

Specification for Subsea Production Control Systems

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API Foreword

This standard is under the jurisdiction of the API Standards Subcommittee on Subsea Production Systems (API C2/SC17). This API standard is identical with the English version of ISO 13628-6:2000. ISO 13628-6 was prepared by Technical Committee ISO/TC 67 *Materials, equipment and offshore structures for petroleum and natural gas industries*, SC 4, *Drilling and production equipment*.

This standard shall become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

The API Standards on Subsea Production Systems consists of a series of Specifications, Recommended Practices and Technical Reports (17 Series), many of which are complementary with ISO Standards in the various standards in the series of ISO 13628-x documents. A list of these corresponding documents:

<u>API Standard</u>	<u>ISO Document</u>	<u>API Title (or Topic & Comments)</u>
RP 17A	13628-1	Design & Operation of Subsea Production Systems
RP 17B	n/a	Flexible Pipe Revised Edition published in 2002
RP 17C	-3	TFL Systems
Spec 17D	-4	Wellhead & Christmas Tree Equipment
Spec 17E	-5	Subsea Production Control Umbilicals
Spec 17F	-6	Subsea Controls
RP 17G	-7	Design & Operations of Completion/Workover Riser Systems
(RP 17H)	-8	Remotely Operated Vehicles No API standard, designation reserved for future Adoption
RP 17I	-5	Installation Guidelines for Subsea Umbilicals To be incorporated into a new 17E
Spec 17J	-2	Unbonded Flexible Pipe
Spec 17K	n/a	Bonded Flexible Pipe
RP 17M	-9	Remotely Operated Tools No API standard, designation reserved for future Adoption

While this list of corresponding documents is current as of the publication date of this standard, API makes no representation that any of these documents will be adopted by API or ISO

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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.

Attention is drawn to the possibility that some of the elements of this part of ISO 13628 may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

International Standard ISO 13628-6 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 C forms a normative part of this part of ISO 13628. Annexes A, B and D are for information only.

Introduction

Description of hardware is included in this part of ISO 13628 to illustrate functional requirements. This part of ISO 13628 should not be interpreted in a way which would limit new solutions with documented improved life-cycle benefits.

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

Part 6: Subsea production control systems

1 Scope

This part of ISO 13628 is applicable to design, fabrication, testing, installation and operation of subsea production control systems.

This part of ISO 13628 covers surface control system equipment, subsea-installed control system equipment and control fluids. This equipment is utilized for control of subsea production of oil and gas and for subsea water and gas injection services. Where applicable, this part of ISO 13628 may be used for equipment on multiple-well applications.

NOTE Typical main elements of a subsea production control system are described in 5.1.1.

This part of ISO 13628 establishes design standards for systems, subsystems, components and operating fluids in order to provide for the safe and functional control of subsea production equipment.

This part of ISO 13628 contains various types of information related to subsea production control systems. They are:

- informative data which provide an overview of the architecture and general functionality of control systems for the purpose of introduction and information;
- basic prescriptive data which must be adhered to by all types of control system;
- selective prescriptive data which is control-system-type sensitive and need only be adhered to when it is relevant;
- optional data or requirements which need only be adopted when considered necessary either by the purchaser or the vendor.

In view of the diverse nature of the data provided, control system purchasers and specifiers are advised to select from this part of ISO 13628 only the provisions needed for the application at hand. Failure to adopt a selective approach to the provisions contained herein can lead to overspecification and higher purchase costs.

Downhole intelligent well-control equipment is beyond the scope of this part of ISO 13628.

Rework and repair of used equipment are beyond the scope of this part of ISO 13628.

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 4406:1987, *Hydraulic fluid power — Fluids — Method for coding level of contamination by solid particles.*

ISO 6073, *Hydraulic fluid power — Petroleum fluids — Prediction of bulk moduli.*

ISO 10432, *Petroleum and natural gas industries — Down hole equipment — Subsurface safety valve equipment.*

ISO 13628-5, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 5: Subsea control umbilicals.*

EN 287-1 + A1, *Approval testing of welders — Fusion welding — Part 1: Steels (Amendment A1:1997 included).*

EN 287-2 + A1, *Approval testing of welders — Fusion welding — Part 2: Aluminium and aluminium alloys (Amendment A1:1997 included).*

EN 288 (all applicable parts), *Specification and approval of welding procedures for metallic materials.*

ANSI/ASME B31.3, *Process Piping.*

API RP 14H, *Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore.*

API Spec 6A, *Wellhead and Christmas Tree Equipment.*

API Spec 17D, *Subsea Wellhead and Christmas Tree Equipment.*

ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, *Rules for Construction of Pressure Vessels.*

ASME Boiler and Pressure Vessel Code, Section IX, *Welding and Brazing Qualifications.*

ASTM D92, *Test Method for Flash and Fire Points by Cleveland Open Cup.*

ASTM D445, *Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (the Calculation of Dynamic Viscosity).*

ASTM D471, *Test Method for Rubber Property — Effect of Liquids.*

ASTM D665, *Test Method for Rust Preventing Characteristics of Inhibited Mineral Oil in the Presence of Water.*

ASTM D892, *Test Method for Foaming Characteristics of Lubricating Oils.*

ASTM D1293, *Test Methods for pH of Water.*

ASTM D1889, *Test Methods for Turbidity of Water.*

ASTM D2596, *Test Method for Measurement of Extreme-Pressure Properties of Lubricating Grease (Four-Ball Method).*

ASTM D4006, *Test Method for Water in Crude Oil by Distillation.*

BS 7201-1, *Hydraulic fluid power — Gas-loaded accumulators — Part 1: Specification for seamless steel accumulator bodies above 0,5 L water capacity.*

BS 7201-2, *Hydraulic fluid power — Gas-loaded accumulators — Part 2: Dimensions of gas ports.*

IP 280, *Petroleum Products and Lubricants — Determination of Oxidation Stability.*

NAS 1638-64, *National Aerospace Standard — Cleanliness Requirements of Parts Used in Hydraulic Systems.*

3 Terms and definitions

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

3.1

boost

pressure maintained on the spring-return side of a subsea actuator for the purposes of improving closing-time response

3.2

commanded closure

closure of the underwater safety valve and possibly other valves depending on the control system design

NOTE Such commands may originate manually, automatically or as part of an ESD.

3.3

control path length

CPL

total distance that a control signal (electrical or hydraulic) travels to the subsea control module or valve actuator

3.4

design pressure

rated working pressure

pressure which is equal to or greater than the maximum service conditions, and for which all components are rated

3.5

direct hydraulic control

control method wherein hydraulic pressure is applied through an umbilical line to act directly on a subsea valve actuator

NOTE Upon venting of the pressure at the surface, the control fluid is returned through the umbilical to the surface due to the action of the restoring spring in the valve actuator. Subsea functions may be ganged together to reduce the number of umbilical lines.

3.6

downstream

direction away from the source of pressure or flow

3.7

electrohydraulic control

control method wherein electrical signals are conducted to the subsea system and used to open or close electrically-controlled hydraulic control valves

NOTE Hydraulic fluid is locally sourced and acts on the associated subsea valve actuator. "Locally sourced" may mean locally stored pressurized fluid or fluid supplied by a hydraulic umbilical line. With electrohydraulic control systems, data telemetry (readback) is readily available at high speed. Multiplexing of the electrical signals reduces the number of conductors in the electrical umbilical.

3.8

hydrostatic test pressure

proof pressure

maximum test pressure at a level greater than the design pressure (rated working pressure)

3.9

minimum operating pressure

lowest operating pressure, at any point in the system, during normal conditions at which the system can operate effectively

3.10

offset

horizontal component of CPL

3.11

response time

sum of the signal time and the shift time

3.12

running tool

tool used to operate, retrieve, position or connect subsea equipment remotely from the surface

NOTE An example is the subsea control-module running tool.

3.13

shift time

period of time elapsed between the arrival of a control signal at the subsea location and the completion of the control function execution

NOTE Of primary interest is the time to fully stroke, on a subsea tree, a master or wing valve that has been designated as the underwater safety valve.

3.14

signal time

period of time elapsed between the remote initiation of a control command and the initiation of a control function operation subsea

3.15

subsea production control system

control system operating a subsea production system during production operations

3.16

surface-controlled subsurface safety valve

SCSSV

safety device that is located in the production bore of the well tubing below the subsea wellhead, and that will close upon loss of hydraulic pressure, as defined in ISO 10432

NOTE Its function is to provide closure of the well flow in the event of catastrophic loss of the primary flow control safety equipment provided by the subsea tree assembly, or when commanded from the surface facility, e.g. in the event of an emergency shutdown Level 0.

3.17

surface safety valve

SSV

safety device that is located in the production bore of the well tubing above the wellhead (platform well), or at the point of subsea well production embarkation onto a platform, as defined in API RP 14H, and that will close upon loss of hydraulic pressure

3.18

umbilical

group of electric cables, hoses or steel tubes, either on their own or in combination (or with optical fibre cables), cabled together for flexibility and oversheathed and/or armoured for mechanical strength

3.19

underwater safety valve

USV

safety valve assembly that is declared to be the USV as defined in API RP 14H and will close upon loss of hydraulic pressure

3.20**upstream**

direction towards the source of pressure or flow

4 Abbreviated terms

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AWS	American Welding Society
BER	bit error rate
cfu	colony-forming units
CIGRE	International Conference on Large Electrical Systems
CIU	chemical injection unit
CPL	control path length
CRC	cyclic redundancy check
DCS	distributed control system
DCV	directional control valve
DHPT	downhole pressure and temperature
EPU	electrical power unit
ESD	emergency shutdown
EXT	extended
FAT	factory acceptance test
FMECA	failure mode effect and criticality analysis
HIPPS	high integrity pipeline protection system
HP	high pressure
HPU	hydraulic power unit
IEC	International Electrotechnical Commission
IP	Institute of Petroleum
LP	low pressure
MCS	master control station
MEA	malt extract agar
MIL-STD	Military Standard
NAS	National Aerospace Standard Institute
NBR	natural buna rubber
NPT	national pipe thread
PARCOMS	Paris Commission
PC	personal computer
PREP	preparation

PSD	process shutdown
PTFE	polytetrafluoroethylene
QA	quality assurance
ROV	remotely operated vehicle
SCM	subsea control module
SCSSV	surface-controlled subsurface safety valve
SEM	subsea electronic module
SSV	surface safety valve
STD	standard
TAN	total acid number
TBN	total base number
THPU	test hydraulic power unit
TSA	tryptone soya agar
UPS	uninterruptible power supply
USV	underwater safety valve
VAC	volts alternating current
VDU	video display unit

5 System requirements

5.1 General requirements

5.1.1 General

The main elements of a subsea production control system typically include the following:

- a) **hydraulic power unit (HPU);**
The HPU provides a stable and clean supply of hydraulic fluid to the remotely operated subsea valves. The fluid is supplied via the hydraulic umbilical, the subsea hydraulic distribution system, and the SCMs to operate subsea valve actuators.
- b) **master control station (MCS);**
The MCS may be the central control "node" containing application software required to control and monitor the subsea production system and associated topside equipment such as the HPU and EPU.
- c) **distributed control system (DCS);**
The DCS can perform the same functions as an MCS, but with a decentralized configuration.
- d) **electrical power unit (EPU);**
The EPU supplies electrical power at the desired voltage and frequency to the subsea users. Power transmission is performed via the electrical umbilical and the subsea electrical distribution system.
- e) **modem unit;**
This unit modulates communication signals for transmission to and from the applicable subsea users.
- f) **uninterruptible power supply (UPS);**
The UPS is typically provided to ensure safe and reliable electrical power to the subsea production control system.

- g) **umbilical;**
The umbilical(s) transfers electrical power and signals, hydraulic power, and/or chemicals to the subsea components of the subsea production system. Signals may be transmitted via power cable (signal on power), signal cable or fibre optic.
- h) **subsea control module (SCM);**
In a piloted-hydraulic, electrohydraulic or electric control system, the SCM is the unit which upon command from the MCS directs hydraulic fluid to operate subsea valves. In an electrohydraulic system the SCM also gathers information from sensors located subsea and transmits the sensor values to the topside facility.
- i) **subsea distribution systems;**
Distribution systems distribute electrical, hydraulic and chemical supply from the umbilical termination(s) to the subsea trees, manifold valves, injection points, and the control modules of the subsea production control system.
- j) **subsea located sensors;**
Sensors located in the SCMs, or on subsea trees or manifolds, provide data to help monitor operation of the subsea production system.
- k) **control fluids;**
Oil-based or water-based liquids that are used to convey control and/or hydraulic power from the surface HPU or local storage to the SCM and subsea valve actuators.
- l) **control buoy.**
A moored buoy housing generation, communication and chemical injection (optional) equipment. The buoy is connected to the subsea components of the subsea production system via an electrical/fibre optic/hydraulic control umbilical. The buoy can communicate with the surface production facility via acoustic, radio or satellite links or a combination thereof.

This part of ISO 13628 covers all systems, both hydraulic and electrohydraulic. Only the relevant clauses should be used.

5.1.2 Service conditions

5.1.2.1 Suitability for working environment

The subsea control system shall be designed and operated with consideration for the external environment. For surface facilities, this will include climatic conditions, corrosion, marine growth, tidal forces, illumination, and hazardous area classifications. For the subsea environment, this will include corrosion, ambient pressure and temperature, and maintenance considerations.

Product designs shall be capable of withstanding design pressure (rated working pressure) at rated temperature without degradation, exceedance of allowable stresses, or impairment of other performance requirements for the design life of the system.

5.1.2.2 Pressure ratings

5.1.2.2.1 General

The design shall take into account the effects of pressure containment and other pressure-induced loads. Specialized conditions shall also be considered, such as pressure rating changes in system and component interfaces (such as subsea control module to receiver plate, umbilical to tree-mounted terminations) and pressurizing with temporary plugs and caps installed. The effects of external loads (i.e. bending moments, tension), ambient hydrostatic loads and fatigue shall be considered.

Hydraulic systems shall have a maximum allowable operating pressure at least 10 % below design pressure (rated working pressure).

5.1.2.2.2 Hydraulic control components

Hydraulic control components other than for SCSSV circuits shall have design pressures (rated working pressures) of 10,3 MPa, 20,7 MPa or 34,5 MPa (1 500 psi, 3 000 psi or 5 000 psi) or according to the manufacturer's written specification. Hydraulic control circuits for SCSSVs shall have a design pressure (rated working pressure) in accordance with the manufacturer's written specification.

5.1.2.2.3 Other equipment

The design pressure (rated working pressure) of other equipment such as running, retrieval and test tools shall comply with manufacturer's written specifications.

5.1.2.3 Temperature ratings (surface-installed equipment)**5.1.2.3.1 Without controlled environment**

Surface-installed equipment covered by this part of ISO 13628 and not installed in a controlled environment shall be designed, tested, operated and stored in accordance with the temperature ratings listed in Table 1.

Table 1 — Temperature rating — Surface-installed equipment without controlled environment

	Electronics		System	
	°C	(°F)	°C	(°F)
Design				
a) Standard	0 to 40	(32 to 104)	0 to 40	(32 to 104)
b) Extended	– 18 to 70	(0 to 158)	– 18 to 40	(0 to 104)
Operate				
a) Standard	0 to 40	(32 to 104)	0 to 40	(32 to 104)
b) Extended	– 5 to 40	(23 to 104)	– 5 to 40	(23 to 104)
Store	– 18 to 50	(0 to 122)	– 18 to 50	(0 to 122)

Temperatures relate to environment, not individual components.

Equipment shall be marked in accordance with 12.1.2.

5.1.2.3.2 Controlled environment

Surface-installed equipment covered by this part of ISO 13628, and installed in a controlled environment, shall be designed, tested, operated and stored in accordance with temperature ratings compatible with the specified controlled environment.

Packaged assemblies or components that are restricted for use in a controlled environment shall be appropriately marked in accordance with the provision of 12.1.3.

5.1.2.4 Temperature ratings (subsea-installed equipment)

Subsea-installed equipment covered by this part of ISO 13628 shall be designed, tested, operated and stored in accordance with the temperature ratings listed in Table 2.

Table 2 — Temperature rating — Subsea-installed equipment

	Electronics		System	
	°C	(°F)	°C	(°F)
Design				
a) Standard	– 10 to 70	(14 to 158)	0 to 40	(32 to 104)
b) Extended	– 18 to 70	(0 to 158)	– 18 to 40	(0 to 104)
Test			N/A	N/A
a) Standard	– 10 to 40	(14 to 104)		
b) Extended	– 18 to 40	(0 to 104)		
Operate				
a) Standard	0 to 40	(32 to 104)	0 to 40	(32 to 104)
b) Extended	– 5 to 40	(23 to 104)	– 5 to 40	(23 to 104)
Store	– 18 to 50	(0 to 122)	– 18 to 50	(0 to 122)

Temperatures in Table 2 relate to environment, not individual components. Subsea sensors which monitor produced or injected fluid may operate outside the ranges given; they shall be rated accordingly.

Equipment shall be marked in accordance with 12.1.2.

5.1.2.5 Storage/test temperature recommendations

If subsea-installed or surface-installed equipment is to be stored or tested on the surface at a temperature outside its temperature rating, then the manufacturer should be contacted to determine if special storage or surface testing procedures are recommended. Manufacturers shall document any such special storage or surface testing considerations.

5.1.2.6 External hydrostatic pressure

In subsea applications, external hydrostatic pressure may be higher than internal system pressure. This external loading situation shall be considered, especially relative to seal design, self-sealing couplings and one-atmosphere enclosures. Umbilical collapse during installation and in service should also be considered.

5.1.2.7 Fluid compatibility

Components shall be selected considering compatibility with both control fluid and chemical injection fluid.

5.1.3 Hydraulic system

5.1.3.1 Hydraulic fluid

Selection of hydraulic fluid shall consider the maximum temperature and pressure to which the hydraulic fluid can be exposed in the well. All parts and components in the system shall be compatible with the selected fluid. Reference should be made to annex A.

5.1.3.2 Cleanliness

The hydraulic fluid-wetted portion of the control system shall be prepared to a cleanliness level as defined in NAS 1638 or ISO 4406. The selected level shall be clearly identified in the manufacturer's written system specification and shall be demonstrated during the testing of the system.

Typical cleanliness levels are NAS Class 6 (ISO 15/12) or NAS Class 8 (ISO 17/14).

All control fluids introduced into the system shall meet the selected cleanliness requirements. Provisions shall be made to maintain cleanliness (e.g. filters) and to take samples.

Methods for circulation and flushing out seawater and solid particle contamination should be considered for the lifetime of the system.

The subsea hydraulic system should be designed to tolerate some contamination by seawater and solid particles. Vulnerable parts with very low fluid consumption (e.g. directional control valve pilot stages) shall be protected by filters or suitable screens.

5.1.3.3 Overpressure protection

System pressure-relief (safety) valve settings shall not exceed design pressure (rated working pressure).

The setting of the primary relieving device shall not be greater than the design pressure.

5.1.3.4 Vibration and pressure pulses

Design of the hydraulic system should consider high-pressure pulses and vibration on lines, valves and couplers. This shall include external sources (e.g. chokes).

5.1.4 Electrical system

The electrical power for the surface control equipment of an electrohydraulic control system, its associated interfaces, and the subsea equipment should be supplied from an uninterruptible power supply (UPS) to ensure continued operation in the absence of primary power for a minimum period of 30 min.

The UPS system should include isolation and regulation to ensure a clean constant supply of electrical power.

In order to minimize the number of conductors in the control umbilical, signal multiplexing and combining power and signal on the same pair of wires should be considered.

For subsea assemblies, electrical components of high reliability shall be used. Components shall be procured to industrial grade or better wherever possible.

Topsides equipment should be procured to industrial grade or better wherever possible. The equipment should be designed to facilitate modular replacement.

5.1.5 Redundancy

The level of redundancy will depend on the actual field development and reliability of equipment used. Generally the following guidelines are applicable.

Redundancy is most important when component replacement is difficult, or when significant production availability or operating capability is lost through single-component failure.

When redundant components are used, the reliability of the method for switching from the primary to the backup component should be evaluated.

The subsea electrical distribution system design should be redundant or include spares that can be configured to replace failed circuits.

The subsea hydraulic distribution system should be redundant or should include spares that can be configured to replace failed lines in either LP or HP service.

The subsea chemical distribution system and supply line should have redundancy consistent with the importance of the treatment chemical.

The number of spares in the umbilical should be specified based on the redundancy needed and relative impact on umbilical design (e.g. spares which fill space in a given cross-section add less cost than those which lead to a diameter increase).

Redundancy of instruments should be based on criticality and retrievability of the sensors.

The level of redundancy throughout the system will influence complexity and reliability. An analysis of the expected benefit from redundancy should be performed for all critical parts of the system.

5.1.6 Reliability

Reliability of the subsea control system should be optimized to result in maximum benefit. The use of high-reliability components should be compared against redundant components of more standard quality. Special consideration should be given to the reliability of components that are difficult to repair or replace.

Minimum reliability, mean time to repair and availability targets for subsea equipment should be stated for each project.

Critical sensor systems located on subsea trees or manifolds should have component reliability, or reliability obtained by redundancy, that is optimum relative to the need for the sensor data and the risk of subsea intervention. This is most important for sensors that trigger safety or shut down responses.

Reliability figures for all critical components and assemblies should be documented and justified by calculations, tests or an accepted industry data base.

5.2 Functional requirements

5.2.1 General performance requirements

Control system equipment built to this part of ISO 13628 should perform in a manner which is efficient, safe and protects the environment. Performance requirements for the control system as a whole should

- provide for individual or multiple operation of all remotely controlled subsea valves;
- provide sufficient data-readback information to operate the system safely and to react promptly to conditions requiring emergency shut-down (ESD);
- provide ESD capability that ensures the subsea system will shut-in production safely within the time specified by this part of ISO 13628 or by applicable regulatory authorities for all production scenarios, including simultaneous drilling, completion and workover operations.

5.2.2 Operating pressure

The control system shall be capable of delivering pressure sufficient to open subsea valves under the worst case set by valve manufacturer specifications. The minimum operating pressure shall be at least 10 % greater than the minimum opening pressure specified by the manufacturer for the worst-case condition. The decrease in operating pressure while a subsea valve is opening should not reach a value at which any of the other opened subsea valves begin to close.

5.2.3 Fail-safe philosophy

Subsea control systems shall be designed to render the production system to a fail-safe status upon loss of hydraulic power. Typically this is achieved by closure of a USV. Such closure can be achieved by either de-energization of electrical circuits or depressurizing of the hydraulic power supply. If the system contains directional control valves, they should be designed to close at a pressure higher than the subsea valves to minimize the

closure time of the subsea valves. If an all-electric-type control system is used, the system shall be fail-safe upon loss of electric power.

There should be no subsea control system component failure which will prevent the fail-safe closure of the SCSSV and the designated USV.

5.2.4 Response time

5.2.4.1 Valve closing

5.2.4.1.1 General

The primary constraint on control system response time is set by the need to execute promptly a shut-in of the subsea production upon command from the surface facilities. Such shut-ins are associated with eliminating a supply of combustible materials to the surface facilities, and/or reducing pollution of the environment in the event of a loss in containment integrity of the subsea system. Where closure of a valve is the means by which a downstream segment of piping is protected against overpressure, the response time shall be less than that which would allow the segment to be overpressured due to continued flow.

5.2.4.1.2 Requirement for contingency closure control mode

All control systems for which malfunction or failure of the primary control system will not necessarily cause the USVs to return to a fail-safe position, and, as such, can potentially allow flow to continue indefinitely, shall be equipped with a contingency closure control mode that can execute the necessary valve closures. If such contingency closure control mode involves bleeding off supply hydraulic pressure, the system shall reset in such a manner to prevent the automatic reopening of the closed valves when supply pressure is restored. The SCSSVs should be the last valves to close.

5.2.4.1.3 USV closing-time requirement using primary control mode

Upon receipt of a commanded closure, the subsea control system shall complete a closure of the designated USV using the primary control mode with a response time not to exceed 10 min. For multiple-well installations, the USVs on all flowing wells shall close within the designated 10 min time allowance.

5.2.4.1.4 USV closing-time requirement using contingency closure control mode

In the event that a subsea control system failure has necessitated a valve closing operation in a contingency closure control mode that is not in compliance with the 10 min closure-time limitation, the contingency closure control mode shall still execute the closure in a manner that meets the general requirements stated in 5.2.4.1.1.

5.2.4.1.5 Shift time limitation

The shift time portion of the overall response time for a single USV shall be limited to 3 min or less. This shift time limitation may be waived if flow in the subsea well associated with the respective USV has already been stopped by other valves or flow control devices that have previously been closed or that are simultaneously responding to the commanded closure.

5.2.4.1.6 Failure of boost system

Failure of the boost system shall not prevent the fail-safe closure of the USV under the loss of hydraulic pressure.

5.2.4.1.7 Relationship of surface and riser safety system response requirements to subsea control system response requirements

The response time of an SSV or riser valve following a commanded closure is established by regional regulations for the protection of the surface facility. The response time of these surface and riser safety devices is independent

of the requirements for subsea control system response. As such, this is not a part of this performance specification, but should be considered in a total system safety evaluation.

5.2.4.2 Valve opening

If equalization of pressure across the USV is not possible prior to opening, the USV shall be constrained to a shift time not to exceed 3 min. This requirement may be waived if there is another valve or flow-control device in the flowstream that can be closed such that the USV can be opened without encountering a prolonged differential pressure.

5.2.4.3 Demonstration of response time

One of the following four methods shall be used to demonstrate that the response time projected for the control system meets the objectives (prior to installation):

- a) run a control system simulation using perfectly elastic umbilical volumetric data and valve operator data, typically available from the respective manufacturers. This approach will typically result in the most conservative calculated response times;
- b) run a control system simulation using viscoelastic umbilical volumetric data, based on measurements made on at least 30 m (100 ft) of sample material of pressure and volume versus time. Combine with manufacturer's valve operator data;
- c) run a control system simulation using a previously calibrated model for an identical umbilical material, allowing for new variables such as CPL, operating pressure, and end device characteristics;
- d) measure response time directly using actual equipment.

5.2.5 Functional considerations

5.2.5.1 Leak tests and diagnostics

The subsea control system shall be capable of performing required diagnostics and regulatory-mandated leak tests on the subsea equipment. Such leak tests will include leak-testing of the SCSSV and leak-testing of the designated USV. In the event of leak-test failure, the control system should provide capability to facilitate diagnostics of the failure conditions.

5.2.5.2 Production pressure monitoring

The subsea control system should accommodate the monitoring of pressure in the tree production bore.

5.2.5.3 Annulus pressure monitoring

The subsea control system should accommodate the monitoring of pressure in the annulus between the production tubing and production casing.

5.2.5.4 SCSSV seal failure

Backflow of well fluids into the subsea control system due to seal failure in the SCSSV shall not impair the ability of the subsea control system to execute the fail-safe closure of the USV.

5.2.5.5 Actuation indication

The production control system shall provide a surface indication of the actuation of a selected hydraulic function. As appropriate to the hardware, such indication may be through use of visual flow indicators, pressure transducers, pressure gauges, position-indication sensors, flow sensors or pressure switches.

5.2.5.6 Protection of SCSSV

Under commanded-closure conditions, the design of the production control system should protect the SCSSV from slam or creep closure on a flowing stream, through operational procedure or introduction of a delay following the closure of the valves downstream of the SCSSV. Any such provisions should not impact the ability of the subsea production control system to close the SCSSV in ESD conditions.

5.2.5.7 Safety isolation during workover

The production control system shall be capable of being positively disabled from operation of tree control functions while a workover control system is in use on that tree.

5.2.5.8 Control fluid venting and leakage

External venting and leakage of control fluids shall not exceed local regulatory requirements. Internal leakage shall not exceed control component manufacturer's written specifications.

5.2.5.9 Load capability

Product designs shall be capable of sustaining rated loads without degradation, exceedance of allowable stresses or impairment of other performance requirements.

5.3 Design requirements**5.3.1 General design requirements**

The design shall provide for reliable and safe operation of the subsea equipment. The design shall also provide means for a safe shutdown on failures of the equipment or on loss of control from the remote control point.

Vulnerable areas for connection such as electrical couplers, hydraulic couplers and hubs shall be furnished with necessary protection equipment in order to protect the equipment when being unmated and in service.

Early in the project, the manufacturer and purchaser should clearly establish utility interface requirements.

5.3.2 Design methods**5.3.2.1 Pressure-containing vessels**

All pressure-containing vessels used for applications in excess of 0,1 MPa (15 psi) shall meet the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, or BS 7201-1 and BS 7201-2, or the applicable code or regulation which applies.

5.3.2.2 Electrical devices

All electrically driven motors, motor starters and all other electrical devices shall conform to the requirements of the appropriate approved electrical code for the equipment location.

5.3.2.3 Interconnection piping

Vibration-induced fatigue failure of the subsea piping system shall be considered. All tubing runs shall be installed with sufficient and appropriate clamps. Interconnecting piping shall meet the requirement of ANSI/ASME B 31.3.

5.3.3 Design analysis

The following analyses shall be performed during detailed design of the production control system for the purpose of establishing system (performance characteristics, requirements, etc.), and only when they are relevant to the type of control system:

- a hydraulic system operation and response time analysis;
- an electrical power distribution analysis;
- an electrical communication analysis.

Hydraulic system analyses should ensure that the hydraulic system performance in the various modes of operation is safe and operationally acceptable. The areas of hydraulic performance that should be addressed are the following:

- the time to prime the hydraulic system from a depressurized state;
- opening and closing response times of the process valves under conditions of minimum and maximum process pressure;
- the time for the pressure to recover following a process valve opening;
- the time to carry out a sequence of valve openings, such as the opening of a tree (neglecting choke valve operation);
- the stability of opened control and process valves to pressure transients caused by operation of other control and process valves (sympathetic control valve delatching, process valve partial closing, etc.);
- response time to close process valves in the event of a common close command, such as an ESD vent-down at the surface, venting off hydraulic control valves via supply lines;
- peak return-line pressure transients that may cause partial opening of closed process valves and damage to hydraulic components with limited return-pressure capability;
- the impact that failure of subsea accumulation and return-line boost pressure systems (assist closing systems) has upon the safe operation and closure of the process valves;
- the extent of control fluid total loss rate;
- hydrostatic conditions which could give rise to line collapse, sea water ingress, etc., caused by differential hydrostatic pressures resulting from differential heads and differential fluid densities;
- chemical system flow analysis should establish that a specified supply of well-treatment, start-up and shut-down chemicals is achieved under the range of wellhead flowing and shut-in process pressures.

The electrical power distribution analysis should establish the following:

- voltage at SEM for maximum and minimum SEM power loads;
- voltages at SEM at maximum and minimum numbers of SCM on the subsea electrical distribution line;
- voltages at SEM at minimum and maximum umbilical lengths;
- voltages at SEM at redundant and non-redundant power distribution (where applicable);
- voltages at SEM at cable parameters for dry and wet umbilical insulations if applicable;

- SEM component stress levels should be maintained within acceptable limits for normal and degraded modes of operation;
- minimum and maximum subsea power requirements;
- maximum current load.

The electrical communication analysis should establish the following:

- signal voltage in SEM and topside at minimum and maximum umbilical lengths;
- signal voltage in SEM and topside at maximum and minimum numbers of SCM on the subsea electrical distribution;
- interference from the subsea and topside power supplies in the signal frequency band;
- power frequency components in subsea and topside receivers due to umbilical cross-talk;
- signal voltage in SEM and topside at cable parameters for dry and wet umbilical insulations;
- BER and signal-to-noise in SEM and topside at minimum and maximum umbilical lengths;
- dynamic bit detection margin (eye pattern) in SEM and topside at minimum and maximum numbers of SCM on the subsea electrical distribution.

The following analyses should also be considered during detailed design:

- reliability, availability and maintainability analysis;
- FMECA;
- structural (static) analysis.

A simulation of the control system shall be created, and analysis made, such that the required opening and closing time requirements for the system may be verified. The response time of the control system shall be simulated in the absence of any bore-pressure assistance to the closure of the valve. The simulation shall properly account for response-time degradation due to use of high density gradient and high viscosity control fluids. Effects of a boost-pressure supply acting to assist the prompt closure of the valve operator may be included in the analysis; however, if the analysis depends on boost pressure to meet the requirements for the primary control mode, then if the boost system fails and boost pressure is lost, the system is not in compliance with this part of ISO 13628.

5.3.4 Design review

Control system design documentation shall be reviewed and verified by a qualified individual other than the individual who created the original design.

5.3.5 Control system design documentation

5.3.5.1 General

The control system design documentation should be maintained for a period of one year following abandonment of the subsea system.

5.3.5.2 Manufacturer's engineering data records

Engineering data records shall include required analyses listed in 5.3.3, other design analyses performed by the manufacturer and FAT procedures and records.

5.3.5.3 Installation, operating and maintenance manual

The installation, operating and maintenance manual should incorporate information on the following.

a) Installation procedures

The manufacturer shall write procedures which prepare the equipment for installation and commissioning in a manner which is effective and minimizes the risk of damage. The procedures shall cover the testing of control modules, control umbilicals and connections just prior to, during, and immediately following installation.

b) Operating procedures

Operating procedures shall be prepared for use by field personnel and service technicians, and should include adequate schematics and block diagrams. They shall define the following:

- 1) general description and features;

This portion shall describe the function of each major component of the system and define its capabilities and interfaces with other components.

- 2) general function and shutdown philosophy;

This information shall include block diagrams, panel logic and schematics that represent the control system. Sensor-initiated inputs and outputs should be included. The interface between the operating circuits on host facilities, instrument and emergency utilities such as air, water and electricity shall be included. The nature and purpose of all signals to and from the surface-facility fire and safety systems, motor control centre, and supervisory controls shall be identified. The approximate time required for shutdown actions to occur should be noted.

- 3) system checkout.

The system checkout shall be based on FAT and integrated tests described in clause 11. The purpose of the procedure is to verify the correct function of all shutdown inputs and safety devices, and to verify the correct setting of all control system adjustments. The procedure should be written to allow testing to the fullest possible extent without interrupting well production. Where mechanical or electrical overrides are required, their active status shall be clearly indicated. A document should be prepared that collects all the set points and allowable ranges for the process variables. This document can be updated as needed and attached to the procedures.

The system checkout shall include a test and documentation of the safety shutdown system.

c) Maintenance procedures

The manufacturer shall furnish suitable instructions concerning field assembly and maintenance of the equipment. Instructions for periodic checks and/or replacement of control system surface equipment should be included.

5.3.5.4 Manufacturer's data record book

The manufacturer shall collect data record information for the supplied equipment, including subcontractor supplied equipment as required by the customer. The following should be included:

- general assembly drawings with list of materials;
- electrical schematics;
- hydraulic schematics;
- interface drawings;

- material certificates with appropriate test reports;
- component data sheets, including performance specifications;
- load test reports;
- welding procedures;
- certificates of conformance.

6 Surface equipment

6.1 General

The purpose of this part of ISO 13628 is to set forth additional requirements that are specific to the surface-installed equipment that is part of a subsea production control system. All such surface-installed equipment shall be designed to perform in accordance with these additional requirements.

6.2 General requirements

All host facility-based production control system equipment shall be built and documented according to specifications applicable for the host facility where the equipment will be located. Relevant standards and installation specifications shall be a part of the contractual documentation for the specific project.

6.3 Functional requirements

The functional requirements for the surface equipment typically include all or some of the following:

- supply and conditioning of electric and/or hydraulic power for the subsea equipment;
- communication with the subsea equipment;
- control and monitoring of subsea equipment;
- communication with the host process equipment;
- ESD/PSD;
- chemical injection;
- recording and storing data;
- communication with drilling rig for rig-initiated shutdown.

6.4 Design requirements

6.4.1 Master control station (MCS)

The MCS is the unit that controls and monitors the subsea production system. It can range in complexity from a manual hydraulic panel to an automated computer system.

The MCS shall be designed to include the following capabilities to:

- operate safely in the sited environment;
- respond to the host safety systems;

- provide effective operational interface;
- display and warn of out-of-limit (fault) conditions;
- display operating status;
- provide a shutdown capability.

The MCS may optionally provide the following additional capabilities:

- sequenced operation of valves;
- software interlocks;
- process-control interconnections with host facility;
- data collection and storage;
- remote communication to offsite control centre;
- interface with remote shut-in system on drilling or workover vessel;
- rate of change of pressure analogue(s) for rudimentary leak detection;
- hydrate detection by pressure/temperature (P/T) curve comparison;
- flowrate control by detection of choke position and pressure sensors up- and downstream of choke.

The application software should be simple. Startup operations after shutdown situations should be under the complete control of the operator, having the appropriate level of access, with a minimum number of inherent interlocks.

The MCS or DCS shall provide the operator interface and automated functions for the production control system, as appropriate to the selected configuration.

The MCS should be installed in a safe area.

6.4.2 Electrical power unit (EPU)

For electrohydraulic systems, an EPU may be installed as a separate system, or may be combined with the modem unit or the MCS.

The EPU, which is normally powered from the UPS, supplies electrical power to the subsea wells via the control umbilical.

The EPU should include safety devices which ensure that, under electrical fault conditions, the equipment and personnel are protected from electrical hazard.

If redundant power conductors are provided in the umbilical, the output voltage of the EPU should be individually adjustable for each umbilical power pair. Each pair should be galvanically segregated from the rest of the system. The design shall allow for individual pair connection/disconnection.

The design should allow easy access to individual power systems for maintenance and repair.

The following EPU parameters should be monitored by the MCS or DCS:

- input voltage;
- input current;
- umbilical voltages/currents;
- line insulation (optional).

The EPU shall be designed to operate safely in the sited environment.

6.4.3 Modem unit

Modems, filters and isolation transformers are typically included in the unit.

The modem unit may either be connected to a MCS, dedicated to the production control system or, alternatively, may interface directly with the host facility DCS via a communication interface unit (part of the DCS).

In either configuration, the communications protocol shall provide a means of ensuring the security of the data being transferred.

The surface-to-surface communications link should employ an industry standard serial link.

The following modem unit parameters should be monitored by the MCS or DCS:

- input voltage;
- input current;
- umbilical voltages/currents;
- line insulation (optional).

The modem unit shall be designed to operate safely in the sited environment.

6.4.4 Uninterruptible power supply (UPS) (optional)

The UPS shall supply electrical power to the EPU, modem unit and the MCS.

Only critical components which are necessary for operation of the production control system should be powered from the UPS. HPU electrical pumps should not be regarded as critical. Each UPS shall have a capacity of 100 % of the total load, and should be designed to include future planned expansion of the production control system.

The UPS battery back up shall be capable of running the system for at least 30 min after loss of host-facility power.

The following parameters should be monitored by the MCS:

- input voltage;
- input current;
- UPS output frequency;
- UPS bypass mode;
- UPS on-line mode;
- UPS failure.

UPS output power shall be conditioned to a range of

- VAC $\pm 5\%$;
- (50 ± 1) Hz or (60 ± 1) Hz;
- maximum 5 % total harmonic distortion;

or according to manufacturer's written specifications.

The UPS shall be designed to operate safely in the sited environment.

6.4.5 Hydraulic power unit (HPU)

6.4.5.1 General

The HPU shall supply filtered and regulated hydraulic fluid to the subsea installations.

The HPU should contain provisions for obtaining and maintaining the specified cleanliness requirement, such as drainage or circulation and filtration capability should the fluid become contaminated. Output fluid from the HPU shall satisfy a cleanliness requirement according to manufacturer's written specification, as defined in ISO 4406 or NAS 1638-64.

Redundancy should be provided on key components such as pumps and filters.

The same type (style) of fitting should be used for each pressure class throughout the system.

The HPU shall be designed to operate safely in the sited environment.

The design should allow maintainable components within the unit to be isolated for servicing or replacement without interrupting the normal operation.

The layout of the HPU should allow easy and safe access to all components for maintenance and repair.

6.4.5.2 Accumulators

The accumulators shall comply with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 and BS 7201-1 and BS 7201-2, or the applicable code or regulation which applies.

All surface-located high pressure accumulator systems shall have a pressure-relieving device to prevent over-pressurization.

As a minimum, the accumulator volume shall allow all valves on one subsea tree to be operated without requiring recharge of the accumulator(s).

Nitrogen precharge pressure should be significantly lower than normal hydraulic operating pressure to maximize stored energy in case of a supply pump failure.

Accumulator capacity shall be in accordance with the following criteria:

- to maintain sufficient subsea pressure to keep process valves open, should a failure of the HPU pumps occur, for a period of 12 h neglecting all other methods of fluid energy storage such as umbilical line expansion and subsea accumulation;
- to prevent short pump-run cycles which would be detrimental to the life and reliability of the pumps;
- a minimum HPU accumulation of 2 l (0,07 ft³) off 37 l (1,3 ft³) accumulators for the common low-pressure header, and 2 l (0,07 ft³) off 10 l (0,35 ft³) accumulators for the common high-pressure header.

Failure of one accumulator (when more than one is used) shall not impair more than 50 % of the surface system capacity. Under such failure conditions, available pressure shall not drop below the minimum level required to maintain system operations.

Visual indication of low nitrogen pressure should be considered.

6.4.5.3 Pumps

Control devices shall be incorporated to shut off pumps upon occurrence of low fluid level in the supply reservoir.

Control devices shall be incorporated to cycle pump(s) on and off to maintain pressure within operating limits.

Pumps shall be fitted with isolation valves, a pressure-relief valve and a non-return valve at each pump discharge line.

The pressure-relieving device shall be installed at the output of all high-pressure pumps upstream of any blocking or isolation valves.

6.4.5.4 Reservoirs

The main reservoir should have a minimum capacity of 1,5 times the fluid required to charge the system including accumulators. However if the main reservoir is 2 000 l (70,6 ft³) or above, a spare capacity of 750 l (26,5 ft³) is acceptable. The reservoir(s) should be sized, or alternative disposal means provided, to accommodate drainage of all fluid in case of a total system depressurization (accumulators, valves and umbilicals).

The hydraulic fluid reservoirs should be equipped with visual level indicators. Calibration of level transmitters should be possible without draining of tanks.

The reservoir(s) should be fitted with an inspection/access hatch and tank-fill breather or pressure-relief mechanism.

The hydraulic fluid tanks should be designed to minimize build-up of contamination and facilitate flushing.

Fluid reservoirs shall be made from non-corrosive material, and should be equipped with circulating pumps and filters. Sample points shall be located no higher than pump suction ports.

Consideration should be given to the use of two fluid reservoirs, one to be used for filling of new fluid, return fluid from subsea (if implemented) and return fluid from depressurization of the system, the other to be used for supplying clean fluid to the subsea system.

6.4.5.5 Control and monitoring

The HPU is typically controlled locally, but may be controlled and monitored from the MCS.

If primary control is from the MCS, provision shall be made for local control. A local control panel shall be fitted with all the necessary gauges, switches, valving and indicators to enable operator control and monitoring. Provision for setting pumps in manual mode shall be provided.

If the facilities provide for ESD capability, then the HPU and control panel, if applicable, shall incorporate devices to bleed off system-control pressure upon execution of ESD.

Should an ESD which requires hydraulic-pressure bleedoff occur, inadvertent reset of any HPU/ESD circuit shall be prevented while ESD conditions are still present.

The HPU parameters monitored may include the following:

- non-regulated supply pressure(s);
- regulated supply pressure(s);
- fluid levels;
- pump status;
- delivery flowrates;
- return flow;
- filter status;
- ESD indicators.

Monitoring of filter clogging should be provided.

6.4.6 Chemical injection unit (CIU)

6.4.6.1 General

This subclause addresses surface facilities for the supply of well-treatment chemicals to the subsea production system via the production control system. Excluded from these requirements are storage and handling of the chemicals.

6.4.6.2 General requirements

The CIU shall supply filtered and regulated chemical injection fluid(s) to the subsea installation. The CIU supply pressure is typically sufficient to deliver fluid into the wellbore, subsea tree, or other delivery points at a pressure in excess of the shut-in pressure.

The CIU should contain provisions for obtaining and maintaining the specified cleanliness requirement. Output fluid from the CIU shall satisfy a cleanliness requirement according to manufacturer's written specification, as defined in ISO 4406 or NAS 1638-64.

The use of redundancy should be considered for critical components such as pumps and filters.

Any accumulators used in the CIU shall comply with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, and BS 7201-1 and BS 7201-2, or the applicable code or regulation which applies.

The CIU shall be designed to operate safely in the sited environment. Special consideration shall be given to toxicity and flammability typical of the injection chemicals.

The design should allow maintainable components within the unit to be isolated for servicing or replacement without interrupting the normal operation.

The layout of the CIU should allow easy and safe access to all components for maintenance and repair.

6.4.6.3 Pumps

Control devices shall be incorporated to shut off pumps upon occurrence of low fluid level in the supply reservoir.

Pumps shall be fitted with isolation valves, a pressure-relief valve and a non-return valve at each pump discharge line.

The pressure-relief device shall be installed at the output of all high-pressure pumps upstream of any blocking or isolation valves.

6.4.6.4 Reservoirs

The chemical injection fluid reservoirs, if integral with the CIU, shall be equipped with visual level indicators. Calibration of level transmitters, if supplied, should be possible without draining the reservoir.

The chemical injection fluid reservoirs, if integral with the CIU, should be designed to minimize build-up of contamination and facilitate flushing.

To prevent undesirable contact between air and chemicals, a bladder tank or a blanket protection system should be considered.

Fluid reservoirs shall be made from non-corrosive material. Sample points shall be located no higher than pump suction ports.

6.4.6.5 Control and monitoring

The CIU is typically controlled locally, but may be controlled and monitored from the MCS.

If primary control is from the MCS, provision shall be made for local control. A local control panel shall be fitted with all the necessary gauges, switches, valving and indicators to enable operator control and monitoring. Provision for setting pumps in manual mode shall be provided.

The CIU and control panel shall incorporate devices to terminate injection upon execution of an ESD/PSD.

The CIU parameters monitored may include

- non-regulated supply pressure(s);
- regulated supply pressure(s);
- fluid levels;
- pump status;
- return flow (if applicable);
- filter status;
- delivery flowrate.

Monitoring of filter clogging should be provided.

6.4.6.6 Fluid compatibility of components and materials

All surfaces and seal materials in contact with the chemical injection fluids shall be verified to be compatible.

Some treatment chemicals require anaerobic conditions to prevent oxidation. Bladder tanks or variable volume tanks should be used when such chemicals are used.

6.4.7 Hydraulic control fluid

6.4.7.1 General

The fluid in a subsea control system is intended to transmit both signals and power from one point in the system to another. The fluid may be either oil-based or water-based.

The fluid is expected to remain in some parts of the system for the life of the project. Since most projects have a life of 10 years to 20 years the long-term stability of the fluid is extremely important.

Reference shall be made to annex C for detailed information on control fluid specifications and testing.

6.4.7.2 Design

Any water-based hydraulic fluid shall be an aqueous solution (not emulsion) of its components. The fluid shall retain its properties and remain a homogeneous solution, within the temperature range, from manufacture through field-life operation.

Any oil-based hydraulic fluid shall be a homogeneous miscible solution of its components. It shall retain its properties and remain stable as a solution, within the temperature range, from manufacture through field-life operation.

7 Subsea equipment

7.1 General

The purpose of this clause is to set forth additional requirements that are specific to the subsea-installed equipment that is part of a subsea production control system. All such subsea-installed equipment shall be designed to perform in accordance with these additional requirements.

7.2 General requirements

Subsea equipment can range in complexity from a simple umbilical interface (direct hydraulic control system) to full electrohydraulic control with multiple-well capability. The subsea-installed equipment shall be designed such that it is safe to install and operate. Running, landing and retrieving shall minimize the hazard to personnel, equipment or environment. Devices requiring diver makeup shall be designed to minimize the possibility of diver injury resulting from sharp corners or edges, and should consider electric shock or stored-energy release. Ease of installation and maintenance should be considered.

All subsea retrievable items of the same type shall be fully interchangeable. The design should consider shocks, vibrations and pressure/temperature variations experienced during transportation, including air and sea freight, and offshore operations during all seasons.

7.3 Functional requirements

The functional requirements for subsea equipment typically include all or some of the following:

- communication with the surface MCS;
- processing and execution of commands from MCS;
- monitoring and transmitting of sensor data;
- monitoring and transmitting of diagnostic data;

- execution of surface or subsea commands under ESD conditions;
- optional monitoring and distribution of well-treatment chemicals in response to surface commands.

7.4 Design requirements

7.4.1 Subsea hydraulic systems

7.4.1.1 Subsea hydraulic distribution system

The subsea hydraulic distribution system distributes hydraulic power from the umbilical termination head to each well.

Consideration should be given to preventing pressure being trapped in critical tree-valve operators or other fail-closed safety systems in the event of inadvertent separation of hydraulic interfaces.

Design of template/manifold hydraulic distribution systems should consider having ROV-reconfigurable connector plates or diver-operated isolation devices, so that leakage can be isolated from the system. A subsea hydraulic distribution module is an approach that allows retrieval, replumbing and replacement to isolate failed lines and activate spares, if available.

Design of hydraulic systems should consider single-point failures, which may be addressed through separation of physical routes and hydraulic isolation of redundant supplies.

7.4.1.2 Multifunction connections

Multifunction connections should be polarized or keyed such that only one possible orientational arrangement is possible. Labelling for proper identification should be considered.

7.4.1.3 Pipe, tubing and hoses

All pipe/tubing shall have a minimum 6 mm (1/4 in) nominal outside diameter.

All pipe/tubing shall be supported and protected to minimize damage during testing, installation/removal and normal operation/ maintenance of the system.

Allowable stresses in pipe/tubing shall be in conformance with ANSI/ASME B31.3.

Design should take into account:

- allowable stresses at working pressure;
- allowable stresses at test pressure;
- external loading;
- collapse;
- manufacturing tolerances;
- fluid compatibility;
- flowrate;
- corrosion/erosion;
- temperature range;

- connection requirement;
- vibration from external sources.

All hose assemblies shall meet the criteria described in the hose sections of ISO 13628-5.

7.4.1.4 Sea chest compensation chamber

The capacity of each sea chest compensation chamber tied to the spring/boost side of the subsea-valve operators should be at least 125 % of the total swept volume for simultaneous actuation of all operators tied to the chamber. The use of bypass check valves should be considered to prevent chest damage.

7.4.1.5 Subsea accumulators

Consideration should be given to designing subsea accumulators to comply with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, and BS 7201-1 and BS 7201-2. However, if not designed to comply with these standards, personnel safety during land testing and other above-water operations shall not be compromised.

Accumulator selection should consider minimizing gas precharge loss due to diffusion or leakage.

The accumulator system design shall consider loss of accumulator efficiency with increasing water depth.

Subsea accumulators may be mounted internally or externally to the SCM. If mounted external to the SCM, accumulator shells should be painted to inhibit the absorption of hydrogen evolved from the cathodic protection reaction.

7.4.2 Chemical injection systems

7.4.2.1 Subsea chemical-injection distribution system

The subsea chemical-injection distribution system distributes chemicals from the umbilical termination head to each well or manifold header. In addition, it may provide the means for supplying and bleeding fluid used in pressure testing and in equalization of pressure differential across flow-control devices. It may also support the removal of fluid from the well annulus for leak detection and during the normal warm-up of a well.

Depending on the well-treatment fluid, the flow capacity of the chemical-injection distribution system may be substantially greater than that of the hydraulic distribution system. Additionally, the pressure rating of the components is typically higher (compatible with wellhead system rating) and corrosivity of the fluids conveyed is typically more severe.

Design of template/manifold chemical-injection distribution systems should consider having ROV- or diver-operated isolation devices, so that leakage can be isolated from the system. A subsea hydraulic distribution module may include chemical-injection lines, allowing for retrieval, replumbing and replacement to isolate failed lines and activate spares, if available.

Design of chemical injection systems should consider single-point failures, which may be addressed through separation of physical routes and flow isolation of redundant supplies.

7.4.2.2 Pipe, tubing and hoses

All pipe/tubing shall have a minimum 6 mm (1/4 in) nominal outside diameter.

All pipe/tubing shall be supported and protected to minimize damage during testing, installation/removal and normal operation/maintenance of the system.

Allowable stresses in pipe/tubing shall be in conformance with ANSI/ASME B31.3.

Design shall take into account:

- allowable stresses at working pressure;
- allowable stresses at test pressure;
- external loading;
- collapse;
- manufacturing tolerances;
- fluid compatibility (injection, annulus and wellbore fluids);
- flowrate;
- corrosion/erosion;
- temperature range.

All hose assemblies shall meet the applicable criteria described in the hose sections of ISO 13628-5.

7.4.2.3 Special considerations

The design shall consider the following:

- friction and wear increase in methanol service;
- seal material compatibility with injected and produced fluids;
- corrosivity of injected and produced fluids;
- permeation of fluids through hose liner materials (typically low-mass constituents);
- selection of control valves and other flow control devices;
- metal-to-metal seals and methanol. An additional resilient elastomer seal should be included as back-up. This is due to problems resulting from cavitation and flow-induced material degradation (erosion wear).

Where diffusion of chemicals through hose materials is anticipated, the system design should ensure that the diffused chemicals do not contaminate the hydraulic control fluid through either leakage or secondary diffusion.

7.4.3 Subsea electrical systems

7.4.3.1 Subsea electrical distribution system

The subsea electrical distribution system distributes electrical power and signals from the umbilical termination head to each well.

The number of electrical connectors in series shall be kept to a minimum. Redundant routing should, if possible, follow different paths.

In order to minimize electrical stresses on conductive connectors, voltage levels should be kept as low as practical.

Manifold electrical distribution cabling and jumper cables from umbilical termination to the SCM should be repairable or reconfigurable by the use of ROV or diver.

If one electrical line supplies more than two SEMs, consideration should be given to the ability to isolate a faulty SEM.

Connection of electrical distribution cabling and electrical jumpers should be made by ROV or diver using simple tools, with minimum implications on rig/vessel time.

A minimum of two barriers should be provided between sea water and the conductor. Barriers should be designed for operation in seawater.

If an oil-filled system is selected, the cable assemblies should be designed and installed such that any seawater entering the dielectric fluid moves away from the end terminations by gravity. The cables should be installed into pressure-compensated fluid-filled lines. The fluid shall be of a dielectric type.

All the materials utilized in the subsea electrical systems shall be compatible with both seawater and, if applicable, the dielectric fluid selected. Qualification testing of new materials to prove their compatibility shall be performed.

7.4.3.2 Prevention of electrical shock

All subsea systems to be serviced by divers shall be designed to protect divers from electrical shock hazards.

7.4.4 Subsea control module (SCM)

The subsea control equipment for piloted or sequential hydraulic or electrohydraulic systems should be packaged in retrievable units/housings. Depending on the system type, the SCM may include some or all of the following:

- electrohydraulic or hydraulic piloted DCV and other valves (e.g. check valves and shuttle valves);
- feed-through connectors (electrical and hydraulic);
- hydraulic manifolds and tubing;
- internal sensors and transmitters;
- filters/strainers;
- accumulators;
- pressure compensator;
- pressure intensifiers;
- pressure reducers;
- chemical-injection regulation valves;
- SEMs.

To maximize production uptime in multiwell systems, it is desirable that installation and retrieval of one SCM should not adversely affect the operation of any other SCM.

All active electronic circuits should be in enclosures filled with nitrogen gas at nominal 1 atm pressure designed for full external pressure conditions.

Electrical elements of subsea electrohydraulic components shall be mounted in a dielectric-fluid-filled and pressure-compensated compartment of the SCM. The SCM design shall be optimized to limit the possibility of draining the dielectric fluid when installed subsea by making any necessary penetrations to the module at as low a level as possible (water usually displaces dielectric fluid until the level of the leak is reached). Although protected

from the environment, all interconnecting cables and connectors shall be suitable for direct exposure to the subsea environment, thus providing a double barrier against seawater-induced malfunctions

Leakage in the hydraulic part of the system shall not affect the integrity of the electric system.

In order to minimize the electrical power consumption, solenoid-operated valves should be pulse-operated and hydraulically latched, with the exception of an electrically held fail-safe valve, if used.

All hydraulic coupler interfaces shall be made up with couplers which seal upon disconnection, unless safety considerations stated in this part of ISO 13628 are compromised. The design shall minimize ingress of external fluid during running and make-up operation. The coupler half containing the seal shall be located in the retrievable equipment.

7.4.5 Subsea electronic module (SEM)

7.4.5.1 SEM hardware

The SEM hardware should be based on the use of one or more microprocessors and power supply units in order to obtain an acceptable level of reliability and flexibility in the design.

The SEM shall be protected against water intrusion. The design should include two separate and testable barriers.

The SEM should be designed with minimum 25 % spare memory capacity. The SEM should have 20 % spare capacity for other capabilities.

Current limitation shall be provided for all SEM outputs and sensor excitation supplies.

The SEM interface to sensors and directional control valves should be limited to the minimum practical number of signal types and formats. International Standards should be adopted wherever possible.

Description of signals shall be specified for each application by reference to International Standards, or by detailed description of signal type.

Due consideration should be given to standardizing SEMs to enable interchangeability as an alternative to optimizing for specific applications.

Consideration should be given to the inclusion of signal processing of critical measurements in the SEM, if required.

7.4.5.2 SEM software

The SEM software should be structured in functional tasks or modules, which should be designed, coded and tested as independent units. These modules typically conform to the defined tasks, including interrupt tasks in the real-time operating system, or the main program calls in a real-time monitor if a simple sequential scan is used. The module and overall software structure may be designed to make later software updating and maintenance easy to perform.

Coding of software modules should be done in a high-level programming language. Only for small, very time-critical tasks should assembly language be used.

The SEM software should have built-in diagnostic functions to simplify testing and debugging of the modem, subsea computer and sensors.

The SEM can be programmable to allow for reprogramming from the surface while in place.

The SEM can have capacity to temporarily store all relevant data gathered from the subsea production system.

The SEM can be capable of performing sequenced monitoring operations and/or sequenced controlling based on one command from the MCS.

The SEM software may be designed to accommodate the DHPT information.

7.4.6 Communication protocol

A reliable and suitable communication system, preferably based on a proven design or an industry standard, is required for supervision, remote control, shut-down and data transfer.

The communication shall transport the defined data signals with high reliability and have sufficient capacity to handle the required traffic in all foreseeable situations.

The communications and power systems should be designed to withstand the normal noise and disturbances typically occurring in the operating environment without malfunction. The communications and power systems should accommodate the specified range of voltage and frequency variations and the changes in the number of connected SEMs that the distribution can support.

The MCS shall be the governing end of the communication link between the MCS and the SEM.

The communication shall be based on formatted messages. The format should have a reliable identification of message start and a defined length.

Message "time out" shall be included.

Reception of corrupted message and "time out" shall result in the MCS retransmission of the message.

Each message shall have CRC or a similar type leaving no possibility for faulty messages to be received and interpreted as correct.

The protocol should be convenient for loading of the SEM software and auxiliary computer software.

Systems communication performance shall meet a BER of $< 1 \times 10^{-5}$ or 1×10^{-6} , as specified by the purchaser, with a BER performance design goal of $< 1 \times 10^{-6}$.

The same communication protocol should be used throughout the subsea control system. Communication protocol should be based on IEC 60870-5-1 [12], IEC 60870-5-2 [13] and IEC 60870-5-3 [14], or an equivalent International Standard.

7.4.7 Subsea instrumentation

All subsea instrumentation shall meet the system requirements given in clause 5. In general, subsea instrumentation should be as simple as possible, so that the number of electrical and hydraulic connections to the SCM is a minimum.

Failure of subsea instrumentation shall not adversely affect the operation of other parts of the system.

For sensors directly exposed to produced fluid, potential blocking of the interface by sand, hydrates or wax should be considered.

Methods of calibration or adjustment of the sensor signals should be taken into consideration when designing the system.

The connections and bodies of any sensors used to monitor well-bore conditions shall have a pressure rating appropriate for the maximum operating conditions and shall comply with the requirements of specifications API Spec 6A and API Spec 17D. A minimum of two independent barriers shall be provided within the sensor body to be compatible with well-bore fluid, and isolate well-bore fluid from the environment.

A method for inferring the position of hydraulically operated tree valves shall be incorporated.

All devices exposed to well-bore fluids shall be installed with isolation valving between the sensor and the well bore if it is installed upstream of the tree master valve or the USV, and the location of the sensing element is remote from the well bore.

7.4.8 High integrity pipeline protection system (HIPPS) (optional)

The HIPPS is designed to protect a pipeline and other associated equipment from exposure to high pressure from the subsea wells, thus allowing the pipeline and equipment to be designed for a pressure lower than maximum well shut-in pressure.

The HIPPS should be an autonomous safety system with a local logic system controlling HIPPS activation. The system should include the following elements:

- control of dual barrier isolation valves;
- minimum dual independent pilots or pressure transmitters responding to the pipeline pressure;
- positive control of system reset, to prevent hunting or throttling through the isolation valves.

7.4.9 Test equipment

7.4.9.1 General

In order to test each type of equipment during FAT, integration testing and during commissioning offshore, a set of test equipment may be required.

All test equipment shall be compatible with the hazardous area classification of the location in which it will be used.

The test equipment should be capable of simulating all primary operations necessary to control and monitor the subsea production equipment in a manner similar to the actual system.

The test equipment should be designed with units identical to the production equipment, where practical.

7.4.9.2 Control module test stand

The control module test stand should support the following test functions:

- verify the mechanical and functional interface between the module and the module receiver plate;
- verify the interface to external process sensors;
- verify the functional operation of the control module.

7.4.9.3 Test hydraulic power unit (THPU)

The THPU, if utilized, should supply hydraulic fluid at system operating pressures to the control module test stand. The THPU may be capable of performing flushing operations as a general source of clean fluid.

7.4.9.4 Dummy control module

The dummy control module should have a mechanical and hydraulic interface to the receiver plate similar to that of the control module. The dummy module can be equipped with manual valves simulating the real directional control valves, and can be used for the following functions:

- verification of control module installation tool operation;
- pressure and functional testing of system hydraulic components;
- flushing of hydraulic systems;
- through-connection to downhole gauges for remote interrogation via cable and/or acoustic link.

7.4.9.5 Umbilical simulator

A simulator may be provided to represent the characteristics of the electrical cables within the umbilical.

The simulator should model the impedance of the communications and power conductors in the umbilical.

7.4.9.6 Electronic test unit

The electronic test unit should be capable of performing the control and monitoring functions of the MCS. All commands described in the communication protocol should be supported. In addition, the electronic test unit should be able to simulate one or more complete control modules. The electronic test unit may be a modular unit including a portable PC and necessary power/signal interfaces.

7.4.9.7 Communication test unit

The communication test unit, if used, should be able to display data from the SCM. It can be used to verify communication if the real topside node is not available. This function may also be provided by the electronic test unit.

7.4.9.8 Sensor test unit

The sensor test unit should simulate each type of sensor used in the SCM, including downhole sensors if applicable. The sensor test unit may be part of the control module test stand or a stand-alone unit.

8 Interfaces

8.1 General

Interfaces between the production control system and other parts of the subsea and host facility systems are critical to successful operation and should be fully defined during initial design.

8.2 Interface to host facility

The subsea production system may be regarded as an extension of the host facility or as an independent system interfacing with the host facility control system.

The interfaces with the host facility are typically:

- host facility control system;
- PSD/ESD system;

- chemical injection system;
- utilities;
- UPS (optional).

The platform-installed subsea control system shall functionally interface with, or optionally be integrated with, the host facility control system.

Subsea wells are typically monitored and controlled from the primary operator station. Temporary operator stations may be used for testing, commissioning, programming and maintenance.

The operator station VDU displays should provide as much commonality as is reasonably possible with the host facility process control system.

All host facility-based production control system equipment should be built and documented according to specifications applicable for the host facility where the equipment will be situated.

If an integrated control-system philosophy is adopted, the interface between the subsea production control system and the host facility shall, as a base case, be between the MCS and host facility nodes. Optionally, the subsea/topside interface can be defined between the MCS and EPU. Hence the topside modem shall always be regarded as functionally part of the subsea system when this option is selected.

If a fully integrated control-system philosophy is selected for the host facility, the subsea wells shall be monitored and controlled from standard operator stations as first option. In this case, the subsea-production control system application software should be integrated with the host facility software to ease offshore maintenance and operation. The control and monitoring of subsea functions should be as similar as possible to that for the topside-located equipment.

8.3 Interface to subsea equipment

The interfaces with the subsea equipment are typically:

- a) tree;
 - 1) mounting footprint;
 - 2) form and fit;
 - 3) maintenance access.
- b) chokes;
 - 1) maintenance access.
- c) manifold;
 - See tree items.
- d) umbilical;
 - 1) electric, hydraulic and optical fibre connectors.
- e) external instrumentation;
 - 1) downhole instrumentation;
 - 2) pressure/temperature transducers;

- 3) position sensors;
 - 4) sand probes;
 - 5) pig detectors;
 - 6) subsea flow meters.
- f) ROV tooling;
 - g) SCSSV.

8.4 Interface to workover control system

The interface between the production control system and the workover control system should ensure that the workover system has control of all functions that might affect safety of the workover operation. The production control system can be utilized for workover control, provided primary control is from the workover rig.

Emphasis shall be put on cleanliness requirements of the workover control system, so that the production control system is not contaminated during workover operations or during subsequent production operations due to residual fluid in subsea valve operators. System design shall minimize possible seawater contamination of control lines during workover operations, and should consider a means for flushing these lines.

9 Materials and fabrication

9.1 General

All components used subsea shall be qualified, either by being field-proven or by qualification testing in simulated environments similar to the specific application.

9.2 Materials

9.2.1 Material selection

Materials selected for use in control system applications shall be capable of being cleaned to a specified cleanliness level and maintained in an environment that provides that specified cleanliness level throughout the life of the system.

9.2.2 Corrosion considerations

Corrosion protection through material selection based upon a marine environment should consider, as a minimum, the following:

- external fluids;
- internal fluids;
- weldability;
- crevice corrosion;
- dissimilar metals effects;
- cathodic protection effects (including classification in carbonate-rich environment);
- coatings;

- bacterial effects;
- marine growth.

9.2.3 Fluid compatibility

All wetted surfaces shall be verified compatible with the wetting-control fluid, chemical-injection fluid, and/or well-bore fluids. Resilient seal materials shall be selected to ensure compatibility with wetting fluids, temperature and pressure.

9.3 Fabrication

9.3.1 Fittings and connections

PTFE tape shall not be used within any parts of the hydraulic system.

NPT threads should be avoided.

Use of fittings in the subsea hydraulic system should be restricted to a minimum. Wherever acceptable, welded connections should be used for performing maintenance.

The same type (style) of fitting should be used for each pressure class throughout the system.

9.3.2 Welding

Structural-load-bearing welds shall be treated as nonpressure-containing welds and shall comply with a documented structural welding code such as AWS D1.1 [7].

All pressure-containing welds shall be in accordance with the ASME Boiler and Pressure Vessel Code, Section IX, or applicable parts of EN 288.

Welders shall be qualified in accordance with EN 287-1 + A1 or EN 287-2 + A1 or ASME Boiler and Pressure Vessel Code, Section IX.

Brazing and soldering are not acceptable for load-bearing systems.

9.3.3 Cleanliness

Hydraulic components should be assembled in a verified clean environment. Equipment should be cleaned to the specified cleanliness standard prior to assembly. Flushing is not accepted as a primary method of cleaning, except for straight piping without dead pockets.

Consideration should be given to cleaning, pickling and passivating stainless steel hydraulic tubing to prevent corrosion.

9.3.4 Electrical and electronic assembly

For the subsea electronics, reliability of components should be established and should meet the specified life, free of failure.

At a minimum, workmanship should conform to MIL-STD-2000 [18] or equivalent for assembly and repair.

10 Quality

Equipment manufactured according to this part of ISO 13628 shall conform to a certified QA programme. The manufacturer shall develop written specifications that describe how the certified QA programme will be implemented.

11 Testing

11.1 General

All testing shall be performed with due consideration for the safety of personnel and potential damage to the surrounding area.

A comprehensive test programme should be undertaken to ensure that control system performance requirements are met.

11.2 Qualification testing

11.2.1 General

Qualification tests shall be performed to confirm the performance of the equipment at its specified operating conditions. As an alternative to testing, the manufacturer may provide other objective evidence, consistent with documented industry practice, that the equipment will perform as specified.

This subclause defines the qualification test procedures to be used to qualify product designs. Equipment or fixtures used to qualify designs should be representative of production models in terms of design, dimensions and materials.

If a product design undergoes any changes in fit, form, function or material, the manufacturer shall document the impact of such changes on the performance of the product. A design that undergoes a substantive change becomes a new design requiring requalification. (A substantive change is a change identified by the manufacturer which affects the performance of the product in the intended service condition.) A change in material may not require requalification if the suitability can be substantiated by other means.

A type test for SEMs should be performed to qualify the design with respect to temperature cycling and vibration.

11.2.2 Hydrostatic and pressure testing (internal and external)

As part of the qualification test, hydrostatic pressure tests shall be performed on all pressured components and/or assemblies. An internal hydrostatic test pressure (proof pressure) test shall be performed at 1,5 times the design pressure (rated working pressure) for components rated at 103,4 MPa (15 000 psi) and below. Internal tests for components rated above 103,4 MPa (15 000 psi) shall be performed at 1,25 times the design pressure. External hydrostatic tests shall be performed at 1,1 times the design ambient pressure.

The test pressure shall be maintained for a minimum of 10 min without external fluid leakage from any component, line or joint.

All hydraulic accumulators shall be isolated from the circuit during the test.

The low-pressure portion of the control equipment, including, if applicable, the fluid reservoir, low-pressure filter, pump-feed lines and system-return lines, shall not be subjected to the hydrostatic test pressure (proof pressure).

11.2.3 Minimum and maximum temperature testing

Qualification tests shall be performed to confirm the performance of the equipment at a test temperature equal to or less than the minimum rated operating temperature classification, and at a test temperature equal to or greater than the maximum rated operating temperature classification.

11.2.4 Cycle testing

Equipment for which cyclic performance is an operational requirement shall be subjected to qualification testing which simulates long-term field service. The number of test cycles shall equal or exceed the number specified for the application.

11.3 Factory acceptance tests (FAT)

11.3.1 General

Factory acceptance testing of the subsea control system elements shall be performed prior to delivery.

The manufacturer shall develop and implement a comprehensive test programme. The programme shall demonstrate that all systems and components of the supplied equipment will perform satisfactorily in service and meet all requirements. A complete subsea production control system test should be part of this programme, using simulators for actual units where they are not available.

Step-by-step procedures with objectives and acceptance criteria shall be available prior to start of the FAT.

As a minimum, during the complete FAT, attention shall be paid to the following:

- electrohydraulic directional control valve performance and leak rates;
- accuracy of monitoring system;
- communication system sensitivity and noise immunity;
- electrical power requirements and sensitivities;
- pressure test of all tubing, pipework and hydraulic components;
- accumulator precharge pressure;
- relief-valve pressure setting;
- fluid and system cleanliness;
- pressure testing of control module;
- verification of equipment mating;
- electrical cable insulation resistance and conductance;
- leak-testing of applicable canisters;
- conductance to sacrificial anodes.

Environmental-stress screening for all subsea instruments and electronics shall be in accordance with manufacturer's written specification. For example, all SEMs may be required to pass a programme of temperature cycling, vibration and burn-in. The purpose of the temperature test is to verify that all components will function over

the design temperature range, and to force possible premature component failures. The purpose of the vibration test is to reveal possible poor workmanship during assembly. All SEMs shall be leak-tested after final closure.

11.3.2 Integrity

Hydrostatic pressure testing shall be as specified in 11.2.2.

Components which may be excluded from this testing are those which have been tested and certified for use by an appropriate regulatory body, (e.g. American Bureau for Shipping, ASME, Det Norske Veritas.) The hydrostatic test-pressure (proof pressure) test shall be performed prior to installation of safety overpressure equipment.

11.3.3 Function and continuity

Functional tests shall be performed to demonstrate proper operation of the equipment. The purpose of these tests is to verify the correct functional operation of the control equipment, including all interlocks, sequences, overrides and resets.

During the test, each hydraulic and electrical circuit shall be tested for proper operation.

Hydraulic circuits shall be tested at the design pressure (rated working pressure) of the circuit.

Electrical circuits shall be tested to ensure that there is no electrical short or open circuit.

Any circuit malfunction shall be reworked and retested to the above criteria prior to final acceptance.

11.3.4 Safety and operational checkouts

These tests are intended to verify that the system adjustments are as prescribed by the design specifications and manufacturer's data sheets, using a checklist of all set points relating to pressure levels (regulators, relief valves, alarm and shutdown switches, accumulator precharges, pump start/stop switches), fluid levels, voltages, time delays, and similar parameters.

All safety features or devices shall be verified to operate correctly.

11.3.5 Other testing which may be required by the purchaser

11.3.5.1 Internal leakage testing

The purpose of leak-testing is to verify that internal system leakage is within acceptable limits in accordance with manufacturer's written specifications. The test shall be performed at the design pressure (rated working pressure) of the hydraulic control system, with all circuits being tested. The minimum duration for testing shall be 10 min. Leakage rate shall be monitored by either

- pressurizing the system to design pressure, isolating the source of supply and monitoring pressure decay. Pressure decay shall be monitored and recorded;
- applying a constant pressure source to the system and monitoring the leakage rate of the various system components.

11.3.5.2 Fluid flushing

The purpose of the fluid flushing is to remove any contamination which may have been introduced into the hydraulic system during fabrication. The fluid flushing should be carried out using the specified system operating fluid. Acceptance criteria shall be in accordance with 5.1.3.2.

11.3.5.3 Sensitivity testing

Sensitivity testing may be performed on subsystems or the complete production control system.

The purpose of this testing is to vary key parameters in a controlled manner while monitoring system performance and limits of operation.

11.4 Integrated system tests

An integrated system test may be performed. If practical, process equipment, subsea hardware and controls should be tested together before installation. These tests are typically performed at a shore base to facilitate modifications and rework that may be necessary.

Integrated system tests should be carried out for all modes of operation and, if applicable, in fully redundant and non-redundant configurations. Separate tests should be conducted for minimum, normal and maximum loadings.

Integrated system tests typically include end devices and interconnecting jumpers, umbilicals, junction boxes, as well as the non-control system components to which they interface, and any running tools that will be used during installation. Function tests would verify the final result of all input signals, overrides and resets. Key set points should be rechecked. A primary benefit during integrated testing is the familiarization of operating personnel with the location of the adjustable devices and the methods used to verify or change the set points.

In addition, performance tests should record actuation times for actuators, accumulator bank discharge volumes, recovery times for pumping systems, power consumption for electrical circuits, delivery rates for chemical injection circuits, expansion volumes for long hoses, and the accuracy of readback monitors.

Reference should be made to ISO 13628-1 [16] for additional discussion on system testing.

11.5 Documentation

The manufacturer shall document the procedures used and the results of all performance verification tests and FATs. The documentation should identify the person(s) conducting and witnessing the tests, and the time and place of the testing.

12 Marking, packaging, storage and shipping

12.1 Marking

12.1.1 Component identification

All major components (e.g. HPU, SCMs, surface computer and electrical power supplies) shall be marked by an identifying tag, name plate, or imprinted identification. The identifying means shall be suitable for the environment and shall include appropriate information such as an identifying manufacturer's number, input utilities ratings, equipment design pressure (rated working pressure), and date of manufacture.

12.1.2 Surface and subsea equipment temperature ratings

Surface and subsea equipment manufactured in accordance with 5.1.2.3 and 5.1.2.4 shall be permanently marked as follows:

a) standard operating temperature;

EXAMPLE Low-temperature rating of 0 °C (32 °F) and high-temperature rating of 40 °C (104 °F)

Stamp: 0 °C – 40 °C (32 °F – 104 °F) STD

b) extended operating temperature.

EXAMPLE Low-temperature rating of $-5\text{ }^{\circ}\text{C}$ ($23\text{ }^{\circ}\text{F}$) and high-temperature rating of $40\text{ }^{\circ}\text{C}$ ($104\text{ }^{\circ}\text{F}$)

Stamp: $-5\text{ }^{\circ}\text{C} - 40\text{ }^{\circ}\text{C}$ ($23\text{ }^{\circ}\text{F} - 104\text{ }^{\circ}\text{F}$) EXT

12.1.3 Special marking — Usage restricted to controlled environment

Surface-installed equipment that is designed to operate in a controlled environment shall be labelled with a blue and white label warning the user to be aware of the environmental usage restrictions to be found in the operator's manual. The label shall have the following format:



12.2 Packaging

12.2.1 Rust prevention

Prior to shipment, parts and equipment shall have exposed metallic surfaces (except corrosion-resistant materials and special items such as anodes or nameplates) either protected with a rust-preventive coating which will not become fluid at temperatures less than $50\text{ }^{\circ}\text{C}$ ($125\text{ }^{\circ}\text{F}$), or filled with a compatible fluid containing suitable corrosion inhibitors in accordance with the manufacturer's written specification. Equipment already coated, but showing damage after testing, should undergo coating repair in accordance with the manufacturer's written specification.

12.2.2 Surface protection for seals

Exposed seals and seal surfaces, threads and operating parts shall be protected from mechanical damage during shipping. Flange faces, clamp hubs and other vulnerable parts shall be protected by suitable covers or other protective devices. Shipping skids or containers should be designed such that equipment does not rest on any seal or seal surface during shipment or storage.

12.2.3 Loose components

Loose components shall be separately packaged and identified as specified in 12.1.

12.3 Storage and shipping

12.3.1 Elastomer age control

The manufacturer shall document instructions concerning the proper storage environment, age control procedures, and protection of elastomeric materials.

12.3.2 Hydraulic and pneumatic systems

12.3.2.1 General

Prior to shipment, hydraulic lines shall be flushed, filled and/or drained in accordance with the manufacturer's written specification. Exposed hydraulic end fittings shall be capped or covered. Follow the instructions in 12.3.2.2 to 12.3.2.5.

12.3.2.2 Pressurized circuits

Bleed all gas and pressurized hydraulic circuits to zero pressure.

12.3.2.3 Accumulators

Bleed the gas precharge of all accumulators to zero pressure.

12.3.2.4 Fluid reservoir

Drain the hydraulic control fluid from the reservoir.

12.3.2.5 HPU fluid and electrical connections

Disconnect all inlet and outlet connections. Cap all connections.

12.3.3 Electrical/electronic systems

The manufacturer shall document instructions concerning proper storage and shipping of all electrical cables, connectors, and electronic packages (SCM, MCS, etc.).

12.3.4 Crating and handling

For shipment, units and assemblies should be securely crated or mounted on skids to prevent damage and to facilitate sling handling.

Protective packing material should be fixed in place over all outside mounted panel gauges to protect them from damage.

12.3.5 Shipping and storage temperature limitations

For shipping and storage, control system equipment should be designed and prepared to allow for the maximum expected temperature range, see 5.1.2.3 and 5.1.2.4.

Annex A (informative)

Types and selection of control system

A.1 System selection

Factors which affect control system selection are cost (including life-cycle estimates that include cost of maintenance and lost production caused by control system failures), offset distance from the host, response-time requirements, and data telemetry requirements.

All-hydraulic systems are generally the least complicated and the most reliable subsea control systems. They are relatively slow to respond, compared to electrohydraulic systems, and have limited capability for providing data telemetry from the subsea system. The specific needs of each application should be carefully considered, particularly with respect to data needs and speed of response, before selecting an all-hydraulic system approach. All-hydraulic systems are generally preferred for single satellite wells located relatively close to the host facility, and where minimum cost must be maintained for project economics.

Electrohydraulic systems have the added complexity of SEMs, but offer much faster response time and have the capability to monitor a wide range of data-telemetry devices. Electrohydraulic systems are typically preferred for multi-well developments where operating flexibility, speed of operation and data telemetry is needed for well control and/or reservoir monitoring.

A.2 All-hydraulic system descriptions

A.2.1 General

The three types of all-hydraulic systems are defined below. A choice among these three system approaches should consider the system response-time needs and umbilical requirements.

A.2.2 Direct hydraulic systems

For direct hydraulic systems, a separate hydraulic line is provided for each function, connected directly to the valve actuator, pressure-sensing point or other subsea function to be controlled. No subsea control equipment is required, other than an umbilical connector and routing of control lines to each function.

A.2.3 Piloted hydraulic systems

Piloted hydraulic systems include a subsea control module containing pilot valves, along with a local subsea source of hydraulic power, generally accumulators which are charged through a separate line from the surface. The signal lines are required to provide only enough fluid to shift one of the small pilot valves, and the fluid to actuate tree or manifold valves is provided locally from the subsea accumulators. This type of system extends the allowable distance between the subsea system and the host, compared to a direct hydraulic system, by minimizing the valve actuation time.

A.2.4 Sequential hydraulic systems

Sequential hydraulic systems also use control modules with special pilot valves which do not require a separate line for each function. An increasing sequence of hydraulic pressure steps on a single pilot line common to all pilot valves in a module causes activation of different pilot valves at each pressure level to control subsea valves, using power fluid from subsea accumulators. The number of hydraulic lines is minimized, since only one pilot line per tree is needed. The disadvantage of this approach is that the opening sequence of subsea valves is predetermined,

with no flexibility for operating valves in a different sequence. This type of system has most commonly been used as a backup to an electrohydraulic system, but has also been used as an independent system to reduce the umbilical requirements and cost.

A.3 Electrohydraulic systems

A.3.1 General

Electrohydraulic control systems replace hydraulic signals with electric signals, which essentially eliminate the signal-time portion of response time. They also add the capability of monitoring a much wider variety of subsea data.

An electrohydraulic control system requires an additional electrical control umbilical, or the inclusion of electrical cables within the hydraulic control/chemical-injection umbilical. However, the hydraulic components requirements in the umbilical are decreased, compared to direct and piloted hydraulic systems, since only system hydraulic supply and chemical injection conduits are needed.

A.3.2 Direct electrohydraulic systems

Direct electrohydraulic systems transmit signals through multiple individual conductors in the control umbilical directly to solenoids on directional control valves located in the subsea modules. This system option increases cost of the umbilical and is sensitive to power losses in the multiple conductors as offset distance from the host facility increases. The umbilical requirements increase in direct proportion to the number of wells controlled.

A.3.3 Multiplexed electrohydraulic systems

Multiplexed electrohydraulic systems transmit electrical signals to one or more subsea SEMs by means of coded, digital messages via a single pair of conductors. The SEM decodes the message and takes the appropriate action, such as valve actuation or query of a subsea sensor. A single umbilical can communicate with all the wells in a subsea development, thus minimizing umbilical control component requirements. Power requirements for signals are low, since power for solenoid actuation is provided through a separate, power function. Communication and power can be via separate conductor pairs, or communications signals can be superimposed on the power conductors, minimizing the total number of conductors in the umbilical.

A.3.4 Autonomous systems

Autonomous systems provide locally generated power and control to the subsea production facility. Hydraulic fluid is locally stored. Communication with the surface facility may be via an acoustic link or via a combination of acoustic/satellite/radio links. The basic system functions are the same as for a multiplexed electrohydraulic system.

Annex B (informative)

Typical control and monitoring functions

B.1 Control functions

A typical list of valves controlled by the subsea control system is as follows:

- SCSSVs;
- production master valve;
- production wing valve;
- annulus master valve;
- annulus wing valve;
- crossover (injection) valve;
- methanol/chemical injection valve;
- scale-inhibitor injection valve;
- corrosion-inhibitor injection valve;
- production choke valve (may require two control functions per choke);
- injection choke valve (may require two control functions per choke);
- manifold valve(s);
- chemical-injection control valve.

B.2 Monitoring functions

A typical list of parameters typically monitored by subsea-located sensors of a subsea control system is as follows:

- production pressure;
- annulus pressure;
- manifold pressure;
- production temperature;
- manifold temperature;
- hydrocarbon leak detection;

- tree valve position (direct or inferred);
- production choke position;
- production choke differential pressure;
- sand detection;
- downhole monitoring;
- multiphase flow;
- corrosion monitoring;
- pig detection.

B.3 SCM parameter monitoring

The following subsea parameters may be monitored inside the SCM:

- hydraulic supply pressures;
- communication status;
- internal voltages in SEM;
- internal temperature in SEM;
- internal pressure in SEM;
- self-diagnostic parameters;
- hydraulic fluid flow;
- hydraulic return pressure;
- insulation resistance.

Consideration should be given to self-diagnostics to detect malfunctions for external sensor systems connected to the control module (e.g. downhole monitoring, multiphase-flow meters, sand detectors). The control system should be capable of performing specific diagnostics in case of a malfunction in a sensor system.

Annex C

(normative)

Properties and testing of control fluids

C.1 Property requirements of control fluids

C.1.1 General

Fluid property requirements for both water-based and oil-based fluids are described in the subclauses below.

NOTE Individual requirements that apply only to one of these two fluid types are so noted.

Qualification tests shall be performed by the fluid manufacturer in order to qualify a fluid formulation under this part of ISO 13628. The fluid being tested shall meet or exceed all acceptance criteria in order to qualify.

C.1.2 Appearance

The fluid shall be a clear, transparent mobile liquid free from suspended material. The turbidity shall be determined in accordance with ASTM D1889. Clarity and transparency are important in permitting determination of the other criteria.

C.1.3 Water content (water-based fluid only)

The water content shall be determined by the Dean and Stark method in accordance with the modified ASTM D4006 method for water-based fluids. The minimum water content for classification as a water-based fluid is 30 %.

C.1.4 Pour point

The pour point shall be determined in accordance with ASTM D1293, in which the acceptance criterion is a minimum pour point of $-10\text{ }^{\circ}\text{C}$ ($14\text{ }^{\circ}\text{F}$).

C.1.5 pH (water-based fluids only)

The pH at $20\text{ }^{\circ}\text{C}$ ($68\text{ }^{\circ}\text{F}$) shall be determined in accordance with ASTM D1293, in which the acceptance criterion is pH 8 to pH 10.

C.1.6 Flash point (oil-based fluids only)

The flash point shall be determined in accordance with ASTM D92. The acceptance criterion is a minimum flash point of $150\text{ }^{\circ}\text{C}$ ($302\text{ }^{\circ}\text{F}$).

C.1.7 Corrosion test

The anti-corrosion performance shall be determined in accordance with ASTM D665, parts A and B. Both tests shall be carried out in duplicate for a period of 24 h at $60\text{ }^{\circ}\text{C}$ ($140\text{ }^{\circ}\text{F}$) using a standard carbon steel test pin. The acceptance criterion is no rust.

C.1.8 Anti-wear test

C.1.8.1 General

The two standard procedures for the assessment of anti-wear performance of water- and oil-based fluid products are the ASTM D2596 (Shell 4 Ball Test) and a modified version of the Falex lubricant test.

C.1.8.2 ASTM D2596

The ASTM D2596 method evaluates the anti-welding characteristics of a lubricant. Performance is evaluated by assessing the load before welding of the test pieces occurs, the load at which initial seizure occurs and the wear occurring under a constant low load. The minimum characteristics are outlined in Table C.1.

Table C.1 —Minimum anti-welding characteristics

Characteristic	Water-based fluid	Oil-based fluid
Weld point:	Min. 1,08 kN (243 lbf)	Min. 1,26 kN (283 lbf)
Initial seizure load:	Min. 0,39 kN (88 lbf)	Min. 0,49 kN (110 lbf)
Mean scar diameter		
— after 1 h at 0,20 kN (45 lbf), 1800 r/min:	Max. 1,50 mm (0,059 in)	Max. 0,40 mm (0,016 in)
— after 1 h at 0,29 kN (65 lbf), 1460 r/min:	Max. 1,70 mm (0,067 in)	Max. 0,60 mm (0,024 in)

C.1.8.3 Falex test

The modified Falex test as defined in C.2.2 evaluates the lubricity of the fluid. The acceptance criteria under Method A is 1,33 kN (300 lbf) load and torque less than 2,26 N·m (20 in·lbf). The acceptance criteria under Method B is less than 15 % change in torque characteristics (from Method A) and a weight loss on the pin of less than 0,2 mN (20 mgf).

C.1.9 Elastomer compatibility

Elastomer compatibility shall be determined in accordance with ASTM D471, in which the acceptance criteria and elastomer type are determined by the purchaser.

Representative compatibility should be assessed in accordance with ASTM D471 using the standard elastomer grades listed below. This is intended to give an indication of a fluid's effect on typical commonly used types of elastomer. A minimum immersion period and temperature is considered to be 168 h at 70 °C (158 °F). However, extended test periods (typically 2 000 h) are recommended to identify the stabilization point.

Typical elastomers: nitrile-butyl rubber (high nitrile), nitrile-butyl rubber (medium nitrile) and fluorocarbon.

C.1.10 Thermoplastics compatibility

Compatibility with thermoplastics materials to be used in umbilicals or as flexible connections in the form of jumper hoses between the umbilical termination and the end user shall be determined by the procedure outlined in ISO 13628-5.

The test method and acceptance criteria for compatibility testing with thermoplastics materials for uses other than in control umbilicals should be determined by the purchaser.

C.1.11 Fluid stability

Given that the lifetime of most projects is between 10 years and 20 years, the long-term stability of the fluid is extremely important. Data on the fluid must be generated, but the scope, method and acceptance criteria shall be agreed by the purchaser.

As a minimum, an ageing period of 2 000 h at temperatures of $-10\text{ }^{\circ}\text{C}$ ($14\text{ }^{\circ}\text{F}$), $0\text{ }^{\circ}\text{C}$ ($32\text{ }^{\circ}\text{F}$), and $70\text{ }^{\circ}\text{C}$ ($158\text{ }^{\circ}\text{F}$) along with a period at a temperature $10\text{ }^{\circ}\text{C}$ ($50\text{ }^{\circ}\text{F}$) above the maximum operating temperature of the fluid is required. Pressure-test vessels made of corrosion-resistant material should be used for the elevated temperature testing.

Changes in viscosity at $40\text{ }^{\circ}\text{C}$ ($104\text{ }^{\circ}\text{F}$) and deposits per litre of fluid should be reported.

The mechanical stability of the fluid shall be evaluated at the operational temperature(s) and at the lower and upper ends of the specified temperature range. The evaluation shall demonstrate that under static conditions, over time and under pressure, the fluid remains 100 % homogeneous and does not form a multiphase system. The effect of seawater ingress on the fluid stability shall also be addressed as part of the evaluation.

C.1.12 Oxidation resistance (oil-based fluids only)

The oxidation resistance of the fluid shall be determined using the CIGRE Test (IP 280) method where fluid, catalysed by iron and copper, is exposed to $120\text{ }^{\circ}\text{C}$ ($248\text{ }^{\circ}\text{F}$) for 168 h with controlled airflow passing through it. The minimum characteristics are outlined below.

Sludge: max. 0,1 %

Total oxidized products: max. 0,5 %

C.1.13 Environmental effects

The use of organometallic compounds should be avoided. Testing should be performed according to the PARCOMS guidelines using the following marine organisms to assess toxicity:

- *skeletonema costatum*;
- *acartic tonsa*;
- *corophium volutator*.

Acceptance criteria should be in accordance with local legislation.

C.1.14 Resistance to microbiological growth**C.1.14.1 Test method**

The test samples are diluted, if required, and the resulting preparations (PREPS) tested.

Day 1	Each PREP is inoculated (challenged) using an appropriate inoculum and then incubated
Day 2	Each PREP is sampled and then re-inoculated using a fresh inoculum and re-incubated
Days 3 to 9	As day 2
Day 10	Each PREP is sampled

C.1.14.2 Inocula

The inocula used in this evaluation are

a) bacteria: *Pseudomonas aeruginosa* C

1 ml (0,061 in³) per 100 ml (6,1 in³) PREP of 24 h culture in nutrient broth incubated at 30 °C (86 °F). This gives a 108 cfu/ml (1770 cfu/in³) bacterial suspension.

b) fungi: *Cephalosporium*

Two drops per 100 ml (6,1 in³) PREP of a seven day culture on a malt extract agar slope at 30 °C (86 °F). The spores are collected using 3 ml (0,183 in³) Tween® 80¹⁾ (2 %) pH 7. The 3 ml (0,183 in³) Tween is added to the slope, then whirl-mixed. This gives a 1 010 cfu/ml (16 551 cfu/in³) fungal suspension.

The level of contamination in the PREP of each inoculum is then 108 cfu/ml (1770 cfu/in³).

The sampling method routinely is:

3 × 10 μl (3 × 0,000 61 in³) of each PREP is streaked out onto both a TSA plate and an MEA plate using a 10 μl (0,000 61 in³) sterile disposable loop. The plates are then incubated at 30 °C (86 °F) and 25 °C (77 °F), respectively.

The acceptance criterion is that no growth is observed in the first eight days of the ten-day test.

C.1.15 User information requirements

Table C.2 gives a list of fluid properties to be supplied to users by the manufacturer. Properties shall be ascertained by the manufacturers using the following test methods.

Table C.2 — Fluid properties to be listed by manufacturer

Property	Method
Density	ASTM 1298
Kinematic viscosity at – 20 °C (– 4 °F), 0 °C (32 °F), 10 °C (50 °F), 40 °C (104 °F) (water-based)	ASTM D445
Kinematic viscosity at – 10 °C (14 °F), 0 °C (32 °F), 20 °C (68 °F), 40 °C (104 °F) and 100 °C (212 °F) (oil-based)	ASTM D445
Bulk modulus	ISO 6073
Foaming characteristics	ASTM D892
Cleanliness count	ISO 4406/NAS 1638

1) Tween 80 is the trade name of a product supplied by ICI Surfactants. This information is given for the convenience of users of this part of ISO 13628 and does not constitute an endorsement by ISO of the product named. Equivalent products may be used if they can be shown to lead to the same results.

C.2 Test methods

C.2.1 Modified Falex lubricant test

Two methods of evaluation are used, both involving a standard Falex lubricant tester. The test pieces used are steel pins and vee-blocks, totally immersed in the fluid.

Method A is carried out by increasing the contact load between the vee-blocks and rotating pins in increments of 0,45 kN (100 lbf) to a maximum load of 1,33 kN (300 lbf). Each load increment is maintained for a period of 60 s. A reading is taken of the resultant torque (proportional to the frictional force) and the number of ratchet teeth required to maintain the load (proportional to the linear wear taking place) at each 0,45 kN (100 lbf) increment. The resultant data are presented as graphs of torque vs. applied load and number of wear teeth vs. applied load.

Method B is carried out immediately after method A, using the same test pieces, and is run at a continuous load of 1,33 kN (300 lbf) for a period of 30 min. Once again, torque and wear are recorded during the test period, and the resultant data are in this case presented as graphs of torque vs. time and number of wear teeth vs. time.

C.2.2 Test method — Falex lubricant tester

C.2.2.1 Method A: 0 kN to 1,33 kN (0 lbf to 300 lbf) load

- a) Insert new pin and vee-block. Fill bath with new test fluid. Start machine with no load applied and allow to run for 60 s.
- b) Apply load via the ratchet mechanism until 0,45 kN (100 lbf) level is reached. Allow to run for 60 s.
- c) Increase load via the ratchet mechanism. If the load has dropped below the 0,45 kN (100 lbf) level during the 60 s run, record the number of ratchet teeth required to re-establish the 0,45 kN (100 lbf) level of load. Record the torque reading at 0,45 kN (100 lbf) load.
- d) Continue loading via the ratchet mechanism until the 0,90 kN (200 lbf) load level is reached. Allow to run for 60 s.
- e) Repeat steps c) and d) for loads up to 1,33 kN (300 lbf) in 0,45 kN (100 lbf) increments. At each increment, record the number of ratchet teeth required to re-establish test load at the end of the 60 s run (if load has dropped) and the torque, prior to proceeding to the next test load, until data for loads up to and including 1,33 kN (300 lbf) load have been obtained.

C.2.2.2 Method B: 30 min at 1,33 kN (300 lbf) load

- a) After completing the 1,33 kN (300 lbf) test period (60 s) and recording the number of ratchet teeth to re-establish the 1,33 kN (300 lbf) load (and the torque), increase the load to 1,38 kN (310 lbf).
- b) Allow the test to continue for 30 min from this point. Should the test load drop to 1,29 kN (290 lbf), use the ratchet mechanism to re-establish the 1,38 kN (310 lbf) load level, record the number of ratchet teeth required, and note the torque on re-establishing the 1,38 kN (310 lbf) test load. Record the time at which the load dropped to 1,29 kN (290 lbf) .
- c) At the end of the test period, remove the load completely prior to switching off the Falex machine.
- d) Retain the pin and vee-block for examination.

C.2.3 High-temperature fluid testing requirements

C.2.3.1 General

This evaluation shall be performed as a minimum whenever the control system operating fluid is intended for service above 90 °C (194 °F). The test temperature shall be 10 °C (50 °F) above the maximum predicted operating temperature.

The tests are designed to record changes in the fluid in the following areas:

- sludge/deposits;

NOTE 1 These can lead to blockages and increased wear.

- acidity for synthetic oil-based products, reported as TAN and TBN;

- pH for water-based products;

NOTE 2 Acidity does not necessarily relate to degradation for water-based products, due to complex pH buffer systems, therefore changes in pH should be recorded.

- viscosity.

Viscosity is a sign of product degradation and shall therefore be recorded. The percent mass change of the fluid before/after test shall be quoted next to any viscosity data, especially for water-based fluids, where e.g. a leak in the test vessel may allow water to boil off significantly, thus affecting viscosity data.

C.2.3.2 Test vessel

The test vessel should have

- 316 stainless steel wetted components;
- a full-opening top to permit "straight through" cleaning and inspection;
- a capacity of 500 ml (30,5 in³).

C.2.3.3 Test procedure (three vessels required)

All fluids used for flushing and cleaning in this procedure shall be filtered through a nominal 0,8 µm pore size filter.

- a) Clean the three test vessels with filtered de-ionized water or, for oil-based fluids, filtered petroleum spirit. Let the vessels dry in a clean lint-free environment. (Do not use an air line to dry the vessels, as this will introduce contamination.) Test for vessel cleanliness by filling with 150 ml (9,15 in³) de-ionized water (petroleum spirit for oil-based fluid tests), agitate, then count particles. The acceptance criterion is less than 500 particles of diameter greater than 5 µm per 100 ml (6,1 in³) of fluid.
- b) Fill vessels with 400 ml (24,4 in³) ± 5 ml (0,3 in³) of the control fluid.
- c) Purge the air space above the control fluid with dry filtered nitrogen and regulate the pressure to a value sufficient to prevent boiling of the control fluid. Maintain this pressure throughout the test. Heat the vessels to the desired temperature and maintain ± 1 % through out the test.

d) Remove one vessel after each of

- 330 h;
- 670 h;
- 2 000 h.

The vessels and fluid shall be weighed before and after test, and any mass loss recorded.

C.2.3.4 Qualification tests

Values for the virgin fluid shall be obtained from the manufacturer or determined in addition to the three aged samples. The virgin sample should have the same batch number as the fluid tested.

a) Appearance evaluation

Pour the contents of the vessel into a clean clear cylinder of 500 ml (30,5 in³) capacity. Do not remove or disturb sediments and deposits. Fluid colour and condition (clear/hazy/opaque) shall be recorded.

b) Acidity evaluation

Use 15 ml (0,92 in³) to 30 ml (1,83 in³) for pH determination for water-based fluids, and for oil-based fluids use the TAN and TBN tests.

c) Deposit and sludge evaluation

Flush sediments from the vessel with filtered fluid. Deposits on the walls shall be scraped and flushed. The mass of the solids shall be determined to within ± 1 %. If any particles were found in the previous tests they should be included here. Report the particle size distribution and characteristics, and the amount of deposits based on Table C.3.

Table C.3 — Deposits

Fluid classification	Deposits	
	mg/l	(lb/in ³)
A	0 to 10	0 to $0,361 \times 10^{-6}$
B	10 to 100	$0,361 \times 10^{-6}$ to $3,61 \times 10^{-6}$
C	100 to 1 000	$3,61 \times 10^{-6}$ to $36,1 \times 10^{-6}$
D	greater than 1 000	$36,1 \times 10^{-6}$

d) Corrosion evaluation

Test the fluid in accordance with IP 135 section A (10 % distilled water dilution).

C.2.3.5 Acceptance criteria

No absolute acceptance criteria have been determined. The original properties of the fluid along with the changes undergone shall be used to evaluate the suitability of the fluid. These tests allow a comparison of fluids and a means for the operator and fluid manufacturer to evaluate the long-term effects of high temperature on the fluid.

Annex D
(informative)

API monogramming

API offers a monogramming programme for the oil and natural gas industry that has been utilized since 1924. For manufacturers that participate in this programme, equipment shall be marked in an appropriate location in accordance with the manufacturer's written specifications and the standardized API monogramming programme established to complement the joint ISO/API standardization effort.

For information, contact API, 1220 L Street, NW, Washington, DC 20005-4070, USA.

Annex E

(informative)

Additional API Monogram information

Note: This annex is derived from API Specification Q1, 6th Edition (Part 2) and is provided in addition to Annex D to allow for an identical adoption of ISO 13628-6 by API

E.0 Introduction

The API Monogram Program allows a licensee to apply the API Monogram to products. Products stamped with the API Monogram provide observable evidence that they were produced in accordance with a verified quality system and in accordance with an API-recognized, international oil and gas industry product specification. The API Monogram Program delivers significant value to the international oil and gas industry by linking the verification of a supplier's quality system with the demonstrated ability to meet specific product specification requirements.

When used in conjunction with the requirements of the API License Agreement, API Specification Q1 Parts One and Two define the program for voluntary licensing of suppliers who wish to provide oil and gas industry products in accordance with an API-recognized international oil and gas industry product specification.

API Monogram Program Licenses are issued only after an on-site audit has verified that the licensee conforms with both the quality system requirements described in API Specification Q1 Part One and the requirements of an API-recognized international oil and gas industry product specification.

For information on becoming an API Monogram Licensee, please contact API at 1220 L Street, N. W., Washington, DC 20005 or call 202-682-8000.

E.1 Scope

This Annex sets forth the API Monogram Program requirements necessary for a supplier to consistently produce products in accordance with API specified requirements

E.2 References

In addition to the referenced standards listed in Section 2, this Annex references the following standard:

API Specification Q1, 6th Edition

E.3 API Monogram Program: Licensee Responsibilities

E.3.1 The requirements for all suppliers desiring to acquire and maintain a license to use the API Monogram shall include:

- a. The quality system requirements of API Specification Q1, Part One.
- b. The API Monogram Program requirements of API Specification Q1, Part Two.
- c. The requirements contained in API recognized product specifications.
- d. The requirements contained in the API License Agreement.

E.3.2 When a licensed supplier is providing monogrammed product, Parts One and Two of API Specification Q1 are mandatory.

E.3.3 Each Licensee shall control the application of the monogram in accordance with the following:

- a. The Licensee shall apply the monogram, license number, and date of manufacture to monogrammed products in accordance with a marking procedure as specified by the applicable API product specification. Where there are no API product specification marking requirements, the licensee shall define the location(s) where this information is applied.
- b. The monogram may be applied at any time appropriate to the manufacturing process but shall be removed if the product is subsequently found to be in nonconformance with API specified requirements. Products determined to be nonconforming to API specified requirements shall not bear the API monogram.
- c. Only an API Licensee may apply its monogram.
- d. The monogram shall be applied at the licensed facility.
- e. The authority responsible for applying and removing the API monogram shall be defined.

E.3.4 Records required by API product specifications shall be retained for the period of time specified therein. Records specified to demonstrate achievement of the effective operation of the quality system shall be maintained for a minimum of 5 years.

E.4 Marking Requirements

See Clause 12 and Annex D. These marking requirements apply only to those API licensees wishing to mark their products with the API Monogram.

E.5 API Monogram Program: API Responsibilities

The API shall maintain, without references to licensees or users, records of reported problems encountered with API monogrammed products produced in accordance with API Specification Q1 and API product standards.

E.6 API Monogram Program: User Responsibilities

The effectiveness of the API monogram program can be strengthened by user reporting problems encountered with API monogrammed products to the API. API solicits information on both new product nonconformance with API specified requirements and field failures (or malfunctions) which are judged to be caused by either specification deficiencies or nonconformance with API specified requirements. Users are requested to report to API problems encountered with API monogrammed products.

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