CHINA CLASSIFICATION SOCIETY

RULES FOR OFFSHORE OIL AND GAS PROCESS SYSTEM

2020

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CHAPTER 1 GENERAL PROVISIONS

SECTION 1 GENERAL

1.1.1 Objectives

1.1.1.1Rules for Offshore Oil and Gas Process System (hereinafter referred to as the Rules) is developed to present the acceptable criteria for the design, manufacture, installation and survey of offshore oil and gas process system, with the purpose of minimizing the risks posed by the system to personnel, environment and property.

1.1.1.2 Another objective of preparing the Rules is to provide technical criteria for the classification, certification or verification services undertaken by China Classification Society (hereinafter referred to as the Society).

1.1.1.3 The Rules may serve as the applicable standard for both parties of the contract.

1.1.2 Scope

1.1.2.1 The Rules offers provisions on crude oil production system, natural gas production system, production oily water processing system and their associated systems and in addition, specifies the requirements regarding purification, liquefaction of natural gas and regasification, transfer of liquefied gas.

1.1.2.2 The Rules is applicable to the oil and gas process system installed on offshore installation; among these rules, the requirements on the purification, liquefaction of natural gas and the regasification, transfer of liquefied gas mainly apply to the systems arranged on floating terminals; and the requirements on liquefied gas regasification and transfer systems, if used, may also apply to the regasification and transfer systems installed on the LNG regasification vessels.

1.2.2.3 For the oil and gas process system on the onshore terminal and on the beach and alongshore that are associated with the offshore oilfield, the design, construction, drawing review, survey and certification may be carried out according to the applicable requirements of the Rules.

1.2.2.4 The requirements on oil and gas process system prescribed in the Rules are to cover and be no less than the related statutory requirements of Chinese government. When the oil and gas process system on the waters of foreign countries is required to be surveyed according to the Rules, the specific statutory requirements of the coastal states are also to be considered to comply with.

1.1.3 Equivalent and exemption

1.1.3.1 In agreement with the involved contract parties and the Society, design provisions that are not consistent with the requirements of the Rules (including acceptance criteria) may be accepted as the alternative to the corresponding requirements in the Rules, provided that a written document proving or showing a safety level at least equivalent to that stated in the requirements of this document is available.

1.1.3.2 For oil and gas process system with novel features, if the application of any of the Rules may impede research of such features, the rule in question may be waived with the approval of the Society.

1.1.4 Application of risk assessment

If the owner, operator, designer or other institution wishes to apply the risk assessment technique in design, construct or operate the system or component, the risk control plan adopted in the risk assessment may be substituted for the whole or part(s) of the Rules, subject to the satisfactory review of the risk assessment information by the Society.

Risk assessment may be performed in accordance with ISO 17776 Guidelines on Tools and Techniques for Hazard Identification and Risk Assessment or as the applicable standard by CCS.

SECTION 2 DEFINITIONS AND ABBREVIATIONS

1.2.1 Definitions

1.2.1.1 For the purpose of the Rules the definitions used are as follows:
(1) **Offshore installation**
Any installations for development of sea oil and gas resources. Offshore installations mainly include fixed offshore platform, mobile unit, floating unit, floating terminal, artificial island as well as subsea production system and pipeline;

(2) **Main Rules for offshore installation**

Refers to the currently effective general Rules of the Society for classification or certification of fixed platform, mobile and floating units, floating terminal and artificial island, including any Guidelines;

(3) **Coastal state administration**

Safety administration of the country in the waters of which operations of offshore installation are carried out;

(4) **Flag administration**

Maritime administration of the country of registry of a flagged mobile or floating unit.

(5) **Administration**

Generic term for the coastal state administration and flag administration.

(6) Oil and Gas Process System

It is a system that satisfies the needs of the products from oil and gas wells and processes the well flow.

1.2.1.2 The definitions limited to specific chapter and/or section will be described in various corresponding chapters or sections.

1.2.2 Abbreviations

1.2.2.1 The abbreviations used in the Rules are as follows:

AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BS	British Standard
DIN	Deutsches Institut fr Normung (German Institute for Norms)
EN	European Norm
GB	China National Standard
IAPH	International Association of Ports and Harbors
ICS	International Chamber of Shipping
IEC	International Electrician Committee
IMO	International Maritime Organization
ISO	International Organization for Standardization
JB	China Mechanical Industry Standard
NACE	National Association of Corrosion Engineers
NB	China Energy Industry Standard
NFPA	National Fire Protection Association
OCIMF	Oil Company International Marine Forum
PD	British Standard for Vessels
SIGTTO	Society of International Gas Tanker and Terminal Operators
SY	China Petroleum and Natural Gas Industry Standard
TEMA	Tubular Exchanger Manufacturers Association

1.2.2.2 The abbreviations limited to specific chapter or section will be described in various corresponding chapters or sections.

SECTION 3 RELATED CODES AND RULES

1.3.1 International codes

The related safety and technical requirements in the following international codes are to be applicable to the offshore oil and gas process system stated in the Rules.

(1) IMO International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC code);

(2) IMO International Convention for the Prevention of Pollution from Ships 73/78 Appendix I and Appendix IV.

1.3.2 Regulations enacted by Chinese government bodies

Offshore oil and gas process system must comply with the applicable statutory requirements enacted by the competent Chinese government bodies. The related specifications of the following statutory regulations have been included into the Rules:

(1) Safety Rules for Fixed Offshore Platform, 2000, enacted by State Economic and Trade Commission;

(2) Safety Rules for Floating Production, Storage and Offloading Unit (FPSO), 2010, enacted by the State Administration of Work Safety;

(3) Safety Rules for Floating Offshore Unit, 1992, enacted by the State Register of Shipping;

(4) Safety Rules for Mobile Offshore Platform, 2013, enacted by State Maritime legal survey of Administration;

(5) Safety Rules for Artificial Island in Shallow Sea, 2010, enacted by the State Energy Administration (SY/T 6777).

1.3.3 Rules of China Classification Society

The applicable safety and technical requirements stated in the following rules of the Society have been included into the Rules:

(1) Rules for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk and its amendments;

(2) Guidelines for Survey of Membrane Tank LNG Carriers and its amendments.

SECTION 4 RECOGNIZED STANDARDS

1.4.1 General requirements

1.4.1.1 Besides compliance with the requirements of the Rules, the Society recognizes the applicable parts of international standards, advanced oversea standards, national standards and industrial standards for the design, manufacturing, installation, survey and test of the mechanical equipment, vessels, piping and instruments associated with the offshore oil and gas process system.

1.4.1.2 When other standards are to be used in substitution of the recognized standards of the Rules, these standards are to be evidenced to represent an overall safety level equivalent to that stated in the recognized standard and be applied only after having been evaluated and approved by the Society.

1.4.1.3 Application of different standards for the same equipment or system is to be avoided.

1.4.1.4 Any inconsistency with design standards and any exemption from and modification to the requirements of design standard are to be expressly indicated in the design document and approved by the owner and the Society.

1.4.1.5 Standard of the latest revision, which is valid on the effective date of design contract, is to be applied, unless otherwise expressly stated in the contract.

1.4.2 Recognized standards

1.4.2.1 National standards in relation to Offshore oil and gas process system recognized by the Society are as follows:

(1)	GB 17820	Natural Gas
(2)	GB/T20368	Production, Storage and Handling of Liquefied Natural Gas (LNG)
(3)	GB150	Pressure Vessels
(4)	GB/T 20972 (All parts)	Petroleum and natural gas industries Material for use in H_2S-containing environments in oil and gas production

1.4.2.2 Other standards recognized by the Society in relation to oil and gas process system will be defined in the following corresponding chapters or sections.

CHAPTER 2 SURVEY AND CERTIFICATION

SECTION 1 GENERAL

2.1.1 General requirements

The Rules is the basis for the Society to perform classification survey, certification survey or verification survey for offshore oil and gas process system; and these rules as approved by the competent administration or the quoted statutory rules can also be the reference for statutory survey.

2.1.2 Classification survey

2.1.2.1 For the Society's classification services, conditions and procedure, see the applicable sections of the classification rules or guidelines for the offshore installation on which the oil and gas process system is installed.

2.1.2.2 After design review, survey have been completed by the Society's surveyor upon the request from the owner or its agent, and compliance with the applicable requirements of the Rules has been confirmed thereby, the following class additional notations may be assigned:

(1) Crude oil or natural gas production system found to be in accordance with the applicable requirements of the Rules may be assigned class additional notation **PROCESS**;

(2) Natural gas production system and purification and liquefaction system found to be in accordance with the applicable requirements of the Rules may be assigned class additional notation **PROCESS (LNG)**;

(3) Liquefied petroleum gas production and recovery system found to be in accordance with the applicable requirements of the Rules may be assigned class additional notation **PROCESS (LPG)**;

(4) Systems found to be in compliance with of the above paragraphs (2) and (3) may be assigned class additional notation **PROCESS (LNG, LPG)**;

(5) Natural gas regasification system found to be in accordance with the applicable requirements of the Rules may be assigned class additional notation **REGAS**.

2.1.2.3Conditions for retaining additional class notations

(1) Various surveys are to be carried out as specified by the Rules confirming that the technical conditions of the object remain compliant with the requirements of the assigned additional class notation;

(2) The offshore oil and gas process system is to be well maintained, managed and operated by the qualified personnel; the operation and test procedures are to be followed; and the working load and environmental conditions are to be confined to be within the specified design envelope;

(3) Any damage, failure and repair that may affect the assigned additional class notation is to be immediately notified to the Society. In such cases the Society will perform evaluation and/or survey and give its requirements and comments.

2.1.3 Certification survey

2.1.3.1 For the Society's certification services, conditions and procedure, see the applicable sections of the main rules for the offshore installation on which the oil and gas process system is installed.

2.1.3.2 Upon request from the owner or its agent or from other entrusting party, the Society's surveyor may carry out review, survey as specified by the Rules and will, once compliance confirmed, issue the corresponding compliance certificate and survey related documents.

2.1.3.3 Conditions for maintaining validity of the certificate:

(1) Various surveys are to be carried out as specified by the Rules confirming that the technical conditions of the object remain compliant with the applicable requirements of the Rules;

(2) Compliance with the requirements stated in 2.1.2.3 (2) and (3)

(3) Compliance with the requirements stated in Section 5.

2.1.4 Coordination with statutory survey

2.1.4.1 If the oil and gas process system is pending application for classification survey or certification survey, the Society may carry out the classification or certification survey in combination with the statutory survey.

2.1.4.2 Statutory survey is to be carried out in accordance with the applicable requirements prescribed in the latest revision of the safety rules enacted by Chinese government, which namely are Safety Rules for Fixed Offshore Platform, Legal survey of Rules for Mobile Offshore Platform or Safety Rules for Floating Production, Storage and Offloading Unit.

2.1.4.3 Where there is any conflict between the technical requirements of the Rules and the requirements of the latest revision of applicable rules enacted by Chinese government, the requirements of the statutory administration are to prevail and be complied with firstly.

2.1.4.4 In case an application for statutory survey of an oil and gas process system arranged on the offshore installation under the jurisdiction of other states is addressed to the Society, it is to be handled in accordance with the requirements from the governing administration of the said offshore installation.

2.1.5 Verification survey

Upon request from an entrusting party, the Society may carry out verification survey for the oil and gas process system or certain equipment of the system according to the Rules requirements or the standards specified by the entrusting party, and will issue the corresponding survey certificate once compliance has been verified.

SECTION 2 DESIGN REVIEW

2.2.1 General requirements

2.2.1.1 Prior to commencement of construction, the applicant is to submit the drawings and documents required by this Section in triplicate or electronic drawings to the offshore engineering drawing review department of the Society for review. When necessary, the Society may require extending the scope of drawings and documents to be submitted for review.

2.2.1.2 The construction and installation technique as well as the commissioning schedule of the oil and gas process system are to be submitted to the Society's survey execution department for review.

2.2.1.3 If there is any principal modification or supplement to the approved drawings and documents, the applicant is to submit the modified or supplemented parts for review.

2.2.2 List of drawings and documents to be submitted

(1) General project statement

The contents of project statement, as a minimum, are to include: brief description of oilfield location, environmental conditions, well shut-in pressure, properties of well flow, production plan, oil and gas storage and transfer arrangement.

(2) General layout

(3) Legend, symbols and notes of oil and gas process system drawings

(4) Arrangement plan of equipment for oil and gas process system

Submission of this plan is not required if it has been included in the general layout.

(5) Heat and mass balance charts

(6) Oil and gas process system flow diagrams

Flow diagrams mainly include:

① Crude oil processing flow diagram;

② Natural gas processing flow diagram;

③ Production oily water processing flow diagram;

④ Subsea production flow diagram;

⑤ Fluid disposal (relief via safety valve and depressing valve and other vents) flow diagram;

⑥ Closed drain flow diagram;

⑦ Open drain flow diagram;

⑧ Chemical injection flow chart;

⑨ Water injection flow diagram;

⑩ Gas injection and gas lift flow diagram;

⑪ Natural gas fuel processing flow diagram;

⑫ Crude oil fuel processing flow diagram;

⑬ Crude oil transfer flow diagram;

⑭ Natural gas purification flow diagram;

⑮ Natural gas liquefaction flow diagram;

⑯ Liquefied natural gas transfer flow diagram;

⑰ Liquefied natural gas regasification flow diagram;

⑱ Regasified natural gas transfer flow diagram;

⑲ Thermal medium flow diagram;

⑳ Utility system flow diagrams (as listed in Chapter 10 of the Rules).

(7) Oil and Gas Process System Piping and Instrument Diagrams (P&IDs)

The following contents are to be shown in P&IDs as a minimum:

① Design and operation conditions;

② Name, dimensions and parameters of all main equipment;

③ Class and specifications of piping elements (e.g., pipe, fitting, valve, flange, expansion joint, filter etc.);

④ Measuring, sensing and controlling instruments;

⑤ Signal circuit;

⑥ Set point of controller;

⑦ Shutdown and pressure relieving devices and their set points;

⑧ Limit of modules and skids.

P&IDs mainly include:

① Crude oil processing P&IDs;

② Natural gas processing P&IDs;

③ Production oily water processing P&IDs;

④ Subsea production P&IDs;

⑤ Fluid disposal (relief via safety valve and depressing valve and other vents) P&IDs;

⑥ Closed drain P&IDs;

⑦ Open drain P&IDs;

⑧ Chemical injection P&IDs;

⑨ Water injection P&IDs;

⑩ Gas injection and gas lift P&IDs;

⑪ Natural gas fuel processing P&IDs;

⑫ Crude oil processing P&IDs;

⑬ Crude oil transfer P&IDs;

⑭ Natural gas purification P&IDs;

⑮ Natural gas liquefaction P&IDs;

⑯ Natural gas transfer P&IDs;

⑰ Liquefied natural gas regasification P&IDs;

⑱ Steam treatment system P&IDs;

⑲ Regasified natural gas transfer P&IDs;

⑳ Thermal medium P&IDs;

㉑ Utility system P&IDs (as listed in Chapter 10 of the Rules).

(8) Safety analysis function evaluation (SAFE) chart or cause and effect matrix chart

①Safety analysis function evaluation chart is to list all the equipment, components and associated instruments, control and safety protection devices and describe the function of each safety protection device.

②Cause and effect matrix may be used to replace the safety analysis function evaluation chart. Cause and effect matrix chart is a chart which reflects the relationship between the cause of a hazardous event and the effect of the event and can also reveal the intrinsically interdependent relations between the initiating event and the consequential event. All causes to the event and the consequential effects are to be listed in cause and effect matrix chart. The cause and effect matrix may be in the form of diagram, chart or block diagram.

(9) Piping arrangement plan

(10) Piping specifications

Piping specifications are to include piping material, welding, manufacturing, survey and test, as well as details regarding piping support and insulation and other aspects.

(11) Pipe dimensions calculation

(12) Stress analysis report for high-pressure, high-temperature piping and cryogenic piping

(13) Design specifications for oil and gas process equipment

The design specifications are to include, as a minimum:

① Brief description of the equipment;

② Equipment structural details (dimensions);

③ Equipment structural calculation report;

④ Design parameter sheet (e.g. pressure, temperature, corrosion allowance, etc.);

⑤ Material specifications

⑥ Welding details;

⑦ Non-destructive test details

⑧ Test requirements;

⑨ Type, class and required temperature group of explosion-proof equipment.

The above mentioned items which are not included in the specifications may also be submitted separately.

(14) Design specifications for skid-mounted equipment

This specification has same contents as equipment specifications except for the skid arrangement plan and assembly drawings which are to be additionally included.

(15) Sizing calculation report for pressure safety relief valve

(16) Sizing calculation report for depressing valve

(17) Sizing calculation report for flare stack

(18) Sizing calculation report for flare knockout drum

(19) Flare tip specifications

(20) Design calculation report for cold vent riser

(21) Specifications of instrument and control system of oil and gas process system

(22) Oil and gas process system control block diagram.

(23) Wellhead control panel specifications

(24) Wellhead control panel block diagram

(25) Process shutdown and emergency shutdown system specifications

(26) Safety requirements and specifications, operation instructions, maintenance and test procedure of high integrity pressure protection system (HIPPS);

(27) Oil and gas process system commissioning and test schedule

(28) Oil and gas process system operation manual.

2.2.3 Key points of drawing review

The key points of drawing review for oil and gas production system are as follows:

(1) Check the primary and secondary protection devices equipped in each processing component (such as pressure vessel, atmospheric tank, heat exchanger, furnace, pump, compressor, manifold etc.), which may experience the following undesirable events:

① Overpressure;

② Leak;

③ Liquid overflow;

④ Gas blow by;

⑤ Under pressure;

⑥ Overtemperature;

⑦ Direct ignition source;

⑧ Excessive combustible vapors in the firing chamber.

(2) Check the high integrity pressure protection system for its independence of other control and shutdown systems and confirm its availability and reliability are no less than the availability and reliability of the individual mechanical pressure relief device being substituted;

(3) Review the reasonability of process shutdown and emergency shutdown arrangement and logic, and check if the two systems are mutually independent and featured with fault detection function.

(4) Review the safety analysis and function evaluation (SAFE) chart and verify on a case-by-case basis the correctness of the safety protection device equipped on each processing component and equipment and the reasonability of the safety functions related to the execution of alarm and shutdown.

(5) Review the sizing design calculation report of safety valves. The relief capacity of the safety valves is to be selected based on the most severe conditions of the following scenarios:

① Block scenario;

② Fire scenario;

③ Thermal effect.

(6) Review the sizing calculation report of depressing valve and confirm the relief capacity of the depressing valve;

(7) Review the calculation reports of flare and cold vent, confirm the reasonable selection of emergency relief capacity, normal relief capacity and heat radiation intensity and thus determine the correctness of the height and diameter of the flare and cold vent stack.

(8) Review the sizing design calculation report of flare and cold vent scrubber and confirm the reasonability of the scrubbers liquid separation and storage capacity, blockage and freeze protection measures.

(9) Review the compliance of the design and sizing calculation of flare and cold vent manifold with the

requirements stated in the Rules.

(10) Review the compliance of the configuration and capacity of the flare pilot with the requirements stated in the Rules.

(11) Review the reasonability of the arrangement of oil leakage collection and containment system and closed drains.

(12) Review the reasonability of the protection measures for cryogenic leak during the liquefaction, regasification and liquefied natural gas transfer and the reliability of the emergency disconnection system.

(13) Check the compliance of the strength calculation, welding details, material, NDT and heat treatment of pressure vessels with the requirements.

(14) Check whether the sizing design of oil and gas process equipment satisfies the Society recognized standards.

(15) Review the sizing calculation report of piping and confirm that its strength meets the requirements and pipe flow velocity is lower than erosion velocity.

SECTION 3 PRODUCT SURVEY

2.3.1 General requirements

2.3.1.1 The products of oil and gas process system are to be inspected to confirm their compliance with the classification requirements, statutory requirements or requirements from an entrusting party.

2.3.1.2 The involved products of the Rules, for which specific technical requirements have not been specified, may be designed, manufactured, inspected and tested in accordance with the standards recognized by the Society.

2.3.1.3 For the products required by the rules, appropriate standards may be accepted as alternative requirements. However, design evaluation, surveys during manufacture, testing and function test are to be carried out to verify that they are equivalent to those stated in the Rules.

2.3.2 Categorization of survey and certificate

2.3.2.1 Products found to be in accordance with the applicable requirements of the Rules can be categorized into such three survey types as below:

(1) Type A equipment: equipment which require the Society to carry out design review and surveys in process of manufacturing, attend completion inspection and witness test (performance, pressure and load test) and review manufacturing records.

(2) Type B equipment: equipment which requires the Society to carry out design review, attend completion inspection and witness test (performance, pressure and load test) and review manufacturing records.

(3) Type C equipment: equipment which is related to safety and requires the Society to accept the product certificate provided by the manufacturer.

2.3.2.2 Categorization of product survey and certificate is to comply with Table 2.3.2.2. CA denotes the product certificate issued by the Society while W denotes the certificate issued by the manufacturer.

Equipment survey and certificate classification Table 2.3.2.2

Equipment	Survey type			Certificate type	
	A	B	C	CA	W
1 Above water Christmas tree					
Christmas tree	×			×	
Wellhead couplings	×			×	
Christmas tree valves, valve assembly and adapters	×			×	
2 Subsea production system					
Subsea wellhead couplings	×			×	
Subsea template/other seabed support structure					
Subsea Christmas tree	×			×	
Subsea manifold	×			×	
Pipeline end manifold	×			×	
Pipeline tee (including Y-type and T-type)	×			×	
Other subsea pipeline connection system/assembly	×			×	
Subsea connector system	×			×	
Subsea distribution unit (electric, hydraulic)	×			×	
Riser	×			×	
Riser base	×			×	
Flexible riser buoyancy block		×		×	
Riser tensioning system		×		×	
Subsea safety isolating valve assembly	×			×	
Subsea separation system	×			×	
Subsea booster system， installation or station	×			×	
Subsea jumper (including spool)	×			×	

Equipment	Survey type			Certificate type	
	A	B	C	CA	W
Subsea flow meter and testing device		×		×	
Subsea equipment protective structure	×			×	
Support structure of split-type subsea equipment	×			×	
Flexible pipe system		×		×	
Subsea umbilical terminal assembly (distribution and control)	×			×	
Umbilical		×		×	
Control system of subsea production system		×		×	
3 Oil, gas and water processing equipment					
Test separator	×			×	
Production separator	×			×	
Crude oil dehydrator (chemical, electrical)	×			×	
Desalter	×			×	
Coalescer	×			×	
Heat exchanger	×			×	
Cooler	×			×	
Crude oil storage tank	×			×	
Closed drain tank	×			×	
Open drain tank		×		×	
Flare and cold vent scrubber	×			×	
Flare and cold vent water seal		×		×	
Slug catcher	×			×	
Fuel gas separator		×		×	
Gas scrubber	×			×	

Equipment		Survey type			Certificate type	
		A	B	C	CA	W
Absorption tower		×			×	
Reboiler		×			×	
Flash tank		×			×	
Oil skimmer			×		×	
Plate type oil interceptor			×		×	
Hydrocyclone			×		×	
Floatator			×		×	
Filter (walnut shell, dual medium, fiber ball)						
4 Liquefaction and vaporization containers						
Cold box		×			×	
Refrigerant (combustible, toxic) storage tank		×			×	
High-pressure pump suction tank		×			×	
Vaporizer		×			×	
Heat transfer medium (combustible, toxic) storage tank			×		×	
5 Other pressure vessels and storage tanks not listed in item 3 and item 4						
Pressure	1<P≤20000/(Di + 1000)		×		×	
	P>20000/(Di + 1000)	×			×	
	Vacuum or external pressure	×			×	
Medium	Steam		×		×	
	Toxic liquid	×			×	
	Thermal oil		×		×	
	Liquid with a flash point (closed cup) lower than 100°C	×			×	
	Combustible liquid with temperature T>150°C	×			×	

Equipment		Survey type			Certificate type	
		A	**B**	**C**	**CA**	**W**
	Other fluids with temperature>220°C		×		×	
	Compressed air/gas with PV≥1.5		×		×	
Material	δ_y >345 Mpa or δ_t>515 Mpa	×			×	

Note:

1 the denotations of the symbols in above table are as follows:

P: Internal pressure 0.1 MPa

Di: Inner diameter mm

V: Volume m^3

T: Design temperature

δ_y:Specified yield strength

δ_t:Specified tensile strength

2 For non-spherical pressure vessels (e.g., plate type heat exchanger), the maximum diagonal distance is to be taken as the diameter.

3 Non-ferric vessels are to be treated case by case.

4 The scope of certification does not include the lift ring and lift points on the equipment.

6 Piping and piping components

Equipment		A	B	C	CA	W
Tubular items, including attachments	Wellhead flowline	×			×	
	Production and test manifold	×			×	
	Flare and vent manifold	×			×	
	Liquefied gas transfer manifold	×			×	
Tubular items, including attachments and supports	Ragas transfer manifold	×			×	
	Pig launcher and receiver		×		×	
	Flare stack		×		×	
	Cold vent stack		×		×	
	Metering spool of oil and gas transfer line	×			×	
	Other special pipe items	×			×	
Flange and coupling	Standard type			×		×
	Standard and high-pressure（≥42MPa）					

Equipment		Survey type			Certificate type	
		A	B	C	CA	W
	Involving toxic medium		×		×	
	Involving combustible medium		×		×	
Valves, including choke valve	Valves used for hydrocarbon and combustible gas (DN≥350 mm and P≥100 bar) or (DN≥25 mm and P≥500 bar)		×		×	
	Valves used for fluid (DN≥25 mm or P≥500 bar)		×		×	
	Non-standard type		×		×	
	Shutdown valve including actuator		×		×	
	Depressuring valve including actuator		×		×	
	Safety valve and rupture disk		×		×	
Filter Metering device	≤ 254 mm or 1.6 MPa			×		×
	>254 mm or 1.6 MPa		×		×	
Non-standard parts	Including pressurized instruments and special pipe fittings		×		×	
Expansion joint, corrugated pipe	Involving combustible or toxic fluid		×		×	
Flexible tube	Involving combustible or toxic fluid	×			×	
7 Mechanical equipment and components						
Skid	Oil and gas process skid	×			×	
	Production water processing skid		×		×	
	Other skids (chemical injection, water injection)		×		×	
Process fired heater		×			×	
Process electric heater		×			×	
Hydrocarbon compressor		×			×	
Pump	Non-standard type	×			×	

Equipment		Survey type			Certificate type	
		A	B	C	CA	W
Pump	Liquefied gas LP transfer pump	×			×	
	Liquefied gas HP transfer pump	×			×	
	Pump with power ≥300kW	×			×	
	Hydrocarbon pump with power<300kW		×		×	
	General purpose pump with power<300kW			×		×
Liquefied gas loading arm		×			×	
Gas return arm		×			×	
Crude oil separator						
Flare tip and its sealing device			×		×	
Flare ignition device			×		×	
Flame arrester			×		×	
Rotary joint and components	Involving combustible or toxic fluid	×			×	
Note: 1 If the equipment within the skid is a product purchased by the skid manufacturer, this purchased product is to be certified as an individual product.						
8 Electrical, instrumentation and automation						
Electric motor	Power ≥100kW		×		×	
	Power<100kW			×		×
Uninterrupted power supply with power ≥50kW, including battery			×		×	
Other electrical equipment				×		×
Monitoring and control system			×		×	
Wellhead control panel			×		×	
Non-standard instruments			×		×	
Standard and mature instruments				×		×

2.3.3 Review of product drawings and documents

2.3.3.1 The applicant is to submit the following drawings and documents related to the product to be certificated in triplicate to the Society for review:

(1) Applicable technical standards for the product;

(2) Product general specification;

(3) Product design drawings and/or manufacture drawings, including parts drawing, list of parts and materials;

(4) Design calculations;

(5) Prototype and /or type test report (if available);

(6) Product inspection and test plan and/or test schedule and acceptance criteria;

(7) Main manufacturing technology documents;

(8) Other documents required by the Society.

2.3.3.2 The Society will review the submitted drawings and documents to verify that the design of the product is in compliance with the Rules or standards recognized by the Society. After review of drawings and documents, the Society will issue drawing review approval notice to the applicant, mark the approval status on the submitted technical documents and return the approved drawings.

2.3.4 Surveys at product manufacture

2.3.4.1 When carrying out specific product survey, besides the product drawings approved according to 2.3.3, the surveyor is also to understand the working mechanism of the entire oil and gas process system, the function of the surveyed product within the system and the specific requirements contained in equipment specifications;

2.3.4.2 The surveyor is to survey the product in accordance with the approved equipment drawings and specifications.

2.3.4.3 Surveys at manufacture are to include the survey carried out during manufacturing and the surveys conducted before delivery from factory.

2.3.4.4 Surveys at manufacture are to include but not be limited to the following survey items:

(1) The manufacturer's qualifications shall be examined during manufacturing inspection. In particular, for special equipment such as pressure vessels, the manufacturer shall obtain an approval certificate issued by the competent authority of the state and confirm that the certificate is valid. Confirm availability of a continuous and effective quality control plan during the course of manufacturing and fabrication, including design, procurement, processing and test, etc.;

(2) Confirm welder’s qualification or examine welders’ qualification;

(3) Check welding procedure specifications and the related welding procedure qualification records;

(4) Check material certificates or documents;

(5) Check the main welded items prior to assembling;

(6) Check the final welded products;

(7) Witness NDT of welding joints and review NDT records;

(8) Check post weld heat treatment records, especially the pressure piping for acid medium for its compliance with the requirements of the applicable standard;

(9) Check whether the dimensions are consistent with the approved drawings;

(10) Check whether the installation, dimensions and alignment of various components and parts are in accordance with relevant standard and technical requirements;

(11) Check whether all control, monitoring and instrument devices conform to the approved drawings;

(12) Witness the pressure test or load test of the entire equipment or its components in line with the manufacturing technology;

(13) Witness equipment test before delivering from the factory based on the specifications;

(14) Check other items agreed in advance by the involved parties.

2.3.5 Issuance of certificate

Corresponding certificate and/or other survey certification documents will be issued to the applicant upon satisfactory survey of the product.

SECTION 4 CONSTRUCTION SURVEYS

2.4.1 General requirements

2.4.1.1 Prior to the construction of oil and gas process system, the applicant is to submit a written application for construction surveys to the headquarters of the Society or other field survey organizations.

2.4.1.2 For yards constructing oil and gas process system firstly, the surveyor is to carry out evaluation on the construction with respect to its production capacity, including production premises and facilities, quality assurance system, overall qualification of the workforce and its subcontractors.

2.4.1.3 Prior to commencement of construction, the surveyor is to inspect and confirm the status of preparations made by the manufacturer for construction commencement and the survey, such as construction preparation plan, construction/welding procedure, welders/NDT personnel qualification, required product certificate list, welding specifications, NDT maps, tightness test diagrams, inspection/test items list, related materials to be used for construction, construction tolerance criteria, subcontractor conditions (when applicable), as well as pre-commencement technical documents such as necessary drawings. For individual projects which do not affect the commencement of construction, the surveyor may inspect and confirm them prior to the corresponding construction stage.

2.4.1.4 The field surveyor confirms that the construction drawings, technique and test schedule are in accordance with the approved drawings, comments of drawing review and documents and the applicable rules and that the survey is carried out according to the approved drawings, documents, technique and test schedule. Confirm the measures taken by the construction plant, if there are any different opinions on the implementation of the examination and approval drawings and the examination and approval opinions of the construction plant, the feedback shall be sent to the examination and approval department in time.

2.4.2 Welding, heat treatment and NDT

2.4.2.1 General requirements

The welding, heat treatment and NDT of pressure vessels, pressure piping and important machinery components are to be in compliance with this subsection or be surveyed according to standards recognized by the Society.

2.4.2.2 Pressure vessels

The welding, heat treatment and NDT range of pressure vessels are to be verified to be compliant with the requirements of Chapter 7, Part 3 of *Rules for Material and Welding* of the Society.

2.4.2.3 Pressure piping

The welding, heat treatment and NDT range of pressure piping are to be verified to be compliant with the requirements of Chapter 9, Part 3 of *Rules for Material and Welding* of the Society. Where there is any inconsistency between the two above mentioned rules, the Rules is to prevail.

2.4.3 Survey of yards self-manufactured equipment

(1) Yards self-manufactured equipment are to be reviewed and surveyed according to the provisions in 2.3 Product Survey.

(2) When equipment are assembled into skid or module, the surveyor is to survey the assembly, piping and electrical connection and witness the pressure and function tests of the entire assembly according to the approved certification documents and test procedures.

2.4.4 Inspection of procured equipment

(1) Certificates of the procured equipment are to be reviewed according to the requirements of 2.3.2 of this Chapter.

(2) Verify the consistency between equipment nameplate and certificate.

2.4.5 Piping prefabrication and installation survey

(1) Confirm that piping fabrication meets the related requirements of Chapter 8 of the Rules;

(2) Confirm that piping installation meets the related requirements of Chapter 3 and Chapter 8 of the Rules.

2.4.6 Set pressure test of safety valves

(1) Confirm that safety valves have been calibrated by a qualified specialized organization;

(2) Confirm that the opening and closing pressure of safety valves meet the applicable requirements;

(3) In case safety valves are being calibrated by an unapproved organization, the surveyor is to witness the field test of them.

2.4.7 Hydrotest

2.4.7.1 The surveyor is to witness the hydrotest of the system and confirm achievement of the following conditions before hydrotest:

(1) Installation of piping system is in compliance with the requirements of design and construction drawings;

(2) Installation of piping supports and hangers has been completed, with correct material and installation position, reliable connection and qualified welding;

(3) All welding, heat treatment and NDT have been completed and qualified;

(4) Welding joints are to be unpainted and the detachable connectors uninsulated, for convenience of inspection;

(5) Items not involved in the test such as safety valves and instruments have been effectively isolated before the tests.

2.4.7.2 Check the type and quality of the liquid used for hydrotest comply with the requirements.

2.4.7.3 Check the ambient temperature for hydrotest complies with the requirements.

2.4.7.4 Check the temperature of the liquid used for hydrotest complies with the requirements.

2.4.7.5 When hydrotest of systems made of Austenitic stainless steel is to be carried out using water, the chlorine ion content of the water is to be checked and no more than 25mg/L.

2.4.7.6 Check the hydrotest pressure is in compliance with paragraph 8.3.13.1, Chapter 8 of the Rules or standards recognized by the Society.

2.4.7.7 Confirm that the system has been flushed and cleaned prior to hydrotest.

2.4.7.8 Confirm that the air inside the system has been fully emptied at the time of hydrotest.

2.4.7.9 Confirm that pressurization and depressurization are carried out slowly during hydrotest.

2.4.7.10 Carry out comprehensive and detailed inspection of the system during pressure-holding period and confirm that the system is free of any leakage and no pressure reading fall which affects the test results and that the piping has not sustained any deformation.

2.4.7.11 The surveyor is to sign the test records after confirming the hydrotest is qualified.

2.4.7.12 In case air tightness test is adopted to replace hydrotest, the applicable provisions of paragraph 8.3.14, Chapter 8 of the Rules are to be complied with.

2.4.8 Comprehensive inspection before commissioning

In order to ensure qualified manufacturing, construction and installation quality of each individual equipment/skid and the system prior to commissioning, the following main inspections are to be carried out according to the approved pre-commencement inspection documents before the start of system commissioning:

2.4.8.1 Review of mechanical completion documents

Review of mechanical completion documents covers the following items:

(1) Review construction inspection and test reports, including piping hydrotest report, air tightness test report, certification of construction materials, inspection reports of constructors, welding quality inspection reports, insulation resistance test reports for electrical system and other mandatory test reports, and check if there is any pending item, especially the comments on corrective actions raised by the certification and survey organization;

(2) Review the factory certification of equipment and check if there is any pending test item;

(3) Review the flushing records for equipment and piping to ensure their internal cleanness.

2.4.8.2 Equipment inspection

(1) Confirm the equipment name plates are securely fixed, durable and legible;

(2) Confirm correctness of the information on equipment nameplates;

(3) Confirm correctness of equipment sign or code;

(4) Confirm correctness of equipment location, orientation and quantity;

(5) Confirm completeness of special tools for the equipment;

(6) Confirm intactness of equipment including accessory parts, piping, instruments and electrical wire;

(7) Confirm intactness of mechanical seal;

(8) Confirm availability of safety protection measures for rotating parts;

(9) Confirm that all connecting bolts have been tightened;

(10) Confirm that the equipment have been assembled and installed in accordance with the installation technique and the manufacturer's instructions;

(11) Confirm equipment is securely connected with the base;

(12) Confirm the equipment base is securely connected with the main structure;

(13) Confirm the interconnecting piping and electrical connection between skids or modules are normal;

(14) Confirm the coating, insulation and installation of supports and hangers conform to the requirements;

(15) Confirm insulation, freeze prevention and ventilation measures are effective;

(16) Confirm the access and space for operation and maintenance comply with the requirements;

(17) Confirm the small operation platforms, guardrails and ladders comply with the requirements;

(18) Confirm the vicinity of the site is free of any foreign material and hazardous material;

(19) Confirm there is no debris inside the equipment or vessel;

(20) Confirm intactness of interior coating;

(21) Confirm that the internal structures, separation plates, devices and piping have been firmly installed and correctly arranged;

(22) Confirm that the covers of manhole and hand hole for internal survey have been tightened;

(23) Confirm absence of trapped liquid inside the vessels by opening and closing the drain valve;

(24) Confirm that the internal corrosion protections for equipment have been correctly installed;

(25) Confirm that the lubricant, heat exchange liquid and additives to be used for equipment commissioning are available.

2.4.8.3 Piping inspection

(1) Confirm the Piping is neatly arranged and convenient for inspection and maintenance;

(2) Confirm that crude oil, natural gas piping does not pass through any enclosed non-hazardous space;

(3) Confirm that the quantity of detachable connectors in the Piping is kept at a minimum required level;

(4) Confirm that the installed piping on the equipment is freely aligned and without any additional stress;

(5) Confirm that the thermal compensation of pipeline is qualified;

(6) Confirm that Piping supporting is qualified;

(7) Confirm that the quantity, type and diameter of valves meet design requirements;

(8) Confirm that flow direction of the medium matches with the valve inlet and outlet;

(9) Confirm the valve rotation direction and the display of opening and closing status are correct;

(10) Confirm that safety valves are installed vertically;

(11) Confirm correct size and installation of inlet pipe and outlet pipe of safety valves;

(12) Confirm that the filter is installed in the correct direction;

(13) Confirm that the filter is easy to replace and the filter core is clean;

(14) Confirm that the quantity, arrangement and quality of shutdown valves meet design requirements;

(15) Confirm that the insulation and heat tracing of pipeline comply with the requirements;

2.4.8.4 Inspection of electrical system

(1) Confirm that wiring principle of power, control, safety and signal circuits is correct;

(2) Confirm that safety circuit is independent of the control circuit;

(3) Confirm that alarm and safety circuit conform to the fail-safe principle;

(4) Confirm that the model and specifications of power cable meet design requirements;

(5) Confirm that power cable has been reasonably routed in such a way that prevents damage and avoids heat sources and liquid leak sources;

(6) Confirm that the power cables have been installed in a firm and neat way, allowing easy route inspection;

(7) Confirm that the bonding connections and grounding connections are correct and effective;

(8) Confirm that the cables for equipment, devices and instruments comply with explosion-proof requirements;

(9) Confirm that the control panel of equipment is intact, reasonably arranged and easy to operate;

(10) Confirm that the systems control and alarm indicators in the control room are complete and intact;

(11) Confirm that wellhead control panel is intact and undamaged;

(12) Confirm that the press buttons, switch indicator lights and indicator instruments on wellhead control panel are correctly installed, intact and undamaged;

(13) Confirm that the input and output wires of wellhead control panel are orderly arranged and that the wiring terminal numbers are legible and durable;

(14) Confirm that the power supply and air supply sources of wellhead control panel comply with the requirements;

(15) Confirm that the set points of the pressure reduce valve and pressure switch of wellhead control panel comply with design requirements;

(16) Confirm that the manual and pneumatic pumps of wellhead control panel are working properly;

(17) Confirm that the location for operation of emergency shutdown meets design requirements.

2.4.8.5 Inspection of instrument and control system

(1) Confirm that all instruments installed in the system have been inspected and calibrated by a specialized organization;

(2) Confirm that the appearance of instruments is clean and their digital symbols are legible;

(3) Confirm that the instruments have been installed at correct position;

(4) Confirm that instrument indicators return to zero or are in steady-state indication.

2.4.8.6 Set pressure test of safety valves

Confirm that safety valves have been tested and comply with the applicable requirements.

2.4.8.7 Hydrotest

Confirm that hydrotest has been completed and complies with the applicable requirements.

2.4.8.8 Air tightness test

Confirm that the required air tightness test has been completed and complies with the applicable requirements.

2.4.8.9 Flushing and cleaning test

Confirm that the purging and cleaning test has been completed and complies with the applicable requirements.

2.4.8.10 Special commissioning tools and testing instruments

(1) Confirm that the complete sets of special tools and instruments required for commissioning have been made available;

(2) Confirm that the testing instruments required for commissioning have been calibrated by a specialized organization.

2.4.8.11 Utility support system

(1) Confirm that utility support systems have been commissioned in accordance with utility system commissioning manual;

(2) Confirm that the utility support systems are always readily available.

2.4.8.12Safety system

(1) Confirm that fire protection, lifesaving and communication systems are readily available;

(2) Confirm that the escape route is clear and unobstructed;

(3) Review and confirm that emergency response plan meets applicable requirements.

2.4.9 Tests of individual equipment and skid-mounted equipment

Tests of individual equipment and skid-mounted equipment are to be carried out after qualified inspection before commissioning. The surveyor will mainly witness the following tests:

2.4.9.1 Equipment safety protection device

Each safety protection device of all equipment (e.g. safety valve, PSH/PSL sensor, TSH/TSL sensor, LSH/LSL sensor etc.) is to be tested according to safety analysis function evaluation (SAFE) or cause and effect diagram, and the test tolerances are to comply with the provisions in Section 5Chapter 4 of the Rules.

High integrity pressure protection system is to be tested according to approved procedure to ascertain its compliance with the safety requirements stated in system specifications.

2.4.9.2 Pump

Pumps are to be kept running continuously for at least 2 hours under full load, and various operation parameters are to be recorded, confirming that:

(1) Pump performance meets the requirements of flow rate and pressure head curve;

(2) Vibration and noise levels are acceptable;

(3) Temperature of pump bearings is acceptable;

(4) Measured resistance in cold and hot state of pump motor complies with the requirements;

(5) Alarm and shutdown functions are qualified.

2.4.9.3 Hydrocarbon compressor

Compressors are to be kept running continuously for at least 2 hours under full load, and various operation parameters are to be recorded, confirming that:

(1) Automatic loading function is tested normal;

(2) Pneumatic control function meets the design requirements;

(3) Bypass valve works normally;

(4) Operational performance of compressors meets the design requirement;

(5) Vibration and noise levels during operation are acceptable;

(6) Measured temperature of various parts is acceptable;

(7) Measured resistances in cold and hot state of compressor motor comply with the requirements;

(8) Alarm and shutdown functions are qualified.

2.4.9.4 Fired pressure vessel

Fired pressure vessels are to be kept running continuously for at least 2 hours under full burning load, and various parameters are to be recorded, confirming that:

(1) Temperature control and monitoring functions (alarm and shutdown) are normal;

(2) Flow rate control and monitoring functions (alarm and shutdown) are normal;

(3) Pressure control and monitoring functions (alarm and shutdown) are normal

(4) Oil leakage monitoring functions (alarm and shutdown) are normal;

(5) Flame and ignition failure monitoring functions (alarm and shutdown) are normal;

(6) Manual shutdown function is normal.

2.4.9.5 Flare

Ignition test of pilot system is to be performed and conformity is to be confirmed.

2.4.9.6 Wellhead control panel

(1) Single well test

Manually open and close the wellhead surface safety valve and confirm that indication of circuit hydraulic pressure and valve position is normal.

(2) Shutdown test

Conduct emergency shutdown test (including fusible plug shutdown) to confirm correct action of the surface and subsurface safety valves; confirm pressure indication and status indication are normal;

Conduct automatic shutdown test (process shutdown) to confirm correct action of the surface and subsurface safety valves; confirm pressure indication and status indication are normal.

2.4.10 System commissioning

System commissioning is to be carried out on the basis of individual equipment commissioning and, generally, the tested items during individual commissioning will not be repeated. The surveyor is to mainly witness the following tests:

2.4.10.1 Shutdown test

(1) Confirm that test of automatic shutdown (process shutdown) due to undesirable events (e.g., overpressure, overtemperature and flame failure) has been completed and complies with the requirements;

(2) Carry out local shutdown and entire platform shutdown tests on a case-by-case basis from each emergency shutdown station and confirm compliance with the design requirements;

(3) Carry out test of shutdown caused by fusible plug loop and confirm compliance with the design requirements;

(4) If leveled shutdown has been designed, each level shutdown test is to be respectively witnessed in an order from low to high level.

2.4.10.2Water circulation test

Water circulation test of crude oil processing system, crude oil transfer system and water injection system is to be performed and last for at least 4 hours. Design conditions that are identical to those of production well flow are to be established as far as possible during the test. Fresh water and air is to be used as the medium for water circulation as far as practically possible, and corrosion inhibitor is to be added in case seawater is to be used. The following items are to be inspected and tested during water circulation test:

(1) Confirm that the pumps in trial running operate normally during water circulation test;

(2) Confirm that the indication of various instruments (for pressure, temperature, level, flow rate) at the local and remote points is normal;

(3) Confirm that the regulator and regulating valve operate normally;

(4) Set parameters for various control instruments, carry out full-range test on the actuator and confirm compliance with the requirements;

(5) Confirm that manual valves can be freely opened and closed and tightly closed;

(6) Confirm that various detection switches function normally and simulation shutdown test for switches linked with shutdown are to be carried out.

(7) Re-verify the opening and closing pressures of safety valve when necessary;

(8) Confirm the heat tracing system functions normally;

(9) Carry out commissioning of field control panel and confirm it is in normal condition;

(10) Carry out joint commissioning of center control system and field instruments, and confirm the indications on alarm display panel are normal;

(11) Test the control instruments, safety devices and shutdown arrangements in the system;

(12) Initiate well fluid heating system, calculate heater load from water flow rate and confirm compliance with the design requirements.

2.4.11 Start-up

Prior to start-up, the air and other fluids in the oil and gas process system are to be displayed gradually following the approved procedure. The surveyor is to confirm that the displacement procedure has been followed and observe the operation of the system under initial productivity for at least 12 hours. If feasible, the operation of the system under different conditions and varying productivity is to be observed.

SECTION 5 SURVEYS IN SERVICE (DURING PRODUCTION)

2.5.1 General requirements

2.5.1.1In order to ensure safety of oil and gas process system during the production, various surveys specified in this section are to be performed. During the survey, the Society's surveyor may extend the survey scope based on his professional judgment, where the owner or operator is to provide the required survey conditions and arrangements.

2.5.1.2 The owner or operator is to, in a timely manner, submit to the Society application for various surveys for maintaining the certificates valid, complete the preparations for the survey items and provide safety protections for the survey according to the requirements of the Rules.

2.5.1.3 If any damage or defect affecting the validity of the certificates has been found during the survey and deemed necessary for immediate treatment, the surveyor is to notify the applicant of the comments on treatment. In case such comments have not been implemented, the surveyor is to immediately report it to the Headquarters of the Society.

2.5.1.4 Surveys during the operation of oil and gas process system may be carried out in accordance with the prescribed provisions of this section. And risk-based inspection may also be performed based on the risk analysis results of the specific system.

2.5.2 Type and period of survey

2.5.2.1 Annual survey

All offshore oil and gas process systems are to be subject to annual survey. Annual survey is to be completed within 3 months before or after the anniversary date of the initial survey date or the last special (or renewal) survey date.

2.5.2.2 Special (or renewal) survey.

All offshore oil and gas process systems are to be subject to special (or renewal) survey and the survey interval is not to exceed 5 years.

2.5.3 Items of annual survey

2.5.3.1 Document review

(1) Review system operation log;

(2) Review system maintenance records;

(3) Review testing records of the safety instruments in the system;

(4) Review the testing records of high integrity pressure protection system maintenance plan;

(5) Review the operation manual.

2.5.3.2 Safety protection device

(1) Check the technical state of the high-pressure and low-pressure control systems and perform tests on the alarm and simulated shutdown action;

(2) Inspect the vent device and overflow device of atmospheric tank;

(3) Inspect the temperature control system and perform tests on the alarm and simulated shutdown action;

(4) Inspect the level gauge and level control system, and perform tests on the alarm and simulated shutdown action;

(5) Visually inspect the technical state of safety valves and verify the opening pressure of them;

(6) Inspect inlet and outlet block valves of the safety valve and check their locking device;

(7) Check the technical state of pressure reducing valve;

(8) Visually inspect the technical state of shutdown valve;

(9) Perform external examination of emergency shutdown station and simulated shutdown action test;

(10) Perform external examination of high integrity pressure protection system and simulated shutdown action test.

2.5.3.3 Pressure vessel

(1) Check the insulation coating;

(2) Check the uninsulated vessels for any corrosion, deformation, crack or other defects;

(3) Check if there is any sign of leakage at the manhole, hand hole, flange and spool pieces and if the bolts are loosened;

(4) Check if the support structure, working platform and stairway handrail of the vessel are intact;

(5) Check the electrical grounding;

(6) Check various instrument parameters and standing book.

2.5.3.4Fired pressure vessel

(1) Visually inspect the applicable items listed in 2.5.3.3;

(2) Perform simulated alarm and shutdown tests of safety protection devices, such as pressure, temperature, level and flame failure protection devices;

(3) Check calibration records of safety valves.

2.5.3.5 Heat exchanger

(1) Carry out external inspection of heat exchanger under working conditions;

(2) Check if various parameters are normal;

(3) Check calibration records of safety valves.

2.5.3.6 Christmas tree

(1) Carry out external inspection of Christmas tree under working conditions

(2) Check the valves for flexibility and tightness or review their inspection records;

(3) Check the maintenance records.

2.5.3.7 Manifold

(1) Visually inspect the manifold for any sign of corrosion and leakage;

(2) Check the valves for flexibility and tightness.

2.5.3.8 Rotating machinery

(1) Perform external examination of rotating machinery under working conditions, check if the moving parts operate normally and if there is any sign of leakage;

(2) Record the parameters.

2.5.3.9 Flare and vent system

(1) Observe the burning condition of the flare to determine the technical state of the flare tip;

(2) Check the conditions of the ignition device;

(3) Check if the heat and smoke exert any influence on equipment, personnel and helicopter take-off and landing;

(4) Check the technical state of the vent pipe and check if the supporting and fixing measures are intact.

2.5.3.10 Piping

(1) Visually inspect the conditions of the external surface, heat insulation layer, painting, coating and the associated hardware of the piping;

(2) Check if the piping sustains any serious deformation, corrosion and other defects;

(3) Check the piping for any signs of displacement, vibration and leakage and special attention is to be paid to any obvious piping displacement caused by fluid impact, hydraulic hammering inside steam Piping or unusual thermal expansion. The branch connectors, fasteners and supports of Piping s subject to vibration are to be inspected by means of magnetic particle inspection or penetrant test for any fatigue defect.

(4) Check if there is any sign of leakage or loosening at the connections of flanges, valves and fittings;

(5) Check if the supports and clamps are in good condition. When corrosion product buildup is found at locations in contact with the pipe rack, the rack needs to be dismantled for inspection.

(6) Check if the cladding of piping is intact;

(7) Check if there is severe vibration in the piping. Special attention is to be paid to crack on or damage to pipe hanger as well as hanger spring being seated on the bottom, falloff of pipe support from its supporting part or other abnormal conditions,

(8) Check the corrugated pipe expansion joint for any abnormal deformation, eccentricity or displacement beyond the design;

(9) Visually inspect the quality of hoses.

2.5.3.11 Oil storage equipment

(1) Check the availability of storage tank operation manual on the platform;

(2) Implement the requirements presented during the last renewal survey or annual survey;

(3) Check if there is any deformation, damage, corrosion and leakage of the bottom plate of the storage tank;

(4) Check if there is any deformation, damage, corrosion and leakage of the shell plate of the storage tank;

(5) Check if there is any deformation, damage, corrosion and leakage of the roof plate of the storage tank;

(6) Check for any defect of the attachments to the storage tank and the connection between the attachment and the tank body;

(7) Carry out visual inspection on welding joints and NDT when necessary;

(8) Check the base and associated platform structure of the storage tank for any deformation, structural deterioration and corrosion;

(9) Thickness measurement of structural areas with serious corrosion are to be taken when necessary;

(10) Inspect and test the level indicating and monitoring system;

(11) Inspect and test the heating, temperature indicating and monitoring system;

(12) Confirm the breather valve works normally without any blockage or obstruction;

(13) Check the attached structures and the piping associated with oil leakage containment.

2.5.4 Special (or renewal) survey

The following items are to be completed in addition to the annual survey items specified in this section.

2.5.4.1 Internal survey of the pressure vessel in open condition is to be carried out. When such internal survey is not practical, thickness measurement may be taken instead of the internal survey.

Thickness measurement plan is to be approved by the Society.

2.5.4.2 Rotating machinery is to be surveyed in open condition.

2.5.4.3 Carry out internal survey of oil storage equipment, perform calibration of the breathing valves or submit the latest calibration report.

2.5.4.4 For important manifolds and pipe sections affecting safety, an internal survey is to be carried out. in open condition. When such internal survey is not practical, thickness measurement may be taken instead of the internal survey; thickness measurement plan is to be approved by the Society. Internal survey may also be carried out using remote control and visualization technology.

2.5.4.5 More thickness measuring points should be selected for any pipe with:

(1) High potential threats to safety and environmental in the event of a leak;

(2) Very high expected or experienced corrosion rate;

(3) Severe local corrosion;

(4) More complex structure, such as inclusion of branch pipe, dead leg, injection points or other similar fittings;

(5) High tendency to corrosion under insulation.

2.5.4.6 According to the actual situation of inspection, the surveyor may require inspection of weld joints of important supports.

2.5.5 Continuous survey

2.5.5.1 With the approval of the Society, the special survey or renewal survey of offshore oil and gas process system may be replaced by continuous survey upon application by the owner.

2.5.5.2 The rules for continuous survey are given in the Society's main rules for the offshore installation on which the oil and gas process system is mounted.

2.5.6 Survey of machinery planned maintenance system

2.5.6.1 With the approval of the Society, the special survey or renewal survey of offshore oil and gas process system may be replaced by machinery planned maintenance system upon application by the owner.

2.5.6.2 The survey methods for machinery planned maintenance system are described in the Society's main rules for the offshore installation on which the oil and gas process system is mounted.

2.5.7 Survey for damage and repair

2.5.7.1 When oil and gas process system is damaged that affects the safety of the system, the application for survey for such damage is to be promptly addressed to the Society.

2.5.7.2 The documents related to repair after the damage are to be submitted to the Society for review and approval, and once the repair is completed, the application for survey for the repair is to be promptly addressed to the Society.

2.5.8 Survey for modification and alteration

When the oil and gas process system is to be modified or altered including process and functional changes, the applicable drawings are to be submitted to the Society for review and approval, and such modification or alternation is to be subject to the surveys by the Society.

CHAPTER 3 GENERAL RULES FOR SYSTEM DESIGN

SECTION 1 GENERAL

3.1.1 Purpose

The purposes of oil and gas process system design are to maintain safe and effective operation of well fluid delivery, separation, natural gas purification and liquefaction, liquefied gas regasification, storage and transfer of oil and gas products in a closed system, and to prevent the accidental leakage of combustible and toxic fluids which leads to fire, explosion, poisoning and pollution accidents.

3.1.2 Functional requirements

In order to achieve the above-mentioned purpose, the oil and gas process system is to have the following functions:

(1) System design suitable for the external marine environment and the internal environment of the delivered fluid;

(2) Design of system strength and tightness sufficient to contain the delivered fluid;

(3) Redundant safety protection measures with the ability to prevent undesirable events;

(4) Shutdown ability in the event of fluid leakage;

(5) Collection and harmless emergency treatment ability in the event of fluid leakage;

(6) Ability to dispose of the released fluid (liquid separation, incineration and cold vent);

(7) Ability to process oil water in compliance with the standards;

(8) Redundant capacity for storage of liquefied natural gas;

(9) Equipment in the system, including elements and instruments, suitable for the intended purpose;

(10) System installed firmly and reliably, without any additional stress;

(11) System arrangements favorable for safety and environment protection and convenient for operation and maintenance.

3.1.3 Definitions

(1) Design pressure:

Pressure which is used together with the design temperature to determine the minimum permissible thickness and physical properties of each component as determined by design specifications in pressure design standard.

The design pressure selected by the user is used to provide a suitable margin above the most severe pressure expected during normal operation at a coincident temperature. This pressure may be used in place of the maximum allowable working pressure (MAWP) where the MAWP has not been established. The design pressure is equal to or less than the maximum allowable working pressure.

(2) Maximum allowable working pressure

It refers to the maximum pressure that the weakest component of the system can withstand, which is inverted from the actual nominal thickness (exclusive of corrosion allowance) based on design standard.

It is to be noted that the maximum allowable working pressure is not always unchanging during the operation life of the system, and it will decrease due to corrosion, wear and fatigue.

(3) Settle out pressure

It refers to the equilibrium pressure value after the compressor system has been shut down due to high pressure, assuming that the system is free of any vent.

3.1.4 Ambient conditions

3.1.4.1 Restrictions on inclination angle during operation

For the design of oil and gas process system which is installed on a floating unit and operates in floating state, the influence of the static and dynamic inclination angles of the floating unit upon system operation is to be taken into consideration. Restrictions on static and dynamic inclination angles during the operation of oil and gas process system are to be expressly stated in the operation instructions.

3.1.4.2 Ambient temperature restrictions

The oil and gas process system is to be designed and arranged taking into account the need of ensuring its normal operation at the most unfavorable atmospheric temperature (including indoor and outdoor temperatures) and seawater temperature in the waters where the system operates.

3.1.5 Selection of design pressure

3.1.5.1 Design pressure of pressure vessels subject to positive pressure

The design pressure of pressure vessels subject to positive pressure is not to be less than the specified values in Table 3.1.5.1.

Design pressure of vessels subject to positive pressure Table 3.1.5.1

Maximum operating pressure P (MPa)	**Design pressure (MPa)**
0＜P≤3.5	P+0.35
3.5＜P≤7	110% P
P＞7	108.5% P but at least no less than P+7

3.1.5.2 Design pressure of atmospheric vessels

Any of the following values is to be taken as the minimum design pressure of atmospheric vessels:

(1) The pressure of liquid column from the level of contained liquid to the high point of air pipe is normally taken as the design pressure for atmospheric vessels, taking into account the resistance when the air pipe overflows;

(2) For vessels fitted with overflow pipes which cannot be blocked, then pressure of liquid column from the level of contained liquid to the high point of overflow pipe outlet plus 7 kPa is taken as the design pressure for such atmospheric vessels;

(3) If the atmospheric vessels are equipped with high level alarm and the measures to cut off the input source at over high level, the pressure of the highest liquid column is taken as the design pressure of such atmospheric vessels.

3.1.5.3 Design pressure of vessels subject to negative pressure

The design pressure of pressure vessels subject to negative pressure is not to be less than the specified values in Table 3.1.5.3.

Design pressure of vessels subject to negative pressure Table 3.1.5.3

Minimum operating pressure P	**Design pressure**
35 kPa<P≤0.1 MPa	P-10 kPa or 50 kPa, whichever is less
P≤35 kPa	0 MPa (full vacuum)

3.1.5.4 When the design pressure affects the selection of material and pressure rating, it is to be noted that selection of the design pressure higher than the specified value is to be avoided.

(1) The design pressure of wellhead flowline is to be equal to or higher than the shut-in pressure;

(2) The production manifold or test manifold is to be equipped with pressure safety protection devices in case its design pressure is less than the shut-in pressure;

(3) The pressure and temperature levels of Piping s connected to atmospheric equipment are not to be less than 150lb pressure-temperature rating.

3.1.6 Determination of maximum operating pressure

3.1.6.1 Typically, maximum operating pressure is 1.05 times of normal operating pressure.

3.1.6.2 The maximum operating pressure of the equipment connected with the suction side of a centrifugal compressor is the maximum stabilizing pressure.

3.1.6.3 The maximum operating pressure of the equipment connected with the discharge side of a centrifugal compressor is the maximum operating pressure of the compressor.

When the maximum operating pressure is not set, the maximum operating pressure of the compressor equals the maximum operating suction pressure of the compressor plus 1.3 times of the pressure differential generated by the compressor.

The maximum operating suction pressure of the compressor is the high shutdown pressure of the upstream separator or the compressor.

3.1.6.4 The maximum operating pressure of the equipment connected with the discharge side of a centrifugal pump is the maximum operating pressure of the pump.

Where accurate information is not available, the maximum operating pressure of the pump equals the suction pressure of the pump in relieved state plus 1.25 times of the pressure differential generated by the pump.

3.1.7 Determination of high trip pressure

The maximum operating pressure is normally taken as the high trip pressure in system pressure control. .

3.1.8 Selection of design temperature

3.1.8.1 Maximum design temperature

(1) Where the maximum operating pressure can be accurately determined, this temperature may be selected as the maximum design temperature;

(2) Where the maximum operating pressure cannot be accurately determined, the maximum design pressure is not to be less than the maximum estimated operating temperature plus 30℃;

(3) The high-temperature shutdown function can restrict the maximum operating temperature according to ISO10418 or API RP 14 C standard. A margin is to be added for determination of the maximum design temperature;

(4) The maximum design temperature is not to be less than 50℃ in any case;

(5) When the maximum design temperature affects the selection of material and pressure rating, it is to be noted that selection of the maximum design temperature higher than the specified value is to be avoided.

3.1.8.2 Minimum design temperature

The minimum design temperature determines the requirements on cryogenic properties of the material; therefore, the most stringent value of the following is to be taken:

(1) Minimum operating temperature (obtained under normal operation, starting, shutdown or upset conditions) plus appropriate margin;

(2) Minimum ambient temperature based on the accessible meteorological data, with a safety factor selected according to the quality of the meteorological data;

(3) Minimum temperature generated during decompression minus 5°C.

3.1.9 Design of equipment and piping system

3.1.9.1 The equipment and piping system is to be designed to withstand the most severe expected temperature and pressure combinations during staring up, normal operation and shutdown and to be able to maintain the mechanical integrity throughout the whole operating life.

3.1.9.2 In addition, the equipment and piping system are to be able to remain safe under abnormal operation conditions caused by:

(1) Instrument malfunction;

(2) Incorrect operation;

(3) Failure of utility system;

(4) External fire;

(5) Liquid gaining heat from solar radiation;

(6) Emergency conditions, etc.

If the mechanical design levels are likely to be exceeded under such abnormal conditions, the equipment and piping system may be fitted with pressure relieving and depressing devices for protection.

3.1.9.3 The detailed design of piping system and equipment are also to be in accordance with Chapter 8 and Chapter 9 of the Rules.

3.1.10 Materials, welding, post weld heat treatment and NDT

3.1.10.1 Materials, welding, post weld heat treatment and NDT are to be in compliance with the applicable requirements specified in the Society's Rules for Materials and Welding.

Materials not specified in the Rules for Materials and Welding may also be used provided that the materials have been qualified through necessary inspections and tests and approved by the Society.

3.1.10.2 Use of asbestos-containing materials on oil and gas process system is prohibited.

3.1.10.3 Material for use in H_2S-containing is in accordance with GB/T 20972.

3.1.11 External corrosion protection

3.1.11.1 The surfaces of oil and gas process system exposed to marine environment are to be protected with effective corrosion protection measures or made of corrosion resistant materials.

3.1.11.2 If the protection is provided by means of anti-corrosion coating, coating materials approved by the Society are to be used, and the materials without approval are not to be used unless agreed by the Society.

3.1.11.3 Aluminum-containing coatings are not to be used in the places classified as hazardous areas.

3.1.12 Internal corrosion protection

3.1.12.1 Oil and gas process system mainly experiences carbon dioxide (CO_2) corrosion, hydrogen sulfide (H_2S) corrosion and chlorine ion corrosion. The design process mainly addresses the corrosion caused by CO_2 and H_2S under acidic conditions. In general, one or a combination of the following measures is to be taken to control corrosion:

(1) Select corrosion resistant materials including high alloy materials;

(2) For carbon steel materials, corrosion allowance is to be included during design;

(3) Add corrosion inhibitor into the system;

(4) Dehydration treatment;

(5) Apply internal coating.

3.1.13 Heat insulation and tracing

3.1.13.1 Personnel protection

Surfaces with a temperature in excess of 60℃ or equipment or piping with a temperature lower than-10℃ are to be heat insulated to prevent the personnel from burns or frost bites. If appropriate, measures such as setting up of fences and warning signs may also be taken to prevent the personnel from contacting the cold or hot surface.

3.1.13.2 Fire and explosion prevention

(1) Equipment or piping surface with a temperature in excess of 204℃ and with a potential contact with liquid hydrocarbon leakage are to be protected by heat insulation for prevention of fires;

(2) Equipment or piping surface with a temperature in excess of 385 ℃ (80% of natural gas auto-ignition temperature) and with a potential contact with combustible gas are to be protected by heat insulation for prevention of explosion.

(3) Insulation layers subject to potential contact with leaked oil are to be protected with, for example, stainless steel plate, zinc galvanized steel plate or aluminum plate cladding;

(4) Nonporous insulation material is to be used within the minimum 0.5m length range on both sides of the potential leak points, so as to prevent ingress of any leaked oil;

(5) Insulation materials are to be noncombustible materials.

3.1.13.3 Heat conservation

Heat conservation measures are to be taken for equipment and piping s to achieve the following purposes:

(1) Restrict heat loss for energy saving and emission reduction;

(2) Avoid generation of harmful wax deposit and hydrates;

(3) Prevent unacceptable high viscosity;

(4) Prevent harmful condensation in gas piping ;

(5) Prevent solidification in liquid piping (e.g. freezing);

(6) Prevent surface condensation at ambient temperature which may cause corrosion.

3.1.13.4 Cold conservation

Equipment and piping for the production, storage and transfer of liquefied natural gas, liquefied petroleum gas or other condensing media are to be protected with effective cold conservation for energy saving.

3.1.13.5 Heat insulation materials

(1) The technical properties of heat insulation materials are to be compliant with the requirements of applicable industrial standards;

(2) The safe service temperature of heat insulation materials is to be higher than the design temperature;

(3) The pH value of heat insulation materials for use in contact with carbon steel is to meet the following criteria:

Calcium silicate: 8~10.5

Foam glass: 7~8

Glass fiber: 8~10.5

Mineral wool: 7~11

(4) The content of chlorine ion, sodium ion and silicate ion in heat insulation materials for use in contact with Austenitic stainless steel is to meet the criteria specified in code ASME C 795;

(5) Alkaline heat insulation materials cannot be used on aluminum products;

(6) Cold conservation materials are to be nonporous;

(7) Heat insulation materials are to be noncombustible.

3.1.13.6 Heat tracing

(1) The commonly used heat tracing methods include external tube heating tracing, jacket pipe heat tracing and heat tracing with electrical heating cable. And heat tracing media include hot water, steam, thermal oil and electrical power. Electrical heat tracing is commonly used as it is economic, safe and reliable, with effectively controllable temperature.

(2) In general, the heat tracing temperature is to be at least 5℃ higher than the temperature with which hydrates, solidified matters or high viscosity will be formed;

(3) When the piping heat dissipation is being calculated during the design stage, the influence of extreme weather conditions and installation positions are to be taken into full consideration;

When the weather conditions anticipated to exceed the design conditions occur, additional freeze protections are to be provided to the heat traced equipment and piping, for example installing of temporary shield at the wind gap;

Attention is to be paid to evaluation of the influence of temporary shield upon the classification of hazardous areas and the selection of explosion-proof equipment.

(4) Instrument tubing, sample points and low-point drain ports are susceptible to blockage caused by freezing, which is to be specially considered during design calculation and preparation of construction techniques. These locations are to be wrapped and clad during construction in strict accordance with the procedural requirements;

(5) As certain gas piping sections with pressure change (e.g. the location of pressure regulator valve) are susceptible to freezing-induced blockage due to heat absorption upon pressure drop, enhanced measures of heat tracing are to be considered during design;

(6) As locations without flowing of fluid (e.g. U pipe) are susceptible to freezing-induced blockage, enhanced measures of heat tracing are to be considered during design;

(7) At locations where the heat traced piping penetrates the bulkhead and deck and in other confined spaces, the

piping is susceptible to insulation defects which lead to freezing-induced blockage. High attention is to be paid to these locations and spaces during construction to ensure construction quality;

(8) When electrical heat tracing is used in hazardous areas, the temperature-self-limiting electrical heating tape recognized by the Society is to be used and its self-limited temperature should not be to exceed 204°C. Electrical heating tape system (especially the joints) is to meet the explosion-proof requirement for the hazardous zone in which it is situated.

3.1.13.7 Prevention of hydrogen sulfide accumulation

In order to prevent hydrogen sulfide from accumulating around the bolts, the flanges for hydrogen sulfide services are not to be heat insulated.

3.1.13.8 Other freeze protection measures

(1) Besides heat insulation and tracing measures, the method of keeping the fluid flowing may also be adopted to prevent liquid freezing. The minimum flow rates required to prevent freezing are listed in table 3.1.13.8.

Table 3.1.13.8 Minimum flow rate for preventing liquid freezing

Piping nominal diameter (mm)	**Minimum flow rate (m^3/h)**
＜75	0.02
≥75	0.10

Note: These requirements are special for 50 m long piping and the values of listed flow rates are to be properly increased if the piping is more than 50 m long.

(2) Water piping may be drained after the flow has been stopped to achieve freeze prevention.

3.1.13.9 Surveys

The inspector and surveyor are to enhance surveys of heat insulation and heat tracing measures to ensure compliance with the requirements of the Rules.

3.1.14 Isolation measures

3.1.14.1 Physical isolation

Physical isolation refers to the isolation achieved by any of the following means:

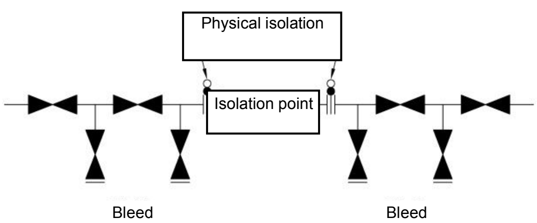
(1) Spectacle blind and flange isolation;

(2) Gasket and blind flange isolation;

(3) Isolation by removing the spool piece and blinding the piping open ends (briefly called spool removal isolation).

For installation of physical isolation, initial isolation measures as shown in Fig. 3.1.14.2(1) and Fig. 3.1.14.2(2) are to be provided.

Physical isolation represents the highest standard of isolation and can prevent any fluid seepage.



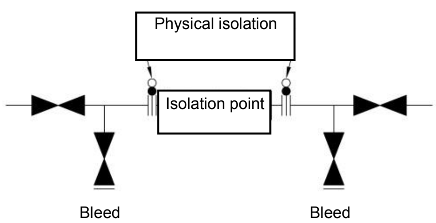
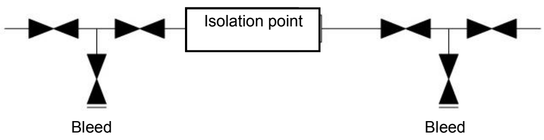


Fig. 3.1.14.2(1) Physical isolation Fig. 3.1.14.2(2) Physical isolation

with double block and bleed with single block and bleed



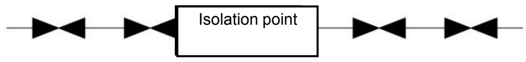
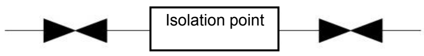


Fig. 3.1.14.2(3) Double block and single bleed isolation Fig. 3.1.14.2(4) Double block isolation



3.1.14.2 Isolation level

The levels of equipment and piping isolation are ranked in a high to low order as follows:

(1) Physical isolation with double block and bleed, as shown in Fig. 3.1.14.2 (1).

The two isolating valves in series are used for initial isolation and the bleed valve is used to bleed off the residual pressure and check the integrity of the isolation.

(2) Physical isolation with single block and bleed, as shown in Fig. 3.1.14.2(2).

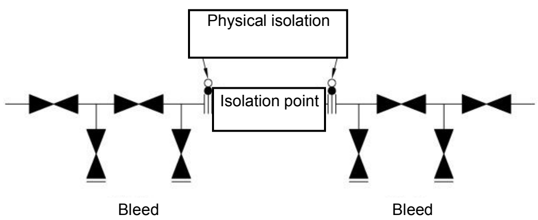
The isolating valve is used for initial isolation and the bleed valve is used to check the integrity of the isolation.

(3) Double block and single bleed isolation, as shown in Fig. 3.1.14.2(3).

The two isolating valves in series are used for redundant isolation and the bleed valve is used to check if there is any leakage from the first isolation; the bleed valve is also used to prevent development of pressure in between the two isolating valves, thus significantly reducing the possibility of leakage from the second isolation.

(4) Double block isolation, as shown in Fig. 3.1.14.2(4).

(5) Single block isolation, as shown in Fig. 3.1.14.2(5).



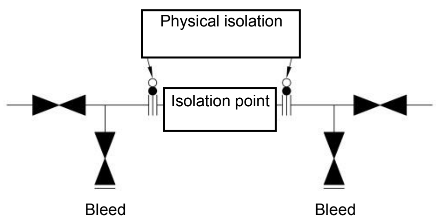
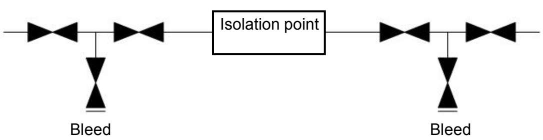


Fig. 3.1.14.2(1) Physical isolation Fig. 3.1.14.2(2) Physical isolation with double block and bleed with single block and bleed



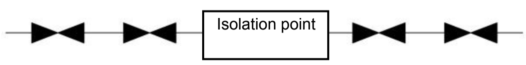


Fig. 3.1.14.2(3) Double block and single bleed isolation Fig. 3.1.14.2(4) Double block isolation

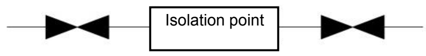


Fig. 3.1.14.2(5) Single Block isolation

3.1.14.3 General requirements of isolation

(1) Oil and gas process system is to be provided with insolation for equipment, instruments, valves and process piping sections, so that safe repair, maintenance and replacement of equipment and piping section can be carried out in a safe manner.

(2) Isolation measures are to be properly planned and indicated on the drawings in design stage.

3.1.14.4 Selection of isolation level

(1) Physical isolation is to be provided when relevant personnel are required to enter the vessels during downtime to carry out internal inspection and maintenance.

(2) Double-train parallel systems are to be provided with physical isolation for each train of the system;

(3) Hydrocarbon pumps and compressors are to be provided with spool removal isolation;

(4) The fuel supply lines of fired pressure vessels should be provided with double block and single bleed measures, so as to prevent oil from leaking into the combustion chamber during the downtime and prevent explosion from occurring in combustion chamber at the time of next ignition;

(5) The insolation connected to the flare, cold vent and closed drain system are to be in accordance with Section 6.2, 6.3 and 6.6, Chapter 6 of the Rules;

(6) Besides the above mentioned levels, isolation level for which specific rules have not been specified is to be selected based on the following principles:

① Hazard of fluid: Higher levels of isolation are to be selected for equipment or piping containing combustible, explosive and toxic fluids;

② Operating pressure and temperature: Higher levels of isolation should be selected for high fluid pressure and temperature;

③ Size and fluid inventory of piping section: For the piping with larger size and inventory, higher levels of isolation should be selected;

④ Downtime: For the equipment and Piping s with longer downtime, higher levels of isolation should be selected.

3.1.14.5 Isolation warning

Non-physical isolation is to be provided with warning signboard to prevent the isolation from being relieved by unauthorized personnel.

3.1.14.6 Isolation interlocking of safety valves

The requirements for isolation interlocking of safety valves (pressure relief valves) are given in paragraph 6.2.8 of Chapter 6 of the Rules.

3.1.14.7 Isolation of pressure relief valve and flare system

The requirements for isolation interlocking of pressure relief valve valve and flare system are given in paragraph 6.3.10 of Chapter 6 of the Rules.

3.1.15 Vent and drain devices

(1) Vessels, pumps and other equipment are to be fitted with vent valves and/or drain valves according to maintenance needs;

(2) Pressurized piping section (for example, the section between the safety valve and inlet isolating valve) with expected need for dismantlement is to be fitted with vent valve;

(3) Liquid piping that is easy to form an air pocket is to be fitted with vent valve at the highest point;

(4) Gas piping that is easy to form a liquid pocket is to be fitted with drain valve at the lowest point.

3.1.16 Lightning and harmful static charging control

(1) Bonding between adjacent equipment and skids is protective measures to eliminate static electricity;

(2) Equipment and piping arranged in hazardous areas are to be grounded reliably, and the electrical resistance between them and platform structure is not to exceed 1MΩ.

3.1.17 Hydrotest

Hydrotest of the system is to be in accordance with Section 3, Chapter 8 of the Rules.

3.1.18 Commissioning and start-up

3.1.18.1 Commissioning activities are to be performed by the specialized commissioning management organization constituted by qualified personnel of various specialties.

3.1.18.2 Commissioning documents (e.g., commissioning schedule or commissioning manual) are to be submitted to the field survey organization of the Society for review.

3.1.18.3 The field surveyor is to carry out inspections and tests according to the approved commissioning documents in order to verify the system design complies with the requirements of applicable codes and standards.

3.1.18.4 Commissioning items which can be completed onshore are to be completed onshore as practically possible in order to shorten the duration of offshore commissioning.

3.1.18.5 The commissioning of oil and gas process system is to be carried out after the safety systems and utility support systems have been successfully commissioned.

3.1.18.6 Prior to commissioning, an emergency response plan is to be prepared, and firefighting, lifesaving, communication and other safety equipment are to be available to ensure safety during the commissioning.

3.1.18.7 After commissioning has been completed and qualified, start-up of the system is to be performed under the direction of the operator. The surveyor is to witness the start-up in order to ascertain the oil and gas process system in normal working condition.

3.1.19 Operation requirements

3.1.19.1 Operation, maintenance and repair procedures for oil and gas process system and the instructions for equipment provided by the product manufacturer are to be available on the offshore installation.

3.1.19.2 Oil and gas process system repair, maintenance and inspection records are to be available on the offshore installation.

3.1.19.3 The offshore installation is to be sufficiently staffed with qualified personnel to operate, maintain and service the oil and gas process system.

3.1.19.4 In order to prevent explosion resulting from excessive accumulation of combustible gas in the combustion chamber, the operation procedure for fired pressure vessels is to be strictly followed. For details, see paragraph 4.2.7.7, Chapter 4 of the Rules.

3.1.19.5 The operator is to perform hazard and operability (HAZOP) analysis, and identify the potential hazards, the causes, the potential consequences as well the actions to be taken in practice under both normal and abnormal conditions.

SECTION 2 ARRANGEMENT

3.2.1 General requirements

3.2.1.1 Equipment are to be arranged in such a way as to allow smooth process system, simplified piping system, convenience for maintenance and repair and assurance of personnel safety.

3.2.1.2 The arrangement of various modules and critical equipment and installations is to be in compliance with the applicable requirements of the main rules for offshore installation.

3.2.2 Equipment arrangement

3.2.2.1 Equipment are to be placed on the open deck with good ventilation.

Equipment or certain parts of the equipment that are not suitable for the open air environment may be arranged in enclosed or semi-enclosed spaces. In case the equipment are placed in an enclosed space with potential explosion risks, the roof of the enclosure is to be weakly constructed or fitted with effective pressure relief device; in addition, such space is to be provided with power ventilation at an air exchange rate of no less than 12 times/hour.

3.2.2.2 When equipment is being arranged, proper access and sufficient lighting are to be provided between them to allow operation and monitoring. Places requiring access to the height are to be provided with ladder and handrails, and in case the height is in excess of 3m, small platform with guardrail is to be built.

3.2.2.3 For equipment requiring normal repair and dismantling inspection during operation, sufficient space for maintenance and repair is to be reserved. And for parts that need to be pulled out, such as heat exchanger core, sufficient space is to be reserved to allow the pull-out.

3.2.2.4 When the center line of equipment manhole is more than 3.6m above the deck and there are detachable internals, or when there is no detachable internals but the center line of manhole is more than 4.3m above the deck surface, a small operation and maintenance platform with guardrail as well as the ladder and handrails leading to the platform are to be provided.

When the safety valve of a pressure vessel is more than 3m away from the deck, a small operation and maintenance platform and vertical access ladder are to be provided.

The dismantling inspection of equipment is to be carried out without hot work.

3.2.2.5 For equipment with greater height, when the height between decks cannot accommodate the height of the equipment, penetration of the equipment through the upper deck may be considered; however, special attention needs to be paid to the influence of its height on the crane layout.

3.2.2.6 During operation, the equipment working on a floating body are to be arranged in such a way as to minimize the impact of shaking of the floating body on the operation of the equipment; for example, for ship-shaped floating platform, the horizontal vessels are to be longitudinally arranged along the hull whereas the vessels most sensitive to level control are to be arranged in the center line.

3.2.2.7 Vessels with direct fire to heat the oil and gas flow, i.e. directly fired vessels (e.g. crude oil processor), are to be arranged separately from the unfired pressure vessels and close to the periphery of the oil and gas processing module and the side of the platform. Fired pressure vessels indirectly heating the oil and gas flow (e.g. thermal oil heater) are to be arranged on the utility module.

3.2.2.8 The operation surface of vessels is to share the same space with the maintenance, firefighting and escape access; while the non-operation surface of the vessels is normally situated close to support structures and walls.

3.2.2.9 Pumps and compressors are to be as close to the equipment being suctioned as possible in order to reduce suction resistance.

3.2.2.10 Hydrocarbon compressors are generally categorized into two types, namely centrifugal type and the reciprocating type. During design, overall consideration needs to be given to the arrangement of compressor set, gas-liquid separator, cooler, oil seal and other accessories as well as the repair machinery and tools.

3.2.2.11 Noise-generating equipment are to be arranged on the side far from the accommodation building.

3.2.2.12 Requirements on the arrangements of pig receiver and launcher are given in Chapter 6 Section 12 of the Rules.

3.2.2.13 Space for installation of the equipment to be added in the future is to be reserved during the design of equipment arrangement.

3.2.3 Equipment installation

3.2.3.1 Equipment is in general to be skid mounted and the skid base is to be firmly welded onto steel structure with sufficient strength.

3.2.3.2 The dimensions of skid base may be designed according to the following criteria or the recognized practical standards:

(1) The width of the base of a horizontal vessel is to be 1.83m more than the diameter of the vessel while the length of the vessel base is to be 0.6m more than that of the vessel;

(2) The width of the base of a vertical vessel is to be 0.9m more than the diameter of the vessel while the length of the vessel base is to be 1.83m more than the diameter of the vessel.

(3) If the base is used as the drip tray, special consideration is to be given to its sizing to enable collection of leaks from the vessel and the associated connections. The base of the vessels operation side and the side with manhole normally has larger dimensions.

3.2.3.3 Non-skid equipment are to be firmly mounted onto the base and the base is to be welded onto steel structure with sufficient strength. The clear height from the deck to the bottom nozzle or drain vale of the equipment is to be no less than 150mm.

3.2.4 Personnel protection

3.2.4.1 Moving parts which may cause personal injury are to be provided with protection guard, guardrail or other safety protection facilities.

3.2.4.2 All work areas, walkways, staircase and other frequently accessed places are to be provided with anti-slip measures so as to ensure personnel safety.

3.2.4.3 Locations with potential tripping, bumping and fall hazards are to be provided with protection measures and easily visible warning signs.

3.2.4.4 To avoid burns by high-temperature surfaces, all hot surfaces are to be heat insulated to reduce the surface temperature to below 60℃. If this requirement cannot be met, barricade is to be set up to protect personnel from contact with the high-temperature surfaces.

3.2.4.5 Preventative measures for electrical shock, electrical fire and other electrical hazards are to be in place.

3.2.5 Prevention of maloperation

3.2.5.1 Oil and gas process system is to be arranged in such a way as to prevent the offshore installation and personnel safety from being jeopardized by a single maloperation error.

3.2.5.2 Emergency stop, emergency shutdown and similar manual buttons are to be provided with protective cover or other protective measures to prevent accidental operation.

3.2.5.3 The open and closed positions of valves are to be apparent and visible.

3.2.5.4 In order to avoid errors during operation and shift of mechanical equipment and system, signboard and labels indicating safe operation instructions are to be provided.

3.2.6 Man-machine interface

3.2.6.1 The operation spaces are to be arranged and designed in such a way as to provide a working environment which is beneficial for personnel safety and health and work efficiency, and to minimize the risks of reduced personal ability and maloperation.

3.2.6.2 Equipment should have function identification marks; piping systems should be color coded and identified with flow direction marks in accordance with the recognized international, domestic or industrial standards; and power cables should be identified with durable labels.

3.2.6.3 The design and arrangement of control panels should comply with the recognized international ergonomic standards.

3.2.7 Failure protection

3.2.7.1 Once the equipment or components within the system suffer a failure, they are to be maintained in a state that causes minimum harm to the system, personnel and environment or in a fail-safe state.

3.2.7.2 The probability of component failure causing damage or leading to failure of other components is to be reduced to an acceptable level.

3.2.7.3 Failure of the redundant components of the system is not to incur damage to and failure of the spare components or parallel-connected components in the system.

3.2.6.4 Equipment or components (e.g., valves and instruments) requiring operation, testing, maintenance and inspection by the competent personnel during operation are to be installed at such locations as to provide convenience to such personnel for necessary operation, maintenance and checks.

3.2.8 Piping arrangement

3.2.8.1 Oil and gas piping are not to pass through closed, non-hazardous space. If avoidance of such case is not practical, protective measures are to be taken and the piping are to be routed with special approval of the Society. When the oil and gas piping (e.g., crude oil transport piping) have to pass through the accommodation area, such piping are to be routed through the open area, and detachable connectors are not to be installed within and in the vicinity of the accommodation area being passed through.

3.2.8.2 Piping are to be arranged in a neat and orderly way, along completely horizontal and vertical directions, and as practically possible, into groups and rows for convenient support.

3.2.8.3 Piping close to the deck are normally to be at a distance of no less than 150mm from the deck to facilitate maintenance and inspection;

3.2.8.4 Where piping is arranged above personnel access, a clear height of no less than 2200mm for the access should be maintained.

3.2.8.5 The connections of piping are to be welded as practically possible in order to ensure tightness of the piping. The detachable connectors along the piping are to be reduced to the minimum number as required by the maintenance.

3.2.8.6 For the piping installed around equipment, attention is to be paid to ensure sufficient space has been reserved to facilitate maintenance and repair of the equipment.

3.2.8.7 Combustible oil and gas piping are to be routed far away from heat sources. When leak from the piping is likely to splash onto any hot surface, this section of the piping is to be provided with splash guard.

3.2.8.8 Equipment, components and piping are to be arranged in such a way as to prevent the leaking or overflowing liquid from splashing onto energized objects.

3.2.8.9 Piping are to be designed and arranged in such a way as to prevent generation of air pocketing in the liquid piping , especially the suction line of centrifugal pumps, and generation of liquid pocketing in gas piping.

3.2.8.10 Piping installed onto the equipment are to be freely aligned and flush in order to prevent any additional stress on the equipment caused by piping installation; equipment subject to stronger vibration are to be provided with vibration compensation measures.

3.2.8.11 Where thermal expansion may cause damage to piping, proper measures are to be taken to compensate the thermal expansion of the piping.

3.2.8.12 The flanges, fittings and valves in the piping are to be arranged in such a way to facilitate inspection, maintenance and operation.

3.2.8.13 The pipes through watertight or airtight structure are to be provided with through fittings or pads welded on structure. Where pads are used the pipe is to be secured by means of studs screwed into the pad, but not screwing into the structure.

The arrangement of pipes passing through deck or bulkhead with fire division is not to damage the integrity of the fire divisions

CHAPTER 4 SAFETY SYSTEM

SECTION 1 GENERAL

4.1.1 Scope

4.1.1.1 Safety system specified in this chapter only includes the safety protection measures taken to protect the oil and gas process system from any accidental event and the shutdown measures taken after occurrence of said event.

4.1.1.2 The requirements for pressure relief of pressure safety protection devices are to be in compliance with Chapter 6 Section 2 of the Rules.

4.1.1.3 The requirements for oil leakage collection and containment are to be in compliance with Chapter 6 Section 5 and Section 6 of the Rules.

4.1.1.4 The measures to prevent ignition of leaked oil and gas and the requirements for detection of combustible gas, toxic gas and fire (including fusible plug loop) are to be in compliance with the applicable provisions of the main rules for offshore installation on which the oil and gas process system is located.

4.1.2 Definitions

(1) Abnormal operating condition

Condition that occurs in a process component when an operating variable ranges outside of its normal operating limits.

(2) Atmospheric operation

Operations within an operating pressure (gauge pressure) range of 0.22 kPa~35 kPa.

(3) Automatically fired vessel

Fired vessel with its burner fuel being controlled by the automatic temperature or pressure controller.

(4) Backflow

Fluid flow in a process component towards the direction opposite to the normal flow direction.

(5) Oil leakage collection and containment

Various methods used on an offshore installation to collect the leaked liquid hydrocarbons and drain the same to a safe location.

(6) Detectable abnormal condition

An abnormal operating condition that can be automatically detected.

(7) Direct ignition source

Ignition sources with sufficiently high temperature and heat capacity to ignite a combustible mixture.

(8) Emergency shutdown system

A system to initiate shutdown of the platform when the button at the manual station is activated.

(9) Overtemperature

The temperature in a process component in excess of the designed operating temperature.

(10) Failure

An abnormal condition that prevents the device or equipment from executing their design functions.

(11) Fired vessel

A vessel in which the temperature increase of the fluid in the vessel is achieved through flame heating.

(12) Fire loop

A pneumatic control line fitted with temperature sensing elements (fusible plug, synthetic tubing etc.) which can initiate platform shutdown when activated.

(13) Flame failure

Flame that is inadequate to instantaneously ignite the combustible vapor entering the combustion chamber.

(14) Flowline

Piping that delivers the well stream from the wellhead to the first downstream process component.

(15) Flowline segment

A segment of a flowline that has an operating pressure different from other portions of the same flowline.

(16) Gas blow by

The phenomenon of gas being discharged from the liquid outlet in a process component.

(17) High liquid level

The liquid level in a process component that exceeds the maximum operating level.

(18) High pressure

The pressure in a process component that goes beyond the maximum operating pressure but less than the maximum allowable working pressure (maximum allowable operating pressure for subsea pipelines).

(19) High temperature

The temperature in a process component that exceeds the rated operating temperature.

(20) Leak

Accidental release of the liquid and/or gaseous hydrocarbons in a process component into the atmosphere.

(21) Liquid overflow

Discharge of liquid from a process component through the gas (vapor) outlet.

(22) Low flow rate

The flow rate in a process component that is less than the minimum operating flow rate.

(23) Low liquid level

The liquid level in a process component that is lower than the minimum operating level.

(24) Low pressure

The pressure in a process component that is lower than the minimum operating pressure.

(25) Low temperature

The temperature in a process component that is lower than the minimum operating temperature.

(26) Malfunction

A condition that causes abnormal operation of a device or equipment but does not prevent execution of its design function.

(27) Maximum allowable operating pressure

The highest operating pressure allowable at any point of a piping system at normal flow state or in static conditions.

(28) Maximum allowable working pressure

See the definition in paragraph 3.1.3(2) of Chapter 3 of the Rules.

(29) Overpressure

The pressure in a process component that goes beyond the maximum allowable working pressure (maximum allowable operating pressure for subsea pipelines).

(30) Subsea pipeline

Pipelines that transfer fluids between platforms or between a platform and an onshore facility.

(31) Platform safety system

An arrangement of safety devices and emergency support systems to initiate platform shutdown, which may consist of a number of individual process shutdown systems and may be actuated through manual control or through the automatic devices that detect the abnormal conditions.

(32) Platform shutdown

The shutting in of all process stations of a platform production process and all support equipment for the process.

(33) Process component

The production equipment having an individual function in the process station and its associated piping, such as separator, heater, pump or tank.

(34) Process shutdown

Isolation of a given process station from the process system through closing the corresponding shutdown valve (SDV), in order to stop the fluid from entering this process station or divert the fluid to another process station.

(35) Process station

One or more process components that perform a specified processing function, such as separating, heating, pumping, etc.

(36) Qualified personnel

The personnel who have acquired, through training or from experience or on reliance of both, certain particular skills or competence which are measured against the issued rules such as the standard or test that can be used to review an individual's ability to perform the specified function.

(37) Safety device

Instruments or controllers used in the safety system.

(38) Sensor

A device that can detect abnormal operating conditions and transmit the signal to perform a specific shutdown function.

(39) Shutdown valve

An automatically-operated fail-closed valve used to isolate process stations.

(40) Shut-in tubing pressure

The pressure inside the tubing at the time of well shut-in.

(41) Subsurface safety valve

A device installed in a well below the wellhead with the design function of preventing uncontrolled well flow when actuated.

(42) Subsurface controlled subsurface safety valve

A subsurface safety valve actuated by oil (gas) well pressure behavior.

(43) Surface controlled subsurface safety valve

A subsurface safety valve controlled from the platform surface by hydraulic, electric, mechanical or other means.

(45) Surface safety valve

A wellhead valve assembly that can close automatically when power supply is lost.

(46) Negative pressure

The pressure in a process component that is less than the design collapse pressure.

(47) Underwater safety valve

A valve assembly installed at the underwater wellhead that can close automatically when the power supply is lost.

(48) Accidental event

An abnormal condition or state that occurs in a process component or process station and jeopardizes safety, such as overpressure, negative pressure, liquid overflow, etc.

(49) Vacuum

Any pressure in a process component that is lower than the atmospheric pressure.

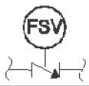
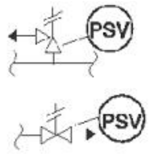
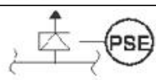
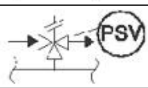
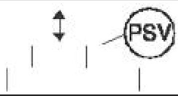
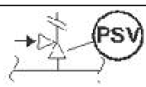
(50) Vent

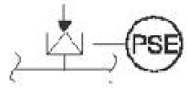
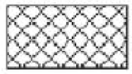
A pipe or fitting on a vessel that is opened to the atmosphere. Vents may include pressure and/or vacuum relief devices.

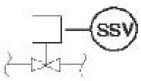
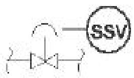
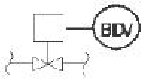
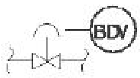
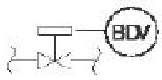
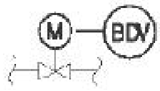
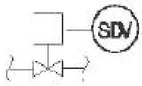
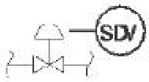
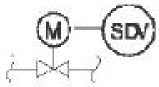
4.1.3 Safety device symbols

Uniform safety device symbols (as shown in Table 4.1.3) should be used in the drawings which describe or involve safety systems. Other conventional symbols in the industry may also be used but must be expressly listed on the drawings.

Safety device symbols Table 4.1.3

Sensing and self-acting device				
Variable	Designation of safety device		Symbol	
	Common	Instrument Society of America (ISA)	Single device	Combination device
Backflow	Check valve	Flow safety valve		
Burner flame	Burner flame detector	Burner safety low		
Flow	High flow sensor	Flow safety high		
	Low flow sensor	Flow safety low		
Level	High level sensor	Level safety high		
	Low level sensor	Level safety low		
Pressure	High pressure sensor	Pressure safety high		
	Low pressure sensor	Pressure safety low		
Pressure	Pressure relief or safety valve	Pressure safety valve		
	Rupture disk or safety head	Pressure safety element		
Pressure or vacuum	Pressure-vacuum relief valve	Pressure safety valve		
	Pressure-vacuum relief manhole cover	Pressure safety valve		
	Vent	None		
Vacuum	Vacuum relief valve	Pressure safety valve		

Sensing and self-acting device				
	Rupture disk or safety head	Pressure safety element		
Temperature	High temperature sensor	Temperature safety high		
	Low temperature sensor	Temperature safety low		
Flame	Flame or stack arrester	None		
Fire	Flame detector (ultraviolet or infrared)			
	Heat detector (thermal)	Temperature safety high		
	Smoke detector (Ionization)			
	Fusible material	Temperature safety element		
Combustible gas concentration	Combustible gas detector	Analyzer safety high		
Toxic gas concentration	Toxic gas detector			

Actuated valves				
Service	Common symbols			
Wellhead or surface safety valve or underwater safety valve			Note: USV denotes underwater safety valve.	
Blow down (depressing) valve				
All other shutdown valves				

4.1.4 Recognized standards

(1)	SY/T 10033	Recommended Practice for Design, Installation and Testing of Basic Surface Safety System for Offshore Production Platforms.
(2)	API RP 14C	Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety System for Offshore Production Platforms.
(3)	IEC 61511	Standard for safety instrumented system.

In addition, for HIPPS of subsea production system, standard API RP 17 O may be referred to.

4.1.5 Design and analysis of safety system

4.1.5.1 During safety system design, safety analysis of each process component is to be performed in order to identify the expected possible accidental events, analyze the causes and consequences of such events, identify the detectable abnormal conditions and determine the corresponding safety protection measures.

4.1.5.2 Safety protection measures are to comply with the following requirements:

(1) Safety systems are to provide two levels of protection (primary and secondary) to prevent or minimize the effect of equipment failure within the process system. In general, safety devices of different types are to be used to provide the two levels of protection, as two completely identical devices will have identical functions and therefore the same intrinsic weakness;

(2) When a single safety device is not able to provide complete primary or secondary protection, a combination of a number of safety devices may be employed to provide necessary protection. For instance, a low pressure sensor and a flow safety valve may be used in combination to prevent fluid leakage and will together provide primary protection;

(3) The safety devices used for the two protection levels are to be independent of the control devices used in normal process operation;

(4) The primary protection is to be quicker, safer and more reliable than the secondary protection. The primary protection device provides protection of the highest order, while the secondary protection device provides protection of the second highest order.

4.1.5.3 If a process component is connected with its upstream or downstream component without isolation under operating conditions, and can be protected by the safety device of its upstream and downstream component, the required safety device for this process component may be waived.

4.1.5.4 An audible and visual alarm is to sound in the attended control station when the safety device detects any accidental event.

4.1.5.5 The safety analysis function evaluation chart is to be used to list the safety devices required by each process component and the safety functions to be executed by each safety device (shutdown, switch of input sources, pressure relief etc.) in order to comprehensively verify reasonability of the safety systems design logic.

SECTION 2 SAFETY PROTECTION

4.2.1 General

4.2.1.1This Section specifies the safety devices for the commonly used components of the oil and gas process system, the reasons for exemption from safety devices as well as positions of safety devices in order to facilitate the design and design review. The non-commonly used components or components with novel features are to be designed and analyzed in accordance with the requirements specified in 4.1.5 of this chapter.

4.2.1.2 The oil and gas process system in addition to the following safety protection requirements, there should be lightning protection and electrostatic protection measures.

4.2.2 Wellhead and flowline

4.2.2.1Pressure safety protection

(1) The flowline segment is to be protected by PSH.

PSH may be waived provided that the maximum allowable working pressure of the flowline segment is higher than the maximum shut-in pressure and that this segment is protected by the high-pressure sensor on the downstream flowline segment.

(2) The flowline segment is to be protected by PSL.

PSL may be waived provided that the flowline segment is located between the wellhead and the first choke device and is less than 3 m in length, or is reasonably close to this distance when installed underwater.

(3) The flowline is to be protected by PSV, and PSV may be waived provided that any of the following conditions is met:

① The maximum allowable working pressure of the flowline segment is higher than the maximum shut-in pressure;

② Two SDVs (one of which may be a SSV), as well as independent PSH, relay and sensing point are mounted where the volume of the flowline upstream of the block valve allows sufficient time for the SDVs to close before the maximum allowable working pressure is exceeded;

③ The flowline segment is protected by an upstream PSV;

④ The flowline segment is protected by the PSV of the downstream component. However, this component cannot be isolated from this flowline segment, and there is no choke device or other restrictions between the flowline segment and the PSV.

4.2.2.2 Flow safety protection

(1) The flowline segment is to be fitted with FSV to prevent backflow;

(2) FSV may be waived provided that the flowline segment is protected by the FSV on the final flowline segment.

4.2.2.3 Safety devices location

(1) Pressure safety device

The PSH and PSL are to be installed at such locations as to prevent damage caused by vibration, impact and unexpected accidents. The sensing points are to be located on the top of horizontal lines or in vertical lines. An independent sensing point is to be provided for the second PSH which is used with SDV as a replacement of PSV protection.

The PSV is to be located upstream of the first blocking device of the flowline segment and its set pressure is not to be higher than the rated working pressure of the flowline segment.

(2) Flow safety device

The FSV is to be installed on the final flowline segment to prevent backflow into the entire flowline.

(3) Shutdown device

As the second valve for the well flow from the well bore, SSV is to be installed at the wellhead and actuated by the flowline pressure sensor, emergency shutdown system, fusible plug loop and the sensor of the downstream process component.

An SDV (besides SSV) may be installed at the wellhead. If an SDV has been installed, it may be actuated by the flowline pressure sensor and the sensor of the downstream process component in lieu of an SSV.

The USV is to be installed at the actual location of well flow and as close to the well bore as possible. The USV is to be actuated by the flowline pressure sensor, ESD system and fusible plug loop, whichever is located upstream of the SDV. SSV is optional for subsea installations fitted with USVs.

4.2.3 Wellhead injection line

4.2.3.1 Pressure safety protection

(1) Wellhead injection line is to be protected by a PSH which may be waived provided that the line and equipment are protected by an upstream PSH;

(2) Wellhead injection line is to be protected by a PSL which may be waived provided that the line and equipment are protected by an upstream PSL;

(3) Wellhead injection line is to be protected by a PSV, which may be waived provided that any of the following conditions is met:

The maximum allowable working pressure of the line and equipment is higher than the maximum pressure that an injection source can apply;

The line and equipment are protected by an upstream PSV.

4.2.3.2 Flow safety protection

Wellhead injection line is to be fitted with an FSV or FSVs to prevent backflow.

4.2.3.3 Safety device's location

(1) Pressure safety device

The PSH and PSL are to be located upstream of the FSV. Sensing points are to be located on the top of the horizontal line or in the vertical line. The PSV is to be so located that it is not isolated from any portion of the injection line.

(2) Flow safety device

The FSV for each injection line is to be located as close to the wellhead as possible in order to protect the entire line from backflow.

(3) Shutdown device

The SDV for injection line is to be located as close to the wellhead as possible in order to minimize the length exposed to impact.

A gas lift line does not require SDV provided that it is protected at the upstream component and is not subject to any backflow from the producing formation.

The water injection line does not require SDV too, provided that it is used for water injection and is not subject to any backflow from the producing layer.

If the closing of an SDV will cause rapid pressure rise in the injection line, consideration is to be given to shut down the injection source and/or use the second FSV in lieu of the SDV.

4.2.4 Headers

4.2.4.1 Pressure safety protection

(1) Headers are to be protected by PSHs, which may be waived provided that any of the following conditions is met:

① Each input source is provided with a PSH and the PSH set point is less than the maximum allowable working pressure of the header;

② The downstream equipment is provided with a PSH and cannot be isolated from the header;

③ Headers are provided for flare, relief, vent or other atmospheric services and without valves on the outlet piping.

(2) Headers are to be protected by PSLs, which may be waived provided that any of the following conditions is met:

① Each input source is provided with a PSL and there is no pressure control device or restriction between the PSL and the header;

② Headers are provided for flare, relief, vent or other atmospheric services.

(3) Headers are to be protected by PSVs, which may be waived provided that any of the following conditions is met:

① The maximum allowable working pressure of the header is greater than the shut-in pressure of any oil well connected to the header;

② Each input source is provided with pressure relief protection and the maximum closing pressure of the input source is higher than the maximum allowable working pressure of the header;

③ The header can be protected by the PSV of the downstream equipment which cannot be isolated from the header;

④ Headers are provided for flare, relief, vent or other atmospheric services and without valves on the outlet piping;

⑤ The input source is an oil well which has a pressure greater than the maximum allowable working pressure of the header but is provided with two SDVs (one of which may be an SSV) controlled by two independent (the relay and sensing point are separate) PSHs. Other input sources with a pressure greater than the maximum allowable working pressure of the header have PSV protection.

4.2.4.2 Safety device's location

If safety devices, PSH and PSL sensors or PSV are required, they are to be installed at such locations as to be able to detect the pressure of the entire header. If the pressure varies in different segments of the header, each header segment is to be provided with the required protection device.

4.2.5 Pressure vessels

4.2.5.1 Pressure safety protection

(1) Pressure vessels are to be protected by PSHs, which may be waived provided that any of the following conditions is met:

① Input source is a pump or a compressor which cannot generate a pressure greater than the maximum allowable working pressure of the vessel;

② Input source is not a wellhead flowline segment, production header or subsea pipeline and is protected by a PSH that protects the vessel;

③ The vessel's gas outlet line connected with the downstream component has sufficient size, but no isolating valve or regulating valve. And the downstream component is protected by a PSH that protects the vessel in the upstream;

④ The vessel serves as the final scrubber for the flare, relief and vent system and can withstand the maximum back pressure;

⑤ The vessels operate at atmospheric pressure and are provided with adequate vent system.

(2) Pressure vessels are to be protected by PSLs, which may be waived provided that any of the following conditions is met:

① The minimum working pressure during operation is atmospheric pressure;

② Each input source is provided with a PSL and there is no pressure control device or restriction between the PSL and the vessel;

③ The vessel is a scrubber or small liquid trap instead of a process component, and is effectively protected by a downstream PSL or designed feature (for example, the vessel is the scrubber for pneumatic safety system or the final scrubber for the flare, relief or vent system);

④ A line of adequate size and without any blocking or regulating valve is connected to the gas outlet of the downstream equipment protected by a PSL that also protects the upstream vessel;

(3) Pressure vessels are to be protected by PSVs, which may be waived provided that any of the following conditions is met:

① Each input source is protected by a PSV with an opening pressure no greater than the maximum allowable working pressure of the vessel, and the vessel is protected by a PSV against fire and thermal expansion;

② Each input source is protected by PSVs with an opening pressure no greater than the maximum allowable working pressure of the vessel, and at least one PSV cannot be isolated from the vessel;

③ The PSV on the downstream equipment satisfies the requirements for vessel pressure relief and cannot be isolated from the vessel;

④ The vessel serves as the final scrubber for the flare, relief and vent system and can withstand the maximum built-up back pressure, without any internal or external obstruction such as mist extractor, back pressure valve and flame arrester;

⑤ The vessel serves as the final scrubber for the flare, relief and vent system and can withstand the maximum built-up back pressure, and is equipped with rupture disk or fusible plug to bypass the internal or external obstruction (e.g., mist extractor, back pressure valve and flame arrester).

4.2.5.2 Level safety protection

(1) Vessels are to be protected by LSHs, which may be waived provided that any of the following conditions is met:

① The equipment downstream the gas outlet is not flare or vent system and can safely handle the maximum amount of liquid entrained by the gas;

② The vessel does not have the function of separating fluid phases;

③ The vessel is a small liquid trap which is drained manually.

(2) Vessels are to be protected by LSLs, which may be waived provided that any of the following conditions is met:

① The liquid level in the vessel is not automatically maintained and the vessel does not have any immersed heating element subject to overtemperature;

② The equipment downstream the liquid outlet can safely handle the maximum gas flow discharged from the liquid outlet, the vessel does not have any immersed heating element subject to overtemperature, and the discharge line may be restricted to reduce gas flow rate.

4.2.5.3 Temperature safety protection

TSH is to be provided for vessels with a heat source, and may be waived provided that the said heat source cannot cause overtemperature.

4.2.5.4 Flow safety protection

Each outlet of a vessel is to be protected by an FSV, which may be waived provided that any of the following conditions is met:

(1) The maximum volume of hydrocarbons flowing back from the downstream equipment can be negligible;

(2) The control devices on the line will effectively minimize backflow.

4.2.5.5 Safety device's location

(1) Pressure safety device

The PSH and PSL sensors and PSV are to be installed at such locations as to be able to detect or relieve the pressure of the gas chamber, namely, on or near the top of the vessel, typically. However, these devices may be installed at the outlet of gas line provided that the pressure drop from the vessel to the sensing point can be negligible and these safety devices cannot be isolated from the vessel. Isolation of these safety devices from the vessel may be caused by external factors (e.g., closing of gas outlet valve) or internal factors (e.g., blockage of mist extractor).

(2) Level safety device

The LSH sensor is to be located at a sufficient distance above the maximum operating level to prevent nuisance shutdown, but adequate vessel space is to be reserved above the LSH sensor to prevent overflow before shutdown.

The LSL sensor is to be located at a sufficient distance below the minimum operating level to prevent nuisance shutdown, but adequate liquid space is to be reserved between the LSL sensor and liquid outlet to prevent gas blow by before shutdown. For fire-tube heated components, the LSL is to be located above the fire tubes.

The LSH and LSL sensors are to be installed preferably on the liquid columns which are in the periphery of the vessel and can be isolated from the vessel. Then these devices can be tested without interrupting the process system. However, if the solid deposits or foams may cause scaling or incorrect indication of the devices installed in the external columns, the level sensors may be directly installed inside the vessel. In this case, a pump will be required to control the liquid level of the vessel during testing.

(3) Flow safety device

Check valves (FSVs) are to be installed on the outlet piping.

(4) Temperature safety device

The TSH sensors other than fusible or surface contact types are to be installed in thermocouple sleeve for convenient removal and testing. The thermocouple sleeves are to be installed at easily accessible locations and able to be immersed continuously in the heated fluid.

4.2.6 Atmospheric vessels

4.2.6.1 Pressure safety protection

(1) Atmospheric vessels are to be protected with vent;

(2) Atmospheric vessels are to be protected with pressure-vacuum devices which may be waived provided that any of the following conditions is met:

① The atmospheric vessel is provided with second vent and can handle the gas at maximum flow rate;

② The atmospheric vessel which does not collapse when designed to be vacuum condition, operates at atmospheric temperature and is fitted with vent pipe of adequate size;

③ The atmospheric vessel does not have pressure sources (excluding blanketing gas and/or manual bleed) and is fitted with vent pipe of adequate size.

4.2.6.2 Level safety protection

(1) Atmospheric vessels are to be protected with LSHs which may be waived provided that any of the following conditions is met:

The liquid filling of atmospheric vessel is continuously monitored;

The overflow from atmospheric vessel is diverted or contained by other components.

(2) Atmospheric vessels are to be protected with LSLs which may be waived provided that any of the following conditions is met:

① Adequate collection and containment system has been provided;

② Liquid level inside the vessel is not automatically maintained, and the atmospheric vessel does not have any immersed heating element subject to overtemperature;

③ The atmospheric vessel is the final container of the collection and containment system.

4.2.6.3 Temperature safety protection

TSHs are to be provided for vessels with a heat source and may be waived provided that the said heat source cannot cause overtemperature.

4.2.6.4 Safety device’s location

(1) Pressure safety device

The vent and PSV are to be located on the top of atmospheric vessels (highest possible position of the vapor section).

(2) Level safety device

The LSH sensor is to be located at a sufficient distance above the maximum operating level to prevent nuisance shutdown, but adequate vessel space is to be reserved above the LSH sensor in order to contain the in flowing fluid during the shutdown period.

The LSL sensor is to be located at a sufficient distance below the minimum operating level to prevent nuisance shutdown. In fire-tube heated components, the LSL is to be located above the fire tubes.

The LSH and LSL sensors are to be installed preferably in the peripheral liquid columns of the vessel so that these devices can be tested without interrupting the process system. However, as stated in 4.2.5.5(2), the internally installed sensors are also acceptable.

(3) Temperature safety device

The temperature sensors other than fusible or surface contact types are to be installed in thermowells for convenient removal and testing. The thermocouple sleeves are to be installed in easily accessible locations that allow continuous immersion in the heated fluid.

4.2.7 Fire and exhaust gas heated components

4.2.7.1 General requirements

(1) The article is applicable to directly fired heater or glycol regeneration furnace;

(2) Closed circulation heaters with forced draft are to be used for oil and gas process system;

(3) Heaters located in hazardous areas are to be in compliance with the explosion-proof requirements specified by the rules or guidelines for the offshore installation on which the oil and gas process system is located.

4.2.7.2 Temperature safety protection

(1) Medium or process fluid is to be provided with TSH protection;

(2) Stack is to be provided with TSH protection.

4.2.7.3 Flow safety protection

(1) FSL protection is to be provided when a combustible medium is circulating through the tubing of the combustion chamber or exhaust heating chamber within a closed circulation component;

(2) Each outlet pipe of the heaters is to be protected with FSV in order to prevent backflow into the combustion chamber or exhaust heating chamber in the event of pipe rupture.

4.2.7.4 Pressure safety protection

(1) Air supply line is to be protected with PSL;

(2) Fuel supply line is to be protected with PSH;

(3) Fuel supply line is to be protected with PSL;

(4) The medium circulating tubes installed inside the combustion chamber or exhaust heating chamber are to be protected with PSVs.

4.2.7.5 Ignition safety protection

(1) The stack is to be provided with flame arrester;

(2) Air draft and motor start interlock is to be provided to cut off fuel and air supply while the motor is failure;

(3) Weak flame safety device (BSL) or TSL is to be installed in the combustion chamber in order to cut off fuel supply when the flame is not adequate to immediately ignite the combustibles entering the combustion chamber.

4.2.7.6 Safety devices location

(1) Temperature safety device

① Temperature sensors other than the fusible or surface contact types are to be installed in thermocouple sleeve for convenient removal and testing;

② If the fire tubes are of immersed type, the TSH sensor is to be installed in the heated liquid medium or process fluid;

③ If the liquid medium or process fluid flows through the tubing of the combustion chamber or the stack gas heating chamber, the TSH sensor is to be installed as close to the heater outlet pipe as possible and in the upstream of all isolating devices;

④ The stack TSH sensor is to be installed close to the base of the stack.

(2) Flow safety device

① FSL sensors are to be installed on the medium circulating tube. These sensors are to be installed on the medium outlet line in the locations as close to the heater as possible and be able to monitor the total flow through the heater.

② The check valves (FSV) are to be installed on the outlet line of the coil.

(3) Pressure safety device

① The PSL sensor at the air intake of the forced draft burner is to be located in the downstream of the blower;

② The PSH and PSL sensors on fuel supply line are to be located between the last pressure regulator and the fuel control valve;

③ The PSV on the tube of a tube heater is to be installed in a location where it cannot be isolated from the heated section of the tube.

(4) Ignition safety device

① The stack arrester is to be installed on the top of the stack;

② The BSL sensor is to be located in the combustion chamber.

4.2.7.7 Safe operation procedure

(1) Confirm complete shutoff;

(2) Discharge the excessive combustibles in the combustion chamber prior to pilot ignition;

(3) Restrict the time period for pilot ignition test and main burner test to prevent excessive fuel accumulation in the combustion chamber. If the time limit has been exceeded, fuel supply is to be cut off and the system can be restarted only after manual reset;

(4) Before feeding fuel to the main burner, confirm that the pilot, fuel-air proportioning dampers and burner control devices are all in low fire state;

(5) The pilot or main burner is to be manually intervened after a flame failure in order to reset and restart up the system;

(6) An appropriate fuel purifying equipment is to be provided to ensure that the fuel is clean and free of impurities and foreign materials;

(7) If possible, confirm that the stack gas inside the stack gas heating component has been fully discharged before activating the heat source.

4.2.8 Pumps

4.2.8.1 Pressure safety protection

(1) Subsea pipeline pumps

① Pump discharge line is to be provided with PSH and PSL protection;

② Pump discharge line is to be provided with PSV protection. When a kinetic pump is used, PSV may be waived as such pump cannot generate a discharge pressure greater than the maximum allowable working pressure of the discharge line.

(2) Other pumps

① Pump discharge line is to be provided with PSH protection which may be waived provided that any of the following conditions is met:

a. The maximum discharge pressure of the pump does not exceed 70% of the maximum allowable working pressure of the discharge line;

b. The pump is a manual pump being continuously attended and monitored;

c. The pump is a small low-volume pump such as chemical injection pump;

d． Pump liquid is discharged into an atmospheric vessel;

e. The pump is a glycol powered glycol pump.

② Pump discharge line is to be provided with PSL protection which may be waived provided that any of the following conditions is met:

a. The pump is a manual pump being continuously attended and monitored;

b. The pump has adequate containment device;

c. The pump is a small low-volume pump such as chemical injection pump;

d. Pump liquid is discharged into an atmospheric vessel.

③Pump discharge line is to be provided with PSV protection which may be waived provided that any of the following conditions is met:

a. The maximum discharge pressure of the pump is lower than the maximum allowable working pressure of the discharge line;

b. The pump has the intrinsic ability to release internal pressure;

c. The pump is a glycol powered glycol pump and its maximum discharge pressure is no greater than the rated value of the low-pressure wet glycol discharge line;

d. The pump is a glycol powered glycol pump and the wet glycol discharge line is protected by the PSV of a downstream component that cannot be isolated from it.

4.2.8.2 Safety device’s location

(1) Pressure safety device

① The PSH and PSL sensors are to be located in the upstream of FSV on the pump discharge line or any block valve;

② For glycol powered glycol pump, the PSL on rick glycol high pressure line is to be located between the pump and the SDV;

③ For transfer pump or other pumps requiring PSV, the PSV is to be located in the upstream of any block valve on the pump discharge line.

(2) Flow safety device

The FSV is to be installed on pump discharge line in order to minimize backflow.

(3) Shutdown device

The SDV on the storage component (e.g., tank, separator, etc.) that supplies product to the pipeline pump is to be located as close to the outlet of the storage component as possible, in order to prevent the hydrocarbons from flowing into the pipeline via the pipeline pump in case a leak on pipeline occurs.

When glycol-powered pumps are used, the SDV is to be located near the high-pressure rich glycol outlet of the glycol contact tower in order to shut off the path of rich glycol supply from the contact tower to the pump and to shut down the pump.

4.2.9 Hydrocarbon compressor

4.2.9.1 Pressure safety protection

(1) Each suction line of the compressor is to be protected by PSH and PSL, unless each input source is provided with PSH and PSL protection that can protect the compressor;

(2) Each discharge line of the compressor is to be protected by PSH and PSL, unless the compressor is protected by the downstream PSH and PSL that cannot be isolated from the compressor;

(3) Each suction line of the compressor is to be protected by PSV, unless each input source is provided with PSV protection that can protect the compressor;

(4) Each discharge line of the compressor is to be protected by PSV which may be waived provided that any of the following conditions is met:

① The compressor is protected by a downstream PSV which is arranged in the upstream of any cooler and cannot be isolated from the compressor in any case;

② The compressor is of kinetic energy type, with a discharge pressure that can never be greater than the maximum allowable working pressure of the compressor itself and the discharge line.

4.2.9.2 Flow safety protection

The final discharge line of the compressor is to be provided with FSV protection to minimize backflow.

4.2.9.3 Temperature safety protection

Each cylinder or shell of the compressor is to be provided with TSH protection.

4.2.9.4 Safety device’s location

(1) Pressure safety device

The PSH and PSL sensors mounted on all suction lines are to be as close to the compressor as possible. And the

PSH and PSL sensors mounted on all discharge lines are to be located in the upstream of the FSV and any block valve.

The PSVs mounted on all suction lines are to be as close to the compressor as possible. And the PSVs mounted on all discharge lines are to be always communicated with the compressor. If the PSV is located inside a building, its discharge outlet is to be piped to a safe location outside the building.

(2) Flow safety device

The FSV is to be installed on the final discharge line of the compressor unit in order to minimize the backflow. If the compressor unit is mounted inside a building, the FSV is to be placed outside the building.

(3) Temperature safety device

All TSH sensors are to be installed on the discharge lines of all compressor cylinders or shells in the locations as close to the cylinder or the shell as possible.

(4) Shutdown device

The SDV is to be installed on each process intake line and fuel gas line of the compressor in order to cut off all input sources of the compressor. If the compressor unit is installed inside a building, the SDVs are to be located outside the building. All SDVs are to be actuated by signals from the ESD system and from the fusible plug loop as well as the signals of any detected abnormal pressure of the intake and discharge lines.

The blow-down valve is to be installed on the final discharge line of the compressor unit. And it may be actuated by the signals from the compressor’s fusible plug loop, gas detection device and compressor’s ESD system.

4.2.10 Subsea pipeline

4.2.10.1 Pressure safety protection

(1) Subsea pipelines are to be protected by PSH which may be waived provided that any of the following conditions is met:

① Transfer pipelines are protected by the PSHs mounted on the upstream equipment;

② Each input source is protected by PSH which can protect the transfer pipeline or bidirectional pipelines at the same time;

③ The pipeline is protected by the PSH mounted on a parallel component.

(2) Subsea pipelines are to be protected by PSLs which may be waived provided that any of the following conditions is met:

① Transfer pipelines are protected by PSLs mounted on the upstream component;

② Each input source is protected by the PSL which can protect the transfer pipeline or bidirectional pipelines at the same time;

③ The pipeline is protected by the PSL mounted on a parallel component.

(3) Subsea pipelines are to be protected by PSVs which may be waived provided that any of the following conditions is met:

① The maximum allowable operating pressure of the pipeline is higher than the maximum pressure of the input source;

② Each input source with a pressure greater than the maximum allowable operating pressure of the pipeline is protected by a set of PSVs with a maximum allowable operating pressure no greater than the maximum allowable operating pressure of the pipeline;

③ Platform process system does not serve as the input source for the pipeline;

④ The input source is a producer well which has a pressure greater than the maximum allowable operating pressure of the pipeline and is fitted with two SDVs (one of which may be an SSV) . And the SDVs are controlled by independent PSHs connected to the isolation relays and sensing points. Other types of input source with a pressure greater than the maximum allowable operating pressure of the pipeline are protected by PSVs.

4.2.10.2 Flow safety protection

(1) Subsea pipelines are to be protected by FSVs which may be waived provided that any of the following conditions is met:

① Transfer pipelines are fitted with SDVs controlled by PSLs;

② All input sources of the pipeline are protected by FSVs which are located in such a way as to prevent backflow into all effective segments of the pipeline;

③ The pipeline is used for bidirectional flow.

4.2.10.3 Safety device's location

(1) Pressure safety device

The PSH and PSL sensors are to be located in the downstream of all input sources and the upstream of the transfer pipeline FSV. If PSVs are required, they are to be located in the downstream of all input sources and kept communicated all the time with the input source.

(2) Flow safety device

Import pipeline delivering fluid to a platform process station is to be provided with FSV located in the immediate upstream of the process station.

The transfer pipeline FSV is to be located in the downstream of the pipeline as far as possible, but in the upstream of any block valve.

(3) Shutdown device

The SDV on subsea pipeline is to be located in such a way as to minimize the exposed portion of the pipeline on the platform. All SDVs are to be actuated by the signals from platform ESD system, fire loop and the sensors mounted on the downstream equipment through which the pipeline fluid flows.

The SDV on a line connected with the departing pipeline is to be actuated by the PSH and PSL sensors mounted on the departing pipeline, ESD system and fire loop.

SDVs are to be mounted at the connections between the bidirectional pipeline and each platform.

Bidirectional pipelines are to be equipped with SDVs on each platform terminus.

4.2.11 Heat exchanger (tube and shell type)

4.2.11.1 Pressure safety protection

(1) The heating section and heated section of heat exchangers are to be respectively protected by PSH which may be waived provided that any of the following conditions is met:

① The input source for each section cannot generate a pressure greater than the maximum allowable working pressure of this heat exchanger section;

② Each input source is protected by the PSH that protects this heat exchanger section;

③ The downstream equipment is protected by the PSH and there is no isolating valve or regulating valve to isolate the PSH from this heat exchanger section.

(2) The hydrocarbon flow containing heating section and heated section of heat exchangers are to be respectively protected by PSL which may be waived provided that any of the following conditions is met:

① The heat exchanger section can be protected by the PSL on another equipment and such PSL cannot be isolated from this heat exchanger section during operation;

② The minimum operating pressure in operation is the atmospheric pressure.

(3) The heating section and heated section of heat exchangers are to be respectively protected by PSV which may be waived provided that any of the following conditions is met:

① Each input source is provided with a PSV with a set opening pressure no greater than the maximum allowable working pressure of the heat exchanger section, and this section is provided with a PSV for fire and thermal relief;

② Each input source is provided with a PSV which has a set opening pressure no greater than the maximum allowable working pressure of the corresponding heat exchanger section and cannot be isolated from this heat exchanger section;

③ The PSV mounted on the downstream equipment can satisfy the needs of pressure relief of the heat exchanger section and is always communicated with this section;

④ The input source for the heat exchanger section cannot generate a pressure greater than the maximum allowable working pressure of this heat exchanger section, and this section cannot be over pressured due to the temperature or pressure factors of other heat exchanger sections;

⑤ Each input source is protected by a PSV with a set pressure no greater than the maximum allowable working pressure of the heat exchanger section, and this heat exchanger section cannot be over pressured due to the temperature or pressure factors of other heat exchanger sections.

4.2.11.2 Safety devices location

The PSH, PSL sensors and PSV are to be located in such a way as to allow pressure sensing and pressure relief of each section of the heat exchanger. If the pressure drop from the heat exchanger section to the sensing point is very small and the safety devices are always communicated with the heat exchanger sections, these safety devices may be installed on the inlet or outlet piping.

4.2.12 Cold box and vaporizer

If heat exchangers serve as the cold box used in liquefaction system and the vaporizer used in liquefied gas regasification, the safety protection devices provided for the equipment are at least to be in compliance with 4.2.11 of this chapter.

4.2.13 Testing of safety devices

Testing of safety devices is to be in accordance with Section 5 of this chapter.

SECTION 3 HIGH INTEGRITY PRESSURE PROTECTION SYSTEM

4.3.1 Components of high integrity pressure protection system

High integrity pressure protection system (HIPPS) is a safety instrumented system (SIS) which normally consists of the following elements:

(1) Pressure sensing element;

(2) Logic solver;

(3) Final element;

(4) Power source;

(5) Inspection, test and maintenance procedure.

The typical configuration of HIPPS is as shown in Fig.4.3.1.

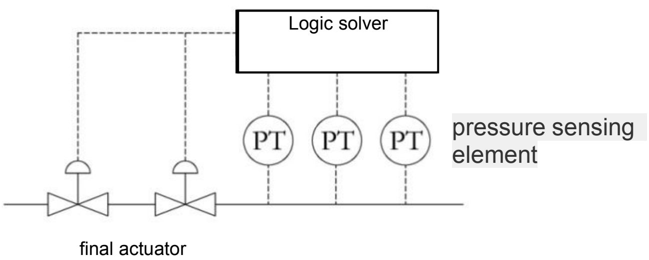


Fig. 4.3.1 Typical configuration of HIPPS

4.3.2Definitions

For the purpose of this section the definition used are as follows:

(1) High integrity pressure protection system (HIPPS)

Mechanical and electric-hydraulic safety instrumented system used to protect production assets from high-pressure upsets.

(2)safety instrumented system (SIS)

Instrumented system used to perform one or more safety instrumented functions.

An SIS is composed any combination of sensor(s), logic solver(s) and final element(s).

(3) Pressure sensing element

A device or combination of devices (e.g., pressure transmitter and pressure switch) for measuring the process pressure.

(4) Logic solver

A part of SIS, performing one or several logic functions.

Logic solver is kind of electric safety system which judges the current status by reading the input pressure signals, and transmits the decision instruction to the final element according to the set conditions and judgment logic.

(5) Final element

An integral part of the safety instrumented system (e.g., a group of shutdown valves) that executes the physical actions necessary to achieve certain safety state.

(6) Safety function

The function performed by SIS, other associated technical safety system or external risk reduction facilities to achieve or maintain a safe state of the process in response to a specific hazardous event.

(7) Safety integrity

The average probability of a safety instrumented system satisfactorily performing the required safety instrumented functions under all the stated conditions within a stated period time.

(8) Safety integrity level (SIL)

The discrete level (one out of four) for specifying the safety integrity requirements of the safety instrumented functions to be allocated to the safety instrumented systems. Safety integrity level 4 has the highest level of safety integrity; safety integrity level 1 has the lowest.

Classification of safety integrity levels Table 4.3.2

SIL	Average probability of failure on demand	Availability
1	10^{-1}~10^{-2}	90.000%~99.000%
2	10^{-2}~10^{-3}	99.000%~99.900%
3	10^{-3}~10^{-4}	99.900%~99.990%
4	10^{-5}~10^{-6}	99.990%~99.999%

(9) Availability

The probability that the system will work normally on demand.

(10) Reliability

The likelihood of a given part of the safety- related equipment to remain in operation within the expected period of time.

(11) Failure

Termination of a functional unit's ability to perform a required function.

(12) Fault

An abnormal condition which may cause a reduction in, or loss of, the capability of a functional unit to perform a required function.

(13) Diagnostic coverage (DC)

Ratio of the failure rate to the total failure rate of the component or subsystem as detected by the diagnostic test. Diagnostic coverage does not include any fault detected by the proof test.

(14) Diversity

The different existing methods to perform a required function.

(15) Channel

One element or a group of elements which independently performs a function.

(16) M out of N (MooN)

N independent channels constituting a safety instrumented system or part of the system, which are connected in such a way that M channels will be sufficient to perform certain safety instrumented functions. For example, take 2 out of 3.

(17) Safety requirement specification

The specification which contains all the requirements of the safety instrumented functions that have to be performed by the safety instrumented system.

(18) Commissioning

The functional validation of equipment and facilities prior to initiating of operation.

(19) Validation

The activity demonstrating that the safety instrumented function(s) and safety instrumented system(s) under consideration, after installation, comply with the safety requirement specification in all respects.

4.3.3 Application conditions of HIPPS

4.3.3.1 When the use of mechanical pressure relieving device as secondary overpressure protection is deemed practically unfeasible (such as excessively high cost, environmental protection issues, etc.), a HIPPS may be used in place of the mechanical pressure relieving device.

4.3.3.2 When a HIPPS is used, its availability and reliability are not to be less than those of the individual mechanical pressure relieving device being replaced.

4.3.3.3 For a given case, the benefits and risks of the application of HIPPS are to be analyzed in a comprehensive way in order to fully measure the advantages and disadvantages of HIPPS and thus determine if it is the optimum solution.

4.3.4 Technical requirements

4.3.4.1 The design and performance of a HIPPS including the activities within the whole life cycle are to be based on standard IEC 61511. In addition, a HIPPS design and performance for a subsea production system are also to be in compliance with standard API RP 17 O.

4.3.4.2 A HIPPS is to be independent of the process control system, process shutdown and emergency shutdown system and performs its pressure safety protection functions independently.

4.3.4.3 The safety integrity level of a HIPPS is to reach SIL3, that is, its availability is to reach at least 99.9%.

There are several methods to increase the availability, and they are listed below:

(1) Using elements of high quality and low unrevealed failure rate. For example, a pressure transmitter is generally selected instead of a pressure switch for sensors, as the pressure transmitter has a lower unrevealed failure rate;

(2) Increasing the level of diagnostic coverage;

(3) Using redundant elements such as triplicate sensing elements;

(4) Using diverse element;

(5) Increasing test frequency.

4.3.4.4 In order to avoid unnecessary production interruption and the risks associated with the interruption, special consideration is to be given during the design of HIPPS configuration to minimize the possibility of potential nuisance shutdown. For example, the voting structure of taking two out of three is used for HIPPS configuration to increase the systems reliability.

4.3.4.5 A HIPPS is to be designed following the fail-safe principle. For example, the shutdown valve is to be in closed position in the event of power supply failure.

4.3.4.6 A HIPPS is to have hardware and software diagnostic and testing functions.

4.3.4.7 A HIPPS is to be provided with a trip (shutdown) that will be a latched function, and the trip is to be relieved only through reset by the operator. Trip reset can be performed only when the pressure indicated by the sensor is lower than the trip pressure.

4.3.4.8 During HIPPS design, the effect of hydraulic hammering resulting from quick valve closing on the design pressure of the upstream component is to be considered.

4.3.4.9 The final elements are to be fitted with at least two shutdown valves.

Shutdown valves are not to be used for unspecified purposes.

Shutdown valves are to be made of corrosion resistant material.

4.3.4.10 Special consideration is to be given to the potential influence of erosion, generation of hydrates, changes of fluid viscosity and wax content on a HIPPS during its design.

For instruments with heat tracing, attention is to be paid with respect to the impact of heat tracing fault on the HIPPS.

4.3.4.11 Control of HIPPS

The following items are to be displayed in the central control room:

(1) Output of pressure sensors;

(2) The open/closed position of shutdown valves;

(3) Status of trip, tripped voting and alarm;

(4) HIPPS controller status report;

4.3.4.12 A HIPPS is to be able to use uninterrupted power supply and the hydraulic and pneumatic sources for the HIPPS are to be provided with redundancy.

4.3.5 Field installation and commissioning

4.3.5.1 The system is to be installed according to the installation plan made in advance and the manufacturers requirements.

4.3.5.2 The system is to be commissioned according to the approved procedure to verify that the HIPPS complies with the safety requirement specifications.

4.3.6 Maintenance and testing

4.3.6.1 Safety instrumented system maintenance and testing procedures are to be developed and the maintenance and testing records are to be properly conserved for review.

4.3.6.2 testing is highly important to detect hidden faults and maintain the availability of the safety instrumented system. Therefore, the elements are to be tested in strict accordance with the test intervals specified during the design, and any extension is not allowed.

4.3.6.3 The field test capacities are to be considered during determination of test interval.

4.3.6.4 Testing as a process, fault and nuisance shutdown may occur due to human errors during the testing, therefore, measures are to be taken to minimize the negative effect posed by the testing.

4.3.6.5 Provided that the expected availability can be achieved, measures (such as supervised circuits, built-in diagnosis and built-in redundancy) are to be taken to reduce the frequency of off-line test (test during suspended production) to the lowest possible level.

4.3.7 Operation and training

For correct operation and maintenance of a HIPPS, adequate training are to be provided to the operation and maintenance personnel to ensure the integrity of the HIPPS is maintained throughout the its whole life.

4.3.8 Documentation

The safety requirement specification, installation and commissioning documents, safe operation manual as well as operation, maintenance and testing procedure for the safety instrumented system are to be kept properly and readily available.

SECTION 4 SHUTDOWN SYSTEM

4.4.1 General requirements

4.4.1.1 Shutdown consists of process shutdown (PSD) and emergency shutdown (ESD).

4.4.1.2 Process shutdown is an automatically actuated shutdown when the instruments have detected abnormal conditions while emergency shutdown refers to the manually actuated shutdown.

4.4.1.3 Shutdown system is to be designed in a fail-safe principle.

4.4.1.4 Shutdown system is to be featured with the function of automatic fault detection.

4.4.1.5 Shutdown system is to be capable of testing without interfering with other systems.

4.4.1.6 Shutdown system is to be able to use uninterrupted power supply, and its hydraulic and pneumatic source are to be provided with redundancy.

4.4.1.7 Shutdown is to be executed according to the predetermined logic. The effect of fluid kinetic energy is to be considered with respect to the continued time of the shutdown process and excessively quick shutdown is to be avoided to prevent system damage.

4.4.1.8 The logic and design of shutdown system should comprehensively consider the properties of the fluid in the process and the impact of shutdown on the process in bad weather.

4.4.2 Process shutdown

4.4.2.1 When any abnormal operating condition has been detected by the safety device of a process component, this process component is to be automatically shut down or the fluid in the component is to be diverted to other components that can safely handle the fluid.

4.4.2.2 In order to avoid cascading reaction (i.e., the chain reaction caused by the shutdown of a downstream component which leads to the sequential shutdown of all the upstream components), the original source generating the abnormal operating condition (such as wellhead, a pump or compressor) is to be shut down simultaneously with or prior to the shutdown of this component.

4.4.2.3 Cascading reaction may be allowed under the following conditions:

(1) The input source of the separator will be frequently alternated as the wellhead is periodically connected to the separator. If the wellhead connected with the separator is directly shut down upon detection of any abnormal operating condition, then the logic of the safety system must be changed each time when a different wellhead is switched to the separator. There might be negligence when the logic of the safety system is changed. In this case, the preferable approach is to close the inlet of the separator in order to allow the generated high pressure in the flowline to shut in the well though the action of PSH sensor. The pressure of the header and flowline must be rated to withstand the maximum pressure generated thereby;

(2) The platform receives the produced fluid from the satellite wells via the flowline. Although the energy source for the system is the wellhead of the satellite wells, the SDV on the incoming flowline must be closed if any abnormal condition has been detected on the platform. If it is expected to shut down firstly the SDV on the flowline on platform and then the satellite wells, the PSH sensors mounted on the flowline at the satellite wells may be used to complete such shutdown process;

(3) At the time of installation, the compressor is equipped with automatic diverter valve which, when the compressor is shut down, allows continued production from the wellheads that can overcome the line pressure. Wellheads which cannot overcome the line pressure may be shut in through the PSH sensors mounted on the flowline, in order to reduce the potential logic issues of the safety system as stated in (1) of this paragraph.

4.4.2.4 Systems designed with automatic shutdown are also to be able to be manually shut down by the operation personnel when abnormal operating conditions are found.

4.4.2.5 Process shutdown system is to be capable of being function tested without interrupting the operation.

4.4.2.6 Audible and visual alarming for process shutdown is to be available and the shutdown valves position is to be displayed in the central control room.

4.4.2.7 Process shutdown valves are to be provided with opening/closing indicator and able to be locally operated.

4.4.3 Emergency shutdown

4.4.3.1 Emergency shutdown system is to be provided in order to shut down the wells, process stations, subsea pipeline and all production activities in case of emergency.

4.4.3.2 Emergency shutdown system may consist of a series of independent shutdown systems that can be respectively activated.

4.4.3.3 Emergency shutdown system is to be designed to allow continued service of the electrical power stations and firefighting system when needed in emergency.

4.4.3.4 Emergency shutdown is completed through manually operated remote device when any anomaly has been detected, but use of fusible plug fire loop allows automatic actuation of emergency shutdown.

4.4.3.5 Emergency shutdown system is to be independent of the process control system

4.4.3.6 The availability of emergency shutdown system is to achieve at least 99.9%.

4.4.3.7 Emergency shutdown button is to be provided with protection device to prevent accidental actuation.

4.4.3.8 Each emergency shutdown station is to be clearly identified with each shutdown function and the position of each emergency shutdown valve.

4.4.3.9 Audible and visual alarming for emergency shutdown is to be available and the shutdown valves position is to be displayed in the central control room.

4.4.3.10 An Emergency shutdown valve cannot be used for other purposes while a process shutdown valve may be used as an emergency shutdown valve.

4.4.3.11 Emergency shutdown valves are to be able to be operated locally.

4.4.3.12 Emergency shutdown valves are to be provided with opening/closing indicators.

4.4.3.13 Emergency shutdown valves and process shutdown valves are to be made of corrosion and fire resistant metal material.

4.4.4 Levels of shutdown

4.4.4.1 If various shutdown actions (such as emergency shutdown, process shutdown, etc.) are integrated to perform the shutdown function at varying levels, the shutdown of each level is to be able to, in addition to triggering shutdowns on the same level, activate shutdowns of a lower level. But the shutdown of a lower level is not to be able to trigger the shutdown of a higher level. The shutdown of each level is to be able to activate the audible and visual alarm respectively in the central control room.

4.4.4.2 The highest-level shutdown is commonly referred to as the platform abandonment shutdown. The shutdown of such level is to be available in at least two locations listed below.

(1) Central control room;

(2) Emergency evacuation stations~~;~~

(3) Helicopter deck;

(4) Near the main entrance/exit of accommodation area;

(5) Platform of exit staircase on each deck;

(6) At each end of a bridge connecting two platforms.

4.4.5 Integrated design of shutdown

During the design of shutdown system for oil and gas process system, overall consideration is to be given with respect to the shutdown systems for other systems on the offshore installation, and the integrated design is to be adopted.

SECTION 5 SAFETY SYSTEM TESTING

4.5.1 General requirements

4.5.1.1 The safety system is to be function tested to demonstrate the safety systems ability to perform its designed safety functions and maintain such ability in service.

4.5.1.2 The results of safety device test are to be recorded and kept to facilitate operation analysis and reliability study.

4.5.2 Design verification

4.5.2.1 Before the oil and gas process system is put into operation, the complete safety system is to be thoroughly reviewed and checked to verify that each device is installed, operable and capable of performing its design function. If applicable, each device is to be calibrated for the specified operating condition.

4.5.2.2 Design verification of the safety devices listed in safety analysis function evaluation (SAFE) chart is to be performed to ascertain that each safety device is operable, has been correctly calibrated and is capable of performing its designed control function within prescribed period of time. This fact is to be recorded in SAFE chart.

4.5.3 Testing in service

4.5.3.1 Purpose

Safety systems are to be tested to verify that each sensing device operates within the set limits and that the control circuit executes the shutdown function as specified.

4.5.3.2 Test frequency

Safety devices and systems are to be tested at the specified interval, once a year as a minimum. The test frequency is to be determined with consideration of the requirements stated in D 2.2 of SY/T 10033-2000 Recommended Practice for Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, as well as the instructions from the manufacturer and field experience.

4.5.3.3 Sensor testing

Safety device test is to confirm that the sensors can properly detect the abnormal conditions and transmit the corresponding signals to complete the specific shutdown function. Sensors are normally tested by simulating an abnormal operating condition and are to actuate the shutdown when detecting any abnormal operating condition.

4.5.3.4 Shutdown device and control circuit testing

Shutdown valves and other shutdown controls are to be tested to ensure they can receive signals from the sensors and perform their design functions. Prior to sensor testing, the final shutdown or control device actuated by the sensor may be de-activated or bypassed in order to prevent real shutdown of process stations or the platform. However, the entire shutdown system or control loop, including the final shutdown valve and control device, is to be subject to annual test as a minimum.

4.5.3.5 Auxiliary device

All auxiliary devices between the sensing device and the final shutdown device are to be tested at least annually to verify the integrity of the entire shutdown system. Apart from sensing devices, these devices including the master control panel and intermediate control panels are also to be tested.

4.5.3.6 Installation for testing

Some devices are to be installed in consideration of running test. Test bypasses may be installed so as to test a single device or the entire circuit without affecting actual shutdown. The safety devices are to be located in an easily accessible manner, and the use of multiple device test manifold and quick connecting accessories is to be considered in order to reduce the test time. When safety devices are bypassed, consideration must be given to the design and operation of the platform and safety systems.

4.5.3.7 Test procedure

Testing of common safety devices is to be carried out according to the test procedure specified in Appendix I. If a device in use has not been included in or is not suitable for the general test procedure, the operator is to prepare a specific test procedure for such device.

If some devices and equipment are out of service due to being tested, they are to be clearly identified to minimize the possibility that they are still in non-operating conditions after the test.

4.5.3.8 Test tolerances

The tolerances for safety device test are to be in accordance with Table 4.5.3.

Safety device test tolerances Table 4.5.3

SN	Safety device	Tolerance
1	Pressure safety valve (PSV)	Where set pressure 480kPa, ±14kPa

SN	Safety device	Tolerance
		Where set pressure >480kPa, ±3%
2	High low pressure sensors (PSHL)	Where set pressure 35kPa, PSHL must function properly within its service range Where set pressure >35kPa, ±5% or 35kPa, whichever is greater
3	High liquid level switch (LSH)	Reserve sufficient gas space and prevent carry-over before shut in. Analog level transmitter: set point ±75cm
4	Low liquid level switch (LSL)	Reserve sufficient liquid space and prevent gas flow into the liquid outlet before shut in. Analog level transmitter: set point ±75cm
5	Flowline check valve FSV	Liquid leak rate ≤0.4L/min Gas leak rate ≤$0.4m^3$/min
6	High low temperature sensors (TSHL)	If the set point is far below the danger point (such as surface ignition temperature), the value of tolerances does not matter. If the set point is close to the operating temperature range, specific tolerances are to be specified.

4.5.3.9 Deficient devices

A safety device that fails, malfunctions or is found unable to operate during the test is to be promptly replaced, repaired, adjusted or calibrated. Before these interventions are completed, the device is to be clearly identified with tags indicating the operational incapability and continuously monitored, and in the meanwhile, the process component is to be bypassed or the entire oil and gas process system is to be shut down.

4.5.3.10 Personnel qualifications

Testing of oil and gas process system is to be performed by qualified personnel.

4.5.3.11 Where the oil and gas process system is put back into operation after it has been shut down for 30 days or a longer period, or after modification of the oil and gas process safety system, the complete safety system is to be thoroughly examined to verify that each device is operable and can perform its due function.

Appendix I Safety Device Test Procedures

1. Burner Flame Detector (BSL).

(1) To check pilot flame-out control:

① Light pilot.

② Block fuel supply to main burner.

③ Shut off fuel supply to pilot and check BSL for detection.

(2) To check burner flame-out control:

① Light main burner.

② Block fuel supply to pilot.

③ Shut off fuel supply to main burner and check BSL for detection.

2. Combustible Gas Detector (ASH).

(1) Adjust the zero control, if necessary, so that meter reads 0% LEL with all gas positively eliminated from sensor.

(2) Place sensing adapter of portable purge calibrator over probe head and open shut-off valve on sample container.

(3) When meter reaches maximum level and stabilizes, record meter reading, calibration gas concentration, low alarm and high shutdown set points (% LEL).

(4). If necessary, adjust meter to read % LEL of calibration gas.

(5). Close shut-off valve on sample container and remove sensing adapter.

(6) Actuate test control or zero control, as appropriate, and observe low and high trip points. Check shutdown relay for actuation.

3. Emergency Shutdown System (ESD).

(1) Operate a manual remote station, preferably one at the boat landing, and observe that appropriate shut in relays operate. This may be done individually or as a group, depending on platform design, in order to avoid actual platform shutdown, unless desired. Record the time (seconds) after operating the manual remote station for a flowline surface valve to close.

(2) Check each ESD station by moving valve handle to the shutdown position. Observe for free valve movement and unobstructed gas bleed. Limit bleed to prevent actual shutdown.

4. Flow Line Check Valve (FSV).

(1) Close upstream valve and associated header valves.

(2) Open bleeder valve and bleed pressure from flow line between closed valves.

(3) Close bleeder valve.

(4) Open appropriate header valve.

(5) Open bleeder valve.

(6) Check bleed valve for back flow. If there is a continuous backflow from bleeder valve, measure the flow rate.

Rate should not exceed 400 ml/min. or 0.4m3/min.

(7) Close bleeder valve and open upstream valve.

5. High and Low level Sensors (LSH) and (LSL)installed internally.

(1) Manually control vessel dump valve to raise liquid level to high level trip point while observing level liquid in gauge glass.

(2) Manually control vessel dump valve to lower liquid level to low level trip point while observing liquid level in gauge glass.

Alternate procedure 1:

(1) Open fill line valve and fill vessel to high level trip point.

(2) Close fill line valve.

(3) Drain vessel to low level trip point.

Alternate procedure 2: (for pressure differential transmitter used for level sensors)

Note: Source pressures utilized for testing transmitters must be external sources separate from the process, utilizing test gauges to observe trip points and verify the zero and span of the transmitters.

(1) Close valve connecting high side of transmitter to vessel.

(2) Close valve connecting low side of transmitter to vessel.

(3) Connect external test pressure source to high side of transmitter. External pressure source is tol have means to measure pressure (or equivalent level) utilizing an external test gauge.

(4) Vent to atmosphere low side of transmitter.

(5) Introduce pressure at high side of transmitter equal to high liquid level and verify LSH actuates within test tolerance.

(6) Introduce pressure at high side of transmitter equal to low liquid level and verify LSL actuates within test tolerance.

(7) Disconnect test pressure source.

(8) Close vent valve of low side of transmitter.

(9) Open valves to vessel and return transmitter to service.

Note: For transmitters without low side connections to vessel, steps (2), (4) and (8) can be omitted.

6. High and Low Level Sensors (LSH) and (LSL)installed in outside cages.

(1) Close isolating valve on float cage(s).

(2) Fill cage(s) with liquid to high level trip point.

(3) Drain cage(s) to low level trip point.

(4) Open cage(s) isolating valves.

Alternate procedure:

(1) Close isolating valve on float cage(s).

(2) Drain cage to low level trip point.

(3) Open lower cage isolating valve.

(4) Slowly bleed pressure from the top of the cage, allowing vessel pressure to push fluid from inside the vessel to the high level trip point.

(5) Open upper cage isolating valve.

7. High and Low Pressure Sensors (PSH) and (PSL)external pressure test.

(1) Close isolating valve on pressure sensing connection.

(2) Apply pressure to sensor(s) with a hydraulic pump, high-pressure gas or nitrogen, and record sensor trip pressure observed from an external test gauge.

(3) If sensors are installed in series with the high sensor upstream from the low sensor, bleed pressure to reset the high sensor. Bleed pressure from sensors and record low sensor trip pressure.

(4) Adjust sensor, if required, to provide proper set pressure.

(5) Open sensor isolating valve.

8. High and Low Pressure Sensors (PSH) and (PSL)bench test.

(1) Mount sensors on a test stand and connect pneumatic supply.

(2) Apply pressure as indicated:

① High pressure sensor (PSH). Apply pressure to sensor with hydraulic pump, high pressure gas or nitrogen bottle, and record high sensor trip pressure.

② Low pressure sensor (PSL). Apply pressure above set pressure and bleed pressure, and record pressure at which low sensor trips.

(3) Tag sensor with set pressure and date.

9. Safety Relief Valve (PSV)external pressure test.

(1) Remove lock or seal and close inlet isolating block valve. (Not required for PSVs isolated by reverse buckling rupture disc or check valve or pilot operated PSVs.)

(2) Apply pressure through test connection with nitrogen, high pressure gas or hydraulic pump, and record pressure at which the relief valve or pilot starts to relieve.

(3) The safety valve or pilot should continue relieving down to reset pressure. Hold the test connection device still until the pressure stops falling to ensure that the valve is reset.

(4) Open inlet isolating block valve and lock or seal.

10. Safety Relief Valve (PSV)bench test.

(1) Mount on a test stand.

(2) Apply pressure through test connection with nitrogen, high pressure gas, or a hydraulic pump, and record pressure at which the relief valve starts to relieve test pressure.

(3) The safety valve should continue relieving down to reset pressure. Hold the test connection device still until the pressure stops falling to ensure that the valve is reset.

(4) Tag PSV with the set pressure and the date of test.

11. Pipeline and Process Shutdown Valve (SDV).

Option (1) operation test.

(1) Bleed pressure off the actuator and allow valve to reach three-quarter closed position.

(2) Return supply pressure to actuator.

Option (2) Full valve closure test.

(1) Initiate signal to close SDV from either remote or local switch.

(2) Close SDV.

(3) Open SDV.

12. Surface Safety Valve (SSV) operation test.

(1) Shut in well.

(2) Close SSV.

(3) Open SSV.

(4) Return well to production.

13. Surface Safety Valve (SSV)pressure holding test.

(1) Shut in well and SSV as for operations test.

(2) Position wing and flow line valves to permit pressure to be bled off downstream of SSV.

(3) With pressure on upstream side of SSV, open bleed valve downstream of SSV and check for continuous flow. If sustained liquid flow exceeds 400 ml/min. or gas flow exceeds 0.4m^3/min. during the pressure holding test, the SSV should be repaired or replaced.

(4) Close bleeder valve.

(5) Return well to production.

14. High and Low Temperature (TSHL) operation test.

(1) Adjust set point until controller trips.

(2) Reset controller set point based on observed temperature as follows:

① Indicating controller—Add or subtract the difference between indicated temperature and trip temperature to the desired trip temperature.

② Non-indicating controller with graduated dials—Add or subtract the difference between dial reading at trip point and actual temperature to calculate the desired trip setting.

③ Devices that neither indicate nor have graduated dials—Reset according to manufacturer's instructions.

15. High and Low Temperature (TSHL)temperature bath test.

(1) Remove temperature sensing probe.

(2) Place a thermometer in a hot liquid bath.

(3) Insert temperature sensing probe in the liquid bath and set manual dial on temperature controller at the same temperature indicated on the thermometer. Record high temperature set point. If the controller does not trip at the temperature of the liquid bath, adjust the controller to trip at that temperature.

(4) Remove temperature sensing probe from liquid bath, allow it to cool, and record low temperature set point.

(5) Remove sensing probe to original location and adjust controller to desired temperature.

16. Underwater Safety Valve (USV)combined operation and leakage test.

Each operator should use a method appropriate to the system that demonstrates the pressure integrity of the USV and quantifies leak rates. Following are two options offered for general guidance only.

Option（1）:

Perform test as in this appendix Item 13

Option（2）:

（1) Shut in well and USV as for operations test (Refer to this appendix , Items 121& 122and close downstream

header or flow line valve.

（2) With pressure on upstream side of USV, measure pressure buildup in the flow line versus time. If the absolute pressure buildup in the confined line segment downstream of the USV is in excess of that which represents a flow rate of 400 ml /min. of liquid or $0.4m^3$min of gas, the USV should be repaired or replaced.

（13) Return well to production.

17. Toxic gas detector (OSH).

Toxic gas detectors should be tested in accordance with the manufacturer's specifications.

CHAPTER 5 PRODUCTION AND PROCESS SYSTEM

SECTION 1 GENERAL

5.1.1 Scope

5.1.1.1 Offshore oil and gas process system consists of crude oil processing system, natural gas processing system and production water treatment system. For subsea production system, refer to the applicable requirements in the Society's Rules for the Subsea Production System.

5.1.1.2 For the safety devices with which the oil and gas process components are to be equipped, refer to the applicable requirements stated in Chapter 4 of the Rules.

5.1.1.3 Besides the requirements in this chapter, oil and gas process equipment are also to be in compliance with Chapter 9 of the Rules.

5.1.2 General requirements

In order to satisfy the needs of testing, field processing, storage and pipeline transfer of the products from oil and gas wells, the oil, gas and water mixture must be processed, that is, the separation, treatment and stabilization of oil, gas and water. For this purpose, a series of production equipment have been provided to separate the oil and gas mixture into individual phases.

5.1.3 Recognized standards

(1)	SY/T0069	Design Code for Crude Oil Stabilization Unit.
(2)	SY/T0045	Design Specification for Crude Oil Electric Dehydration.
(3)	SY/T0076	Design Specification for Natural Gas Dehydration.
(4)	SY/T0083	Design Specification for Oil Removal Tank.
(5)	GB 50428	Code for Design of Oilfield Produced Water Treatment.
(6)	GB4914	Effluent Limitations for Pollutants from Offshore Petroleum Exploration and Production.

SECTION 2 CRUDE OIL PROCESSING SYSTEM

5.2.1 General

Crude oil processing system is used to remove gas, water and impurities from the wellhead fluid in order to reach the standards for safe storage and transfer and ensure the maximum recovery rate of crude oil. The process system consists of the following stages:

(1) Oil and gas separation;

(2) Heating or cooling (when needed) prior to separation;

(3) Crude oil dehydration or desalting (when required);

(4) Cooling (when needed) and pump transfer.

5.2.2 Oil, gas and water separation

5.2.2.1 The well fluid of offshore oilfields is to be processed, that is the separation and treatment of oil, gas and water. Separator is the main processing equipment and other equipment includes heat exchanger, pump, dehydrator, stabilization unit etc.

5.2.2.2 The well fluid mixture is a typical multi-component fluid and the separation of well fluid consists of two-phase separation and three-phase separation.

Oil and gas two-phase separation is to condition the mixture to a balanced state at specific operating temperature and pressure, make the gas in oil segregate and the oil in gas condense and then separate the gas and oil.

Oil, gas and water three-phase separation is to separate the free water from the mixture besides the separation of oil and gas.

5.2.3 Basic separation methods

The physical difference between fluid components is mainly manifested in three aspects, namely density, particle size and viscosity, and the difference is also subject to the influence of flow velocity, temperature, etc. Based on these influential factors, there are three basic methods of separating oil, gas and water.

(1) Gravitational separation

Gravitational separation uses the density difference of fluid components to make the heavier liquid droplets settle and separate from the continuous fluid phase.

(2) Centrifugal separation

When a two-phase flow changes its moving direction, the phase of higher density will tend to remain moving in a linear direction and as a result, it collides with the vessel and separates from the fluid of lower density.

(3) Collision and coalescing separation

If the fluid encounters obstruction in the normal flow path, the entrained liquid droplets will collide against and be adsorbed onto the obstacles, thus being separated, then coalesce with other particles and separate from the continuous phase. The process is called collision and coalescing separation.

The mesh mist arrester at the outlet of gas liquid separator and packing in the separator are designed and considered according to this mechanism. In addition, lipophilic or hydrophilic material is selected as the packing material of the separator based on the different positions of gas phase and liquid phase, in order to improve the effect of collision and coalescing separation.

5.2.4 Separator type selection

5.2.4.1 General

The commonly used separators in oilfields (gas field) mainly consist of vertical type and horizontal type depending on their shapes; gas liquid two-phase separator and oil, gas and water three-phase separator by its function; and negative pressure (<0.1MPa), low pressure (<1.5MPa), middle pressure (1.5 - 6.0MPa) and high pressure (>6.0MPa) separators by operating pressure.

5.2.4.2 Vertical separator

Vertical separator is usually used to process oil and gas mixture with a high gas-liquid radio, for example, serving as gas scrubber, liquid separation tank, etc. It is used to remove the small-amount liquid contained in large volume of gas.

5.2.4.3 Horizontal separator

Horizontal separator is mostly used when the liquid-gas ratio is higher, such as crude oil separator, buffer tank etc.

Normally, the vessel is to be loaded inside with packing to improve dehydration efficiency. The packing may be provided in the form of inclined plate, corrugated plate or the combination of packing and inclined plate to facilitate the coalescing of droplets. And in the meanwhile, the coalesced liquid will percolate down the packing, thus reducing the settlement time.

5.2.4.4 High-efficiency three-phase separator

Generally, high-efficiency three-phase separator is a horizontal separator.

High-efficiency three-phase separator is to achieve high-efficiency separation of crude oil through proper internal structure design and using mechanical, thermal and chemical technologies. This kind of separator is generally used in high density, high viscosity of crude oil processing due to the complexity of its internal structure.

5.2.5 Separator design calculations

The separator is to be designed with the consideration to directly separate the liquid droplets with a particle size larger than 100μm from the gas and the liquid droplets smaller than 100μm are to be separated by means of collision, commonly using mesh pad mist extractor. The mesh pad mist extractor can remove 99% of the liquid droplets with a diameter more than 10m from the gas flow and reduced the content of entrained liquid to no more than 50mg/m^3. For three-phase separator, consideration is to be given to remove as much free water in the oil as possible (in general, the separator is expected to separate water droplets of 0.5mm particle size from the oil) and to reduce the oil content of the separated free water to below 2000mg/L. The water content of the dehydrated crude oil is to be determined based on the number of separation stages, crude oil property, separation requirements and test results or experience.

5.2.6 Selection of separation system process and determination of critical parameters

The parameters of a separation system are to be determined according to the actual conditions and requirements of the oilfield. The main parameters of a separation system should be determined in accordance with the following requirements.

5.2.6.1 Number of separation stages

The number of separation stages and pressure are determined mainly based on the oil wellhead pressure, physical properties of well fluid, gas content of well fluid, as well as the separation objective and requirements. Theoretically, the more separation stages are arranged, the higher the crude oil recovery rate will be; however, more stages require larger coverage of area and higher economic investment. Based on comprehensive consideration, three-stage separation is normally used for high-pressure oilfield with higher gas-oil ratio and two-stage separation used for low-pressure oilfield with lower gas-oil ratio.

5.2.6.2 Operating pressures for various stages

The separation pressure depends on the wellhead pressure or upstream pressure, the number of separation stages and the requirements on other gas system or transfer pressure. The technical feasibility and cost-effectiveness of the system need to be considered in an integrated way.

5.2.6.3 Operating temperatures for various stages

The separation temperature, with a given number of separation stages, depends on the physical properties of the well fluid. Generally, it is determined on the basis of the data of oilfield separation test.

5.2.6.4 Residence time

In integrated consideration of cost-effectiveness and feasibility, the related codes have also given the theoretically recommended material stream residence time in the separator depending on crude oil density. However, the specific residence time is significantly affected by the physical properties of the crude oil such as density, viscosity etc., and is normally considered in an integrated way and determined through tests combined with the operating temperature.

5.2.6.5 Water contents at the outlets of various separation stages

The water contents at the outlets of various separation stages are to be determined according to the number of separation stages, physical properties of crude oil, operating temperature and final separation requirements. In general, in a three-stage separation process for crude oil, the water content at first stage outlet is required to be less than 40% (volumetric fraction); the water content at second stage outlet is to be within the range of 10 - 30% (volumetric fraction); and the commercial dehydration requirement for the third stage is achieved through thermochemical dehydration or dehydration using electric dehydrator.

Dehydrated crude oil is classified into the following levels depending on light crude oil, medium crude oil and heavy crude oil:

(1) Dehydrated light crude oil, its water content is to be less than or equal to 0.5% (mass fraction);

(2) Dehydrated medium crude oil, its water content is to be less than or equal to 1.0% (mass fraction);

(3) Dehydrated heavy crude oil, its water content is to be less than or equal to 2.0% (mass fraction).

5.2.7 Crude oil stabilization

5.2.7.1 General

In order to reduce the evaporation loss of crude oil during oil and gas gathering and transportation, the highly volatile light fractions in the crude oil need to be removed to reduce the vapor pressure of the crude oil under atmospheric temperature and pressure conditions. This process of removing the light fractions from the crude oil before storage is called crude oil stabilization.

Crude oil stabilization can not only minimize the evaporation loss of the light fractions, but also plays an important role in ensuring safe transfer and storage of crude oil.

As crude oil saturated vapor pressure mainly depends on the content of volatile components in the crude oil, the extent of crude oil stabilization can normally be measured by crude oil saturated vapor pressure at the maximum storage temperature.

5.2.7.2 Crude oil stabilization standard

(1) The condition for transport of crude oil specified by the International Convention for the Safety of Life at Sea is that the Reid vapor pressure must be lower than the atmospheric pressure. Crude oil produced offshore and to be transported by carriers must meet this requirement.

(2) Crude oil stabilization is to be in accordance with the requirements specified in China industrial standard SY/T0069 Design Code for Crude Oil Stabilization Unit. After stabilization, the designed saturated vapor pressure of crude oil at its maximum storage temperature should not exceed 0.7 times of the local atmospheric pressure.

(3)The requirements of different countries on the saturated vapor pressure of stabilized crude oil are not fully identical. Some foreign countries require that the Reid vapor pressure of stabilized crude oil is to be controlled within 10~12 lb/in^2.

5.2.8 Crude oil dehydration

5.2.8.1 Purpose of dehydration

The ultimate purpose of dehydration is to separate the waste water and impurities from the oil and gas mixture in order to obtain the qualified commercial crude oil and reach the water content criteria for crude oil sales.

5.2.8.2 Method of dehydration

The commonly used methods of crude oil dehydration mainly include gravitational settlement, heating settling method, chemical dehydration, eclectic dehydration and electrochemical dehydration. All these methods can be adopted, but electrochemical dehydration should be used on an offshore installation because it features high anti-emulsification ability, high dehydration efficiency, small footprint etc.

5.2.8.3 Criteria of dehydration

Water content of crude oil is to comply with user requirements or the requirements of industrial standards such as SY/T 0045 Design Specification for Crude Oil Electric Dehydration.

5.2.9 Crude oil desalting

5.2.9.1 Purpose of desalting

The purpose of crude oil desalting is to reduce the corrosion to equipment or pipeline caused by the salt during the course of crude oil processing, transfer, storage and use.

5.2.9.2 Technique of desalting

In order to meet the users' requirements for salt content, economic and effective desalting techniques are to be employed.

Desalting techniques mainly use fresh water to dilute the salts contained in crude oil and then dehydration to meet the specified requirements for salt content.

5.2.9.3 Criteria of desalting

The salt content of crude oil is to be in compliance with the users' requirements.

SECTION 3 NATURAL GAS PROCESS SYSTEM

5.3.1 General

In order to meet the users consumption or transport requirements, natural gas needs to be dehydrated, deacidification gas or denitrification treatment before it is delivered to the end users.

5.3.2 Dehydration of natural gas

If the natural gas produced in offshore gas field or oil-gas field needs to be transferred via long-distance pipeline, it is to be dehydrated offshore in order to prevent hydrates generation and pipeline corrosion caused by sour gas during the transfer.

5.3.3 Criteria for natural gas dehydration

The requirements for the extent of natural gas dehydration are as follows:

(1) Meet user requirements;

(2) The water dew point of pipeline transferred natural gas at initial transfer pressure is to be 5C less than the lowest ambient temperature under transfer conditions;

(3) The hydrocarbon dew point is to be less than or equal to the lowest temperature of pipeline transferred gas;

(4) For natural gas condensate recovery device, the water dew point is to be at least 5C less than the lowest refrigerating temperature;

(5) For natural gas subject to cryogenic treatment, the downstream processing techniques should be incorporated to determine a reasonable hydration extent.

5.3.4 Techniques and methods of natural gas dehydration

The methods of natural gas dehydration include low temperature dehydration, solvent absorption method, solid adsorption method, etc. The most widely used method is solvent absorption method which uses glycol as the dehydrating agent.

(1) Low temperature dehydration method mainly consists of injection of throttling and dewatering hydrate inhibitors such as methanol, ethylene glycol or diethylene glycol, air cooling method, cold medium refrigerating method and expansion method.

(2) In solvent absorption method, the absorbing agent contacts with the natural gas in reverse direction to effectively remove the water vapor in the gas.

(3) Solid adsorption method usually uses molecular sieve as the absorbent. This method is mainly used for natural gas dehydration when there are cryogenic devices in the subsequent process (Light hydrocarbon recovery by cryogenic separation method, cryogenic denitrification) and the process flow that must reduce the water dew point below -80℃.

5.3.5 Compression of natural gas

Natural gas produced offshore may be transferred to the land via pipeline or be used for gas lift (production), gas injection (to maintain reservoir pressure) or as platform fuel. In this case, the natural gas is normally required to be compressed to increase its pressure to a usable level.

5.3.6 Types of compressor

Compressors commonly used in offshore oilfield include reciprocating compressor, screw compressor and centrifugal compressor, which are driven by electrical motor or natural gas engine.

5.3.7 Compressor selection and gas property

5.3.7.1 Safety

The medium compressed by natural gas compressor is hydrocarbon mixture, and as the pressure increases, the low explosion limit will basically remain unchanged while the upper explosion limit will increase significantly.

The measure to prevent the creation of explosive mixture in the compressor or piping is to avoid dead leg as local explosive mixture may be created in the dead leg if it has not been sufficiently purged. Therefore, the compressor is to be purged prior to starting.

5.3.7.2 Influence of gas property

During the process of natural gas gathering and transfer, the composition and properties of natural gas will usually change. Therefore, the selected compressor set is to have a better adaptability to gas composition. Normally a range of composition variation is to be specified and special attention is to be paid to selection of centrifugal compressor, otherwise, the compressor may be seriously affected by the significant change of parameters such as gas molecular weight and adiabatic index.

5.3.7.3 Liquefaction during compression

A portion of the natural gas may be liquefied during compression, so attention is to be paid to the separation and removal of the condensate liquid. For a reciprocating compressor, the clearance volume of compressor cylinders of various stages is to be slightly larger to prevent cylinder knocking; and when there is a large amount of condensate liquid, the outlet valve is to be arranged in the lower section of the cylinder to prevent condensate liquid accumulation. In the meanwhile, the crankcase is to be properly sealed in order to prevent ingress of liquefied gas which will reduce the flash point and viscosity of the lubricating oil.

For oil-injected screw compressor, the minimum gas discharge temperature is to be specified according to gas composition in order to avoid gas liquefaction which will dilute the lubricating oil. Once the lubricating oil is diluted, its properties must be reinstated.

When a centrifugal compressor is selected, the system is to be equipped with degassing separator as the shaft sealing oil may be diluted by the invading gas. The degasser is to be provided with electric or steam heater, agitator and gas extraction arrangements to improve degassing efficiency.

5.3.7.4 Restrictions on gas discharge temperature

The main component of natural gas is alkane, so the gas discharge temperature should be controlled below 140℃ to reduce oil vapor carbonization and fire risks; nowadays the outlet temperature of compressors from some manufacturers can reach 150℃.

5.3.8 Considerations for compressor type selection

5.3.8.1 Process requirements

Process requirements are to be firstly complied with when selecting a compressor. The main process requirements are as follows:

(1) Requirements presented by compressed medium, including if medium leakage at small amount is allowed, if the medium contamination by lubricant is allowable, and the restrictions on gas discharge temperature etc.;

(2) Discharge rate of the compressor;

(3) Inlet and outlet pressures of the compressor.

5.3.8.2 Type comparison

Provided that above mentioned process requirements are met, further comparison of compressor types is to be made according to the following criteria:

(1) For high pressure and super high-pressure compression, generally, a reciprocating compressor is to be used. However, with the scaling-up development of industrial installations, the discharge rate of compressors is becoming higher and higher and the advantages of selecting a centrifugal compressor increase;

(2) Centrifugal compressor features the advantages of continuous and high discharge rate, smooth operation, small overall size, lower weight, small floor area, less quick-wear parts, long service life and less maintenance, and is free of gas contamination by lubricant. A centrifugal compressor should be selected where large gas volume is required, gas volume fluctuation is not significant and medium to low discharge pressure is desired;

(3) The velocity type compressor firstly provides the gas with kinetic energy and then converts the kinetic energy to pressure energy. For the gas with a lower density relative to air, the gas velocity needs to be increased to achieve the same compression ratio, and at the same time, the wear will increase. Therefore, using a centrifugal compressor to compress gases of low molecular weight is not favorable. Nevertheless, as gas density will increase under high pressure, the disadvantage of low molecular weight is overcome;

(4) When the required flow rate is lower, a reciprocating type or screw type compressor is to be selected;

(5) As an oil-injected screw compressor combines many advantages of a reciprocating compressor and a centrifugal compressor and features broader adjustment range and stable operation, it has high practical values in the refrigeration industry and its use has been gradually extending to the natural gas gathering, transfer and processing industry.

Compared with oil-injected screw compressor, the oil-free screw compressor also has abovementioned features except for its gas rate adjustment and low single-stage compression ratio. Moreover, it can handle wet gas and is a unit with good practical values.

5.3.9 Selection of compressor driver

(1) Motor

Motor can drive both reciprocating compressor and centrifugal compressor. It features obvious advantages such as compact structure, less investment (total investment equals only 1/2~2/3 of that for gas turbine compressor station), free selection of motors with an arbitrary size, simple operation, stable running, long service life (able to reach 150000 h), low installation and maintenance cost and high operational reliability.

The disadvantage of motor lies in difficult speed adjustment. The synchronous motor itself cannot change speed, so its speed increase or decrease is achieved through a set of speed changing gear which needs to accommodate the load changes of the compressor. And it is very difficult to realize stepless speed changing.

Explosion-proof requirements for the motor are to be taken in account during selection of motor.

(2) Gas reciprocating engine

The advantages of gas reciprocating engine are its high thermal efficiency (around 35%~37%), low consumption of fuel gas (0.25~0.3m^3/kWh), direct connection with reciprocating compressor without the necessity of speed changing, and convenient adjustment. And its disadvantages include heavy weight, complex structure, high installation and maintenance cost, more and complicated auxiliary equipment, high operation vibration, high noise, small single engine power compared with gas turbine, and low compatibility with centrifugal compressor. Therefore, the gas reciprocating engine should be used to drive a reciprocating compressor only when the required compression ratio is high.

(3) Gas turbine

Compared with other types of thermal engine, the gas turbine has a simpler structure and smaller weight and volume. In addition, its power still increases when the ambient temperature becomes low, this happens to suit the seasonal changes of gas consumption demand. Gas turbine does not require a cooling for itself and only a small amount of cooling water is required to cool down the lubricating oil system. It also features high RPM, ability of direct connection with centrifugal compressor, less auxiliary equipment in comparison with gas engine and easier achievement of automatic control.

SECTION 4 PRODUCTION WATER PROCESSING SYSTEM

5.4.1 General

The oily water produced by an offshore oil and gas installation mainly consists of the water carried by the crude oil from the formation, which is also called production water; and the oil and water leaked from equipment and piping, oily water from flushing the equipment, piping and platform decks during the production. Normally the oily water, after processed, is to be discharged to the sea or injected into the reservoir being exploited.

5.4.2 General requirements

5.4.2.1 Oily water is to be injected back into the formation as practically possible to reduce the amount of oily water discharge.

5.4.2.2 The mature and suitable new processes, technologies, equipment and materials both at home and abroad are to be introduced in a proactive way during the engineering design of production water processing.

5.4.2.3 The oil content of the original water entering a produced water processing station is to be no higher than 1000 mg/L. The oil content of the original water entering a polymer drive produced water processing station should be no higher than 3000 mg/L; and oil content of the original water entering a produced water processing station for extra-thick and super-thick crude oil production should be no higher than 4000 mg/L.

5.4.2.4 Metering facilities and water quality monitoring sample points are to be provided for production water and purified water of the production water processing system.

5.4.2.5 Storage adjusting equipment is to be provided when the amount and quality of the production water being processed by the production water processing system fluctuate significantly.

5.4.2.6 The production water treatment process is to be determined through tests or from similar project experiences based on the properties of production water and requirements on purified water quality after technical and economic comparison.

5.4.2.7 The production water treatment process should be designed to be of assembled, modularized and skid-mounted type to increase the percentage of shop prefabrication and minimize the work quantity of field construction.

5.4.2.8 The production water treatment process should be centrally and automatically controlled in order to reduce the number of field operators or eliminate the need of field attendance.

5.4.2.9 During production water processing, the frequency of pump lifting of oily water is to be minimized to prevent oily water emulsification and decrease of oil droplet particle size and facilitate oil removal.

5.4.2.10 Production water is not to flow back into the crude oil processing system in order to avoid adverse effect on oil and water separation.

5.4.2.11 Production water processing system is to be designed with higher flexibility to meet the requirements of load changes, potential ability and maintenance.

5.4.2.12 For the production water processing system of thick oil oilfield, the applicable provisions in 5.4.2.1~5.4.2.9 of this Chapter and the following principles are to be complied with:

(1) During selection of thick oil production water treatment process and equipment, the influence of thick oil physical properties on process/equipment operation is to be taken into full consideration;

(2) The thermal energy of the produced water is to be adequately utilized in thick oil production water treatment process;

(3) The dirty oil produced by thick oil production water processing system should be disposed of separately.

5.4.2.13 If the production water needs to be stored in the production water tank, the concentration of hydrogen sulfide in the production water should match the chemical properties of materials, welds and coatings. If the material of the production water tank is the same as that of the crude oil tank, it should be treated at least to the allowable standard value of hydrogen sulfide in the product crude oil, which is usually below 20 ppm.

5.4.3 Discharge standard

5.4.3.1 Discharge of processed production water is to be in accordance with GB4914-2008 Effluent Limitations for Pollutants from Offshore Petroleum Exploration and Production which specifies the following aspects:
(1) Standard levels

The oily water discharge requirements/concentration limits for offshore petroleum exploration and production are divided into three levels based on the waters into which the oily water is discharged:

Level 1: Applicable to Bohai Sea, Beibu Gulf, other special conservation ocean areas delineated by the state and other marine waters no more than 4n mile away from the nearest land.

Level 2: Applicable to waters excluding Bohai Sea, Beibu Gulf, other special conservation ocean areas delineated by the state more than 4 n mile and less than 12 n mile away from the nearest land.

Level 3: Applicable to waters other than the above-mentioned level 1 and level 2 waters.

(2) Standard values

The maximum allowable concentrations for discharge of oily water in offshore petroleum production industry are to be in compliance with Table 5.4.3.

Production water discharge concentration limits Table 5.4.3

<table>
<tr><th>Item</th><th>Level</th><th colspan="4">Concentration limits /(mg/L)</th></tr>
<tr><td rowspan="3">Petroleum</td><td>Level 1</td><td rowspan="3">Momentary allowable value</td><td>≤30</td><td rowspan="3">Monthly average value</td><td>≤20</td></tr>
<tr><td>Level 2</td><td>≤45</td><td>≤30</td></tr>
<tr><td>Level 3</td><td>≤65</td><td>≤45</td></tr>
</table>

5.4.3.2 The discharge of production water should take into full consideration the protection of Marine environment and Marine ecology, and should be cooled adequately before discharge.

5.4.4 Design considerations for production water treatment process

Production water treatment process is determined mainly depending on the oil specific weight and the requirements after processing.

(1) Where the specific weight of oil is light and the difference between oil specific weight and water specific weight is large, the processing is easier and the number of processing stages is less;

(2) If the processed water is discharged, the required oil content of the discharged water will vary with the change of waters. Waters with more stringent discharge requirements will require more treatment stages;

(3) Production water is to be injected back into the formation as practically possible to minimize pollution to ocean environment. If the processed water is for back injection, it is to meet the standards of injection water.

5.4.5 Oily water processing equipment

5.4.5.1 Free settlement tank

Production water needs to stay in the free settlement tank for approximately 8 hours, which requires an enormous design capacity for the tank. Only the process tank of floating production, storage and offloading unit should be used as the free settlement tank.

5.4.5.2 Plate type oil interceptor

By plate shape and installation pattern, plate type oil interception equipment can be classified into parallel plate interceptor (PPI), corrugated plate interceptor (CPI) and cross flow interceptor (CROSSFLOW), among which the corrugated plate interceptor is commonly used.

For the design of plate type oil interceptor, the equipment capacity should be estimated assuming a residence time of 30 minutes to make sure that the system will not be seriously impacted by pulsation.

5.4.5.3 Floatation tank (Floatation)

(1) General

Floatation is a process during which fine gas bubbles are injected into the water phase, the oil droplets in the water adhere to the gas bubbles and float to the water surface with the gas bubbles, then the oil droplets on water surface are collected in the form of foams and skimmed off from the surface. Based on different methods of gas introduction, floatation is classified into induced gas floatation, jet flow floatation and dissolved gas floatation.

(2) Selection of floatation tank

The type and gas source of floatation tank are to be selected through tests or from similar project experience based on the properties of produced water and the requirements on purified water quality after technical and economic comparison.

Buffering equipment should be provided in the upstream of the floatation.

The floatation is to be equipped with oil collection and mud draining facilities.

When a floatation tank is selected, appropriate water treatment agents should be used jointly to demulsify any emulsified oil and water and stabilize the gas bubbles.

(3) Sealing blanket

An inert gas blanket and a slight positive pressure are to be maintained in the upper space of the floatation tank in order to prevent accidents caused by dispersion of residual natural gas in the production water and oxygen ingress into the water to be back injected.

5.4.5.4 Hydrocyclone

(1) Selection of hydrocyclone

Hydrocyclones are to be selected through tests or from similar project experience based on the properties of produced water, the requirements on purified water quality and designed water capacity after technical and economic comparison.

At least two groups of hydrocyclones should be equipped.

A screw pump or low-speed centrifugal pump should be used as the booster pump in the upstream of the hydrocyclone, and its water pressure and flow rate are to remain steady.

Hydrocyclones should be used on floating unit because their functions are not susceptible to the influence of motions of the floating unit.

(2) Restrictions on use of hydrocyclone

The oil-water density difference is to be more than 0.05 g/cm^3.

The oil content of original water should be relatively higher and the degree of oil emulsion lower.

Hydrocyclone should not be used alone for oily water processing.

5.4.5.5 Filter oil removal equipment

(1) General

Filtering is a separation process in which the dispersed and emulsified oil in the oily water is removed through absorption onto the filtering medium. Due to different particle diameters in the filtering material layer, various pores are created inside the layer and the dirty oil and suspended impurities contained in the oily water will be absorbed and intercepted by these pores. The most commonly seen oil removal filtering devices are walnut shell filter, double-medium filter and active carbon filter.

(2) Selection of filter

Filter types are to be selected through technical and economic comparison based on the design scale, requirements for operation management, quality of incoming and outgoing water, arrangement and space of platform equipment.

No less than two sets of filters should be provided.

When a walnut shell filter is used, special attention is to be paid to make sure the oil content of the water at filter inlet is less than 100 mg/l, otherwise it will be rapidly saturated by oil, resulting in reduced filter cycle.

(3) Back washing

Automatically controlled variable strength back washing should be adopted for filters using granular filtering material. The back washing strength is to be determined through tests. Where test conditions are not available, the back washing strength may be determined based on experiences of the existing filters working under similar conditions. In case of limited data availability, the back washing strength for the filter may be selected as per Table 5.4.5.5(1) and Table 5.4.5.5(2).

Water back washing strength Table 5.4.5.5 (1)

Type of filtering material	Back washing strength of primary filter (L/(m^{2}s))	Back washing strength of secondary filter (L/(m^{2}s))
Walnut shell	6~7	---
Quartz sand	14~15	12~13
Quartz sand + Magnetite	15~16	13~14
Modified fiber ball	---	5~6

Air back washing strength Table 5.4.5.5 (2)

Type of filtering material	Air back washing strength (L/(m^{2}s))
Graded quartz sand	15~20
Uniform quartz sand	13~17
Double layer filtering material (coal, sand)	15~20

5.4.6 Chemical agent

5.4.6.1 Chemical agents are to be added during the processing of oily production water, which is linked with the success of the treatment process. Reversed demulsifier and polymer are usually added.

5.4.6.2 Reversed demulsifier is a kind of water-soluble surfactant which modifies the surface activity of emulsified liquid and causes the emulsified liquid droplets to break down. The demulsified small oil droplets will bond into larger oil droplets that tend to float to the surface, and thus the separation of oil from water is achieved.

5.4.6.3 Polymers are to be added from the outlet of the floatation as they can stabilize the gas bubbles and facilitate the floatation. If production water is used as injection water, it needs to be filtered. In this case, flocculant is to be added, prior to filtering, to make the fine solid particles coalesce and thus better remove the suspended solids.

SECTION 5 SUBSEA PRODUCTION SYSTEM

5.5.1 System constitutes

Subsea production system mainly consists of subsea wellhead system, subsea tubing hanger/Christmas tree system, well completion/workover riser system, auxiliary equipment, mudline casing suspension systems, production control system, subsea pipeline system, subsea template and manifold system.

5.5.2 Main functions of the system

The main functions of subsea production system are to:

(1) Safely deliver well fluid to above the water surface for processing;

(2) Safely deliver the to-be-injected fluid into the well;

(3) Effectively control the fluids being output from and input into the well.

5.5.3 Recognized standard

The Society accepts that subsea production system is designed, manufactured, installed, surveyed and tested in accordance with GB/T 21412, ISO 13628 or API RP 17 standard series.

5.5.4 System design

5.5.4.1 Subsea production system is to be designed taking systematically into account the requirements for the installation, operation, testing, maintenance, repair and abandonment of the subsea production system.

5.5.4.2 At an early design stage, the demand on production expansion in the future is to be considered.

5.5.4.3 Subsea production system is to be designed taking into integrated consideration the demands of various production stages of the oilfield/gas field, the needs of oilfield operation, design data and design load at the location where the subsea production system will be installed.

5.5.5 Equipment manufacturing and survey

5.5.5.1 Subsea equipment are to be manufactured according to the quality system, drawings and documents approved by the Society.

5.5.5.2 Individual component or items of equipment is to be in conformity with the specific product requirements and be verified through factory acceptance test and system integration test.

5.5.5.3 A comprehensive acceptance test programs are to be fully implemented in the fabrication site in order to ensure that the components have been manufactured in line with the specific product requirements and meet the systems performance requirements.

5.5.6 Installation and commissioning

5.5.6.1 Equipment associated with the subsea production system are to be transported, installed and commissioned in accordance with the procedure approved by the Society.

5.5.6.2 The subsea production system is to be commissioned before it is put into production, to verify that various interfaces and the entire system are in good conditions and ready for start-up.

5.5.7 Subsea system control

5.5.7.1 The control of subsea system is to be designed in an integrated way in combination with the above water system.

5.5.7.2 The subsea control system is to be of fail-safe type, and controlled shutdown upon failure of certain system component (e.g., failure of pilot control, multiplex signals or electrohydraulic signals) is to be achievable.

5.5.7.3 Response time of the entire system (e.g., time to complete the demanded action) is to be specified, and where relevant, the two response time levels may be defined to reflect the normal operation and fail-safe operation when e.g., multiplex controls have failed.

5.5.7.4 The subsea control system is to accept the input signals from system shutdown, and the shutdown of topside production system or riser shutdown valve is to be able to normally cause the shutdown of the wing valve or other barrier valves mounted at the wellhead.

5.5.7.5 Emergency shutdown of a higher level is to lead to the shutdown of all subsea barrier valves.

5.5.7.6 The general segregation requirements between the control system and the shutdown system of subsea production system is not mandatory and it can be incorporated into the operational control functions (e.g., control or state of the check valves, pressure and temperature monitoring).

5.5.7.7 The control fluid used in open control system that trains to sea is to be harmless to the environment.

5.5.7.8 Hydraulic oil return line subject to possible contamination by the well fluid is to be segregated from other systems and the connections with detachable joints are to be considered as secondary grade release source for hazardous area classification.

CHAPTER 6 AUXILIARY PROCESS SYSTEM

SECTION 1 GENERAL

6.1.1 Introduction

Auxiliary process system consists of pressure-relieving system, emergency depressing system, flare and cold vent system, open and closed drain system, chemical injection system, water injection system, special oil displacement and artificial lift system, natural gas and crude oil fuel system, crude oil storage and offloading system.

6.1.2 Definitions

(1) Pressure-relieving device

A device actuated by the inlet static pressure and designed to open under emergency or abnormal conditions to prevent increase of internal fluid pressure to a value in excess of the specified design pressure. Such device may also be used to prevent excessive negative internal pressure. A pressure-relieving device may be a pressure relief valve, a non reclosing pressure-relieving device or a vacuum relief valve.

(2) Pressure-relief valve

A pressure-relieving device which is designed to open and relieve the excessive pressure, and is able to reclose when normal conditions are restored to prevent further outflow of fluid. It is termed as safety valve in ISO4126-1.

(3) Relief valve

A spring-loaded pressure-relief valve actuated by the static pressure in the upstream of the valve. Normally, the opening degree of the valve is in direct proportion to the pressure increment to opening pressure. Relief valve is mainly used for incompressible fluid.

(4) Safety valve

A spring-loaded r pressure relief valve actuated by the static pressure in the upstream of the valve, with the feature of quick opening or pop action, which is commonly used for compressible fluid.

(5) Safety relief valve

A spring-loaded pressure- relief valve which can be used as either a safety valve or a relief valve depending on the application.

(6) Conventional pressure relief valve

A spring-loaded pressure-relief valve whose operating characteristics are directly affected by back pressure changes.

(7) Balanced pressure relief valve

A spring-loaded pressure-relief valve fitted with bellows or other arrangements for minimizing the effect of back pressure on the valves operating characteristics.

(8) Pilot-operated pressure-relief valve

A pressure-relief valve which is constituted by a main relief device or a main valve and a self-actuated auxiliary pressure-relief valve(pilot) and controlled by the pilot.

(9) Rupture disc device

A non reclosing pressure-relieving device which is actuated by the static pressure difference between the inlet and outlet and performs its design function through bursting of the rupture disc. The rupture disc device is composed of a rupture disc and a disc holder.

(10) Relieving conditions

The inlet pressure and temperature on a pressure-relieving device during an overpressure period. Relieving pressure equals the valve set pressure (or rupture disc burst pressure) plus the overpressure. The temperature of the flowing fluid may be higher or lower than the operating temperature at relieving conditions.

(11) Accumulated pressure

The pressure increases in excess of the maximum allowable working pressure of the vessel during the discharge period of the pressure-relieving device.

Note: accumulated pressure is expressed in pressure unit or the percentage of the maximum allowable working pressure or design pressure. The maximum allowable accumulated pressure is determined based on the corresponding pressure design standards for emergency operations and accidental fire.

(12) Design pressure and maximum allowable working pressure (MAWP)

The definitions of design pressure and maximum allowable working pressure are given in 3.1.3 of the Rules.

(13)Operating pressure

The pressure experienced by process system during normal operation, including normal pressure variations.

(14) Overpressure

The pressure increments beyond the set pressure of the relieving device, expressed in pressure unit or percentage. When the design pressure of the relieving device is set at the maximum allowable working pressure of the vessel, the overpressure equals the accumulated pressure.

(15) Set pressure

The inlet gauge pressure set for the pressure relieving device under operating conditions.

(16) Back pressure

Pressure that exists at the outlet of the pressure-relieving device, which equals the sum of superimposed back pressure and build-up pressure.

(17) Built-up back pressure

The pressure increments at the outlet of the pressure-relief device, which results from the fluid flow after the pressure-relief device opens.

(18) Superimposed back pressure

The static pressure at the outlet of the pressure-relief device when the device is required to operate.

Note: the pressure caused by other pressure sources within the discharge system, which may be steady or variable.

(19) Relieving pressure differential

The difference between the set pressure and the closing pressure of the pressure-relief valve, which is expressed in percentage of the set pressure or in pressure unit.

(20) Opening pressure

A pressure at which a measurable lift of the valve disc or continuous fluid discharge is determined by the sense of sight, touch or hearing when the inlet static pressure increases to such value.

(21) Closing pressure

A pressure at which a re-contact between the valve disc and valve seat or zero lift is determined by the sense of sight, touch or hearing when the inlet static pressure drops to this value.

(22) Valve simmering

The audible or visible leak of compressible fluid between valve seat and disc, which may occur when the inlet static pressure is lower than the set pressure and before the pressure-relief valve opens.

(23) Leak test pressure

The specified inlet static pressure for leak test of valve seat.

(24) Air seal (purge reduction device)

A device used to minimize or eliminate invasion of air from the outlet into the stack.

(25) Buoyancy seal (diffusion seal)

A dry vapor seal used to minimize the required purge gas and prevent air infiltration.

Note: By collecting and storing a certain volume of lighter gas in the inverted trap, the buoyancy seal prevents the displacement of light flare gas by air.

(26) Velocity seal (orifice seal)

A dry vapor seal used to minimize the required purge gas and prevent air infiltration to the flare burner outlet.

(27) Assist gas

A fuel gas which is added from upstream of the flare burner or at the burning location to increase the heating value.

(28) Enclosed flare

A flare with one or more burners arranged inside an enclosure so that the flame is not visible.

(29) Elevated flare

A flare with a burner or burners highly elevated off the ground for heat radiation reduction and better dispersion.

(30) Flame front generator

A device used to ignite the flare pilot by means of a flame front.

(31) Flame stabilizer

A physical device used to prevent flame blowout from the flare burner.

(32) Flare

A device or system used to safely dispose of the released fluid by means of burning in an environmentally friendly way.

(33) Flare burner (flare tip)

A part of a flare where fuel and air are mixed at specific velocity, turbulence and required concentration to establish and maintain proper ignition and maintain stable burning.

Note: In consideration of the designed nature of the project, inclusion of flame stabilizer and the mostly adopted special design, the name flame burner is deemed more appropriate than flare tip.

(34) Flame velocity

The speed at which the flame front travels to the unburned combustible gas mixture.

(35) Detached stable flame

A stable and burning flame front which is in the vicinity of the flare burner but is not in contact with the flare burner.

(36) Blow off

The loss of stable burning where the flame is lifted above the burner when fuel velocity exceeds flame velocity.

(37) Flashback

A phenomenon that occurs in the combustible mixture when the local velocity of the air and combustible gas mixture is less than flame velocity, which causes the flame to travel back towards the gas-air mixing point.

(38) Low heat value (net heat value)

A value equal to high heat value minus the latent heat of vaporization of water (including water generated by combustion products and water already present in the flare gas).

(39) Mach number

The ratio between the flow velocity measured relative to a particular obstacle or geometric figure and the transmission speed of sound waves through this fluid.

(40) Purge gas

The fuel gas or non-condensable inert gas filled into the flare header to mitigate air invasion and burn back.

(41) Radiation intensity

The transfer rate of the radiant heat from flare flame, which is usually considered as the heat transfer rate at a particular elevation.

(42) Ringelman number

The visually comparative scales used to define opacity. 0 denotes clear,5 denotes black and 1-4 describe the increasing gray levels of the incompletely combusted hydrocarbons smoke.

(43) Stack

The pipe or conduit which delivers the released gas to the flare burner or into the atmosphere.

(44) Wind shield

A device used to protect the downwind side of the elevated flare burner from direct flame impingement.

(45) Flame arrester

A safety device installed at the opening of an enclosed space or connected to the pipework of the enclosed space system, having the function of allowing gas flow-through while preventing flame propagation.

(46) End-of-line flame arrester

A flame arrester which is fitted with only one pipe connection.

(47) In-line flame arrester

A flame arrester which is fitted with two pipe connections, with one connection onto each side of the flame arrester element.

(48) Deflagration

An explosion propagating at a subsonic velocity.

(49) Unconfined deflagration

An explosion that occurs when the combustible atmosphere outside the vessel or other process equipment is ignited.

(50) Confined deflagration

A confined deflagration occurs when the combustible mixture is ignited in the a pipe line and the flame front initially travels along the pipe at a subsonic velocity.

(51) Detonation

An explosion that propagates at a supersonic velocity and has the features of shock wave.

6.1.3 Recognized standards

The Society accepts that the pressure relief, depressing, flare and cold vent systems are designed, manufactured, installed and tested in accordance with the following recognized standards.

(1)	API RP 520	Sizing, Selection, and Installation of Pressure-relieving Devices in Refineries.
(2)	ISO 23251/ API RP 521	Petroleum, Petrochemical and Natural Gas Industries --Pressure-relieving and depressuring Systems.
(3)	ISO 25457/API Std 537	Petroleum, Petrochemical and Natural Gas Industries-Flare Details for General Refinery and Petrochemical Services.
(4)	API Std 526	Flanged Steel Pressure Relief Valves.
(5)	API Std 527	Seat Tightness of Pressure Relief Valves.
(6)	EN 12874:2001	Flame Arresters-Performance Requirements, Test methods and Limits for Use.
(7)	API RP 2028	Flame Arresters in Piping Systems.

SECTION 2 PRESSURE RELIEF SYSTEM

6.2.1 General requirements

(1) Each pressurized process component is to be equipped with pressure-relieving devices to prevent its internal pressure from exceeding the maximum allowable accumulated pressure;

(2) For pressurized process components protected by pressure relief valve, any isolated internal section without overpressure protection, which is caused by valve closure, solidification and blockage or damage of valve internals, is to be avoided;

(3) Pressure relief valves are to be designed, manufactured and inspected according to the standards recognized by the Society and the anticipated offshore environmental conditions.

6.2.2 Relieving capacity of pressure relief valve

The relieving capacity of a pressure relief valve is to be selected taking into account the following, but not limited to the following, causes of overpressure that the protected component may experience under operating, starting and shutdown conditions:

(1) Outlet blockage (e.g., blockage caused by damaged vessel internals);

(2) Fire (e.g., fire around the vessel);

(3) Tubing rupture (e.g., tubing in the heat exchanger);

(4) Control valve failure (e.g., the opening of pressure regulating valve being out of control);

(5) Gas blow by (usually caused by loss of liquid level control);

(6) Thermal expansion (e.g., isolated pipe sections heated by solar radiation);

(7) Excessive energy input (e.g., loss of regulation control of boiler burner).

The required flow rate for each pressurized component in the process system under each overpressure condition is to be calculated and recorded. The pressure relief valve is to be sized as per the highest required flow rate.

6.2.3 Set pressure and maximum relieving pressure of pressure relief valve

The relationship between the set pressure and other pressure parameters of the pressure relief valve is to be in accordance with Table 6.2.3.

The relationship between set pressure and other pressures of pressure relief valve Table 6.2.3

	Expected maximum operating pressure	Maximum allowable set pressure	Allowable pressure for simmering	Closing pressure	Maximum relieving pressure	
					Non-fire condition	Fire condition
Maximum allowable working pressure/design pressure ratio	90%	100%	98%	92.5%	116%	121%

Note:

① The closing pressure is to be higher than the maximum operating pressure, but not excessively high. When the relieving pressure differential is too small, frequent valve opening and closing will occur and further result in valve damage;

② The tabulated maximum relieving pressure is equal to the maximum accumulated pressure specified by the standard. The maximum accumulated pressure varies in different pressure vessel standards, for instance, in BS standard for pressure vessels, the maximum accumulated pressures under fire and non-fire conditions are no greater than 110% of design pressure. The tabulated values conform to ASME standards;

③ For multiple valves used for protection, at least one valve is set at 100% of the maximum allowable working pressure/design pressure, and other valves are set at 110% of the maximum allowable working pressure/design pressure.

6.2.4 Selection of pressure relief valve

(1) In general, pressure relief valves are to be used instead of rupture disc in oil and gas process system as oil and gas production will be affected once the rupture disc bursts and fully relieves the pressure;

(2) Spring-loaded pressure relief valves are to be used under normal conditions and pilot-operated or air-assisted pressure relief valves may be selected under special conditions;

(3) Non-balanced spring-loaded pressure relief valves are to be used when the built-up back pressure is no greater than the maximum allowable overpressure;

(4) Balanced spring-loaded pressure relief valves are to be used when the built-up back pressure is greater than the allowable value for non-balanced spring-loaded pressure relief valve. However, the back pressure is not to exceed 50% of the set pressure in consideration of the maximum allowable operating pressure of the bellow.

6.2.5 Equipping of pressure relief valve

The equipping or waiving of pressure relief valve for each pressurized process component are to be in accordance with the requirements stated in Section 2Chapter 4 (in which it is referred to as pressure safety valve) of the Rules.

6.2.6 Material of pressure relief valve

The material of pressure relief valve is to be suitable for the valve inlet and outlet temperatures resulting from the severe working conditions and emergent conditions. The material of the spring is to be selected taking into consideration the most severe non-fire conditions. The springs are to be protected by effective coating to prevent occurrence of general corrosion and hydrogen sulfide stress corrosion cracking.

6.2.7 Prevention of malfunction of pressure relief valve

Measures are to be taken to prevent potential hydrates generation, occurrence of freezing, and the effect of process fluid solidification and corrosion on valve functions.

6.2.8 Isolation of pressure relief valve

(1) If possible, isolating valves are not to be provided in the upstream and downstream of a pressure relief valve in order to eliminate the possibility of the relief valve being isolated by error;

(2) If the arrangement of any isolating valve is intended, two sets of pressure relief valve are to be provided:

Only an inlet isolating valve is required for pressure relief valves directly discharging to the atmosphere via their independent discharge lines;

An inlet isolating valve and an outlet isolating valve are to be provided for pressure relief valves directly discharging to a common flare system;

(3) The following conditions are to be met if the pressure relief valve is provided with inlet or outlet isolating valves:

① The isolating valve is to be of fully open type and its flow area is to be no less than that of the relief valve;

② In order to ensure the pressurized components are always protected by a pressure relief valve, for inlet isolating valves, one valve is to be always in locked open position and the other in locked closed position; and for outlet isolating valves, both valves are to be in locked open position. It is recommended to design an automatic interlocking system for operation of the isolating valves;

③ Devices indicating the opening and closing state of the isolating valve are to be provided at the local operation points and in the manned control room;

④ The unlocking, opening and closing of the isolating valve are to be operated by the authorized personnel;

⑤ Where the pressure relief valve is removed, a spare valve or a spool piece of identical size is to be installed in place of the original valve;

⑥ The disassembling and reassembling procedure for pressure relief valve is to be prepared;

⑦ A bleed valve is to be provided on the pipe section between the pressure relief valve and the inlet/outlet isolating valves.

6.2.9 Position and installation of pressure relief valve

The installation and position of pressure relief valve are to be in accordance with the applicable requirements in Chapter 4 Section 2 of the Rules, in addition to the following principles:

(1) The pressure relief valve in the protected process component is to be positioned as far from the sources of pressure fluctuation as possible;

(2) In order to protect the entire pressurized process component, the pressure relief valve assembly is to be positioned, as practically possible, in the upstream of the protected process component and as close to the overpressure source as possible;

(3) The pressure relief valve is to be connected to the gas cavity of the protected process component. For vessels fitted with mist extractor, the pressure relief valve is to be installed in the upstream of the mist extractor;

(4) Spring-loaded, pilot-operated or air-assisted and thermal expansion relief valves are to be vertically installed;

(5) The pressure relief valve is to be adequately supported to withstand the strong reaction force generated at the time of pressure relieving;

(6) The inlet and outlet lines of the pressure relief valve are to be arranged in such a way as to ensure no liquid accumulation at the inlet or outlet of the pressure relief valve;

(7) The pressure relief valve connected to a closed relief system is to be positioned higher than the relief header. The outlet line of the pressure relief valve is to be connected to the top of the header or in such a way as to prevent backflow to the valve outlet line when the header is filled with liquid.

6.2.10 Inlet line of pressure relief valve

(1) The flow area of all pipes, fittings and valves between the protected process component and the pressure relief valve is to be at least equal to that of the pressure relief valve;

(2) The pressure drop between the protected process component and the pressure relief valve is to be no more than 3% of the set pressure;

(3) The inlet line is to be of self-draining design.

6.2.11 Thermal expansion relief valve

(1) Installation requirements

Thermal expansion relief valves are required where the entire isolated liquid-filled system is subject to heat input from the environment or the process. It is to be specially noted that thermal expansion protection is to be provided in the following cases:

① The cold side of a heat exchanger which can be blocked in;

② The piping sections having an internal containment of more than 500L liquefied petroleum gas (LPG) or toxic liquid which cold be blocked in;

③ Storage area piping or transport line which is periodically isolated and subject to solar radiation heating or heat tracing during normal operation;

④ All sections of cryogenic piping (which operate at temperatures lower than ambient temperature) subject to possible isolation (whether conventional or not).

(2) Valve connection type and size

The valve is to be flanged and its minimum flow area is to be no less than 0.71 cm^2.

(3) Liquid discharge

The liquid discharged from the thermal expansion relief valve is to be diverted via an isolating valve (normally locked open) to the downstream pipe sections or to the collecting pipe and further into other vessels.

(4) Prevention of unexpected events

During normal operation, the thermal expansion relief valve is not to cause unexpected operational accidents such as liquid leak, permanent leak and valve chatter.

SECTION 3 DEPRESSURING SYSTEM

6.3.1 Introduction

(1) When fire occurs around a pressure vessel in the oil and gas process system, it is highly likely that the non wetted portion in the vessel will reach a temperature that causes reduced material strength. The vessel may rupture if the pressure is not reduced. In general, the pressure relief valve cannot provide decompression function and it can only limit the pressure to a given value under emergent conditions, while the vapor decompression system is

able to reduce the pressure to a safe level.

(2) Classification of decompression

For the purpose of the Rules, decompression is classified into the following types:

① Decompression described in 6.3.2(1) and (2) is emergency decompression;

② Decompression described in 6.3.2(3) is non-emergency decompression;

③ Decompression of the vessels exposed to fire is called thermal decompression; decompression under other conditions is called cold decompression;

④ Decompression described in 6.3.3(1) is general emergency decompression;

⑤ Decompression described in 6.3.3(2) is rapid emergency decompression.

6.3.2 Objective

The main objectives of the decompression system are as follows:

(1) Prevent the pressure vessel from being ruptured due to loss of strength in the event of fire around the process system;

(2) Reduce the amount of leakage from the vessels found leaking (thermal or cold decompression);

(3) Depressurize the entire process system or part of the system to allow inspection and maintenance during the shutdown period.

6.3.3 Requirements on decompression **capacity**

(1) The decompression system is to have adequate ability to reduce the vessel stress to such a level that rupture stress will not immediately occur. For this purpose, the decompression system is to be able to reduce the vessel pressure to 50% of its design pressure within 15 minutes (this does not imply the decompression will stop after 15 minutes);

This rule is based on the relationship between the vessel-wall temperature and the corresponding failure stress and applies to carbon steel vessels with a wall thickness no less than 25.4 mm. For vessels with thinner wall, the decompression rate is to be increased as appropriate.

(2) The decompression system is to be considered to reduce the vessels internal pressure to 690 kPa within 15 minutes for large vessels with an operating pressure equal to or higher than 1700 kPa, in order to reduce the amount of leakage from the vessels to be depressurized and promptly bring the fire under control.

The abovementioned requirements do not imply that the decompression will stop after 15 minutes.

6.3.4 Design conditions

The sizing calculations for decompression valves should be based on the following assumptions:

(1) The input and output of the process, and all heat sources in the process are stopped during the fire;

(2) The most unfavorable values of the vessels internal pressure, internal temperature and the wetted surface are taken;

(3) Insulation and water spray are not considered for the heat transfer of the vessel.

6.3.5 System control

(1) All types of decompression valves are to be able to be manually actuated from the control room and the operation buttons are to be provided with protection device to prevent inadvertent operations;

(2) If the decompression valve is designed to open automatically, it is to be provided with reliable measures for prevention of nuisance opening;

(3) The operation system of decompression valve valves is to be designed with the ability to keep the d decompression valve valves in open position when loss of pressure source and/or power source occurs;

(4) The action from the start of remote operation to the full opening of the decompression valve is to be completed within the shortest possible time, which is not to exceed 30s for general emergency decompression valve and 20s for rapid emergency decompression valve.

6.3.6 Decompression valve status indication

Indication of valve status is to be provided at the local and remote-control positions.

6.3.7 Installation position of decompression valve

(1) The principles specified in 6.2.9(3), (6) and (7) of this chapter also apply to decompression valve;

(2) Filters are not to be installed in the upstream of a decompression valve;

(3) Decompression valves are to be installed at easily accessible positions.

6.3.8 Decompression valve

(1) The minimum valve size is to be no less than DN50;

(2) Valve actuation is to be designed with the ability to fully open or close the valve, and valve closure is to be tight;

(3) The Mach number at valve outlet is to be no greater than 7;

(4) The noise generated during decompression is to be no higher than 115 dB.

6.3.9 Effect of low temperatures

(1) The decompression valve and its upstream and downstream piping and equipment are to be designed taking into account the low temperature effects sustained during decompression g, especially during cold decompression;

(2) In addition to the decompression measures, specifications for other means to mitigate the risks associated with equipment exposed to fire are also to be complied with, for example, water sprinkle, heat insulation, equipment arrangement, open drain and emergency response, etc.;

(3) The flare system is to be able to accommodate all the released volumes from emergency decompression.

6.3.10 Flow orifice plate and isolating valve

(1) The decompression valve should be provided with a downstream orifice plate to prevent the released pressure from exceeding the design pressure of the downstream piping.

(2) An isolating valve for isolation from the flare system is to be provided in the downstream of the decompression valve and orifice plate. Normally, the isolating valve is in open position under normal conditions but in closed position during test of the decompression valve and inspection of the orifice plate.

SECTION 4 FLARE AND COLD VENT SYSTEM

6.4.1 System component

The flare and cold vent system boundary includes the piping, manifold, vessels and other equipment from the relief-device outlet to the final disposal point. This system is also called disposal system.

6.4.2 Objective

The objective of flare and cold vent system is to safely dispose relieved gases and liquids at normal operation and emergency conditions, and to protect environment from pollution.

6.4.3 Functional requirements

Flare and cold vent system is to have the following functions:

(1) Collecting gas stream relieved from process system;

(2) Removing liquid droplets from the gas stream and returning the liquid to process system;

(3) Recovering the relieved gases under possible condition;

(4) Discharging relieved gases that are invaluable to recover to flare or to vent to atmosphere.

6.4.4 Selection of flare and cold vent system

6.4.4.1 Released gases/vapors that are invaluable to recover are normally to be flared in order to convert flammable, toxic or corrosive gases/vapors to less objectionable compounds.

6.4.4.2 Released gases/vapors can be coldly vented to atmosphere provided that one of following is met:

(1) The vent system is only for dealing with emergency release and the amount is small

(2) The vent system is dealing with normal operation relief that requires very small back pressure;

(3) Atmospheric storage tanks of non-process can be vented directly to atmosphere;

(4) The vented gases/vapors are not toxic.

6.4.5 Division of flare system

Normally, the flare system is divided into high pressure flare system and low pressure flare system in order to meet the different back pressure requirement for the different pressure relief/depressuring devices. These two systems may share common flare scrubber and flare tip in certain circumstances.

6.4.6 Definition of System Load

The first requirement in designing a flare system is to define the loadings to be handled. System load is to choose the maximum figure from the following cases:

(1) The maximum flow rate handled by a flare system in normal operation condition plus the maximum flow rate caused by a single control valve failure.

(2) The maximum flow rate handled by a flare system in normal operation condition plus the flow rate caused by the biggest single relief valve.

(3) The flow rate caused by opening of all emergency depressuring valves in the event of evacuation.

The system design basis is not necessarily based on the maximum mass load but it is the flow that will impose the highest pressure drop in the system. Thus the temperature and molecular weight of the vapor must be known.

6.4.7 Design of piping and manifold

6.4.7.1 The basic criterion for sizing the discharge piping and the relief manifold is that the back pressure which can exist or be developed at any point in the system is not to reduce the relieving capacity of any of the pressure-relieving valves below the amount required to protect the corresponding vessels from overpressure.

6.4.7.2 The back pressure of relief valves is to meet the following criteria or to meet the back pressure value given by the valve manufacture in order not to reduce the design relief flow:

① Superimposed back pressure < 10% of set pressure; using non balanced spring-loaded relief valves;

② Superimposed back pressure < 21% of set pressure for fire cases and applying equipment following ASME VIII; using non balanced spring-loaded relief valves;

③ Superimposed back pressure < 50% of set pressure; using balanced-bellows spring-loaded relief valves;

④ Superimposed back pressure < 70% of set pressure; use pilot-operated relief valves.

6.4.7.3 The sizing of relief-discharge piping can usually be simplified by starting at the system outlet, where the pressure is known, and working back through the system to verify acceptable back pressure at each pressure-relief device.

6.4.7.4 The design is also ensured that if two or more emergency depressuring valves are opened simultaneously, flow from the high pressure system will not back up into the low pressure system sufficiently to overpressure it or hinder its operation.

6.4.7.5 Relief valve outlet lines are to be connected to the top of the header, or at least so that the header cannot drain back into outlet lines even with the header full of liquid up.

6.4.7.6 An angle entry for laterals at 45 or even 30 to the header axis is recommended in order to reduce the pressure drop (including velocity head losses) and reaction forces.

6.4.7.7 The discharging piping is to be self-draining towards the flare and vent scrubber. Pocketing of discharge lines is to be avoided. The minimum slope should be 1:500 for all laterals and headers.

6.4.7.8 The discharge piping system is to be provided with appropriate and adequate anchors, guides and supports. it is preferable to select anchor points so that header movements and the resultant forces and moments are not imposed on the bodies or the discharge piping of valves.

6.4.8 Flare and cold vent scrubber

6.4.8.1 General requirements

(1) Flare and vent scrubber (or scrubbers) are to be provided in order to:

① separate liquid from the released gas stream before the gases entering to flare or to vent;

② hold a certain amount of separated liquid; and

③ return the liquid to the process system.

(2) Scrubbing vessels are to be designed to withstand the maximum anticipated pressure and to handle the maximum anticipated releases.

(3) The selection between a horizontal or vertical knock-out drum is to be based on economic considerations taking into account the required slope of the flare header and the maximum amount of liquid which has to be contained

6.4.8.2 Droplet remove capability

The scrubber is to have an adequate vapor space above emergency relief liquid level, proper inlet and outlet location and necessary fittings to ensure that it is able to remove 300 to 600 micron droplets from the gas stream.

6.4.8.3 Liquid retention capacity

(1) The scrubber liquid volume contains normal liquid volume and emergency liquid volume.

(2) The normal liquid volume is the volume under the maximum liquid alarm level (LAHH) designed for control purpose and pump operation. This volume is to determine by the designer accordingly. The value is recommended not to be less than 1.89 m3.

(3) The emergency liquid volume is based on maximum emergency release that lasts the time. Within this time corrective measures to control the release to be affected without liquid carryover. The last time is recommended to be 2030 min. The last time can be reduced properly when HIPPS system specified by the Ch.4 of this Rule is applied.

(4) If a horizontal scrubber drum is used, it may be considered to have a liquid boot at the bottom.

6.4.8.4 Liquid return system

(1) A liquid return system is to be installed in order to return the liquid in the scrubber to oil and gas process system.

(2) The liquid return system of the scrubber shall have sufficient capacity to ensure that excessive liquid will not accumulate in the tank during continuous operation of the flare.

(3) Reliable measures against flow-back are to be taken in the liquid return system.

(4) Liquid discharge pumps are to be automatically started at high liquid level and automatically stopped at low liquid level.

(5) Stand-up pump is to be provided in addition to the main pump.

6.4.8.5 Level control during normal operation

The distances among different levels are recommended at least as follows in order to ensure normal level control operation (pump start and stop, high high and low low alarm)

(1) LALL is 0.15 m above horizontal vessel bottom.

(2) LSL for starting pump is 0.20 m above LALL or the liquid volume between the two levels is to be at least 1 minute's pump out capacity, whichever requirement is the more stringent. (Note: too small distance will lead to false alarm or pump trip or pump trip)

(3) LSH for stopping pump is 0.20 m above LSL or the liquid volume between the two levels is to be at least 5 minutes pump out capacity, whichever requirement is the more stringent.

(4) LAHH is 0.15 m above LSH or 1 minute's pump out capacity, whichever requirement is the more stringent.

(5) The LAHH alarm indicates that the pump out facilities are not operating properly or that a major liquid relief is entering the scrubber. This alarm is critical and is to have proper safety integrity and availability level.

(6) An alarm is to be activated while the pumps start or stop.

Liquid level, liquid level alarm, pump on/off alarm and pump working condition are to be indicated in the manned control station.

6.4.8.6 Emergency release high level alarm and shutdown.

LSHH is to be provided with at the proper height above the normal LALL. The whole process shut down with an alarm is to be initiated when the emergency relief liquid reaches LSHH level.

6.4.8.7 Plugging prevention measures

If the scrubber has an internal component, such as a mist extractor, or an external component, such as a back pressure control valve or flame arrester, then a relief device is to be installed in order to bypass these components, should they become plugged.

6.4.8.8 Winterization measures

Depending on the climate and the nature of the liquid in the system, winterization or automatic control heating measures may be taken.

If electrical heater is to be used measures are to be taken to ensure that the heating elements are always situated blow the minimum liquid level.

6.4.8.9The effect of floating on scrubber design

Regarding the scrubber fixed on the floating unit the adverse effects on the internal component strength, the quality of separation and level control precision of the scrubber caused by floating hull movement are to be taken account in the design.

6.4.9 Selection of flare types

The elevated flares, in general, are to be selected in order to reduce the effects of radiation intensity and to aid burned gas dispersion. If enclosed flares be selected the enclosure wall are to be well insulated and the radiation intensity outside the enclosed flares is within the acceptable level.

6.4.10 Design of elevated flare stack height

6.4.10.1 The flare stack height is designed per maximum emergency released rate, maximum wind speed in the concerned sea area and accept maximum radiant heat intensity for personnel.

(1) The flare released heat value is proportional to the flare gas flow. The flare released heat value is maximum at maximum emergency released rate.

(2) The greater the wind speed, the more the flare flame tilted by wind, the smaller the distance from the epicenter of the flame to the object being considered.

(3) The farther the personnel away from the epicenter of the flame, the smaller thermal radiation intensity exposed to the personnel. The accept thermal radiation intensity for personnel is shown in the table 6.4.10.1.

Recommended design thermal radiation for personnel table 6.4.10.1

Conditions	**Permissible design level kW/m^2**
Maximum radiant heat intensity at any location where personnel with appropriate clothing a can be continuously exposed.	1.58
Maximum radiant heat intensity in areas where emergency actions lasting 2 min to 3 min can be required by personnel without shielding but with appropriate clothing.	4.73
Maximum radiant heat intensity in areas where emergency actions lasting up to 30 s can be required by personnel without shielding but with appropriate clothing.	6.31
Maximum radiant heat intensity at any location where urgent emergency action by personnel is required. When personnel enter or work in an area with the potential for radiant heat intensity greater than 6.31 kW/m^2, then radiation shielding and/or special protective apparel (e.g., a fire approach suit) should be considered. **SAFETY PRECAUTION: It is important to recognize that personnel with appropriate clothing a cannot tolerate thermal radiation at 6.31 kW/m^2 for more than a few seconds.**	9.46
note:1 Appropriate clothing consists of hard hat, long-sleeved shirts with cuffs buttoned, work gloves, long-legged pants and work shoes. Appropriate clothing minimizes direct skin exposure to thermal radiation. 2 The intensity of solar radiation is in the range of 0,79 kW/m^2 to 1,04 kW/m^2 Consideration is to be taken	

account in the design.

6.4.10.2 The calculation equation to determine the heat radiation intensity of burning flares is given as below:

$$K = \frac{TFQ}{4\pi D^2}$$

where:

K is the heat radiation level, expressed in kW/m^2

T is the fraction of heat intensity transmitted through the atmosphere

F is the fraction of heat radiated

Q is the heat released related to lower heating value, expressed in kW

D is the distance from epicenter of flame to the object considered, expressed in m

6.4.10.3 The calculation details for heat radiation intensity of burning flares is to be submitted to the Society for approval.

6.4.10.4 During design the negative effect of heat radiation to the heat sensitive systems, the heat sensitive materials and electrical equipment and instrumentation is also to be considered in addition to the effect of personnel.

6.4.11 Design of inner diameter of elevated flare stack

6.4.11.1 Flare-stack inner diameter is generally sized on a velocity basis. Flare blow-off is possible to happen if gas flow velocity too high. The flame front is possible to locate down to the flare tip and to overheat it if gas flow velocity too low.

6.4.11.2 The Mach 0.2 is normally selected for normal release flow. The Mach 0.5 is normally selected for emergency. The flare tip exit velocity of more than Mach 0.5 can be applied if pressure drop, noise and other factors permit.

The relation equation between flare stack inner diameter is expressed as follows:

$$Ma_2 = 3.23\times10^{-5}\left(q_m / p_2 d^2\right)\left(ZT / kM\right)^{0.5}$$

Where:

Ma_2 is the Mach number at pipe outlet

q_m is the gas mass flow rate, expressed in kilograms per hour

p_2 is the pipe outlet absolute pressure, expressed in kilopascals

Z is the gas compressibility factor

T is the absolute temperature, expressed in kelvin (degrees Rankin)

M is the gas relative molecular mass

k is the heat capacity ratio

Note that flare-diameter calculations are based on a basic flare. Most commercial flares have flame retainers that restrict flow area by 2 % to 10 %, which should be accounted for in the flare and header sizing.

6.4.11.3 Pressure drop is to be checked as large as 14 kPa. Modern conventional flare tips with proper flame stabilization can operate well above this level. The special-duty high-pressure flares can operate at gauge pressures around 700 kPa or higher.

6.4.12 Measures against flashback in flare system

The following measures are to be taken in order to protect flare system from flashback and further causing explosion in the upstream equipment:

(1) The gas flow velocity Mach Number is not less than 0.2.

(2) A pre-commissioning purge with a hydrocarbon gases or inert gases are to be supplied to the flare system.

(3) In the event of low flow during production a purge with a hydrocarbon gases or inert gases are to be supplied to the flare system.

(4) A flow measurement device is to be fitted on the purge inlet line and a flow low alarm is to be given in the main control room.

(5) A flow measurement device is to be fitted on the scrubber gas outlet line and a flow low alarm is to be given in the main control room.

(6) A velocity seal (air lock seal) is to be located within the flare tip or a buoyancy seal (molecular seal) is to be located below the flare tip in order to reduce the purge flow.

(7) A liquid seal or a flame arrester is not to be selected to substitute for purging.

6.4.13 Flare burner (Flare tip)

6.4.13.1 Functional requirements

A flare burner is to have the following functions:

(1) Maintaining stable combustion under the specified environmental and service conditions;

(2) Reducing the proportion of unburned gases released to the atmosphere as far as possible;

(3) Reducing radiation levels as far as possible;

(4) Reducing smoke formation as far as possible or eliminating smoke formation;

(5) Having higher integrity and reliability and the minimum maintenance intervals is not to be less 5 years under the defined service conditions.

6.4.13.2 Design considerations

The following aspects are to be considered in design to achieve the functionality of flare burner:

(1) Flare burners are to incorporate flame retention devices or aerodynamic methods with proven capability to provide a detached stable flame and prevent the flame from being blown out.

(2) In order to improve combustion, reduce smoke formation and reduce heat radiation, high speed flare tips (sonic tips) are be used wherever possible

(3) Air assist, steam assist or flammable gas assist measures may be used to suppress smoke and at least Ringelman blackness No. 1 criteria is to be met for the maximum continuous flow flare.

(4) Air or steam injection, if applied, is to not disrupt the basic flame stabilization mechanisms of the flare burner.

(5) Steam condensate is to be drained from the internal steam/air injection point and from any muffler surrounding these tube assemblies for flare burners with internal steam injection to induce air.

(6) The following measures may be taken in order to prevent flare tip from sustaining excess heat stresses that could cause damage to the flare tip:

①Avoiding operating low flow in order to prevent flame from impinging on the inside and outside of the tip;

②Flame contacting the tip external is commonly caused by low pressure zone created by wind. Hence, all flare tips should be fixed windshields or deflectors which breakup the low pressure zones created by the wind. To cope with thermal expansion the windshields or deflectors is to be attached to the tip at one fixed point;

③Multi-point flares with smaller diameter may be used to reduce or eliminate low pressure zones around the tip;

④A supplementary flow, such as compressed air may be used to push the flame away from the tip;

⑤The material of the flare tip and all ancillaries connected to the tip is to be sufficiently heat and corrosion resistant.

6.4.14 Pilot

6.4.14.1Configuration requirement

All flare systems are to be provided with continuous pilot burners to ignite the flare gas as it leaves the tip.

6.4.14.2 Location requirement

The location of the pilot burners is to be such that they are not engulfed by the flame of the main flare even in strong winds, whilst ignition of the main flare is guaranteed under these condition.

6.4.14.3 Installation number requirement

The minimum number of pilots required is to be in compliance with the following:

The minimum number of pilots required Table 6.4.14.3

NO.	d	number
1	d≤200 mm	one, for toxic gas, at least two
2	200mm<d≤600 mm	two
3	600mm<d≤1050 mm	three
4	1050mm<d≤1500 mm	four;
5	d>1500 mm	selected by designer

6.4.14.4 Capacity requirement

The pilots provided at the main flare tip are to be capable of maintaining stable combustion under all process and meteorological conditions and continuously igniting the flare gas.

In order to ensure this capability, the pilot is to have the following performances:

(1) The pilot is to remain lit at wind speeds up to 160 km/h under dry conditions and 140 km/h when combined with 50 mm of rainfall per hour;

(2) The pilot is to be capable of being rekindled under the same above environmental conditions;

(3) The pilot heat release is not to be less than 13.2 MW.

6.4.14.5 Failure detection

(1) Each pilot is to have at least one dedicated flame-failure detection device. Failure of a pilot is to be indicated in the manned control room by an alarm;

(2) The pilot-flame detection system is to be able to distinguish between pilot flame and flare-burner flame;

(3) The pilot-flame detection system is to be able to detect the pilot flame at wind speeds up to 160 km/h under dry conditions and 140 km/h when combined with 50 mm of rainfall per hour.

6.4.14.6 Ignition system design

(1) Separate ignition lines are to be provided for each pilot;

(2) The pilot ignition system is to be able to light the pilot during all defined operating and emergency relief cases, including a site-wide general power failure;

(3) The use of an ignition system of the flame front generating type is recommended because if it fails it can be repaired while the flare relief system remains in service;

(4) Re-ignition of the pilot is to be performed manually from a safe location at grade from where the pilot tip is visible.

6.4.14.7 Fuel gas and air

(1) The fuel gas and the air used to supply the pilot lights and ignition system are to be dried and filtered to prevent blockage of the lines;

(2) A continuous source of clean fuel is to be provided with and the fuel gas is to have a defined range of heating value and composition;

(3) A back-up bottled gas supply is to be provided for start-up if there is no other reliable source available.

6.4.14.8 Protection from liquid pocket

Gas and air lines are to be arranged to avoid forming liquid pocket.

6.4.14.9 Materials

Pilot tip and components exposed to flame is to be constructed of a heat-resistant material. Pipes are to be constructed of a corrosion-resistant material.

6.4.14.10 Performance tests

A product of combination of pilot flare, ignition system for the pilot flare and pilot flare flame failure detection system are to be tested under the defined weather condition to verify the ability to meet the performance specified by the Rule or standard recognized by the Society.

6.4.14.11 Maintenance interval

The design of pilot is to ensure that the pilot requires minimum maintenance. Under the defined service conditions the minimum maintenance interval is not to be less than 5 years.

6.4.15 Cold vent system

6.4.15.1 Vent outlet location

The following considerations are to be taken to locating the vent outlet:

(1) the concentration of any toxic products is to be diluted to a safe level at any area where personnel are likely to be present;

(2) in the event of accidental ignition of the vent, the heat radiation intensity to equipment or personnel is to be within the acceptable limits;

(3) Vent stack location is to be designed that the horizontal distance from the discharge point to any structures or equipment being higher than the vent outlets is to be at least 15 m to ensure that flammable vapors emanating from the vent outlet are to be diluted with air to below the lower flammable limit level before reaching the structures or equipment;

(4) Accidental liquid carryover of the cold vent is not to fall on hot surfaces or personnel normally working and living areas.

6.4.15.2 Vent velocity and direction

The average vent velocity is not to be less than 30 m/s through the vent outlet for all flow rates and is to be discharged vertically upwards in order to enable gases to disperse quickly and to prevent flashback in the event of accidental ignition of the released gases.

6.4.15.3 Flashback prevention measures

One of following measures against flashback is to be provided:

(1) Maintaining the vent velocity is not to be less than 30 m/s and an inert gas purging system is provided as back-up. Purging is started while vent velocity is below 30 m/s

(2) A high velocity vent valve is to be installed on the end of the vent stack through which the discharge velocity is not to be less than 30 m/s;

(3) A flame arrester is to be installed on the end of the vent stack. If it is not installed on the end of the stack, in a diction, a by passing safety rupture-disk device is to be provided;

(4) A water seal approved by the Society is to be installed before the vent stack

All of the above devices are accessible to inspection and maintenance.

6.4.15.4 Selection of a flame arrester

(1) Flame arresters are divided into three groups with IIA, IIB and IIC. The group of flame arrester is to be selected as per the discharged gas group. The gas groups are defined in IEC 79-20 standard.

(2) An end-line flame arrester or an on-line flame arrester is to be selected as per the distance between arrester and the ignition source.

(3) An end-line flame arrester is an unconfined deflagration arrester which can be fitted within the distance of 50 pipe nominal diameters counted from the pipe end or the distance specified by the arrester manufacture.

(4) An in-line flame arrester is a confined arrester. An in-line arrester is also divided into a deflagration arrester and a detonation arrester. A deflagration arrester or a detonation arrester is to be selected by the manufacture through experiment test as per the distance between the arrester and the pipe end, pipe and fitting resistances.

(5) All flame arresters including high velocity vent valves and water seals are to be certified by the society.

6.4.15.5 Prevention of rainwater ingress

Measures are to be taken to protect vent stack from entering rain and foreign bodies.

6.4.15.6 Prevention of entrapped liquid

(1) Measures are to be taken to protect vent piping from trapping liquids

(2) The dew point of vented gas is to be less than the minimum anticipated ambient temperature to against condensation formation.

6.4.15.7 Electrostatic protection

Vent pipe stack is to be earthed. The end of the discharge pipe is to be cut off squarely and rounded off to minimize the risk of ignition by static electricity.

6.4.15.8 Fire extinction

An extinguishing system is to be fitted if vented gas is accidentally ignited by ignition sources e.g. lightning or static discharge.

6.4.15.9 Vent of non-process

(1) Local venting of non-process and low-volume sources (e.g., storage tank vents, surge tank vents, etc.) is to be led to a safe location.

(2) Pressure/vacuum valves and devices to prevent the passage of flame into tanks are to be installed on the end of the vent of the tanks that contain flammable liquid with flash point below 60 ℃.

(3) Pressure/vacuum valves are to be complied with the requirements specified in ISO 15364 Ships and marine technology--Pressure/vacuum valves for cargo tanks and to be certified by the Society.

(4) Devices to prevent the passage of flame into tanks are to be complied with the requirements specified in IMO MSC/Circ.677 Revised standards for devices to prevent the passage of flame into cargo tanks and to be certified by the Society.

6.4.16 Flare-gas recovery system

6.4.16.1 Objective

A flare-gas recovery system is to be installed in the case of cost-effective in order to protect environment.

6.4.16.2 Path to flare

Flare systems are used for both normal process releases and emergency releases. Emergency streams, such as those from pressure-relief valves, depressuring systems, etc., are to always have flow paths to the flare available at all times. The design of flare-gas recovery systems is to be not compromise this path.

6.4.16.3 Back flow protection

Because flare-gas recovery systems usually involve compressors that take their suction directly from the flare header, the back flow of air from the flare into the compressors at low flare-gas loads is possible. The following measures should be taken to prevent back flow:

(1) Oxygen content measurement device for the flare gas stream should be provided and automatically to shut down the flare-gas compressors if potentially dangerous conditions exist;

(2) Low-suction-pressure controls for flare gas recovery system should be equipped and automatically to shut down the flare-gas compressors if potentially dangerous conditions exist;

(3) Additional reverse flow detector should be installed in the header downstream of the suction pipe of the flare-gas recovery system and automatically to shut down the flare-gas compressors in the case of reverse flow.

6.4.16.4 Prevention of liquid intake by compressor

(1) The tie-in line to the flare gas recovery system should come off the top of the flare line to minimize the possibility of liquid entrance;

(2) A liquid-knockout vessel is to be provided on the suction line of the flare-gas compressors and automatically to shut down the flare-gas compressors in the case of higher liquid level in the Vessel.

6.4.17 Flaring and vent noise control

6.4.17.1 The noise level is not to be greater 115 dB (A)for emergency release conditions at the base of the stack.

6.4.17.2 The noise level is not to be greater 86 dB (A)for normal operation conditions at the base of the stack.

6.4.18 Flare and vent structure

6.4.18.1 For the detail requirements of flare and vent structures see the applicable provisions of the structure Part of the main rules for offshore installation on which the oil and gas process system is located.

6.4.18.2 Flare and vent structures are to be fitted with stairs, ladders, handrails or guards to provide access for personnel inspection and maintenance.

6.4.18.3 Aviation warning lights are to be provided on the structure top if necessary.

SECTION 5 OPEN DRAIN SYSTEM

6.5.1 Scope

6.5.1.1 Open drain system generally consists of:

(1) Open drain of weather deck areas (rainwater, fire water, flushing water and green water, etc.);

(2) Open drain of bilge water in enclosed spaces;

(3) Open drain of drip trays around storage tanks, vessels or equipment;

(4) Draining of sanitary water (living sewage) of the enclosed accommodation areas.

6.5.1.2 The design of open drain systems is to firstly comply with the related provisions in the main rules for the offshore installation on which the oil and gas system is installed, as well as the following provisions of this section.

6.5.2 Oil leakage collection and containment system

6.5.2.1 Oil leakage collection and containment system is used to collect and direct the leaked liquid hydrocarbons to a safe location. All equipment subject to possible leakage or overflow are to be fitted with curbs, gutters, or drip trays to drain the leaks into an oily water tank(sump). Oil leakage collection and containment system may be waived provided that there is no disposal vessels or other equipment subject to possible leakage or overflow (for example, the offshore installation is only fitted with wellhead, manifold, pipeline, crane and/or instrument air scrubber) on the offshore installation.

6.5.2.2 The capacity of drip trays is to be selected based on an assessment of the potential leak rate, and the height of the drip tray coaming for normal equipment except pressure vessels is to be no less than 50 mm.

6.5.2.3 The capacity of drip trays for large tanks, pressure vessels and heat exchangers is to be determined based on an assessment of the number of leak sources, and volume and the consequences of the leak (e.g. leak onto equipment or below the deck). In general, 5% of the vessel volume may be taken as the drip tray capacity.

6.5.2.4 All open (gravity) drain piping networks are to be designed to prevent escape of gas from sumps through the drain points. The typical way is to install water seal at each drain point or on each drain header, or with a total network water seal located in the tank inlet piping. Installation of check valve is not appropriate for this purpose and is not to replace the protection by water seal.

6.5.2.5 All water seals are to be accessible for inspection.

6.5.2.6 In addition to water seal, all inlet lines into the collection tank are to be immersed below the minimum water level to prevent backflow of hydrocarbon gas.

6.5.3 Open drain tank

6.5.3.1 All oily water tanks are to be provided with automatic discharge features in order to handle the maximum inflow. The oil content of oily water discharged into the sea is not to be in excess of the standard limit specified by the administration. The separated oil may be pumped into the closed drain tank.

6.5.3.2 The operating temperature of oily water tanks is to be kept higher than the freezing point or cloud point of the crude oil. Internal heating source for the tanks is to be considered in case the ambient temperature is lower than the operating temperature of the tank.

6.5.3.3 Oily water tanks are to be arranged such that gravity draining is possible from all sources.

6.5.3.4 Oily water tanks are to be fitted with vent system for the purpose of safely dissipating hydrocarbon vapors. The vent outlet is to be directed to a safe location. Flame arrester and fire screen are not required for the vent pipe. The vent pipe is not to be connected with the cold vent system of utilities.

6.5.3.5 Where open-end sump piles are provided, the following requirements are to be met:

Properly designed open-end sump piles may be used for temporary collection of the water drained from the deck or the liquid drained from drip trays and treated production water. Except during emergency upset condition, liquid hydrocarbon from the vessels (e.g., flare scrubber, condensate oil accumulator and various fuel filter scrubbers) cannot be directly discharged into the open-end sump pile. Open- end sump piles oil drum is to be provided with measures against hydrocarbon outflow (top overflow and/or under outflow). Such measures are to be determined on a case-by-case basis and the considerations include pile length, liquid properties, maximum inflow rate, wave effects and tidal changes.

6.5.4 Drilling drain system

The open drain system for drilling operation is not to be connected with production open drain system, as the solids produced during drilling activities may cause blockage of the production open drain system and damage to pumps and valves.

6.5.5 Piping system

Piping systems are to be designed with rod-out/flushing facilities. The diameter of headers is to be no less than 76.3 mm.

SECTION 6 CLOSED DRAIN SYSTEM

6.6.1 General requirements

6.6.1.1 Oil and gas production system is to be equipped with closed drain system to collect hydrocarbon liquid trains from equipment and piping, and safely dispose and degas the liquid.

6.6.1.2 The closed (pressure) drain system is to be independent of the open drain system.

6.6.1.3 At least one isolating valve and one check valve are to be fitted on the oil line between the open drain tank and closed drain tank if the oil in the open drain tank needs to be pumped into a closed drain tank.

6.6.1.4 The line between the equipment to be drained and the closed drain tank is to be fitted with at least two isolating valves in series so that another valve can be closed if one valve is blocked by hydrate ice during release. According to the maintenance needs, the requirements specified in paragraph 3.1.14 of Chapter 3 of the Rules are to be met. The isolating valves are to be as close as possible to the drain point.

6.6.1.5 Inert gas purge facilities are to be provided if required.

6.6.2 Closed drain tank

6.6.2.1The operating temperature of the closed drain tank is to be higher than the freezing point or cloud point of crude oil.

6.6.2.2 The operating pressure of the closed drain tank is to be lower than the pressure of all discharge sources but no lower than the operating pressure of the flare scrubber.

6.6.2.3 Flare or vent scrubber may serve as the closed drain tank, but in the meantime, the functional requirements for these two kinds of vessels are to be met.

6.6.2.4 The volume of closed drain tank should be able to contain the released amount of the vessel which is the largest release source. Other factors are also to be considered to select the drum volume, for example, reclaimed pump flow rate and transit time as well as the required minimum liquid retention time.

6.6.3 Reclaimed oil pump

The reclaimed oil pump is to be of low shear type to avoid shearing of water droplets. At least two pumps are to be provided.

6.6.4 Piping system

6.6.4.1 Piping's material is to be suitable for the maximum and minimum expected input temperatures.

6.6.4.2 The piping through which the reclaimed oil is pumped into the process equipment is to be fitted with a check valve which is to be close to the inlet of the equipment.

SECTION 7 CHEMICAL INJECTION SYSTEM

6.7.1 Introduction

6.7.1.1 Chemical agents need to be used in oil and gas production in order to improve processing efficiency and prolong the service life of equipment and piping.

6.7.1.2 The types and actions of the commonly used chemicals are listed below:

(1) Demulsifier: to break down the stability of the emulsified liquid and improve the oil-gas separation.

(2) Defoamer: to prevent oil foaming and improve oil-gas separation.

(3) Corrosion inhibitor: to prevent and mitigate corrosion of the processing system caused by well fluid corrosive materials.

(4) Pour point depressant: to prevent condensation of crude oil in the process system.

(5) Reversed demulsifier: to make the micro-organic particles in the oily water accumulate and settle, thus achieving the purpose of water purification.

(6) Oxygen scavenger: to eliminate the oxygen from the deaeration tower in order to prevent corrosion due to long time exposure to seawater.

(7) Bactericidal: to control the growth of bacteria in the water processing system.

(8) Chemical agent for marine growth prevention: to prevent growth of marine organisms in seawater systems.

(9) Scale inhibitor: to aid the dissolution of carbonates and sulfates in the seawater or production water and reduce scaling.

(10) Flocculant: mainly used to eliminate the suspended solid particles from water.

(11) Floatation agent: to stabilize gas bubbles to improve the floatation effects of the floatation.

(12) Anti-freezing agent: to reduce the temperature at which natural gas hydrates are formed.

6.7.1.3 Demulsifier, defoamer, corrosion inhibitor and pour point depressant are usually used in crude oil processing system; reversed demulsifier, corrosion inhibitor, scale inhibitor and floatation agent are generally used in production water processing system; scale inhibitor, corrosion inhibitor and chemicals for marine growth prevention (for chlorides, copper oxide or aluminum oxide may also be used) are used in seawater system and anti-freezing agent is usually used in natural gas system.

6.7.1.4 Agents used for diluting chemicals are mainly water and diesel. Water-soluble chemicals are diluted with water while the oil-soluble chemicals are diluted with oil.

6.7.2 General provisions

6.7.2.1 Chemical injection system is to be able to store, mix and distribute chemical solutions and inject the solutions into the required systems.

6.7.2.2 The material of chemical injection system is to be compatible with the chemical agents.

6.7.2.3 Chemical injection system, if used at lower ambient temperature, is to be provided with heat conservation and heat tracing measures.

6.7.2.4 Safety shower and eye wash stations are to be provided in the vicinity of harmful chemicals storage and handling areas.

6.7.2.5 If the chemicals can react with each other, the hoses for filling these chemicals are to be attached with unique labels to avoid misuse.

6.7.3 Storage tank

6.7.3.1 Chemical storage tanks are divided into two types, namely fixed type and translortable type.

6.7.3.2 Lashing and fixing measures are to be provided if a mobile chemical storage tank is used. Mobile chemical storage tank and chemical solutions are to be supplied by the supply ship.

6.7.3.3 The capacity of the storage tank depends on the required daily injection volume and the delivery cycle of the supply ship.

6.7.3.4 The storage tank is to be fitted with level gauges. Use of armored level gauge which can automatically close the cocks is recommended for hazardous or corrosive fluids.

6.7.3.5 Tank level monitoring is to be available. In addition, flow monitoring device is to be provided for the systems which are critical to chemical injection.

6.7.3.6 An agitator is to be installed inside the storage tank as needed.

6.7.4 Drip tray

6.7.4.1 All chemical storage tanks, injection pumps and handling stations are to be equipped with drip trays for leakage and spillage collection.

6.7.4.2 The handling locations are to be designed with carrying tanks to handle the leaked liquid, instead of discharging the liquid into an open drain system or into the sea.

6.7.4.3 The liquid overflow system and drip tray drains from different tanks may be routed to a common header. Independent collection system is to be provided for chemicals which react with other fluids.

6.7.4.4 Drag reducer may react with water or hydrocarbons to create viscous mud which is to be directed to an independent transport tank.

6.7.4.5 Injection system containing cryogenic liquid is to be installed on the insulated bulkheads which are designed to collect liquid leakage and prevent the adverse effects of low temperature on structures and equipment.

6.7.5 Injection pump

6.7.5.1 The injection pump is to be capable of accurate control of the injection rate and a wider working range is required. The discharge line of injection pump should be fitted with a calibration instrument to check the precision of flow rate.

6.7.5.2 The design pressure of chemical injection pump is to be at least equal to the pressure of the system into which the chemical is injected.

6.7.6 Injection point

6.7.6.1 Common chemical injection points are located at the wellhead manifold or other manifolds in order to ensure the transfer of chemicals into all production processes. The specific injection points are to be determined by the designer based on the actual situations.

6.7.6.2 Check valve and cut-off valve are to be installed as close as possible to the injection points.

6.7.7 Piping

6.7.7.1 The piping of chemical injection system must be compatible with chemical properties, operating conditions and environmental conditions, and the suction and discharge lines are to be sized adequately to handle the instantaneous peak flow. The method of increasing the wall thickness is generally adopted to prolong the corrosion resistant life.

6.7.7.2 The piping from the movable tank or boat landing station to the permanent storage tank or other facilities is to be of self-draining type.

6.7.7.3 The permanently installed piping and hose connectors are to be protected against damage during handling operations.

6.7.8 Shutdown

Consideration is to be given to shut down the chemical injection system simultaneously when the injected system is being shut down, unless the injected system requires continued injection at the time of shutdown.

6.7.9 Maintenance

The system is to be designed to ensure that maintenance of one chemical injection system wont affect operation of other chemical injection systems.

6.7.10 Additional requirements for methanol injection system

6.7.10.1 Water-containing natural gas will generate hydrates at sufficiently high pressure and sufficiently low temperature. Hydrates are likely to cause blockage of piping, valves and instruments. Methanol is widely used hydrate inhibitor in gas field.

6.7.10.2 The system is to be designed with focus on system tightness as methanol features lower boiling point and high volatility; and methanol is moderately toxic, therefore, measures are to be taken to prevent personnel poisoning.

6.7.10.3 Loading hoses are to be identified with unique marks and the couplings are to be earthed.

6.7.10.4 Draining facilities are to be designed to minimize the possibility of personnel contact with the methanol during maintenance. All equipment is to be fitted with permanent connection to a closed drain.

6.7.10.5 Storage tanks are to be provided with blanket, preferably inert gas blanket, but for this purpose, fuel gas may also be used in replacement; direct venting is also acceptable for unmanned simple platform.

SECTION 8 WATER INJECTION SYSTEM

6.8.1 Introduction

6.8.1.1 In order to maintain or increase formation pressure to improve oil recovery rate, one of the commonly used methods is to inject water into the formation.

6.8.1.2 There are usually three water sources as listed below:

(1) Seawater;

(2) Oilfield production water;

(3) Well source water.

6.8.2 General provisions

6.8.2.1 The quality of the water to be injected is to meet the following basic requirements:

(1) Stable water quality, sediment will not occur when injection water is mixed with formation water;

(2) The water does not cause hydration swelling or suspension of the clay minerals after being injected into the formation r;

(3) The water is free of any visible suspended matters to prevent plugging of the percolation cross section and flow pores;

(4) Less corrosion to water injection facilities;

(5) When mixed water injection is adopted, tests are to be performed to verify the two kinds of water are mutually compatible and harmless to oil layer.

6.8.2.2 The primary control indexes of water quality are to be in compliance with the relevant national or industrial standards.

6.8.2.3 The secondary control indexes of injected water quality should comply with the following requirements:

(1) Dissolved oxygen concentration no greater than 0.1mg/L and preferably less than 0.05 mg/L;

(2) Carbon dioxide concentration less than1 mg/L;

(3) Sulfide concentration less than 2 mg/L;

(4) Water pH value 70±0.5.

6.8.3 Seawater injection system

6.8.3.1 System components

Seawater injection system usually consists of seawater lift pump, backwash coarse filter, backwash fine filter, air blower, deaeration tower, Venturi tube, gas-liquid separation tank, booster pump and injection pump.

6.8.3.2 Seawater lift pump

(1) Seawater lift pump should be provided with a spare pump;

(2) Seawater lift pump should be fitted with pressure and flow rate monitoring devices.

6.8.3.3 Filter

(1) Coarse and fine filters are to be provided to remove the suspended matters in seawater;

(2) Spare filters are to be provided as needed;

(3) Filter differential pressure monitoring device is to be provided;

(4) The system is to be designed to allow automatic back washing of the filter based on pressure differential or time;

(5) The filtered seawater piping is to be fitted with turbidity and residual chlorine analyzer.

6.8.3.4 Deaeration tower

(1) The main function of deaeration tower is to remove the oxygen in the water to make the waters oxygen content meet the standard, so as to prevent:

① the oxygen in the water from corroding the equipment and piping in contact with water;

② bacteria reproduction in the water, generating suspended solids that block the formation and make water injection difficult.

(2) When vacuum deaeration tower is used, the absolute pressure in the tower is not to be lower than the saturated steam pressure at the operating temperature in order to prevent generation of large volume of steam inside the tower;

(3) When the oxygen concentration has reached 0.3 mg/L after vacuum deoxygenation, continued use of vacuum deoxygenation is not economic any more, and at this point, chemical agents are usually used for further deoxygenation;

(4) Oxygen concentration monitoring devices are to be provided in the downstream of the deaeration tower.

6.8.3.5 Water injection booster pump

The types of booster pump are to be selected taking into account that the pump is to be able to operate properly under negative pressure head and a proper flow margin is to be kept.

6.8.3.6 Water injection pump

(1) Multistage centrifugal pump is normally used as water injection pump and the pump material is to be corrosion resistant;

(2) Water injection pump pressure and flow rate monitoring devices are to be provided.

6.8.3.7 Wellhead protection filter

Wellhead protection filter is to be provided as needed and the filter is to be able to remove the suspended solids having a size more than 1μm.

6.8.3.8 Chemical agents

(1) The chemical agents to be added of seawater injection system are shown in Table 6.8.3:

Seawater injection system chemicals summary table Table 6.8.3

Chemical name	Injection point	Injection condition
Polymer	Piping in the upstream of fine filter	Continuous
Bactericidal	Piping in the upstream of fine filter	Intermittent
	In front of injection pump inlet	
Defoamer	In front of water inlet of deaeration tower	Continuous
Oxygen scavenger	Water storage space in the lower	Continuous

	section of deaeration tower	
Scale inhibitor	In front of injection pump inlet	Continuous
Corrosion inhibitor		

(2) The injection points of mutually reacting chemicals (such as oxygen scavenger and bactericidal) are to be as far as possible from each other to minimize the possibility of chemical reaction.

6.8.4 Oilfield production water injection system

6.8.4.1 Production water is to be used as the injection water source as practically possible in order to prevent environmental pollution.

6.8.4.2 Measures are to be taken to prevent oxygen ingress into the production water system.

6.8.4.3 The suspended solids, oil content and bacteria in the production water are to be treated in order to meet the standards for water injection.

6.8.5 Well source water injection system

6.8.5.1 Well source water system mainly consists of underground pump, desander, fine filter, injection pump and manifolds.

6.8.5.2 The water from source wells can be introduced into the well only after satisfactorily treated.

6.8.5.3 Scale inhibitor and corrosion inhibitor are to be continuously injected from the upstream of the desander.

6.8.6 Anti-freezing measure

Water injection systems expected to operate at an ambient temperature lower than -5℃ are to be provided with anti-freezing measures during shutdown period.

6.8.7 Safety protection device

The pressure safety protection device, backflow safety protection device and shutdown valves to be installed on the wellhead water injection line are to be in compliance with the related provisions in Section 2, Chapter 4 of the Rules.

SECTION 9 SPECIAL OIL DISPLACEMENT AND ARTIFICIAL LIFT SYSTEM

6.9.1 Gas injection and gas lift system

Check valve and automatic shutdown valve are to be installed at the injection point of the well.

6.9.2 Compound heat carrier injection system

6.9.2.1 Composite heat carrier generator system is to be surveyed and certified by the Society.

6.9.2.2 If the module of compound heat carrier generator system needs to be installed on an offshore installation during the operation, a request for additional survey is to be addressed to the Society in order to confirm:

(1) Whether the installation location affects safety;

(2) Whether the connection with utility systems on the offshore installation (e.g., electrical system, control circuit, piping) is safe and reliable.

SECTION 10 NATURAL GAS FUEL TREATMENT SYSTEM

6.10.1 Introduction

6.10.1.1 Intended purpose of processed natural gas

The natural gas produced from gas field and the associated gas produced from oilfield, after processed, can be used as fuel for power station, thermal energy station and flare pilot or as sealing gas, purge gas, stripping gas and lifting gas.

6.10.1.2 Removal of heavy hydrocarbons and saturated water

Fuel gas normally comes from the flashed vapor in the gas-liquid separator and the flashed vapor often contains a large amount of heavy hydrocarbon compounds and saturated water which are to be separated and removed prior to use of the vapor.

6.10.1.3 Sulfur, sodium and potassium content limit

After the sulfur in fuel gas is burned, sulfur dioxide and sulfur trioxide will be generated and mix with water to form strongly corrosive sulfur and sulfuric acid; sodium and potassium will generate strongly corrosive acids by reaction with other compounds such as sulfur and vanadium. The existence of sodium and potassium will increase the speed of conversion from sulfur dioxide to sulfur trioxide and sulfuric acid and accelerate the formation of alkaline metal sulfates. For abovementioned reasons, the content of sulfur, sodium and potassium in the fuel gas must be detected and limited.

6.10.1.4 Hazards of hydrogen and carbon monoxide

Hydrogen embrittlement effects are to be considered when the volumetric content of hydrogen in the vessel is in excess of 4%; special starting and scrubbing systems are to be used where the hydrogen content lies between 4% and 9% or the carbon monoxide content is between 12.5% and 18%; standard fuel is to be used for starting and acceleration when the hydrogen content is higher than 9% or the carbon monoxide content higher than 18%; and special safety protections are to be provided in case the hydrogen content exceeds 40%.

6.10.1.5 Limit of solid particle

The solid particles in fuel gas generally refer to the inert solid particles, oil and water soluble metal compounds which can cause wear of critical elements, block the nozzles and result in malfunction of control valves, sealing devices and engine blades. Some soluble metal compounds will cause corrosion to the engine under high temperature condition. Therefore, the quantity and size of the solid particles are to be limited.

6.10.1.6 Limit of hydrogen sulfide

Hydrogen sulfide is a kind of highly toxic gas which can generate corrosive sulfuric acid or sulfur dioxide after burning. The content of hydrogen sulfide in the fuel gas is to be strictly restricted.

6.10.2 User's requirements on fuel gas quality

Fuel gas is to meet the user's requirements on its quality. As different users have different requirements on fuel gas quality, the designer of fuel gas system is to communicate with the suppliers of the user to obtain the users specific requirements on fuel gas quality when determining the process of the fuel gas system. But for the purpose of preliminary design calculations, the design may be performed according to the following general requirements:

6.10.2.1 General technical requirements on fuel gas for turbine engine

(1) Low heat value of fuel gas is to be within the range of 33.53~52.2 MJ/Sm^3;

(2) Gas supply temperature is to be within the range of 0~71℃;

(3) The required gas supply pressure can be determined based on the heat value of fuel gas;

(4) H_2S volumetric concentration is to be no more than 0.1%;

(5) Fuel gas is to be free of any free water;

(6) Sodium content of fuel gas is to be less than l mg/L;

(7) Fuel gas supply temperature is to be at least 5℃ higher than the hydrocarbon dew point and water dew point, whichever is higher;

(8) Total solid and liquid hydrocarbon content is to be less than 20 mg/L;

(9) The diameter of 99% solid particles is to be less than 10 μm, the diameter of the maximum liquid hydrocarbon particle is to be no greater than 52 μm.

6.10.2.2 General technical requirements on fuel gas for reciprocating engine

(1) Low heat value of fuel gas is to be within the range of 29.8~44.75 MJ/ Sm^3;

(2) Gas supply temperature is to be within the range of 0~93℃;

(3) The gas supply pressure can be determined as needed;

(4) According to the compression ratio of the engine, the octane number of fuel gas is to be within the range of

85~110;

(5) Fuel gas must be purified and filtered;

(6) Total liquid hydrocarbon (C_5^+) content is to be less than 2%;

(7) H_2S volumetric concentration of the fuel gas is to be less than 0.1%;

(8) Hydrogen content is to be less than 12%;

(9) Total content of inert gas such as nitrogen and carbon dioxide is to be less than 25%.

6.10.2.3 General technical requirements on fuel gas for fired heater

The requirements on fuel gas for fired heater are not quite stringent compared with those on engines, and many manufacturers do not specify requirements on fuel gas to be used for fired heaters.

6.10.3 System components

Fuel gas treatment system generally consists of gas scrubber, heater, filter and distribution manifold. Separators subject to low pressure are often equipped with compressor and cooler.

6.10.4 Considerations for System design

6.10.4.1 Selection of fuel gas heat value

The heat value of fuel gas directly determines the amount of fuel gas to be used and the dimensions of equipment. Heat value is usually used to estimate fuel gas consumption. The low heat value of the fuel gas can be obtained by multiplying the mole percentage of each component of natural gas by the total sum of the low heat values of this component.

6.10.4.2 Determination of fuel gas anti-knock property

The anti-knock property of fuel gas is an index to measure the ignition, combustion speed and anti-knock quality of the fuel gas. If the fuel gas has an excessively low anti-knock property, it cannot be rapidly ignited and combusted, and accordingly, the engine cannot run normally. The fuel gas anti-knock property is commonly expressed in motor octane number (MON) and is mostly expressed by methane number (MN) in recent years.

Octane number and methane number are to meet the demands of the engine.

6.10.4.3 Determination of total fuel gas demand

The total fuel gas demand is to be designed according to the user type, power or thermal load value.

6.10.4.4 Sources of fuel gas

Flashed vapor is to be firstly considered as a fuel gas source and sufficient flashed vapor can be obtained from one or more low-pressure separators. This is mainly because the flashed vapor from the low-pressure gas-liquid double-phase separator has a lower H_2S content than that of the production gas. Use of dehydrated gas or high-pressure wet gas may be considered where the flashed vapor needs to be cooled or heated or the amount of flashed vapor is insufficient.

6.10.4.5 Considerations for hydrogen sulfide removal

Absorption device using iron oxide or zinc oxide as absorbing agent may be used if the fuel gas contains a small amount of hydrogen sulfide. But it is to be noted that the existence of carbon dioxide will inhibit the zinc oxides ability to absorb hydrogen sulfide and thioalcohol.

6.10.4.6 Considerations for gas supply pressure design

Gas supply pressure is to meet the user’s demand. The gas source of fuel gas needs to be boosted if the gas source pressure is low; and the pressure of the fuel gas source needs to be regulated and reduced if the gas source pressure is high. But it is to be noted that the temperature after temperature drop is to be higher than the hydrate forming temperature.

6.10.4.7 Considerations for gas supply temperature design

In order to prevent liquid condensation when the fuel gas passes through the engine vaporizer or spray nozzle and further damage to the engine, the fuel gas supply temperature is to be at least 5℃ higher than the dew point (the higher value of hydrocarbon dew point and water dew point). The specific temperature difference is to be in accordance with user’s requirements.

The following methods may be used to increase the difference between gas supply temperature and dew point:

(1) Heat the fuel gas after it is separated by the scrubber to increase the gas supply temperature;

(2) Firstly, cool down the natural gas in front of the gas scrubber, then separate the gas at low temperature to reduce the dew point of the fuel gas and finally heat the gas to the required supply temperature;

(3) Use glycol dehydrated dry gas as its dew point will be far less than the required water dew point;

(4) Use high-pressure wet gas. Firstly, cool down the high-pressure wet gas using Joule-Thomson effect, then separate the gas and finally heat it to the required supply temperature.

6.10.4.8 Considerations for system heat preservation

The system heat preservation measures (e.g., heat tracing) are to be taken to avoid liquid accumulation caused by temperature decrease in the piping and equipment after shutdown.

6.10.4.9 Sizing of scrubber

(1) Fuel gas scrubber is often a vertical double-phase separator and used to remove mist droplets with a diameter greater than 100μm.

(2) The diameter of the scrubber is usually depending on the gas flow rate. Unlike the design of common separators, the fuel gas demand for fuel switchover of the generator unit under extreme conditions is to be considered during design of the volumes of fuel gas scrubbers (especially the last stage scrubber).
(3) Mesh or vane type mist extractor is usually installed inside the scrubber. Based on experiences, 20%~50% margin should be considered for scrubber volume.

6.10.4.10 Selection of solid particle filter

Filters are to be provided in the upstream of turbine engine or reciprocating engine. In addition, small line filters are to be installed on the gas inlet to each user.

6.10.5 Safety requirements for natural gas fuel supply system

The safety requirements for natural gas fuel supply system (e.g., arrangement, control, explosion protection, etc.) are to be in accordance with the corresponding requirements in the main rules for the offshore installation on which the oil and gas system is located.

SECTION 11 CRUDE OIL FUEL TREATMENT SYSTEM

6.11.1 Introduction

Crude oil fuel may be used when the offshore installation is in lack of natural gas or associated gas for combustion equipment.

6.11.2 Users requirements for crude oil fuel

6.11.2.1 Crude oil fuel is to meet the user's requirements on its quality. As different users have different requirements on the quality of crude oil fuel, the designer of crude oil fuel system is to communicate with the suppliers of the users to obtain the users specific requirements on crude fuel quality when determining the process of the crude oil fuel system.

Taking the equipment from a manufacturer as an example, the technical requirements for crude oil fuel are shown in Table 6.11.2:

Technical requirements for crude oil fuel Table 6.11.2

Property	Limits	Property	Limits
Viscosity: before jet pump	Min.2.0 cSt	Aluminum + silicon: before engine	Mass ratio Max. 15 mg/kg
Viscosity: before jet pump	Max.24 cSt	Calcium + potassium + magnesium: before engine	Mass ratio Max. 50 mg/kg
Density at 15℃	Max.991/1010kg/m^3	Carbon residual	Mass fraction Max.22%
Caculated Carbon Cromaticity	Max. 870	Asphaltenes	Mass fraction Max.14%

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Water content: before engine	Volume fraction Max. 0.3%	Reid vapor pressure (RVP)	Max.65 kPa
Sulfur	Mass fraction Max. 3.5%	Pour point	Max. 30℃
Ash	Mass fraction Max. 0.15%	Cloud point or cold filter plugging point	Max. 60℃
Vanadium	Mass ratio Max. 600mg/kg	Total sediment potential	Mass fraction Max. 0.1%
Sodium: before engine	Mass ratio Max. 30mg/kg	Hydrogen sulphide	Mass ratio Max. 5 mg/kg

6.11.2.2 When the density of crude oil is higher than 991 kg/m^3, the crude oil fuel treatment system is to be able to remove the water and solid particles in the crude oil at this density.

6.11.2.3 The crude oil treatment system and oil supply system (includes storage tanks) which are to be kept, during standby, start-up and operation, at a temperature 10℃-15℃ higher than the pour point of crude oil to prevent crystallization and wax deposition which may cause blockage of the filters and small-diameter components. In addition, it is to be noted that for crude oil temperature in excess of its pour point, there is an upper limit which is not to cause crude oil density to be lower than the minimum value required by the jet pump.

6.11.2.4 The sulfur, sodium and potassium contained in the crude oil are corrosive to equipment; calcium, magnesium and other oxides will generate very hard scale on equipment surface; and the solid particles and water-soluble metal compounds will aggravate the wear of critical elements. The content of these harmful components is to be limited.

6.11.2.5 Excessively high Reid vapor pressure (excessively low flash point) may cause troubles to oil purifier, gas pockets in piping and cavitation corrosion of jet pump. The crude oil supply system usually needs to be pressurized before the crude oil enters the engine in order to prevent occurrence of gas pocket and cavitation. The typical value of the applied pressure is between 1MPa and 1.5MPa.

6.11.3 System components

Crude oil fuel treatment system generally consists of equipment such as crude oil settling tank, heater, filter, transfer pump, degassing tank, crude oil purification unit, sludge discharge tank, daily oil tank, crude oil supply pump and booster pump and the associated piping.

6.11.4 Crude oil settling tank

6.11.4.1 The main function of crude oil settling tank is to further separate the water and flammable vapor by means of settling.

6.11.4.2 The crude oil in a crude oil settling tank is to be the stabilized crude oil from the crude oil processing system.

6.11.4.3 Crude oil settling tanks should be protected with inert gas.

6.11.4.4 Crude oil settling tanks should be fitted with heating devices.

6.11.4.5 Crude oil settling tanks are to be fitted with local and remote level and temperature measuring devices.

6.11.4.6 Crude oil settling tanks are to be fitted with high-level and low-level suction ports for the pump.

6.11.5 Crude oil degasser

Crude oil degasser is to be provided when the flash point of the crude oil cannot meet the requirements of crude oil fuel system.

6.11.6 Filter

6.11.6.1 Crude oil treatment and supply lines are to be fitted with filters (including coarse filter and fine filter) and these filters are to be arranged in such a way as to ensure uninterrupted supply of filtered crude oil during washing of filters. Duplex filters should be fitted for this purpose.

6.11.6.2 The duplex filters are to be arranged to minimize the possibility of them being opened under pressure due to inadvertent operation. Filters/filter chambers are to be provided with appropriate measures for venting when they are in service and for pressure relief before they are opened. Therefore, drain valves and piping leading to a safe location are to be provided.

6.11.6.3 Measures are to be taken to monitor the oil pressure drop through filters.

6.11.7 Crude oil transfer pump

6.11.7.1 Primary and spare crude oil transfer pumps with adequate capacity are to be provided. The failure of the primary pump is not to affect the normal operation of the spare pump.

6.11.7.2 Crude oil transfer pump may be waived provided that the crude oil settling tank is positioned higher than the crude oil purification unit.

6.11.8 Crude oil purification unit

6.11.8.1Crude oil purification equipment is to be provided to remove the harmful components in crude oil in order to meet the quality requirements on crude oil fuel for combustion equipment users.

6.11.8.2 Crude oil purification unit usually consists of oil supply pump, heater, oil purifier, sludge discharge tank, piping and instruments.

6.11.8.3 At least two sets of crude oil purification equipment are to be provided, and the capacity of each set is to be able to satisfy the demands of the combustion equipment under maximum continuous load; and the failure of either set of equipment cannot affect the normal operation of another set.

6.11.8.4 Each set of equipment is to be equipped with oil supply pump and the flow rate of the pump should be slightly higher than the treatment amount of the oil purifier.

6.11.8.5 Each set of equipment is to be equipped with heaters and each heater is to be able to satisfy the demands of the purification system. The temperature of the heating medium is not to exceed 204C and the heater is to be fitted with high temperature alarm and shutdown devices.

6.11.8.6 Reliable measures are to be in place to prevent leakage of crude oil into the heating medium, otherwise the heating medium circulation system is to be considered as a secondary release source and the area where the system is situated is to be considered as a zone 2 hazardous area.

6.11.9 Sludge discharge tank

6.11.9.1 Sludge discharge tank is to be provided to receive the oil sludge and residues discharged from the purification unit.

6.11.9.2 Sludge discharge tank should be fitted underneath the purification unit.

6.11.9.3 Sludge discharge tank is to be provided with inert gas protection.

6.11.10 Crude oil daily tank

6.11.10.1Two crude oil daily tanks are to be provided for crude oil fuel users. Crude oil daily tanks are to be arranged so that another oil tank can continue to supply fuel oil when one oil tank is under cleaning or repair. The capacity of each tank is to be able to keep supplying oil to the users under maximum continuous working load for 8 hours.

6.11.10.2 The water or sludge drain valves or cocks of crude oil daily tanks are to be of self-closing type and the sampling valve or cock fitted on the crude oil daily tanks is also to be of self-closing type. The discharged materials are to be collected into the sludge discharge tank.

6.11.11 Valves on crude oil tank

6.11.11.1 The inlet and outlet lines of oil tanks (including but not limited to storage tanks, settling tank or daily tank), through which crude oil is likely to overflow in case of any damage, are to be directly fitted with a cock or valve which can be controlled locally and closed remotely from an easily accessible location outside the area where the cock or valve is located. An automatic check valve in place of the cut-off valve may be fitted on the oil inlet line.

6.11.11.2 The remotely operated cut-off valve can be closed manually by mechanical means or closed by power (e.g., hydraulic, pneumatic or electric power). The power source is to be reliable and located in a space outside the valve location if the valve is closed by power. The valve and its closing mechanism within the valves located area are to be made of fire-proof material.

6.11.12 Crude oil supply pump and booster pump

6.11.12.1 Primary and spare crude oil supply pumps and booster pumps are to be provided. And the failure of the primary pumps is not to affect the normal operation of the spare pumps.

6.11.12.2 The pressure of crude oil supply pumps and booster pumps is to be set to prevent occurrence of harmful gas pocket or cavitation in the supply system.

6.11.13 Crude oil changeover

6.11.13.1 Spare diesel fuel is to be provided to ensure continued normal operation of the combustion equipment in the event of an interruption of crude oil supply.

6.11.13.2 Diesel engines burning crude oil are to be fitted with switchover apparatus for immediate switch to diesel.

6.11.13.3 When the crude oil fuel system has sustained any leakage, fire or other dangerous events, the alarm is to be activated and the original fuel is to be switched over to diesel to maintain continued operation.

6.11.14 Displacement of crude oil fuel system

Measures for diesel displacing and flushing crude oil fuel system are to be provided f in order to perform maintenance and repair of the system.

6.11.15 Safety requirements for crude oil fuel treatment system

The requirements for pressure, temperature and level control of oil fuel treatment system is to be in accordance with the applicable provisions in Chapter 4 of the Rules.

6.11.16 Safety requirements for crude oil fuel supply system

6.11.16.1 Crude oil fuel supply system refers to the piping system through which the crude oil is transferred from the daily tanks to the combustion users.

6.11.16.2 The safety requirements for crude oil fuel supply system (e.g., arrangement, control, explosion protection, etc.) are to be in accordance with the applicable provisions in the main rules for the offshore installation on which the oil and gas process system is located.

6.11.16.3 The requirements of 6.11.16.2 may be exempted provided that the flash point (closed cup) of the crude oil after flashing treatment is no less than 60℃. However, it is to be noted that if the flashed crude oil needs to be heated during its use, the temperature of the heated oil is not to exceed its flash point.

SECTION 12 CRUDE OIL STORAGE AND TRANSFER SYSTEM

6.12.1 The purpose of crude oil storage

The purpose of crude oil storage is to provide sufficient buffer capacity for continuous and stable oilfield production.

6.12.2 Crude oil storage capacity

The capacity of offshore oil storage equipment depends on oilfield output, and the number, size, and delivery cycle of oil carriers, as well as the restrictions of offshore conditions on oil loading. The capacity of offshore oil storage equipment is usually designed according to the 7-15 days of peak oil production of the concerned oilfield.

6.12.3 Basic methods of crude oil storage and transfer

There are two basic methods commonly used for storage and transfer of crude oil in offshore oilfields:

(l) Oil storage equipment is installed offshore and the crude oil is transferred by shuttle tankers or directly by oil storage vessels (of small tonnage);

(2) The crude oil is transferred via subsea pipeline to a terminal on an artificial island or onshore terminal, and then delivered to the users by other means.

6.12.4 Oil storage equipment

6.12.4.1 Offshore floating storage and offloading tanker (FSO) and offshore floating production, storage and offloading tanker (FPSO)

(1) FSO and FPSO are the most commonly employed ways of offshore crude oil storage and transfer, which are of great significance in saving investment costs for some marginal oilfields. The oil storage vessels have a good mobility and are easy to be relocated upon completion of oilfield production to support the development of the

other new oilfields.

FSO and FPSO can be constructed by modifying an old oil tanker and can also be a purpose-designed and constructed.

(2) The specific requirements for crude oil storage by means of FSO and FPSO are to be in accordance with the applicable provisions in Part 4 of the Society's Rules for Classification of Offshore Floating Installations.

6.12.4.2 Platform storage tank

(1) Platform storage tanks are usually installed on an artificial island or on a special oil storage platform. Normally, a steel structure dock is constructed on the side of the oil storage platform for the shuttle tankers to dock, load and transfer crude oil.

(2) The specific requirements for platform storage tanks are to be in accordance with the applicable provisions in Part 6 of the Society's Rules for the Construction and Survey of Fixed Offshore Platforms in Shallow Waters.

6.12.4.3 Subsea oil storage tank

(1) The advantages of subsea oil storage tanks are that the tanks can avoid the impact of wind and waves and oilfield production can continue in inclement weathers; as the tanks are immersed underwater, the risks of fire and lightning have been eliminated.

(2) Subsea oil storage tanks can be constructed by metal material, reinforced concrete and other non-metallic materials and in the shape of a cylinder, rectangle, elliptical paraboloid, sphere or other composite spheres. Special attention is to be paid to corrosion protection as the tanks are soaked in the seawater for a long term.

(3) Subsea oil storage tanks require that the seabed terrain is even and the ocean current washing action on the seabed is not serious. The tank bottom is connected with seawater as this type of storage tank is designed on the basis of oil-water displacement mechanism. If the seabed terrain is sloped and the washing action of the ocean flow is severe, the crude oil in the tank is likely to overflow when the tank is close to the full load. And the possibility of crude oil overflow will increase in the waters with a shallow water depth and high wind and waves, as the action of surface waves is more easily transferred to the seabed.

(4) The structure type of the subsea oil storage tanks is to be designed taking into account the action of ocean current, waves and tides, as well as many other factors such as water depth, seabed soil conditions, etc.

(5) The function of oil-water replacement shall be considered in the process design of subsea oil storage tanks. If the dirty oil replaced by oil and water is directly discharged into the sea, it shall meet the requirements of pollution prevention.

6.12.4.4 Gravity platform support leg oil tank

(1) Gravity platform requires stable ballast and the ballast tank of such structure can be designed for an oil storage tank.

(2) Gravity platform support leg oil tank can be delivered in entirety to the field. The work quantity of offshore lifting operations will be saved if the deck can be installed on the substructure in advance. In addition, the riser of oil wells may be placed in the concrete structure to allow installation and operation of the riser and equipment in a dry environment and prevent corrosion caused by underwater environment.

6.12.4.5 Oil storage and mooring complex unit

Oil storage and mooring complex unit consists of a mooring buoy which has been enlarged to serve as an oil storage tank, and the additional production, utility and accommodation facilities make full use of the mooring device.

6.12.5 Pig launcher and receiver

6.12.5.1 The pig launcher and receiver are to be fitted with a double block and single bleed valve set for isolation of the hydrocarbon source when the door is opened.

6.12.5.2 A system is to be provided to ensure the pig launcher and receiver are flushed and depressurized before the launcher/receiver door is opened.

6.12.5.3 Pig launcher and receiver are to be fitted with devices (e.g., pressure gauge, pressure interlock, whistle, etc.) to allow the operator to confirm the vessel has been fully depressurized before the door is opened.

6.12.5.4 Pig launcher and receiver are to be arranged with the direction of the center lines deviated from any critical equipment or structure.

6.12.5.5 Oil trays for leakage collection are to be installed below the doors of pig launcher and receiver and arranged in such a way as to safely handle and store the attached materials (e.g., wax or scale) from the pig and subsea pipeline.

6.12.5.6 Pig launcher and receiver are to be manufactured according to the recognized standards.

6.12.6 Crude oil transfer pump

6.12.6.1 Pump protection system, set point and response time are to be designed to prevent damage to the downstream pipelines and facilities.

6.12.6.2 High-volume pipeline outlet and offloading pumps are to be fitted with minimum flow bypass devices to limit temperature rise in accordance with the recommendations from the pump manufacturer.

6.12.6.3 Check valve is to be fitted in the downstream of the pump to prevent backflow.

6.12.7 Transfer of crude oil from offshore floating installations

The specific requirements for the crude oil transfer system on offshore floating installations are to be in accordance with the related provisions in Part 4 of the Society's Rules for Classification of Offshore Floating Installations.

CHAPTER 7 PRE-PROCESSING AND LIQUEFACTION OF NATURAL GAS, REGASIFICATION AND TRANSFER OF LIQUEFIED GAS

SECTION 1 GENERAL

7.1.1 Scope

7.1.1.1 This chapter covers the purification and liquefaction of natural gas, LNG regasification and transfer.

7.1.1.2 The requirements for liquefied gas storage are to be in accordance with the applicable provisions in the main rules for the offshore installation on which the natural gas purification, liquefaction, LNG regasification and transfer system is located.

7.1.2 Definitions and abbreviations

7.1.2.1 For the purpose of this chapter, the definitions used are as follows:

(1) The word liquefaction includes both the liquefaction of natural gas and the liquefaction of petroleum gas.

(2) The word transfer denotes the loading and unloading of LNG.

7.1.2.2 The abbreviations used in this chapter are as follows:

BOG	Boil off gas
LNG	Liquefied natural gas
LNG FSRU	Liquefied natural gas floating storage and regasification unit
LNG SRV	Liquefied natural gas shuttle regasification vessel
LNGC	Liquefied natural gas carrier
LNG FSRV	Liquefied natural gas floating storage and regasification vessel
LPG	Liquefied petroleum gas

7.1.3 Recognized standards

The Society accepts that natural gas purification and liquefaction, LNG regasification and transfer system is designed, constructed, installed and tested in accordance with the following standards:

(1)	**ISO 28460**(EN1532)	Petroleum and natural gas industries -- Installation and equipment for liquefied natural gas -- Ship-to-shore interface and port operations.
(2)	EN 1474	Installation and Equipment for Liquefied Natural Gas - Design and Testing of Marine Transfer Systems.
(3)	GB/T 20368	Production, Storage and Handling of Liquefied Natural Gas (LNG)
(4)	ICS	Tanker Safety Guide (Liquefied Gas).
(5)	NFPA-59A	Production, Storage, and Handling of Liquefied Natural Gas (LNG)
(6)	OCIMF	Design and Construction Specification for Marine Loading Arms.
(7)	OCIMF	Mooring Equipment Guidelines (MEG).
(8)	OCIMF	Guide to Manufacturing and Purchasing of Hoses Used for Offshore Moorings (GMPHOM).
(10)	SIGTTO	Liquefied Gas Handling Principle on Ships and in Terminal Liquefied Gas Processing.
(11)	SIGTTO /OCIMF	Manifold Recommendations for Liquefied Gas Carrier.

(12) SIGTTO/ICS/OCIMF Ship to Ship Transfer Guide for Petroleum, Chemicals and Liquefied Gases.

SECTION 2 NATURAL GAS PURIFICATION

7.2.1 Introduction

7.2.1.1 Natural gas condensate liquid is to be separated prior to liquefaction of natural gas. However, different natural gas users have different requirements on natural gas specifications; for instance, some natural gas users have specific requirements on the high heat value of natural gas. It is required to reserve a certain proportion of natural gas condensate in the natural gas in order to meet the users' needs.

7.2.1.2 Natural gas must be purified to remove the following harmful substances prior to liquefaction:

(1) Water: water in natural gas can form solid hydrates (combustible ice) which can further block the piping or affect the control system;

(2) Water vapor: along with the liquefaction, water vapor will freeze and further block the piping or affect the control system;

The process to remove water and water vapor from natural gas is normally called dehydration.

(3) Carbon dioxide, hydrogen sulfide, carbon monoxide: these are corrosive substances which can shorten the service life of equipment and piping. In addition, solids will precipitate from carbon dioxide during temperature reducing and lead to blockage risks to equipment and piping. When the content of carbon dioxide is high (e.g., higher than 10%), it is to be collected or reinjected into the formation to reduce greenhouse gas emission;

The process to remove these sour gases from natural gas is normally called sweetening or deacidification.

(4) Mercury: mercury can cause serious corrosion to the aluminum equipment in the liquefaction process, such as cold box; in addition, mercury presents hazards to the environment and maintenance personnel;

(5) Hydrogen sulfide: hydrogen sulfide is a highly toxic gas and is to be removed in natural gas production process.

(6) Carbonyl sulfide: carbonyl sulfide can be hydrated by a very small amount of water to generate hydrogen sulfide and carbon dioxide, resulting in corrosion fault.

7.2.1.3 Recovery and separation of light hydrocarbons

LPG is usually separated before natural gas liquefaction for separate storage and use as LPG has higher economic values than LNG. Ethane and propane may also be separated from LPG as needed. Removal of ethane and propane can be achieved using pre-cooling and liquefaction technology or other fractional technology.

7.2.2 Requirements for the quality of feed gas of liquefied natural gas

The feed gas of liquefied natural gas is to meet the requirements on gas quality for liquefaction process after dehydration, deacidification and heavy metal removal. In general, the allowable content of its harmful components is to be in accordance with Table 7.2.2.

Limits of harmful component content after purification of feed gas Table 7.2.2

Component	**Allowable content**	**Component**	**Allowable content**
Water(volumetric content)	$<0.1\times10^{-6}$	Total sulfur	10~50 mg/m^3
Carbon dioxide (volumetric content)	$(50\sim100)\times10^{-6}$	Mercury	<0.1 μg/m^3
Hydrogen sulfide	3.5 mg/m^3	Aromatic hydrocarbons (volumetric content)	$(1\sim10)\times10^{-6}$
Carbonyl sulfide (volumetric content)	$<0.1\times10^{-6}$	C^+_5	<70 mg/m^3

7.2.3 Design of purification process

7.2.3.1 The purification process is to be designed in an integrated way with the main process system of natural gas production.

7.2.3.2 The requirements for the safety devices, instruments, controls and shutdown devices with which the purification process equipment is to be fitted are to be in accordance with the relevant provisions in Chapter 4 of the Rules.

7.2.4 Selection of purification process

7.2.4.1 Proven and mature techniques are to be selected for the separation, deacidification, dehydration, mercury removal and light hydrocarbons recovery of the condensate liquid.

7.2.4.2 Purification equipment on floating terminals is to be selected taking into account the influence of floating structure movements on the safety of purification equipment and purification effects.

7.2.4.3 Purification equipment is to be selected taking into account the equipment footprint and available space on the deck.

7.2.5 Design of purification process module

Purification process module is to be designed taking into account that the congestion level of equipment and piping should not be too high and good natural ventilation should be ensured in order to mitigate the consequences of possible explosion.

SECTION 3 NATURAL GAS LIQUEFACTION

7.3.1 The purpose of natural gas liquefaction

The purpose of natural gas liquefaction is to reduce its volume by around 600 times under atmospheric pressure to facilitate storage and transfer.

7.3.2 Natural gas liquefaction methods

As natural gas has a lower critical temperature and a higher critical pressure, it cannot be liquefied by compression at atmospheric temperature. Temperature reducing method is usually adopted to liquefy the natural gas when its temperature is reduced to around -162°C.

7.3.3 Considerations for design of liquefaction process

7.3.2.1 Liquefaction process is to be designed to accommodate the special needs of offshore environment, for example, the process is to be simple, compact, smaller footprint and highly safe and reliable, and the maintenance interval cannot be too short.

7.3.2.2 The equipment installed on a floating installation is to be designed to work safely under the specified mobile conditions. Special attention is to be paid to the design, support and location of fractional tower and other high structures.

7.3.2.3 The system design is to be considered that the influence of cross contamination of cooling medium and cooled medium will be minimized.

7.3.4 Design of liquefaction process module

Liquefaction process module is to be designed taking into account that the density of equipment should not be too high and good natural ventilation should be ensured to mitigate the consequences of possible explosion.

7.3.5 Hazardous material storage amount

The amount of stored hazardous material in the liquefaction equipment is to be as small as possible in order to mitigate the consequences in the event of an accident.

7.3.6 Cryogenic leak protection

In the liquefaction area, stainless steel collection and containment are to be provided below the process components where cryogenic liquid leakage may occur, and any leak is to be routed to a safe location.

SECTION 4 NATURAL GAS REGASIFICATION

7.4.1 Scope

This section is applicable to the natural gas regasification system on LNG FSRU. Natural gas regasification system on LNG SRV and LNG FSRV can also be designed, manufactured and surveyed in accordance with the applicable provisions of this section.

7.4.2 Regasification flow

The general regasification flow on LNG FSRU is as follows: LNG in a cargo tank is transferred to the suction drum using LNG cryogenic submersible pump, then LNG is transferred by high-pressure pump from the suction drum to the vaporizer for vaporization, and natural gas from the vaporizer is filtered, metered and delivered to the onshore facility via transfer manifold or to the pipe network of onshore natural gas users via subsea pipeline.

The vaporizer is normally heated jointly by seawater and other intermediate media (such as methane, water-glycol) or by an intermediate medium only.

7.4.3 LNG low-pressure pump

7.4.3.1 LNG low-pressure pump is to be provided to transfer LNG from the cargo tank to the suction drum.

7.4.3.2 Spare pumps are to be provided to ensure reliability of LNG transfer, and if appropriate, LNG main pump and spray pump can be used as spare pumps.

7.4.4 Suction drum

7.4.4.1 Suction drum consists of liquid space and gas space, and its main function is to:

(1) Serve as a buffer vessel for LNG supplied from cargo tank to the regasification system and maintain the inlet pressure of LNG high-pressure pump;

(2) Serve as a buffer vessel for BOG and depressurized fluid generated during the operation of regasification system;

(3) Ensure LNG in it can prevent damage to LNG high-pressure pump in the event of unexpected failure of the low-pressure pump.

7.4.4.2 Suction drum plays an important role for stabilized LNG supply to regasification system and BOG disposal. If a suction drum is a single component, robust design is to be employed and special attention is to be paid to its manufacture quality.

7.4.4.3 The suction drum is to be fitted with safety valve (pressure-relief valve) and depressuring valve (refer to the relevant provisions in Chapter 6 of the Rules). Measures to prevent cargo tank overpressure are to be made available when the fluid is to be discharged into the cargo tank and measures to avoid liquid ingress into the vent stack are to be made available when the fluid is discharged to the cold vent stack. A throttling ring is to be fitted in the downstream of each depressuring valve to prevent the pressure of depressuring line from exceeding the design pressure.

7.4.4.4 Depressuring valve is to be manually actuated and it can also be automatically actuated through the fusible plug type of fire detector. If the valve is to be automatically actuated by other types of fire detector, it is to be executed by means of voting in order to prevent nuisance opening.

7.4.4.5 The pressure in suction drum is to be at least 0.3 MPa higher than cargo tank pressure so as to maintain the sub-cold state of LNG in the suction drum. This sub-cold state is beneficial for improvement of high-pressure pump performance and to prevent impeller from cavitation.

7.4.4.5 Monitoring and control

The suction drum is to be monitored and controlled from the cargo control room regarding the following items:

(1) High pressure and low pressure alarms;

(2) Low level alarm and ultra-low-level shutdown;

(3) High temperature alarm.

7.4.5 LNG high-pressure pump

7.4.5.1 The function of LNG high-pressure pump is to pressurize low LNG to higher pressure (typical around 10 MPa) and then transfer LNG to the evaporator. The objective of increasing the LNG pressure is to make regasification gas to keep certain initial pressure in order to deliver it to the user.

7.4.5.2 Vapor will be produced in the pump suction pot due to the heat generated by the pump during normal operation. Measures to vent the vapor are to be made available to ensure stable operation of the high-pressure pump.

7.4.5.3 In order to pre-pressurize the regasification system before start-up, a proper number and appropriate capacity of small type pumps may be provided according to the need.

7.4.5.4 The suction side of the high-pressure pump is to be fitted with filters.

7.4.5.5 The discharge side of the high-pressure pump is to be fitted with safety relief valve.

7.4.5.6 The high-pressure pump should be fitted with over-current and under-current protections.

7.4.5.7 The high-pressure pump should be provided with automatic start program and starting interlock protection.

7.4.5.8 The high-pressure pump should be fitted with vibration monitoring device for protection of the equipment and system.

7.4.6 Vaporizer

7.4.6.1 Vaporizer design considerations

(1) During selection of vaporizer types, comprehensive consideration is to be given with respect to cost-effectiveness, safety, environmental protection and energy saving;

(2) Immersed burning evaporator should not be selected for the purpose of energy saving and reduction of exhaust emission to the atmosphere;

(3) The heating source of the vaporizer is to make full use of the seawater and the residual heat of exhaust gases;

(4) The difference between the suction temperature and discharge temperature of the seawater heating system should not be excessively high (generally no more than 5℃) in order to minimize the negative effects on marine ecology; the bactericidal used in seawater system is to minimize the effects on marine ecology;

(5) The risks associated with seawater freezing are to be considered for systems using seawater to directly heat the cryogenic LNG;

(6) The surfaces in contact with seawater are to be easily accessible for inspection and cleaning;

(7) Measures to flush the vaporizer seawater circuit with fresh water or chemicals when the vaporizer is taken out of service are to be provided;

(8) Proper temperature, pressure and flow rate control measures and proper leak detection measures are to be considered in the overall design of vaporizer.

7.4.6.2 Special considerations for design of vaporizer performance

Vaporizer operates at supercritical pressure and its heat transfer mechanism and design are different from those of the conventional heat exchanger. In view of the great temperature difference, high pressure and use of seawater or other medium as the heating medium, special consideration is required for heat transfer and mechanical design, material selection and fabrication.

7.4.6.3 Consideration of impacts of floating unit characteristics

(1) Vaporizer is to be selected with consideration to minimize the impact of floating unit motion on vaporization effects. For example, printed plate type or tube and shell type vaporizer may be selected;

(2) Compact vaporizer should be selected in consideration of the limited space of the floating unit.

7.4.6.4 Monitoring and control

The vaporizer is to be monitored and controlled from the cargo control room regarding at least the following items:

(1) Heating medium inlet should be fitted with low pressure/temperature alarms and ultra-low pressure/temperature shutdown devices;

(2) Heating medium outlet should be fitted with low temperature alarm, ultra-low temperature shutdown and low-pressure alarm;

(3) LNG inlet is to be fitted with high and low pressure alarms;

(4) Natural gas outlet is to be fitted with high and low pressure alarms, low temperature alarm, ultra-low temperature shutdown and high temperature alarm.

7.4.7 Vaporizing trains

7.4.7.1 A vaporizer with its heating medium circulation system, high-pressure LNG pumps and associated piping are normally formed a vaporizing train.

7.4.7.2 Each vaporizing train may be equipped with one spare high-pressure LNG pump as needed.

7.4.7.3 The ragas system on each LNG FSRU is to be equipped with at least a spare vaporizing train in addition to the main vaporizing trains.

7.4.7.4 Each vaporizing train is to be independent of the other trains. Any vaporizing train is to be able to reliably isolated during normal regasification operation to allow repair and maintenance.

7.4.8 Seawater heating system

7.4.8.1 Main and spare seawater intake pumps are to be provided. Ballast pumps may also be used as spares provided that their pressure head and flow rate are suitable.

7.4.8.2 Main and spare seawater sea water booster pumps are to be installed to provide continuous heating source to the vaporizers. Spare seawater booster pumps are to be provided.

7.4.8.3 Reliable measures are to be taken to avoid natural gas leak into the seawater system. Otherwise, the seawater flow-through areas are to be considered as class 2 hazardous areas.

7.4.8.4 Seawater heating piping is to be made of corrosion resistant material.

7.4.8.5 Seawater system is to be able to take in seawater from at least two sea chests. Failure of any seawater intake line is not to affect the normal operation of the other seawater intake lines.

7.4.8.6 In addition to the coarse filter fitted at the seawater intake, the main seawater supply line is to be fitted with suitable filter system in order to meet the quality requirements of the seawater required by the heat exchangers.

7.4.8.7 Seawater heating pumps are to be fitted with proper controls and display of parameters such as pressure and temperature, as well as automatic starting system of the spare pump.

7.4.9 Piping

7.4.9.1 Stress analysis of cryogenic and high-pressure piping is to be performed.

7.4.9.2 The piping length between the high-pressure LNG pump and vaporizer is to be as short as possible to minimize the possible leakage of high-pressure cryogenic LNG.

7.4.9.3 Butt welded joints for cryogenic and high-pressure piping are to be used as practically possible.

7.4.9.4 Flangeless cast valves are to be used on high-pressure piping as practically possible.

The valves welded neck is to be long enough to ensure that valve deformation will not occur due to connection welding and post weld treatment.

7.4.9.5 Piping is to be fitted with safety relief valve as required and piping having a storage capacity greater than 400kg is to be fitted with depressuring valve.

7.4.9.7 The gasification system is to be equipped with a proper number of trains and nitrogen injection connections for pressure bleed-off and inert gas purging of the system and associated equipment.

7.4.9.8 The isolation of equipment or piping is to be in accordance with paragraph 3.1.14 0f Chapter 3 of the Rules.

7.4.9.9 The gasification system is to be fitted with special vent stack (mask) and associated piping and valves for natural gas removal and inert gas purging.

7.4.10 Natural gas transfer

7.4.10.1Metering device

(1) Each regasification system is to be fitted with metering devices, gas analyzer and special metering calculator for metering of the transferred gas. The metering signals are to be transmitted to the cargo control room.

(2) Metering devices requiring minimum maintenance and having maximum reliability are to be selected. Use of two sets of metering devices in series may be considered in order to ensure metering continuity.

7.4.10.2 Transfer manifold

Each LNG FSRU is to be equipped with transfer manifold in the fore part and also the units side is usually fitted with transfer manifold to accommodate the needs of side-by-side mooring of gas carrier and gas transfer.

7.4.10.3 Export pressure control valve and shutdown valve

Natural gas export line is to be fitted with pressure control valves and shutdown valves.

7.4.10.4 Monitoring and control of gas transfer parameters

The following items of gas transfer parameters should be monitored and controlled from the cargo control room:

(1) High pressure and low pressure alarms, ultra-high pressure and ultra-low pressure shutdown;

(2) Low temperature alarm and ultra-low temperature shutdown.

7.4.11 LNG and high-pressure natural gas leakage protection

7.4.11.1 In LNG flow-through places within the regasification area, stainless steel drip trays are to be provided to collect any possible LNG leakage, and any LNG leak is to be routed to a safe location.

7.4.11.2 Structures in the regasification area which are subject to potential effects of cryogenic LNG leak are to be made of low-temperature resistant material.

7.4.11.3 Each flanged connection of high-pressure natural gas piping is to be provided with shield protection to prevent possible leakage and jet flame.

7.4.11.4 Combustible gas detectors are to be provided within the entire regasification area.

7.4.12 Safety of intermediate heating medium

7.4.12.1 Where combustible media such as propane are used as heating medium, attention is to be paid to the safety of the storage and circulation system.

7.4.12.2 The liquid level of propane storage and circulation tank and glycol expansion tank is to be monitored.

7.4.12.3 Measures to detect leakage of LNG, natural gas and other heated media into the intermediate heating medium are to be provided. Audible and visual alarm is to be activated in the central control room upon detection of any leak.

7.4.13 Water spray protection

The entire regasification area is to be covered by water spray protection.

7.4.14 Test

7.4.14.1 Pressure test of high-pressure piping is to be carried out in the manufacturer upon completion of regasification module.

7.4.14.2 Running and full load test of pumps for seawater heating system is to be carried out in the ship yard.

7.4.14.3 Cold test and full load regasification function test of regasification system is to be carried out as practically possible before the regasification system is put into service.

SECTION 5 LIQUEFIED GAS TRANSFER

7.5.1 Operation limits

The limits for transfer operation are to be specified with respect to the following relevant parameters:

(1) Sea conditions for safe approach, berthing and departure of LNG carriers;

(2) Operational envelope of the loading arms;

(3) Loads of the mooring lines and fenders between the terminal and the LNGC.

7.5.2 Transfer technology

7.5.2.1 Where existing technology is intended to be used, the difference in operation and loading from typical applications is to be addressed and the systems ability of satisfactory performance is to be documented.

7.5.2.2 Where novel transfer solutions are intended to be adopted, a certain form of evaluation of the technology is to be performed.

7.5.3 Disconnection

7.5.3.1 The transfer system is to be fitted with a Quick Connect and Disconnect Coupling (QCDC) which is used during normal operation of the transfer system.

7.5.3.2 The QCDC system is to be fitted with an interlock to prevent inadvertent disconnection while transfer is underway or the lines are under pressure.

7.5.3.3 The transfer system is to be fitted with an Emergency Release System (ERS) which will permit rapid disconnection in the event of an emergency.

7.5.3.4 The control of the ERS is to be arranged to prevent inadvertent operation of the system. Testing of the ERS function should be possible without releasing the coupling.

7.5.3.5 The ERS is to be fitted with means to minimize any leakage in the event of operation of the system. This may typically involve installation of block valves on each side of the separated connection.

7.5.3.6 The transfer system is to be designed to accommodate any LNG remaining in the transfer system either following normal disconnection or emergency disconnection.

7.5.3.7 The transfer control system must be linked with the emergency shutdown system, communication system and carrier berthing system (line tension and disconnect systems) to allow safe disconnection in emergency.

7.5.4 Cryogenic leak protection

7.5.4.1 Any structural member subject to the effects of cryogenic liquid is to be designed to withstand such low temperature or protected from the cryogenic effects by means of shielding or water spray.

7.5.4.2 The potential effects of LNG leakage into the waters between the ship and the terminal are to be documented (e.g. the scenario of rapid phase transition).

7.5.5 Loading arm and gas return arm

7.5.5.1 The receiving terminals (either fixed or floating) or export terminals are to be equipped with loading arms for transfer of liquefied gas between the ships and terminals.

7.5.5.2 The objective of installing vapor return arms is keeping communication between ships tanks and receiving tanks during unloading operation from LNGC to the receiving tanks in order to avoid unloading tanks forming negative pressure and loading tanks forming overpressure.

7.5.5.3 Loading and unloading arms are to have alarms to indicate that the arms are approaching the limits of their extension envelopes. Automatic disconnection is to be conducted while being out of their working envelopes

7.5.5.4 Counterweights are be selected to operate with ice formation on non insulated hoses or arms.

7.5.5.5 After draining, a positive nitrogen pressure is to be used to inactivate the arms before disconnection and returning them in the stored position.

7.5.5.6 Loading and unloading arms are to be manufactured according to the standards recognized by the Society.

7.5.6 Transfer pump

7.5.6.1 Pumps for liquefied gas service are to be designed taking into account the most unfavorable liquefied gas density.

7.5.6.2 Pumps used for transfer of liquids at temperatures below -55℃, are to be provided with suitable means for precooling to reduce the effect of thermal shock.

7.5.7 Transfer hose

7.5.7.1 Hoses are to be designed to accommodate the operating temperature and pressure conditions of the loading or unloading system.

7.5.7.2 The designed burst pressure of hoses is to be no less than five times of the working pressure.

7.5.7.3 Flexible metallic hose or pipe and metallic swivel joint are to be used when the operating temperature is lower than -51℃.

7.5.7.4 Hoses are to be pressure tested to the maximum pump pressure or safety valve set pressure at least annually, and to be visually inspected for any damage or defect before each use.

7.5.7.5 Hoses are to be manufactured according to the standards recognized by the Society.

CHAPTER 8 PIPING

SECTION 1 GENERAL PROVISIONS

8.1.1 Application

The requirements presented in this Chapter apply to the piping of oil and gas process system and the associated utility systems. Piping is an assembly of piping components used for the transfer, distribution, mixing, separation, discharge, meter, control or snub of fluid flows, including pipes, valves, pipe fittings (e.g., elbow, tee, spool, reducer, outlet), flanges, supporting elements such as pipe supports, hangers and clamps, as well as flexible hose composed of hose, valves and fittings.

8.1.2 Recognized codes and standards

The recognized codes and standards for piping design and fabrication include:

(1)	GB50316	Design Code for Industrial Metallic Piping.
(2)	SY10042	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.
(3)	SY 10033	Recommended Practice for the Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.
(4)	ASME B31.3	Process Piping.
(5)	API RP14E	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.
(6)	API RP14C	Recommended Practice for the Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.

8.1.3 Definition

8.1.3.1 High-pressure piping: pressure piping having a nominal pressure higher than 42 MPa.

SECTION 2 DESIGN REQUIREMENTS

8.2.1 General requirements

8.2.1.1 The individual effect and collective effect of the following, but not limited to the following, factors are to be considered in piping design:

(1) Corrosion and erosion;

(2) Vibration and hydraulic hammer;

(3) Pressure fluctuation;

(4) Abnormally extreme temperature;

(5) Impact force;

(6) Accidental load;

(7) Leakages.

8.2.1.2 Oil and gas process piping system must be properly isolated from the utility piping systems in order to prevent the contamination of utility medium (e.g., steam, compressed air and cooling water, etc.) by the combustible process medium.

8.2.1.3 For piping subject to flexibility analysis is deemed necessary according to ASME B31.3 or API RP 14E, the flexibility analysis report is to be submitted to the Society. For pipelines whose design temperature is no higher than -110 ℃ , the flexible and stress analysis shall comply with the relevant provisions of CCS Stress analysis guide for low-temperature pipeline.

8.2.1.4 The internal and external piping accessories are to be designed with the following considerations: (1) Installation of accessories is not to cause pipe ovalization;

(2) Installation of accessories is not to cause excessive local stress;

(3) Installation of accessories is not to cause harmful temperature gradient on pipe wall;

(4) Stress concentration during piping installation is to be minimized, especially for piping bearing cyclic loads.

8.2.1.4 Liquid pocket or gas pocket in all piping systems, especially in the following systems, is to be avoided as possible:

(1) Blow down and safety valve discharge line;

(2) Compressor suction line;

(3) Lines subject to possible trapped water and freezing;

(4) Lines for transfer of corrosive and acidic fluids or other fluid that may freeze;

(5) Line containing solids and in which settlement is likely to occur;

(6) Lines in which condensation is likely to occur.

8.2.1.5 The piping connect to equipment is to be arranged to provide sufficient clearance for operation, inspection, repair and maintenance Attention is to be paid to clearances required for removal of equipment such as pump, pump driver, exchanger tube bundle etc.

8.2.1.7 All piping is to be identified by color code or other acceptable means, and the color of piping is to be accord with the requirements of relevant codes or standards

8.2.2 Determination of piping size

8.2.2.1 The diameter of liquid piping is to be determined in such a way as to achieve a moderate flow velocity, in order to minimize flashing of the liquid media and deposition of contaminant.

8.2.2.2 The diameter of gas piping is to be determined in such a way as to avoid generation of unacceptable noise due to excessive flow velocity in the pipe.

8.2.2.3 The piping for delivery of gas and liquid mixture is to be designed with the following considerations:

(1) The flow velocity of the fluid in pipe is not to be too low to prevent pipe blockage;

(2) The flow velocity of the fluid in pipe is to be lower than noise velocity;

(3) The flow velocity of the fluid in pipe is to be lower than the erosion velocity calculated from below formula.

$$V_e = \frac{1.22C}{\sqrt{P_m}}$$

Where: V_e ——Erosional velocity, m/s

C ——Empirical constant, taking 100 for continuous operation and 125 for intermittent operation

P_m ——Fluid density, kg/m^3

8.2.3 Requirements on pipe wall thickness

8.2.3.1 The minimum design wall thickness for piping is to include the calculated wall thickness plus the following additional allowances:

(1) Bend allowance;

(2) Thread allowance;

(3) Corrosion allowance;

(4) Erosion allowance;

(5) Negative manufacturing tolerance.

8.2.3.2 The wall thickness of the piping and piping components are to be calculated according to the standards recognized by the Society (e.g., ASME B31.3).

8.2.3.3 When a weld outlet of non-approved type is used for connection of piping branch, the calculation of reinforcement is to be made in accordance with the requirements of the applicable recognized standards (e.g. ASME B31.3).

8.2.4 Expansion joint and flexible hose

8.2.4.1 The positions of expansion joints and flexible pipes are to be clearly indicated in the design documents.

8.2.4.2 Pipe sections with expansion joints or bellows are to be sufficiently adjusted and aligned during installation. Installation of protection devices may be required when necessary to prevent mechanical damage to the expansion joints or bellows.

8.2.4.3 The piping is to be arranged to ensure adequate accessibility for inspection of the expansion joint and flexible pipe elements.

8.2.4.4 The burst pressure of flexible pipe is to be no less than 4 times of the maximum working pressure. The burst pressure of large-diameter high-pressure flexible pipe may be specifically considered. In any case, the burst pressure is not to be less than 2 times of the maximum working pressure.

8.2.4.5 Means to isolate the flexible pipes are to be provided when the hoses are used for systems in which uncontrolled spillage of hazardous media may occur.

8.2.4.6 The integrity and functional property of flexible pipes is to be maintained within the period required by the entire piping system.

8.2.4.7 The end fittings of flexible pipes are to be designed and manufactured according to the codes or standards recognized by the Society.

8.2.5 Requirements for valves

8.2.5.1 Screwed-on valve bonnets are not to be used for valves with nominal diameter exceeding 50mm.

8.2.5.2 The welded neck of valves is to be long enough to ensure that valve internals will not experience distortion and deformation when welding and post weld heat treatment of the joint are being carried out.

8.2.5.3 Ball valves and plug valves are not to be used for throttling purpose because the seal surface of these valves will be exposed to and damaged by the fluid medium when the valves are partially opened.

8.2.5.4 Manually-operated gate valves with a nominal diameter greater than 50 mm are to be fitted with flexible gate disc or expandable gate disc.

8.2.5.5 Gate valves with unprotected rising stems are not to be used because the offshore environment will cause corrosion to the exposed valve stem and screw, resulting in difficult valve operation and damage to stem packing.

8.2.5.6 The material of valves used for lines delivering non-corrosive medium is to be selected in accordance with the following requirements:

(1) Cast-iron or forgeable cast-iron valve bodies cannot be used for the piping for hydrocarbon and ethylene glycol service, but they can be used for water piping;

(2) Non-ferrous metal valves cannot be used for hydrocarbon piping, but they can be used for instrument or control systems;

(3) Small-diameter needle valves used for hydrocarbon piping are to be made of Austenitic stainless steel.

8.2.6 Connection of piping system

8.2.6.1The number of detachable connections in a piping system is to be limited by the number necessary for installation and dismantling. The detachable connections of piping system are to be in compliance with the applicable codes or standards.

8.2.6.2 The joints of piping with a nominal diameter greater than 50 mm are usually connected by means of butt weld, flange or screw unions with non-sealing threads. Where the piping is not used for corrosive medium, the joints of piping with a nominal diameter less than 50 mm may be connected through welding or by means of thread plus sealing weld.

8.2.6.3 Piping branch connection is to be in accordance with the following requirements:

(1) When the nominal diameter of the branch pipe is no less than 50 mm and greater than half of the nominal diameter of the main pipe, the welded branch connectors are to be butt welded straight tee or reducing tee;

(2) When the nominal diameter of the branch pipe is no less than 50 mm but less than half of the nominal diameter

of the main pipe, welded spool can be used;

(3) When a branch pipe with a nominal diameter less than 38 mm needs to be connected to a main pipe with a nominal diameter less than 38 mm, a socket weld tee is to be used and when the said branch pipe needs to be connected to a main pipe with a nominal diameter equal to 50 mm or above, sock let or equivalent fitting is to be used;

(4) Straight tee, swage reducers, or reduced outlet tees. are to be used for branch connection in threaded piping systems. All threaded piping systems and welded piping systems are to be isolated with block valves.

8.2.7 Pipe support

8.2.7.1 Piping is to be adequately supported so that the equipment connected with the piping does not have to bear the weight of the piping. The weight of valves and pipe fittings are not to impose significant additional stress on the adjacent piping.

8.2.7.2 Axial force due to internal pressure changes of, pipe direction and cross section area are to be considered during piping installation.

8.2.7.3 Piping is to be supported to avoid any detrimental vibration in the system.

8.2.7.4 The attachments of high-pressure piping, such as pipe support, trunnion and lifting lugs, are not to be directly welded to the piping.

8.2.7.5 The piping is to be arranged with adequate flexibility to prevent damage due to the force generated by platform movement and temperature changes.

8.2.8 Heat insulation of piping

Heat insulation of piping is to be in accordance with 3.1.13 of the Rules.

8.2.9 Design considerations for particular pipe sections

8.2.9.1 Wellhead Accessory Items

Sampling, chemical injection connections and chokes are to comply with the following applicable requirements:

(1) The sampling pipe and chemical injection pipe are to be as close as possible to the wellhead and their nominal diameter is to be no less than12 mm;

(2) A directly connected block valve is to be arranged in the sampling or chemical injection piping close to the connection.

(3) A spring-loaded globe check valve is to be fitted in the immediate vicinity of the block valve on chemical injection pipe;

(4) Choke bodies are to be installed in a manner that will permit easy removal and inspections. The downstream flow passage within ten nominal pipe diameters is to be free of abrupt changes.

8.2.9.2 Flowline section and its attachment

The flowline is to comply with the following applicable requirements:

(1) The flowlines are to be designed taking into account the effects of pressure, temperature, flow velocity, corrosion and erosion on the pipe;

(2) Flowlines are to be properly supported and securely fixed to minimize vibration and prevent whip;

(3) In order to protect the pressure sensors from blockage, the nominal diameter of sensor line is to be not less than 12mm, and the material of the line is to be stainless steel;

(4) Pressure sensor connections on the bottom of the flowline or in turns are to be avoided. Sensors are be installed with an external test connection and block valve.

8.2.9.3 Production manifold

(1) Each part of the manifold is to be designed with restricted maximum flow velocity and the piping leading to production header should be of the shortest length and minimum tortuous;

(2) The terminus of the manifold runs is be blind flanged to provide a fluid cushion area and for possible future expansion.;

(3) In each manifold branch connections, weld base are to be used. Care is to be taken to ensure the entrance hole

is smooth and free of burrs after it is welded in place;

(4) The manifold is to be arranged so that each valve is easily accessible and operable.

8.2.9.4 Pressure relief manifold

(1) Generally, the location of manifold header is to be lower than every pressure relief valve and depressed valves. Level section of each branch is to maintain 2mm per meter inclination downward. Every branch is to be connected to the main pipe upward and be 30or 45with the main pipe;

(2) Consideration is to be given so that the flow rate of each safety valve will not be affected by the back pressure generated in the entire manifold when a number of safety valves are relieving simultaneously.

(3) The cryogenic property is to be considered during selection of manifold material.

8.2.9.5 Safety valve inlet and outlet pipes

(1) The bore size of safety valve inlet pipe is to be no less than the inlet diameter of the safety valve;

(2) The inlet pipe of safety valve is to be as short as possible and the pressure loss from the protected vessel to the safety valve inlet is to be no more than 3% of the set pressure of the safety valve;

(3) The bore size of safety valve outlet pipe is to be no less than the outlet diameter of the safety valve;

(4) The number of elbows on the outlet pipe is to be minimized and the bend angle is to be no greater than 90;

(5) The outlet pipe is to be securely installed and adequately supported to protect the valves from any additional stress.

8.2.9.6 Pump inlet and outlet pipes

(1) Pump suction piping are be designed so the available net positive suction head (NPSH) at the pump inlet flange exceed the pump required NPSH. In the suction flange of pump, pressure of fluid must be higher than its vapor pressure;

(2) Pump inlet pipe is to be designed and arranged to avoid gas pocket;

(3) The bore size of pump inlet pipe is to be no less than the inlet diameter of the pump;

(4) The bore size of pump outlet pipe is to be no less than the outlet diameter of the pump;

(5) When a group of pumps shares one suction manifold, measures are to be taken to prevent flow contention between the pumps;

(6) For reciprocating pumps, a dampener is to be fitted close to the suction side and discharge side to reduce pressure pulsation of the piping system.

SECTION 3 MANUFACTURING REQUIREMENTS

8.3.1 Tack welding

The positioning welding of the joint root shall be made of the same filler metal as that used in the root pass. Location welding with cracks and other welding defects should be removed and integrated with the root weld. The bridge positioning block on the weld line shall be removed after welding.

8.3.2 Requirements for welding environment

No welding is be done if there is impingement on the weld area of rain, snow, sleet, or excessive wind, or if the weld area is frosted or wet.

8.3.3 Valve welding

The welding sequence and procedure and any heat treatment for a welding end valve are be such as to preserve the seat tightness of the valve.

8.3.4 Fillet weld and socket weld

8.3.4.1 Fillet welds and socket welds may vary from convex to concave. The size of a fillet is determined as in Fig. 8.3.4.1. The size of an equal leg fillet weld is the leg length of the largest inscribed isosceles right triangle within the weld cross section. and the size of unequal leg fillet weld is the leg lengths of the largest right triangle which can be inscribed within the weld cross section.

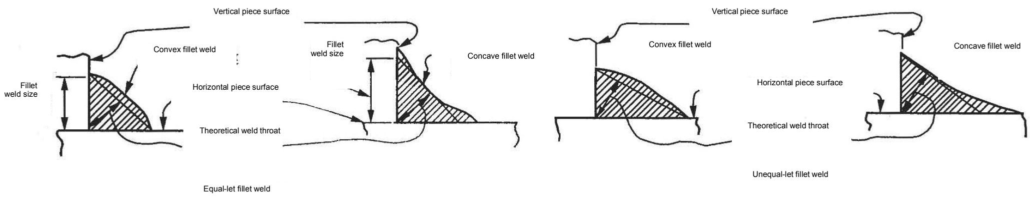


Fig. 8.3.4.1 Fillet weld size

8.3.4.2 Weld details for slip-on and socket welding flanges are shown in Fig. 8.3.4.2 (1); minimum welding dimensions for other socket welding components are shown in Fig. 8.3.4.2 (2).

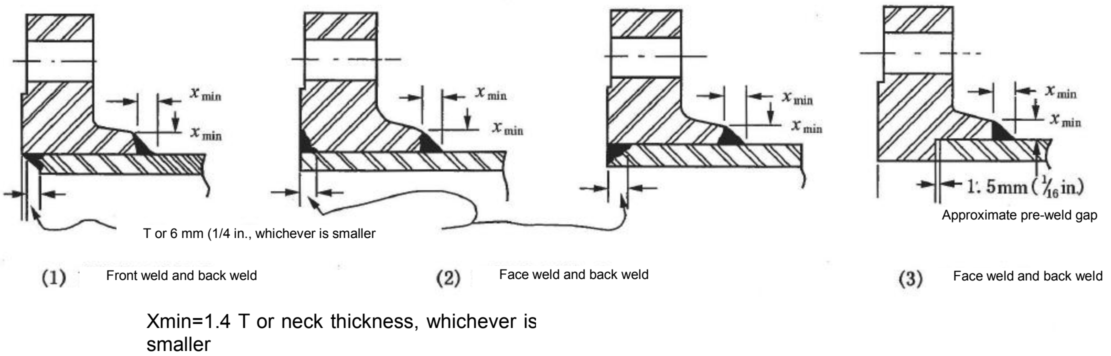


Fig. 8.3.4.2 (1) Typical weld details for double-side slip-on welded flange and socket welded flange

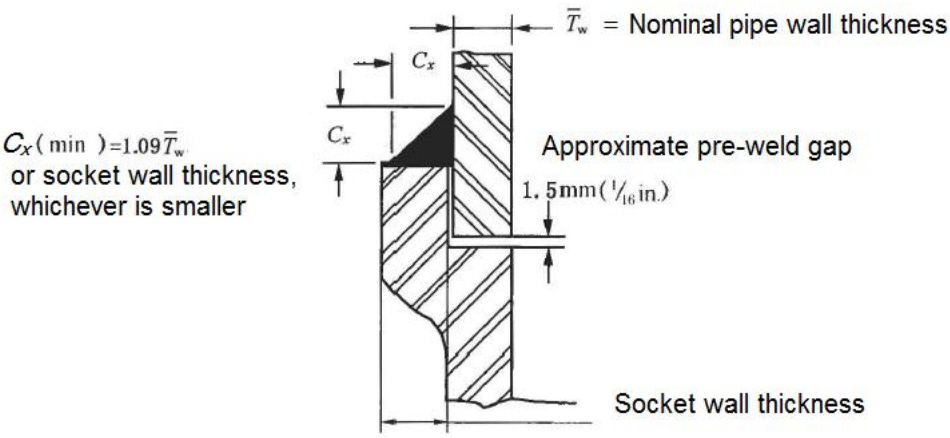


Fig. 8.3.4.2 (2) Minimum weld size of socket welded assemblies other than flange

8.3.4.3 If slip-on flanges are single welded, the weld is to be at the hub.

8.3.5 Sealing weld

The thread seal welds are to cover all the exposed threads.

8.3.6 Welded branch connection

8.3.6.1 The symbols used in this subsection are as follows:

$\overline{T_b}$ ——Nominal wall thickness of branch pipe

$\overline{T_h}$ ——Nominal wall thickness of run pipe

$\overline{T_r}$ ——Nominal thickness of reinforcement pad

t_c ——0.7$\overline{T_b}$ or 6.4 mm, whichever is smaller

t_{min} —— $\overline{T}_b$ or $\overline{T}_r$, whichever is smaller

8.3.6.2 The acceptable direct connections of branch pipe to run pipe with or without reinforcement are shown in Fig.8.3.6.2 (1) ~ (3).

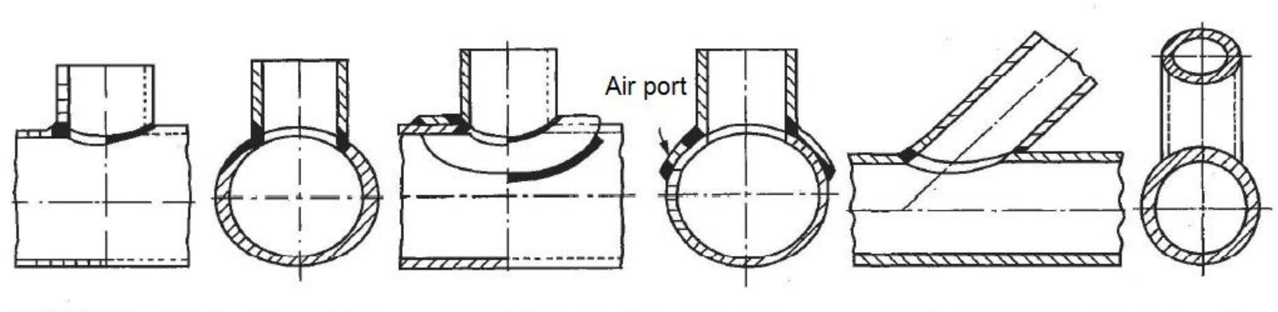
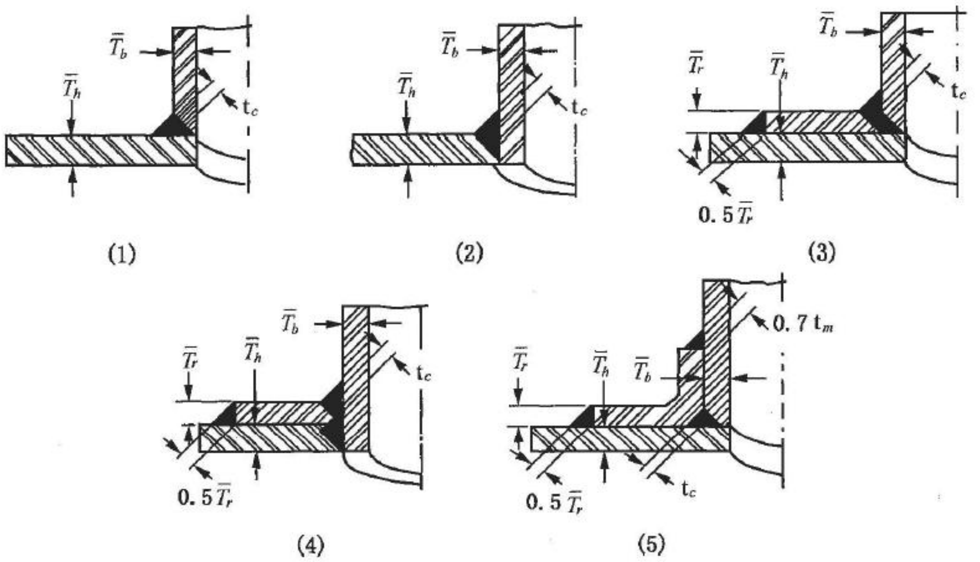


Fig. 8.3.6.2 Typical welded branch connection

8.3.6.3 The location and minimum size of attachment welds are to conform to the requirements of this paragraph, and the welds are to be not less than the sizes shown in Fig. 8.3.6.3.



General note: the sizes shown in the figure are the minimum allowable weld sizes and the real welds can be larger than the indicated sizes

Fig. 8.3.6.3 Allowable nodes of branch weld

8.3.6.4 Branch connections, including branch connection fittings, which abut the outside of the run or which are inserted in an opening in the run are to be attached by fully penetrated groove welds which are to be finished with cover fillet welds having a throat dimension not less than tc. See Fig. 8.3.6.3(1) and (2).

8.3.6.5 The reinforcement pad or saddle is to be attached to the branch pipe by any one of the following methods:

(1) A fully penetrated groove weld finished with a cover fillet weld having a throat dimension not less than tc;

(2) A fillet weld having a throat dimension not less than $0.7t_{min}$. See Fig. 8.3.6.3(5).

8.3.6.6 The outer edge of a reinforcing pad or saddle is to be attached to the run pipe by a fillet weld having a throat dimension not less than $0.5T_r$ as shown in Fig. 8.3.6.3 (3), (4) and (5).

8.3.6.7 Reinforcing pads and saddles are to have a good fit with the parts to which they are attached. A vent hole is to be provided at pad or saddle to reveal leakage in the weld between branch and run and to allow venting during welding and heat treatment. A pad or saddle may be made in more than one piece if joints between pieces have strength equivalent to pad or saddle parent metal, and if each piece has a vent hole.

8.3.7 Weld preheating

Preheating is used, along with heat treatment, to minimize the detrimental effects of high temperature and severe thermal gradients inherent in welding. The necessity for preheating and the temperature to be used are be specified in the engineering design and demonstrated by procedure qualification.

8.3.8 Heat treatment

Heat treatment is used to avert or relieve the detrimental effects of high temperature and severe temperature gradients inherent in welding, and to relieve residual stresses created by bending and forming. For the specific requirements on heat treatment, refer to the applicable provisions in the technical standards recognized by the Society, such as the requirements of Article 331 of ASME B31.3.

8.3.9 Bending and forming

8.3.9.1 Pipe may be bent and components may be formed by any hot or cold method which is suitable for the material, the fluid service, and the severity of the bending or forming process. The finished surface is to be free of cracks and buckling. Thickness after bending or forming Pipe may be bent and components may be formed by any hot or cold method which is suitable for the material, the fluid service, and the severity of the bending or forming process. The finished surface is to be free of cracks and buckling. Thickness after bending or forming is to be not less than that required by the design is not to be less than that required by the design.

8.3.9.2 Cold bending of ferritic materials is to be done at a temperature below the transformation range. Hot bending is to be done at a temperature above the transformation range and in any case within a temperature range consistent with the material and the intended service.

8.3.9.3 Flattening of a bend, the difference between maximum and minimum diameters at any cross section is not exceed 8% of nominal outside diameter for internal pressure and 3% for external pressure. Removal of metal is not to be used to achieve these requirements.

8.3.10 Assembly and erection

8.3.10.1 Any distortion of piping to bring it into alignment for joint assembly which introduces a detrimental strain in equipment or piping components is prohibited.

8.3.10.2 Unless otherwise specified in the engineering design, the alignment of flanged joint is to be in accordance with the following requirements:

(1) Before bolting up, flange faces are to be aligned to the design plane within 1 mm in 200 mm measured across any diameter;

(2) The flange bolt holes are to be aligned and the offset between bolt holes is to be no more than 3 mm.

8.3.10.3 The gasket is to be uniformly compressed to the correct design load during assembly of flanged joint.

8.3.10.4 During assembly of flanged joint, special attention is to be paid if the mechanical properties of one flange are greatly different from another flange. It is recommended to tighten the bolts to the predetermined torque.

8.3.10.5 Bolts are to extend completely through their nuts. Any which fail to do so are considered acceptably engaged if the lack of complete engagement is not more than one thread.

8.3.10.6 The contact surface is not to be fitted with more than one gasket during assembly of flanged joint.

8.3.10.7 The thread compound or lubricant is to be suitable for the service conditions and not to have adverse reaction with the delivered fluid or pipe material.

8.3.10.8 Thread compound is not to be used at threaded connections to be seal welded.

8.3.10.9 Typical straight-thread joints using surface seal (instead of thread) are shown in Fig. 8.3.10. Special attention is to be paid to avoid deformation of the seal face when such joints are welded, brazed or bonded to the piping assembly.

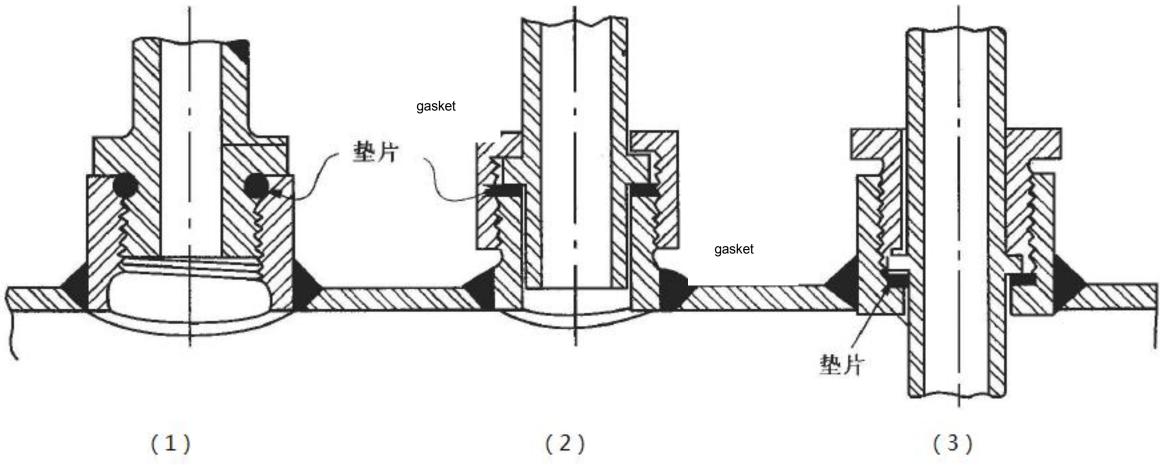


Fig. 8.3.10 Typical straight-thread joints

8.3.10.10 Before installation, the seal surface of the flare is to be inspected for imperfections. Imperfective flare is to be rejected.

8.3.10.11 For straight threaded joints, where the manufacturer's instructions call for a specified number of turns of the nut, these are to be counted from the point at which the nut becomes finger tight.

8.3.10.12 Caulked joints are to be installed and assembled in accordance with the manufacturer's instructions, as modified by the engineering design. Care is to be taken to ensure adequate engagement of joint members.

8.3.11 Inspection examination and test

8.3.11.1 The acceptance criteria for welded pipe joints are to be indicated in the engineering design and comply with at least the following requirements:

(1) Table 8.3.11.1 (1) lists the acceptance criteria for welded joints containing the typical imperfection (allowable range of imperfection).

(2) Ultrasonic examination of welded pipe joints is to be in compliance with the requirements of 8.3.11.4.

Acceptance Criteria for Welds and Examination Methods for Evaluating Weld Imperfections Table 8.3.11.1(1)

Criteria for Types of Welds and for Service Conditions [1]						**Weld imperfection**	**Testing method**			
Norminal fluid condition			Severe cyclic condition							
Type of Weld			Type of Weld							
Girth,, miter groove and branch connection [4]	Longitudinal Type of Weld [2]	Fillet weld [3]	Girth,, miter groove and branch connection [4]	Longitudinal groove [2]	Fillet weld[3]		Visual	Radiographic	Magnetic	Liquid penetrant
A	A	A	A	A	A	Crack	√	√	√	√
A	A	A	A	A	A	Lack of fusion	√	√	…	…
B	A	N/A	A	A	N/A	Incomplete penetration	√	√	…	…
E	E	N/A	D	D	N/A	Internal porosity	…	√	…	…
G	G	N/A	F	F	N/A	Internal slag inclusion, tungsten inclusion, or elongated	…	√	…	…
H	A	H	A	A	A	Undercutting	√	√	…	…
A	A	N/A	A	A	A	Surface	√	…	…	…

						porosity or exposed slag inclusion [Note (5)]				
N/A	N/A	N/A	J	J	J	Surface finish	√	…	…	…
K	K	N/A	K	K	N/A	Concave root surface (suck up)	√	√	…	…
L	L	L	L	L	L	Weld reinforcement or internal protrusion	√	…	…	…

General note:

(1) N/A indicates the Code does not establish acceptance criteria or does not require evaluation of this kind of imperfection for this type of weld.

(2) Check () indicates examination method generally used for evaluating this kind of weld imperfection.

(3) Ellipsis (. . .) indicates examination method not generally used for evaluating this kind of weld imperfection.

Note: Severe cyclic conditions are the conditions defined by ASME B31.3 300.2.

Criterion Value Notes for Table 8.3.11.1 (1) 8.3.11.1 (2)

<table>
<tr><th>Symbol</th><th>Measure</th><th colspan="2">Acceptable Value Limits[6]</th></tr>
<tr><td>A</td><td>Extent of imperfection</td><td colspan="2">Zero (no evident imperfection)</td></tr>
<tr><td>B</td><td>Depth of incomplete
penetration Cumulative length of incomplete penetration</td><td colspan="2">≤1mm 和 0.2$\overline{T}_w$
≤38 mmin any 150 mm weld length</td></tr>
<tr><td>D</td><td>Size and distribution of internal porosity</td><td colspan="2">See BPV Code, Section VIII, Division 1, Appendix 4</td></tr>
<tr><td>E</td><td>Size and distribution of internal porosity</td><td colspan="2">For $\overline{T}_w$≤ 6 mm, limit is same as D
For $\overline{T}_w$ > 6 mm, limit is 1.5 D</td></tr>
<tr><td>F</td><td>Slag inclusion, tungsten inclusion, or elongated indication
Individual length
Individual length
Cumulative length</td><td colspan="2">≤$\overline{T}_w$/3
≤2.5mm, and $\overline{T}_w$/3
≤4$\overline{T}_w$ in any 12$\overline{T}_w$ weld length</td></tr>
<tr><td>G</td><td>Slag inclusion, tungsten inclusion, or elongated indication
Individual length
Individual length
Cumulative length</td><td colspan="2">≤2$\overline{T}_w$
≤3mm, and $\overline{T}_w$/3
≤4$\overline{T}_w$ in any 150 weld mm weld length</td></tr>
<tr><td>H</td><td>Depth of undercut</td><td colspan="2">≤1mm, and≤4$\overline{T}_w$</td></tr>
<tr><td>J</td><td>Surface roughness</td><td colspan="2">≤ 500 min. Ra per ASME B46.1</td></tr>
<tr><td>K</td><td>Depth of root surface concavity</td><td colspan="2">Total joint thickness, incl. weld reinf., ≥$\overline{T}_w$</td></tr>
<tr><td rowspan="5">L</td><td rowspan="5">Height of reinforcement or internal protrusion [7] in any plane through the weld is to be within limits of the applicable height value in the tabulation at right. Weld metal is to merge smoothly into the component surfaces.</td><td>For $\overline{T}_w$ mm</td><td>Height, mm</td></tr>
<tr><td>≤6</td><td>≤1.5</td></tr>
<tr><td>>6，≤13</td><td>≤3</td></tr>
<tr><td>>13，≤25</td><td>≤4</td></tr>
<tr><td>>25</td><td>≤5</td></tr>
</table>

Notes:

[1] Criteria given are for required examination. More stringent criteria may be specified in the engineering design.

[2] Longitudinal groove weld includes straight and spiral seam.

[3] Fillet weld includes socket and seal welds, and attachment welds for slip-on flanges, branch reinforcement, and supports.

[4] Branch connection weld includes pressure containing welds in branches and fabricated laps.
[5] These imperfections are evaluated only for welds 5 mm in nominal thickness.
[6] Where two limiting values are separated by and, the lesser of the values determines acceptance. Where two sets of values are separated by or, the larger value is acceptable. $\overline{T_w}$ is the nominal wall thickness of the thinner of two components joined by a butt weld.
[7] For groove welds, height is the lesser of the measurements made from the surfaces of the adjacent components. Both reinforcement and internal protrusion are permitted in a weld. For fillet welds, height is measured from the theoretical throat.

8.3.11.2 The minimum extent of non-destructive testing (NDT) is to be in accordance with the requirements of Table 8.3.11.2.

Piping NDT range Table 8.3.11.2

Pipe class	Weld type [4]	Visual inspection	Radiographic test	Magnetic particle/penetrant test
Pressure rating no higher than PN20 and temperature no higher than 185℃[1]	Longitudinal weld	100%	10%	10%
	Circumferential weld	100%	5%	5%
	Fillet weld	100%	-	10%
Pressure rating no higher than PN50[2]	Longitudinal weld	100%	20%	20%
	Circumferential weld	100%	10%	10%
	Fillet weld	100%	-	100%
Pressure rating higher than PN50[3]	Longitudinal weld	100%	100%	100%
	Circumferential weld	100%	100%	100%
	Fillet weld	100%	-	100%

Notes:

[1] Piping and components for non-flammable, non-toxic medium service. Pressure rating no higher than PN20, upper temperature limit 185℃;

[2] Utility and process piping having a pressure rating no higher than PN50;

[3] Utility and process piping having a pressure rating higher than PN50 or working under severe cyclic conditions;

[4] Longitudinal weld: including spiral weld; Circumferential weld: including stub-in and butt-welded joints; Fillet weld: including the fillet welds of outlets, reinforcement ring, etc.

8.3.11.3 The acceptance criteria for imperfection NDT are also to be in accordance with acceptable codes and standards for piping design and fabrication.

8.3.11.4 Ultrasonic examination may be used in lieu of radiography where impracticable and where radiography does not give definitive results.

8.3.11.5 Magnetic particle inspection is used to detect surface defects while penetrant test is used to detect surface defects of non-ferromagnetic materials.

8.3.11.6 Visual inspection of fabricated components, spools etc. are cover both fabrication, welding, erection and assembly. The inspection points to be covered during fabrication, erection and assembly are to be defined in the clients' procedures and are to be sufficiently extensive to ensure that code requirements and design intent are incorporated during fabrication.

8.3.11.7 The final NDT is usually performed after heat treatment where post weld heat treatment is required.

8.3.11.8 The final NDT is to be performed before any process that would make the required NDT impossible or would have erroneous results as a consequence (e.g., coating of surfaces).

8.3.11.9 All performed examination and results are to be recorded systematically for traceability.

8.3.11.10 The mechanical tests of weldments are to be performed by qualified personnel according to the applicable standards, and the documented test records are to be confirmed by the surveyor.

8.3.11.11 Weldments of piping and equipment for H_2S service are to be hardness tested according to ANSI/NACE MR0175.

8.3.12 General requirements for pressure test

8.3.12.1 Pressurized piping is to be able to withstand the test pressure specified in the Rules and other relevant standards and codes recognized by the Society.

8.3.12.2 The pressure holding time of pressure test is to be no less than 10 minutes or in accordance with the requirements of the applicable standard or code. The pressure holding time is to be long enough to allow thorough inspection after the pressure is stabilized.

8.3.12.3 The pressure and duration of the test, such as pressure test curves, are to be recorded and documented for review.

8.3.12.4 During the test, the nominal stress of the piping is not to exceed 90% of the yield strength of the piping material.

8.3.13 Hydrotest

8.3.13.1 Hydrotest at 1.5 times of design pressure is to be carried out after the piping system has been accepted through inspection upon completion of installation. When the design temperature is higher than the test temperature, the minimum test pressure is to be calculated as per the following formula but S_T/S cannot be greater than 6.5.

$$P_T = \frac{1.5PS_T}{S}$$

Where:

P_T ——Minimum test pressure

P ——Design pressure

S_T ——Stress at test temperature

S ——Stress at design temperature

However, in any case, it is to be ensured that the stress generated at the test pressure and temperature is no greater than the yield strength of the material at test temperature.

8.3.13.2 Clean fresh water is usually used for hydrotest and other liquids may also be used where the production process presents any special requirement. Where use of flammable fluid is intended, the flash point of such fluid is to be no less than 66℃.

8.3.13.3 When water is used for hydrotest of items of Austenitic stainless steel, the chlorine iron content of the test water is to be no higher than 25 mg/L.

8.3.13.4 The requirements on liquid temperature at the time of test are as follows:

(1) No less than 5℃ for non-alloy steel and low-alloy steel piping;

(2) No less than 15℃ and higher than the ductile-brittle transition temperature of the corresponding metal material for high-alloy steel piping.

8.3.13.5 Isolation of equipment during hydrotest

(1) A system to be hydrotested is to be isolated from the following equipment:

① Pumps, turbines and compressors;

② Rupture discs and safety valves;

③ Rotor flowmeters and displacement flowmeters.

(2) The following equipment is to be tested to the design pressure and then isolated:

① Indicating pressure gauges, when the test pressure will exceed the scale range;

② External float type level shutdown devices and controllers, when the float is not rated for the test pressure. The float is to be subjected to design pressure; then the float chambers to be isolated from the system.

(3) Check valves are to be held open and block and bleed ball valves are to be in the one-half open position during testing.

8.3.13.6 Measures are to be taken to displace the air in the system prior to the hydrotest.

8.3.13.7 During hydrotest, the pressure is to be applied slowly and once a given pressure is reached, the pressurization is to be stopped for inspection and to be continued if there is no problem. When the pressure reaches the test pressure, the pressure is to be held for at least 10 minutes and a thorough inspection of the tested system is to be carried out, and the strength test is considered acceptable if there is no abnormal condition. The pressure is to be held for 30 minutes when the pressure is lowered slowly to the design pressure, and the tightness test is considered acceptable if there is no abnormal condition.

3.1.13.8 In order to ensure internal cleanness, the piping system and vessel to be hydrotested are to be flushed prior to the test and the water supply line is to be confirmed free of any internal debris. The piping system is to be reinstated and system integrity is to be assured after flushing is completed.

8.3.13.8 Hydrotest of piping with vessel as one system

(1) If the test pressure of the piping connected to the vessel is lower than or equal to that of the vessel, the piping and vessel can be tested together at the test pressure of the piping.

(2) Where the piping test pressure is higher than the vessel test pressure and it is not practicable to isolate the piping from the vessel, the piping and vessel can be tested together at the vessel test pressure provided that the vessel test pressure is no less than 77% of the piping test pressure calculated as per the formula in 8.3.13.1.

8.3.14 Air tightness test

8.3.14.1 Air tightness test can be performed where hydrotest is not appropriate, for example, the tests of instrument air, heating liquid, and refrigerating systems. Special preventative measures and monitoring are to be made available during air tightness test as such test tends to cause unsafe factors. Only air or nitrogen gas (whether tracer is used or not) can be used as the test medium. The size of each test system is to be minimized.

8.3.14.2 In general, the test pressure is 1.1 times of the maximum design pressure or 700 kPa, whichever is smaller. Where the test pressure needs to be higher than the above mentioned values as necessitated by the specific requirements of the project, adequate safety measures and an emergency response plan are to be made available for the test, and the test can be carried out only after the test program has been submitted to the Society for review. In order to prevent the risks of brittle rupture, the minimum metal temperature of all components is to be no less than 15.6C during the test.

8.3.14.3 During the test, the pressure is to be gradually increased not more than 175 kPa and held until all joints have been inspected for leaks with soap solution. If no leaks are found, the pressure is to be increased in increments of approximately 105kPa until the final test pressure is reached. The pressure should then be reduced to 90% of test pressure, and held for a sufficient length of time to permit inspection of all joints, welds, and connections with soap solution.

8.3.14.4 Where hydrotest and air tightness test are not practicable, the following measures or other measures specified in the Society's Rules are to be taken as an alternative:

(1) All welded joints subject to pressure in the piping system are to be 100% radiographic tested;

(2) The welded joints not subject to pressure (such as connection welds of structures) are to be inspected by penetrant test or magnetic particle inspection;

(3) Flexibility analysis of piping systems has been to be performed.

CHAPTER 9 MAIN EQUIPMENT

SECTION 1 GENERAL PROVISIONS

9.1.1 Scope

9.1.1.1 The requirements in this Chapter are applicable to the general equipment of oil and gas process system. The equipment includes:

(1) Pressure vessel;

(2) Atmospheric pressure vessel;

(3) Heat exchanger;

(4) Pump;

(5) Compressor;

(6) Wellhead equipment.

9.1.1.2 The equipment of offshore oil and gas process system is to be designed, manufactured, installed and tested according to the recognized codes and standards in this Chapter.

9.1.1.3 For equipment not specified in this Chapter, the corresponding requirements are to be determined on a case-by-case basis and agreed with the involved parties. Where possible, the standards recognized by the Society may be used as the supplementary requirements to the Rules.

9.1.2 Design conditions

The equipment of offshore oil and gas process system is to be designed taking into account all applicable environmental, operational and test loads or their combined effects. These loads include but are not limited to:

(1) Environmental load

① Earthquake;

② Wind;

③ Snow;

④ Temperature;

(2) Operational load

① Static pressure;

② Bending;

③ Instantaneous pressure fluctuation;

④ Vibration;

⑤ Temperature fluctuation;

⑥ Inertia force produced by offshore installation movement;

⑦ Hydrostatic head;

⑧ Tension.

(3) Loads generated during equipment transport

(4) Loads generated during equipment installation

(5) Loads generated during commissioning

(6) Test load

SECTION 2 PRESSURE VESSEL AND HEAT EXCHANGER

9.2.1 General requirements

9.2.1.1 Pressure vessels are to be designed, manufactured and tested in accordance with the listed standards. It can also be considered acceptable that the pressure vessels are designed, manufactured and tested according to other standards, and a safety level equivalent to that specified in the standards listed in 9.2.2 has been achieved.

9.2.1.2 All pressure vessels are to be adequately supported and fixed.

9.2.1.3 In addition to the design loads listed in 9.1.2, the design is also to ensure, where applicable, that the stress on the vessels which is generated by the external loads such as the force applied by the piping to the vessel, the inertia force generated by offshore installation movement and wind loads is within the allowable range specified in the recognized standards listed in 9.2.2.

9.2.2 Accepted standards

Accepted standards for pressure vessels and heat exchangers are as follows:

(1)	GB/T 150	Pressure Vessels
(2)	GB/T 151	Tube and Shell Heat Exchangers
(3)	NB/T 47013	Non-destructive Testing of Pressure Equipment
(4)	JB/T 4730	Non-destructive Testing of Pressure Equipment
(5)	JB/T 4731	Steel Horizontal Vessels
(6)	JB 4732	Steel Pressure Vessels Design by Analysis
(7)	JB/T 4710	Steel Vertical Vessels supported by skirt
(8)	NB/T 47004JB/T4752	Plate-type heat exchangers
(9)	PD 5500	Specification for Unfired Fusion Welded Pressure Vessels
(10)	ASME	Boiler and Pressure Vessel Code
(11)	EN 13445	Unfired Pressure Vessels
(12)	TEMA	Standard for Heat Exchangers
(13)	API SPEC 12J	Specification for Oil and Gas Separators

9.2.3 Material

Low melting points material or brittle materials such as cast iron, aluminum, brass, and bronze or glass fiber are not to be used to make the pressurized components of pressure vessels containing flammable or toxic fluids.

9.2.4 Thermal considerations

The support and heat insulation layer of a vessel are to be designed taking into account vessel deformation caused by temperature changes of the medium contained in the vessel.

9.2.5 Heat exchanger

9.2.5.1 Process heat exchangers with a design pressure greater than 0.1 MPa and flammable fluid as the medium are to be designed, fabricated and tested according to the requirements for pressure vessels.

9.2.5.2 Tube and shell type heat exchangers are to be designed according to GB 151 and other recognized applicable standards.

9.2.5.3 Plate type heat exchangers for flammable fluid service are to comply with the following restrictions and requirements:

(1) Safety protection devices are to be provided in accordance with the requirements in Chapter 4 of the Rules;

(2) Each exchanger is to be provided with an exchanger enclosure, protective wall, shield or similar barrier, capable of containing spray in case of gasket leakage during operation;

(3) Each heat exchanger is to be fitted with oil leakage collection and discharge device which has a capacity of no less than 10% of the maximum flow rate of flammable medium.

9.2.5.4 Air-cooled heat exchangers are to be in compliance with the applicable criteria prescribed in NB/T 47007 and other recognized standards.

9.2.6 Electric heater

9.2.6.1 Electric heaters for oil and gas processing are to be fitted with surface high temperature alarm of the heating element.

9.2.6.2 Where the vessel, tank or piping segment containing an electric heater can be isolated, a relief valve is to be provided for overpressure protection. It is to be sized for a blocked-in condition with the heater operating at full power.

9.2.6.3 Process electric heaters in liquid service are to be protected by low level, low flow, or high liquid temperature sensor to shut off electrical input.

9.2.7 Fired pressure vessel (heater)

9.2.7.1 All fire-tube type fired pressure vessels with a shell side design pressure greater than 0.1 MPa are to be designed according to Section I of ASME Boiler and Pressure Vessel Code.

9.2.7.2 Direct fired pressure vessel (heater)

The vertical or horizontal demulsifier directly exposed to fire shall be designed and and manufactured according to API Spec. 12J.

9.2.7.3 Where burner ignition or light-off is part of an automatic sequence, the following control functions are to be provided:

(1) Automatic timed purge interval prior to admitting pilot fuel. Purge is to be by fan.

(2) Firing limit on a trial for ignition on each attempted pilot light-off is maximum 15 s.

(3Confirmation of pilot lighting prior to admitting main burner fuel.

9.2.7.4 Manual ignition

(1) For manually ignited burners, the location of ignition operation is to be protected to prevent injury of operation personnel by flashback.

(2) The burner is to be fitted with sight glass in order to confirm if the ignition is successful and observe the main flame.

9.2.7.5 The combustion air of fired pressure vessels is to be taken in from non-hazardous areas.

9.2.8 Pig launcher/receiver

The shell of pig launcher/receiver is to be designed and manufactured in accordance with the recognized standards listed in 9.2.2.

(1) Isolating valve for the pressurized component is to be fitted to allow dismantling of the pressurized component when needed.

(2) Pressure relieving devices are to be fitted which is visible from the operator's position in order to confirm that the internal pressure is equal to atmospheric pressure before quick opening of the shell of pig launcher/receiver.

SECTION 3 ATMOSPHERIC PRESSURE VESSEL

9.3.1 General requirements

Atmospheric or low-pressure vessels containing flammable liquids are to be designed and manufactured according to the accepted standards listed in 9.3.2.

9.3.2 Recognized standards

Recognized standards for atmospheric pressure vessels are listed below:

(1)	API Std 650	Welded Steel Tanks for Oil Storage
(2)	BS 2554	Vertical refrigerated Storage Tanks with Butt-welded Shells for Petroleum Industry
(3)	DIN 4119	Above-ground Cylindrical Flat-bottom Tank Structures of Metallic Materials
(4)	JB/T 4735	Steel Welded Atmospheric Pressure Vessel

SECTION 4 PUMP AND COMPRESSOR

9.4.1 General requirements

Pumps and compressors for oil and gas processing are to be designed and manufactured according to the recognized standards listed in 9.4.2.

9.4.2 Recognized standards

Recognized standards for pumps and compressors are listed below:

(1)	GB/T 3215	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries
(2)	GB/T 3216	Rotodynamic Pumps-Hydraulic Performance Acceptance Tests-Grades 1 and 2
(3)	GB/T 7782	Metering Pump
(4)	ASME/ANSI B73.1	Specification for Horizontal End Suction Centrifugal Pumps for Chemical Process
(5)	ASME/ANSI B73.2	Specifications for Vertical In-line Centrifugal Pumps for Chemical Process
(6)	ISO 13709(API Std 610)	Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries
(7)	API Std 674	Positive Displacement Pumps Reciprocating
(8)	API Std 675	Positive Displacement Pumps Controlled Volume
(9)	API Std 676	Positive Displacement Pumps Rotor
(10)	API Std 617	Centrifugal Compressors for Petroleum, Chemical and Gas Industry Services
(11)	API Std 618	Reciprocating Compressors for Petroleum, Chemical and Gas Industry Services
(12)	API Std 619	Rotary-Type Positive Displacement Compressors for Petroleum, Petrochemical, and Natural Gas Industries
(13)	API Std 672	Packaged, Integrally Geared Centrifugal Air Compressors for Petroleum, Petrochemical, and Natural Gas Industries
(14)	ISO 13631	Packaged Reciprocating Gas Compressors

9.4.3 Protection of shaft seal of centrifugal pump delivering hydrocarbon liquids

Centrifugal pumps having stuffing box pressures in excess of 1.4 MPa are to be provided with either single-balanced mechanical seals with means to collect and contain seal leakage, or tandem-balanced mechanical seals with alarm, to indicate primary seal failure.

SECTION 5 WELLHEAD EQUIPMENT

9.5.1 General requirements

Wellhead equipment is to be designed and manufactured according to the recognized standards listed in 9.5.2.

9.5.2 Recognized standards

Recognized standards for wellhead equipment are listed below:

(1)	GB/T 25513	Petroleum and Natural Gas Industries - Drilling and Production Equipment Wellhead and Christmas Tree Equipment;
(2)	ISO 10423	Petroleum and Natural Gas Industries - Drilling and Production Equipment Wellhead and Christmas Tree Equipment;
(3)	ISO 10433	Petroleum and Natural Gas Industries Drilling and Production Equipment Specification for Wellhead Surface Safety Valves and Underwater Safety Valves (based on API SPEC 14D);
(4)	API Spec 6A	Specification for Wellhead and Christmas Tree Equipment;
(5)	API Spec 6FA	Specification for Fire Test for Valves;
(6)	API Spec 6FC	Specification for Fire Test for Valves with Automatic Backseats;
(7)	API Spec 6FD	Specification for Fire Test for Check Valves;
(8)	API RP 14B	Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems;
(9)	API RP 14H	Recommended Practice for Installation, Maintenance and Repair of Offshore Surface Safety Valves and Underwater Safety Valves.

9.5.3 Christmas tree

9.9.3.1 The Christmas tree is to have at least one remotely operated, self-closing master valve and a corresponding wing valve for each penetration of the tree. In addition, there is to be a closing device for each penetration at a level higher than the wing outlets.

9.9.3.2 Additional wing outlets, such as injection lines, are to penetrate the Christmas tree above the lowest remotely operated master valve, and be fitted with a remotely operated, self-closing control valve and a check valve installed as close as possible to the injection point. The injection point for hydrate inhibitor may be fitted below the lowest self-closing master valve if the Christmas tree is fitted with valve(s) below this point.

9.9.3.3 All valves in the vertical penetrations of the Christmas tree are to be capable of being opened and kept in the open position by means of an external operational facility independent of the primary actuator.

9.9.3.4 Valves that are important in connection with the emergency shutdown system such as the master and wing valves are to be fitted locally with visual position indicators.

9.5.4 Wellhead control panel

9.5.4.1 Wellhead control panel is to be suitable for the explosion-proof requirements for the area where it is installed.

9.5.4.2 The operation buttons and handles on wellhead control panel are to be provided with safety measures for prevention of accidental operations.

9.5.4.3 The shutdown function of wellhead control panel is to be connected with the fire loop detection devices to ensure prompt closure of the wells in the event of a fire happened in the wellhead area.

CHAPTER 10 UTILITY SYSTEM

SECTION 1 GENERAL

10.1.1 Introduction

10.1.1.1 For the purpose of the Rules, utility systems refer to the following systems:

(1) Diesel system (or fuel oil system);

(2) Natural gas fuel system;

(3) Crude oil fuel system;

(4) Helicopter fuel system;

(5) Lubrication oil system;

(6) Hydraulic oil system;

(7) Compressed air system;

(8) Boiler water supply, drainage and condensate system;

(9) Fresh water (including potable water) supply system;

(10) Seawater system;

(11) Exhaust gas system;

(12) Tank vent system;

(13) Tank overflow system;

(14) Tank sounding system;

(15) Open drain system;

(16) Fire water system;

(17) Gas extinguishing system;

(18) Foam extinguishing system;

(19) Water sprinkler, spray, and water mist spray system;

(20) Inert gas system.

For offshore installations with floating body, the following additional systems are included:

(1) Bilge system;

(2) Ballast system;

In addition to those above mentioned systems in connection with piping system, the following systems are also involved:

(1) Electrical, instrumentation and control system;

(2) Heating, ventilation and air conditioning system.

10.1.1.2 The main equipment associated with the utility systems includes:

(1) Power equipment, such as diesel engines, gas turbines;

(2) Unfired pressure vessels;

(3) Boilers;

(4) Pumps;

(5) Compressors;

(6) Cranes;

(7) Generators;

(8) Electric motors;

(9) Power distribution equipment.

10.1.2 General requirements

10.1.2.1 The oil and gas production main process system and auxiliary process systems are to be designed in an integrated way with utility systems. The flow diagrams and piping and instrumentation diagrams of all the systems of the offshore installation are to be designed and submitted together for review.

10.1.2.2 Utility systems are expressly specified in the Society's main rules for the offshore installation. Utility systems are to be designed, manufactured and surveyed in accordance with the provisions of the main rules for the offshore installation on which the oil and gas process system is located, or in accordance with the applicable requirements specified in the Utility System Part of the Society's Rules for Classification of Offshore Floating Units. Special attention is to be paid to the following interfaces:

(1) Open drain system is specified both in the main rules and the Rules, and is to be designed in compliance with the requirements of both rules;

(2) Natural gas fuel treatment is specified in the Rules and the safety requirements for natural gas fuel into the combustion equipment and engine room are specified in the main rules. Both rules are to be complied with;

(3) Crude oil fuel treatment is specified in the Rules and the safety requirements for crude oil fuel into the combustion equipment and engine room are specified in the main rules. Both rules are to be complied with;

(4) Instrumentation, control and shutdown systems are to be designed in accordance with the relevant provisions in both the Rules and the main rules.

10.1.2.3 The main technical requirements for utility equipment and product certification requirements are specified in the main rules. The requirements of the relevant Rules are to be complied with during design.

10.1.2.4 Fired pressure vessels directly heating oil and gas fluids and glycol reboiler are belong to processing equipment which are to be in accordance with the Rules. As this equipment involve crude oil and flammable gas, their locations are classified as hazardous areas. And this equipment is to be selected according to the applicable provisions contained in the Fire Protection and Explosion-proof Part of the Society's main rules for the offshore installation.

10.1.2.5 All mechanical equipment, electrical equipment and power cables used for oil and gas process system are to be designed and selected according to the applicable provisions contained in the Fire Protection and Explosion-proof Part of the Society's main rules for the offshore installation.