PDHonline Course M182 (3 PDH)

Basic Process Design Engineering for Non Process Engineers

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NORSOK STANDARD

PROCESS DESIGN

P-001
Rev. 4, Oct. 1999

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FOREWORD

NORSOK (The competitive standing of the Norwegian offshore sector) is the industry initiative to add value, reduce cost and lead time and remove unnecessary activities in offshore field developments and operations.

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and are jointly issued by OLF (The Norwegian Oil Industry Association) and TBL (Federation of Norwegian Manufacturing Industries). NORSOK standards are administered by NTS (Norwegian Technology Standards Institution).

The purpose of this industry standard is to replace the individual oil company specifications for use in existing and future petroleum industry developments, subject to the individual company's review and application.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of this standard will be used to provide input to the international standardization process. Subject to implementation into international standards, this NORSOK standard will be withdrawn.

Annex A is normative.

INTRODUCTION

This standard replaces NORSOK P-001 rev. 3. Revisions are marked with a vertical line in the margin.

Major changes to section 4 regarding use of HIPPS and simplification to section 6 regarding isolation principles and connections to flare, vent and drain. The heading of chapter 6 has also been changed to better reflect the content.

There has also been made minor changes throughout the document based on the incoming comments on the draft version.

1 SCOPE

The scope of this standard is to provide requirements for the following aspects of topside process piping and equipment design on offshore production facilities:

- Design Pressure and Temperature.
- Line Sizing.
- System and Equipment Isolation.
- Insulation and Heat Tracing.

These criteria are applicable for all process, process support, utility and drilling systems. The design pressure and temperature criteria are mainly based on API RP 521 and line sizing criteria on API RP 14E.

2 REFERENCES

2.1 Normative references

The following standards include provisions which, through reference in this text, constitute provisions 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 or exceed the requirements of the standards referenced below.

ANSI/ASME B31.3	Process Piping
API RP 14C	Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms. (New revision of ISO 10418 to be used, when issued in 2000).
API RP 520	Sizing, Selection and Installation of Pressure-Relieving Systems in Refineries
API RP 521	Guide for Pressure-Relieving and Depressuring Systems.
BS MA 18	Salt water piping systems in ships
DIN 3381	Safety devices for gas supply installations operating at working pressures up to 100 bar; pressure relief governors and safety shut-off devices
IEC 61508	Functional safety of electrical/electronic/programmable electronic safety related systems.
NORSOK L-CR-001	Piping and valves (will be renumbered L-001)
NORSOK R-CR-004	Piping and equipment insulation (will be renumbered R-004)

NORSOK S-DP-001	Technical safety (Will be renumbered S-001)
NORSOK S-002	Working environment

2.2 Informative references

API 2000	Venting Atmospheric and Low-Pressure Storage Tanks
API RP 14 E	Design and Installation of Offshore Production Platform Piping Systems. (Will be covered in the new ISO standard 13703 which is now in preparation. When issued, the ISO standard will replace API RP 14E as a guideline for calculation methods, etc.)
ISO/DIS-14313	Petroleum and Natural Gas Industries, Pipeline, Check, Gate and Plug valves
ASME VIII	Boiler and Pressure vessel code
BS 5500	Unfired Fusion Welded Pressure Vessel Code.
TBK 1-2	General Rules for Pressure Vessel.
NORSOK O-CR-001	Life cycle cost for systems and equipment (will be renumbered O-001)
NORSOK R-001	Mechanical equipment
NORSOK S-003	Environmental care.

3 DEFINITIONS AND ABBREVIATIONS

3.1 Definitions

Can	Can requirements are conditional and indicates a possibility open to the user of the standard.
Design pressure	The maximum internal or external pressure to be used in determining the minimum permissible wall thickness of equipment and piping. Note that the minimum permissible wall thickness may be derived from a lower operating pressure, but higher operating temperature. Relief is normally initiated at design pressure.
Double Block & Bleed	Two barriers with a bleed between the barriers. Typical arrangement is two block valves with a bleed valve in the middle. Double block and bleed as defined in ISO DIS-14313, and adopted by some valve manufacturers, is not according to the definition in this NORSOK standard. A single valve is acceptable as double block and bleed only if the force acting on the seal faces is independent of system pressure, and if a bleed connection is provided between the two seal faces (typically a double expanding gate valve). Further,

	such a valve must be lockable in closed position to avoid malfunction or maloperation.
Heat tracing	Use of heat from electrical cables, steam pipes or heating medium for heat conservation or frost protection**.**
Insulation	Use of a material with a low conductivity applied to equipment and piping in order to prevent energy flow (i.e. heat, noise).
Isolation	Isolation means a physical barrier (blind) or a tested barrier
Maximum design temperature	The material temperature representing the most severe condition of coincident pressure and temperature. The design temperature shall encompass the maximum operating temperature.
Maximum operating pressure	The maximum pressure predicted including deviations from normal operations, like start-up/shutdown, process flexibility, control requirements and process upsets.
Maximum operating temperature	The maximum temperature in the equipment including plant operation at unstable conditions, like start-up/shutdown, control requirements, process flexibility and process upsets.
May	May indicates a course of action that is permissible within the limits of the standard (a permission).
Minimum design temperature	The minimum temperature which serves as a base for specifying the low temperature characteristics of the material. The design temperature shall encompass the minimum operating temperature.
Minimum operating pressure	The minimum pressure predicted including deviations from normal operations, like process start-up and shutdown.
Minimum operating temperature	The minimum temperature in the equipment including plant operation at unstable conditions, like start-up, shutdown and depressurizing.
Maximum settle out pressure	The maximum settle out pressure is calculated from coincident high trip pressures on both suction and discharge side of the compressor.
Operating pressure	The pressure in the equipment when the plant operates at steady state condition, subject to normal variation in operating parameters.

Operating temperature	The temperature in the equipment when the plant operates at steady state condition, subject to normal variation in operating parameters.
Settle out pressure	The pressure equilibrium after a compressor shutdown (pressure trapped between the upstream and downstream check valve).
Shall	Shall is an absolute requirement which shall be followed strictly in order to conform with the standard.
Should	Should is a recommendation. Alternative solutions having the same functionality and quality are acceptable.
Shut in pressure	The shut in pressure for pumps and compressors is determined by the curves for a “no flow” situation, i.e. blocked outlet.
Single Block & Bleed	One isolation and a bleed. The point to be isolated can be bled down by the bleeder, but there is only one barrier against the pressure side (e.g. a valve).
Winterization	Use of insulation and heat tracing, or insulation only, for frost protection.

3.2 Abbreviations

FB	Full Bore
HIPPS	High Integrity Pressure Protection System
HP	High Pressure
LC	Locked Closed
LCC	Life Cycle Cost
LO	Locked Open
LP	Low Pressure
NPSH	Net Positive Suction Head
PSV	Pressure Safety Valve

4 DESIGN PRESSURE AND TEMPERATURE

4.1 General

Systems and components shall normally be protected according to relevant international codes API RP 14C and API RP 520/521.

4.2 Design Pressure

The design pressure shall be calculated using the following procedures:

For systems protected by a PSV, the criteria in Table 1 shall as a minimum be applied.

When rupture disks are applied the margin between the design pressure and the operating pressure must be considered in the selection of rupture disk type, as the maximum permitted ratio of system operating pressure to burst pressure will vary. As an indication API RP 520 may be consulted.

For piping being protected from overpressure by a PSV, it is allowable to have a PSV setpoint above the design pressure of the piping for some piping design codes. This shall be evaluated for each case, and only applied after examination of the relevant piping design code.

Table 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 1 are to ensure proper operation of the PSV.

Mechanical design codes for piping and equipment have different limitations with regard to maximum allowable overpressure. It follows from this that piping and equipment in a system may have different design pressures. For low pressure systems such differences should be avoided, so that the same design pressure is used for the whole system.

For piping occasional variations in the operating pressure above the design pressure is permissible in some design codes. This may be used to limit the design pressure of the piping, but shall be subject to due consideration of all aspects in the piping design code ANSI/ASME B31.3. If such variations are permitted by the project owner, the duration and extent of overpressure that the piping is subject to, shall be logged. Logging is not considered required when it is evident that overpressure not will occur more frequent than allowed by the piping code, e.g. due to a pressure relieving event (i.e. PSV set above the piping design pressure which may be permitted by ANSI/ASME B31.3).

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.

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

The design pressure at the discharge of positive displacement pumps shall be calculated in accordance with Table 1.

Equipment not protected by PSV or rupture disc and located downstream of a pump or a compressor shall be designed for the shut-in pressure.

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. Table 1 shall be used to set the design margin.

For equipment where cooling or condensing vapours (e.g. after steamout 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, except for vessels where the design requirements for equipment operating below atmospheric pressure shall be used (Table 2).

Table 2 - Design pressure for pressure vessels operating below atmospheric pressure.

Minimum operating pressure	Design pressure
0.35 bara and below	full vacuum
0.35 - 1.00 bara	the minimum operating pressure minus 0.1 bar, but maximum 0.5 bara

4.2.1 Maximum operating pressure

Maximum operating pressure for vessels is defined as follows:

- Separators; the highest pressure resulting in a trip.
- Compressor suction scrubber and cooler; maximum settle-out pressure.

When accurate information is unavailable, the maximum operating pressure (shut-in pressure) for centrifugal compressors should be determined as the maximum operating suction pressure +1.3 times the normal differential pressure developed by the compressor, to include for pressure rise at surge condition and maximum speed. The maximum operating suction pressure for a compressor is 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 by choosing the greater of the two following criteria:
- Operating suction pressure +1.25 times the normal differential pressure developed by the pump.
- Maximum suction pressure at relieving conditions plus the normal differential pressure developed by the pump.

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

The maximum operating pressure may be limited by installation of full flow pressure safety valves (PSVs).

4.2.2 Piping

The design pressure of a piping system comprising pipes, fittings, flanges and valves shall in general be according to NORSOK L-CR-001. Pipe classes for design pressures between those pressure class ratings shall be developed when justified by cost savings.

Static head, friction loss and surge pressures shall be taken into consideration.

Occasional variation above design according to ANSI/ASME B31.3 should be evaluated where total cost can be significantly reduced**.**

4.3 Design Temperature

4.3.1 Maximum design temperature

Where the maximum operating temperature can be calculated accurately, this temperature shall be used as maximum design temperature, without adding a safety margin.

Where the maximum operating temperature can not be calculated accurately, the maximum design temperature is normally determined by adding 30 °C to the operating temperature. For equipment operating at ambient conditions, the maximum design temperature is 50 °C for the North Sea.

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

4.3.1.1 Sea water systems

For seawater supply systems where the maximum operating temperature is defined by the seawater yearly variations, the maximum operating temperature shall be used as the maximum design temperature.
For seawater return systems the maximum operating temperature shall be calculated at the minimum seawater flow. Minimum seawater flow is calculated at lowest seawater supply temperature and heat exchanger without fouling.

4.3.1.2 Compressor systems

The maximum operating temperature on a compressor discharge shall be determined as follows:

- When a compressor curve is not available it can roughly be defined as 15 °C above the predicted design point temperature to allow for lower efficiency and higher pressure ratio at compressor surge conditions.
- When compressor curves are available, the temperature at surge conditions and maximum compressor speed for normal and start up cases.

The following shall be used to determine the maximum design temperature:

- Add 15 °C to the operating temperature to allow for margins in the compressor curves, and for wear and tear giving lower efficiency over time.
- Add 10 °C as an additional margin

4.3.1.3 Compressor suction scrubber

Compressor suction scrubber maximum design temperatures are defined as the higher of the following:

- Maximum operating temperature at the compressor suction in the event of cooling medium failure. Maximum operating temperature can be limited by a high temperature shutdown function on the compressor suction or discharge.
- Maximum recycle temperature (maximum discharge (temperature trip) minus Joule Thompson drop across anti-surge valve) in the event of cooling medium failure.
- Maximum temperature due to settle out conditions.
- Operating temperature plus 30 °C.

4.3.1.4 Heat exchangers

For all heat exchangers, both sides shall have the same maximum design temperature determined by the hottest of the fluids on either side. For upset conditions occasional variations above design could be used to determine maximum design pressure and temperature for the connected piping system.

4.3.2 Minimum design temperature

The minimum design temperature shall be the more 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. Lowest temperature should be based on available weather data. Safety factors should be selected based on the quality of such weather data.
- Minimum temperature occurring during depressurising from settle-out conditions, including cool down when depressurisation is delayed, with a margin of 5 ºC.
  Designing the process plant for lower design temperature at full design pressure often will result in a conservative design and should be avoided. To determine if this is acceptable, the time it takes to heat the system to minimum design temperature @ maximum operating pressure after a blow down (to allow start up), shall be calculated and submitted project owner for approval. If calculations result in unacceptable values, operational procedures may be included for only partial depressurisation of equipments or start of depressurisation at higher temperature. However, if quick start up of the plant is required, the plant shall be designed for minimum temperature @ maximum operating pressure.

The depressurisation calculations shall as a minimum include heat transfer between fluid and vessel.

4.4 HIPPS - High Integrity Pressure Protection System

Some relieving scenarios may require the installation of an instrumented system named high integrity pressure protections system (commonly named HIPPS) as the secondary protection instead of or combined with relief devices.

HIPPS shall only be used when the use of pressure relieving devices is impractical (e.g. due to extreme field investments).
Where HIPPS is applied as a pressure protection system, the system shall be documented to have the same or better safety reliability as a pressure relief device system. Alternatively IEC 61508, part 5 can be used to develop the appropriate Safety Integrity Level (SIL) for each specific HIPPS application. The safety reliability of the HIPPS system shall be documented to meet the selected SIL

level considering for instance common mode failures, as the HIPPS system may consist of several identical HIPPS loops.

For an overpressure protection system to be termed a "HIPPS" system, the following are the minimum requirements:

- The system complies with DIN 3381
- It has quick closing valves with a closing time of less than 2 seconds. System dynamics (e.g. pipeline systems) may justify to extend the closing time without jeopardizing the overall safety level.
- It has dedicated instrumentation that is not connected to other instrumentation in a way that reduces the safety reliability of the HIPPS system, i.e. the HIPPS instrumentation and valves shall be separate from the plant's PSD, ESD and control system.
- It has local reset.
- It is fail close for any loss of instrument air, hydraulic power, electric power or instrument signals.
- Each HIPPS loop within a HIPPS system is independent of all other loops.
- Execution of a third part verification of the design, installation and operational procedures.

Typical HIPPS loops are shown in figure 1.

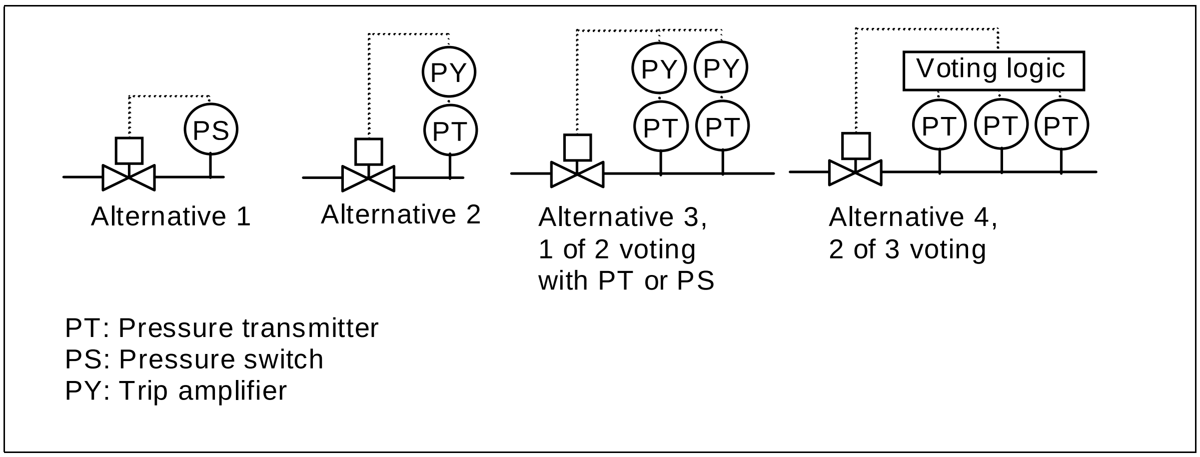


Figure 1, Recommended components for a HIPPS loop.

HIPPS loop alternative 1 may be more attractive than alternative 2 if fluid characteristics will be critical to the functionality of the pressure transmitter.
Alternative 3 will be advantageous if the pressure transmitter or pressure switch is the weakest component in the loop with respect to safety reliability.
Alternative 4 includes a voting logic to improve the regularity. A voting logic may complicate the system and thereby reduce the safety reliability.

When applied in wellstream and fluid service, special consideration should be given to the design of the instrument loops due to the potential for erosion problems, hydrate formation, fluid viscosity, wax content etc. Common mode failure due to loss of heat tracing should de considered.

4.4.1 HIPPS application

The following HIPPS applications are currently accepted:

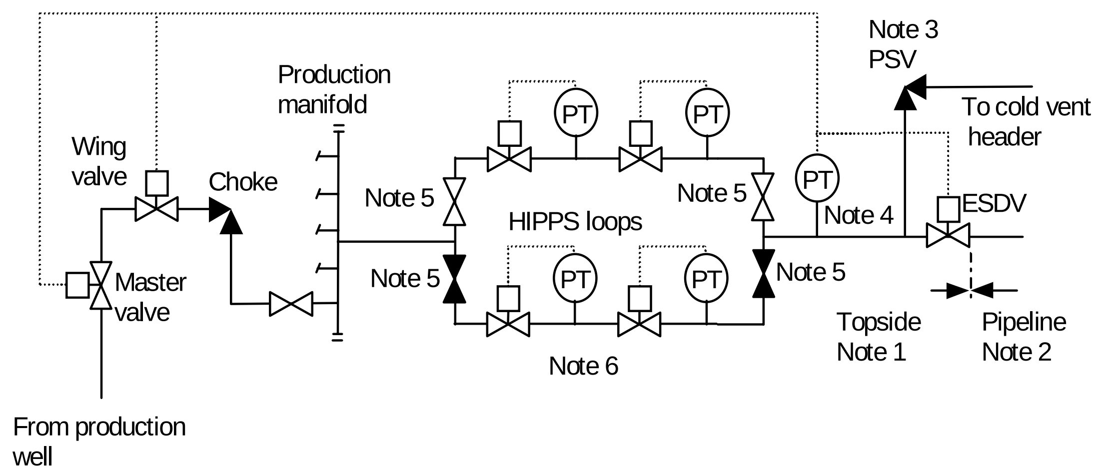
- as a replacement for PSVs to protect subsea pipelines against overpressure
- in process plants to reduce the PSV and flare design capacity

4.4.1.1 HIPPS to protect subsea pipelines

When used for pipelines, HIPPS replaces the secondary protection against overpressure as described in API RP 14C.
This application may require two HIPPS loops in series to achieve the required SIL level. However, for applications where the maximum foreseeable pressure in the protected pipeline can be shown to be below the hydrostatic test pressure of the pipeline, it may be considered to install one HIPPS loop.

Where leakage through the HIPPS valves may be crucial to the integrity of the downstream system, a small PSV should be installed to prevent a valve leakage from over pressuring the system. The maximum acceptable leakage rate through the valve should be in accordance with the valve vendor, but should not exceed 50 % of the PSV capacity.

A typical pipeline HIPPS arrangement is shown in figure 2. The HIPPS arrangement may also be used where the pressure source is a compressor or a pump. The design pressures will have to allow for "water hammering" effects caused by the HIPPS valves short closing time, in particular for liquid service.



Notes:
1. Designed for well shut in pressure
2. Pipeline design pressure
3. Designed for HIPPS valve leakage, set at pipeline design pressure
4. Shutdown all the wells and pipeline ESD valve
5. Block valves must be interlocked
6. 2 x 100% HIPPS loops to allow for testing during operation

Figure 2, typical pipeline HIPPS for a wellhead platform.

4.4.1.2 HIPPS to reduce the PSV and flare design capacity

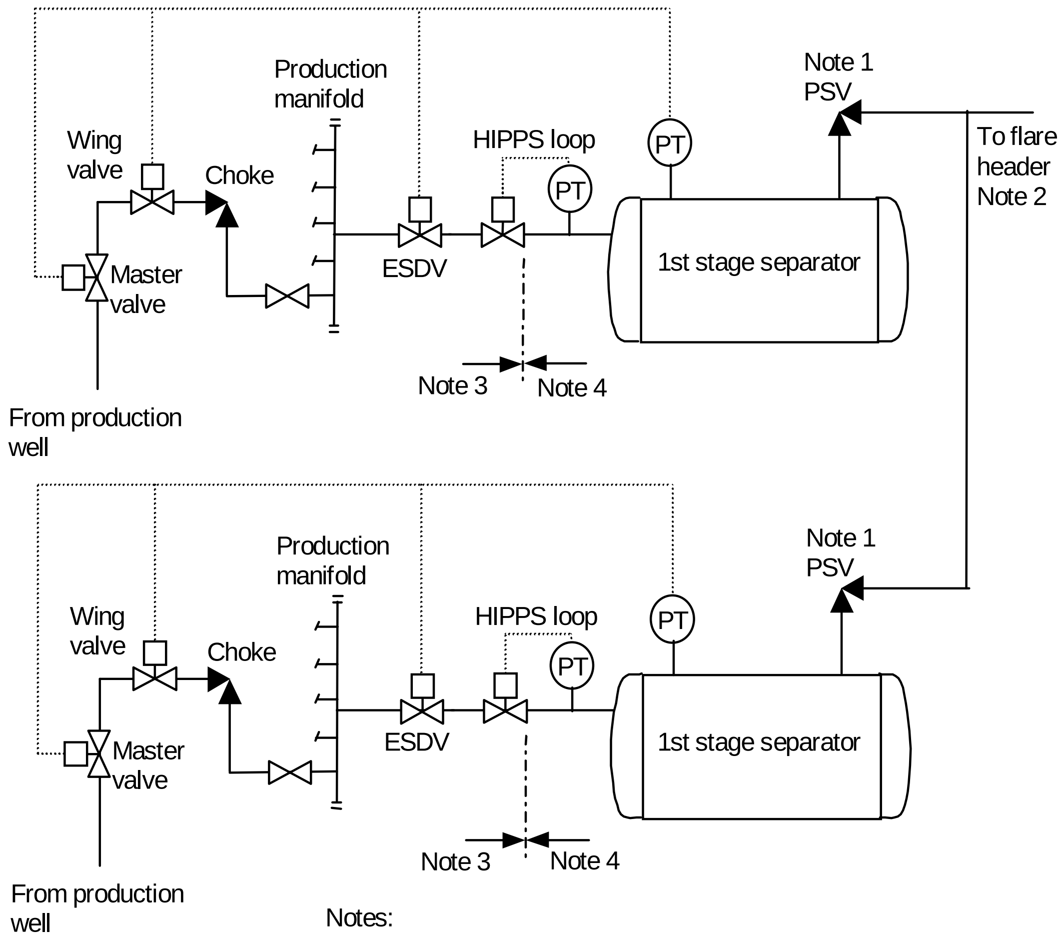
HIPPS can not be used instead of PSVs in process plants to protect pressure vessels, piping or equipment, but the relief capacity may be reduced by the use of HIPPS.

HIPPS can be used in process plants with parallel equipment trains to avoid simultaneous flaring from being a design scenario for the flare system. As a consequence the flare stack may have its design capacity considerably reduced.

One HIPPS loop per process equipment in parallel normally meets the required SIL level.

In practice HIPPS loops may be installed upstream of parallel separator trains to avoid simultaneous relief from PSVs on the separators.

A typical process plant HIPPS arrangement is shown in figure 3.

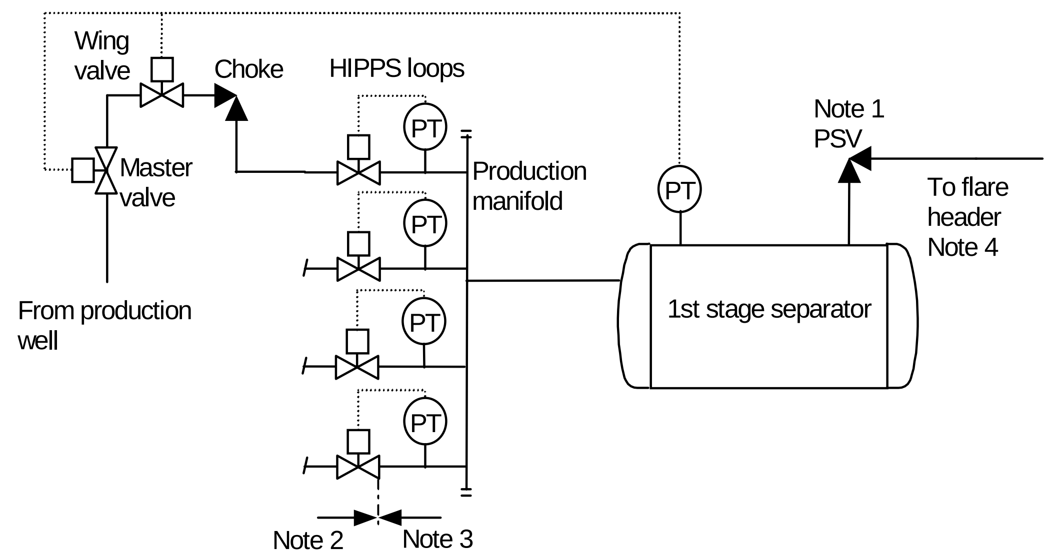


Notes:
1. PSV designed for blocked outlet
2. Flare header with sufficient capacity to accept failure in both HIPPS loops
3. Designed for well shut in pressure
4. Separator design pressure

Figure 3. Typical process plant HIPPS arrangement for parallel separator trains.

Furthermore HIPPS can be used to reduce the relief design rate on topside equipment and piping where three or more flowlines each with independent HIPPS loops feed the same equipment. The probability of more than two (largest feeds) independent HIPPS loops failing simultaneously is neglible and need not to be considered as design scenario.
Typically a SIL 3 will be required for HIPPS system reducing the design capacity of a separator PSV.

A typical arrangement where the PSV capacity may be reduced by the use of HIPPS is shown in figure 4.



Notes:

1. PSV including piping designed for blocked outlets and failure of two HIPPS loops
2. Designed for well shut in pressure
3. Separator design pressure
4. Flare header with sufficient capacity to accept failure in two HIPPS loops

Figure 4. Typical arrangement where the PSV capacity may be reduced by the use of HIPPS.

Regardless of the HIPPS solution the following apply for the flare system design:

- The hydraulic capacity of the PSV, flare piping, knock out drum and flare stack shall be designed for failure of two HIPPS loops.
- The flare stack shall, as a minimum, be designed for the failure of one HIPPS valve according to normal flare heat radiation criteria for personnel protection.

4.4.2 Testing

HIPPS systems shall be functionally tested every 3rd month to obtain the required safety reliability. The leakage rate in the HIPPS valve shall be tested annually. The testing of the HIPPS valves shall be documented with test certificates as is done with PSVs and shall be kept on the installation. The requirement for testing shall be accounted for in the design.

A high system regularity demand may dictate the need for HIPPS valves in parallel to enable testing without affecting the plant production.

5 LINE SIZING CRITERIA

5.1 General

When sizing lines the sizing criteria shall be minimum life cycle cost, this may include evaluation of functional requirements, cost of piping, weight, CO_2-tax, energy costs, mechanical and process limitations, expected lifetime of piping, maintenance cost etc.

When sizing piping, the following constraints shall be addressed:

1. Required capacity/available driving pressure
2. Flow induced forces
3. Noise/vibration
4. Pressure surges
5. Material degradation - erosion, corrosion, cavitation
6. Liquid accumulation/slug flow
7. Sand accumulation

In some cases the constraints will govern the pipe size selection, not the life cycle cost evaluation.

5.2 Design Basis

5.2.1 Permissable pipe sizes

A minimum size of DN50 (2") should in general be used for all process, process support and utility piping to ensure adequate mechanical integrity. Smaller piping can be used , where protection and/or support is provided to withstand human activity.

Minimum size for the sewage and open drain header shall be DN100 (4") and sub-headers DN80 (3"). 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.

5.2.2 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
Glassfiber Reinforced Pipe (GRP):	0.02 mm
Polyethylene, PVC:	0.005 mm

Flexible hose: Vendor to be consulted. (As a rough estimation, ID/20 mm can be used (ID in inch) for steel carcass and 0.005 mm for plastic coating.)

5.3 Sizing of Liquid Lines

5.3.1 Velocity limitations

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

A compromise between line size and pump power has to be taken.

Table 3 – Recommended maximum velocities for sizing of liquid lines.

Fluid	Maximum velocities (m/s)			
	CS	SS/Titanium	CuNi 4)	GRP
Liquids	6	2)	3	6
Liquids with sand 3)	5	7	N.A.	6
Liquids with large quantities of mud or silt 3)	4	4	N.A.	N.A.
Untreated Seawater 1)	3	7	3	6
Deoxygenated Seawater	6	2)	3	6

Notes:
1) For pipe less than DN200 (8"), see BS MA-18 for maximum velocity limitations.
2) For Stainless Steels and Titanium the maximum velocity is limited by system design (available pressure drop/reaction forces). 7m/s may be used as a typical starting value for sizing.
3) Minimum velocity is 0.8 m/s
4) Minimum velocity for CuNi is 1.0 m/s.

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

5.3.2 Centrifugal pump suction and discharge lines

The suction piping shall be sized based on NPSH requirements. Maximum velocity from Table 3 and the following maximum pressure drops shall be used:

Subcooled 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 subcooled liquids.

The maximum velocity in the discharge piping is given in Table 3. As a guideline, a pressure drop of up to 0.9 bar/100 meter may be used.

5.3.3 Reciprocation pump suction and discharge lines

For reciprocating pumps, the suction piping shall be sized based on NPSH requirements.

Table 4 - Recommended maximum velocity in reciprocating pump piping.

Speed (RPM)	Maximum velocity (m/s)	
	Suction	Discharge
< 250	0.6	1.8
250-300	0.5	1.4
> 300	0.3	0.9

The limits are for a single plunger pump and the velocity is the average during several strokes. The discharge velocities can be increased if the number of plungers are increased, and/or if dampers are installed (ref. API RP 14E).

5.3.4 Control valve inlet lines

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

5.3.5 Liquid flowing by gravity

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 must 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.

Near horizontal pipes not running full shall be sized based on the maximum flow as given in Table 5.

Table 5 - Flow Capacity - near horizontal pipes.

Diameter (mm (inch))	Liquid flow capacity		
	Entrance to pipe (m^3/h)	Slope 1:50 (m^3/h)	Slope 1:100 (m^3/h)
50 (2)	1.8	3.0	2.5
100 (4)	8	20	15
150 (6)	20	60	35
200 (8)	50	240	170
250 (10)	80	440	310
300 (12)	130	620	440
350 (14)	200	710	500
400 (16)	280	890	630

Vertical gravity lines (such as liquids from sea water returns and produced water discharge) shall be designed such that the Froude number is less than 0.3 to avoid air entrainment and ensure undisturbed flow without pulsations.

Froude number = $\frac{V}{\sqrt{Dg}}$

V = Velocity assuming full pipe (m/s)
D = pipe inner diameter (m)
g = gravity constant (m/s^2)

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:

$$Q = \frac{8855.8D^{2.5}}{\sqrt{f}}$$

Q = flow (m^3/h)
f = Moody friction factor = $\frac{1}{\left(2\log\left(\frac{D}{2k}\right)+1.74\right)^2}$ (Nikuradse formula)
D = pipe inner diameter (m)
k = pipe roughness (m)

The flow formula is based on setting 50% of the available head equal to the piping friction loss i.e. $\rho g 0.5L = f(L/D)\rho V^2/2$, ρ=density, L= pipe length, V=velocity, g= gravitational constant 9.81 m/s^2.

For sea water and produced water discharge lines to sea, a vent line is normally included from top of the vertical gravity line from platform topside to sea. The vent line should be designed for an air volumetric flowrate equal to the liquid volumetric flow through the vertical line and a pressure loss of maximum 0.02 bar/100 m.

5.3.6 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 unfavorable pipe routing to those systems.

In the ring main pipework the flow velocity shall not exceed the velocity as given in Table 3. 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.

5.3.7 Oily water systems

The lines for oily water to water treatment facilities, shall be sized in order to retain the size of oil droplets in the water. 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.

5.3.8 Drilling fluid systems

The minimum flowing velocity of drilling fluid shall not be lower than 0.8 m/s in order to avoid sand settling in pipes.

The maximum velocity in carbon steel should not exceed 4 m/s to avoid problems such as cavitation/erosion on bends and damage to inline equipment/vessels internals.

Line sizing criteria for drilling fluids are summarised in Table 6.

Table 6 - Allowable pressure drop and velocity in drilling fluid systems.

Line Service	Max pressure drop [bar/100 m]	Velocity limits [m/s]	
		Min	Max
Pump Suction (and Gravity) flow (Carbon Steel pipes)	0.3	0.8	4.0

5.4 Sizing of Gas Lines

5.4.1 General

When sizing gas lines the sizing criteria will be a compromise between the maximum velocity (section 5.4.2) and allowable pressure drop (section 5.4.3). Where pressure drop is not critical the requirements in 5.4.2 should be used. Where the pressure drop is critical the recommendation in 5.4.3 should be used. 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 contractors etc.

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

5.4.2 Maximum velocities

In lines where pressure drop is not critical (see 5.4.1), gas velocity shall not exceed limits which may create noise or vibrations problems. As a rule of thumb the velocity should be kept below:

$$V = 175\left(\frac{1}{\rho}\right)^{0.43}$$ or 60 m/s, whichever is lowest

where : V = max. velocity of gas to avoid noise (m/s)
ρ = density of gas (kg/m^3)

For sizing and arrangement connected to and adjacent to pressure control valves in order to avoid excessive dispersion of noise, the valve manufacturer shall be consulted.

For antisurge lines the constant 175 in the formula may be replaced with 200 during process upsets, if the noise level is acceptable. However, during normal recycle, the velocity shall be limited to the velocity as given by the equation above.

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

5.4.3 Recommended pressure drops

Where pressure drop is critical (see 5.4.1) the guidelines in Table 7 should be used. The pressure drop should be prorated between the operating pressures given.

Table 7 - Pressure drop for single phase gas process lines

Operating pressure (Barg)	Pressure drop (Bar/100 m)
0 - 35	0.001 - 0.11
35 - 138	0.11 - 0.27
Over 138	P/500 [1)]

Note 1: P is operating pressure in bara.

5.5 Sizing of Gas/Liquid Two-or Multi-Phase Lines

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

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

$$V = 183\left(\frac{1}{\rho_{mix}}\right)^{0.5}$$

V = max. velocity of mixture (m/s)
ρ_{mix} = density of mixture (kg/m^3)

When sizing two- or multiphase lines, unstable flow and slugging must be considered.
The number and length of multiphase lines should be reduced where possible.

<u>Non corrosive service</u>
For non corrosive wellstream and for corrosion resistant pipe materials the velocity should be limited to maximum 25 m/s if the wellstream includes only small amounts of sand or proppants (typical less than 30 mg sand/liter in the mixed flow).

<u>Corrosive service</u>
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.

<u>Particle erosion in non corrosive service</u>
For wellstream contaminated with particles the maximum 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 computer programmes are 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 unstabilities 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.

5.6 Sizing of Gas Relief Lines

5.6.1 General

In general, all flare lines shall be designed to keep the $\rho V^2 < 200\ 000\ kg/ms^2$ criteria (ρ is the fluid density or mixed density for two phase conditions in kg/m^3).

Where the ρV^2 criteria will not be met, additional calculations will be required to document that the selected pipe size is still acceptable. This involves evaluating piping stress levels, supporting, noise etc.

Further, the selection of piping specification must consider the effect of acoustic fatigue, which are affected by factors such as:

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

5.6.2 Flare headers and subheaders

Piping for flare and subheaders shall be designed for a maximum velocity of 0.6 Mach.
Where the Mach 0.6 criteria cannot be be met, additional calculations will be required to document that the selected pipe size is still acceptable. This involves evaluating piping stress levels, supporting, noise etc.

5.6.3 Pressure safety valve lines

The upstream and downstream line shall be sized based on the rated capacity of the PSV. The upstream line shall be sized so that the pressure loss is below 3% of valve set pressure to avoid valve chattering. Pilot operated valves can tolerate a higher inlet-pipe pressure losses when the pilot senses the system’s pressure at a point that is not affected by inlet-pipe pressure drop. In any case the upstream line size should be at least equal to the PSV inlet nozzle size.

The maximum back pressure on PSVs should be determined by consulting API 520/521. Normally the maximum back pressure on a spring loaded PSV is 10% of set point. The backpressure on a bellows type conventional PSV may be limited by the bellows design pressure. If the backpressure on a PSV goes above 30-50% of set pressure the flow in the PSV may become subsonic. This is normally not advisable, as the flow through the PSV becomes unstable. For special applications it may be acceptable, but then after due consideration of all aspects.

Maximum flowing velocity in the lines downstream of the PSVs to the first subheader, shall in general be less than 0.7 Mach. For the PSVs where the outlet velocity is higher, a reducer shall be installed as close as possible to the PSV to increase line size and hence limit the velocity to max 0.7 Mach 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.

5.6.4 Controlled flaring lines

Flaring lines downstream of control valves shall be designed for a maximum velocity of 0.5 Mach.

5.6.5 Depressurisation lines

In the lines, upstream or downstream of the blowdown valve, the value of ρV^2 should not exceed 200 000 kg/ms^2. The maximum flowing velocity in the lines downstream the reducer shall be 0.7 Mach.

The pressure loss shall be so as not to impose any restrictions on the depressurisation objectives.

5.6.6 Two/multiphase relief lines

Two/multi phase relief lines shall be sized based on the following criteria:

- For potential slug/plug flow: $V < 50$ m/s (branch lines only)
- For homogenous flow: $\rho V^2 < 200\,000\ kg/ms^2$

5.6.7 Vent lines

Maximum backpressure shall be 0.07 barg .

5.7 Maximum allowable velocities due to reaction forces

If $\rho V^2 > 200\,000$ the piping discipline shall be consulted in order to consider reaction forces. (ρ is fluid density in kg/m^3 and V is velocity in m/s)

This applies to all fluid services (gas, liquid, two-phase).

6 DETAILED REQUIREMENTS FOR SYSTEMS AND EQUIPMENT

6.1 System and Equipment Isolation

6.1.1 General

It shall be possible to isolate equipment or process sections during maintenance work to obtain safe working conditions for the maintenance personnel. Process sections will also be isolated for leak testing before commissioning, after a maintenance operation, and for pressure testing.

In general single block and bleed shall be used on all systems.

Double Block and Bleed shall only be used for isolation of parallel equipment or parallel trains, when maintenance is done during normal operation on the adjacent equipment or train. PSVs and control valves are not considered equipment in this context.
During installation or removal of the blind it shall be possible to bleed down the trapped pressure by a valve.

Provisions necessary to facilitate isolation are:
- Shut off valves or manual block valves on all connections to equipment or the process section to be isolated.
- Vent/drain (bleed) between isolation valves, or between a valve and a blind.
- Flange pair with blind at the point of isolation.

The actual blinding is accomplished through one of the following arrangements:
- Spectacle blind.
- Spade and spacer.
- Spool piece and blind flange.

When sandwich type butterfly valves are used, an additional flange must be provided between the valve and the spool piece to allow for spool removal without disturbing the butterfly valve.

The location of line blinds and isolation spools shall be shown on the P&ID's.

6.1.2 Isolation of pressure vessels

All vessel that can be entered shall be equipped with spectacle blinds or blinds/spacers on all nozzles (including PSV nozzles), except for instrument nozzles and nozzles not permanently connected to live systems.

Vessel isolation shall be located as close to the vessel as practical, normally directly on the nozzle.

Connections to vent/drain systems from instruments shall be isolated on the instrument.

6.1.3 Isolation for removal of equipment for maintenance

Spool pieces shall be used when necessary for maintenance purposes. After removal a blind can be installed to achieve isolation. This type of isolation requirement is generally used for pumps, compressors and heat exchangers.

6.1.4 Isolation of control valves and PSVs

Control valves shall be equipped with single isolation and bleed valves. See Annex A, Figure A.4.

On non essential systems, single control valve without isolation is acceptable. See Annex A Figure A.6.

If tight shut-off is required, an isolation valve shall be installed upstream the bypass throttling valve. See Annex A, Figure A.5.

For PSVs single isolation valve and bleed is sufficient as the valve will be replaced with a blind when being removed. See Annex A, figure A.8 and A.9.
A bleed between the PSV and downstream block valve is required when the flare system is normally pressurized.

6.1.5 Isolation of pressure and level instruments, chemical injection and sample points

Generally, the same requirements applies to instruments as to system and equipment isolation.

All pressure instruments shall have a flanged isolation valve at the point where pressure is tapped off on a process line, vessel, etc.

6.2 Connections to Flare, Vents and Drains

6.2.1 General

The philosophy for connections to flare, vents and drains is described below:

<u>Flare system</u>
Process relief system. Also used to blow down equipment to flare header pressure.

<u>Vent system</u>
System for venting of hydrocarbon gas to an atmospheric vent at a safe location. Used during maintenance before equipment is opened and normally done after blowdown of equipment to flare system.

<u>Closed drain system</u>
Intended for draining of liquid after depressurisation from vessels, piping and other equipment due to maintenance work etc. All pressure drain connections shall be equipped with a blind to avoid accidental draining of pressurised liquids/gas.

6.2.2 Connections to Flare

a) Single relief valve discharging to flare shall be equipped with a single block valve downstream. See Annex A, Figure A.8.

b) Relief valves or rupture discs with spare shall be equipped with single selector valves or locked block valves upstream and downstream and a single blinded bleed valve, upstream of each relief valve. See Annex A, Figure A.9.

c) The pressure relief valves shall be located at high points in the piping system. Piping to pressure relief valve inlet shall be as short as possible. All branch connections on relief and blowdown system will enter the header at 90° unless otherwise highlighted on the P&ID's.

d) Blow down shall be arranged with one blow down valve, locked open block valve and orifice alternatively one blow down valve, orifice and a locked open, full bore, block valve. See Annex A, Figure A.10a and Figure A.10b repectively.

e) Manual blow down to flare for maintenance purposes requires orifice and block valves alternatively throttle valve and block valve. See Annex A, Figure A10 and A11 respectively.

f) A single piping block valve with blind flange/plug shall be used for level transmitters and level gauges for connections to flare system. If permanently connected to the flare system, the blind is not necessary.

6.2.3 Connections to Vent

a) Atmospheric vents discharging from hazardous sources including tanks shall be routed to the atmospheric vent system. Atmospheric vents discharging from non-hazardous tanks shall be routed to atmosphere.

b) Connections to the atmospheric vent system from pressurised vessels require single isolation, valve and blind. Connections to the atmospheric vent system from atmospheric vessels require a blind.

c) All pressure vessels shall be provided with a vent valve and blind, to allow for venting to atmosphere during maintenance, alternatively permanently connected to a vent system. For permanent connections to a common vent system precautions shall be taken to avoid excess pressure in the system and equipment connected to it. Recommended connections are:

- Block valve and orifice, see Annex A, Figure 12. Orifice to be sized to protect downstream system in case of accidental opening of block valve at operating pressure. Penalty is low flow rate at normal venting conditions.
- Double block and bleed as for connections to closed drain, see Annex A, Figure 7. The throttle valve to be replaced with a block valve. Penalty is turning of spectacle blind to allow venting.

d) Vent nozzles on equipment not permanently connected to the vent system shall have a valve with a blind (such as pumps and heat exchangers).

6.2.4 Connections to Drain

a) Connections to the closed drain system from equipment and piping shall have two valves, one block and one throttling valve, and single blinded bleed valve arrangement. A spectacle blind shall be located between the upstream block valve and the bleed valve. See Annex A, Figure A.7.

b) The drain pipe down to the T-piece connection on the header, should be designed for the same pressure as the system to be drained. Pressure testing according to closed drain specification is sufficient.

c) A single piping block valve with blind flange/plug shall be used for level transmitters and level gauges for connections to closed drain system. If permanently connected to the closed drain system, the blind is not necessary.

d) Drain nozzles on equipment not permanently connected to the closed drain system shall have a valve with a blind (such as pumps and heat exchangers). On stacked exchangers operating in series, drain valves with blind shall be installed on the lower exchanger only.

6.2.5 Operational Drain, Vent and Flushing requirements

a) All equipment and piping shall be provided with highpoint vents and lowpoint drains. All such vents and drains shall be fitted with valve and blind flange.

b) If required for inspection, flushing and cleanout of vessels and piping, steamout and utility connections shall be provided close to upstream isolation valve.

c) If flushing is required for piping diameters above DN 150 (6"), the connections for flushing shall be DN 150 (6"), to give access for rotating hoses.

d) Where provisions shall be made for chemical cleaning of heat exchangers with the tube bundle in place, blind flange connections shall be provided for chemical hose attachments. The connections shall preferably be DN 80 (3"), but not exceeding line size, and shall be located between the exchanger nozzles and the block valves.

7 INSULATION AND HEAT TRACING OF PIPING AND EQUIPMENT

7.1 Insulation and Heat Tracing Requirements

7.1.1 General

Due to corrosion under insulation being a general problem on insulated equipment, the philosophy shall be to avoid insulation where possible. Appropriate coating systems shall be selected to minimise the above problem when insulation is required.

The insulation and heat tracing requirements shall be determined with due consideration to safety aspects as well as to process aspects and with the objective to minimise life cycle cost. All operating modes shall be considered.

The insulation classes are designated as follows:

Class	Description	Abbreviation
0.	No Insulation	NI
1.	Heat Conservation	HC
2.	Cold Medium Conservation	CC
3.	Personnel Protection	PP
4.	Frost Proofing	FP
5.	Fire Proofing (Insulation)	FI
6.	Acoustic 10 dB	AI
7.	Acoustic 20 dB	AI
8.	Acoustic 30 dB	AI
9.	External Condensation and Icing Protection	EP

Design requirements and criteria for the respective insulation classes are specified in the following sections. (Detailed requirements for application of insulation is given in NORSOK standard R-CR-004 Piping and equipment insulation.)

7.1.2 Heat conservation

Insulation/Heat tracing for this purpose shall be used where heat losses from the piping and equipment to the surroundings are to be minimised for the following reasons:

- Maintain a proper heat balance for optimum operation of the process and utility systems.
- Limit heat losses in heat exchangers and heater systems to minimise required heat input and thereby reduce equipment size and weight.
- To avoid internal condensation in gas systems (e.g. fuel gas system).
- To maintain sufficient liquid temperature and avoid increased liquid viscosities.
- To avoid formation of wax and hydrates on safety related equipment, piping or instruments.

Insulation and heat tracing of “dead legs” are not required if the distance from the main pipe to the first isolation is one meter or less.

If sufficient (waste) heat is available, consideration shall be given to possibly avoid insulation.

7.1.3 Cold conservation

This insulation type shall be used for piping and equipment including valves and instruments which normally operate below ambient temperature and where heat transfer from the surroundings shall be minimised for the following reason:

- Maintain a proper heat balance and low temperature in the process system.
- Limit heat input to piping, and thereby reduce equipment size and weight.

7.1.4 Personnel protection

Shields are the preferred option for personnel protection against hot and cold surfaces, unless insulation is required for other purposes.

Where shields are not a practical solution, insulation for personnel protection shall be considered on surfaces that can be reached from workareas, walkways, ladders, stairs or other passageways and where the surface temperature exceeds 70 °C or is below –10 °C (see NORSOK S-002 and NORSOK R-CR-004).

7.1.5 Frost protection

Insulation/heat tracing for external low temperature protection shall only be used for safety reasons or where a positive effect on regularity can be demonstrated.

Equipment and piping should be protected for purposes such as:

- Prevention of hydrate formation. Heat tracing specified to maintain minimum fluid temperature required.
- Protection of standby pumps in unheated areas to avoid the pumping medium to freeze or become too viscous to pump.
- Heat tracing to maintain operating temperature may be required for operational reasons, e.g. instrument connections and impulse lines. In this service, thermostat controlled heat tracing is preferred.
- Frost protection of equipment, piping and instrumentation in systems carrying fluids which in a stagnant flow and low ambient temperature condition may be subject to solidification. This may be applicable to liquid-filled small bore lines carrying fresh water, sea water or pure glycol. Heat

tracing shall be specified to maintain minimum temperature 5 °C above freezing point, however, for pure glycol, the temperature shall be maintained above 20 °C to reduce viscosity.

No winterization is required for water lines (sea water, fresh water, produced water and completion fluid) where continuous flow is assured or the system is self draining when shutdown.

The piping shall be arranged to minimise the part of the system containing stagnant or slow moving fluids. Stagnant conditions shall be avoided by design, but where this cannot be done, provisions must be made to drain or flush out the system (i.e. winterization bleeds). Adequate protection may sometimes be obtained by increasing the velocity in a line.

Maintaining the flows listed below is generally sufficient to avoid freezing in lines up to 50m length. The flowrate should be increased pro rata with the exposed length for lengths over 50m. Table 8 can be used for sea water and, if applicable, fresh water.

Table 8. Minimum flow to avoid freezing.

Line Size	Minimum Volumetric Flowrate
below 3"	0.02 m^3/h
3" and above	0.10 m^3/h

Where such provisions can not be made, heat tracing and/or insulation shall only be applied based on a critical evaluation of:
- Location/Environmental conditions.
- Ambient conditions.
- System criticality.

For lines where intermittent flow and stagnant conditions cannot be avoided, the time to freezing shall be calculated based on local weather conditions. The time to freezing will then determine the need for insulation and heat tracing.
As a guideline Table 9 can be used for lines containing seawater at temperatures down to –10 °C (ambient).

Table 9. Insulation and heat tracing for lines with stagnant conditions.

Line size	Action
< 3"	Heat trace and insulate
3"-10"	Insulate
>10"	No winterization

For tanks containing stagnant water, the same guidelines should be applied.

7.1.6 Fire proofing

Fireproofing insulation shall be applied on equipment and piping where passive protection against a fire is required, and on equipment which is required to be operable during a fire.

The philosophy and criteria for application of passive fire protection are detailed in NORSOK S-DP-001.

7.1.7 Acoustic insulation

Acoustic insulation comprise Insulation Classes 6, 7 and 8. The respective requirements for these classes are 10, 20 and 30 dB linear average attenuation between 500 and 2000 Hz.

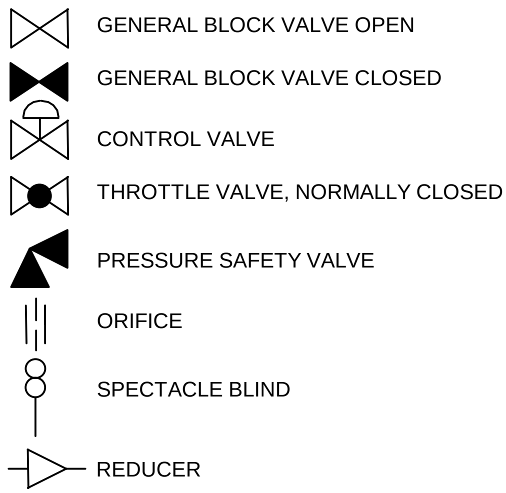
The philosophy and criteria for application of such insulation are detailed in NORSOK Standard S-002.

7.1.8 External condensation and icing protection

This type of insulation shall be used to prevent external condensation and icing on piping and equipment in order to protect personnel and equipment. Normally, insulation for external condensation and icing protection shall not be installed.

ANNEX A - FIGURES (NORMATIVE)

Legend:



SPEC. BREAK = Pressure specification break

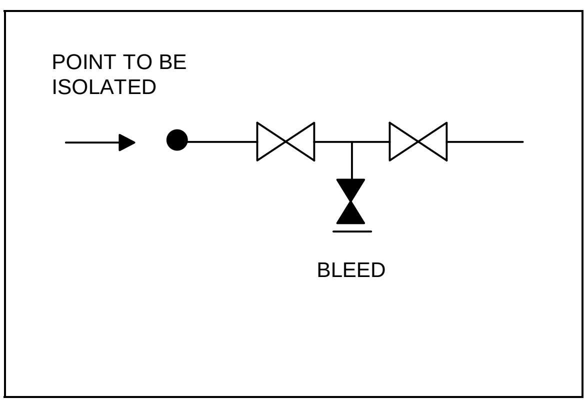


Figure A.1: Double block and bleed for process systems

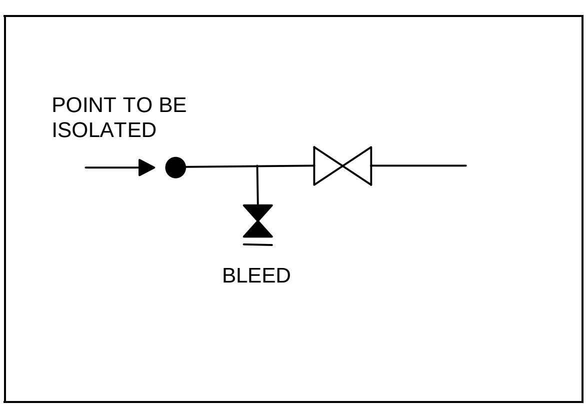


Figure A.2: Single block and bleed for process systems

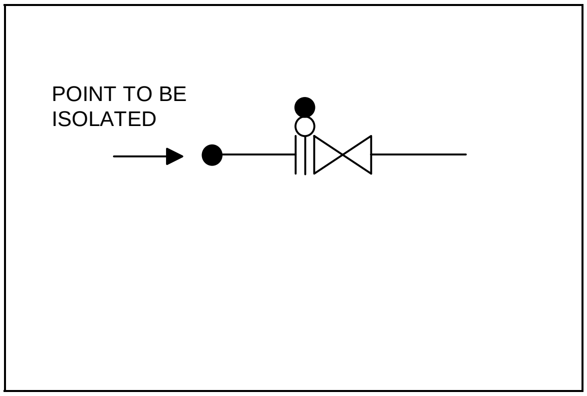


Figure A.3: Single block for pressure vessel isolation.

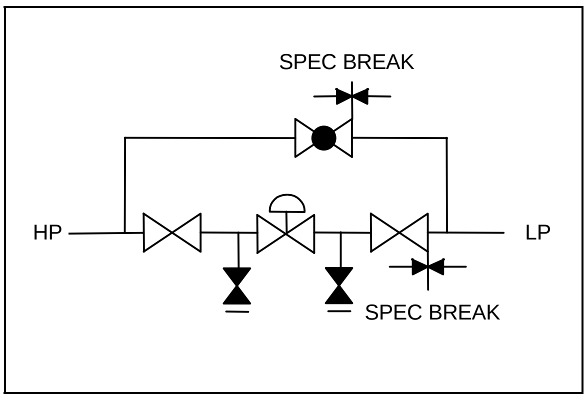


Figure A.4: Isolation of control valve having bypass.

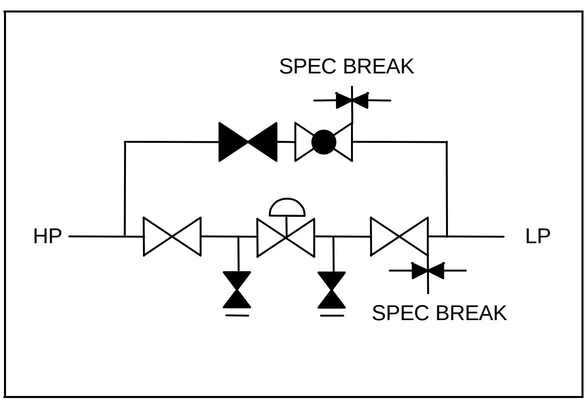


Figure A.5: Isolation of control valve having bypass where tight shut off of bypass is required.

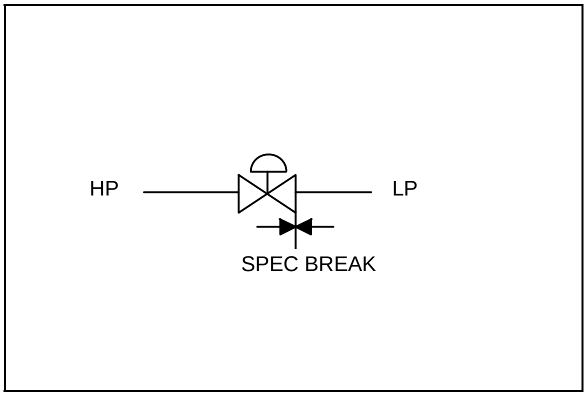


Figure A.6: Single control valve on non essential systems (no isolation).

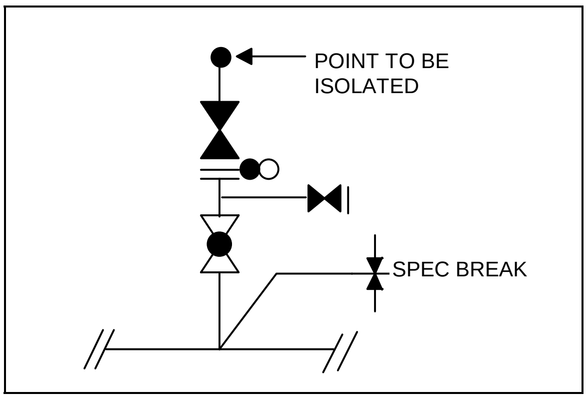


Figure A.7: Double block for connection to closed drains.

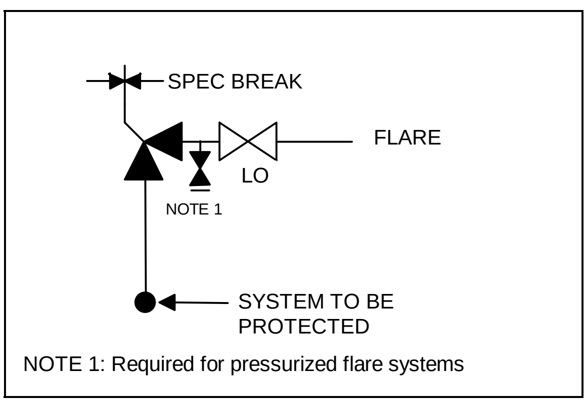


Figure A.8: Arrangement for single relief valve (PSV).

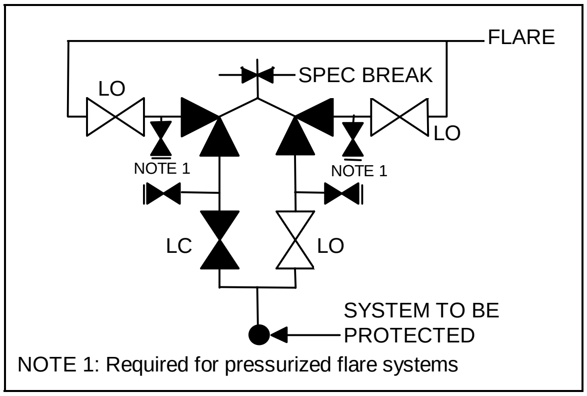


Figure A.9: Arrangement for locked relief valves (PSVs).

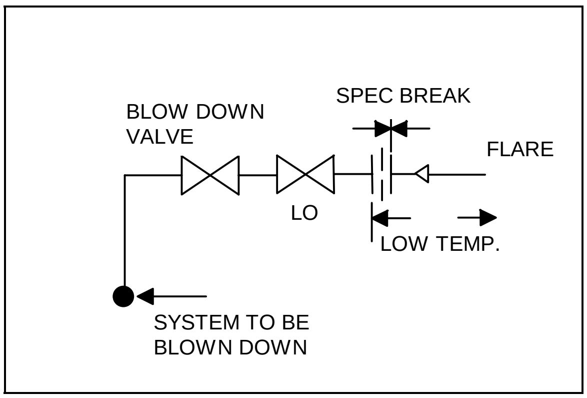


Figure A.10a: Blow down valve arrangement where the orifice can be inspected when the flare is shut down.

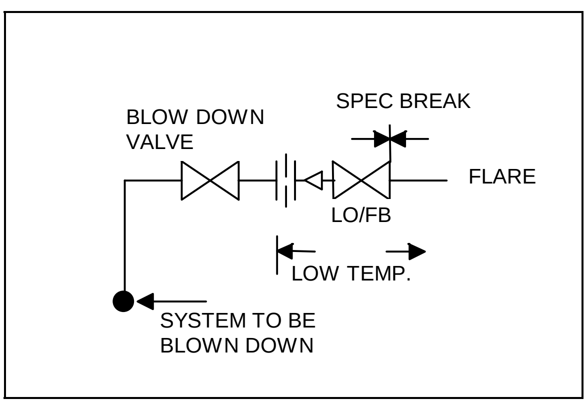


Figure A.10b: Blow down valve arrangement where the orifice can be inspected when the flare is in operation.

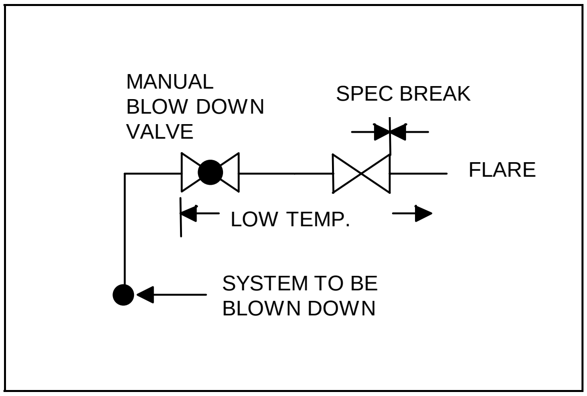


Figure A.11: Manual blow down for maintenance purposes

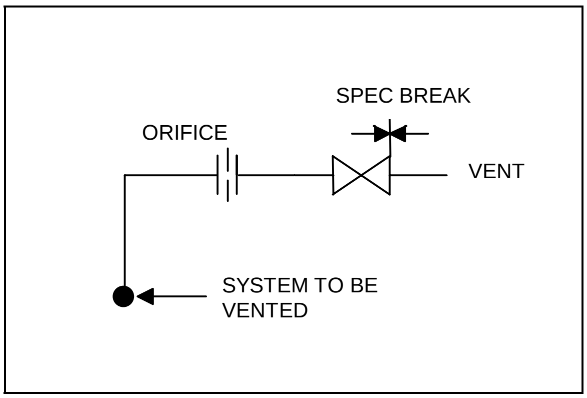


Figure A.12: Connection to a common Vent system.