

Petroleum and natural gas industries — Design and operation of subsea production systems —

Part 1: General requirements and recommendations

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The UK participation in its preparation was entrusted to Technical Committee PSE/17, Materials and equipment for petroleum and natural gas industries, which has the responsibility to:

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Summary of pages

This document comprises a front cover, an inside front cover, pages i and ii, the EN ISO title page, page 2, the ISO title page, pages ii to iv, pages 1 to 108, an inside back cover and a back cover.

This standard has been updated (see copyright date) and may have had amendments incorporated. This will be indicated in the amendment table on the inside front cover.

This British Standard, having been prepared under the direction of the Engineering Sector Committee, was published under the authority of the Standards Committee and comes into effect on 15 June 1999

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English version

Petroleum and natural gas industries — Design and operation of subsea production systems — Part 1: General requirements and recommendations

(ISO 13628-1:1999)

Industries du pétrole et du gaz naturel —
Conception et exploitation des systèmes de
production immergés — Partie 1: Exigences
générales et recommandations
(ISO 13628-1:1999)

This European Standard was approved by CEN on 15 February 1999.

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European Committee for Standardization
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Foreword

The text of the International Standard ISO 13628-1:1999 has been prepared by Technical Committee ISO/TC 67 “Materials, equipment and offshore structures for petroleum and natural gas industries” in collaboration with Technical Committee CEN/TC 12 “Materials, equipment and offshore structures for petroleum and natural gas industries”, the secretariat of which is held by AFNOR.

This European Standard shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by August 1999, and conflicting national standards shall be withdrawn at the latest by August 1999.

According to the CEN/CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and the United Kingdom.

Endorsement notice

The text of the International Standard ISO 13628-1:1999 was approved by CEN as a European Standard without any modification.

NOTE Normative references to International Standards are listed in Annex ZA (normative).

INTERNATIONAL
STANDARD

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13628-1

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**Petroleum and natural gas industries —
Design and operation of subsea production
systems —**

**Part 1:
General requirements and recommendations**

*Industries du pétrole et du gaz naturel — Conception et exploitation des
systèmes de production immergés —*

Partie 1: Exigences générales et recommandations



Reference number
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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 3.

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.

International Standard ISO 13628-1 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13628 consists of the following parts, under the general title *Petroleum and natural gas industries — Design and operation of subsea production systems*:

- *Part 1: General requirements and recommendations;*
- *Part 2: Flexible pipe systems for subsea and marine applications;*
- *Part 3: Through flowline (TFL) systems;*
- *Part 4: Subsea wellhead and tree equipment;*
- *Part 5: Subsea control umbilicals;*
- *Part 6: Subsea production control systems;*
- *Part 7: Workover/completion riser systems;*
- *Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems;*
- *Part 9: Remotely Operated Tool (ROT) intervention systems.*

Annex A, Annex B, Annex C, Annex D, Annex E and Annex F of this part of ISO 13628 are for information only.

Introduction

This part of ISO 13628 has been prepared to provide general requirements, recommendations and overall guidance for the user to the various areas requiring consideration during development of a subsea production system for the petroleum and natural gas industries. The functional requirements defined in this part of ISO 13628 will allow alternatives in order to suit specific field requirements. The intention is to facilitate and complement the decision process rather than replace individual engineering judgement and, where requirements are non-mandatory, provide positive guidance for the selection of an optimum solution.

This part of ISO 13628 constitutes the overall subsea production system standard, with the intention that the more detailed requirements for the subsystems are retained in the complementary parts of ISO 13628. However, in some areas (e.g. structures, manifolds, marking) detailed requirements are included herein, as these subjects are not covered in a subsystem standard.

This part of ISO 13628 was developed on the basis of API RP 17A, *Design and Operation of Subsea Production Systems*, and other relevant documents on subsea production systems.

1 Scope

This part of ISO 13628 provides general requirements and overall recommendations for development of complete subsea production systems from the design phase to decommissioning. This part of ISO 13628 forms a top-level document to govern other standards dealing with subsystems typically forming a part of a subsea production system.

The complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells to a given processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells. This part of ISO 13628 and the subsystem standards apply as far as the interface limits described in clause 4.

Specialized equipment, such as split trees and trees and manifolds in atmospheric chambers, are not specifically discussed because of their limited use. However, the information presented is applicable to those types of equipment.

2 Normative references

The following normative documents contain provisions which, through reference in this text, constitute provisions of this part of ISO 13628. For dated references, subsequent amendments to, or revisions of, any of these publications do not apply. However, parties to agreements based on this part of ISO 13628 are encouraged to investigate the possibility of applying the most recent editions of the normative documents indicated below. For undated references, the latest edition of the normative document referred to applies. Members of ISO and IEC maintain registers of currently valid International Standards.

ISO 898-1, *Mechanical properties of fasteners made of carbon steel and alloy steel — Part 1: Bolts, screws and studs*.

ISO 898-2, *Mechanical properties of fasteners made of carbon steel and alloy steel — Part 2: Nuts with specified proof load value*.

ISO 10423, *Petroleum and natural gas industries — Drilling and production equipment — Wellhead and christmas tree equipment*.

ISO 13628-3, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 3: Through flowline (TFL) systems*.

ISO 13628-4:—, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 4: Subsea wellhead and tree equipment*¹⁾.

ISO 13628-6, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 6: Subsea production control systems*.

ISO 13819-1, *Petroleum and natural gas industries — Offshore structures — Part 1: General requirements*.

ISO 13819-2, *Petroleum and natural gas industries — Offshore structures — Part 2: Fixed steel structures*.

ANSI/ASME B31.8, *Gas Transmission and Distribution Piping Systems*.

API RP 17C, *TFL (Trough Flowline) Systems*²⁾.

API RP 17G, *Design and Operation of Completion/Workover Riser Systems*³⁾.

ASTM A 193, *Specification for Alloy — Steel and Stainless Steel Bolting Materials for High Temperature Service*.

¹⁾ To be published.

²⁾ For the purposes of this part of ISO 13628, API RP 17C will be replaced by ISO 13628-3 when the latter becomes publicly available.

³⁾ For the purposes of this part of ISO 13628, API RP 17G will be replaced by ISO 13628-7 when the latter becomes publicly available.

ASTM A 320, *Specification for Alloy Steel Bolting Materials for Low-Temperature Service*.

3 Terms, definitions and abbreviations

For the purposes of this part of ISO 13628, the following terms, definitions and abbreviations apply.

3.1 Terms and definitions

3.1.1 sealine

flowline, service line, cable, umbilical or pipeline

NOTE For description of pressure and temperature ratings, the definition given in the applicable subsystem standard and other relevant standards and design codes is used.

3.2 Abbreviations

ADS	atmospheric diving suit
API	American Petroleum Institute
BOP	blow-out preventer
BS&W	basic sediment and water
CRA	corrosion-resistant alloy
DCV	directional control valve
DFI	design, fabrication, installation
DFO	documentation for operation
EDP	emergency disconnect package
EFC	European Federation of Corrosion
ESD	emergency shutdown
ESP	electrical submersible pump
FAT	factory acceptance test
FPU	floating production unit
GOR	gas-oil ratio
GRP	glass-fibre-reinforced plastic
HAT	highest astronomical tide level
HAZOP	hazards in operation analysis
HB	Brinell hardness
HIPPS	high integrity pipeline protection system
HPU	hydraulic power unit
HV	Vickers hardness
IMR	inspection, maintenance and repair
IRJ	instrument riser joint
ISO	International Organization for Standardization
LAT	lowest astronomical tide level
LMRP	lower marine riser package (for drilling)
LMV	lower master valve

LRP	lower riser package (for workover)
MIV	methanol injection valve
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
PC	personal computer
PCDA	plant control and data acquisition system
PCS	production control system
PGB	permanent guide base
PLC	programmable logical controller
PMV	production master valve
PRE	pitting-resistance equivalent
PSD	process shutdown
PSV	production swab valve
PWV	production wing valve
P&A	plug and abandonment
RAL	“Reichsausschuss für Lieferbedingungen”. A colour system used by German paint manufacturers
ROT	remotely operated tool
ROV	remotely operated vehicle
SAS	safety and automation system
SAFOP	safety in operation analysis
SCM	subsea control module
SCSSV	surface-controlled subsurface safety valve
SEM	subsea electronic module
SMYS	specified minimum yield strength
TFL	through-flowline system
THRT	tubing hanger running tool
TLP	tension leg platform
TRSCSSV	tubing-retrievable surface-controlled subsurface safety valve
TRT	tree running tool
UNS	unified numbering system
UPS	uninterruptable power supply
UTM	universal transversal mercator
VDU	visual display unit
WHP	wellhead pressure
XT	tree
XTRT	tree running tool

4 Systems and interface descriptions

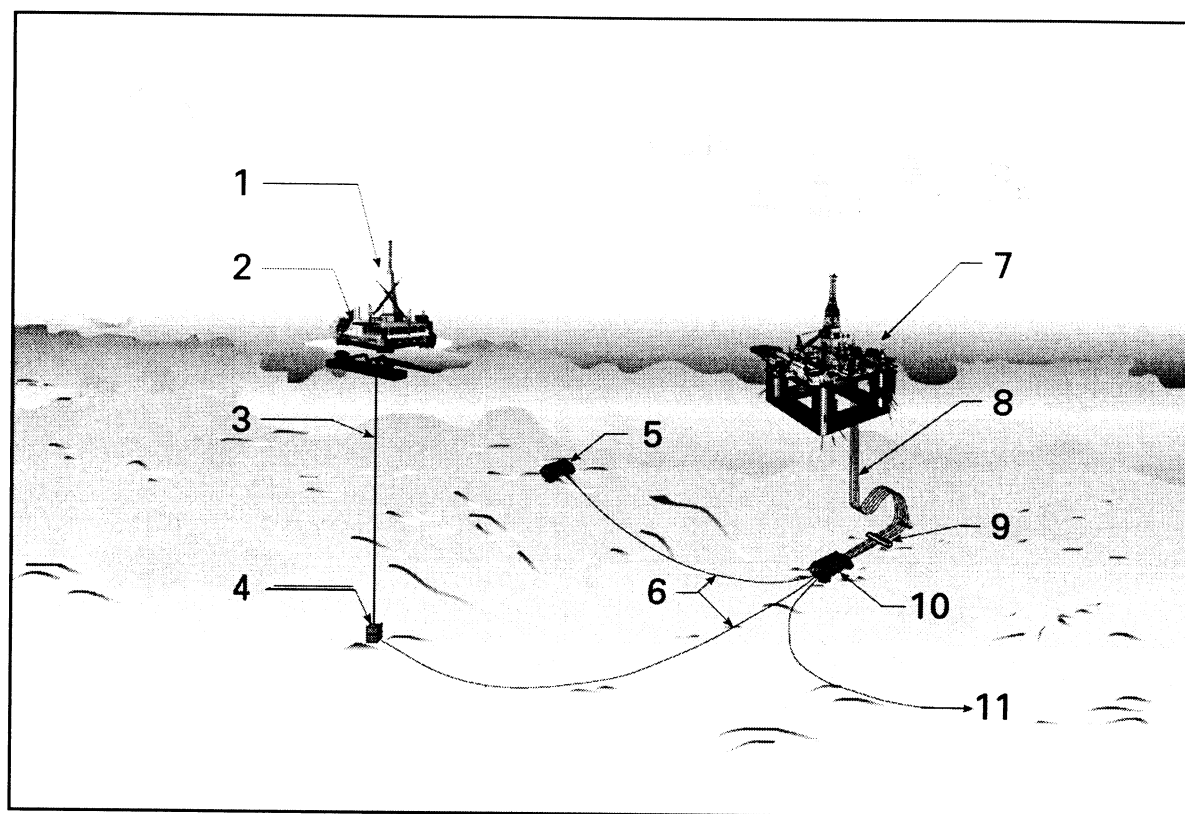
4.1 General

Complete subsea production systems range in complexity from a single satellite well with a flowline linked to a fixed platform, to several wells on a template producing to a floating facility.

The elements of a typical subsea production system are shown in Figure 1. These are wellheads (both subsea and mudline casing suspension systems) and trees, sealines and end connections, controls, control lines, single-well structures, templates and manifolds, ROVs/ROTs and completion/workover and production risers (both rigid and flexible). In some areas (not covered by subsystem standards), detailed requirements are included (these apply to structures, manifold piping, materials, colour and marking).

The objective of this subclause is to describe the systems in general and define the subsystem interfaces. For a detailed description of subsystems and components, see Annex A.

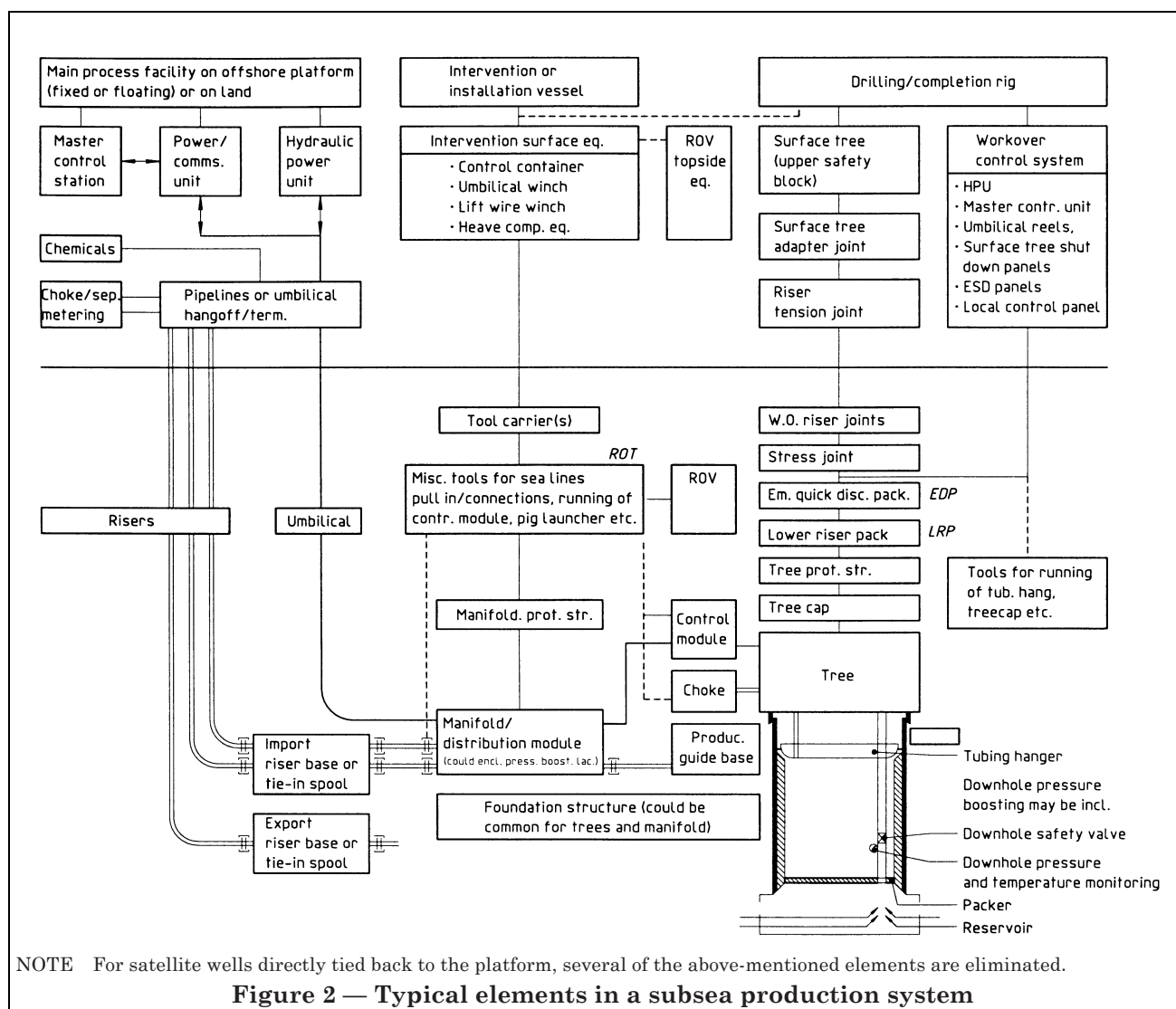
A schematic drawing illustrating typical elements of a subsea production system is shown in Figure 2.



Key

1	Running and retrieving tools	7	Production controls
2	Installation and workover controls	8	Production riser
3	Completion riser and control lines	9	Riser base
4	Satellite well	10	Manifold
5	Template	11	Export
6	Sealines		

Figure 1 — Typical development scenarios



4.2 Overall system description

4.2.1 General

Subsea production or injection systems are used to develop reservoirs, or parts of reservoirs, of a nature which dictates drilling of the wells from more than one location. Subsea production systems may also be used to develop reservoirs or parts of reservoirs beyond the reach of platform drilling facilities. Deep water may also in itself dictate development of a field by means of subsea completions.

The main elements of a subsea production or injection system are:

- a wellhead system with associated casing strings and production/injection tubing;
- a structural foundation and a guidance system for orientation and lateral guidance of modules during installation/retrieval. This unit is not always used;

- a set of flow and pressure control valves normally integrated in a tree;
- a production control system for remote monitoring and control of all subsea functions;
- a protective structure (optional);
- a sealine system;
- a manifold system (optional);
- installation and intervention equipment and tools with associated control systems.

The elements of the subsea production/injection system may be configured in numerous ways, dictated by specific field requirements and by operator strategy.

The most common configurations are:

- single satellite wells tied individually to a surface processing facility;

- one or more satellite wells tied individually to a subsea manifold located a given distance from the surface processing facility;
- multiple wells located on a common template incorporating a manifold.

In the following, the main characteristics of these scenarios are briefly described.

4.2.2 *Single satellites*

For relatively shallow water, this configuration is characterized by short offset (outside the drilling reach of the host platform if this is a combined drilling production facility) and, if an infrastructure with a surplus of tie-in capacity exists, this scenario can be very effective. In terms of required permanent works this is basically a single satellite development copied a number of times over. Usually the flowline and umbilical are required to be installed as first-end tie-in at the infrastructure and second end pull-in at the satellites in order to limit congestion on the seabed around the infrastructure.

Flowline and umbilical are for some systems connected directly to the tree structure. This approach offers some rationalization in hardware.

4.2.3 *Manifold/satellite cluster*

This concept is based on tie-in of a number of single satellites to a central manifold. The manifold in turn is tied to the infrastructure by means of one or more sealines. An arrangement including two production flowlines with same size, service and control lines is quite common. This arrangement facilitates operation of wells at two different pressure levels simultaneously, as well as convenient round-trip pigging.

The system has flexibility with respect to simultaneous drilling and production, which can save some drilling time, and has flexibility with respect to installing wells in optimal locations rather than in batches at the same location, ref. template arrangement described below.

4.2.4 *Template*

This concept includes some of the features described in the previous subclause, but with some notable differences. The wells and the manifolds are located on the same structure. Headers and lines often have much of the same configuration as the manifold/cluster option. Template designs have some additional mechanical tolerance problems relative to cluster designs.

4.3 Subsea wellhead system

4.3.1 *General*

The main function of a subsea wellhead system is to serve as a structural and pressure-containing anchoring point on the seabed for the drilling and completion systems and for the casing strings in the well. The wellhead system incorporates internal profiles for support of the casing strings and isolation of the annuli. In addition, the system incorporates facilities for guidance, mechanical support and connection of the systems used to drill and complete the well.

4.3.2 *Wellhead system elements*

A typical wellhead system consists of the following elements:

- a) a drilling guidebase with a central opening for drilling of the first section of the well and facilities for attachment of guidelines. The temporary guidebase, acts as a support for the permanent guidebase, providing a controlled reference point for wellhead elevation. Note that on single satellite wells the drilling guidebase may be omitted if there are no requirements for accurately controlled elevation of the wellhead. On multiple well templates, the drilling guidebase forms an integral part of the template;
- b) a permanent guidebase with facilities for attachment to the conductor housing, and guidance of the drilling and completion equipment (universal guide frame, BOP, production tree). If used together with a temporary guidebase, the permanent guidebase incorporates a gimbal arrangement on the under side (curved profiles that interfaces with a cone landing area on the temporary guidebase) to compensate for any angular misalignment between the temporary guidebase and the permanent guidebase due to the seabed topography, and the verticality of the well;

NOTE On satellite wells, depending on the overall tree configuration, the permanent guidebase may be replaced by a production guidebase, prior to installation of the tree, incorporating facilities for pull-in and connection of the sealines and connection to the tree. Alternatively, a production guidebase can be designed to serve as both the drilling guidebase and the production guidebase. It can be either permanent or retrievable. The sealines may also be connected directly to the tree.

- c) a conductor housing welded to the conductor casing, which forms the initial anchoring point to the seabed. The conductor housing incorporates an internal landing shoulder for the wellhead housing, and facilities on the outside for attachment of the permanent guidebase. The conductor housing may be installed together with the permanent guidebase;

- d) a wellhead housing with internal profiles for support of all subsequent casing strings and the tubing hanger, and external profiles for attachment of the drilling and completion equipment (BOP, tree) and landing in 762 mm (30 in) housing;
- e) casing hangers with seal and lock-down assemblies for suspension of the casing strings and isolation of the annuli.

4.3.3 *Running and retrieving tools*

Dedicated tools are used to install, test and retrieve the various elements of the wellhead system. The tools are activated by either mechanical manipulation of the drill string (push, pull, rotation) or in some cases by hydraulic functions through the drill string or dedicated hydraulic lines. These tools interface with dedicated handling profiles in the associated equipment.

4.3.4 *Miscellaneous wellhead equipment*

A set of wear bushings is used to protect the internals of the wellhead at various stages of the drilling/completion operation.

4.4 *Subsea tree system and tubing hanger*

4.4.1 *General*

The equipment required to complete a subsea well for production or injection operations incorporates a tubing hanger and a tree. The subsea tree and the wellhead system form the barrier between the reservoir and the environment in the production mode. In the installation/workover mode the barrier function is transferred to a LRP or BOP.

There are two main categories of trees, conventional and horizontal. The conventional tree is described as the main option, whilst the characteristics of the horizontal tree are described in 4.4.6.

In conventional subsea completions, the tubing hanger is installed inside the wellhead. The tree is installed on top of the wellhead. The tubing hanger forms the connection between the production/injection tubing and the tree. During installation and workover, the tree production/injection and annulus valves are locked open or held open hydraulically to allow access to the wellbores. The well barrier function is then covered by a lower riser package installed between the riser and the tree.

4.4.2 *Tubing hanger*

The tubing hanger system supports the tubing string and isolates the annulus between the tubing and the casing. The tubing hanger is locked down inside the wellhead and includes seal bores for connection with bore extension subs from the tree.

4.4.3 *Tree*

The tree consists of a valve block with bores and valves configured in such a manner that fluid flow and pressure from the well can be controlled for both safety and operational purposes. The tree includes a connector for attachment to the wellhead. The connector forms a pressure-sealing connection to the wellhead and includes bore extension subs from the tree to the tubing hanger, forming pressure-sealing conduits from the main bore and annulus of the well to the tree and additional conduits as required.

External flow loops provide fluid paths between the bores of the tree and the flowline connection point. The flowline may be connected either directly to the tree, or via flow loops on a production guidebase. The flowline connection joins the tree with the subsea flowline, using a choice of connections described in Annex A.

4.4.4 *Tree cap*

A tree cap is usually installed on top of the tree to prevent marine growth on the tree upper connection and seal bores. The cap may either be pressure-containing or purely a protective cap, depending on the barrier configuration of the tree. The tree cap could incorporate facilities to convert certain functions of the tree from workover control mode to production control mode.

4.4.5 *Tree running tool/lower riser package*

The tree running tool is used to install the tree, and consists of a connector interfacing the top of the tree. It is often combined with a lower riser package containing a set of safety valves to control the well during installation/workover operations. The lower riser package may include valves capable of cutting wire and coiled tubing.

4.4.6 *Horizontal tree*

The main difference between a conventional tree and a horizontal tree is that the horizontal tree is designed to be installed prior to the tubing hanger, and that the tubing hanger, when installed, is located inside the tree instead of the wellhead. Horizontal trees are configured with the valves located in the horizontal bore sections of the tree, in order to provide a large vertical bore through the tree. In installation/workover mode the well barrier function is covered by a conventional drilling BOP connected to the top of the tree, with a tubing safety valve inside the BOP, as part of the tubing hanger running string.

4.5 Completion/workover riser systems

4.5.1 A completion riser is generally used to run the tubing hanger and tubing through the drilling riser and BOP into the wellbore. A workover riser is typically used in place of a drilling riser to reenter the well through the tree. The completion and workover riser may be a common system with items added or removed to suit the task being performed.

4.5.2 Either type of riser provides communication between the wellbore and surface equipment. Both resist mass and pressure loads and accommodate wireline tools for necessary operations. The workover riser also resists external loading.

4.5.3 The interfaces are naturally defined at the physical connection points with the other subsea and surface equipment to which they attach. For the completion riser, these are typically the subsea tree mandrel and surface tree riser-tensioning system.

4.6 Mudline casing suspension system description

4.6.1 Mudline casing suspension systems are designed to be used with bottom-supported drilling rigs (jack-ups), tension leg platforms, etc. The systems provide a suspension point near the mudline to support the mass of casing strings within the wellbore. The conductor and casing strings with their respective annuli are tied back to the surface, where they are terminated in conventional wellhead equipment with a surface BOP, or surface tree.

4.6.2 Wells drilled with mudline casing suspension systems can be completed with a subsea tree, provided proper adaptation for subsea completion is made.

4.6.3 In general, mudline suspension completions are best suited for shallow-water applications where wellhead strength/robustness is not an issue.

4.7 Production control system

4.7.1 General

Production control systems appear in several major architectures (see Annex A). Only the two most common systems are described in this subclause.

4.7.2 Direct hydraulic control system

This is a simple type of system, characterized by cost-effectiveness and high-reliability for simple tasks, i.e. control of single satellites tied back to an infrastructure located at a short distance. For more complex scenarios with manifolded multiple-well completions, long offsets and/or deep water, this system architecture is not cost-effective and does not offer optimum performance.

The system consists basically of an HPU and a valve panel (often controlled by means of a PLC-type industrial computer) located at the infrastructure usually with one control umbilical per well and a simple interface to the tree actuators. Normally the instrument requirements for single satellites are modest, and most of the sensors may be located on the surface infrastructure. For several satellites tied back to a platform, congestion and requirements for J-tubes can represent a complication (one umbilical per tree).

Single satellites typically require only a few subsea process sensors. Direct wiring back to the infrastructure for one or two instruments is typical.

4.7.3 Electrohydraulic multiplexed systems

For any combination of manifolded wells, long offsets, and/or deep water, this system architecture is preferred for cost and performance effectiveness. Electrohydraulic systems usually include the following components:

a) topside computer;

This is usually a dedicated unit which interfaces with the ESD system, the SAS system, the UPS and the HPU.

b) the HPU;

This unit provides the hydraulic power supply, usually two pressure levels, for actuation of subsea and downhole valve actuators. It interfaces with the SAS system.

c) electrical power unit;

This unit provides power at the desired voltage and frequency to feed the subsea users. It may interface with the UPS.

d) modem units;

These units modulate communication signals for transmission on the control umbilical. Some systems use communication superimposed on the power lines.

e) control umbilical;

The control umbilical has electrical wires for power and communication, hydraulic conduits for chemical injection purposes, annulus access, and hydraulic power transmission. It interfaces with the platform hangoff arrangement topsides and well tree/structure (satellite case) or the manifold subsea (manifolded option). In some cases electrical and hydraulic functions are provided in separate umbilicals.

f) control modules and base plates;

These modules represent the most critical components with respect to reliability. They invariably contain one or two SEMs as interface circuitry for sensors, modems, valve drivers, etc. The hydraulic outputs from the control modules are directed to tree actuators and downhole functions. The interface with the tree is of particular importance in terms of system design. A control module usually has hydraulic accumulators for storage of energy. A control module also contains a hydraulic manifold with DCVs which facilitate control of hydraulic pressure in the tree actuators.

The base plate which interfaces with the control module has stab connectors (electrical and hydraulic) to match those of the control module. This is the interface point between the tree and the SCM. The latter also has an interface with the SCM running tool which is used to replace failed modules.

g) process sensors;

An installation of this type is usually equipped with several process sensors. They are interfaced to the control module via the base plate. Most process sensors are only retrievable with the tree and are thus required to be of highly reliable design.

h) manifold/tree wiring and tubing;

Both the manifold and the trees have electrical and hydraulic distribution for power, communication and output/input functions. Wet mateable stab connectors are used to interface with the control module base plate, umbilical, etc.

i) interface with the workover control system.

It is common practice that some valve actuator function lines from the SCM are routed via the tree cap such as to isolate all connections between the PCS and the valve actuators. Thus only the rig-based control system may operate vertical valves in the tree during workover operations. Certain control module functions may be used from the work-over control system during work-over operations.

4.8 Sealine systems

4.8.1 This subclause describes in general subsea sealines and end connectors used in a subsea production system, and covers the unique factors of subsea systems which are: high pressure, multiphase flow, multiple lines, subsea connections, TLFs and pigging traps.

4.8.2 Sealines may be dedicated to a number of purposes, including the following:

- a) flowlines for production;
- b) gathering lines;
- c) injection lines;
- d) service lines (test, kill, etc.).

4.8.3 Components used in a sealine system may include the following:

- a) connector;
- b) spool (short piping segment commonly used in connecting pipelines);
- c) safety joint (weak links) (device designed to fail at a predetermined structural load).

4.8.4 Purpose-built special tools are often used for pulling in and making sealine connections, particularly in water depths requiring diverless operations.

4.8.5 After placing a sealine on the seabed, it may be necessary to reposition the ends, modify them (by adding extensions), or both, so that a connection can be made without further gross adjustment. If TFL or pigging is specified, then the bends, welds, etc., of the line configuration should comply with API RP 17C or specific pigging requirements.

4.8.6 A sealine system begins with both halves of the connector used at the subsea facility and ends with one of the following:

- a) both halves of a connector used at another subsea facility;
- b) the sealine side of a surface connection or weld at the top of a platform riser;
- c) at the static flowline to dynamic riser interface/connection;
- d) the interface to the flexible pipe is typically at the flanges on the end fitting.

4.8.7 Sealines may be buried (trenched or rockdumped) for protection and/or thermal insulation purposes. Protection may also be necessary in order to avoid buckling/expansion problems.

4.9 Subsea template and manifold systems**4.9.1 General**

The description includes all template and manifold systems supported on the seabed which may incorporate and physically support wellheads, drilling and production risers, pipeline connections, trees, manifolds, control system components and protective framing.

4.9.1.1 *Template*

Production from the templates may flow to floating production systems, platforms, shore or other remote facilities. A template typically comprises a structure that provides a guide for drilling and/or support for other equipment, and provisions for establishing a foundation (piled or gravity-based).

The template is typically used to group several subsea wells at a single seabed location. Templates may be of a unitized or modular design. Several types of template are described below. Actual templates may combine features of more than one of these types.

4.9.1.2 *Well spacer/tieback template*

A multiwell template used as a drilling guide to pre-drill wells prior to installing a surface facility. The wells are typically tied back to the surface facility during completion. The wells could also be completed subsea, with individual risers back to the surface.

4.9.1.3 *Multiwell/manifold template*

A template with multiple wells drilled through it and supporting a manifold system.

4.9.1.4 *Manifold template*

A template used to support a manifold for produced or injected fluids. Wells would not be drilled through such a template, but may be located near it or in the vicinity of the template.

4.9.1.5 *Riser base*

A template which supports a marine production riser or loading terminal, and which serves to react loads on the riser throughout its service life.

4.9.1.6 *Modular template*

A template assembled in modules around a base structure (often the first well). These modules may or may not be of a cantilevered design.

4.9.2 *Manifold*

A system of headers, branched piping and valves used to gather produced fluids or to distribute injected fluids. A manifold system may also provide for well testing and well servicing if TFL capability is included along with annulus monitoring and bleed capability. The associated equipment may include valves, connectors for pipeline and tree interfaces, chokes for flow control, and TFL diverters. The manifold system may also include control system equipment such as a distribution system for hydraulic and electrical functions, as well as providing interface connections to control modules. All or part of the manifold may be retrievable such that it can be installed with the template or separately at a later date if required.

4.9.3 *Interfaces*

The manifold and associated flowlines shall be made to a piping code, e.g. ANSI/ASME B31.8, with interfaces at the weld, flange or coupling to connecting equipment.

4.10 *Production risers*

4.10.1 The portion of a pipeline extending from the seabed to the surface is termed a production riser. Examples include

- a) conventional riser, consisting of rigid piping attached to the platform structure and serving as the pipeline;
- b) J-tube riser, for rigid pipe, and J-tube or I-tube riser, for flexible pipe which permits installation of the pipeline without connections on the seafloor and consists of rigid conduit attached to the platform through which the pipelines are pulled;
- c) flexible pipe riser, consisting of flexible pipe attached to a platform (in a manner similar to a conventional riser) or suspended from a floating facility;
- d) riser from a subsea template.

The function of a subsea production riser is to provide conduit(s) for hydrocarbons or injection fluids between the sea-floor equipment and the production facility. The risers and support structures may also provide support for auxiliary lines and control umbilicals.

4.10.2 Production risers fall into three broad design types: rigid pipe riser, flexible pipe riser and combinations of rigid and flexible pipe.

4.11 *Intervention systems*

Remotely operated intervention systems fall into two principal categories: swimming vehicles and surface-run tooling.

Intervention systems may be operated by divers (including ADS), remotely operated vehicles (ROVs) or dedicated remotely operated tooling (ROTs), and are typically used for

- inspection;
- operation of valves;
- injection or sampling of fluids;
- installation and recovery of equipment;
- connection of sealines.

ROVs are near-neutral buoyant submersible vehicles that may be used to perform tasks such as valve operations, hydraulic stab and general manipulator tasks. They can also carry tooling packages to undertake specific tasks, such as pull-in and connection of sealines, and component replacement.

ROTs are dedicated tools that are usually deployed on lift wires, umbilicals or drillpipe. Lateral guidance may be by guidewires, dedicated integral thrusters or ROV assistance. Generally, ROT intervention systems are used for pull-in and connection of sealines or for installation of component replacement tasks that require surface lift capacity that is beyond the ROV capability.

5 Design

5.1 General

When designing a subsea production system, a systems approach should be used which considers installation, operation, inspection, maintenance, repair and abandonment requirements.

Also provision for possible future extensions should be planned at an early design stage.

The design of such a subsea production system shall take in account the above phases of the field development, the requirements to operate the field, the design data and design loads relevant at the location of the subsea installation. The information should be provided on data sheets. Typical data sheets are included in Annex F.

The following subclauses give an overview of typical information required.

5.2 Design criteria

5.2.1 Environmental data

The following environmental data are typically required for the installation site of the subsea installation and applicable along the pipeline route to the processing facility:

5.2.1.1 Oceanographic data

- water: depth, visibility, salinity, temperature, LAT, HAT, resistivity, oxygen content;
- currents: velocity, profile, direction, distribution and periodic occurrence;
- seabed: oil description, friction angles, soil shear-strength, depth profile and load-bearing capacity, pockmarks, presence of shallow gas, earthquake data, seabed topography, stability under cyclonic conditions, resistivity, density, marine growth.

5.2.1.2 Meteorological data

- waves: height, wavelength, frequency, direction, distribution and periodic occurrence;
- weather: air temperature, wind speeds, wind direction, distribution and periodic occurrence;
- icebergs: size, occurrence frequency, direction, velocity.

5.2.2 Reservoir and fluid data

The following data are typically required:

- reservoir characteristics (BS&W data including reservoir depth, reservoir structure type, reservoir life);
- product characteristics (flowing/shut-in pressure, temperature, density, GOR, water cut, bubble-point, chemical composition, corrosivity (H_2S and CO_2 mol %), sand, emulsions, wax content, asphaltenes and hydrates, flowrates, API gravity, chlorides/salinity/pH of produced water, viscosity, cloud points, pour point and scaling potential, formation-water content of minerals);
- injection characteristics (turbidity, oil in water or gas allowances, scaling probability, pressure, temperature, corrosivity, filtration requirements).

See data sheet F.1 in Annex F.

5.2.3 Well completion data

The following information related to drilling operation, corresponding well completion and well intervention is required:

NOTE Depending on the scenario, some of the information asked for below will be required at different stages.

- a) wellhead details, i.e. size, pressure rating;
- b) wellhead type, i.e. subsea, mudline, hybrid, etc.;
- c) drilling and casing programme;
- d) subsea BOP and drilling riser system details, i.e. size, pressure rating, etc.;
- e) guidebase details;
- f) wellhead elevation and orientation;
- g) equipment installation system, i.e. guidelines or guidelineless ROV, ROT, ADS and diving systems;

- h) potential drilling loads on the wellhead system;
- i) completion/workover riser type, dual string, single string, concentric, etc. and interfaces with stress-joint, EDP/TRT, LRP, and THRT;
- j) completion tubing size with relevant plug nipple information;
- k) downhole control and monitoring requirements (i.e. valve, pump, sleeve, pressure, temperature and flow functions);
- l) well barrier requirements;
- m) tubing hanger system and design, i.e. mechanically or hydraulically set, size, configuration, etc.;
- n) completion/workover riser facilities, i.e. running of subsea tree, running of tubing hanger, wireline, coiled tubing, snubbing and operations, well stimulation, clean-up and testing, etc.

5.2.4 Process and operation data

The following process and operating data are typically required:

- a) production systems requirements [flowrates, flow regimes, flow control requirements, pressures (flowing and shut-in) and temperatures at wellhead and at processing facility, insulation, circulation and heating requirements];
- b) injection systems (water and/or gas) requirements [flowrates, flow regimes, flow control and filtration requirements, pressures (flowing and shut-in) and temperatures at wellhead and at processing facility];
- c) chemical injection requirements (type and characteristics of fluids, rates, flow control requirements, pressures and temperatures at wellhead and processing facility);
- d) well shut-in requirements (barrier requirements, ESD requirements, kill/service fluids, rates, pressures and temperatures at wellhead and at drilling rig or processing facility, hydrate control philosophy during start-up and shut-down, HIPPS);
- e) flowline cleaning requirements (pigging round-trip/bidirectional);
- f) well management requirements (flow control requirements, rate limitations, testing/logging requirements);
- g) inspection requirements (type of inspection to be performed, inspection frequency, access requirements, intelligent pigging requirements, barrier testing);

- h) intervention requirements (intervention methods; ROV, ROT, ADS and diving);
- i) well workover frequency (type of workover operation and methods to be used);
- j) simultaneous drilling and production requirements;
- k) abandonment requirements (P&A).

5.2.5 Receiving facilities data

The subsea system interfaces with the receiving facility and relevant interface information for the facility is required:

- a) type of receiving facility, i.e. fixed platform, floating production facility or land terminal;
- b) production riser type and characteristics, i.e. rigid or flexible;
- c) service facilities available, i.e. electrical, hydraulic, air, water, chemicals, etc.;
- d) ESD and control interface;
- e) deck plan for equipment location;
- f) flowline and umbilical interfaces, including pigging and kill facilities;
- g) flowline and umbilical approach corridors;
- h) existing and planned seabed installations, i.e. pipelines, flowlines and umbilicals;
- i) protection requirements for sealines and equipment inside receiving-defined-facility safety zones, if applicable;
- j) distance between subsea facilities and host facility.

5.2.6 Safety and hazards

Safety includes all operational, technical and emergency preparations significant for the protection of people, environment, the installations and vessels present.

To prepare for marine and mudline activities and to establish safety criteria for technical design solutions for production equipment, early information about the following is important:

- shallow gas pocket(s);
- fishing intensity;
- vessel activities;
- military activities;
- seabed scouring;
- iceberg activity;
- mudslide probabilities;
- subsea volcanic activity;
- sand waves;

- environmental protection (wildlife, breeding seasons, etc.);
- emergency preparations;
- other infrastructure.

5.3 Field development

5.3.1 System definition

In defining the field development, due consideration should be given to the following aspects:

- a) field configuration, i.e. template, well cluster, satellite wells, manifolds, etc.;
- b) details of existing facilities and infrastructure, i.e., platforms, appraisal wells, pipelines, etc.;
- c) moored and/or dynamically positioned drilling-vessel type, i.e. semisub, monohull or jack-up;
- d) anchor patterns and/or footprint;
- e) field development schedule, i.e. planned development wells, future wells, future production tie-in philosophy, spare capacity including hook-up philosophy;
- f) possibilities for “early” well testing, and early production;
- g) artificial lift requirements, i.e. ESP, hydraulic turbines or gas lift;
- h) well stimulation requirements, i.e. acidizing, fracturing, etc.;
- i) requirement for well killing (kill fluid characteristics, flowrates and pressure);
- j) requirement for gas or water injection to boost wellhead flowrates (flowrates and pressures);
- k) requirement for chemical injection or periodic squeeze treatment for prevention of hydrate formation, waxing, scaling, corrosion, etc. (injection chemical type, flowrates and pressure);
- l) requirement for any sealine over-pressure protection system;
- m) well testing requirements;
- n) workover system type, i.e. conventional and/or subsea lubricator type;
- o) control and monitoring philosophy;
- p) intervention philosophy, i.e. diver or diverless;
- q) sealine cleaning requirements.
- b) simultaneous production through sealine transport system during rig activity in affected area;

5.3.3 Environment

In order to protect the marine environment, due consideration shall be taken of the following:

- a) seabed congestion from subsea structures and pipelines;
- b) restrictions on fishing activities and marine traffic;
- c) hydraulic fluid discharge (design should comply with applicable regulations);
- d) purge/pigging fluids disposal (design should comply with applicable regulations);
- e) drilling fluids and cuttings disposal (design should comply with applicable regulations).

5.4 Design loads

5.4.1 General

All applicable loads that may affect the subsea production system during all relevant phases, such as fabrication, storing, testing, transportation, installation, drilling/completion, operation and removal, shall be defined and form the basis for the design.

Accidental loads are project-specific and should be verified by a special risk analysis for the actual application. Accidental loads may include dropped objects, snag loads (fishing gear, anchors), abnormal environmental loads (earthquake), etc.

The data sheet F.4 in Annex F may be used to define applicable loads.

5.4.2 Unpressurized primary structural components

Unpressurized primary structural components such as guidebases shall be designed in accordance with accepted industry practices and documented in accordance with ISO 13819-1 and ISO 13819-2.

As an alternative, a design verification load test of 1,5 times its rated capacity may be substituted for design analysis. The component shall sustain the test loading without deformation to the extent that any other performance requirement is not met, and the test documents shall be retained at an agreed location for an agreed time.

5.3.2 Simultaneous operations

The potential for simultaneous operations during installation and/or intervention should be assessed. Simultaneous operations may be achieved typically in the following combinations:

- a) simultaneous rig intervention on template/or manifold-cluster well and hydrocarbon production from neighbouring wells;

5.4.3 Design of lifting devices

5.4.3.1 Padeyes

Padeyes shall be designed in accordance with documented industry practice using a design safety factor of typically 4 or greater based on minimum specified ultimate material strength at the maximum rated pickup angle. Load capacities of padeyes shall be marked as specified in ISO 13628-4:—, 5.5.2.

5.4.3.2 Other lifting devices

Other lifting devices, such as running tools shall be designed as specified in ISO 13628-4:—, 4.1.3.5. If the lifting devices are either pressure-containing or -controlling, and are designed to be pressurized during lifting operations, then the load capacity shall include stresses induced by internal rated working pressure. Load capacity shall be marked on all lifting devices as specified in ISO 13628-4:—, 5.5.3.

5.5 System design

5.5.1 Overall design

5.5.1.1 The subsea production system should be designed to optimize life cycle benefit while meeting functional requirements, without any compromise on safety.

5.5.1.2 The system shall be designed such that any operation can be suspended, leaving the well(s) in a safe state if predefined operational limits are about to be exceeded.

5.5.1.3 The system should be designed for easy fault diagnosis without system retrieval.

5.5.1.4 A high system availability should be obtained through use of simple designs and reliable products (suppliers' standard equipment preferably with a satisfactory field performance record). Use of redundant designs should only be selected after a system performance analysis.

5.5.1.5 Operational reliability should be documented for the subsea systems. For noncritical and temporary equipment, relaxed requirements may be accepted.

5.5.1.6 Connectors with critical functions shall have an arrangement preventing unintentional release.

5.5.1.7 Means of obtaining/maintaining cleanliness in hydraulic systems to the standard required for safe operation shall be included.

5.5.1.8 Drag/wave-induced forces during launching/retrieval through the splash zone shall be considered for design and arrangement of structural elements, including those which are not rigid members of the overall structure, e.g. hatches.

5.5.1.9 Heavy modules designed for guidelineless marine operation such as subsea trees and BOPs, shall sustain all relevant loads and be equipped for guidance during landing of tools and modules. The load-absorbing structure shall have sufficient strength to withstand loads determined by the operation parameters of the defined intervention strategy.

5.5.1.10 All tree block penetrations serving hydraulic and/or chemical injection lines shall be equipped with isolation valves to maintain the barrier philosophy.

5.5.1.11 A single isolation valve between the environment and a pressurized manifold/header is acceptable for short-term periods (e.g. well workover), provided the pressure integrity of the valve can be verified. For long-term periods (e.g. rig off location) the manifold/header shall be secured by a high-pressure cap. The above requirement typically applies to subsea tree-to-manifold connections and connection points for subsea equipment (e.g. pig launchers).

5.5.1.12 The subsea production system shall have facilities for safe and reliable testing of the pressure integrity of subsea barriers.

5.5.1.13 The subsea system should include, where practical, protection of sensitive equipment from potential damage caused by fishing gear and dropped objects. The protection should be evaluated on a probability/consequence basis. For protection related to intervention, overall design requirements shall be evaluated based on operational philosophy and procedures.

5.5.1.14 The subsea production system shall include means of determining the fully open and closed positions for all equipment such as valves and connectors etc. that may cause damage or be damaged due to wrong/unknown position when performing an operation.

5.5.1.15 Critical equipment located in areas which may require intervention by ROV/diver shall be protected. The protection should be evaluated on a probability/consequence basis.

5.5.1.16 The marking of subsea equipment for identification and operational purposes shall remain visible for the design life of the equipment.

5.5.2 Subsea completion equipment

5.5.2.1 Structural integrity

5.5.2.1.1 General

The wellhead system is the structural foundation for a subsea completion. It must be capable of transferring loads applied to the casing strings into the surrounding soil. Depending on the configuration of the production system, the environmental conditions and soil conditions, the loads applied to the wellhead system may vary significantly. Structural integrity should be verified for maximum load conditions considering all drilling and production operations.

5.5.2.1.2 External loading

Loads on a subsea wellhead system may include component dead loads (mass, weight, gravity), riser loads, sealine pull-in loads, thermal growth, and direct environmental action. Typical loads are shown in Figure 3.

Riser loads are generally the largest loads applied. Bottom riser tension acting through an angle induces tension, bending moment, and shear. These loads should be determined by performing a riser analysis. This type of analysis is especially important for floating drilling vessels. Further guidance can be obtained from API RP 16Q. Fatigue analysis may also be required when variable loading conditions exist (such as riser vibration due to high current).

Sealine pull-in loads may induce significant shear and bending moments on the wellhead. Consideration shall also be given to the effects of thermal growth or contraction in the well tubulars and attached flowlines and to additional loads due to the possible non-verticality of the well.

A subsea completion may be subject to some direct environmental loads, such as current, wave action, earthquakes, ice, and soil movements. Dropped objects and snag loads from anchors or trawls may also be a concern for certain applications.

5.5.2.1.3 Structural analysis

The soil data, external loads and reactions are used as input to a structural analysis of the subsea wellhead system. This structural evaluation shall verify that all components, as well as the foundation, will retain structural integrity operation and workover. ISO 13819-2 contains a discussion of methods available for this type of soil-structure analysis.

5.5.2.2 Pressure rating

Subsea wellhead systems are designed to a specific maximum working pressure. The design of the subsea wellhead housing is such that the BOP stack or tree is usually attached directly to the housing. Therefore, the housing must be designed to the maximum pressures anticipated for the life of the well, including shut-in pressure and pressure during well kill, stimulation, or injection operations. In deep-water applications, the differential pressure across pressure-containing bodies is substantially reduced by the effect from the external hydrostatic pressure. This effect may be taken into consideration when determining actual working pressure for such equipment.

Note that pressure tests under atmospheric conditions shall be modified accordingly.

Subsea wellhead systems commonly being manufactured are rated to working pressures of 34,5 MPa (5 000 psi), 69 MPa (10 000 psi) and 103,5 MPa (15 000 psi).

5.5.2.3 Service

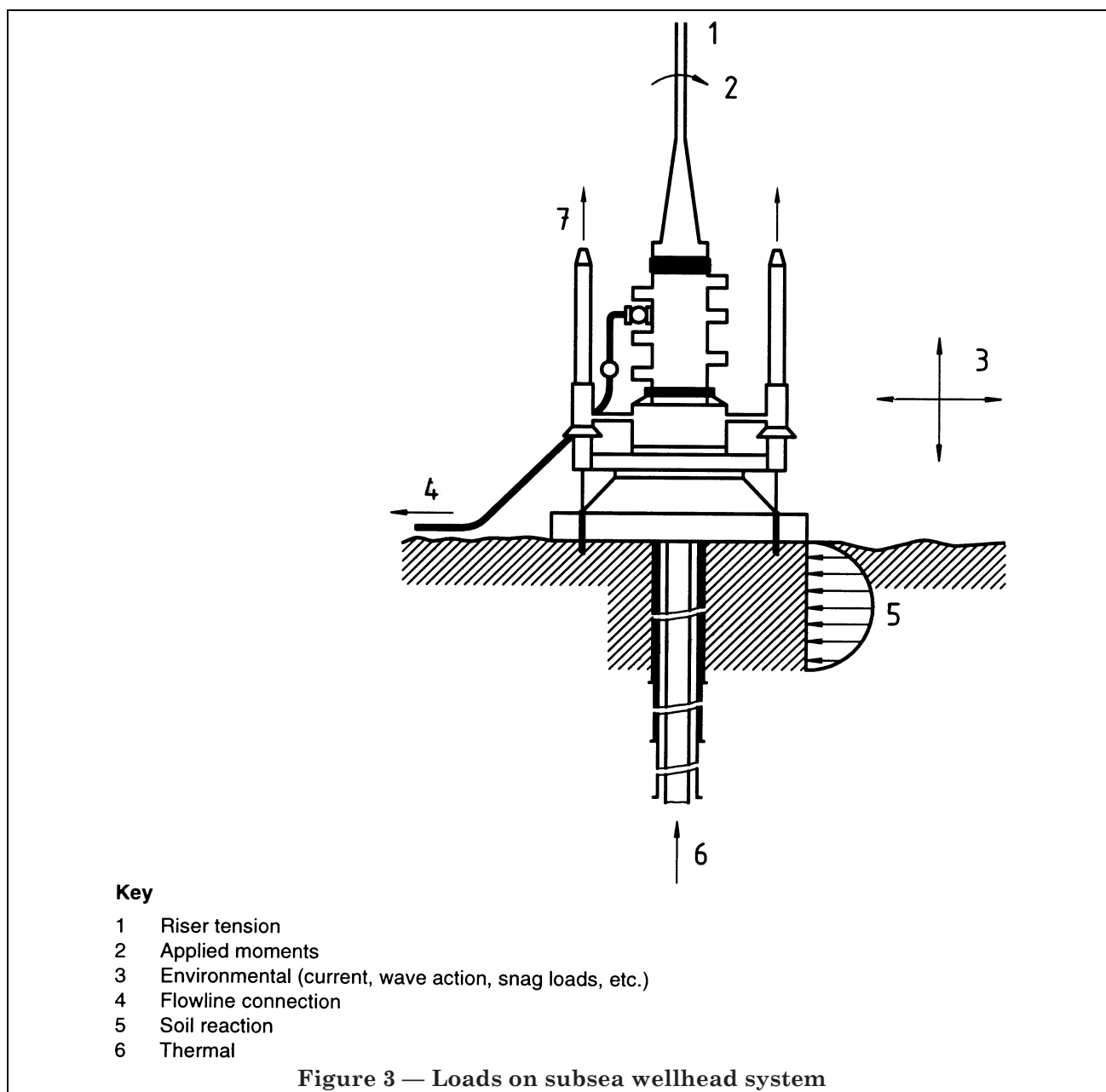
Subsea wellhead systems shall be compatible with the type of service anticipated after completion as a subsea well. Consideration shall be given to produced fluid temperature and the presence of carbon dioxide, hydrogen sulfide or chlorides; all of which may contribute to mass loss, corrosion or stress corrosion/cracking failures.

5.5.2.4 Running tool requirements

In addition to specific requirements, each running tool design should meet these basic guidelines:

- a) adequate flowby area around or through the tool;
- b) sufficient length on the OD to prevent a hang-up in a BOP ram cavity;
- c) resistance to drilling mud and cuttings;
- d) shouldered connections for tools required to transmit torque;
- e) running protection for seals located on the OD;
- f) allow strip-down and redressing on the rig.

All running tools shall be compatible with the running string tensile load, cementing practices, and internal pressure rating for the casing string being run.



5.5.2.5 Completing exploratory wells

In some cases, wells originally drilled as exploratory evaluation wells are converted to subsea production or injection wells. The recommendations in this document should be applied to such wells, and potential problem areas identified. The wellhead system should be carefully inspected to ensure that damage has not occurred since the well was suspended. Areas to be investigated prior to making a decision to complete exploratory wells are:

- a) height of the wellhead above mudline;
- b) setting of casing hangers at dedicated locations within the wellhead housing;

- c) condition and pressure integrity of casing hanger seal assemblies;
- d) condition of the permanent guidebase;
- e) condition of the latching profile and seal area of the wellhead housing;
- f) condition of uppermost casing hanger internal seal area;
- g) a detailed review of the well history to determine other possible problem areas.

5.5.3 Tubing hanger/tree design considerations

5.5.3.1 System design considerations

The general considerations given earlier in clause 5 for subsea wellhead systems are also applicable to the tubing hanger and tree systems.

5.5.3.2 Tubing hanger system

Specific design considerations with regard to the tubing hanger system include the following:

- a) number, size and mass of tubing strings to be supported;
- b) type of threaded connection for the tubing;
- c) number and size of control ports and pressure rating for downhole safety valve(s) and others as required;
- d) installation of tubing hanger to be in its appropriate receptacle;
- e) requirement for electrical connectors for downhole monitoring and/or control;
- f) manufacturer and type of wireline or TFL plug profiles (if any) to be machined in the major bores;
- g) whether or not the tree design permits vertical access to the tubing hanger annulus port. This determines whether a wireline plug, stab-to-open check valve, hydraulically actuated sleeve or other means is used to secure the annulus when the tree or BOP is removed;
- h) orientation, if required, relative to a given datum for corresponding interface with the tree;
- i) type of riser, integral riser or individual tubing tieback strings used for installation and for wireline work;
- j) protection of control ports from debris/fluid contamination.

5.5.3.3 Tree design considerations

The following areas need special consideration in the design of a subsea tree:

a) **pressure rating;**

A complete profile of the expected maximum and minimum pressures for the wellbore, annulus, service bore (if used) and hydraulic lines shall be outlined.

Flow pressure, shut-in pressure, injection, and/or kill pressure of the well shall be considered. In addition, the maximum service pressure for a TFL tree and the maximum control pressure for the SCSSV should be considered. The pressure information shall be evaluated in conjunction with the external loads acting on the system for the particular operation taking place.

All components and connections should have a pressure rating consistent with the system rating. Wye spools shall be rated to the same pressure as other tree components (see Figure A.8). Tree loops shall be designed to the same pressure rating as the flowline, if located downstream of the wing valve, or the tree components if located upstream. The tree running tool(s) should have a pressure rating equal to or greater than the lesser of the tree or the installation riser. Proof testing of the components, pressure testing across valves and plugs, and gas testing, required for trees used in gas service, shall be performed. ISO 13628-4 and the guidelines in clause 8 should be followed for selection/identification of test criteria.

b) **service;**

Tree components shall be evaluated with respect to fluid compatibility. A careful examination of potential fluid types and constituents should be performed (considering amounts, states, total and partial pressures, and temperature ranges), see clause 6.

c) **water depth;**

The installation water depth shall be considered so that hydraulic- and pressure-compensation devices can be adequately specified and designed. These devices are relevant for such items as the control system, running tools and hydraulic valve actuators.

d) **rig type;**

Overall tree and running tool sizes and shapes should be compatible with vessel handling space and opening constraints. This should be evaluated early in the design. The use of a bottom-supported or floating vessel will determine the tension and bending capabilities required of the tree.

e) **external loads;**

There are two primary external load cases, other than environmental loads, that a subsea tree and its upper and lower connectors may be subjected to. The first is installation, which includes riser loads and sealine connection loads. The second external load case is a workover situation in which an LRP and a workover riser may be used. The loads for each case shall be stated as maximum tension, bending and torsion with points of reaction.

Structural analysis shall be performed to guarantee that in case the installation/workover vessel accidentally loses its position (rig drift-off) and the installation tool does not disconnect immediately, then the structural failure will occur in a point above the subsea tree re-entry mandrel, leaving the well in a safe state.

Snag loads imposed on the tree and/or the flowlines may also be a concern. If the loads are such that damage is unavoidable, then the failure point and the consequence for the tree functions after the damage shall be considered.

When flow loops are connected to pressure-containing members such as valve bodies, the external loads, in addition to maximum pressure loads, shall be considered to act on the valves.

f) tree valve configuration;

Arrangements of tree valves depend on the intended service. Valves and bore configuration shall be studied to assure safety and the necessary operational flexibility including compatibility with downhole tools, plugs, wireline operations, and TFL equipment as specified in API RP 17C. In addition, the fluid paths shall be examined for potential fluid or solids collection and erosion. If the tree piping/loops are to be pigged, the design shall be consistent with the type(s) of pig(s) to be used.

A composite valve block should be considered when installation and workover will be from a floating vessel. This approach has greater external load-carrying capacity, fewer connections and more compactness. At least one master valve per bore shall be a fail-closed valve. A diver/ROV override shall be considered for hydraulic valves that are critical to well kill operations;

g) bore size;

The production or injection bore shall permit the installation/removal of plugs, wireline-retrievable valves and running of other downhole tools in the tubing string as required. Flow direction, fluid type, suspended particle type and size, and flowrates should also be considered.

In the case of TFL trees, the Wye spool shall be designed to pass TFL tools in accordance with API RP 17C. The annulus bore may be either directly vertically accessible from the upper tree connection to the tubing hanger bore, or it may be accessible only for pressure monitoring/equalization and injection. If injection of a fluid (into the annulus) will be performed, then the path configuration shall be designed to avoid potential erosion.

h) flowline connection;

The method and type of flowline connection influences the transmission and reaction of loads that may be imposed on the tree.

The flowline connector should be designed for the same pressure rating as the flowline, when mounted outboard of the wing valve. If used with a TFL tree, the bores of the flowline connection should be designed in accordance with API RP 17C. Flowline connections are discussed in more detail in 5.5.7.

i) subsea intervention;

The type of installation, whether diver-assisted or diverless, and how backup operations will be handled if the primary method fails, are important concerns. These topics are addressed in more detail in 8.5 (see also a recognized industry standard for ROV⁴⁾ and ISO 13628-9).

If an ROV is to be used, the capabilities and the type of ROV should be considered. Special ROV concerns include: access, docking/reaction points, required mechanical or hydraulic power, load carrying capacity of the ROV, and the design of special service tools.

j) tree control;

There are a number of control systems and associated configurations available for trees and they are covered in detail in Annex A. The external loading, layout and space constraints for the interface with the tree shall be considered in the design of both components.

All hydraulic/electrical functions needed for tree operation should be controlled from the remote-control station. A tree control module, if used, can be mounted at any location on the tree that provides access and protection. Hydraulic piping and electrical cables, if used, should be routed to minimize potential damage. The mass and location of the production control system module should be considered in order to attain a balanced tree configuration.

⁴⁾ For the purposes of this part of ISO 13628, the industry standard will be replaced by ISO 13628-8 when the latter becomes publicly available.

k) **piping, connections, ring grooves and gaskets;**

Piping runs shall be examined for potential fluid or solids collection points and erosion, and appropriate allowances made for expected corrosion/erosion.

l) **tree running tool.**

For guideline or guidelineless operations from floating vessel, the tree running tool and/or workover BOP running tool should be provided with a high-angle release connector. Also, a quick disconnection feature shall be provided.

Angle capability and disconnect time shall be established for each specific application. Factors to be considered for design of high-angle release connections are:

- local regulations;
- water depth and weather conditions;
- vessel station-keeping capability, etc.

5.5.4 Completion workover riser system

5.5.4.1 Specific design considerations for completion and workover risers include: connection strength, axial and bending capacity, water depth, tubing pressure/rating, inside diameter, tubing configuration/spacing, wireline restrictions, riser seal, other dimensional constraints, control line or umbilical requirements, operating weather conditions, and operating life.

5.5.4.2 The completion/workover riser design is analogous to downhole tubing design if it is to be used only inside the marine riser and BOP stack or jackup conductor pipe.

A workover or completion riser to be used in the open sea, shall additionally be designed by riser analysis considering also the environmental loading factors. These may include surface vessel motion (if floating), wave action and current.

5.5.4.3 The completion/workover riser shall be designed to suit the subsea tree with respect to drift diameters, bore spacing, etc. In addition operating conditions for the specific field development shall be reflected in the design of the riser system. Detailed design requirements for completion and workover risers are given in API RP 17G.

5.5.5 Mudline casing suspension system

5.5.5.1 System design considerations

The general design requirements for completing a mudline casing suspension well subsea are essentially the same as for a subsea wellhead (see 5.5.3).

5.5.5.2 Specific design considerations

The following items outline specific design considerations for subsea completion on mudline casing suspension systems:

- a) the system should be compatible with jack-up/TLP or other bottom-supported rigs;
- b) casing loads should be suspended near the seabed to reduce loads on the rig and provide a disconnect/reconnect point;
- c) the tension capacity, pressure rating and drift requirements should be selected to meet the requirements of the particular wells. Care should be exercised when selecting reduced-bore hangers to ensure that they are compatible with the drilling programme;
- d) adequate annulus flowby areas should be incorporated in mudline components, both in the running and landed conditions. Evaluate the combined total area and the quality of the flowpaths;
- e) the casing annuli should be accessible at the surface wellhead during drilling operations, but may be isolated when a subsea tree is to be installed;
- f) applied external loads which affect the mudline drilling system shall be considered (i.e. wave and current forces, riser/BOP weight, etc.);
- g) direction of rotation and required downhole torque of mudline components shall be compatible with the rest of the drilling system for installation and retrieval;
- h) accessibility and adaptability should be incorporated for abandonment;
- i) maximum allowable misalignment and lateral offset between the running/tieback strings and hangers shall be defined;
- j) upon temporary abandonment, individual casing risers should be removed to meet elevation requirements at the ocean floor;
- k) a protective cap (or caps) should be installed on the well, as required for the well programme;
- l) an annulus seal assembly should be installed between the production casing and intermediate casing strings at the tie-back/adaptation point. Seal selection for component interfaces require particular attention.

5.5.6 Production controls

The following general factors should be considered during control system design:

5.5.6.1 Control system availability may be maximized by

- selecting high-reliability assemblies and components;

- selecting components that have a high resistance to wear and corrosion;
- providing component redundancy;
- providing back-up or secondary systems;
- providing diver/ROV/ROT intervention capability;
- providing system bypasses;
- providing spare units (modules) for replacement;
- establishing control fluid properties and cleanliness standards.

5.5.6.2 Maintenance should be considered early in system design. Maintainability of surface and subsea equipment can be enhanced by

- designing equipment for accessibility and easy maintenance;
- designing control system assemblies to be retrieved independently from subsea completion hardware.

5.5.6.3 The production control system and its components shall be designed according to ISO 13628-6.

5.5.7 Sealine systems

5.5.7.1 General

The sealine system shall be designed according to a recognized standard, e.g. [10] and [1], depending on its type and function.

The choice of a sealine alignment method and its subsequent design is influenced by several considerations, including the following:

a) target area;

The location and accuracy in which the sealine end is placed and its effect on the lateral and angular alignment and related stresses;

b) sealine installation method;

The procedures and equipment of the chosen alignment method should be compatible with the procedures and equipment chosen to install the rest of the sealine. Alignment equipment should also be designed for any residual sealine reaction loads caused by the sealine installation method and/or thermal expansion loads;

c) sealine end configuration;

The type and amount of alignment forces required of the chosen alignment method can be influenced by the sealine being a single, bundle, or cased bundled pipe design and by pipe size, mass, strength, stiffness and TFL requirements;

d) local seabed conditions;

Soil friction forces and bearing capacity, local obstructions and seabed topography may affect the alignment procedure;

e) connection point;

Alignment design is influenced by the connection point being either another subsea facility or an offshore platform. An offshore platform can offer additional sealine alignment methods, such as conventional riser installation or J-tube installation. Connection points may also require expansion loops, breakaway features, or valves to complement the overall design. Spool pieces may be required to incorporate these added features;

f) end connection method;

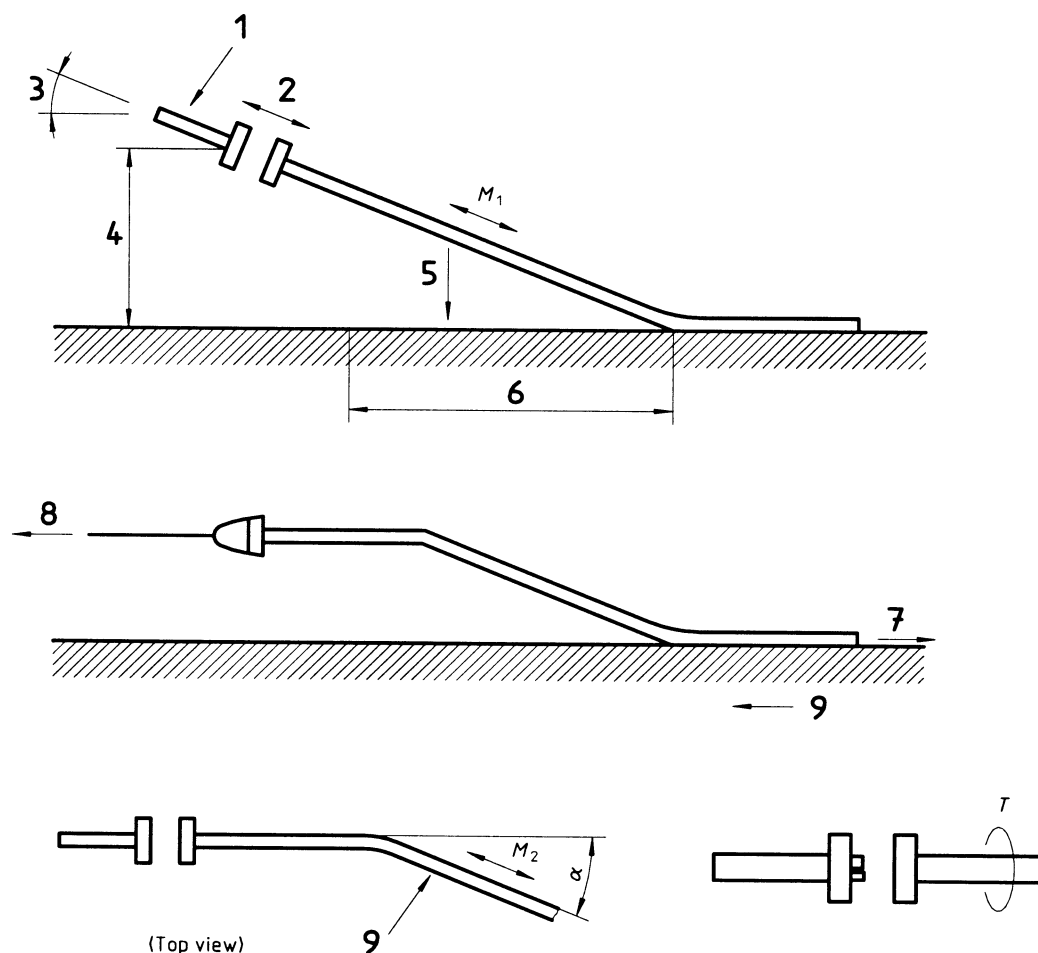
It is essential to the integrity of the end connection that the alignment method positions the end of the pipe within the appropriate axial, lateral and angular make-up tolerances of the sealine connector. Rotational alignment should also be accommodated for bundled sealines to guarantee proper port orientation;

g) alignment loads and stresses.

The design of the sealine near the end connection and its alignment hardware are influenced by the strength and stiffness of the sealine, and the amount of movement required to align the sealine end with its connection point. Pull-in and lay-away methods require repositioning the sealine, which imparts axial loads and bending moments which should be accounted for in the sealine and alignment equipment design. Spool piece methods leave the line in its as-laid configuration.

Factors (see Figure 4) which influence the design loads and resultant sealine stresses during alignment operations include:

- connection point height and relative angle off bottom;
- sealine weight (and buoyancy);
- sealine axial and torsional stiffness;
- unsupported span length;
- lateral and angular movement to align the sealine;
- pull-in forces vs. residual sealine installation forces and soil friction;
- torque required (to orient ports).



Key

- | | | | |
|----------|---|---|------------------------------|
| 1 | Subsea connection point | 6 | Unsupported span length |
| 2 | Additional axial movement for connection work | 7 | Pipeline installation forces |
| 3 | Angle relative to bottom | 8 | Pull-in forces |
| 4 | Height off bottom | 9 | Soil friction |
| 5 | Pipe weight | | |
| M_1 | Vertical bending moment applied to pipe for end alignment | | |
| M_2 | Horizontal bending moment applied to pipe for end alignment | | |
| α | Angular movement of end for repositioning connector | | |
| T | Torque applied to bundled pipe for proper port orientation | | |

Figure 4 — Factors that influence alignment loads and stresses

5.5.7.2 Sealine connector

The connection between the sealine and the connection point is generally made after sealine end alignment is complete. The primary purpose of the connection methods described below is to create a pressure-tight seal that resists the loads associated with subsea environments. If TFL is specified, then the connectors should comply with API RP 17C. For deep water, all seals experiencing hydrostatic pressure should have bidirectional capability.

The following are several types of sealine connectors which typify the numerous options available:

a) **bolted flange;**

Bolted flange designs are covered in ANSI/ASME B16.5 and ISO 13628-4. These designs make use of metal ring joint gaskets which compress when the bolts are tightened. Special consideration should be given to these gaskets for underwater applications. Some gaskets (i.e. API BX gaskets) tend to trap water behind the gasket when made up underwater, resulting in improper sealing of the gasket and flange connection. The gasket ring grooves should be specified with welded in-lays to provide a corrosion-resistant surface finish. Welded inlays are not relevant when CRA materials are used for flanges.

Bolted flange connections may permit a limited degree of initial misalignment. However, rotational alignment is restricted because of bolt-hole orientation. Swivel flanges may be used to facilitate bolt-hole alignment.

Compact flange design may be considered at the interfaces, similar to connections at a subsea or receiving facility, since this may give advantages due to the smaller size on the interfacing subsystems.

b) **clamp hub;**

A clamp hub connector is similar in principle to a bolted flange connector. Clamp hub connectors may use the same metal ring gaskets as bolted flange connectors, or use proprietary gasket designs. The clamping device forces the mating hubs together as the clamping device is tightened.

Clamped hub connections are generally faster to make up than bolted flange connections, because fewer bolts are required. Rotational alignment is unnecessary since the mating hubs do not have bolt holes, except for multibore hubs. On the other hand, most clamped hubs do not permit the amount of initial misalignment that bolted flange connections may provide.

c) **welded connection;**

Existing practice in welding underwater is to use one of two dry-welding methods that involve either a one-atmosphere chamber or a chamber filled with an inert gas at ambient water pressure (hyperbaric).

d) **proprietary connectors.**

Proprietary connectors are underwater connectors specially designed to perform final alignment, locking and seal-energizing tasks. Proprietary connectors latch the sealine to the connection point by various means, such as expanding collets, locking dogs or other mechanical devices. The latching procedure generally includes a short distance of axial travel for one or both ends being connected.

Proprietary connectors can be classified as either mechanical or hydraulic. Mechanical connectors are activated by divers or remotely through special tools. These tools are retrieved after connection, leaving only passive mechanical hardware subsea. Hydraulic connectors are mechanical connectors with hydraulic actuation devices. Hydraulic connectors are generally operated via multihose hydraulic control lines, and may leave the hydraulic actuation devices subsea after connection.

Proprietary connectors typically use specially designed metal gaskets which are deformed when the connector is locked.

5.5.7.3 Connector design

Sealine connector choice and subsequent design should consider factors such as water depth, intervention method, type of connection point, sealine installation method and misalignment tolerance compatibility with the alignment method. In addition, the choice and design of the connector can be influenced by the following:

a) **connector stresses;**

Residual stresses in the line itself and the sealine connector resulting from a particular alignment method and the additional axial movement required for end connection should be analysed in conjunction with operating stresses to determine if the combined stress is within allowable limits.

b) **make-up requirements**

Make-up requirements for connectors should be reviewed to ensure that

- 1) the connector will deform or deflect (energize) the gasket to effect a seal;
- 2) there is enough preload in the connector to offset the installation and operating loads which could otherwise break the gasket seal;

- 3) there is enough axial clearance and access for seal replacement.

The sealine connector design shall be such that after make-up it will not lose its sealing capability under cyclic pressures, temperatures or natural vibration loading and design external loads.

c) testing.

Sealine connectors should be in-plant tested to the hydrostatic test pressure stipulated for the sealine as recommended in [10]. In some cases, the connector may be part of and tested with the subsea facility. In such cases the connector should be tested to the hydrostatic test pressure stipulated for the subsea facility. If TFL is specified, each made-up connector should be drifted in accordance with API RP 17C.

Additional in-plant testing may be required to verify make-up preloads, fit, and functional performance of locking devices and hydraulic actuation devices.

End-connector equipment should be designed to provide some testing means to verify that the gasket has formed an adequate seal and the connector has been fully actuated or clamped together after it has been installed subsea.

5.5.7.4 Sealine protection

When a sealine protection system is required, the following apply:

- a) a sealine protection system in the tie-in area shall be designed as a part of the total protective design of the subsea structure and the sealines;
- b) the sealine protection system shall not cause restriction of any operations during installation, drilling, completion, production or IMR of the structure or sealines;
- c) the sealine protection system shall accommodate thermal and pressure expansion, long-term settlement and necessary intervention operations to be performed.

5.5.8 Template and manifold systems

5.5.8.1 General

The template is the framework that supports other equipment such as manifolds, risers, drilling and completion equipment, pipeline pull-in and connection equipment and protective framing (template and protective framing is often built as one integrated structure). The template should provide foundation to sufficiently transfer design loads into the seabed.

5.5.8.1.1 Drilling and completion interface

If wells are to be drilled through the template, it should provide a guide for drilling, landing/latch capability for the first casing string, and sufficient space for running and landing a BOP stack. If subsea trees are to be installed, the template should provide proper mechanical positioning and alignment for the trees and sufficient clearance for running operations.

5.5.8.1.2 Alignment

The template should provide alignment capability for proper physical interfaces among subsystems, such as wellhead/tree, tree/manifold and manifold/sealines.

5.5.8.1.3 Guidance

The template should provide for a guidance system to support operations through the life of the installation. If guidelines are used, the template should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items.

5.5.8.1.4 Abandonment provisions

If the template is to be recovered at the end of the project, its design should include provisions for this requirement.

5.5.8.2 Template installation requirements

In addition, the template should provide sufficient capability to allow for all installation requirements. Different types of installation vessel, such as drilling rigs or crane barges, should be evaluated. The requirements may include some or all of the following items:

- loadout;
- transportation to site;
- launch capability;
- crane capacity;
- buoyancy capability;
- ballast/flooding system;
- system for lowering to seabed;
- positioning capability;
- levelling system;
- foundation interface.

5.5.8.3 Structures

5.5.8.3.1 Subsea structures shall be designed according to relevant standards such as ISO 13819-1 and ISO 13819-2. The following apply:

- a) the structure shall ensure sufficient alignment capability for proper physical interfaces between subsystems such as wellhead/production guidebase, subsea tree/manifold and piping system, manifold/sealine termination and installation aids, protective structure (if relevant) and other relevant interfaces;
- b) the subsea structures may be fixed/locked to the wellhead system or they can be separate with no direct fixed connection to the wellhead. Hence, corresponding piping shall be connected by built-in flexibility in the wellhead modules and/or manifold module.

5.5.8.3.2 Loads induced on the guide frame/bottom frame from the well system will depend upon the following:

- a) soil conditions and axial stiffness of well system;
- b) structural design and stiffness of bottom frame against vertical deflection;
- c) structure/well interface design and flexibility tolerances (if any);
- d) casing thermal expansion.

Well-supporting structures shall provide guiding/landing/latch capability for the conductor housing and sufficient space for running and landing a BOP stack on the corresponding wellhead and adjacent to a neighbouring subsea tree.

The well-supporting structure/production guidebase design shall allow for individual thermal expansion of the conductor/wellhead housings.

A drill-cuttings disposal system may be considered. Alternatively, accumulation of cuttings within the structure is allowed as long as this does not interfere with planned operations.

The structure shall allow onshore assembly and testing of equipment supported by the structure.

The structure shall transfer all design loads from interfacing systems and equipment to the foundation system.

Consistent with the dropped-object philosophy, protective structures and/or operational procedures should protect the subsea equipment against damage from dropped objects, fishing gear and other relevant accidental loads. Structural design should also avoid snagging of ROV umbilicals and guide wires.

5.5.8.3.3 The subsea template, structure and its equipment shall be designed as follows, in order to facilitate efficient intervention.

- a) Suitable viewing positions shall be provided for observations during running, connection and operation of tools, modules and equipment;
- b) suitable landing area and/or attachment points should be provided where manipulative tasks are required to be carried out;
- c) sensitive components/items on the subsea structure which may be damaged by the intervention system shall be protected;
- d) bucket(s) designed for easy replacement of acoustic transponder(s) may be provided. Acoustic shielding and potential snagging shall be avoided;
- e) all locking mechanisms on protection hatches and lifting frames should be easily operated in accordance with the defined intervention strategy;
- f) replaceable guideposts should utilize locking mechanisms operated by the selected intervention system;
- g) all permanently installed guideposts which require guidewire attachment should be designed such that a new guidewire can be re-established upon broken wire or anchor overpull;
- h) any special equipment or arrangements installed on the subsea structure which require torque to be applied during operation should be designed to use a dedicated torque tool and interface;
- i) the design shall be such that location of anodes and other construction details do not represent any obstruction or snagging point for the selected intervention system;
- j) tools, BOP, modules and all retrievable equipment shall have an adequate running clearance to any part of the structure, adjacent module or equipment, etc. to avoid any unintended impacts or clashes during installation and retrieval. Recommended clearances are
 - 1) minimum 1,0 m (3,28 ft) for monohull and 0,5 m (1,64 ft) for semisubmersible operations, respectively, at 0,8 m (2,62 ft) above guidepost top and upward when running on guidewires;
 - 2) minimum 0,2 m (0,66 ft) when running on guideposts.

NOTE For guidelineless operations, positive restrictions, such as guide funnels or bumper beams, should be provided to avoid impact between adjacent equipment.

k) operational requirements for running intervention systems from vessels, necessitating offset angles on the guidelines, shall not restrict ROT access, reduce running clearances or otherwise deteriorate operational safety and reliability.

5.5.8.4 Foundation and levelling

Generally, subsea systems require the template to be reasonably level in its final position for proper interface and mating of the various components and subsystems. Typical levelling methods include one- and two-way slips between piles and pile guides, jacking systems at the template corners and the active suction method. A means for level indication should also be included.

In order to design the foundation and levelling system, the following shall be considered:

- a) seabed slope, installation tolerances and effects from possible scouring;
- b) suction loads due to repositioning or levelling;
- c) intrusion of soil into pile sleeves shall be prevented;
- d) a foundation system for well-supporting structures, based on support/anchoring on the well conductor housings may be used. The integrity of the foundation system shall be verified;
- e) for foundation and skirt systems, arrangements shall be made for air escape during splash-zone transfer and water escape during seabed penetration. Lift stability and wash-out of soil shall be taken into account;
- f) structures with skirt foundation should be designed for self-penetration;
- g) skirt-system facilities for suction and pumping shall, where required, be included to allow for final penetration, levelling and breaking out prior to removal. The suction and pump systems shall be operated in accordance with the selected intervention strategy;
- h) settlement of the structures (installation and lifetime) shall be accounted for;
- i) impact of heat from produced hydrocarbons should be considered, particularly if gas hydrates are present.

5.5.8.5 Manifold and piping

5.5.8.5.1 Functional requirements

Manifold systems may provide some of the following functional requirements:

NOTE Some or all of these capabilities are required for every manifold system.

- a) the manifold shall provide sufficient piping, valves and flow controls to safely gather produced fluids or distribute injected fluids such as gas, water or chemicals;
- b) the manifold may provide for testing of individual wells;
- c) the manifold should provide appropriate valving and line-bore dimensions to allow pigging of sealines and appropriate manifold headers;
- d) if the system is designed for TFL capability, the manifold shall provide piping and well diverters to support that capability;
- e) if wells are to be completed on the template, the corresponding manifold should provide for connection to the tree;
- f) the manifold may provide for mounting and protecting equipment needed to control and monitor production/injection operations. The manifold system may include a distribution system for hydraulic and/or electrical supplies for the control system;
- g) the manifold shall provide for connection of sealines. The manifold typically provides sufficient flexibility to make and break these connections.

Production manifolds and piping systems shall be designed in accordance with ANSI/ASME B31.8. For flanges, ISO 10423 shall be used.

5.5.8.5.2 Design

Design of manifolds and piping systems shall take into account the fluid characteristics. These fluids include produced hydrocarbons (liquids and gases), formation water, injected water and gases, and injected chemicals.

The general design characteristics for these fluids include

- pour point;
- pressure;
- temperature;
- chemical composition;
- viscosity;
- gas/oil/water ratio;
- sand/paraffins/hydrates;
- corrosivity.

5.5.8.5.3 *Manifold piping*

The size (diameter, wall thickness, etc.) of production piping will be determined from anticipated well flowrates and well pressures for individual lines and/or combined streams. Consideration should be given to plans for water/gas injection, gas lift and TFL operation, see API RP 17C. Fluid velocities should be considered in sizing pipes to reduce pressure drops and control flow-induced erosion. An internal corrosion allowance should be considered in determining required wall thickness. Overall design and clamping of piping/valves shall consider load-effects from anticipated slug flow. External hydrostatic pressure can be taken into account when determining pressure ratings. Special consideration shall be given to piping downstream of chokes, due to possible high fluid velocities.

5.5.8.5.4 *Maintenance*

Maintenance is a key factor in system design and the maintenance approach should be considered early in the design of a template/manifold system. Some factors to consider are:

- diver assist or remote maintenance methods;
- the need for components to be made retrievable;
- clear access space for divers, ROVs or other maintenance equipment;
- clear markings to allow similar components to be distinguished;
- height above seabed for adequate visibility;
- system safety with components removed;
- fault analysis capability to identify failed components.

5.5.8.5.5 *Number of wells*

Where wells are incorporated into the template and manifold, the number will vary depending on the site-specific application and greatly influence template size and manifold design. The addition of spare well slots should be considered for contingencies such as changes in reservoir depletion plan, dry holes, drilling problems and other unforeseen production requirements.

5.5.8.5.6 *Well spacing*

Well spacing may be governed by the type and size of drilling and production equipment used, the functional requirements of the manifold and subsequent maintenance and inspection requirements.

Consideration should be given to providing space for such items as sealine and wellhead connections and their running tools and adjacent BOP and production tree clearances. Access shall also be provided for inspection and maintenance tools.

5.5.9 *Production risers*

5.5.9.1 *General*

Production risers shall be designed according to recognized codes and standards. See for example [1], [2] and [3].

5.5.9.2 *Design considerations*

Design of the production riser system requires definition of the production functions (flow paths), properties of fluids in the lines, environmental loadings that will be imposed on the riser, and motions of the equipment to which the riser will be connected. Resulting loads, forces, moments, and displacements can then be investigated and analysed for a given production riser system design and its components.

Similarities exist between the methods of analysis for drilling risers and rigid pipe production risers. However, unique functional differences do exist and shall be accounted for in the design and analysis of production risers. These differences include service life, fluid types, high pressure and opportunity for frequent inspection.

5.5.9.3 *Functional and operational considerations*

Each line shall be designed to satisfy requirements for throughput rate, pressure, corrosion, erosion and temperature while maintaining structural integrity. Operational considerations include provision for riser-system handling during extreme storm conditions, mooring failures, marine fouling, interface loads between lines and riser protection against external loading. Long-term plans for inspection, maintenance and repair can influence the riser system design. Operational activities, such as pigging through the various flowlines and provisions for displacing hydrocarbons prior to riser disconnect, may also influence production riser design.

To achieve satisfactory operating performance, the riser design shall be coordinated with the design of the equipment to which it is connected, both at the hang-off of the FPU and at the seabed. Also, operating choices shall be made about whether the riser is to be designed to remain connected at extreme FPU offsets, disconnected and hung off, or disconnected and fully recovered. The riser size and complexity can be reduced by commingling production at the seabed, but this may result in added subsea equipment complexity.

5.5.9.4 *Production aspects*

Design of the production riser requires not only definition of the loads that may occur on the system, but a clear definition of the number, size and service for each of the lines needed to meet the initial and projected system production requirements. Service requirements may include produced fluids, product export, injection fluids (water, gas, chemicals), well test, annulus monitor/control functions and TFL tools. Expected requirements for workover may be a major factor in design selection. Each riser design will also be influenced by the various upstream and downstream choices. For example, the riser flow path may be designed for full shut-in pressure of the wells. Alternatively, an isolation valve may be placed subsea, and the riser flow path protected against over-pressure with a relief valve at the surface, provided that no blockage can occur between the seabed isolation valve and the surface relief valve.

The functional life of the production riser is an important consideration, not only from the standpoint of assessing wear and fatigue, but also from the standpoint of corrosion (both internal and external) and the probability of extreme load occurrences. Early decision about these matters can simplify the interactive process required to arrive at a satisfactory production riser design.

5.5.9.5 *Inspection and maintenance*

The level of inspection and maintenance required in the operation of a production riser shall be addressed at the preliminary design specification stage of the design process. Inspection method(s) may significantly impact the size and configuration of the riser. Inspection philosophy should be coordinated with service life projection and regulatory requirements. Maintenance requirements may influence the riser spacing configuration and fastening assemblies, thereby influencing the riser system design.

5.5.9.6 *Handling and storage*

For many components, handling and storage may impose the most severe loadings. Refer to [19] which is specifically for drilling risers, and could also give general guidance for other riser systems.

5.5.9.7 *Installation and retrieval*

The riser system shall be analysed considering the loads due to installation and retrieval, as well as operational loads.

5.5.10 *ROV/ROT intervention systems*

Intervention systems may be operated by diver, ROV or specific ROT. The design of ROV interfaces with the subsea production system shall be in accordance with recognized industrial standards.

5.5.11 *Colours and marking*

WARNING — A commonality of abbreviation between subsea facilities and surface-operating equipment is essential.

To minimize confusion and enhance safety where the control units are designed for multiple applications, it is recommended that functions be identified both on the subsea packages and on their control units, using common abbreviations listed in this International Standard.

Where the valve arrangements are unique, the documentation should clearly define the abbreviation used in the marking of equipment.

5.5.11.1 *General*

All equipment on the subsea production systems that is designed for subsea intervention shall have a colour and marking system enabling easy and unique identification.

The colour and marking system shall act as a guidance map for the intervention operations by

- a) identifying the structure and orientation;
- b) identifying the equipment mounted on the structure and intervention interface;
- c) identifying the position of any given part of the structure relative to the complete structure;
- d) identifying the operational status of the equipment, e.g. connector lock/unlock and valve open/close.

The marking system shall enable positive verification of the end stop and/or locked position for retrievable components such as guideposts to lock-down clamps etc.

5.5.11.2 *Colour design*

The main elements of the colour design are

- object colour;
- background colour;
- foreground colour;
- relative object size.

The colours should be clearly distinguishable at a minimum distance of 10 m (32,8 ft) in artificial lighting with adjustable intensity and the red part of the light spectrum with the highest intensity.