

NORSOK STANDARD

P-002

Edition 1, August 2014

Process system design

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Foreword	6
Introduction	6
1 Scope	7
2 Normative and informative references	7
2.1 Normative references	7
2.2 Informative references	8
3 Terms, definitions and abbreviations	8
3.1 Terms and definitions	8
3.2 Abbreviations	9
PART [I] – GENERAL PROCESS SECTION	10
4 Design pressure and temperature	10
4.1 General	10
4.2 Design pressure	10
4.3 Design temperature	11
5 General system design	12
5.1 Design for minimum impact of facility movement	12
5.2 Material selection	12
5.3 Maintenance and isolation	12
6 Safety requirements	13
6.1 Objectives	13
6.2 Safety analysis	13
6.3 Hazard and operability	13
6.4 Overpressure protection	14
6.5 Check valves	15
6.6 Piping	15
7 Line sizing criteria	15
7.1 General	15
7.2 Sizing of liquid lines	16
7.3 Sizing of gas lines	18
7.4 Sizing of gas/liquid two phase / multiphase lines	19
7.5 Sizing of flare and vent lines	20
8 General process equipment design	21
8.1 Horizontal separator design	21
8.2 Vertical separator design	23
8.3 Scrubber design	23
8.4 Atmospheric tank design	25
8.5 Heat exchanger design	25
8.6 Pig launcher/receiver design	29
8.7 Filters	29
9 Detailed requirements for system and equipment isolation	29
9.1 General	29
9.2 Physical separation	29
9.3 Level of isolation	30
9.4 Connections to flare, vents and closed drains	33
9.5 Operational drain, vent and flushing requirements	35
10 Insulation and heat tracing of piping and equipment	35
10.1 General	35
10.2 Heat conservation and frost protection	36
PART [II] – SYSTEM DESIGN SECTION	37
11 Topside flow lines and manifolds (system 13)	37
11.1 General	37
11.2 System design	37
11.3 Monitoring	37
11.4 Safety	37

12	Separation and stabilisation (system 20)	37
12.1	General	37
12.2	Pressure and level control	37
12.3	Test separator	37
12.4	Layout	38
12.5	Injection of chemicals	38
13	Crude handling (system 21)	38
13.1	General	38
13.2	Design requirements	38
13.3	Safety	38
14	Gas compression (systems 23, 26 and 27)	39
14.1	General	39
14.2	System design	39
14.3	Compressors	39
14.4	Safety	40
14.5	Layout	40
15	Gas treatment (system 24)	40
15.1	General	40
15.2	Glycol contactors	40
15.3	Regeneration unit and storage	41
15.4	Wet gas inlet coolers	42
15.5	Safety	42
15.6	Layout	42
15.7	Environmental requirements	42
16	Gas conditioning (system 25)	42
16.1	General	42
16.2	Heat exchangers and scrubbers	43
16.3	Turbo expander and recompressor unit	43
16.4	Design pressure and temperature	43
16.5	Layout	43
17	Water injection (system 29)	43
17.1	General	43
17.2	Filtration	44
17.3	Disinfection	44
17.4	Deoxygenation	44
17.5	Pumps	44
17.6	Chemical injection	44
17.7	Monitoring	44
18	Cooling medium (system 40)	44
18.1	General	44
18.2	Filtration	45
18.3	System operating pressure	45
18.4	Expansion tank	45
18.5	Layout	45
19	Heating medium (system 41)	45
19.1	General	45
19.2	Pumps	46
19.3	Waste heat recovery units	46
19.4	Filter	46
19.5	Expansion tank	46
19.6	Layout	46
20	Chemical injection (system 42)	46
20.1	General	46
20.2	Storage tanks	47
20.3	Drip trays and drainage	47
20.4	Injection points	47
20.5	Safety	47
20.6	Maintenance	47

21	Flare and vent (system 43)	48
21.1	General	48
21.2	Knock-out drum	48
21.3	Thermal radiation	48
21.4	Flare gas recovery systems	48
21.5	Layout	49
21.6	FPSO Considerations	49
22	Oily water treatment (system 44)	49
22.1	General	49
22.2	Produced water treatment	49
22.3	Flash drum	50
22.4	Layout	50
23	Fuel gas (system 45)	50
23.1	General	50
23.2	System design	50
23.3	Fuel gas heating	50
24	Methanol injection (system 46)	50
24.1	General	50
24.2	System design	50
24.3	Storage tank	51
24.4	Injection	51
25	Chlorination (system 47)	51
25.1	General	51
25.2	System design	51
25.3	Electrolysis cells	52
26	Sea water (system 50)	52
26.1	General	52
26.2	Pumps	52
26.3	Filters	53
26.4	Prevention of marine growth	53
26.5	Layout	53
27	Fresh water (system 53)	53
27.1	General	53
27.2	Fresh water treatment	53
27.3	Maintenance	53
28	Open drain (system 56)	54
28.1	General	54
28.2	System capacity	54
28.3	Drain tanks	54
28.4	Drilling drain	54
28.5	Maintenance	54
28.6	Layout	54
28.7	Safety	55
29	Closed drain (system 57)	55
29.1	General	55
29.2	Closed drain flash drum	55
29.3	Design temperature	55
29.4	Reclaimed oil sump	55
29.5	Reclaimed oil sump pump	55
29.6	Safety	56
30	Diesel oil (system 62)	56
30.1	General	56
30.2	Storage tanks	56
30.3	Hose loading stations	56
30.4	Day tanks	56
30.5	Maintenance	56
31	Compressed air (system 63)	56

31.1	General	56
31.2	Dehydration	57
31.3	Filtration	57
31.4	Air receiver	57
31.5	Sparing	57
31.6	Safety	57
31.7	Layout	57
32	Inert gas (system 64)	58
32.1	General	58
32.2	System design	58
32.3	Sparing	58
32.4	Operational requirements	58
33	Hydraulic power (system 65)	58
33.1	General	58
33.2	Reservoir	58
33.3	Pumps	59
33.4	Filters	59
33.5	Accumulator capacity	59
33.6	Safety	59
33.7	Maintenance	59
34	Sewage (system 66)	59
34.1	General	59
34.2	System capacity	60
34.3	Operating temperature	60
34.4	Layout	60

Foreword

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are, as far as possible, intended to replace oil company specifications and serve as references in the authorities' regulations.

The NORSOK standards are normally based on recognised international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Where relevant, NORSOK standards will be used to provide the Norwegian industry input to the international standardisation process. Subject to development and publication of international standards, the relevant NORSOK standard will be withdrawn.

The NORSOK standards are developed according to the consensus principle generally applicable for most standards work and according to established procedures defined in NORSOK A-001.

The NORSOK standards are prepared and published with support by the Norwegian Oil and Gas Association, The Federation of Norwegian Industries, Norwegian Shipowners' Association and The Petroleum Safety Authority Norway.

NORSOK standards are administered and published by Standards Norway.

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In the first print, shadow elements were displayed with some of the figures in Clause 9. They have been removed. Print format was checked and some sections were numbered due to inconsistency in the first print. No words have been changed.

Introduction

The development of this NORSOK standard is primarily based on proven technology, but it does not preclude the use of new technology. The system design sections are based on the most frequently used systems, but this does not imply that alternatives may not be used (for example dehydration by use of glycol is covered, but not the use of molecular sieves or other means).

The following changes have been made to this NORSOK standard:

- P-001 and P-100 have been combined into a single document to improve accessibility and remove redundancy.
- Content has been simplified and some superfluous text has been deleted.
- The document has been updated to reflect current industry practice and relevant international standards.
- In clause 21.2, the sizing of knock out drum with respect to liquid accumulation, has been made more consistent with international standards. The use of instrumented protection functions to allow for reduced liquid accumulation capacity requires more stringent documentation.
- API Std 521, sixth edition issued January 2014 covers acoustic fatigue in piping, sizing of flare knock-out drums, choke valve failure, water hammer and allowance for non-return valves in some depth, so these sections have been removed or edited.
- ISO 23251 and ISO 28300 have been classed as Informative in this document as they are similar to API Std 521 and API Std 2000, which have been recently updated and better reflect current thinking.
- For HAZOP studies, the recommendation to use full reporting has been removed. This is seen as being up to the individual company's standards.

The system numbers used in this NORSOK standard are those defined in NORSOK Z-DP-002.

1 Scope

This NORSOK standard provides requirements for the following aspects of topside process piping and equipment design on offshore production facilities:

- design pressure and temperature;
- safety instrumented secondary pressure protection systems;
- line sizing;
- system and equipment isolation;
- insulation and heat tracing.

These criteria are applicable for all processes, process support and utility systems.

Additionally this NORSOK standard defines the minimum functional requirements for process systems on an offshore installation. The standard includes a number of recommendations to give additional guidance for the system design.

2 Normative and informative references

The following standards include provisions and guidelines which, through reference in this text, constitute provisions and guidelines of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided it can be shown that they meet the requirements of the referenced standards.

2.1 Normative references

API 2000,	<i>Venting Atmospheric and Low-pressure Storage Tanks</i>
API RP 14C	<i>Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms</i>
API RP 170	<i>Recommended Practice for Subsea High Integrity Pressure Protection Systems</i>
API Std 520	<i>Sizing, Selection and Installation of Pressure-relieving Devices in Refineries</i>
API Std 521	<i>Pressure-relieving and Depressuring Systems</i>
API Std 537	<i>Flare Details for General Refinery and Petrochemical Service, Second Edition</i>
BS MA-18	<i>Salt water piping systems in ships</i>
DNV-OS-E201	<i>Oil and Gas Processing Systems</i>
EN 1473	<i>Installation and equipment for liquefied natural gas – Design of onshore installations</i>
FOR-1994-02-10-123,	<i>Norwegian Maritime Directorate (NMD): Forskrift for flyttbare innretninger med produksjonstekniske installasjoner og utstyr</i>
IEC 61508,	<i>Functional safety of electrical/electronic/programmable electronic safety related systems</i>
IEC 61882	<i>Hazard and operability studies (HAZOP studies) – Application guide</i>
IEC 61511 (All parts)	<i>Functional safety – Safety instrumented systems for the process industry sector</i>
ISO 4126	<i>Safety devices for protection against excessive pressure</i>
ISO 10418 (All parts)	<i>Petroleum and natural gas industries – Offshore production installations – Basic surface process safety systems</i>
ISO 12241	<i>Thermal insulation for building equipment and industrial installations – Calculation rules</i>
ISO 13628-6	<i>Petroleum and natural gas industries – Design and operation of subsea production systems – Part 6: Subsea production control systems</i>
ISO 13702	<i>Petroleum and natural gas industries – Control and migration of fires and explosions on offshore production installations – Requirements and guidelines.</i>
ISO 13703	<i>Petroleum and natural gas industries – Design and installation of piping systems on offshore production platforms</i>
ISO 25457	<i>Petroleum, petrochemical and natural gas industries – Flare details for general refinery and petrochemical service.</i> NOTE This standard is similar to API Std 537.
NORSOK I-104	<i>Fiscal measurement system for hydrocarbon gas</i>
NORSOK I-105	<i>Fiscal measurement systems for hydrocarbon liquid</i>
NORSOK M-001	<i>Materials selection</i>
NORSOK R-001	<i>Mechanical equipment</i>
NORSOK R-004	<i>Piping and equipment insulation</i>

NORSOK S-001	<i>Technical safety</i>
NORSOK S-002	<i>Working environment</i>
NORSOK H-003,	<i>Heating, ventilation and air conditioning (HVAC) and sanitary systems</i>
NORSOK S-003,	<i>Environmental care</i>
NORSOK Z-DP-002,	<i>Coding System</i>
KS	<i>Standard abonnementsvilkår for vann og avløp – Tekniske bestemmelser</i>
TEMA,	<i>Standards of Tubular Exchanger Manufacturers Association</i>
Water Report 120	<i>Safe, Sufficient and Good Potable Water Offshore.</i> <i>A guideline to design and operation of offshore potable water systems</i>

2.2 Informative references

API RP 2210,	<i>Flame Arrestors for Vents of Tanks Storing Petroleum Products</i>
API RP 576,	<i>Inspection of Pressure-relieving Devices</i>
GPSA,	<i>Engineering Data Book, Gas Processors Suppliers Association</i>
ISO 23251	<i>Petroleum, petrochemical and natural gas industries – Pressure-relieving and depressuring systems.</i> NOTE This standard is similar to API Std 521.
ISO 28300	<i>Petroleum, petrochemical and natural gas industries – Venting of atmospheric and low-pressure storage tanks</i> NOTE This standard is similar to API Std 2000.
Norwegian Oil and Gas guideline 070,	<i>070 Guidelines for the Application of IEC 61508 and IEC 61511 in the petroleum activities on the continental shelf</i>

3 Terms, definitions and abbreviations

For the purposes of this NORSOK standard the following terms, definitions and abbreviations apply.

3.1 Terms and definitions

3.1.1

can

verbal form used for statements of possibility and capability, whether material, physical or casual

3.1.2

design pressure

pressure, together with the design temperature, used to determine the minimum permissible thickness or physical characteristic of each component as determined by the design rules of the pressure design code

NOTE The design pressure is selected by the user to provide a suitable margin above the maximum operating pressure at coincident temperature.

3.1.3

maximum operating pressure

maximum pressure including plant operation at unstable conditions

NOTE Unstable conditions include start-up/shutdown, control requirements and process upsets.

3.1.4

maximum operating temperature

maximum temperature including plant operation at unstable conditions

NOTE Unstable conditions include start-up/shutdown, control requirements and process upsets.

3.1.5

may

verbal form used to indicate a course of action permissible within the limits of this NORSOK standard

3.1.6**minimum operating temperature**

minimum temperature including plant operation at unstable conditions

NOTE Unstable conditions include start-up, shutdown and depressurizing.

3.1.7**operating pressure**

pressure during normal operation, including normal variations

3.1.8**operating temperature**

temperature during normal operation, including normal variations

3.1.9**settle out pressure**

pressure equilibrium after a compressor shutdown

3.1.10**shall**

verbal form used to indicate requirements strictly to be followed in order to conform to this NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties

3.1.11**should**

verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required

3.1.12**shut-in pressure**

pressure for pumps and compressors determined by the curves for a “no flow” situation, i.e. blocked outlet

3.2 Abbreviations

CCR	central control room
CS	carbon steel
ESD	emergency shutdown
FB	full bore
GOR	gas oil ratio
GRP	glass fibre reinforced polyester
HAZOP	hazard and operability
ID	internal diameter
LAHH	level alarm high high (trip level)
LALL	level alarm low low (trip level)
LO	locked open
NPSH	net positive suction head
PAH	pressure alarm high
PAHH	pressure alarm high high (trip pressure)
PCHE	printed circuit heat exchanger
PSD	process shutdown
PSV	pressure safety valve
SS	stainless steel

PART [I] – GENERAL PROCESS SECTION

4 Design pressure and temperature

4.1 General

Where pressure relief devices are used, set points for these shall be in accordance with the design code applied for the components in the system.

4.2 Design pressure

4.2.1 Maximum design pressure

For systems protected by a PSV, the criteria in Table 4.1 should be applied unless the PSV manufacturer guarantees that use of other margins is acceptable. The minimum margin is defined to avoid unintentional PSV opening. The relation between high trip pressure and maximum operating pressure is given in Figure 4.1.

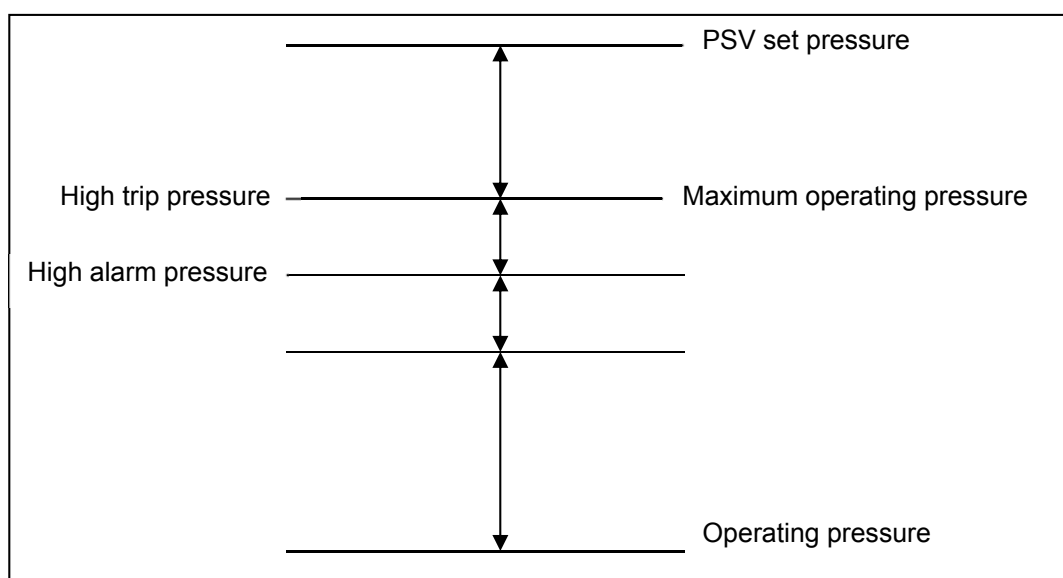


Figure 4.1 – Pressure relations

Table 4.1 – Design pressure criteria for pressurised systems

Maximum operating pressure (barg)	Design pressure (barg)
0-35	Maximum operating pressure +3.5 bar
35-70	Maximum operating pressure +10%
70-200	Maximum operating pressure +8.5% but minimum 7 bar and maximum 10 bar
200 +	Maximum operating pressure + 5%

The limitations given in Table 4.1 are to ensure proper operation of the PSV. As shown in API std 520, valves will begin to simmer at around 98 % of set pressure and reseal at about 92 % of set pressure. The guidelines above will be correct if PAHH is taken as maximum operating pressure, giving some conservatism to PAH. System dynamics may require more conservatism.

When rupture disks are applied, sufficient margin shall be included to

- prevent unintentional disk ruptures, i.e. margin between the disk set pressure and the operating pressure,
- ensure system pressure protection, i.e. margin between the disk set pressure and the maximum accumulated overpressure.

The use of double rupture disks in series to avoid variations in pressure in the flare system affecting the effective set pressure for the (first) rupture disk should be considered.

Reference is made to relevant pressure relieving design codes for further guidance.

When accurate information is unavailable, the shut-in pressure for centrifugal compressors should be determined as the maximum operating suction pressure +1,3 times the normal head developed by the compressor, to include for pressure rise at surge condition and maximum speed. The maximum operating suction pressure for a compressor shall in this case be determined by the high trip pressure from upstream separators or compressors.

When accurate information is unavailable, the maximum operating pressure (shut-in pressure) for centrifugal pumps should be determined as the suction pressure at relieving conditions +1,25 times the normal differential pressure developed by the pump

Care should be taken not to define higher design pressure than required when it affects the selection of material and pressure class rating.

To minimise the requirements for process relief (full flow) the design pressure should be kept identical for systems with almost identical operating pressures.

For piping, occasional variations in the pressure above the design pressure is permissible in some design codes. This shall be subject to due consideration of all aspects in the relevant piping design code. If such variations are permitted by the project owner, the duration and extent of overpressure that the piping is subjected to shall be logged. Logging is not considered required if it can be documented that overpressure will not occur.

Atmospheric tanks shall as a minimum be designed to be liquid filled to the highest point of the overflow line, and with an overpressure of 0,07 bar. If the overflow line can be blocked or have reversed flow (e.g. during loading) the atmospheric tank shall be designed for a liquid filled vent line up to the goose neck. Reference is made to ISO 28300 / API 2000 for further guidance.

For flare knock out drums, it is acceptable that the design pressure is equal to the maximum operating pressure. A safety margin shall be added to the maximum operating pressure in the design phase to account for increase due to uncertainties in the calculations. When accurate information is unavailable, the maximum backpressure that can be imposed by the flare tip at maximum design load shall be used as a minimum.

4.2.2 Minimum design pressure

For equipment where cooling or condensing vapours (e.g. after steam-out of vessels), drainage or pump out may lead to less than atmospheric pressure, the equipment shall be designed for full vacuum or protected by vacuum relief. Reference is made to API Std 521 or ISO 23251 for further guidance.

4.3 Design temperature

4.3.1 General

The guidelines given in this standard for temperature are based on operation in the Norwegian sector. Consideration should be taken that the equipment or system may be constructed or used elsewhere and that higher temperatures may be experienced due to solar radiation. Consideration should also be taken for the possibility of higher temperatures during flare operation.

4.3.2 Maximum design temperature

Where the maximum operating temperature can be determined accurately, this temperature should be used as maximum design temperature, without adding a safety margin. As an example, this can apply to the use of reservoir temperature as maximum design temperature for platform inlet facilities.

Where the maximum operating temperature cannot be calculated accurately, the maximum design temperature should be determined by adding 30 °C to the normal operating temperature. For equipment operating at ambient conditions, the maximum design temperature should be limited to 50 °C in the Norwegian sector.

A high temperature shut down function, in accordance with ISO 10418 or API RP 14C, can limit the maximum operating temperature.

Care should be taken not to define higher design temperature than required as it may affect the selection of material, pressure class rating and layout.

Vessels and instruments subject to steam-out shall be designed for coincidental temperature and pressure during steam-out operation.

Specific recommendations for individual systems are included in the system design sections.

4.3.3 Minimum design temperature

The minimum design temperature determines the requirements to the low temperature characteristics of the material, and shall be the most stringent of the following:

- minimum operating temperature (obtained during normal operation, start-up, shutdown or process upsets) with a margin of 5 °C;
- minimum ambient temperature, the lowest temperature should be based on available weather data, and safety factors should be selected based on the quality of such weather data;
- minimum temperature occurring during depressurising with a margin of 5 °C, the temperature calculations shall as a minimum include heat transfer between fluid and vessel, and the most conservative starting conditions for depressurising shall be used including the following considerations as a minimum:
 - o cool down to minimum ambient temperature after shut-in at PSV set pressure and corresponding temperature (including reduction in pressure during cool down);
 - o conditions during a start-up operation following a depressurisation;
 - o minimum operating temperature and maximum operating pressure.

The minimum design temperature may be limited by initiating depressurisation at a higher temperature than the minimum ambient temperature. If implemented, this shall be subject to project owner approval, and be addressed in documentation for operation.

The minimum design temperature may be limited by delaying start-up (to heat the system prior to start-up). If implemented, this shall be subject to project owner approval, and be addressed in documentation for operation.

5 General system design

5.1 Design for minimum impact of facility movement

Design criteria for floating installations shall take into account movements and accelerations under which the process facility is required to operate. Any limitations shall be specified in the engineering documentation.

5.2 Material selection

All chemical components and their concentrations in the fluid in all services shall be specified to ensure correct material selection. Certain chemicals (e.g. methanol) are aggressive against gasket materials and titanium and require special considerations. Refer to NORSOK M-001.

5.3 Maintenance and isolation

It shall be possible to isolate pumps and clean the suction strainer without draining upstream tank/vessels. Provision shall be made for withdrawal of sump pumps during operation of the system without loss of blanket or purge gas and minimizing liquid flashing to atmosphere, e.g. by use of a well inside the tank.

Bypass piping should be considered installed across heaters, coolers, filters and coalescers.

Utility stations shall be located to enable flushing of all drip trays and mechanical equipment.

6 Safety requirements

6.1 Objectives

The goal of process safety system design is

- to protect personnel, the environment, and the facility from risks caused by the production process,
- to prevent the release of hydrocarbons or high pressure or toxic fluids from the process, and to minimize the adverse effects of such releases if they occur,
- to shut in the process or affected part of the process to stop the flow of hydrocarbons to a leak or overflow if it occurs,
- to prevent ignition of released hydrocarbons,
- to shut in the process in the event of a fire,
- to prevent undesirable events that could cause the release of hydrocarbons from equipment other than that in which the event occurs.

These objectives are met by a combination of the process safety functions (Process Shutdown System (PSD) and secondary safety devices) and Emergency Shutdown System (ESD), which shall be independent of each other. ESD requirements are specified in NORSOK S-001.

6.2 Safety analysis

The following systems shall be designed in accordance with ISO 10418/API RP 14C and the shutdown functions shall be realised in the PSD system:

- all hydrocarbon containing systems in wellhead and main process (system 13, 20 to 39, except 34);
- flare (system 43);
- oily water treatment (system 44) including injection of produced water (system 29);
- fuel gas (system 45);
- methanol injection (system 46);
- hazardous open drain (system 56);
- closed drain (system 57);
- jet fuel (system 61);
- diesel oil (system 62).

Design in accordance with ISO 10418/API RP 14C shall also be considered for other systems that involve hazards due to

- flammability/flash point,
- temperature,
- pressure,
- volatility,
- toxicity,
- fluid content/volume.

6.3 Hazard and operability

HAZOP studies shall be carried out in accordance with IEC 61882.

HAZOP shall as a minimum include the systems covered by ISO 10418/API RP 14C as defined in 6.2 including equipment packages and non-hazardous open drain (system 56). Additional systems and equipment packages may require a HAZOP analysis.

The team shall be as small as possible consistent with the relevant technical and operating skills and experience being available. The number of participants shall be limited to ensure an efficient HAZOP process. For description of roles and responsibilities, including the requirement for an independent study leader, see IEC 61882.

The documentation shall be in accordance with requirement in IEC 61882.

6.4 Overpressure protection

6.4.1 General

Overpressure protection shall be in accordance with the recommendations in ISO 10418/API RP 14C, for systems as defined in 6.2. All scenarios as described in ISO 23251/API Std 521 shall be covered. A risk based design approach shall not be used to eliminate any of these standard scenarios. The existence of other credible scenarios shall be evaluated. Instrumented secondary pressure protection systems may be used, as covered in subclause 6.4.2.

The low pressure side of a shell and tube heat exchanger shall be protected against overpressure in case of a sudden tube rupture. For further guidance, see ISO 23251/API Std 521.

Pressure protection of expansion tanks may require careful consideration, as all relief scenarios for the serviced system may also be relevant for the expansion tank. This includes scenarios such as heat exchanger internal failure, tube rupture with subsequent liquid displacement and gas blow-by. These potential causes of overpressure shall be taken into account when determining the design pressure of the expansion tank and when sizing the relief devices or vessel vent.

6.4.2 Relief devices

Location of relief devices and design of inlet and outlet piping should be in accordance with ISO 10418, ISO 23251, ISO 4126, API Std 521 and API Std 520.

Design of pilot operated relief valves used in dirty service (typically well-stream and hydrate forming fluids) shall include compensatory measures due to the risk of clogging impulse lines and/or the pilot.

For pumps with internal pressure relief capability, a dedicated external relief device shall be installed if the internal relief device is not designed and located such that maintenance and testing is possible.

6.4.3 Safety instrumented secondary pressure protection systems

6.4.3.1 General

Mechanically based pressure protection systems (e.g. PSV) shall be the preferred solution for secondary pressure protection.

Use of safety instrumented secondary pressure protection systems shall be based on acceptance criteria for overall system integrity, and shall be limited to the following applications:

- as a replacement for PSVs to protect pipelines against overpressure. The pressure specification break shall be downstream the pipeline riser valve. Where leakage or other flow from upstream system through valves in the safety instrumented system may be crucial to the integrity of the downstream system, a PSV shall be installed to prevent overpressure. The valve leakage rate shall be based on relevant experience and consideration of valve damage scenarios;
- to reduce the relief design rate by avoiding simultaneous flaring from parallel equipment/equipment trains. The safety instrumented system is for pressure protection of the flare system only;
- to reduce the relief design rate for process equipment and piping where multiple feeds (each with instrument loops to protect the equipment by shutting off the feed) enter the same equipment. Overpressure protection of the equipment/piping then depends on the safety instrumented system.

The relief design rate shall as a minimum be based on instrument loop failure for the largest feed. However, acceptance criteria for overall system integrity may require more failures to be included. This relief rate shall be accommodated within the flare system design pressure. Similarly, flare radiation for this relief rate should meet the radiation criteria in API Std 521.

Acceptance criteria for frequency of rupture of the protected equipment and piping (i.e. due to pressure exceeding test pressure) as defined in NORSOK S-001 shall be applied.

Safety instrumented secondary pressure protection systems shall be designed in accordance with IEC 61508 and IEC 61511, API RP 170 and API Std 521 Annex E. Norwegian Oil and Gas guideline 070 can be used as guidance in the application of IEC 61508/61511 standards.

Special consideration shall be given to the design of the safety instrumented system due to the potential for erosion problems, hydrate formation, fluid viscosity, wax content, etc. Common mode failures (e.g. loss of heat tracing), shall be considered.

The design pressures shall allow for “water hammering” effects caused by valve closure, in particular for liquid service.

6.4.4 Instrumentation for shutdown purposes

Instrumentation with input to PSD, ESD or other autonomous protection systems (ref. subclause 6.4.2), shall be regarded as safety critical. A system shall be established and maintained in order to ensure that manual valves on impulse lines are secured in open position. Transmitters are preferred rather than switches as they can be monitored, reducing undetected failure rates.

6.5 Check valves

When two check valves are installed in series to prevent overpressure by reverse flow, leakage shall be regularly tested, e.g. by monitoring of the intermediate pressure. Design shall cater for the testing of each valve for double check valves. For more guidance, see API Std 521/ISO 23251.

If credit is taken for check valves in determining required relief flow, the check valves shall be tagged, defined as safety critical and included in a maintenance program.

6.6 Piping

Hydrocarbon piping through non-hazardous area should be avoided. Where this is unavoidable, the pipes shall be welded and the use of flanges (e.g. for connection to turbine fuel gas) minimised.

7 Line sizing criteria

7.1 General

When sizing piping, the following constraints shall be addressed:

- required capacity/available driving pressure;
- flow induced forces;
- noise/vibration;
- pressure surges;
- material degradation – erosion, corrosion, cavitation;
- liquid accumulation/slug flow;
- sand accumulation.

Line sizing criteria in the sub clauses below shall be adhered to for design of new installations. For modification of existing installations, additional considerations shall be given to life cycle cost, and increased velocity and/or pressure drop may be accepted if mechanical integrity can be documented, e.g.

$\rho V^2 > 200\,000 \text{ kg/ms}^2$ for a line in the flare system.

In general, sizing of lines should be in accordance with ISO 13703.

7.1.1 Permissible pipe sizes

A minimum size of DN 50 (2 in) should in general be used for all process, process support and utility piping to ensure adequate mechanical integrity, particularly for connections to vessels. Smaller piping can be used where protection and/or support is provided to withstand human activity and where small volume flows make the use of small piping a requirement.

Minimum size for the sewage and open drain header shall be DN 100 (4 in) and sub-headers DN 80 (3 in). Overflow from atmospheric tanks shall as a minimum be equal to the largest inlet pipe.

Tubing may be used for air, hydraulic oil and other non-combustible/non-hazardous fluids.

7.1.2 Pipe roughness

For all calculations of pressure drop, the following pipe roughness values should be used:

Carbon steel (CS) non-corroded:	0,05 mm
Carbon steel (CS) corroded:	0,5 mm
Stainless steel (SS):	0,05 mm
Titanium and Cu-Ni:	0,05 mm
Glass fibre reinforced polyester (GRP):	0,02 mm
Polyethylene, PVC:	0,005 mm
Flexible hose:	vendor to be consulted (see NOTE)

NOTE As a rough estimation, ID/20 mm can be used (ID is the internal diameter in inches) for steel carcass and 0,005 mm for plastic coating.

7.2 Sizing of liquid lines

7.2.1 Velocity limitations

The velocities shall in general be kept low enough to prevent problems with erosion, water-hammer pressure surges, noise, vibration and reaction forces. In some cases a minimum velocity is required.

Table 7.1 – Recommended maximum velocities for sizing of liquid lines

Fluid	Maximum velocities (m/s)			
	CS	SS/Titanium	CuNi ^c	GRP
Liquids	6	^b	3	6
Liquids with sand ^d	5	7	NA	6
Liquids with large quantities of mud or silt ^d	4	4	NA	NA
Untreated seawater ^a	3	7	3	6
Deoxygenated seawater	6	^b	3	6

^a For pipe less than DN 200 (8 in), see BS MA-18 for maximum velocity limitations.
^b For stainless steels and titanium the maximum velocity is limited by system design (available pressure drop/reaction forces). 7 m/s may be used as a typical starting value for sizing.
^c Minimum velocity for CuNi is 1,0 m/s.
^d Minimum velocity for liquids with sand should be in accordance with ISO 13703.

When the service is intermittent, the velocity can be increased to 10 m/s. For CuNi the maximum velocity is 6 m/s to 10 m/s depending duration and frequency of operation.

7.2.2 Centrifugal pump suction and discharge lines

The suction piping shall be sized based on NPSH requirements. Maximum velocity from Table 7.1 and the following maximum pressure drops should be used:

sub-cooled liquids: 0,25 bar/100 m;
boiling liquids: 0,05 bar/100 m.

The fluid temperature shall be at least 15 °C below the fluid boiling point temperature to allow sizing based on the criterion for sub-cooled liquids.

The maximum velocity in the discharge piping is given in Table 7.1. As a guideline, a pressure drop of up to 0,9 bar/100 m may be used.

7.2.3 Reciprocating pump suction and discharge lines

For reciprocating pumps, the piping shall be sized based on ISO 13703.

7.2.4 Control valve inlet lines liquid service

Control valve inlet lines shall be sized such that single phase liquid is maintained.

7.2.5 Liquid flowing by gravity

7.2.5.1 General

Lines flowing by gravity includes tank overflows, drains (sanitary, closed and open drains), and other lines where the liquid flows due to gravity forces instead of pressure difference. Generally, for fixed installations, a minimum downward slope of 1:100 shall be used. However, with mud and/or sand, the slope shall be at least 1:50. On floating installations the slopes shall be evaluated according to planned installation trim.

Pipes that are running full, and do not require a minimum downward slope to avoid particle deposition, shall be sized according to the total available static pressure head, and the maximum allowable velocities for liquid lines.

7.2.5.2 Near horizontal lines

Near horizontal pipes not running full shall be sized based on the maximum flow capacities as given in Table 7.2.

Table 7.2 – Flow capacity – Near horizontal pipes

Diameter mm (in)	Liquid flow capacity (see NOTE) m ³ /h	
	Slope 1:50	Slope 1:100
50 (2)	3,7	2,6
80 (3)	9,9	6,9
100 (4)	24	17
150 (6)	70	49
200 (8)	150	106
250 (10)	271	192
300 (12)	441	312
350 (14)	665	471
400 (16)	950	672

NOTE According to the Manning formula (see Finnemore and Franzini, "Fluid Mechanics with Engineering Applications", McGraw-Hill, New York, 10. ed. 2002) a pipe "filling degree" of 75 % is assumed.

The liquid in the entrance part of a near horizontal pipe normally needs some acceleration distance to reach fully established velocity. To reduce the entrance pressure loss, the inlet section should have increased diameter compared to Table 7.2. For the first ten pipe diameter length, the next larger pipe diameter in Table 7.2 should be selected ending with an eccentric reducer.

7.2.5.3 Vertical lines

Vertical gravity lines with or without submerged outlets (e.g. so-called "dump caissons") should be designed such that the Froude number is less than 0,7. This is to avoid air entrainment and ensure undisturbed flow without pulsations.

$$\text{Froude number} = \frac{V}{\sqrt{D \times g}} \quad (1)$$

where

V is the velocity assuming full pipe in m/s

D is the pipe inner diameter in m

g is the gravity constant in m/s²

A vent line shall be included from top of the vertical gravity line to prevent vacuum, flashing or pulsations. The vent line should be designed for an air/vapour volumetric flow-rate equal to the liquid volumetric flow through the vertical line and a pressure loss of maximum 0,005 bar. The vent line for vertical lines/caissons to sea, shall also be designed for the wave motion inside lines/caisson.

The liquid inlet to the "dump caissons" should be tangential and sloped downwards.

Drainage of deluge water from drain boxes through vertical lines shall be sized on basis of 50 % of the available head (assuming the pipe running full of liquid) and not Froude number. The following formulas can be used to determine the capacity:

$$Q = \frac{8855,8 \times D^{2,5}}{\sqrt{f}} \quad (2)$$

where

Q is the flow in m³/h

f is the Moody friction factor

D is the pipe inner diameter in m

The Moody friction factor for fully turbulent flow can be calculated by the Nikuradse formula, given by:

$$f = \frac{1}{\left[2 \log\left(\frac{D}{2k}\right) + 1.74\right]^2} \quad (3)$$

where the pipe diameter D and pipe roughness k shall be given in the same units.

The flow formula is based on setting 50 % of the available head equal to the piping friction loss i.e.

$$\rho \times g \times 0,5 \times L = \frac{f \times L \times \rho \times V^2}{D \times 2} \quad (4)$$

where

ρ is the density in kg/m³

L is the pipe length in m

V is the velocity in m/s

g is the gravity constant in m/s²

7.2.6 Fire water

The line sizing of fire water lines shall be based on available system pressure and allowable flow velocities.

The pressure drop to the large deluge systems shall be calculated on basis of the most unfavourable pipe routing to those systems.

In the ring main pipe-work the flow velocity shall not exceed the velocity as given in Table 7.1. Upstream the deluge skids, the flow velocities should not exceed 10 m/s. Some areas may require velocities higher than 10 m/s in order to hydraulically balance the systems, which is acceptable, provided the reaction force within the system does not cause excessive stress in the pipe work or the supports.

7.2.7 Oily water systems

Where retaining the size of oil droplets in the water is crucial, this can be achieved by providing low flow velocities. Typically the velocity should not exceed 3 m/s. This should also be considered in selection of fittings and instruments in these lines to avoid shearing of oil droplets.

7.3 Sizing of gas lines

7.3.1 General

When sizing gas lines the sizing criteria will be a compromise between the maximum velocity (see 7.3.2) and allowable pressure drop (see 7.3.3). The compromise is driven by installation cost, power for compressors and noise.

Piping with gas at the dew-point and/or with some droplets shall be designed as gas lines.

7.3.2 Maximum velocities

In lines where pressure drop is not critical, gas velocity shall not exceed limits which may create noise or vibrations problems. As a rule of thumb the velocity should be kept below:

$$V = 175 \times \left(\frac{1}{\rho} \right)^{0,43} \quad (4)$$

where

- V is the maximum velocity of gas to avoid noise in m/s
- ρ is the density of gas in kg/m³
- or 60 m/s, whichever is lowest.

In order to avoid excessive dispersion of noise in lines connected to pressure control valves, the valve manufacturer shall be consulted.

For anti-surge lines, the constant 175 in the formula (4) may be replaced with 200 during process upsets, if the noise level is acceptable. However, during normal recycle, the velocity should be limited to the velocity as given by the formula (4).

If solid particles exist, special attention shall be given to particle erosion.

7.3.3 Recommended pressure drop

Where pressure drop is critical the guidelines in Table 7.3 should be used. The pressure drop should be prorated between the operating pressures given. The pressure drop is considered critical when:

- the cost increase due to additional power requirement is larger than the potential cost savings due to reduced pipe diameter
- it results in unacceptable liquid drop out in suction lines between scrubber and compressor suction, inlet lines to turbo expanders and contactors, etc.

Table 7.3 – Recommended pressure drop for single phase gas process lines

Operating pressure (barg)	Pressure drop (bar/100 m)
0 to 35	0,001 to 0,11
35 to 138	0,11 to 0,27
over 138	P/500 ^a
^a P is operating pressure in bara.	

7.4 Sizing of gas/liquid two phase / multiphase lines

7.4.1 General

Wellhead flow-lines, production manifolds, process headers and other lines made of steel and transporting two-phase or multiphase flow, have a velocity limitation. When determining the maximum allowable velocity, factors such as piping geometry, well-stream composition, sand particle (or proppant) contamination and the material choice for the line shall be considered.

As a guideline, the maximum allowable velocity can be calculated by:

$$V = 183 \times \left(\frac{1}{\rho_{mix}} \right)^{0,5} \quad (5)$$

where

V is the maximum velocity of mixture in m/s

ρ_{mix} is the density of mixture in kg/m³

When sizing two- or multiphase lines, unstable flow and slugging shall be considered. The number and length of multiphase lines should be kept to a minimum where possible.

7.4.2 Non corrosive service

For non-corrosive well-stream and for corrosion resistant pipe materials the velocity should be limited to maximum 25 m/s if the well-stream includes only minimal amounts of sand or proppants.

7.4.3 Corrosive service

For carbon steel piping systems the corrosion rate often limits the life time. With increased flow velocity the corrosion rate tend to increase due to increased shear forces and increased mass transfer.

The flow velocity should be restricted to maximum 10 m/s to limit the erosion of the protective layer of corrosion products and reduce the risk for a corrosion inhibitor film break down.

7.4.4 Particle erosion in non-corrosive service

For well-stream contaminated with particles the maximum allowable velocity shall be calculated based on sand concentration, piping geometry (bend radius, restrictions) pipe size and added erosion allowance. For the calculation of maximum velocity and life time, specialised software is available and should be employed.

If the available pressure drop allows, the velocity shall in general be sufficiently high to ensure homogeneous flow. This prevents instabilities due to liquid accumulations, and it allows simple pressure drop calculations. If lower velocities are required due to limited available pressure drop or at turndown situations, problems with slugging and/or liquid accumulation in the lines shall be considered.

7.5 Sizing of flare and vent lines

7.5.1 General

In general, all flare lines should be designed to keep below $\rho v^2 < 200\,000 \text{ kg/ms}^2$ (where ρ is the fluid density or mixed density for two phase conditions in kg/m^3 and v is the velocity in m/s) to minimise reaction forces in piping systems.

Further, the selection of piping specification shall consider the effect of acoustic fatigue, ref API Std 521, which is affected by factors such as

- relative differential pressure in upstream restriction device,
- temperature in the flowing gas,
- molecular weight of flowing gas,
- pipe diameter and wall thickness,
- mass flow rate.

7.5.2 Flare headers and sub-headers

Piping for flare headers and sub-headers should be designed for a maximum velocity of Mach 0,6.

7.5.3 Pressure safety valve lines

The upstream and downstream line shall be sized according to requirements in the relevant pressure relieving design code.

Maximum flowing velocity in the lines downstream of the PSVs to the first sub-header, should in general be less than Mach 0,7. For the PSVs where the outlet velocity is higher, a reducer should be installed as close as possible (preferably flange-to-flange) to the PSV to increase line size and hence limit the velocity to maximum Mach 0,7 downstream of the reducer. Nevertheless, the actual back pressure at the PSV outlet and in the block valve shall be checked to be consistent with back pressure limitations.

7.5.4 Controlled flaring lines

Flaring lines downstream of control valves shall be designed for a maximum velocity of Mach 0,5.