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Oil and gas industries including low carbon energy — Design and operation of subsea production systems —

Part 1: General requirements and recommendations

Industries du pétrole et du gaz, y compris les énergies à faible teneur en carbone — Conception et exploitation des systèmes de production immergés —

Partie 1: Exigences générales et recommandations

Reference number
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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO document should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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This document was prepared by Technical Committee ISO/TC 67, *Oil and gas industries including lower carbon energy*, Subcommittee SC 4, *Drilling, production and injection equipment*, in collaboration with the European Committee for Standardization (CEN) Technical Committee CEN/TC 12, *Oil and gas industries including lower carbon energy,* in accordance with the Agreement on technical cooperation between ISO and CEN (Vienna Agreement).

This third edition cancels and replaces the second edition (ISO 13628-1:2005), which has been technically revised. It also incorporates the Amendment ISO 13628-1:2005/Amd 1:2010.

The main changes are as follows:

— ISO 13628-1 has been fully re-written compared to the 2005 edition of the document;

— ISO 13628-1 has been aligned with API RP 17A and is now a technically equivalent document.

A list of all parts in the ISO 13628 series can be found on the ISO website.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

This document has been prepared to provide general requirements and recommendations for the user to the various areas requiring consideration during development of a subsea production system for the petroleum and natural gas industries. The requirements and guidance in this document are intended to complement engineering judgement and facilitate the decision process.

Oil and gas industries including low carbon energy — Design and operation of subsea production systems —

Part 1:
General requirements and recommendations

1 Scope

This document provides general requirements and recommendations for the development and operation of subsea production/injection systems, from the concept development phase to decommissioning and abandonment.

Flexible pipe standards form part of the API 17-series of documents (see 4.3.3); however, this document (technically equivalent to API RP 17A 6th edition) does not generally cover flowlines/pipelines or production/injection risers (associated with flowlines/pipelines). These components form part of a complete subsea production system (SPS), as shown in Figure 1.

2 Normative references

There are no normative references in this document.

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

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

ISO and IEC maintain terminology databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at https://www.electropedia.org/

3.1.1
barrier
element forming part of a pressure-containing envelope that is designed to prevent unintentional flow of production/injected fluids, particularly to the external environment

3.1.2
factory acceptance test
FAT
test conducted to verify that the specified requirements for a product have been fulfilled

3.1.3
first article
first of a product produced using the "normal processes" as will be used to make multiple numbers of the same product

EXAMPLE The first of a new design of SCM manufactured on a production line and intended for use in the field.

Note 1 to entry: As distinct from a prototype, a first article should accurately represent all aspects and functionality of the production-model product.

The “normal processes” typically includes the standard design, procurement, manufacture, QA/QC, and testing processes, as would be used in the production of a production model/production product.

Such a product is suitable for normal use.

First article products are often subjected to comprehensive *verification testing* (3.1.9) and *validation testing* (3.1.8), as well as subsequent strip-down and inspection for evidence of component deterioration and/or loss of functionality.

3.1.4
high-pressure high-temperature
HPHT
any environment above 103,5 MPa (15 000 psi) working pressure and/or operating above 177 °C (350 °F)

3.1.5
interchangeability test
ICT
test conducted to verify that the interchangeability requirements of “identical” products [including products of like design, with respect to the relevant interface(s)], which may be interfaced with other mating products at the installation site, have been fulfilled

3.1.6
life cycle
series of identifiable stages through which an item goes, from its conception to disposal

3.1.7
pilot
first of a product used for an extended period in the intended service in order to validate a concept or process, prior to the manufacture and deployment of additional similar products

EXAMPLE The Troll Pilot subsea separation system.

Note 1 to entry: Similar to a prototype, a pilot is usually a “one-off” and therefore is often not produced using the exact same processes as will be used to make the actual production model of a product (of which multiple numbers are typically produced).

However, unlike a prototype, a pilot should accurately represent all aspects and functionality of the intended production model product in order to ensure a valid test and to be suitable for use in the field.

Based on the results gained from the extended field testing of a pilot, it is not uncommon for the actual production model to be different from the pilot in some aspects.

3.1.8
validation testing
test conducted to confirm that the requirements for a specific intended use or application of a product have been fulfilled

3.1.9
verification testing
test conducted to confirm that the specified requirements for a product have been fulfilled

3.1.10
qualification
process to demonstrate the ability to fulfil specified requirements

EXAMPLE Auditor qualification process, material qualification process.

Note 1 to entry: The term “qualified” is used to designate the corresponding status.

Note 2 to entry: Qualification can concern persons, products, processes or systems.

3.1.11
validation
confirmation, through the provision of objective evidence, that the requirements for a specific intended use or application have been fulfilled

Note 1 to entry: The term "validated" is used to designate the corresponding status.

Note 2 to entry: The use conditions for validation can be real or simulated.

3.1.12
verification
confirmation, through the provision of objective evidence, that specified requirements have been fulfilled

Note 1 to entry: The term "verified" is used to designate the corresponding status.

Note 2 to entry: Confirmation can comprise activities such as:

— performing alternative calculations;

— comparing a new design specification with a similar proven design specification;

— undertaking tests and demonstrations;

— reviewing documents prior to issue.

3.2 Abbreviated terms

BOP	blowout preventer
CRA	corrosion-resistant alloy
C/WO	completion/workover
EDP	emergency disconnect package
FMEA	failure modes and effects analysis
FMECA	failure mode, effects, and criticality analysis
HAZOP	hazard and operability study
HIPPS	high integrity pressure protection system
HSE	health, safety and environment
IWOCS	installation workover control system
LMRP	lower marine riser package
LRFD	load and resistance factored design
MODU	mobile offshore drilling unit
MPFM	multiphase flow meter
OEM	original equipment manufacturer
OREDA	offshore and onshore reliability data
PLEM	pipeline end manifold
QRA	quantitative risk assessment

ROT	remotely operated tool
ROV	remotely operated vehicle
SCM	subsea control module
SUT	subsea umbilical termination
USV	underwater safety valve
VIV	vortex induced vibration
WSD	working stress design

4 Subsea production system

4.1 General

A complete subsea production/injection system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a processing/host facility located offshore (fixed, floating, or subsea) or onshore, or to inject water/gas via subsea facilities and/or wells (as shown in Figure 1).

NOTE The term "subsea production system" is used generically throughout this document to describe both production and injection systems.

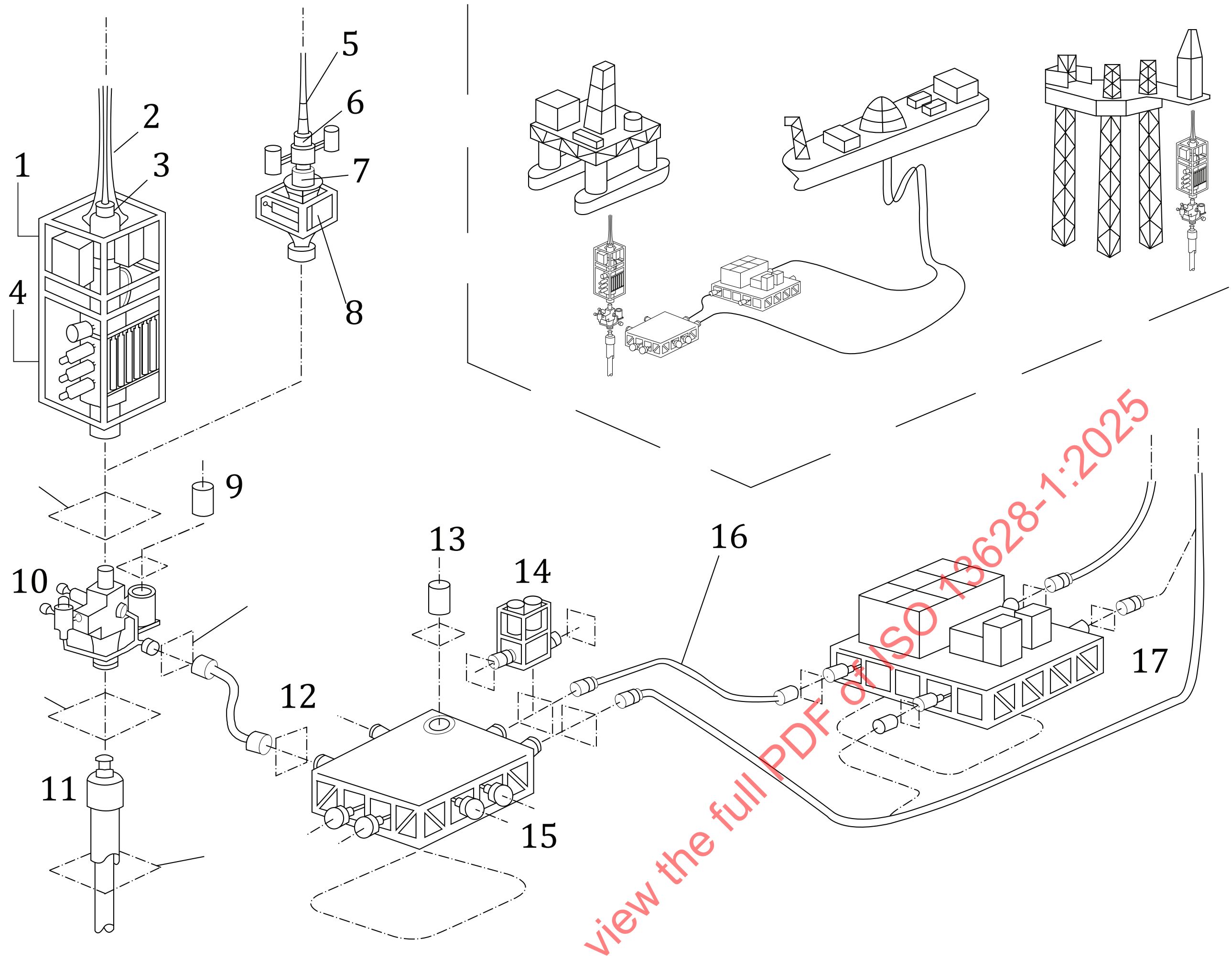
Subsea production systems range in complexity from a single satellite well linked to an offshore or onshore installation to several wells comingled in a subsea manifold producing to a fixed, floating, or onshore facility.

Subsea production systems can be used to produce from shallow-water or deepwater reservoirs. Deepwater conditions can inherently dictate development of a field by means of a subsea production system, since fixed structures such as a steel-piled jacket can be either technically infeasible or uneconomical due to the water depth.

Subsea equipment may be used for the injection of water/gas into various formations for disposal and/or to provide pressure maintenance to the reservoir, and/or for gas lifting operations.

4.2 System configuration

The elements of the subsea production or injection system may be configured in numerous ways, as dictated by the specific requirements and the field development strategy. For a description of the various components, assemblies, and subsystems that can be combined to form a complete subsea system, refer to API 17TR13. Figure 1 provides an overview of a basic subsea system.



Key

1	LMRP	10	XT
2	marine riser	11	wellhead
3	flex joint	12	jumper
4	BOP	13	HCM
5	workover riser	14	HIPPS
6	stress joint	15	manifold
7	EDP	16	flowline
8	ERP/well control module	17	process station
9	SCM		

Figure 1 — Basic subsea systems

4.3 Overview of API 17 series documents by categories

4.3.1 System level documents

Subsea documents that address system requirements include the following.

— API RP 17A provides general requirements and recommendations for the development of subsea production systems, from the design phase to decommissioning and abandonment. API 17A also provides guidance to other parts in the API 17 series and related documents.

NOTE API RP 17A is technically equivalent to this document.

— API RP 17N provides recommended practice for subsea production system reliability and technical risk management. Reliability is critical to subsea production system design and operation. API RP 17N provides a comprehensive approach to help ensure that reliability needs are achieved with subsea systems. It is broadly referenced in the deepwater technical community as a foundation document for addressing reliability.

— API RP 17O provides recommended practice for high integrity pressure protection systems (HIPPS). It establishes criteria for HIPPS that are seeing increased utilization in industry as a means to safely provide overall system pressure capability while restricting the section that requires full shut-in pressure rating to a segment that is close to the source.

— API RP 17Q provides recommended practice for subsea equipment qualification. It provides guidance on relevant qualification methods that may be applied to facilitate subsea project execution.

— API RP 17V provides recommended practice for analysis, design, installation, and testing of safety systems for subsea applications. It provides a comprehensive treatment of the requirements for safety systems necessary for a variety of subsea applications.

— API 17TR5 addresses avoidance of blockages in subsea production control and chemical injection systems. It also includes requirements and gives recommendations for the design and operation of subsea production systems with the aim of preventing blockages in control and production chemical fluid conduits and associated connectors/fittings.

— API 17TR6 addresses attributes of production chemicals in subsea production systems. Production chemicals delivered to a subsea production system via a chemical injection system can be complex formulations that have a wide range of chemical and physical properties. In service, the production chemicals can come into contact with other fluids, metallic and polymeric materials, and a range of physical conditions related to temperature and pressure. API 17TR6 was developed with the objective of minimizing the risk of a production chemical not being delivered at the required volumetric rate due to inadequate specification of the production chemical delivery system or formation of restrictions or blockages in that system.

— API 17TR13 provides general overview of subsea production systems. It covers descriptions and basic design guidance on subsea production systems.

4.3.2 Subsea hardware (wellheads, trees, manifolds, structures, connectors, and pumps)

Subsea documents that address assembled equipment include the following.

— API Spec 17D provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads, vertical and horizontal subsea trees, and the associated tooling for handling, testing, and installing this equipment.

— API RP 17P provides recommendations for subsea structures and manifolds used for pressure control in both subsea production of oil and gas and subsea injection ser-vices.

— API RP 17X provides guidance for the design, manufacture, installation, and operation of subsea pumps, including rotary displacement and rotodynamic types for single-phase and multiphase services. It applies to all subsea pump modules placed at or above the mudline.

— API 17TR3 documents the results of a study of the risks and benefits of additional penetrations in subsea wellheads below the blowout preventer (BOP) stack for the purpose of monitoring additional casing annuli for sustained casing pressure. Special attention was paid to the risk and benefits introduced by monitoring annuli other than the "A" annulus (the annulus between the production tubing and the production casing strings).

— API 17TR4 addresses the impact of operation in deepwater on the pressure rating of equipment is a special concern. The objective of API 17TR4 is to foster a better understanding of the effects of simultaneous internal and external pressures on the rated working pressure of equipment covered by the scope of API 17D.

— API 17TR7 provides requirements and recommendations for the verification and validation of subsea connectors along the vertical centreline of subsea hardware (i.e. tree, tubing head, tree cap, tree running tool, well control package connectors and EDP connectors), the subsea wellhead, and the completion/workover riser. The methodology provided in API 17TR7 may also be used in other connector designs. Connectors outboard of the vertical centreline are addressed in API 17R.

— API 17TR8 typically cover deepwater applications where the shut-in pressure is 103,5 MPa (15 000 psi) or less. In recent years, industry has been pursuing deepwater assets that have shut-in pressures above 103,5 MPa (15 000 psi); and operators and regulatory agencies have had to address these applications on a singular basis. API 17TR8 establishes a standardized industry approach to the analysis, design, material selection, testing, and application of subsea component hardware for these high-pressure high-temperature (HPHT) applications.

— API 17TR11 provides guidance to the industry on allowable pressure loading of subsea hardware components that can occur during hydrotesting of subsea flowlines and risers and during pre-commissioning leak testing of these systems. There are potential problems with confusion arising from high hydrostatic pressure in deepwater, partially due to the variety of applicable test specifications and partly from the inconsistent use of a variety of acronyms for pressure terminology.

— API 17TR12 provides a detailed review of the full system considerations that are to be taken into account if one is to consider external pressure in the design of an irregular-shaped subsea pressure-containing or pressure-controlling device.

4.3.3 Flowlines and risers

Subsea documents that address risers and flowlines include the following.

— API RP 17B, API Spec 17J, API Spec 17K, API Spec 17L1, and API RP 17L2 These documents provide a comprehensive treatment of the design, manufacture, testing, packaging, and utilization criteria for both bonded and unbonded flexible pipe, as well as the ancillary equipment necessary to control the flexible pipe behaviour, protect a transition area, or provide a means of attachment and seal.

— API RP 17R provides applicable criteria for all types of remote connections, and associated pipework, made between subsea flowline/pipeline end connections, manifolds, and subsea trees. It covers subsea flowline connectors and jumpers used for pressure containment in both subsea production of oil and gas and subsea injection services.

— API RP 17U provides guidance for the performance, qualification, application, quality control, handling, and storage requirements of wet and dry thermal insulation for subsea applications in the petroleum and gas industries. It also covers the inspection of the insulation and the repair of insulation defects.

— API 17TR1 defines the methodology and test procedures necessary for the evaluation of polymeric materials suitable for use as the internal pressure sheath of unbonded flexible pipes in high-temperature applications. It describes the processes by which the critical material properties, both static and dynamic, can be measured and evaluated against relevant performance criteria.

— API 17TR2 provides comprehensive guidance on materials and pipe issues regarding the use and operation of PA-11 in flexible pipe applications, typically in production and gas handling applications up to 100 °C. It concentrates on the use of PA-11 in the internal sheath of flexible pipes, although similar considerations may also apply to other uses of PA-11 within flexibles, e.g. anti-wear layers, intermediate sheathes, and outer sheathes.

4.3.4 Control systems

Subsea documents that address control system requirements include the following.

— API Spec 17E specifies requirements for the design, material selection, manufacture, design verification, testing, installation and operation of subsea umbilicals and their ancillary equipment. It applies to umbilicals for static or dynamic service, with surface-surface, surface-subsea, and subsea-subsea routings.

— API Std 17F provides criteria for the design, manufacture, testing, and operation of various types of surface control system equipment, subsea control systems, and requirements for the associated control fluids. This equipment is used for control of subsea production of oil and gas and for subsea water and gas injection services.

— API RP 17S provides minimum requirements for subsea multiphase flow meters to help assure mechanical and electrical integrity, communications capability, and measurement performance for reliable use.

— API 17TR9 is a reference guide during the early field development planning stage to ensure that due consideration is given to the implications of the size of UTAs and possible consequences during installation.

— API 17TR10 address installation of subsea umbilical terminations (SUTs), the risks of installation and the measures required to minimize these risks.

4.3.5 Intervention systems

Subsea documents that address requirements for intervention systems include the following.

— API Std 17G defines a minimum set of requirements for performance, design, materials, testing and inspection, hot forming, welding, marking, handling, storing, and shipping of new build subsea well intervention equipment [through-BOP intervention riser system (TBIRS) and open-water intervention riser system (OWIRS)].

— API RP 17G3 provides design guidelines for the use of non-ferrous materials in subsea intervention systems and components.

— API RP 17G5 provides the requirements for the design, manufacture, and testing of intervention workover control system (IWOCS) equipment.

— API RP 17H provides recommendations for the development and design of remotely operated subsea tools and interfaces on subsea production systems to maximize the potential of standardizing equipment and design principles. Criteria for standardized interfaces found in this document are used in nearly all other subsea operations (e.g. drilling, construction) that require remotely operated vehicle (ROV) support or interaction.

— API RP 17W captures the best practices in the design and operation of existing capping stacks and provides a foundation for consistent practices in the design, manufacture, testing, and utilization of future stacks. It is intended to be applied to the construction of new subsea capping stack components, but can be also used to improve existing subsea capping stacks.

5 Systems engineering

5.1 General

Consistent with the following definitions provided by the International Council on Systems Engineering (INCOSE), system engineering of subsea production systems should address the complete system, from the reservoir to the host facility.

— “A system is an arrangement of parts or elements that together exhibit behaviour or meaning that the individual constituents do not.”

— “Systems engineering is a transdisciplinary and integrative approach to enable the successful realization, use, and retirement of engineered systems, using systems principles and concepts, and scientific, technological, and management methods.”

A complete system can include the following:

— fluid processing/injection system(s), e.g. separation systems, water/gas injection systems);

— associated support systems, e.g. subsea control system, chemical injection system, installation/ workover system.

System engineering should consider the requirements of each of the life-cycle phases of a development, including:

— concept development;

— start-up/operation;

— workover/maintenance/modification;

— decommissioning.

System engineering should consider all of the project activities required to deliver a complete, functional subsea production system, including:

— technology development/qualification;

— contracting;

— engineering;

— procurement;

— construction;

— inspection/testing;

— installation;

— systems completion;

— training.

Systems engineering is a systematic and holistic engineering approach covering the entire scope and life cycle of a subsea production system. Systems engineering includes consideration of all of the interfacing systems to the subsea production system.

The objectives of adopting a systems engineering approach include but are not limited to:

— ensuring the system performs as required (refer to 5.3);

— maximizing value for the various stakeholders;

— minimizing value erosion;

— recognizing and managing system level risks effectively and efficiently.

One of the most fundamental drivers in the design of any subsea production system is flow assurance, including hydraulic modelling of the various fluid flows from within the reservoir itself to the product export point(s) at the host facility.

5.2 Systems engineering process

General guidance on the systems engineering process can be found in the following documents:

— INCOSE Systems Engineering Handbook;

— ISO/IEC/IEEE 15288;

— ISO/IEC/IEEE 24748-4;

— NASA Systems Engineering Handbook;

— Systems Engineering Body of Knowledge (SEBoK).

The benefits of performing systems engineering are maximized by completing an appropriate level of systems engineering early in the project life cycle (i.e. during concept development/selection and front-end engineering). As the project progresses through front end engineering and detailed design, further systems engineering needs to be performed at increasing levels of detail.

Like many fundamental project processes, systems engineering is both iterative and recursive in nature; for example:

— due to the many interdependencies of the various sub-systems, various aspects of the system must be analysed multiple times to optimize the design;

— system requirements successively cascade down (and up) to sub-systems, assemblies, components, and parts in increasing levels of detail.

The overall systems engineering process consists of the management of all of the technical aspects of the project. An evaluation of the need for application of the various systems engineering processes should be performed for each specific field development, based upon the unique and specific characteristics of the development. The systems engineering process should maintain focus on the information that is required to transfer the system from one phase to another through the complete project life cycle.

Further information on the topic of systems engineering (including INCOSE work to refine ISO/IEC/IEEE 15288 to reflect Agile principles) is contained in NASA Systems Engineering Handbook (see Annex A).

5.3 Subsea system production assurance and reliability management

Production assurance and reliability management is important for the safe and efficient operation of subsea production systems.

Redundancy of equipment, components, and/or functions should be analysed as a system and should consider safety, cost, reliability, and availability. API 17N should be used as the primary source of guidance on reliability management activities, including FMECA analysis during each of the life-cycle phases.

Competing options/alternatives can be compared using a life-cycle costing approach, as described in ISO 15663. Application of ISO 14224 is relevant to ensure that correct reliability data are used in the reliability work processes. The best available subsea reliability data should be used in these reliability activities and analyses from appropriate sources [e.g. in-house reliability data, offshore and onshore reliability data (OREDA), JIP databases and handbooks]. In-house reliability data should be documented and justified by in-service records, calculations, and/or empirical tests, and should be checked for relevance to the proposed service and environmental conditions.

Consideration should be given to comparing spare parts lists against existing spare parts inventories managed by operations, particularly for brownfield projects, to optimize required spare parts. A recommended list of spare parts and ROV/ROT tooling is typically needed at the start of design to allow time for operations to determine spare order quantity and as input to operations and maintenance activity/procedure development.

Obsolescence of equipment is inevitable and may result in a loss of system availability. Guidance on obsolescence management in subsea systems is provided in 7.2.

Reliability, integrity, and technical risk management during design (from concept to detailed design) manufacture, assembly, testing, installation, and commissioning/systems completion should be per-formed at a procedural level. Implementation of these activities can be performed by the operator's subsea system project team and/or by the supplier/contractor. Further information and guidance on this topic can be found in API 17N and ISO 20815.

6 Equipment design requirements

6.1 Design basis

This document recommends a systemwide approach when designing and implementing subsea systems. This section discusses general design requirements that should be applied to the equipment design and cites references to relevant documents.

A detailed design basis should be developed to document design input to the equipment design. The basis-of-design document provides the project-specific data and references to key documents such as philosophies used during the design process. The basis of design should be updated as the design advances through the project phases.

The basis of design typically includes the following:

— description of the subsea system;

— scope of the system;

— design life;

— reservoir data;

— production profiles;

— metocean data;

— performance requirements;

— regulatory requirements;

— references to the relevant codes and standards.

General guidance regarding functional requirements that should be considered during the design phase can be found in Section 4 of API RP 17P.

6.2 Safety

6.2.1 General

The strategy and performance standards for safety systems should be developed in accordance with API RP 17V and recognized principles of health, safety, and environment (HSE) management systems. Additional guidance may be found in IEC 61508, IEC 61511, ISO/TR 12489, and Offshore Norge Guideline 070.

The system and component level design should incorporate safety aspects of the equipment. This is accomplished by implementing requirements such as:

— permanent or temporary access ladders, footholds, platforms, fall protection tie-off points, built-in mounts handrail stanchions (these safety devices should be designed as non-snagging points subsea);

— temporary and removable ladders, platforms, scaffolds, mounts, and/or handrail stanchions should be provided to complement permanent safety devices where manned intervention is required during manufacturing, load-out, and transportation (these temporary safety devices should not damage subsea structure paint integrity upon removal);

— permanent lifting and/or tie down points to facilitate handling and temporary securement of heavy equipment loads during transportation should be integrated in equipment design where practical (these permanent safety devices should be designed to not be snagging points subsea).

6.2.2 Safety strategy

A safety strategy should be developed early in the project cycle. The safety strategy should address all project phases, including manufacturing, fabrication, testing, transportation, installation, operation, and recovery. The safety strategy should include the following topics:

— managing technical safety;

— maintaining or improving the level of safety of the system;

— reducing the probability that hazards will arise;

— reducing the probability of a hazard escalating into an undesirable event or condition;

— halting or limiting the escalation process or reducing the scope and duration of undesirable events;

— limiting the impact of accidents.

Management of technical safety in project development and design processes comprises activities to identify and mitigate risks and develop safety strategies and performance requirements for safety systems and barriers. Such activities should include the following:

— complete a systematic identification and evaluation of the hazards and effects that may arise during design, fabrication, transportation, load-out, installation, systems completion, operation, and abandonment;

— defining the need for, and role of, the risk-reducing measures and safety systems;

— outlining the design principles for layout, arrangement, and selection of which safety barriers and systems go into the design, ensuring a consistent and robust design that will be the basis for a safe operation of the system;

— addressing operational aspects, which then should serve as an input to the development of the operational procedures;

— involving monitoring of performance in service and during testing and maintenance;

— performance should be reassessed against original requirements on a regular basis.

6.2.3 Safety by design

The outcome of a systematic identification and evaluation of the hazards and effects that may arise will define the need for risk-reducing measures and performance standards for the safety systems. General guidance on tools and techniques for hazard identification and risk assessment, control, and mitigation can be found in ISO 17776.

Emphasis should be placed on inherently safer designs to eliminate or reduce hazards at the source. Applying inherently safer design principals early in project development provides the greatest opportunity for risk reduction and should be part of the system engineering process.

6.3 Barrier and isolation considerations

6.3.1 Barrier philosophy

As part of the overall subsea production system design, a comprehensive barrier philosophy should be developed. The barrier philosophy should provide clear and concise guidance on barrier requirements, with the objective of preventing unintentional release of produced/injected fluids that may harm personnel and/or the environment.

The barrier philosophy should be developed before the commencement of detailed design. The barrier philosophy should define what types and how many barriers are required for operation of the facilities. The barrier philosophy should cover all of the various phases of the field life, including the following:

— installation activities, including tie-in of subsequent wells to a live manifold;

— drilling and completion activities, including well testing and clean-up activities;

— hook-up and commissioning activities;

— routine production operations, for both producing/injecting and shut-in modes, as well as for service modes such as circulating of flowlines and pigging;

— well intervention activities involving re-entry into a well and or retrieval of a tree;

— maintenance activities, such as replacement of a subsea choke;

— decommissioning activities.

The barrier philosophy should describe the requirements for the pressure-containing and pressure-controlling elements of the system, from the reservoir to the various boarding/export/isolation valves at the receiving/injecting/service facilities on the host facility or the mobile offshore drilling unit (MODU)/intervention vessel, as applicable.

Where a project/field-specific barrier philosophy has not been defined (e.g. for pre-existing subsea production facilities), the barrier requirements for routine operations of the system (i.e. production, shut-ins, interventions, and barrier testing) should be documented. A specific barrier philosophy should be developed before any intervention, workover, or activity to address those elements not covered in the barrier philosophy document.

Given the wide variety of possible field characteristics and equipment configurations, and the varying requirements of existing local regulations combined with field operator preferences, it is not possible or desirable to provide specific guidance that can be used as a standard barrier philosophy.

Typically, barrier philosophies are based on the following principles.

— It is presupposed that the barrier philosophy for each subsea production is consistent with all applicable local regulations.

— While some aspects of a barrier philosophy may be applicable to many subsea production systems, each specific situation should be evaluated on a case-by-case basis to at least confirm that the barrier philosophy is appropriate and applicable.

— Development of a barrier philosophy requires the use of experienced personnel and typically involves the use of risk assessment techniques such as hazard and operability study (HAZOP), failure modes and effects analysis (FMEA), quantitative risk assessment (QRA), task analysis, and/or scenario-based risk assessment.

— The barrier philosophy should be clearly communicated to all relevant personnel, including design engineers, equipment suppliers, and field personnel.

— The guidance/requirements contained in the barrier philosophy should be clear and concise (i.e. not open to different interpretations and/or misinterpretation).

The following documents provide relevant information regarding barrier considerations for subsea equipment:

— API Spec 17D (provides guidance on recommended XT valve configurations);

— API RP 17P;

— API RP 17V (provides guidance on recommended safety valves, including in the production/injection flowstream);

- API RP 90;
- API RP 96;
- IMCA D044;
- IOGP Report 485;
- ISO 16530-1;
- NORSOK D-010;
- OGUK Well Life Cycle Integrity Guidelines;
- Offshore Norge recommended guideline 117.

6.3.2 Barrier requirements

A risk/safety assessment shall be performed prior to any subsea operations that involve removal of an environmental barrier to ensure risks are identified and mitigated.

Primary environmental barriers intended for long-term service should be metal-to-metal sealing type. Double barriers shall be provided for all external connection points to protect against external leakage from pressurized systems to the environment. Individual barrier integrity can be confirmed with leak testing. The final dual barrier integrity should be verified prior to the introduction of fluids.

NOTE For additional guidance on barriers for subsea manifolds, refer to API 17P. For additional guidance on hot-stabs as barriers, refer to API 17H.

For temporary, time-limited operations, it can be acceptable to use only one metal-to-metal sealing isolation valve for isolating pressurized piping toward the environment. The primary barrier valve should be verified to ensure it is holding pressure prior to releasing the outboard barrier. An overall risk/safety assessment should be performed for the activity prior to the start of operations.

If the primary barrier valve cannot be verified, depressurization of the pressurized piping to prevent flow to the environment may be an acceptable alternative to verifying the primary barrier valve.

The closure element of a valve (e.g. gate, ball) should not be permanently exposed to the environment. Where possible, an inhibited volume should be provided on the environmental side of the isolation valve to avoid seawater-imposed corrosion of and fouling of the valve.

The volume between barrier valves should be maintained with stagnant fluid to minimize issues with corrosion and hydrates (i.e. close both valves with fluid trapped in the volume).

6.3.3 Subsea isolation philosophy

A subsea isolation philosophy describes the systems and components where actuated valves are available to provide isolation from pressure sources in the subsea system. The philosophy typically addresses the subsea production system, the subsea injection systems, and the export systems. All remotely actuated subsea isolation valves below the boarding valve are typically identified in the subsea isolation philosophy. The document does not typically consider manual or ROV actuated valves.

An isolation philosophy should be documented for each field development. The subsea isolation philosophy is different from a barrier philosophy. The barrier philosophy establishes what barriers are needed and when they are applied. The subsea isolation philosophy identifies existing functionality that can be used to mitigate leaks or operational issues. The subsea isolation philosophy can assist with safety studies such as HAZID, HAZOP, and SIMOPS.

The philosophy typically includes the following components from the host facility to the subsea wells:

- trees;
- risers;

— flowlines;

— pipelines;

— jumpers;

— subsea structures;

— chemical injection systems,

A subsea isolation philosophy typically includes the following topics:

— description of the subsea configuration;

— description of each major system (e.g. production, water injection, gas injection, gas lift, chemical injection, gas export, oil export);

— identification and location of each actuated valve that can be used for isolation.

6.4 Materials

The project design criteria should be considered when selecting materials for subsea design, including design life, inspection and maintenance philosophy, safety and environmental profiles, operational reliability, and specific project requirements. A documented material selection philosophy can be useful during the design process.

General guidance pertaining to materials selection and corrosion control for equipment used in the oil and gas industry can be found in ISO 21457, NACE SP0176, and NORSOK M-001. EEMUA 194 contains specific guidance for materials selection and corrosion control for subsea equipment.

API Spec 6A and several of the API 17 series of documents also contain relevant guidance and requirements regarding materials selection for specific equipment.

NOTE ISO 10423:2022 is an ISO supplement to API Spec 6A 21st edition (2018).

Specifically, API Spec 17D contains procedures for screening tests for material compatibility, while API RP 17P contains general guidance on materials and welding for subsea structure components. DNV-RP-B204 also provides guidance on welding of subsea equipment.

Guidance on materials for use in H2S-containing environments may be found in the ISO 15156 series, while guidance on the use of duplex stainless steels exposed to cathodic protection is contained in DNV-RP-F112.

General guidance on forgings is contained in API Spec 20B and API Std 20C. DNV-RP-0034, DNV-SE-0241, and DNV-RP-B202 contain specific guidance on carbon and low-alloy steel forgings for use in subsea applications.

API Spec 20E and API Spec 20F apply to carbon steel and corrosion-resistant bolting, respectively.

DNV-RP-B401 provides guidance on cathodic protection design, while DNV-CP-0107 and DNV-CP-0106 provide guidance regarding sacrificial anodes and the associated fastening devices, respectively.

Relevant guidance on protective coatings for subsea equipment is contained in API 17D, ISO 8501-1, ISO 8503, ISO 9588, ISO 12944; and NORSOK M-501. ISO 12736 contains guidance on wet thermal insulation coatings for subsea equipment.

DNV-ST-B203 provides guidance on additive manufacturing of metallic parts.

6.5 Structural analysis

6.5.1 General

Structural analysis of subsea equipment should be completed per the guidance provided in API RP 17P. The structural analysis should verify that all components and the foundation will retain structural integrity during fabrication, lifting, drilling, installation, operation, workover, and abandonment operations.

6.5.2 Wellhead, tree, and C/WO riser system analysis

Loads on a subsea wellhead system may include component dead loads (i.e. mass, weight, gravity), riser loads, flowline pull-in and expansion loads, thermal growth, and direct environmental action. Depending on the tree system, these loads may be applied to the subsea tree.

Riser loads are transferred to the wellhead/tree system during drilling, well completion, and workover. Depending on the type of subsea system, these loads can be either temporary (i.e. marine drilling riser and C/WO riser) or permanent (i.e. production risers or injection risers). These loads should be determined by performing a riser analysis. Fatigue analysis may also be required where variable loading conditions exist [i.e. due to vessel motions and/or wave/vortex-induced vibration (VIV) riser loads].

Applicable loads and applicable load combinations and operational criteria for the determination of riser loads, identification of accidental riser loads, identification of any code break inconsistencies, and their implications should be established during system engineering.

Note that riser design codes account for normal, extreme, and accidental loading conditions. The design codes used for subsea trees and wellhead systems are normally based on rated capacity for normal operating conditions and on the working stress format. Riser codes are based on either working stress design (WSD) format or load and resistance factored design (LRFD) format.

Further guidance can be found in API Std 17G, DNV-ST-F201, DNV-RP-E104, and NORSOK U-001.

Flowline pull-in loads can induce significant shear and bending moments on the wellhead. Consideration should 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 wellhead.

For template wells, the interface between the well and the template manifold piping is particularly critical and should be analysed for tolerances related to variation in temperature, pressure, position, and elements of orientation of both well and manifold components. All permutations in parameter values should be considered, including thermal growth of the well and the well's different global index with respect to the manifold piping, and any expected subsidence of the template supporting structure. This interface is a typical critical design feature of a template design and should be carefully analysed.

A subsea completion may be subject to direct environmental loads, e.g. current, wave action, earth-quakes, ice, and soil movements. Dropped objects and snag loads from anchors or trawls can also be a concern for certain applications.

6.6 Pumps, piping, and valves

Subsea pumps can be used to boost the flow rate of produced fluids from the subsea facilities to the host. Such pumps require greater levels of power than are required for a typical subsea control system. Guidance on subsea pumps and the related power systems can be found in API RP 17X, as well as DNV-RP-F303 and DNV-RP-F401.

Piping analysis of subsea equipment should be completed per the guidance provided in API RP 17P. External loads, reactions, and fluid characteristics from reservoir and environmental data are used as input to piping analysis of the subsea equipment, including erosion per API RP 14E and fatigue. Flow path piping analysis typically includes the insulation system and excludes corrosion/erosion allowances [including corrosion-resistant alloy (CRA)-clad material] in any design strength calculation.

Further guidance on piping and valve components can be found in API Spec 17D, API Std 17G, API Spec 17J, API RP 17P, API RP 17R, API RP 17W, API Spec 6DSS, API Std 6DSSX, and the Energy Institute's Guidance for the avoidance of vibration-induced fatigue failure in subsea systems.

6.7 Dropped objects and fishing gear loads

Dropped object and fishing gear load analysis of subsea equipment should be completed per the guidance provided in API RP 17P.

Each project should perform a field-specific examination in the early phase to establish the requirement for dropped object and fishing gear loads (snag loads) protection. Both historical data and expectations for the future should be assessed. Relevant loads and load combinations for the actual application should be defined in the project-specific design basis. The impact force from actual objects that will be handled over the structure should be used as initial design loads.

In the absence of site-specific data, the requirements found in NORSOK U-001 may be used.

6.8 Lifting components, padeyes, and unpressurized structural components

Structural components and padeyes should be designed to withstand transportation, lifting, deployment, operational, and retrieval loads. Such components should be designed in accordance with a recognized and relevant industry standard, such as API Std 2CCU, API RP 2A, DNV-RP-N201, DNV-ST-E273, DNV-ST-N001, and/or EEMUA 101. The design factor and other design limitations should be documented in accordance with the design standard provisions. Lifting components, such as shackles and sling sets, should be selected in accordance with the same design standards.

Guidance on the design and testing of padeyes for subsea wellhead and tree equipment is provided in API 17D.

6.9 Colours and marking

Subsea marking should follow the principles and guidelines provided in API RP 17H. Load capacity should be marked on all padeyes and other lifting devices.

A commonality of marking abbreviations among subsea facilities and surface-operating equipment is essential. To minimize confusion and enhance safety where the control units are designed for multiple applications, functions should be identified both on the subsea packages and on their control units, using common abbreviations listed in API 17H. If the valve arrangements are unique, the documentation should clearly define the abbreviations used in the marking of equipment.

The colour and marking system should fulfil the following functions.

— top coat colours should follow the recommendations in API RP 17H;

— identify the structure and orientation;

— identify the equipment mounted on the structure and intervention interfaces;

— identify the position of any given part of the structure relative to the complete structure;

— identify the operational status of the equipment, e.g. connector lock/unlock and valve open/close;

— the marking system should enable positive verification of the end stop and/or locked position for retrievable components, such as guideposts to lockdown clamps.

6.10 Tolerance evaluation

Tolerance evaluation should determine maximum allowable tolerances between mating components and subassemblies (e.g. stack-up, alignment, and engagement) and demonstrate that repeatable interfaces are attainable. Ultimately, this may involve some interchangeability tests (ICT).

6.11 Design for installation

Equipment design should not unnecessarily restrict the installation sequence of the subsea equipment, flowlines, pipelines, risers, and umbilicals. Installed equipment size, shape, configuration, and weight may be limited by handling and installation considerations, both onshore and offshore.

The design of the subsea production system should address the following installation-related issues by ensuring that the relevant components:

— do not rely on hydraulic pressure to retain the necessary locking force in connectors;

— allow for cessation of installation operations without compromising safety;

— minimize entry of water or contamination into hydraulic circuits during connections (which can jeopardize system functionality);

— are tolerant of small amounts of seabed debris between the interface connections or allow flushing prior to the makeup action;

— are tolerant of hydrodynamic loads, including wave-induced, current, and hoisting loads;

— avoid loss of harmful fluids into the environment during installation operations.

Constructability analyses should also be completed, to ensure that the proposed facilities are constructible in a safe and efficient manner. Such analyses should consider issues such as types of construction equipment required versus that which is available, pipeline lay direction and potential interference with other seabed equipment, trade-off studies of structure types [e.g. pipeline end manifolds (PLEMs), manifolds, in-line structures], and installation logistics.

6.12 Environmental considerations

The equipment should be capable of withstanding the environmental conditions to which the equipment may reasonably be expected to be exposed during fabrication, testing, transportation, storage, installation, and operation, without significant damage or degradation.

The OGUK publication "Seabed Environment Survey Guidelines" provides guidance on seabed survey techniques.

Geohazards (as described in IOGP Report 425) may present a specific risk (i.e. to the integrity of the subsea facilities and/or wells) that needs to be considered in the design of the facilities/wells.

Consideration should be given to the potential impact of the equipment on existing flora and fauna, including the impact of intended fluid discharges and any noise emanating from production facilities. IOGP Report 406 provides information regarding the transmission of sound underwater.

6.13 Evaluation of subsea pressure testing limitations

When defining pressure testing requirements, each subsea hardware subassembly/component's maximum design pressure should be evaluated to identify potential overpressure points. The evaluation should consider the performance and integrity of each subassembly/component within the system, barrier philosophy, and environmental considerations, in accordance with the subsea system testing philosophy. The following test activities should be evaluated to determine the testing criteria:

— back seal test(s) (initial verification of connection integrity between subassemblies);

— barrier test(s) (often brownfield specific) to prove a subassembly/component (e.g. valve, seal) is leak-tight in advance of an internal leak test);

— internal leak test(s) (final verification of connection integrity between subassemblies);

— subsea hydrotest(s) (verification of flowline/pipeline integrity or any other subsea equipment subassembly that has not already been verified via an onshore hydrotest).

Additional guidance can be found in API 17TR4, API 17TR11, API 17TR12, API RP 1110, and API RP 1111.

6.14 Design for intervention

Subsea equipment design should be influenced by maintenance requirements.

— Equipment components requiring periodic inspection and/or maintenance should be de-signed to be independently retrievable.

— Components subject to wear under normal operating conditions that require maintenance and/or intervention should be designed and configured in a location that accommodates repair or replacement within the parent equipment or assembly (see API RP 17H for guidance).

— The method for retrieval of independently retrievable components should be by ROV, with divers as an exception for shallower water depths.

— A method of parking flying leads should be provided in the vicinity of all independently retrievable components.

— All equipment and components of an identical/like design should be designed and fabricated such that they are interchangeable.

— ROV/ROT tooling and interfaces should be according to API RP 17H.

— Consideration should be given to the likelihood and severity of marine fouling (including calcareous deposits forming), which may make operation and/or retrieval/installation of some components problematic.

The manufacturer should document instructions and requirements concerning maintenance and preservation of equipment.

API Std 17G defines a minimum set of requirements for performance, design, materials, testing and inspection, hot forming, welding, marking, handling, storing, and shipping of new-build subsea well intervention equipment [through-BOP intervention riser system (TBIRS) and open-water intervention riser system (OWIRS)]. Structural design methods and criteria given in API Std 17G are limited to components manufactured from materials that ensure ductile failure modes (e.g. carbon steels, low-alloy steels, and corrosion-resistant alloys). Components manufactured from materials that may not ensure ductile failure modes (e.g. composite materials, titanium, and titanium alloys) are beyond the scope of API Std 17G.

API RP 17H contains guidance relevant to the development of intervention philosophies and strategies, which should be taken into account in the design of the subsea equipment.

7 Technology management guidance

7.1 Technology development and qualification

Equipment, methodologies, and modes of operation classified as new or modified technology (or existing technology to be used in a new application) should be suitably qualified prior to use.

As stated in API RP 17Q, “the overall aim of a qualification program is to provide evidence that a selected technology or equipment will meet functional and performance requirements, within specified operational limits, and with an acceptable level of confidence.”

Both API RP 17N and API RP 17Q make a distinction between standard qualification programs (SQPs) and new technology qualification involving a unique/formal technology qualification program (TQP). The latter usually requires a greater degree of testing and analysis effort to demonstrate that the equipment will meet specified reliability and integrity requirements. The decision to implement a new TQP or SQP depends on the degree of novelty or change involved in the design, manufacture, or operation of products. Further details regarding TQP and SQP can be found in API RP 17Q.

Qualification of equipment may also include non-fixed equipment, such as ROV tooling, WOC riser systems, and IWOCS.

API 17N, API 17Q, and DNV-RP-A203 all provide further guidance on this topic.

Concepts relevant to technology development and qualification include:

— prototype;

— pilot;

— first article;

— product;

— production model/production product.

7.2 Obsolescence management

Obsolescence of equipment is inevitable and, depending on the design basis, it may not be possible to avoid some replacement components becoming unavailable during the field life of the subsea system. Electronic equipment and software are particularly prone to obsolescence.

The negative impacts of obsolescence can be mitigated and/or deferred through a proactive approach (e.g. a robust sparing strategy). As obsolescence management is a continuous activity during field life, a comprehensive obsolescence management strategy and plan should be developed during the project development phase that covers operation of the equipment through to decommissioning.

The obsolescence management strategy and plan should cover the following areas:

a) design of new products;

b) new technology insertion into existing products;

c) support and maintenance of legacy products.

IEC 62402 provides generic guidance for establishing a framework for obsolescence management and for planning a cost-effective obsolescence management process that is applicable through all phases of the product life cycle, wherein the term “product” includes:

— capital equipment;

— infrastructure;

— consumer durables;

— consumables;

— software products.

As described in OTC 25872-MS, two joint operator specification documents (3428A and 3428B) have been created by a joint industry effort, to assist the application of IEC 62402 to subsea equipment.

Additional specific guidance on managing obsolescence in subsea systems is also available in API Spec 17F, IOGP Report 551, and the Energy Institute’s Guidelines for the management of obsolescence in subsea facilities, and Guidance on managing obsolescence and upgrading industrial automation and control systems (ICAS).

8 Manufacture, assembly, testing, installation, and commissioning guidance

8.1 Manufacture

API 17D contains recommended guidelines for inquiry and purchase of various subsea equipment, including guidance on product specification levels, material class, and suggested data the manufacturer will require (in the form of data sheets).

Equipment should be manufactured according to the manufacturer's quality program, relevant industry standards, and ISO 29001 or API Spec Q1.

API Spec Q1 establishes the quality system requirements necessary for organizations to consistently manufacture products in accordance with API or other specifications. Organizations that supply services should meet the requirements of ISO 29001 or API Spec Q2.

Guidance on the documentation typically required to be provided by the equipment manufacturer can be found in NORSOK Z-018 and DNV-RP-O101.

IOGP S-561 (and the associated documents: S-561D, S-561L, and S-561Q) provides a list of potential supplementary requirements to API Spec 17D for subsea trees and tubing hangers.

8.2 Assembly

All components, including spares, should be tested for ease of assembly, handling, and interchangeability. Interface checks should be made under static and dynamic conditions.

Jigs and dummies may be used where testing of actual interface components is not practical. However, the actual equipment should be used where feasible. For large orders with identical equipment items, testing should be performed on the initially produced equipment at a minimum.

Fit tests should be performed in such a way as to prove the guidance and orientation features of the system. In certain cases, it is necessary to perform wet-simulation testing to prove correct functioning of components and systems underwater.

Certain areas can require cycle testing and make-break testing to prove repeatability of function for new or unqualified designs. Prime targets for this type of testing are valve functions, data transfer functions, hydraulic and chemical connector interfaces, and tooling functions.

Misalignment checks should consider stack-up tolerance, stack-up elevation, horizontal plane orientation, and angular alignment. Equipment with self-alignment features should intentionally be misaligned to verify its alignment capability.

Functional checks should include makeup, normal emergency release, reversibility, repeatability, and pressure integrity. The sequence and items to be tested are normally individual components, running tools, subsystems, and the total system assembly.

8.3 Testing

8.3.1 General

Onshore and preinstallation testing can detect early failures in an accessible environment, allowing efficient recording and rectification. Testing should not be a series of isolated test activities, but rather a series of related tests that are progressively executed as part of a clearly defined overall project testing strategy and test plan that ensures subsea equipment reliability. The test plan should cover all onshore and preinstallation testing requirements on each subsystem, including the:

— sequence and definition of tests;

— testing requirements for all phases of field life;

— relevant regional and company-specific test requirements;

— hardware and software interfaces.

Various tests are typically undertaken on subsea equipment to demonstrate that the numerous components, assemblies, and systems have been manufactured in accordance with the specified requirements and are suitable for the intended use.

Performance tests may be appropriate and can supply data on response-time measurements, operating pressures, fluid volumes, and fault-finding and operation of shutdown systems. Cycle testing and make-break testing should be implemented to prove repeatability and operational life on unqualified designs. Reliability growth testing and accelerated life testing should be performed to validate reliability performance targets.

Tests may also include simulations of actual field and environmental conditions for some or all phases or modes of operations, from installation through maintenance. Special tests may be needed for handling and transport, dynamic loading, and backup systems.

8.3.2 Inspection and test plans

An inspection and test plan (ITP) is a document that describes the plan for managing the quality control and assurance of a particular element of the construction works providing information on the requirements, overview of the method(s) to be used, responsibilities of relevant parties, and documentary evidence to be provided to verify compliance.

The purpose of an ITP is to document all inspection and testing requirements relevant to a specific process.

An ITP typically identifies:

— items, materials, and work to be inspected or tested;

— who is responsible for each of the inspection and testing activities;

— stages and/or frequency of the testing;

— inspection, witness and hold points in the process;

— references to relevant standards;

— acceptance criteria;

— inspection and test records to be maintained.

ITPs, when properly implemented, help ensure that, and verify whether, work has been undertaken to the required standard and requirements, and that documented records are created. An ITP should be developed for each major piece of equipment that is consistent with the overall project testing strategy, which includes the requirements and acceptance criteria for testing.

8.4 Transportation, preservation, and storage

Plans for the transport, preservation, and storage of equipment should address the following issues:

— transportation;

— handling;

— security;

— preservation;

— inspection;

— testing;

— maintenance;

— repair;

— refurbishment.

General transportation requirements (such as tie-down analysis for all delivery modes, protective covers, packaging and handling) should be addressed and documented. DNV-ST-N001 provides guidance on sea transport operations.

Equipment handling plans should address certification of lifting equipment and should take into account that different lifting equipment may be required offshore versus onshore, due to increased dynamic loading factors.

Equipment preservation should take into account the need for protection from environmental conditions.

— Equipment should be stored under cover if possible.

— Elastomeric/thermoplastic components (and assemblies containing such components, e.g. valve actuators) should not be exposed to direct sunlight for prolonged periods.

— Electronic components should be stored in an environmentally (i.e. temperature, humidity, and debris) controlled area.

— Hydraulic fluid cleanliness should be maintained.

— Appropriate preservation fluids should be used to protect equipment surfaces from long-term degradation.

— Inspection and testing may include, but not be limited to, visual inspections, flow tests, function tests, electrical checks, dimensional checks, fluid cleanliness checks, and/or pressure tests.

Routine equipment maintenance may include refreshing equipment preservation and/or hydraulic fluids.

Prior to load-out, equipment that has been stored should be appropriately inspected and/or tested and prepared for transport/deployment. In some cases, this may involve:

— various de-preservation activities, such as change-out of preservation fluid in the SCM with the control fluid that will be used when the equipment is in operation;

— repair or refurbishment of equipment.

General guidance regarding transportation, preservation, and storage of subsea equipment can be found in API RP 17P.

8.5 Load-out and installation

Load-out planning is critical to ensure that risks are managed between parties and mitigations are put in place. Load-out planning should address, but not be limited to, the following:

— safety, personnel communication, and access;

— sensitive equipment protection during load-out [e.g. flying leads, subsea control modules (SCMs), MPFMs];

— installation aids/sea fastening;

— lifting procedures/crane specifications;

— drawings (e.g. vessel layouts, transportation routes, and vessel/crane elevations);

— quay schedule, load-out sequences/checklists, and constraints relative to transportation vessel, quay, and site;

— mobilization of temporary equipment (e.g. cranes, transports);

— temporary personnel (e.g. marine warranty surveyors);

— marine requirements (e.g. ballasting, bumpers/fenders, moorings, gangways, and additional barges to position vessel);

— potential physical hazards (e.g. sharp edges on support equipment that can damage umbilical, stray electrical currents from welding that could damage electrical equipment).

The methods and equipment used for installation of the subsea equipment should ensure safe and reliable performance of installation operations.

DNV-RP-N103 provides guidance for modelling and analysis of marine operations, particularly for lifting operations, including lifting through the wave zone and lowering objects in deepwater to landing on the seabed.

Additional references are DNV-ST-N001 for load transfer operations, sea transport operations, and lifting operations; DNV-RP-N201 and ISO 13535 for guidance on lifting appliances; and DNV-RP-N101 for guidance on risk management in marine operations.

Service supply organizations' quality management systems should meet the requirements of API Spec Q2.

8.6 Commissioning/systems completion

As described in API 1FSC, systems completion includes the following.

— factory acceptance tests (insofar as the systems completion process is reliant on the completion of the various tests performed prior to equipment deployment, which, in the case of subsea equipment, typically involves more than just FAT per se, as described in 8.3);

— verification of mechanical completion (which is the point where field construction/installation is complete and mechanical integrity has been verified);

— pre-commissioning (which involves activities to verify that the equipment is in the required state of readiness for full dynamic testing); sometimes also referred to as "static commissioning";

— commissioning (which involves activities undertaken to verify dynamically that the system is ready for start-up); sometimes also referred to as "dynamic commissioning";

— start-up [which involves the introduction of process fluids (normally hydrocarbons) into the system];

— performance testing (which involves operating the facilities to perform tests versus the design/contract parameters).

Following successful completion of performance testing, responsibility for the facility is typically transferred from the project team to the operations group.

NOTE Although the vernacular term "commissioning" is still widely used throughout the industry, this phase of the project activities is increasingly referred to by the more comprehensive term "systems completion," of which commissioning is a subpart.

9 Operations guidance

9.1 Integrity management

9.1.1 Condition monitoring

The ongoing condition of the subsea equipment should be monitored via a combination of assessment of the data available via the subsea control system, performance of periodic underwater inspections, corrosion control, condition monitoring (hydraulic and electrical), and routine integrity testing of critical equipment (such as tree valves).

API RP 14H provides guidance on in situ testing of underwater safety valves (USVs) on subsea trees.

Specific guidance on integrity management data collection is contained in API RP 17N.

An initial integrity management status inspection should be performed within the early life of a subsea facility to define the initial condition of the facility, and should be compared against known and potential hazards. Engineered barriers of the subsea system should be demonstrated to be fit for service. Subsea emergency response procedures should include procedures and techniques for implementation of repair and restoration of an operable subsea system. Subsea system integrity performance should be reviewed periodically. Monitoring and inspecting subsea system activities should be prioritized based on outcomes of risk assessments and be reassessed based on the results of data analysis.

API RP 17N provides an explanation of how to manage an appropriate level of reliability and integrity throughout the life cycle of subsea systems and recognize the trade-offs between up-front reliability, integrity, and engineering versus operational integrity management and maintenance.

The Energy Institute's Guidelines for the management of integrity of subsea facilities, Good operational practice on the management of subsea production control systems and associated hydraulic fluids, Guidance on integrity management for subsea production control systems, DNV-RP-0002, and EEMUA 227 all provide useful specific guidance regarding the integrity management of various aspects of subsea systems.

DNV-RP-F302 provides a summary of industry experiences and knowledge regarding subsea leak detection systems, and can be used as a technical reference.

API RP 17N, NORSOK U-009, and Offshore Norway Recommended guideline 122, provide useful guidance regarding the issues and considerations surrounding the use of subsea systems beyond their originally specified service life.

API 18LCM defines the requirements of a management system for service providers performing life-cycle management of pressure-containing and/or pressure-controlling products for wellbore fluids, and may also be applied to other equipment that is specified by the product owner or customer.

DNV-RP-O501 provides guidance on managing sand production and erosion.

The OGUK publications Flexible pipe integrity management guidance and good practice, Guidance note on monitoring methods and integrity assurance for unbonded flexible pipes, Guideline on aging and life extension of subsea pipelines and risers, and State of the art report on flexible pipe integrity provide guidance relating to the integrity management of flexible pipes.

9.1.2 Reliability data collection/reporting

A failure reporting process should be in place, and all equipment failures should be communicated back to the original equipment manufacturer (OEM), so that lessons learned can be appropriately incorporated into future designs. ISO 14224 provides requirements and guidance on the collection and exchange of reliability and maintenance data.

9.1.3 Subsea production system maintenance

Various maintenance tasks can be performed on equipment located on or near the seabed (i.e. choke inserts, control modules, valves, flow meters, manifolds, templates, etc.) by modular replacement or via in situ repairs by ROV/divers. IMCA D044 provides guidance regarding isolation and intervention during diver access to subsea systems. IOGP Report 570 lists various hazards that should be considered prior to commencing intervention work on subsea facilities.

Surface equipment (i.e. production control system components, chemical injection systems, etc.) should be maintained via implementation of a routine maintenance program.

9.2 Production management

Routine operation of the subsea system requires careful control of all of the relevant operating parameters. Subsea production systems (versus subsea water/gas injection systems) involve multiphase flow, and therefore should be carefully managed with respect to several related issues, including start-up, shutdown, and solids management.

Most subsea production systems rely on some level of chemical injection as part of the solids management strategy; therefore, particular care should be taken with the management of the chemical injection system, especially with respect to blocking lines/injection points as described in API 17TR5 and API 17TR6.

Production optimization and long-term reservoir management are also typically more challenging for subsea production systems than for production systems using dry trees, e.g. well testing of subsea wells.

10 Well intervention guidance

Where a well is accessed vertically, appropriate subsea or surface BOP equipment should be employed that satisfies the required service conditions.

Subsea wells should be safely secured prior to commencing any well intervention involving potential exposure to live well fluids. Refer to 6.3 for guidance on barrier considerations.

Extreme care should be taken when lowering and landing tools that connect to the subsea tree and/or wellhead to minimize potential damage to installed components. If possible, the rig or surface vessel should be displaced to a position offset from the centre of the well when handling and running packages to reduce the risk of dropping objects or debris onto the well or adjacent components.

After completion of the well intervention, downhole and tree components should be reinstalled and tested in accordance with the relevant installation procedures.

The well control during a well intervention should only be possible via the workover control system. It should be possible to initiate a shutdown of associated neighbouring wells from the well intervention vessel by reliable communication with the host facility.

All subsea tree valves that can prevent downhole access in the event of hydraulic failure should be equipped with a mechanical override feature.

IOGP Reports 594 and 595 provide guidance on emergency response planning, and capping stacks, for subsea wells.

11 Decommissioning guidance

The variable elements related to decommissioning are the plugging and abandonment of wells, any necessary removal of seabed equipment, seabed clean-up, and final survey. The effect on the operating environment, for example, discharge of hydrocarbons during decommissioning, should be minimized.

At decommissioning, the subsea production system should:

— allow cessation of operations without compromising safety;

— allow production products and chemicals to be flushed from subsea trees, umbilicals, flowlines, pressure vessels, manifolds, etc.;

— allow any hydrocarbon-containing equipment to be removed or, if left in place, be flushed clean. The flushed fluid should be recovered at the surface to avoid unintended releases to the environment.

When the decision has been made to abandon subsea equipment, the method of abandonment should be reviewed in light of changes to the applicable equipment and removal technology. In certain situations, it may be acceptable for the equipment to be left in place. If it is to be removed, a subsea survey should be conducted to ascertain the physical condition. The integrity of the lifting points and ballasting system, if fitted, is critical. After collecting the desired information, a detailed plan of removal should be developed.

API RP 17N, the Energy Institute's Guidance on managing human and organizational factors in decommissioning, and Offshore Norway's decommissioning work breakdown structure handbook contain general guidance relevant to decommissioning of subsea equipment.

The following documents also provide guidance on decommissioning of subsea facilities: IOGP Reports 469 and 584, plus OGUK's Decommissioning of pipelines in the North Sea region, Guidelines on late-life/decommissioning inspection and maintenance, Long-term degradation of offshore structures and pipelines: decommissioned and left in situ, and The management of marine growth during decommissioning.

DNV-RP-E103, IOGP Report 585, and OGUK's Guidelines for the abandonment of wells and Well decommissioning guidelines contain guidance on abandonment of subsea wells.

Per API Bulletin E2, those performing retrieval of equipment should address the possible presence of naturally occurring radioactive materials (NORM).

After the abandonment operation, the site should be surveyed and mapped for remaining equipment/debris.