equipment, machinery or other item covered by this certificate has met one or more of the Rules, Guides standards or other criteria of ABS or of a National Administration and is issued solely for use by ABS, its committees, its clients or other authorized entities. The validity, applicability and interpretation of this certificate is governed by the Rules and Standards of ABS, and ABS shall remain the sole judge thereof. Nothing contained in this certificate or in any notation made in contemplation of this certificate shall be deemed to relieve any designer, builder, owner, manufacturer, seller, repairer, operator or other entity of any warranty express or implied. IRC-3-09

Attachment to ABS Independent Review Certificate No.

Date: _____

DRAWING AND DOCUMENTATION LIST

[illegible]

RELATED CORRESPONDENCE/PREVIOUS APPROVALS:

- This certificate is a representation that the structure, item of material, equipment, machinery or other item covered by this certificate has met one or more of the Rules, Guides standards or other criteria of ABS or of a National Administration and is issued solely for use by ABS, its committees, its clients or other authorized entities. The validity, applicability and interpretation of this certificate is governed by the Rules and Standards of ABS, and ABS shall remain the sole judge thereof. Nothing contained in this certificate or in any notation made in contemplation of this certificate shall be deemed to relieve any designer, builder, owner, manufacturer, seller, repairer, operator or other entity of any warranty express or implied. IRC-3-09

APPENDIX 4

Example of Certificate of Conformity (CoC)

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APPENDIX 4

Example of Certificate of Conformity (CoC)

SECTION 1

Example of Certificate of Conformity (CoC)

The following is an example of ABS Certificate of Conformity (CoC), issued in accordance with 3-2/7.3 and 3-2/Table 3.

The contents of the IRC and associated CoC are to be specific to the equipment and its respective design parameters and approval.

AMERICAN BUREAU OF SHIPPING

CERTIFICATE OF CONFORMITY

Certificate No.:

ABS OPN/PID: _____

Date: _____

Independent Review Certificate (IRC)

IRC No.: _____

Issuance Date: _____

This is to certify that the undersigned Surveyor has surveyed the following equipment in accordance with the *ABS Guide for the Classification of Drilling Systems*.

Manufacturer & Address

: ABC Manufacturing Company
 : 12345 Street Avenue
 : City, State (Zip Code)

Description of Equipment

: Ram Assembly 5 1/2" 18-15M

Equipment Model No.

:

Equipment Part/Serial No.

: XXX-YYY

Date of Survey

: Jan 01, 2017

Equipment Design Conditions:

Maximum Rated Working Pressure/Load:

Design Temperature: (min / max) °C

Service Condition

H₂S (yes / no)

Equipment Design Code or Standard

:

Scope of Survey:

Equipment Testing, as applicable:

Test Pressure / Load :

Temperature :

Gage Number :

Calibration Date :

Hold Time :

Drawing or Documentation:

Port of Issue: _____

Issued by: _____

ABS Surveyor

 Signature

This Certificate evidences compliance with one or more of the Rules, guides, standards or other criteria of ABS and is issued solely for the use of ABS, its committees, its clients or other authorized entities. This Certificate is a representation only that the structure, item of material, equipment, machinery or any other item covered by this Certificate has met one or more of the Rules, guides, standards or other criteria of ABS as of the date of issue. Parties are advised to review the Rules for the scope and conditions of classification and to review the survey records for a fuller description of any restrictions or limitations on the vessel's service or surveys. The validity, applicability and interpretation of this Certificate are governed by the Rules and standards of ABS, and ABS shall remain the sole judge thereof. Nothing contained in this Certificate or in any notation made in contemplation of this Certificate shall be deemed to relieve any designer, builder, owner, manufacturer, seller, supplier, repairer, operator or other entity of any warranty express or implied.

APPENDIX 5
Example of Survey Report (SR)

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APPENDIX 5

Example of Survey Report (SR)

SECTION 1

Example of Survey Report (SR)

The following is an example of ABS Survey Report (AB Report Vendor), issued in accordance with 3-2/7.1 and 3-2/Tables 1, 3, 5, 7 and 9.

The contents of the Survey Report are to be specific to the equipment and its respective design parameters and approval.



AMERICAN BUREAU OF SHIPPING

Customer Name:	ABC MANUFACTURING COMPANY	Purchase Order No.:	12345678
Attending Office:	City, State (Zip Code)	Report Number:	HS1234567
First Visit Date:	January 02, 2017	Last Visit Date:	February 02, 2017

Certification Of: Bonnet Assembly Quantity: One (1)

Manufacturer: ABC MANUFACTURING COMPANY
12345 Street Avenue
City, State (Zip Code)

Survey Location: ABC MANUFACTURING COMPANY

Equipment Data: Serial No. XY-11111-01

EXAMPLE

This is to Certify that the undersigned surveyor(s) to this Bureau did, at the request of the customer, carry out the following survey and report as follows:

Surveyor(s) to The American Bureau of Shipping
Attending Surveyors

Last Name, First Name _____

Reviewed By: _____

NOTE: This report evidences that the survey reported herein was carried out in compliance with one or more of the Rules, guides, standards or other criteria of ABS and is issued solely for the use of ABS, its committees, its clients or other authorized entities. This Report is a representation only that the vessel, structure, item or material equipment, machinery or any other item covered by this Report has been examined for compliance with, or has met one or more of the Rules, guides, standards or other criteria of American Bureau of Shipping. The validity, applicability and interpretation of this report are governed by the Rules and standards of ABS, and ABS shall remain the sole judge thereof. Nothing contained in this Report or in any notation made in the contemplation of this Report shall be deemed to relieve any designer, builder, owner, manufacturer, seller, supplier, repairer, operator or other entity of any warranty express or implied.

AB Report Vendor

APPENDIX 6

Example Maintenance Release Note (MRN)

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APPENDIX 6

Example Maintenance Release Note (MRN)

SECTION 1

Example Maintenance Release Note (MRN)



Report Number: HS03179
 Port of: Houston
 Date: Jan 01, 2017
 P.O. No.: AA-BB-CCC

Owner: XYZ Drilling Corporation
 Address: _____
 Name of Drilling Unit: XYZ-001
 ABS OPN/VID: 0123456
 Supplier & Location: Drilling Rig Equipment Inc. – Houston, Texas

EXAMPLE ABS CLASSED DRILLING SYSTEM COMPONENT MAINTENANCE RELEASE NOTE

This is to certify that the undersigned Surveyor to this Bureau, did at the request of the Client, carry out an examination of the below stated drilling system component in accordance with *ABS Guide for the Classification of Drilling Systems* and other below stated standards.

The component(s) was(were) examined, pressure-tested (as applicable), its function and shutdowns, as fitted, were tested, its maintenance records and documentation package including the nondestructive examination records (as applicable) were reviewed, and considered satisfactory subject to installation on board the above noted drilling unit.

The undersigned recommends that this report be considered as contributing towards demonstration of compliance with the *ABS Guide for Classification of Drilling Systems* subject to the reservations contained in this report (if any).

The component(s) will be re-examined to extent deemed necessary by the attending ABS Surveyor at time of next due periodical survey of the drilling unit

Description of drilling system component :

Codes, standards, or specifications :

Details of survey :

 ABS Surveyor

NOTE: This Certificate evidences compliance with one or more of the Rules, Guides, standards or other criteria of ABS and is issued solely for the use of ABS, its committees, its clients or other authorized entities. This Certificate is a representation only that the structure, item of material, equipment, machinery or any other item covered by this Certificate has met one or more of the Rules, Guides, standards or other criteria of ABS as of the date of issue. Parties are advised to review the Rules for the scope and conditions of classification and to review the survey records for a fuller description of any restrictions or limitation on the vessel's service or surveys. The validity, applicability and interpretation of this Certificate are governed by the Rules and standards of ABS, and ABS shall remain the sole judge thereof. Nothing contained in this Certificate or in any notation made in contemplation of this Certificate shall be deemed to relieve any designer, builder, owner, manufacturer, seller, supplier, repairer, operator or other entity or any warranty express or implied.

APPENDIX 7

Design Plans and Data - Submittal Requirements

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APPENDIX 7

Design Plans and Data - Submittal Requirements

SECTION 1

Design Plans and Data

The following paragraphs describe documentation and ABS approval requirements for Classing of drilling systems, subsystems, equipment, and/or components.

- i)* Chapter 3, Section 2 provides the general process for ABS approval of a drilling system. In addition, 3-2/Tables 1, 3, 5, 7, and 9 identify the typical drilling systems, subsystems, equipment and/or components that require approval for ABS Classification of the drilling system.
- ii)* The shipyard and manufacturer's plans and data, as specified in this Appendix, are generally to be submitted electronically to ABS. However, hard copies will also be accepted.
- iii)* All plan submissions originating from shipyards, manufacturers and subcontractors are understood to be made with the knowledge of the main contracting party. Coordination of equipment suppliers and systems integrators is the responsibility of the main contracting party for the CDS notation. In the case of a modification to an existing classed CDS system, the rig Owner is considered the main contracting party.

1 General Arrangement for Drilling System

General arrangement plans are to provide the following information, as applicable:

- i)* General arrangement of the installation/facility where the drilling system and its machinery are installed.
- ii)* Equipment layout, detailed arrangements, footprint and elevation drawings showing.
 - a)* Locations of all machinery, equipment, and structures for drilling operations
 - b)* Equipment operating zones showing operational interferences with other equipment, structures and personnel work areas.
 - c)* Piping systems associated with the drilling systems, and support systems
 - d)* Locations of all control panels/stations for drilling systems, including all drilling support systems
 - e)* Locations of the fire and gas monitoring and fire-fighting control locations
 - f)* Escape and egress routes, including their protections, and muster stations
 - g)* The locations of openings (air intake, exhaust, windows, doors, etc.) for all closed spaces
 - h)* Ventilation arrangements

- iii) HAZOP and HAZID study reports per Chapter 2.
- iv) FMEA/FMECA or similar analysis, and the associated Validation testing program per Chapter 2.
- v) Classified areas (hazardous areas) drawings and/or details identifying nonhazardous areas and hazardous areas in accordance with the ABS *MOU Rules*, API 500 or API 505.
- vi) Locations of potential hydrocarbon release from drilling operations.

3 Well Control Systems and Equipment

Typical well control systems and equipment are identified as follows:

- Blowout preventer (BOP) equipment
- Lower marine riser package (LMRP) for subsea well control
- Choke and kill equipment
- Marine drilling riser systems (see 2-3/13)
- Diverter equipment
- Auxiliary well control equipment

The following are to be submitted for the well control systems and equipment:

- i) General arrangement of well control systems, subsystems, equipment and components
- ii) FMEA/FMECA or similar analysis for the well control systems and subsystems (see 2-2/3.5 and 3-2/Tables 3, 5, 7 and 9)

3.1 Blowout Preventer Systems and Equipment

Submit the following documentation for the well control systems, BOP systems and/or well control equipment, as applicable:

- i) Design basis:
 - a) Descriptions of the well control systems and equipment for surface and subsurface BOPs
 - b) Design parameters: pressure rating, temperature rating (min/max)
 - c) P&IDs and schematic diagrams
 - d) Shutdown logic
 - e) Details on hierarchy of control: primary, secondary, emergency, etc.
 - f) Equipment technical specifications and data sheet
 - g) Design references, codes, standards, or guidelines
- ii) All control panel arrangements for BOP control systems
- iii) Design and manufacturing details for BOP stack equipment to include preventers, drill spools, wellhead connectors, clamps, spacer spools, adapter spools, etc.:
 - a) Design parameters: pressure rating (RWP/MAWP, or design pressure), temperature rating (min/max), loads, maximum water depth, service conditions, etc.
 - b) Dimensional detailed drawings and fabrication details
 - c) Material specifications and material properties
 - d) Design analysis for pressure-retaining equipment
 - e) Individual BOP (annular and ram) details. This is to include manufacturer documentation to specify and to attest BOP minimum and maximum capability with regard to:

- Drill pipe size
 - Tool joints
 - Casing
 - Wire line, or
 - Combination of the above
- f)* Data and documentation to confirm the shear rams capability of shearing the various tubulars (sizes, grades, strengths, etc.) under the specified design conditions
- g)* Prototype test data, as required by the design code
- h)* Manufacturing specifications (see Appendix 7, Section 2)
- iv)* BOP stack assembly:
 - a)* BOP stack configuration with individual annular and ram preventer details. This is to include the manufacturer's documentation to specify and to attest BOP stack minimum and maximum capability with regard to:
 - Drill pipe size
 - Tool joints
 - Casing
 - Wire line, or
 - Combination of the above
 - b)* BOP stack assembly drawings for BOP systems showing:
 - Stack configuration showing all equipment
 - Structural frame details
 - Lift points/attachments
 - Arrangements showing accumulators, pods, valves, piping, connectors, jumper lines, etc.
 - c)* Design details and structural analysis for BOP structural frame and lifting attachments
 - d)* Material specifications and material properties
 - e)* Manufacturing specifications (See Appendix 7, Section 2)
- v)* Control system details:
 - a)* Control panel and control equipment arrangements, showing locations on drilling unit
 - b)* See "Control Systems" listed below
- vi)* Pressure relief system: arrangements, size, materials, back pressure and capacity calculations, as applicable
- vii)* Design details electrical systems and equipment:
 - a)* See "Electrical Systems and Equipment" listed below
- viii)* Design details for pressure vessels, accumulators, cylinders:
 - a)* See "Pressure-Retaining Equipment" listed below
- ix)* Design details for piping, valves, and fittings:
 - a)* See "Piping Systems and Piping Components" listed below

- x)* Design details for flexible lines and hydraulic hoses:
 - a)* See “Flexible Lines/Hydraulic Hoses” listed below
- xi)* Manufacturing specifications (see Appendix 7, Section 2)
- xii)* Manufacturer’s affidavit of compliance

3.3 Lower Marine Riser Package

- i)* Design basis, including, as applicable:
 - a)* Descriptions of the lower marine riser package system
 - b)* Equipment technical specifications and data sheets
 - c)* Maximum design load condition
 - d)* Design references, codes, standards, or guidelines
 - e)* Design analysis methodology for the lower marine riser package, including computer modeling and computer program used
 - f)* Design analysis methodology of lower marine riser package, including loading parameters from global marine drilling riser analysis, computer modeling, and computer program used
- ii)* Design analysis of lower marine riser package mechanical-load bearing components and pressure-retaining equipment, as applicable.
- iii)* LMRP components and systems are typically integrated into the BOP system and equipment. Applicable submittal requirements for the following items are listed below:
 - a)* Equipment, component
 - b)* Control system
 - c)* Electrical systems
 - d)* Pressure vessels, accumulators, cylinders
 - e)* Piping, valves, and fittings
 - f)* Flexible lines and hydraulic hoses
- iv)* Subsea control pods details, drawings and arrangements inclusive of component descriptions
- v)* LMRP structural frame
- vi)* Material specifications, including material properties
- vii)* Prototype test data, as required by the design code
- viii)* Manufacturing specifications (see Appendix 7, Section 2)
- ix)* Manufacturer’s affidavit of compliance

3.5 Choke and Kill Systems and Equipment

Typical choke and kill systems and equipment are identified as follows, as applicable:

- Choke and kill manifold and buffer tanks
- Chokes
- Flexible choke and kill lines
- Drape hoses
- Jumper hoses, mud boost

- Hydraulic hoses
- Rigid choke and kill lines
- Swivel joints
- Union connections
- Drilling choke controls
- Valves: check, flow, gate
- Crosses and tees
- Elbows and targeted flanges
- Kill unit
- Control system
- Actuators: valves, drilling choke, or production choke
- i)* Design basis:
 - a)* Descriptions of the choke and kill systems and equipment and kill unit, including design parameters, pressure rating (internal/external), temperature rating (min/max.)
 - b)* P&IDs and schematic diagrams
 - c)* Equipment arrangement details
 - d)* Equipment technical specifications and data sheet
 - e)* Design references, codes, standards, or guidelines
- ii)* Pressure relief equipment rating/capacity
- iii)* Details of prime movers, such as diesel engines, motors, and generators, as applicable
- iv)* Design details for pumps, including:
 - a)* Power rating and capacity
 - b)* Temperature rating
- v)* Design details for mechanical load-bearing components:
 - a)* See “Mechanical Load-Bearing Components” listed below
- vi)* Design details electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- vii)* Control system details:
 - a)* See “Control Systems” listed below
- viii)* Design details for manifolds, pressure vessels, and tanks:
 - a)* See “Pressure-Retaining Equipment” listed below
- ix)* Design details for rigid piping, valves, and fittings:
 - a)* See “Piping Systems and Piping Components” listed below
- x)* Design details for flexible lines:
 - a)* See “Flexible Lines/Hydraulic Hoses” listed below
- xi)* Prototype test data, as required by the design code
- xii)* Manufacturing specifications (see Appendix 7, Section 2)
- xiii)* Manufacturer’s affidavit of compliance

3.7 Diverter Equipment

- i)* Design basis:
 - a)* Descriptions of the diverter system and equipment, including design parameters, pressure rating, temperature rating (min/max)
 - b)* P&IDs and schematic diagrams
 - c)* Equipment technical specifications and data sheet
 - d)* Design references, codes, standards, or guidelines
- ii)* Design details electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- iii)* Control system details:
 - a)* See “Control Systems” listed below
- iv)* Design details for manifolds:
 - a)* See “Pressure-Retaining Equipment” listed below
- v)* Design details for piping, valves, and fittings:
 - a)* See “Piping Systems and Piping Components” listed below
- vi)* Prototype test data, as required by the design code
- vii)* Manufacturing specifications (see Appendix 7, Section 2)
- viii)* Manufacturer’s affidavit of compliance

3.9 Auxiliary Well Control Equipment

Typical auxiliary well control equipment includes kelly valves, drill pipe safety valves, IBOP, drill string float valves, etc.

- i)* Design details for valves, and fittings
- ii)* Manufacturing specifications, as applicable
- iii)* Manufacturer’s affidavit of compliance

5 Marine Drilling Riser Systems Components

Typical marine drilling riser subsystem components include the following:

- Riser tensioning system and equipment
- Riser recoil system
- Riser joints
- Riser couplings (connectors): mechanical, hydraulic, etc.
- Telescopic joints
- Pup joints
- Buoyancy devices
- Ball and flex joints
- Riser running equipment
- Special equipment, including fill-up valves, mud boost system, drag reducing devices

Submit the following documentation for the marine drilling riser system and/or its components, as applicable:

- i)* Design basis, including, as applicable:
 - a)* Descriptions of the marine drilling riser system and its components (telescopic joint (slip joint), flexible joint, connectors, etc.)
 - b)* Equipment technical specifications and data sheets
 - c)* Equipment design capacities and suggested operation limits including water depth, net pressure, equivalent tension per API 16F
- ii)* Riser and its components fabrication drawings
- iii)* Material specifications, including material properties
- iv)* Design validation test data, as required by the design code
- v)* Design details for mechanical load-bearing components:
- vi)* Design details electrical systems and equipment:
- vii)* Design details for control systems:
- viii)* Design details for pressure vessels, accumulators, cylinders:
- ix)* Manufacturing specifications (see Appendix 7, Section 2)
- x)* Manufacturer's affidavit of compliance

7 Conductor Tensioning System/Unit

Submit the following documentation for the conductor tensioning system/unit and its equipment and components, as applicable:

- i)* Schematics and P&IDs
- ii)* Design basis:
 - a)* Descriptions of the conductor tensioning system and associated equipment and components
 - b)* Design parameters, pressure rating (internal/external), temperature rating (min/max)
 - c)* Load capacity
 - d)* Equipment technical specifications and data sheets
 - e)* Design references, codes, standards, or guidelines
- iii)* Prototype test data, as required by the design code, as applicable
- iv)* Design details for mechanical load-bearing components:
 - a)* See "Mechanical Load-Bearing Components" listed below
- v)* Design details electrical systems and equipment:
 - a)* See "Electrical Systems and Equipment" listed below
- vi)* Design details for control systems:
 - a)* See "Control Systems" listed below
- vii)* Design details for pressure vessels, accumulators, cylinders:
 - a)* See "Pressure-Retaining Equipment" listed below
- viii)* Design details for piping, valves, and fittings:

- a)* See “Piping Systems and Piping Components” listed below
- ix)* Design details for flexible lines:
 - a)* See “Flexible Lines/Hydraulic Hoses” listed below
- x)* Manufacturing specifications (see Appendix 7, Section 2)
- xi)* Manufacturer’s affidavit of compliance, as applicable

9 Drill String Compensation Systems

The drill string compensation system and equipment can be categorized as follows:

- Active heave compensation (AHC)
- Passive heave compensation (PHC)

Submit the following documentation for the drill string compensation system and associated equipment, as applicable:

- i)* Schematics and P&IDs
- ii)* Design basis:
 - a)* Descriptions of the drill string compensation systems and associated equipment, inclusive of fast and dead line compensation, as applicable
 - b)* Design parameters, pressure rating (internal/external), temperature rating (min/max)
 - c)* Load capacity
 - d)* Equipment technical specifications and data sheets
 - e)* Design details of locking mechanism, mechanical and/or hydraulic
 - f)* Design references, codes, standards, or guidelines
- iii)* Prototype test data, as required by the design code
- iv)* Design details for mechanical load-bearing components:
 - a)* See “Mechanical Load-Bearing Components” listed below
- v)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- vi)* Design details for control systems:
 - a)* See “Control Systems” listed below
- vii)* Design details for pressure vessels, accumulators, cylinders:
 - a)* See “Pressure-Retaining Equipment” listed below
- viii)* Design details for piping, valves, and fittings:
 - a)* See “Piping Systems and Piping Components” listed below
- ix)* Manufacturing specifications (see Appendix 7, Section 2)
- x)* Manufacturer’s affidavit of compliance, as applicable

11 Bulk Storage, Transfer, Conditioning, and Circulation Systems

The bulk storage, circulation and transfer system equipment can be categorized as follows:

- Bulk storage and transfer equipment

- Cementing system and equipment
- Mud return system and equipment
- Mud conditioning equipment
- Well circulation system and equipment
- Mud-gas separator (poor boy),
- Degasser

Submit the following documentation for the bulk storage, circulation and transfer systems, as applicable:

- i)* P&IDs and schematic diagrams
- ii)* Design basis:
 - a)* Descriptions of the bulk storage, circulation and transfer systems, and all associated equipment (e.g., mud-gas separator, degasser, desilter, desanders, shale shakers, agitators, etc.)
 - b)* Design parameters, pressure rating (internal/external), temperature rating (min/max) and flow simulation
 - c)* Pressure relief philosophy
 - d)* Equipment technical specifications and data sheets
 - e)* Design references, codes, and standards
- iii)* Pressure relief equipment rating/capacity
- iv)* Details of prime movers, such as diesel engines, motors, and generators, as applicable
- v)* Design details for pumps, including:
 - a)* Pressure rating, power rating and capacity
 - b)* Temperature rating
- vi)* Design details for mechanical load-bearing components:
 - a)* See “Mechanical Load-Bearing Components” listed below
- vii)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- viii)* Design details for control systems:
 - a)* See “Control Systems” listed below
- ix)* Design details for pressure vessels, accumulators, cylinders:
 - a)* See “Pressure-Retaining Equipment” listed below
- x)* Design details for piping, valves, and fittings:
 - a)* See “Piping Systems and Piping Components” listed below
- xi)* Manufacturing specifications (see Appendix 7, Section 2)
- xii)* Manufacturer’s affidavit of compliance, as applicable

13 Hoisting, Lifting, Tubular Handling Systems

Submit the following documentation for the hoisting, lifting, and tubular (riser, pipe) handling systems, as applicable:

13.1 Derrick Structure

- i)* Design basis for the derrick structure, including:
 - a)* Descriptions of the derrick structure and associated components
 - b)* Equipment technical specifications
 - c)* Design references, codes, standards, or guidelines
 - d)* Load cases and limit states for all design and operating conditions
 - e)* Assumptions used in the design analysis of the derrick structure and associated components
 - f)* Design conditions, including:
 - Environmental
 - Operating
 - Static
 - Storm survival
 - Waiting on weather
 - Temperature, min/max
 - Field transit
 - Ocean transit
 - Lifting, if applicable
 - Supporting structure deflection
 - g)* Combined load cases and limit states for all design and operating conditions
 - h)* The center of rotation (floating condition) specified in terms of the vertical and horizontal distances between the derrick base and the center of flotation of the vessel/unit
 - i)* Design analysis methodology for the derrick structure and associated components, and component analyses including computer modeling and computer program used
 - j)* Material specifications and material properties for all load-bearing components and bolts (if bolted design), including CVN testing requirements, as applicable
 - k)* Corrosion control plans
 - l)* Rigging arrangement
- ii)* Identification of the host vessel/unit for the derrick
- iii)* Descriptions of all computer programs, analysis methodologies and limits, and other calculation procedures that will form the basis of the structural design and analysis
- iv)* Structural analysis report:
 - a)* Design load development and computer input for all design conditions
 - b)* Computer model geometry plots (group IDs, joint numbers, members and lengths, critical unity checks)
 - c)* Allowable stresses
 - d)* Computer stress analysis
 - e)* Computer output; support reactions, unity stress checks
 - f)* Justifications for any stress exceeding the stated allowable stress
 - g)* Derrick bolt design and torque procedures by manufacturer

- h)* Attachment locations for other equipment (e.g., drill string compensation, tubulars handling, blowers, air reservoir, accumulator, tugger winches, ancillary equipment, etc.)
- i)* Supplemental calculations:
 - Sheave shaft strength (including shafts for cluster, fastline, and deadline sheaves)
 - Crown frame and Water table beams (or Top beams)
 - Maximum allowable crown weight and CG to determine suitability for crown mounted compensator
 - Bolting designs for base plates and splice plates
 - Strength of welded joints
 - Platforms or sub-structure, as applicable
 - Padeyes, as applicable
- v)* Structural drawings:
 - a)* General arrangement drawings
 - b)* Derrick assembly drawings
 - c)* Crown block assembly drawings
 - d)* Water table assembly drawings
 - e)* Geometry layout drawing; showing overall dimensions of derrick and indicating the size of each member
 - f)* Detailed drawings of the main structural elements of the derrick, crown frame, and water table beams, including:
 - Details and sizes for main structural elements
 - Material specifications and material properties for all load-bearing components and bolts (if bolted design), including CVN testing requirements, as applicable
 - Bolt connections and tightening procedures
 - Welding details and other methods of connection
 - g)* Base plate, anchor bolt plan and bolting procedures
 - h)* Bolts sheet
- vi)* Manufacturing specifications (See Appendix 7, Section 2)
- vii)* Manufacturer's affidavit of compliance, as applicable

13.3 Cranes and Lifting Appliances

- i)* Design basis for the cranes (gantry or pedestal), including:
 - a)* Descriptions of the crane structures and associated components
 - b)* Equipment technical specifications
 - c)* Design references, codes, standards, or guidelines
 - d)* Load cases and limit states for all design and operating conditions or combination thereof:
 - Dead, live and dynamic loads, including loads due to list and/or trim of the drilling unit, as applicable
 - Environmental loads including the effects of wind, sea state, snow and ice
- ii)* General arrangement, assembly plans and description of operating procedures and design service temperature

- iii)* Details of the principal structural parts and crane supporting structure
- iv)* Stress diagram, stress analysis and other supporting calculations, suitably referenced. Where computer analysis is used for the determination of scantlings, details of the programs describing input and output data and procedures are to be included together with the basic design criteria.
- v)* Expected duty cycle in frequency of use and percentage of load
- vi)* Wire rope specifications
- vii)* Material specifications including material properties
- viii)* Welding details and procedures and a plan indicating extent and locations of nondestructive inspection of welds for crane structure and foundation
- ix)* Crane capacity rating chart
- x)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- xi)* Design details for control systems:
 - a)* See “Control Systems” listed below
- xii)* Manufacturing specifications (see Appendix 7, Section 2)
- xiii)* Manufacturer’s affidavit of compliance, as applicable

13.5 Tubulars Handling

- i)* Design basis for the tubulars handling system:
 - a)* Description of system
 - b)* Equipment technical specifications and data sheets
 - c)* Design references, codes, or standards
 - d)* Design conditions:
 - Environmental
 - Operating
 - Static
 - Survival
 - Lifting, if applicable
 - e)* Load and temperature rating
 - f)* Rotating equipment power rating
- ii)* General arrangement drawings showing locations of all equipment
- iii)* Assembly and equipment drawings
- iv)* Structural analysis report
- v)* Dimensional detailed drawings
- vi)* Prototype test data, if required by the design code
- vii)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- viii)* Design details for control systems:
 - a)* See “Control System” listed below, as applicable

- ix)* Design details for pressure vessels, accumulators, cylinders:
 - a)* See “Pressure-Retaining Equipment” listed below
- x)* Design details for piping, valves, and fittings:
 - a)* See “Piping Systems and Piping Components” listed below
- xi)* Manufacturing specifications (See Appendix 7, Section 2)
- xii)* Manufacturer’s affidavit of compliance

13.7 Other Load-bearing Equipment

- i)* Load-bearing equipment, and associated support structural may include, but is not limited to, BOP handling crane, BOP transporter/skidder, drawworks, crown block, traveling block, top drive, hook and rotary swivel, power swivel, pipe, rackers/manipulator systems, stabbing board, racking platforms, man-riding elevators, winches, wire lines/ropes, cranes, and other lifting devices.
- ii)* Design details for mechanical load-bearing equipment:
 - a)* See “Mechanical Load-Bearing Equipment” listed below
- iii)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- iv)* Design details for control systems, as applicable:
 - a)* See “Control Systems” listed below
- v)* Manufacturing specifications, as applicable
- vi)* Manufacturer’s affidavit of compliance, as applicable

15 Mechanical Load-Bearing Equipment

The following documentation for mechanical load-bearing components are to be submitted for ABS review, as applicable.

See 3-2/Tables 1, 3, 5, 7 and 9, as applicable, for ABS approval requirements.

- i)* Design specifications, including design codes, standards, and references
- ii)* Design parameters: loads, temperature, environmental conditions, etc.
- iii)* Design analysis and/or calculations, as applicable
- iv)* Dimensional drawings and fabrication details
- v)* Material specifications and material properties
- vi)* Prototype test data, if required by the design code
- vii)* Design details for electrical systems and equipment:
 - a)* See “Electrical Systems and Equipment” listed below
- viii)* Design details for control systems, as applicable:
 - a)* See “Control Systems” listed below
- ix)* Manufacturing specifications, as applicable
- x)* Manufacturer’s affidavit of compliance, as applicable

17 Burner/Flare Booms (Permanently Fitted)

Submit the following documentation for the burner/flare boom fitted as part of the well control system:

- i)* Design basis for the burner/flare boom, including:
 - a)* Descriptions of the burner flare boom and associated components
 - b)* Equipment list
 - c)* Equipment technical specifications and data sheets
 - d)* Load cases and limit states for all design and operating conditions
 - e)* Assumptions used in the design analysis of the burner flare boom structure and associated components
 - f)* Design conditions, including:
 - Environmental
 - Operating
 - Survival
 - Lifting, if applicable
 - g)* Combined load cases and limit states for all design and operating conditions
 - h)* Plans showing intended location of the boom on the installation
 - i)* Design references, codes, standards, or guidelines
 - j)* Design analysis methodology for the burner flare boom structure and associated components, and component analyses including computer modeling and computer program used
 - k)* Design temperature (maximum, minimum)
 - l)* Material specifications and material properties for all load-bearing components and bolts (if bolted design), including CVN testing requirements, as applicable
- ii)* Descriptions of all computer programs, analysis methodologies and limits, and other calculation procedures that will form the basis of the structural design and analysis
- iii)* Structural analysis report:
 - a)* Design load development and computer input for all design conditions
 - b)* Computer model geometry plots (group IDs, joint numbers, members and lengths, critical unity checks)
 - c)* Allowable stresses
 - d)* Computer stress analysis
 - e)* Computer output: support reactions, unity stress checks
 - f)* Justifications for any stress exceeding the stated allowable stress, as applicable
- iv)* Structural drawings:
 - a)* General arrangement drawings
 - b)* Burner Flare Boom assembly drawings
 - c)* Geometry layout drawing; showing overall dimensions of burner flare boom and indicating the size of each member
 - d)* Detail drawings of the main structural elements of the burner flare boom, including:
 - Details and sizes for main structural elements

- Material specifications and material properties for all load-bearing components and bolts (if bolted design), including CVN testing requirements, as applicable
- Bolt connections and tightening procedures
- Welding details and other methods of connection
- e) Base plate and anchor bolt plan
- f) Bolts sheet

19 Electrical Systems and Equipment

Design plans and data are to be submitted for electrical systems and equipment in accordance with 4-3-1/5, 4-3-2/1, 4-3-3/1 and 4-3-4/1 of the ABS *MOU Rules*. See 2-7/7 of this Guide.

21 Control Systems

The following control system plans and data are to be submitted for design review, as applicable:

- i) Arrangement plans showing location of units controlled, instrumentation and control devices
- ii) Design basis and specifications for control and instrumentation equipment
- iii) Set points for control system components
- iv) Control system operating and maintenance manuals
- v) Control system details:
 - a) Details on hierarchy of controls: primary, secondary, emergency, etc., as applicable
 - b) Details and description of interconnections between control systems
 - c) Primary power source and emergency power source details, as applicable
 - d) Volumetric capacity calculations for the accumulator systems, primary and secondary (as applicable)
 - e) Hydraulic power unit (HPU) details/arrangements:
 - Pump system details and arrangements
 - Prime mover details
 - Reservoir capacity and arrangements
 - f) Hydraulic, pneumatic, and electrical schematics
 - g) Pressure relief system: Arrangements, size, materials, back pressure and capacity calculations, as applicable
 - h) Manufacturing specifications
 - i) Manufacturer's affidavit of compliance
- vi) FMEA, FMECA or similar analysis for control systems as defined in Chapter 2 for system, subsystem, and equipment
- vii) Documentation in accordance with the recognized industry standard is to be submitted for review to justify the safety integrity levels, when applicable
- viii) Calculations for control systems demonstrating the system's ability to react adequately to anticipated occurrences, including transients
- ix) Arrangements and details of control consoles/panels, including front views, installation arrangements together with schematic plans and logic description for all power, control and monitoring systems, including their functions

- x)* Type and size of all electrical cables and wiring associated with the control systems, including voltage rating, service voltage and currents, together with overload and short-circuit protection
- xi)* Schematic plans and logic description of hydraulic and pneumatic control systems together with all interconnections, piping sizes and materials, including working pressures and relief-valve settings
- xii)* Description of all alarm and emergency tripping arrangements and functional sketches or description of all special valves, actuators, sensors and relays
- xiii)* Shutdown logic and/or shutdown cause and effect charts
- xiv)* Hydrocarbon and sour gas detection system plans and data, including detectors, piping, set points, type of detectors, and location of alarm panels, and recalibration program for gas detectors

23 Pressure-Retaining Equipment

The following documentation for pressure-retaining equipment is to be submitted for ABS review and approval, as applicable:

- i)* Design specifications, including design codes, standards, and references
- ii)* Design parameters: pressure rating (internal/external), temperature rating (min/max), loads, etc.
- iii)* Design analysis and/or calculations, as applicable
- iv)* Dimensional drawings and fabrication details
- v)* Material specifications and material properties
- vi)* Details for manufacturing specifications
- vii)* Manufacturer's affidavit of compliance, as applicable

See 3-2/Table 1, 3, 5, 7 and 9, as applicable, for ABS approval requirements.

25 Piping Systems and Piping Components

Design documentation is to be submitted for review and is to include the following information, as applicable:

- i)* Piping Systems:
 - a)* P&IDs for piping systems associated with drilling systems or subsystems
 - b)* Piping specifications, including material specifications
 - c)* Design parameters: pressure, temperature rating (min/max)
 - d)* Pipe stress and flexibility analyses, including design verification of erosional allowance due to fluid velocity
- ii)* Piping components are considered, but not limited to, pipes, valves, hoses, fittings, flanges, bolts, etc. Piping component design specifications to include the following information in accordance with piping standard rating, as applicable:
 - a)* Technical specifications
 - b)* Design pressure (internal/external) and/or pressure rating
 - c)* Design temperature (min/max)
 - d)* Fluid medium (specifically note if piping standard rating is for sour service)
 - e)* Design code and standards
 - f)* Corrosion/erosion allowances

- g)* Wall thickness for each line size
- h)* Material specifications including material properties
- i)* Details for manufacturing specifications
- j)* Manufacturer's affidavit of compliance

See 3-2/Tables 1, 3, 5, 7 and 9, as applicable, for ABS approval requirements.

27 Flexible Lines/Hydraulic Hoses

Flexible lines and hydraulic hoses documentation is to include, as applicable:

- i)* Pressure (internal/external) and temperature (min/max) ratings
- ii)* Construction materials details/material specifications
- iii)* Design analysis
- iv)* Prototype testing procedures and data, as required by design code
- v)* End connections and termination details, as applicable:
 - a)* Stress analysis
 - b)* Material specifications
 - c)* Prototype testing procedures and data
- vi)* Manufacturing specifications
- vii)* Manufacturer's affidavit of compliance

APPENDIX 7

Design Plans and Data - Submittal Requirements

SECTION 2

Manufacturing Specifications

Manufacturing specifications and test procedures are required for manufacturing and testing of CDS systems and equipment as required by this Guide. Manufacturing specifications are to be submitted to the ABS technical office in association with the design review if required per Chapter 5, Section 1. Test procedures are to include procedures for design validation testing per the design specification and the testing to be carried out both during and at completion of manufacturing and for installation/commissioning on board, where applicable. All testing will be required to be completed prior to issuance of the CDS Classification. Test procedures requiring submittal include, but are not limited to, the following documentation:

- i)* Quality plans and specifications
- ii)* Prototype and production testing, as required by the design codes or manufacturer specifications
- iii)* Hydrostatic pressure test
- iv)* Load testing
- v)* Post-test NDE
- vi)* Factory Acceptance Tests (FATs)
- vii)* Factory Integration Tests (FITs)
- viii)* System Integration Tests (SITs)
- ix)* Commissioning Procedures
- x)* FMEA Validation test Procedures
- xi)* Specification sheets and MACs for sub vendor/externally sourced or purchased assemblies/subassemblies/parts within the operational load path, forming part of the control system, or otherwise subject to design review and/or Survey requirements
- xii)* Any additional special procedures, inspection and testing plans, or other documentation pertaining to the manufacturing and testing of the systems and equipment, as applicable.
- xiii)* Any additional test procedures as identified during the design review

APPENDIX 8

Certification of Existing Drill-Through Equipment

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APPENDIX 8

Certification of Existing Drill-Through Equipment

SECTION 1

Certification of Existing Drill-Through Equipment (1 August 2018)

1 Purpose

The purpose of this Appendix is to provide general provisions for the certification of existing drill-through equipment that is not currently ABS certified.

2 Scope

This Appendix applies to the following equipment:

- i)* BOP Stack assemblies
- ii)* Ram blowout preventers (BOPs)
- iii)* Ram blocks, operators, packers, and top seals
- iv)* Annular BOPs
- v)* Annular packing units
- vi)* Hydraulic wellbore connectors (wellhead, riser, or LMRP)
- vii)* Drilling spools and spacer spools
- viii)* Mandrels (for wellbore connectors)
- ix)* Adapters
- x)* Loose connections
- xi)* Clamps
- xii)* API 6A flanges
- xiii)* Other end connections (OECs)

Note:

All items used in this Appendix are based on definitions contained within this Guide and common terminology used throughout the industry, API 16A, API 16AR.

3 Design Review

Equipment meeting the full traceability requirements defined by API 16AR level RSL-3, will be considered for certification. Requests for review of equipment meeting API 16 AR level RSL-2 will be subject to special consideration.

Design documentation is to be submitted by the manufacturer or owner/operator and is to include the reports, calculations, plans, manuals and other documentation necessary to verify the design is in compliance with this Guide and in accordance with any applicable Coastal State Regulations for the area of intended operation.

4 Required Documentation

The equipment manufacturer's design information and historical documentation is to be submitted in accordance with Appendix 7 of this Guide and is to include the following where applicable.

4.1 General

- i) Name/type of equipment
- ii) Part number
- iii) Name of manufacturer and supplier
- iv) Date(s) of manufacture, remanufacture and repair
- v) Serial number of main assemblies and/or components
- vi) Maintenance and Operating manuals

4.2 Test Plans and Data

- i) FMEA/FMECA Validation test documentation
- ii) Installation, and Commissioning plans and procedures
- iii) The material traceability documentation is to include, but is not limited to:
 - 1) Certified MTR
 - 2) Chemical and mechanical properties for each heat
 - 3) Heat treatment temperatures and time at temperature
 - 4) Charpy impact values and temperatures
 - 5) Hardness test readings (as applicable to materials meeting NACE MR0175)
 - 6) Information on associated Elastomers
 - 7) Bolts and nuts for fastening and/or connections used in pressure retaining, pressure containing, pressure controlling applications (closure bolting per API Spec 6A, Spec 16A and Spec 20E or 20F). See also 5-1/11 of this Guide.
 - 8) MTRs for the following materials as defined in Chapter 5 of this Guide:
 - Primary structure-load bearing components
 - Primary mechanical-load bearing components
 - Pressure retaining/containing/controlling equipment and piping components
 - All piping, valves and fittings with an ANSI B16.5 Class 150 or greater

4.3 Manufacturing/Remanufacturing/Repair History

- i) Detailed Inspection and Test Plans (ITPs), including associated test procedures for system, subsystem, equipment or component, as outlined in 3-2/Tables 1 through 4, as applicable

- ii)* Surface treatment (electroplating, galvanizing, etc.) plans and specifications as applicable
- iii)* Disposition of any major manufacturing non-conformances and major engineering changes
- iv)* Quality plans and specifications (See 7/2.1)
- v)* Welding records with all approved qualifications
- vi)* Post weld heat treatment results
- vii)* NDT results
- viii)* Hardness test results (as applicable to materials meeting NACE MR0175)
- ix)* Dimensional check results
- x)* Hydrostatic pressure tests
- xi)* Low pressure tests and rated pressure tests
- xii)* Load tests
- xiii)* Electrical tests
- xiv)* Function tests
- xv)* Required tension results in accordance with installation procedures for closure, pressure controlling and pressure retaining bolting as identified in 5-1/11 and 5-1/13. See also 7-2/1 ii) j), 7-2/5 v), and 7-2/1 i).

4.4 Others

- i)* Manufacturer's Certificate of Conformance (MCOC)
- ii)* Nameplate photograph or equivalent evidence of equipment pedigree
- iii)* Previous Certifying Authority Documentation
- iv)* Detailed Description of Critical Components, as defined by the OEM. See 5-1/5.
- v)* Additional requirements for BOP stack assembly control systems per A7-1/21

5 Surveys

Surveys are to be carried out by an ABS surveyor and are to include the following tests and inspections:

- i)* A full dismantling of the equipment covered by this Appendix to each individual component to the extent associated with a major overhaul in accordance with manufacturers recommended practices is to be conducted and witnessed by an ABS Surveyor in accordance with the applicable sections of Chapter 7 of this guide.
- ii)* Internal examinations, including dimensional examinations as applicable are to be witnessed by an ABS Surveyor.
- iii)* All weld repairs are to be witnessed by an ABS Surveyor.
- iv)* NDE is required to be carried out in accordance with the provisions of Chapter 6 of this Guide.
- v)* Hardness readings are to be taken at each weld in accordance with the provisions of this Guide (as applicable to materials meeting NACE MR 01-75).
- vi)* All sealing surfaces and ring grooves are to be dimensionally examined and non-destructively tested by a suitable crack detection method in accordance with Chapter 6.
- vii)* Testing is to be carried out in accordance with 7-2/5 and 3-2/Table 4 of this Guide and is to be witnessed by an ABS Surveyor.
- viii)* Shear rams and casing shear rams are to meet the requirements of 2-3/3.5 and 8-3/1 xviii).