

Petroleum and natural gas industries — Drilling and production equipment

**Part 1: Design and operation of
marine drilling riser equipment (ISO
13624-1:2009)**

ICS 75.180.10

National foreword

This British Standard is the UK implementation of EN ISO 13624-1:2009.

The UK participation in its preparation was entrusted to Technical Committee PSE/17/-/4, Drilling and production equipment for petroleum and natural gas industries.

A list of organizations represented on this committee can be obtained on request to its secretary.

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Foreword

This document (EN ISO 13624-1:2009) has been prepared by Technical Committee ISO/TC 67 "Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries" in collaboration with Technical Committee CEN/TC 12 "Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries" the secretariat of which is held by AFNOR.

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Endorsement notice

The text of ISO 13624-1:2009 has been approved by CEN as a EN ISO 13624-1:2009 without any modification.

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

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ISO 13624-1 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13624 consists of the following parts, under the general title *Petroleum and natural gas industries — Drilling and production equipment*:

- *Part 1: Design and operation of marine drilling riser equipment*
- *Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report* (Technical Report)

Introduction

Since the first edition of API RP 16Q was first issued in November, 1993, hydrocarbon exploration in deep-water environments has increased significantly. As a consequence of this, the need has been identified to update that code of practice to address the issues of deep-water drilling risers in sufficient detail to supplement API RP 16Q for drilling in water depths up to 3 048 m (10 000 ft).

Under the auspices of the DeepStar programme, substantial work was commissioned during 1999 and 2000 by the DeepStar Drilling Committee 4502 and lead to the development by several contractors of *Deep-water Drilling Riser Methodologies, Operations, and Integrity Guidelines* in February 2001. These guidelines were intended to supplement the existing text of API RP 16Q (1993). In a subsequent Joint Industry Project funded by DeepStar 5500 and in collaboration with API, these guidelines were supplemented with other identified revisions to produce a draft update second edition of API RP 16Q and an associated API Technical Report 16TR1, designed to be read in conjunction with the revised API RP 16Q and to supplement its contents, by providing additional guidance on recommended riser analysis methodologies through detailed explanations, step-by-step procedures and worked examples.

API publications can be used by anyone desiring to do so. Every effort has been made to assure the accuracy and reliability of the data contained in them. It is the responsibility of the users of this part of ISO 13624 to ensure that its use does not result in any loss or damage or in the violation of any federal, state, or municipal regulation.

Annex A through Annex E are informative.

Petroleum and natural gas industries — Drilling and production equipment —

Part 1: Design and operation of marine drilling riser equipment

1 Scope

This part of ISO 13624 pertains to the design, selection, operation and maintenance of marine riser systems for floating drilling operations. Its purpose is to serve as a reference for designers, for those who select system components, and for those who use and maintain this equipment. It relies on basic engineering principles and the accumulated experience of offshore operators, contractors, and manufacturers.

NOTE Technology is advancing in this field and improved methods and equipment are continually evolving. Each owner and operator is encouraged to observe the recommendations outlined herein and to supplement them with other proven technology that can result in more cost effective, safer, and/or more reliable performance.

The marine drilling riser is best viewed as a system. It is necessary that designers, contractors, and operators realize that the individual components are recommended and selected in a manner suited to the overall performance of that system. For the purposes of this part of ISO 13624, a marine drilling riser system includes the tensioner system and all equipment between the top connection of the upper flex/ball joint and the bottom of wellhead conductor outer casing. It specifically excludes the diverter. Also, the applicability of this part of ISO 13624 is limited to operations with a subsea BOP stack deployed at the seafloor.

Clauses 1 through 7 of this part of ISO 13624 are directly applicable to most floating drilling operations. Special situations are addressed in 8.1 and 8.4 dealing with deep-water drilling and collapse. The special considerations required for guidelineless drilling are addressed in 8.2. In addition, 8.3 and 8.5 address operations in cold-weather conditions and H₂S considerations.

It is important that all riser primary-load-path components addressed in this part of ISO 13624 be consistent with the load classifications specified in ISO 13625.

2 Normative references

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

ISO 13625, *Petroleum and natural gas industries — Drilling and production equipment — Marine drilling riser couplings*

BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*

3 Terms, definitions, and abbreviations

3.1 Terms and definitions

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

3.1.1

accumulator

⟨BOP⟩ pressure vessel charged with gas (nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers

3.1.2

accumulator

⟨riser tensioner⟩ pressure vessel charged with gas (generally nitrogen) over liquid that is pressurized on the gas side from the tensioner high-pressure gas supply bottles and supplies high-pressure hydraulic fluid to energize the riser tensioner cylinder

3.1.3

actuator

mechanism for the remote or automatic operation of a valve or choke

3.1.4

air-can buoyancy

tension applied to the riser string by the net buoyancy of an air chamber created by a closed top, open-bottom cylinder forming an air-filled annulus around the outside of the riser pipe

3.1.5

annulus

space between two pipes when one pipe is inside the other

3.1.6

apparent weight

effective weight

submerged weight

weight minus buoyancy

NOTE Apparent weight is commonly referred to as weight in water, wet weight, submerged weight, or effective weight.

3.1.7

auxiliary line

conduit (excluding choke-and-kill lines) attached to the outside of the riser main tube

EXAMPLE Hydraulic supply line, buoyancy-control line, mud-boost line.

3.1.8

back pressure

pressure resulting from restriction of fluid flow downstream

3.1.9

ball joint

ball-and-socket assembly that has a central through-passage equal to or greater than the riser internal diameter and that may be positioned in the riser string to reduce local bending stresses

3.1.10

blowout

uncontrolled flow of well fluids from the wellbore

3.1.11

**blowout preventer
BOP**

device attached immediately above the casing, which can be closed to shut in the well

3.1.12

blowout preventer

(annular type) remotely controlled device which can form a seal in the annular space around any object in the wellbore or upon itself

NOTE Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

3.1.13

BOP stack

assembly of well-control equipment, including BOPs, spools, valves, hydraulic connectors and nipples, that connects to the subsea wellhead

NOTE Common usage of this term sometimes includes the lower marine riser package (LMRP).

3.1.14

bottom-hole assembly

BHA

assembly composed of the bit, stabilizers, reamers, drill collars, various types of subs, etc., that is connected to the bottom of a string of drillpipe

3.1.15

box

female member of a riser coupling, C&K line stab assembly or auxiliary line stab assembly

3.1.16

breech-block coupling

coupling that is engaged by rotation of one member into an interlock with another member by an angle of rotation of 90 ° or less

3.1.17

buoyancy-control line

auxiliary line dedicated to controlling, charging or discharging air-can buoyancy chambers

3.1.18

buoyancy equipment

devices added to riser joints to reduce their apparent weight, thereby reducing riser top tension requirements

NOTE The devices normally used for risers take the form of syntactic foam modules or open-bottom air chambers.

3.1.19

choke-and-kill line

C&K line

kill line

external conduit arranged laterally along the riser pipe and used for circulation of fluids into and out of the wellbore to control well pressure

3.1.20

control pod

assembly of subsea valves and regulators that, when activated from the surface, directs hydraulic fluid through special porting to operate BOP equipment

3.1.21

coupling

mechanical means for joining two sections of riser pipe in an end-to-end engagement

3.1.22

diverter

device attached to the wellhead or marine riser to close the vertical flow path and direct well flow away from the drill-floor and rig

3.1.23

dog-type coupling

coupling having wedges (dogs) that are mechanically driven between the box and pin for engagement

3.1.24

drape hose

flexible line connecting a choke, kill or auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure

NOTE A U-shaped bend or “drape” in this line allows for relative movement between the inner barrel of the telescopic joint and the outer barrel of the telescopic joint as the vessel moves.

3.1.25

drift-off

unintended lateral move of a dynamically positioned vessel off of its intended location relative to the wellhead, generally caused by loss of stationkeeping control or propulsion

3.1.26

drilling fluid

mud

water- or oil-based fluid circulated down the drillpipe into the well and back up to the rig for purposes including containment of formation pressure, the removal of cuttings, bit lubrication and cooling, treating the wall of the well and providing a source for well data

3.1.27

drive-off

unintended move of a dynamically positioned vessel off location driven by the vessel's main propulsion or stationkeeping thrusters

3.1.28

dynamic positioning

automatic stationkeeping

computerized means of maintaining a vessel on location by selectively driving thrusters

3.1.29

dynamic tension limit

maximum allowable pressure multiplied by the effective hydraulic area, divided by the number of line parts

3.1.30

effective hydraulic cylinder area

net area of moving parts exposed to tensioner hydraulic pressure

3.1.31

effective tension

tension that controls the stability of risers

See 5.4.4.

3.1.32

factory acceptance testing

testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings

3.1.33

fail safe

term applied to equipment or a system so designed that, in the event of failure or malfunction of any part of the system, devices are automatically activated to stabilize or secure the safety of the operation

3.1.34

fillup line

line through which fluid is added to the riser annulus

3.1.35

flange-type coupling

coupling having two flanges joined by bolts

3.1.36

fleet angle

angle between the vertical axis and a riser tensioner line at the point where the line connects to the telescopic joint

See Figure 1.

3.1.37

flex joint

steel and elastomer assembly that has a central through-passage equal to or greater in diameter than the riser bore and that may be positioned in the riser string to reduce local bending stresses

3.1.38

gooseneck

type of terminal fitting using a pipe section with a semicircular bend to achieve a nominal 180° change in flow direction

3.1.39

guidelineless re-entry

establishment of pressure-containing connection between the BOP stack and the subsea wellhead or between the LMRP and the BOP stack using a TV image and/or acoustic signals instead of guidelines to guide the orientation and alignment

3.1.40

handling tool

running tool

device that joins to the upper end of a riser joint to permit lifting and lowering of the joint and the assembled riser string in the derrick by the elevators

3.1.41

heave

vessel motion in the vertical direction

3.1.42

hot spot stress

local peak stress

highest stress in the region or component under consideration

NOTE The basic characteristic of a peak stress is that it causes no significant distortion and is principally objectionable as a possible initiation site for a fatigue crack. These stresses are highly localized and occur at geometric discontinuities.

3.1.43

hydraulic connector

mechanical connector that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack

3.1.44

hydraulic supply line

auxiliary line from the vessel to the subsea BOP stack that supplies control system operating fluid to the LMRP and BOP stack

3.1.45

instrumented riser joint

IRJ

riser joint equipped with sensors for monitoring parameters, such as tension in the riser pipe wall, riser angular offset, annulus fluid temperature and pressure, etc.

3.1.46

jumper hose

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

3.1.47

key-seating

formation of a longitudinal slot in the bore of a riser system component caused by frictional wear of the rotating drillstring on the riser component

3.1.48

landing joint

riser joint temporarily attached above the telescopic joint used to land the BOP stack on the wellhead when the telescopic joint is collapsed and pinned

3.1.49

landing shoulder

riser support shoulder

shoulder or projection on the external surface of a riser coupling or other riser component for supporting the riser and BOP stack during deployment and retrieval

3.1.50

lower marine riser package

LMRP

upper section of a two-section subsea BOP stack consisting of a hydraulic connector, annular BOP, flex joint, riser adapter, jumper hoses for the choke, kill and auxiliary lines, and subsea control pods

NOTE This interfaces with the lower subsea BOP stack.

3.1.51

made-up length

actual length contributed to a riser string by a made-up riser component (overall component length minus box/pin engagement)

3.1.52

make-up time

riser coupling

time period beginning when the box and pin are stabbed and ending when the coupling is fully preloaded

3.1.53

make-up tool

preload tool

device used to engage and/or preload coupling members

3.1.54

marine drilling riser

tubular conduit serving as an extension of the wellbore from the equipment on the wellhead at the seafloor to a floating drilling rig

3.1.55

maximum tensioner setting

maximum setting that, when added with dynamic variations, is less than the **dynamic tension limit** (3.1.29)

3.1.56

mud-boost line

auxiliary line that provides supplementary drilling fluid from the surface and injects it into the riser at the top of the LMRP to assist in the circulation of drill cuttings up the marine riser, when required

3.1.57

nipple up

assemble a system of fluid handling components

3.1.58

nominal stress

stress calculated using the nominal pipe wall dimensions of the riser at the location of concern

3.1.59

pin

male member of a riser coupling or a choke, kill or auxiliary line stab assembly

3.1.60

preload

compressive bearing load developed between box and pin members at their interface

NOTE This is accomplished by elastic deformation during make-up of the coupling.

3.1.61

protector, box

protector, pin

cap or cover used to protect the box or pin from damage during storage and handling

3.1.62

pup joint

shorter than standard length riser joint

3.1.63

rated load

nominal applied loading condition used during riser design, analysis and testing based on maximum anticipated service loading

See API Spec 16F.

3.1.64

response amplitude operator

RAO

⟨regular waves⟩ ratio of a vessel's motion to the wave amplitude causing that motion and presented over a range of wave periods

3.1.65

riser adapter

crossover between riser and flex/ball joint

3.1.66

riser annulus

space around a pipe (drillpipe, casing or tubing) suspended in a riser

NOTE Its outer boundary is the internal surface of the riser pipe.

3.1.67

riser connector

LMRP connector

hydraulically operated connector that joins the LMRP to the top of the BOP stack

3.1.68

riser disconnect

operation of unlatching of the riser connector to separate the riser and LMRP from the BOP stack

3.1.69

riser hang-off system

means for supporting a disconnected deep-water riser from the drilling vessel during a storm without inducing excessive stresses in the riser

3.1.70

riser hang-off tool

tool used to latch onto an interior profile in the riser and connect it to the motion compensator

3.1.71

riser joint

section of riser main tube having the ends fitted with a box and pin and including choke, kill and (optional) auxiliary lines and their support brackets

3.1.72

riser main tube

riser pipe

seamless or electric-welded pipe that forms the principal conduit of the riser joint

NOTE The riser main tube is the conduit for guiding the drillstring and containing the return fluid flow from the well.

3.1.73

riser recoil system

means of limiting the upward acceleration of the riser when a disconnect is made at the riser connector

3.1.74

riser spider

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

3.1.75

riser string

deployed assembly of riser joints

3.1.76

riser tensioner

means for providing and maintaining top tension on the deployed riser string to prevent buckling

3.1.77

riser tensioner ring

structural interface of the telescopic joint outer barrel and the riser tensioners

3.1.78

rotary kelly bushing

RKB

bushing that sits on top of the rotary table

NOTE It transmits torque from the rotary table to the kelly and is commonly used as a reference for vertical measurements from the drill-floor.

3.1.79

stab

mating box and pin assembly that provides a pressure-tight engagement of two pipe joints

NOTE An external mechanism is usually used to keep the box and pin engaged.

EXAMPLE Riser joint choke and kill stabs are retained in the stab mode by the make-up of the riser coupling.

3.1.80

standard riser joint

joint of typical length for a particular drilling vessel's riser storage racks, the derrick V-door size, riser-handling equipment capacity or a particular riser purchase

3.1.81

storm disconnect

riser disconnect to avoid excessive loading from vessel motions amplified by inclement weather conditions

3.1.82

strakes

helically wound appendages attached to the outside of the riser to suppress vortex induced vibrations

3.1.83

stress amplification factor

SAF

F_{SA}

value equal to the local peak alternating stress in a component (including welds) divided by the nominal alternating stress in the pipe wall at the location of the component

NOTE This factor is used to account for the increase in the stresses caused by geometric stress amplifiers that occur in riser components.

3.1.84

thrust collar

device for transmitting the buoyant force of a buoyancy module to the riser joint

3.1.85

subsea fill-up valve

special riser joint having a valve means to allow the riser annulus to be opened to the sea

NOTE To prevent riser pipe collapse, the valve can be opened by an automatic actuator controlled by a differential-pressure sensor.

3.1.86

support bracket

bracket positioned at intervals along a riser joint that provides intermediate radial and lateral support from the riser main tube to the choke, kill and auxiliary lines

3.1.87

surge

vessel motion along the fore/aft axis

3.1.88

sway

vessel motion along the port/starboard axis

3.1.89

syntactic foam

typically, a composite material of spherical fillers in a matrix or binder

3.1.90
telescopic joint
slip joint

riser joint having an inner barrel and an outer barrel with a means of sealing between them

NOTE 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 experiences surge, sway, and heave.

3.1.91
telescopic joint packer

means of sealing the annular space between the inner and outer barrels of the telescopic joint

3.1.92
terminal fitting

connection between a rigid choke, kill or auxiliary line on a telescopic joint and its drape hose, effecting a nominal 180° turn in flow direction

3.1.93
threaded-union coupling

coupling having mating threaded members on the pin and box to form the engagement

NOTE The threads on one side of the coupling are free to rotate relative to the riser pipe, so it is not necessary that the joint rotate to make up the coupling. The threads do not form the seal.

3.1.94
tension ring

support ring around the top of the joint where tensioner lines are attached

3.1.95
type certification testing

testing by a manufacturer of a representative specimen (or prototype) of a product that qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture

3.1.96
vortex induced vibration

in-line and transverse oscillation of a riser in a current induced by the periodic shedding of vortices

3.1.97
wellhead connector
stack connector

hydraulically operated connector that joins the BOP stack to the subsea wellhead

3.2 Abbreviations

BOP	blowout preventer
DP	dynamic positioning
DTL	dynamic tension limit
ID	internal diameter
LFJ	lower flex joint
LMRP	lower marine riser package
OD	outside diameter
RAO	response amplitude operator

RKB	rotary kelly bushing
ROV	remotely operated vehicle
SAF	stress amplification factor
UFJ	upper flex joint

4 Component function and selection

4.1 Introduction

General requirements common to all components are outlined in 4.2 and, where appropriate, individual components are addressed in the rest of Clause 4. The following general format is used:

- a) function: the basic function of the component is described;
- b) typical designs: examples of typical designs are presented;
- c) selection criteria: general performance requirements are outlined.

4.2 Component selection criteria

Design of a riser system begins with an assessment of expected operating conditions and an engineering analysis to establish parameters, such as tensile, bending and combined stresses (maximum and mean), buoyancy requirements, top tension requirements, vessel response amplitude operators (RAOs), etc. Other factors influencing riser system design include riser length (water depth), dimensional requirements (bore, wall thickness, etc.), internal pressure rating, choke/kill, and auxiliary-line specifications, make-up method, storage and handling conditions, operating economy, etc. Once established, these riser-system design criteria should permit the selection of riser components that suit the application.

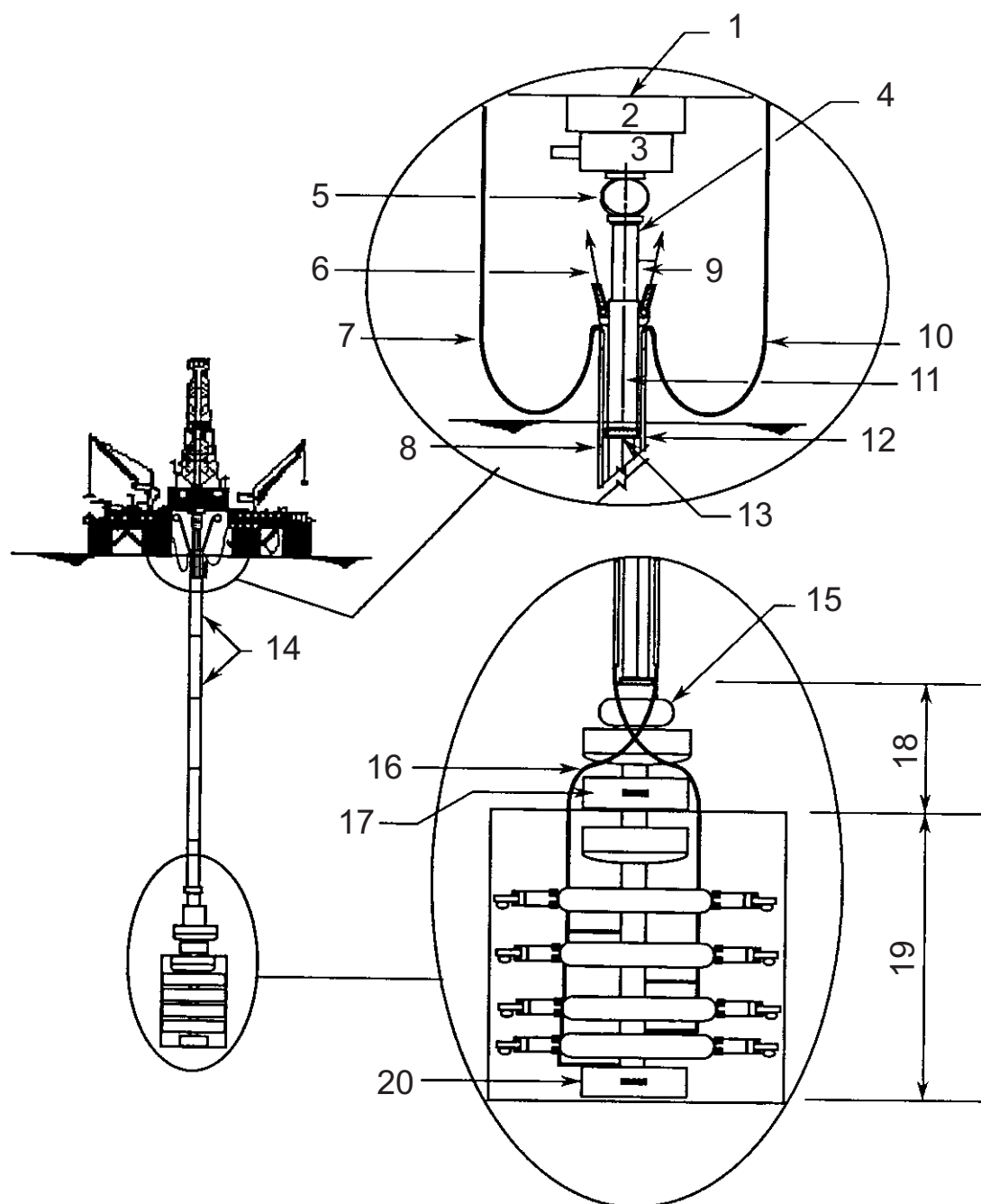
All riser primary-load-path components addressed in this part of ISO 13624 shall be consistent with the load classifications specified in ISO 13625.

4.3 Marine drilling riser system

The marine riser system forms an extension of the wellbore from the blowout preventer (BOP) stack to the drilling vessel; see Figure 1.

The primary functions of the marine riser system are to

- a) provide for fluid communication between the well and the drilling vessel
 - 1) in the riser annulus under normal drilling conditions,
 - 2) through the choke-and-kill lines when the BOP stack is being used to control the well;
- b) support the choke, kill and auxiliary lines;
- c) guide tools into the well;
- d) serve as a running and retrieving string for the BOP stack.



Key

1 rotary kelly bushing (RKB)	8 choke line	15 flex/ball joint
2 rotary	9 fleet angle	16 riser/BOP jumper hose
3 diverter	10 kill drape hose	17 LMRP connector
4 telescopic joint inner barrel	11 telescopic joint outer barrel	18 lower marine riser package (LMRP)
5 diverter flex/ball joint	12 kill line	19 blowout preventer (BOP) stack
6 tensioner line	13 riser coupling	20 wellhead connector
7 choke drape hose	14 marine riser joints	

Figure 1 — Marine riser system and associated equipment

4.4 Tensioner system

4.4.1 Function

Tensioner units are used to apply vertical force to the top of the marine drilling riser to control its stresses and displacements. The units are normally located on the drilling vessel near the periphery of the drill-floor. They provide a nearly constant axial tension to the riser while the floating drilling vessel moves vertically and laterally in response to the wind, waves and current.

4.4.2 Typical design

A typical tensioner unit uses a hydraulic ram with large-volume, air-filled auxiliary pressure vessels (APV) to maintain a nearly constant pressure/tension on a line (wire rope). One end of the line is attached at the vessel and the other is attached to the outer barrel of the telescopic joint. Typically, a four-part line-reeving system is used so that the piston stroke is equal to one-quarter of the vessel heave. The number and rating of tensioner units used determines the total capacity of the tensioner system. The tension applied by each unit can be varied up to its design capacity by increasing or decreasing the applied air pressure. The tensioner system should be capable of providing sufficient tension based upon the maximum rated water depth, maximum expected mud weight, and other loadings determined from riser analyses.

Direct-acting hydraulic rod-cylinder tensioners are also used on deep-water drilling vessels.

Designs for tensioner systems are described in ISO/TR 13624-2:—, Clause 4.

4.4.3 Selection criteria

Some important considerations for designing an effective tensioner system are as follows.

- a) Fleet angle: The idler sheaves should be placed so as to minimize the fleet angle. This maximizes the vertical component of tension, minimizes the horizontal component and increases wireline life.

Because of the fleet angle, the vertical tension applied to the outer barrel of the telescopic joint is less than the tension supplied by the tensioner system. A reduction factor (see 5.3.2) should be used to reconcile these parameters.

- b) Wireline life: Wireline life is a function of many parameters, including wire-rope construction, sheave diameter, applied tension, operating circumstances relating to travel, etc. See API RP 9B.
- c) Accumulators and air-pressure vessels: Each tensioner unit should have an accumulator that is large enough to store a volume of hydraulic fluid greater than the cylinder volume. Large air-pressure vessels reduce pressure changes caused by the compression and expansion of the stored air as the tensioner strokes in and out.
- d) Fluid and air flow requirements: Properly sized lines reduce tension variations caused by piping-system pressure losses.

A list of hydraulic fluids compatible with the tensioner units should be specified by the tensioner manufacturer.

- e) Friction and inertia losses: Seal friction, sheave friction and inertia of sheaves, wire rope, tensioner rods, and pistons all contribute to variations in the wireline tension.
- f) Dynamic tension limit (DTL): Tensioner ratings are defined differently by various manufacturers. This part of ISO 13624 defines a dynamic tension limit, F_{DTL} , as given in Equation (1); see also 3.1.29:

$$F_{DTL} = P_A \times A_{CYL} / N_{LP} \quad (1)$$

where

P_A is the maximum allowable system operating pressure;

A_{CYL} is the effective hydraulic area;

N_{LP} is the number of line parts.

- All components in a riser-system installation, including piping, should be designed for the maximum allowable working pressure. See ASME UG 125-136 for relief-valve-setting criteria.
 - The tensioner system should be designed to permit one unit to be out of service for maintenance or repair without jeopardizing the ability of the remaining tensioner units to provide the required tension to the marine drilling riser. A unit may be either a single tensioner or a pair of tensioners, depending on specific design.
- g) Maximum tension setting: The maximum tension setting should not exceed 90 % of the F_{DTL} so that the maximum tension, including dynamic variations, is less than the F_{DTL} .
- h) Velocity-limiting device: Some type of flow-control device is normally located in the line between the fluid port on each tensioner and its respective air/liquid interface bottle. This device should offer minimal resistance to fluid flow during all anticipated heave velocities. However, if a tensioner wireline should break or other failure occur that allows the tensioner to stroke out at an uncontrolled rate, this flow-control valve should sense the abnormally high fluid flow rate and immediately stop or greatly reduce the fluid flow into the tensioner.

4.5 Diverter system (surface)

4.5.1 Function

When drilling a top hole through the structural casing, the riser may be employed enabling the use of weighted mud to provide overbalance, if needed. Blowout preventers (BOPs) are not in place at this stage (see 4.14.1) because the structural casing normally lacks sufficient pressure integrity to allow shut-in. Therefore, if the well flows, the riser directs that flow to the diverter system aboard the rig. Typically, the diverter system includes an annular sealing device, means to both open the vent line and close the mud flowline, and a control system.

4.5.2 Location

Surface diverter systems on floating rigs are usually installed directly below the rotary table. The diverter unit is latched into a built-in housing. The upper flex/ball joint, which is the uppermost component in a marine drilling riser system, is usually mounted to the bottom of the diverter unit.

A subsea diverter stack may be installed on the wellhead to divert subsea.

4.5.3 Operation

API RP 64 provides recommended practices for diverter systems equipment and operations.

4.6 Telescopic joint (slip joint)

4.6.1 Function

The basic function of the telescopic joint is to compensate for the relative translational movement between the vessel and the riser. The outer barrel provides structural support for riser tensioner loads.

4.6.2 Typical design

4.6.2.1 General

A telescopic joint has an outer barrel that is connected to the drilling riser, an inner barrel that is connected to an upper flex joint, and a tensioner ring that transmits loads from the tensioner system to the outer barrel of the riser.

4.6.2.2 Riser tensioner attachment

The riser tensioner lines typically attach to the tensioner ring near the top of the telescopic joint outer barrel. This attachment provides the structural interface between the marine riser and the tensioner system. Padeyes on the tensioner ring accommodate pinned connections at the ends of the tensioner lines. The tensile load to support the riser is transmitted through the riser tensioner ring to the pipe wall of the outer barrel and, subsequently, through the couplings and pipe walls of the riser joints.

4.6.2.3 Optional features of the tensioner ring

The following lists optional features of the tensioner ring.

- a) For turret-moored and dynamically positioned vessels, a low-friction bearing on the tensioner ring allows the vessel to rotate. Resulting torsional loads on the riser and wellhead should be considered.
- b) For guidelineless re-entry, an hydraulic motor drive may be provided on the tensioner ring to orient the LMRP with the BOP stack.
- c) For operational convenience, the riser tensioner ring may be detached from the outer barrel and fitted for latching to the bottom of the diverter housing for storage. This arrangement eliminates the time-consuming operations of connecting/disconnecting tensioner lines when deploying/retrieving the riser. Integral stab connectors may also be provided to permit ready connections of the drape hose terminal fittings.

4.6.3 Selection criteria

The selection of a telescopic joint should include consideration and evaluation of the following basic items.

- a) Strength: In both its retracted and extended positions, the telescopic joint should support the weight of the riser and BOP stack. The dynamic loads on the telescopic joint should be considered.
- b) Stroke length: The maximum stroke length required for the telescopic joint should accommodate the combined expected heave, vessel offset, tidal change and maximum anticipated vessel excursion in the event of a stationkeeping failure.
- c) Tensioner ring: Angular orientation on the padeyes on the tensioner ring should accommodate the positions of the tensioner line sheaves. The tensioner ring should be rated for the maximum load capacity of the telescopic joint.
- d) Auxiliary lines: The designer of the attachments for auxiliary lines, choke-and-kill lines, and the telescopic joint packing pressure line should consider the layout of the rig and the ease of making and breaking the connections during running and retrieving operations.
- e) Packing elements: The packing element that is used to seal between the outside of the inner barrel and the inside of the outer barrel is available as either single-element or double-element units. The advantage of the double-element unit is that when one of the packing elements fails, the second element can be energized, thus maintaining the seal between the drilling fluid and the environment, without having to shut down the drilling operation.
- f) Handling and storage: The telescopic joint is typically longer and heavier than the standard riser joint and, therefore, it has special handling and storage requirements.

4.7 Riser joints

4.7.1 Function

A riser joint is a large-diameter, high-strength pipe (riser main tube), either seamless or electric welded, with couplings welded to each end. When the riser system is being deployed, the riser joints are coupled together on the drill-floor and lowered into the water. The string of riser joints represents the principal component of the riser system and is used to perform the riser-system functions listed in 4.3. The box or pin coupling at the upper end of the riser joint usually has a landing shoulder. This landing shoulder, or riser-support shoulder, supports the loads (static and dynamic) of the marine riser and BOP stack when it is suspended from the riser spider (see 4.11.2.2). The coupling may also provide support for choke, kill and auxiliary lines, and load reaction for buoyancy devices.

4.7.2 Typical designs

4.7.2.1 Main tube

Riser main tube and the associated couplings are generally sized to be compatible with a specific BOP stack size. Compatible BOP bore and riser outer diameter combinations are shown in Table 1.

Table 1 — Compatible BOP bore and riser outer diameter combinations

BOP bore mm (in)	Riser outer diameter mm (in)
346,1 (13-5/8)	406,4 (16) riser
425,5 (16-3/4)	473,1 (18-5/8) riser
476,3 (18-3/4)	508 (20) riser, or 533,4 (21) riser, or 558,8 (22) riser with thick wall

4.7.2.2 Riser couplings

The four basic riser coupling designs are

- a) dog type;
- b) flanged;
- c) threaded union;
- d) breech-block.

Each riser manufacturer usually offers couplings with different strength ratings.

4.7.2.3 Choke/kill and auxiliary lines

Typically, riser joints have choke/kill and auxiliary lines attached to the exterior of the main riser tube by support brackets. On most risers, these lines pass through the riser support shoulder. These riser-mounted choke/kill and auxiliary lines are described in 4.12.

4.7.3 Selection criteria

The following items should be considered when selecting, designing or specifying riser joints.

- a) Riser main tube: The riser main tube should have adequate strength to withstand combined loads from waves, current, applied tension, motion of the rig and drilling fluid weight in accordance with Table 2. Collapse pressure and handling loads should also be considered. The strength characteristics of the main tube are dictated by its diameter, wall thickness and grade of steel. Steel grades commonly used in risers are X-52, X-65, and X-80, where the numbers refer to the minimum yield strength, expressed in kilopounds-force per square inch, of each grade.
 - The inside diameter shall provide sufficient annular space to accommodate the desired casing programme.
 - Typically, riser-joint lengths range from 15,2 m to 27,4 m (50 ft to 75 ft). The storage and handling characteristics on the rig shall be considered in the selection of the length.
- b) Pup joints: Pup joints are riser joints that are shorter than full-length riser joints. Pup joints of various lengths should be available to accommodate riser spaceout. See 6.4.2.
- c) Riser couplings: Coupling selection should be based on
 - strength;
 - load rating of support ring;
 - stress amplification factor (fatigue resistance);
 - reliability;
 - speed of make-up;
 - preload for make-up;
 - maintenance requirements;
 - main tube dimensions;
 - strength-to-weight ratio.

4.8 Lower marine riser package (LMRP)

4.8.1 Function

The lower marine riser package (LMRP) typically includes an assemblage of a riser adapter; a flex/ball joint; one, two, or no annular BOPs; subsea control pods; and an hydraulic connector mating the riser system to the BOP stack. The LMRP provides a releasable interface between the riser and the BOP stack. In addition, it provides hydraulic control of BOP stack functions through the control pods. Jumper hoses provide a flow path around the flex/ball joint for the choke and kill lines.

4.8.2 Typical design

The LMRP can be designed to a variety of configurations depending upon the type, size, ratings and operational water depth of its components. Some design considerations are

- a) standard guidepost radius (see API RP 53);
- b) minimum bore size and compatible pressure ratings;
- c) bending strength;

- d) clearance for retrievable control pods;
- e) accommodation for subsea accumulators;
- f) loads and clearances during an emergency disconnect;
- g) available space for storage and handling aboard drilling vessel;
- h) emergency recovery system for deep-water BOPs;
- i) guidance system for re-entry of guidelineless BOPs;
- j) sequenced, retractable control pod stabs and choke/kill stabs on guidelineless systems;
- k) flexible lines (see 4.10);
- l) guidance structure for BOP handling.

4.8.3 Selection criteria

The selection of LMRP components should be based on the following factors:

- a) well-control considerations;
- b) BOP pressure rating and bore;
- c) guideline or guidelineless operations;
- d) overall height and weight limitations;
- e) operating environment and design loads;
- f) method of BOP control and operational fail-safe design features;
- g) operational water depth;
- h) method for running/retrieving control pods;
- i) methods for re-entry on guidelineless systems;
- j) methods for emergency recovery.

4.9 Flex and ball joints

4.9.1 Function

Flex and ball joints are used to allow angular misalignment between the riser and the BOP stack, thereby reducing the bending moment on the riser. They are also used at the top of the riser to allow for the motion of the rig. In some instances, they may also be installed at some intermediate level in the riser string below the telescopic joint to reduce stresses in the riser. The rotational stiffness of flex joints makes them more effective than ball joints in controlling riser angles. Typically, the rotational stiffness of a flex joint is a non-linear function of angle and ranges from 13 600 N·m (10 000 ft-lbf) per degree of rotation to 108 800 N·m (80 000 ft-lbf) per degree of rotation. Rotational stiffness can also vary with temperature.

4.9.2 Typical design

4.9.2.1 Flex joints

The flexure members of a flex joint are typically bonded laminations of elastomer between stacks of spherically shaped steel rings. The elastomer provides flexure and pressure sealing. Some designs provide a landing shoulder for a readily removable wear bushing. Still others provide a wear ring that can be replaced

during periodic overhaul of the flex joint. Because of the design of flex joints, repair of major key-seat damage can prove uneconomical. The user should request that the supplier provide a list of facilities with the capabilities to repair key-seat damage.

4.9.2.2 Ball joints

A ball joint is a forged steel ball and socket containing a cylindrical neck extension with a riser adapter attached at the end of the neck. The ball and socket employs a seal that contains the drilling fluids. In most designs, replaceable wear rings or wear bushings are used. Some ball joints require pressure balancing.

4.9.3 Selection criteria

The following items should be considered when selecting, specifying or designing flex joints and ball joints:

- a) flex/ball joint function and location in the riser system;
- b) maximum angular rotation and maximum rotational stiffness required, which can be determined by a preliminary riser analysis;
- c) pressure rating; the flex/ball joint should maintain pressure integrity throughout exposure to wellbore fluids, maximum anticipated temperatures, maximum design mud weight, and maximum design water depth;
- d) maximum tensile load being applied;
- e) maximum torque being applied.

4.10 Flexible choke-and-kill lines

4.10.1 Function

Flexible choke-and-kill lines allow relative movement at the telescopic joint (drape hose) and at flex/ball joints (jumper hose) in the riser system.

4.10.2 Typical design

Three basic designs are commonly used:

- flexible pipe;
- steel reinforced hoses;
- flow loops with threaded, clamped, or flanged end fittings.

If threaded end fittings are used, they shall contain a means of sealing other than the threads.

4.10.3 Selection criteria

Flexible lines should be compatible with the rest of the choke-and-kill piping system and with the BOP stack, riser and choke-and-kill manifold. Selection of flexible lines should take into account the following considerations:

- a) length requirement and tolerance;
- b) end fitting compatibility;
- c) pressure rating (gas and liquid);

- d) collapse rating;
- e) temperature rating (maximum, minimum, and ambient conditions);
- f) minimum bend radius;
- g) fluid compatibility;
- h) resistance to wear by abrasive fluids;
- i) corrosion resistance;
- j) fatigue resistance to bend and pressure cycling.

4.11 Riser running equipment

4.11.1 Function

Riser and diverter handling tools are used for hoisting and lowering the riser and BOP stack. The riser spider is used to support the riser and BOP stack while they are being run or retrieved. When used, guidelines direct the riser and associated subsea equipment to the wellhead.

4.11.2 Typical design

4.11.2.1 Handling tools

Riser handling tools make up to the top of the riser during deployment and retrieval. The top connection is a short length of pipe that is supported by the hoisting equipment.

Another tool of importance is the diverter-handling tool, which may be used to carry the entire riser system load prior to landing the stack on the wellhead. If the diverter-handling tool is used to support the entire riser and BOP stack, it should meet the same standards as the riser-handling tool.

4.11.2.2 Riser spiders

A riser spider provides support for the riser and BOP stack at the drill-floor. Shock-absorbing spiders are designed to reduce impact loads on riser-support shoulders. Gimbaling spiders reduce bending moments on the shoulders.

4.11.2.3 Guidelines

Guidelines may be used to direct the riser and associated subsea equipment to their mating connections near the seafloor. Generally, four wire rope guidelines, forming the corners of a square, extend up from the temporary guidebase to the floating drilling vessel where each is tensioned by a guideline tensioner (similar to a riser tensioner). Typically, the guideline attachment points are 2 m (6 ft) from the centre of the wellbore forming a square measuring approximately 2,6 m (8,5 ft) per side.

4.11.3 Selection criteria

The selection, rating and testing of riser running equipment should be based on the following:

- a) maximum static loading capacity;
- b) dynamic loads induced by vessel motions, waves and currents;
- c) bending loads during riser running operations;
- d) impact loads.

4.12 Riser-mounted choke/kill and auxiliary lines

4.12.1 Function

These lines carry fluids along the length of the riser. On most risers, they are an integral part of each riser joint and are attached on the outside of the riser main tube by support brackets. Generally, these lines are used for the following purposes.

- a) Choke/kill lines are used to provide a controlled flow of oil, gas or drilling fluid from the wellbore to the surface when the blowout preventer stack is closed.
- b) Mud-boost lines are used as conduits for drilling fluid that is pumped into the riser just above the blowout preventer stack to increase annular circulating velocities.
- c) Air-inject lines are used to supply air to increase riser buoyancy for air-can buoyancy risers.
- d) Hydraulic supply lines carry hydraulic operating fluid to the blowout preventer subsea control system. Most blowout preventer systems incorporate a flexible hydraulic-fluid supply line inside the control line hose umbilical.

4.12.2 Typical designs

Typical riser joints have integral choke-and-kill lines. This provides redundancy and also allows for the following well-control operations:

- a) circulating down one line and up the other line;
- b) circulating down the drillpipe and up one line.

A mud-boost line is incorporated for some risers. Air-inject lines are required for riser systems that use air-chamber buoyancy systems. Hydraulic supply lines can be used as either a primary or secondary supply line.

Generally, choke/kill and auxiliary lines of one riser joint are connected to their counterparts on adjoining riser joints by stab-in couplings. The box contains an elastomeric radial seal that expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized. These stab-in couplings also facilitate fast make-up while deploying the riser.

4.12.3 Selection criteria

The following items should be considered when selecting, designing or specifying choke/kill and auxiliary lines for riser joints.

- a) The type of fluid to be carried by the line: Hydraulic supply lines are generally constructed of corrosion-resistant material to prevent rust particles from clogging hydraulic operator ports and damaging seals and sealing surfaces. Choke/kill and mud-boost lines are generally constructed of steel. Care should be taken to ensure that proper galvanic protection is provided between the steel components of the riser joints and the hydraulic supply lines if corrosion-resistant material (e.g. stainless steel) is used.
- b) The operating pressures to which the line can be exposed during its lifetime.
 - 1) Hydraulic supply lines: Working pressure rating should be compatible with the working pressure rating of the BOP control system.
 - 2) Mud-boost lines: Pressure rating should be suitable for the intended service.
 - 3) Choke/kill lines: Pressure rating should be the same as that of the BOP stack.

- c) The choke/kill and auxiliary line couplings: These couplings shall be able to seal against full pressure while allowing for relative motion between the box and pin caused by:
- 1) Poisson's effect;
 - 2) structural compression caused by pressure exerted on the ends of the pins;
 - 3) temperature differences between the fluid in the main riser and the fluids in the choke/kill or auxiliary lines;
 - 4) bending loads imposed by deflections of the riser; this relative motion can cause fatigue cracking of the support bracket if an adequate gap is not provided between the support bracket and the coupling.
- d) Internal diameter of the line: The ID of the choke/kill lines should be selected to suit well-control operations. The ID of the mud-boost line should be selected to suit drilling fluid requirements. The ID of the hydraulic supply line should be selected to suit control system requirements.
- e) Failsafe design and orientation of choke/kill and auxiliary lines: To prevent accidental mismatching of the choke/kill and auxiliary lines when the riser is deployed, the couplings should be oriented asymmetrically around the riser support ring. To prevent accidental over-pressuring of the mud-boost line while testing during deployment, the test caps for the choke/kill lines should be designed so that they cannot be installed on the mud-boost line.
- f) Support bracket design: The support brackets attach the lines to the riser and prevent buckling when they are pressurized. The spacing of the support brackets is dependent upon the rated pressure of the choke/kill lines and the buckling characteristics of the pipe.
- g) H₂S service requirements: If H₂S can enter the choke and kill lines, material selection should meet the requirements of ANSI/NACE MR0175/ISO 15156.
- h) Pressure ratings: All pressure piping should be designed to meet the requirements of API Spec 16C.
- i) Corrosion/erosion allowances: The minimum design thickness should include a corrosion/erosion allowance of 1,27 mm (0,05 in) as recommended in API RP 14E.

4.13 Buoyancy equipment

4.13.1 Function

Buoyancy equipment may be attached to riser joints to reduce top tension requirements by decreasing the submerged weight of riser joints.

4.13.2 Typical designs

4.13.2.1 Foam modules

Syntactic foam is typically a composite material of spherical fillers in a matrix or binder. The most common forms of syntactic foam consist of tiny glass microspheres in a matrix of thermo-setting plastic resin, often with larger microspheres of glass-fibre-reinforced plastic.

The diameter of syntactic-foam modules depends primarily on the buoyancy requirements and the foam density. The foam density depends on the design water depth. Denser material is normally used for deeper water to withstand higher collapse pressures. Maximum allowable diameter is determined by the bore of the diverter housing and/or other restrictions through which it is necessary that the riser joint pass. See 5.9 for high-current operations.

Typically, foam modules are installed in pairs around the riser joint, several pairs per joint, and have cut-outs to accommodate choke, kill and auxiliary lines. The modules are held in place by either circumferential straps or other suitable means. Fastener material should be selected to avoid galvanic corrosion.

The vertical lift of the foam module is imparted to the riser by a thrust collar fitted to the riser pipe just below the upper coupling. A matching collar is generally installed at the lower end of the assembled modules to retain them in place during riser handling.

4.13.2.2 Open-bottom air chambers

Open-bottom air cans are typically attached to the riser coupling and provide an annular space around the riser. Air-injection and pilot lines provide the means to inject air at ambient hydrostatic pressure. Air displaces seawater from the annular space to provide buoyancy. A float valve in the injection line near the bottom of the chamber maintains the water at the preset level. Air can be bled from the system through a discharge valve actuated by the pilot line. Valves can be arranged and adjusted to provide the desired buoyancy level. Compressors aboard the drilling vessel are used to supply air through the injection line to the air chambers.

4.13.3 Selection criteria

Foam modules should be selected to provide the required lift and resistance to pressure at the rated service depth. Their design should be such that they do not restrain the bending of the riser tube and can be safely handled and stored. Maintenance and repair procedures should be investigated to ensure that they can be performed on the rig with minimal difficulty. For foam densities and water absorption considerations, see the manufacturer's specifications.

Open-bottom air cans are relatively resistant to handling damage, but they can increase bending stresses at the riser coupling because of the added resistance of the air cans. This should be investigated by the designer to make sure that adequate provision is made for this in the riser operating programme. The systems required to operate and maintain the riser should be evaluated to ensure that adequate redundancy is provided for critical equipment, such as air compressors.

4.14 Speciality equipment

4.14.1 Latch (pin connector), 76,2 cm (30 in)

Under some conditions, it is advantageous to have the riser deployed while drilling the 66,0 cm (26 in) hole. In that event, a 76,2 cm (30 in) latch is used to connect the marine riser to the 76,2 cm (30 in) wellhead housing. A ring-joint pressure seal is effected between the latch assembly and the wellhead housing. Hydraulically operated multiple segments are used to form the mechanical latch engagement; the segments extend radially inward to engage a support shoulder on the wellhead housing OD. The 76,2 cm (30 in) latch is normally controlled by a dedicated hydraulic hose bundle run from the surface diverter/BOP control system. The 76,2 cm (30 in) latch is usually fitted with a flex/ball joint and a riser adapter.

4.14.2 Riser hang-off system

When environmental conditions exceed the limits for safe operation with the riser connected, the riser and LMRP are disconnected from the BOP stack and may be hung-off until weather conditions improve. The disconnected riser may be hung off from the hook, the spider, the diverter housing or specially designed beam structures. This is called the hard hang-off method.

Another method, called a soft hang-off, may be used to hang-off the riser from either the tensioners only or from the tensioners and the motion compensator. A tool called the riser hang-off tool is employed if the motion compensator is used in conjunction with the tensioners to set up a soft hang-off.

The dynamic loads of the riser should be considered to ensure that the hang-off system components provide adequate strength to support the axial and transverse loads imparted by the suspended riser without damage to either the riser or the vessel.

5 Riser response analysis

5.1 General considerations

The drilling riser has very little inherent structural stability. Its ability to resist environmental loading is derived from the applied tension. The marine drilling riser should be designed, and the top tension selected, based on the riser's response to the environmental and hydrostatic loads, as well as the requirement that it properly perform its functions. Among the functional constraints are the angles at both the lower flex/ball joint and the telescopic joint, the mean and alternating stresses, the resistance to column buckling and hydrostatic collapse, the percentage of the DTL applied to the top of the riser and forces and moments transferred to the BOP stack, wellhead and casing.

Specialized computer programs are generally used to predict riser behaviour under the design conditions, and to determine top tension requirements, maximum permissible vessel offsets and maximum loads on riser components.

Because of the manner in which the riser is employed, design of the drilling riser components cannot be separated from operational procedures. For example, when drilling, upper and lower flex/ball joint angles should be maintained within rather low limits. However, in the presence of severe weather, drilling may be suspended and the limitation on flex/ball joint angles relaxed. Limiting criteria for riser design can, then, become maximum stresses. During such a change of operational mode, proper handling of the riser can dictate a change in the top tension. In even more severe conditions, the proper riser handling can dictate disconnecting the bottom of the riser and hanging it off from the rig. Decisions such as when to make such changes are part of the riser-design process and require analysis of the riser in each of the potential operational modes.

This subclause applies equally to the design of a new riser system or the site-specific evaluation of an existing riser system. Riser analyses should be performed for a range of environmental and operational parameters. If the riser is being designed, this requires starting with a proposed design and then iterating until the riser parameters, such as wall thickness and material strength, that satisfy the design objectives are found. For an existing riser system, the options available to the analyst include

- a) specifying the appropriate top tension for each combination of environmental and drilling parameters;
- b) coordinating the mooring system design to evaluate the position of the top of the riser;
- c) specifying the distribution of bare and buoyant riser joints throughout the riser string;
- d) selecting the conditions at which the operational mode is changed (from drilling to non-drilling, and when to disconnect).

5.2 Riser analysis procedure

5.2.1 General

Annex A is a data worksheet for recording data prior to performing a riser analysis.

5.2.2 Vessel stationkeeping considerations

The vessel's stationkeeping ability should be determined and used in conjunction with the riser analysis to assess flex/ball joint angles and riser stresses. The mooring and riser analyses are used to define operating limits for the riser. In some cases, mooring lines may be adjusted in response to long-term variations in environmental conditions, such as current and/or wind.

5.2.3 Riser-induced load considerations

The riser introduces shear, bending and tension loads into the LMRP, the BOP stack, the hydraulic connectors, the wellhead and the casing. These loads and moments should be evaluated to ensure that the

maximum stresses are within design allowables and the fatigue life is acceptable. The riser also induces loads on the drilling vessel that it can be necessary to consider in the stationkeeping analysis.

5.2.4 Currents

For currents exceeding 1 m/s (~2 kn), see 5.9.

5.2.5 Drilling fluid density

Top tension requirements should be determined for several values of drilling fluid density ranging from that of seawater up to the maximum anticipated density.

5.3 Design

5.3.1 Operating modes

Three operating modes are normally encountered in offshore drilling operations.

- a) Drilling mode: The drilling mode is that combination of environmental and well conditions in which all normal drilling activities can be safely conducted, including drilling ahead, tripping, under reaming, circulating, etc. Special operations, such as running casing, cementing, or formation testing, can dictate more restrictive operating limits.
- b) Connected non-drilling mode: In this mode, the only drilling operation that should be conducted is circulating. The drillpipe should not be rotated. The riser may be displaced with seawater and preparations made to shut-in the well and disconnect the riser, if necessary.
- c) Disconnected mode: If environmental conditions exceed the limits for safe operation in the connected non-drilling mode, the riser should be disconnected to avoid possible damage to surface or subsea equipment.

5.3.2 Recommended guidelines for design

Selection of the appropriate combination of environmental conditions and hydrodynamic coefficients for the analysis involves judgment, experience and an understanding of the type of riser analysis being employed. Design and operating limits for the key riser parameters – upper and lower flex/ball joint angles, mean and alternating stress and the appropriate factor of safety on DTL – are selected based on sound engineering principles and successful operating experience.

Table 2 defines recommended design practices for the three operating modes. It contains two stress criteria methods for the drilling mode, at least one of which should be satisfied. Generally, method A is appropriate for most water depth locations and method B is recommended for deep-water locations. Table 2 addresses riser analysis for exploratory drilling. In cases of extended drilling in a harsh environment, such as on a North Sea template, a fatigue analysis of the riser can be advisable. The mean and maximum flex/ball joint angle limits given for the normal drilling mode are intended to prevent wear and key-seating damage to the riser and flex/ball joint. Prudent operational procedure should strive to maintain these angles as small as possible (e.g. 1° or less), and consider 2,0° (mean) and 5,0° (maximum) as upper bounds. The maximum flex/ball joint angle limits for the connected non-drilling mode and disconnected mode are intended to prevent damage to the riser, flex/ball joint and BOP stack. The upper flex/ball joint angle rarely has a significant effect on riser design; however, this angle should be considered when evaluating clearances in the moonpool area.

Table 2 — Marine drilling risers — Maximum design guidelines

Design parameter	Riser connected		Riser disconnected
	Drilling	Non-drilling	
Mean upper flex/ball jt. angle ^a	1° to 1,5°	N/A	N/A
Max. upper flex/ball jt. angle ^a	5,0°	90 % available (or contact with moonpool structure)	90 % available (or contact with moonpool structure)
Mean lower flex jt. angle ^b	2,0°	N/A	N/A
Max. lower flex jt. angle ^b	5,0°	90 % available	N/A
Stress criteria: ^{c,d}			
— Method “A” - allowable stress ^e	0,40 σ_y^f	0,67 σ_y^f	0,67 σ_y^f
— Method “B” - allowable stress ^e	0,67 σ_y^f	0,67 σ_y^f	0,67 σ_y^f
— Sign. dyn. stress range ^e			
@ SAF $\leq 1,5^g$	69 MPa (10 ksi)	N/A	N/A
@ SAF $> 1,5^g$	15/ F_{SA}	N/A	N/A
Minimum top tension ^h	T_{min}	T_{min}	N/A
Dynamic tension limit ⁱ	F_{DTL}	F_{DTL}	N/A
Maximum tension setting	90 % F_{DTL}	90 % F_{DTL}	N/A

NOTE 1 The flex/ball joint angles are differential global angles around the flex or ball joints and, because the wellhead tilt and riser angle (or vessel pitch/roll and riser angle) can be in different planes, they are not easily determined by independent bullseye levels both above and below the flex/ball joint. It is necessary to keep the flex/ball joint angles as small as practicable to avoid wear in the riser system components. The value of 2° in Table 2 is specified to include routine situations with low risk of significant wear, which could not continue with a more restrictive angle. For many drilling operations, mean differential angles are maintained at less than 1°.

NOTE 2 The rate of wear at flex/ball joints between two pieces of metal is dependent on four parameters:

- contact force;
- relative velocity;
- material parameters;
- properties of the surrounding fluid.

For a drillstring in a riser system, the relative velocity is dictated by operations, either rotation rate or running/pulling speed; the material properties are usually specified (steel); and the surrounding fluid is the drilling fluid returns (more of an abrasive than a lubricant). The only parameter subject to control is the contact force.

The contact force is of concern where the drillstring is forced to conform to the bore of the riser system (primarily near the flex/ball joints). The force is amplified when the annulus between the drillstring and the riser bore is small (smaller ID risers, larger OD drillpipe), and when the drill-string tension at the point of contact is high (drill-string is less flexible). Examples of high wear cases include

- a) wells deep below the mud line: high tension in the drillstring at the lower flex/ball joint;
- b) use of large diameter drillpipe (168 mm [6-5/8 in], for example): smaller annulus, together with higher tension due to a heavier drillstring.

An example of a low wear case is a shallow well drilled with small diameter drillstring. The tool joints are usually responsible for much of the wear.

^a Upper joint is with respect to vertical and does not include vessel motions.

^b Lower joint is the differential angle. (See Notes 1 and 2 above.)

^c These guidelines apply to the global riser response.

^d All stresses are calculated according to von Mises stress failure criterion, σ_{vm} , as given in Equation (2); see 5.3.2:

$$\sigma_{vm}^2 = \frac{1}{2} [(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2] \quad (2)$$

where σ_1 , σ_2 and σ_3 are the principal stresses as shown in Figure 2.

The stress criterion is the static stress plus the maximum dynamic stress amplitude.

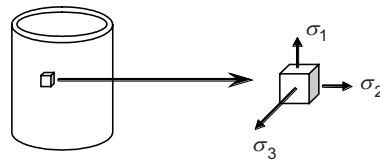
^e Allowable stress and significant dynamic stress ranges are defined in Figure 3.

^f σ_y is the minimum yield strength of the material.

^g See 3.1.83 for definition of stress amplification factor, F_{SA} .

^h The minimum top tension, T_{min} , required to prevent global buckling of riser is calculated as given in Equation (3).

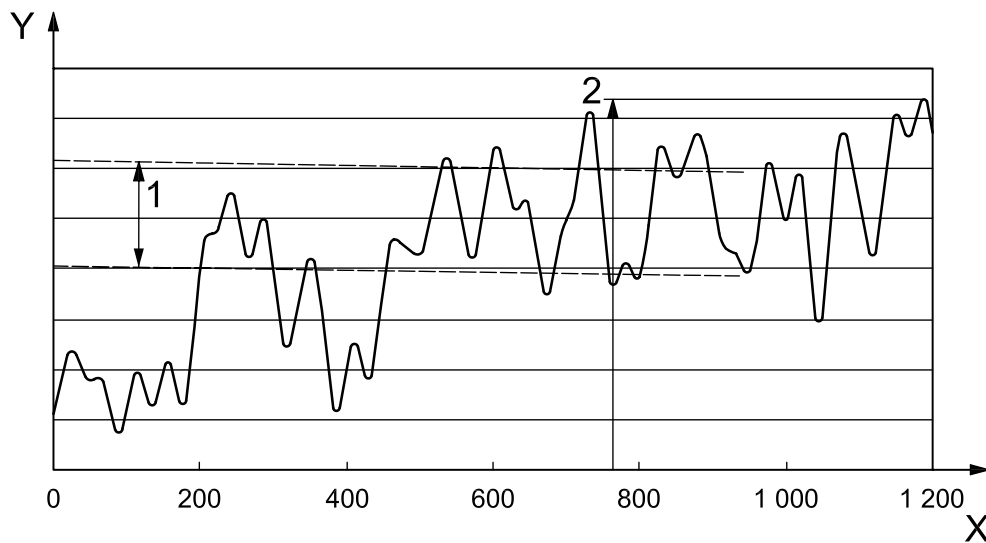
ⁱ The dynamic tension limit, F_{DTL} , is calculated as given in Equation (1).



Key

- σ_1 axial plus/minus the bending stress
- σ_2 hoop stress
- σ_3 radial stress

Figure 2 — Riser internal stresses



Key

- X time, expressed in seconds
- Y stress, expressed in megapascals (kilopounds per square inch)
- 1 significant dynamic stress range
- 2 allowable stress

Figure 3 — Allowable stress and significant dynamic stress range

The purpose of the maximum stress analysis is to ensure that the riser is strong enough to support the maximum design loads. This is accomplished by requiring the riser to support the maximum design loads while keeping the maximum stresses below the allowable stress. This limit is intended to prevent structural deformation that can lead to failure and includes a margin of safety. All stresses in Table 2 refer to the von Mises stress criterion, σ_{vm} , (see Higdon, *et al.*, 1985). Local peak stresses (3.1.42) are not considered for the maximum load analysis; however, these peak stresses can be of concern for evaluating the fatigue life of the riser. Fatigue analysis is discussed in Annex B.

A minimum tension setting is required to ensure the stability of the riser. The tension setting should be sufficiently high so that the effective tension, as addressed in 5.4.4, is always positive in all parts of the riser even if a tensioner should fail. In most cases, the minimum effective tension is encountered at the bottom of the riser.

The minimum top tension, T_{min} , is determined by Equation (3):

$$T_{min} = T_{Srmin} \times N / [R_f (N - n)] \quad (3)$$

where

- N is the number of tensioners supporting the riser;
- n is the number of tensioners subject to sudden failure;
- R_f is the reduction factor, relating vertical tension at the slip ring to tensioner setting to account for fleet angle and mechanical efficiency;
- $T_{Sr \min}$ is the minimum tensioner ring tension, as given by Equation (4):

$$T_{Sr \min} = W_s f_{wt} - B_n f_{bt} + A_i [\rho_m H_m - \rho_w H_w] \quad (4)$$

where

- W_s is the submerged riser weight above the point of consideration;
- f_{wt} is the submerged weight tolerance factor (minimum value of 1,05, unless accurately weighed);
- B_n is the net lift of buoyancy material above the point of consideration;
- f_{bt} is the buoyancy loss and tolerance factor resulting from elastic compression, long-term water absorption and manufacturing tolerance (maximum value of 0,96, unless accurately known by submerged weighing under compression at rated depth);
- A_i is the internal cross sectional area of riser, including choke, kill and auxiliary fluid lines;
- ρ_m is the drilling fluid density;
- H_m is the height of the drilling fluid column to the point of consideration;
- ρ_w is the seawater density;
- H_w is the height of the seawater column to the point of consideration, including storm surge and tide.

Note that in Equation (4) for $T_{Sr \min}$, the exterior pressure, $\rho_w H_w$, is multiplied by the internal cross-sectional area of the riser, A_i , rather than the exterior cross-sectional area, A_o . This is because the buoyancy of the riser pipe walls, $\rho_w H_w (A_o - A_i)$, has been included in the submerged riser weight, W_s .

See sample calculation in Clause C.2 for a determination of the minimum top tension setting.

The significant dynamic stress range limit should also be used in conjunction with the maximum load analysis. This limit is intended to provide some control on the fatigue damage accumulated by the riser. Incorporation of this limit in the maximum load analysis eliminates large dynamic stresses that can lead to accelerated fatigue.

Additional operating modes that can influence the design should be considered. Specifically, the disconnected mode, handling-tool interfaces, hang-off on either spider or riser hang-off structure, special handling situations, and emergency conditions should be reviewed for their impact on riser system design.

5.3.3 Riser analysis report

Results of the design analysis should be appended to the riser operations manual (see 6.2). Instructions for determining required top tensions as a function of all the relevant parameters, such as mud density, should be included. The operating tensions provided to the operating personnel should be the tensions that it is necessary to set on the tensioner units. These tensions shall include corrections for tensioner-line fleet angles and losses through the tensioner system. Sufficient tension should be set so as to prevent riser buckling in the event of a tensioner unit failure.