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Petroleum and natural gas industries — Design and installation of piping systems on offshore production platforms

*Industries du pétrole et du gaz naturel — Conception et installation de
systèmes de tuyauterie sur les plates-formes de production en mer*



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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 3.

Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

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

International Standard ISO 13703 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 6, *Processing equipment and systems*.

Annexes A, B and C of this International Standard are for information only.

Introduction

This International Standard is based on API RP 14E, 5th edition, October 1991.

Petroleum and natural gas industries — Design and installation of piping systems on offshore production platforms

1 Scope

This International Standard specifies minimum requirements and gives guidance for the design and installation of new piping systems on production platforms located offshore for the petroleum and natural gas industries. It covers piping systems up to 69 000 kPa (ga) maximum, within temperature range limits for the materials meeting the requirements of ASME B31.3.

NOTE For applications outside these pressure and temperature ranges, this International Standard may be used but special consideration should be given to material properties.

Annex A gives some worked examples for solving piping design problems.

2 Normative references

The following normative documents contain provisions which, through reference in this text, constitute provisions of this International Standard. For dated references, subsequent amendments to, or revisions of, any of these publications do not apply. However, parties to agreements based on this International Standard are encouraged to investigate the possibility of applying the most recent editions of the normative documents indicated below. For undated references, the latest edition of the normative document referred to applies. Members of ISO and IEC maintain registers of currently valid International Standards.

ISO 13623, *Petroleum and natural gas industries — Pipeline transportation systems*.

API RP 520-2¹⁾, *Recommended practice for design and installation of pressure-relieving systems in refineries — Part 2*.

ASME²⁾, *Boiler and pressure vessel code: Section VIII: Pressure vessels, Division 1*.

ASME B 31.3, *Process piping*.

NACE MR0175³⁾, *Sulfide stress cracking resistant metallic materials for oil field equipment*.

NACE TM0177, *Laboratory testing of metals for resistance to specific forms of environmental cracking in H₂S environments*.

NACE TM0284, *Evaluation of pipeline and pressure vessel steels for resistance to hydrogen-induced cracking*.

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2) American Society of Mechanical Engineers, 345 East 47th Street, New York, N.Y. 10017, U.S.A.

3) National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218-8340, U.S.A.

3 Terms, definitions, symbols and abbreviated terms

For the purposes of this International Standard, the following terms, definitions, symbols and abbreviated terms apply.

3.1 Terms and definitions

3.1.1

chloride stress-corrosion cracking service

service in which the process stream contains water and chlorides in a sufficient concentration, and at a high enough temperature, to induce stress-corrosion cracking of susceptible materials

NOTE Other constituents present, such as oxygen (O_2), may contribute to such chloride stress-corrosion cracking.

3.1.2

choke

device specifically intended to restrict the flow rate of fluids

3.1.3

corrosion-erosion

eroding away of a protective film of corrosion product by the action of the process stream, exposing fresh metal which then corrodes

NOTE Extremely high metal mass loss can occur under these conditions.

3.1.4

corrosive gas

gas which, when dissolved in water or other liquid, causes corrosion of metal

NOTE Corrosive gases usually contain hydrogen sulfide (H_2S), carbon dioxide (CO_2) and/or oxygen (O_2).

3.1.5

corrosive hydrocarbon service

service in which the process stream contains water or brine and carbon dioxide (CO_2), hydrogen sulfide (H_2S), oxygen (O_2) or other corrosive agents under conditions which cause corrosion of metal

3.1.6

expansion bellows

corrugated piping device designed to absorb expansion and contraction

3.1.7

expansion bend

piping configuration designed to absorb expansion and contraction

3.1.8

flowline

piping that carries well fluid from wellhead to manifold or first process vessel

3.1.9

flow regime

flow condition of a multi-phase process stream

EXAMPLES Slug flow, mist flow or stratified flow.

3.1.10

fluid

gas, vapour, liquid or combinations thereof

3.1.11**header**

part of a manifold that directs fluid to a specific process system

See Figures 5 and 6.

3.1.12**hydrocarbon wettability**

ability of the process stream to form a protective hydrocarbon film on metal surfaces

3.1.13**manifold**

assembly of pipe, valves and fittings by which fluid from one or more sources is selectively directed to various process systems

3.1.14**nipple**

section of threaded or socket-welded pipe, shorter than 300 mm, used as an appurtenance

3.1.15**nominal pipe size****nominal size****NPS****DN**

designation of size in inches which is common to all components in a piping system other than those components designated by outside diameter

NOTE Nominal pipe size is designated by the letters NPS (when relating to inches) or DN (when relating to millimetres) followed by a number; it is a convenient number for reference purposes and it is normally only loosely related to manufacturing dimensions.

3.1.16**non-corrosive hydrocarbon service**

service in which the process stream conditions do not cause significant metal mass loss, selective attack, chloride stress-corrosion cracking or sulfide stress-cracking

3.1.17**normal conditions**

absolute pressure of 101,325 kPa and temperature of 0 °C

3.1.18**platform piping**

any piping intended to contain or transport fluid on a platform

3.1.19**pressure rating**

number relating to the pressure for which a system is suitable

NOTE The number may relate directly to the rated working pressure (e.g. ISO 10423 [1] pressure rating 13,8 MPa and API pressure rating 2 000 psi) or may have a more indirect correlation (e.g. ASME class 300).

3.1.20**pressure sensor**

device designed to detect a predetermined pressure

3.1.21**process component**

single functional piece of production equipment and associated piping

EXAMPLES Pressure vessel, heater, pump, etc.

3.1.22

riser

vertical portion of a pipeline (including the bottom bend) arriving on or departing from a platform

3.1.23

shutdown valve

automatically-operated valve used for isolating a process component or process system

3.1.24

sulfide stress-cracking service

service in which the process stream contains water or brine and contains a sufficient concentration of hydrogen sulfide (H_2S) to induce sulfide stress-cracking of susceptible materials

3.1.25

wellhead pressure

maximum shut-in surface pressure that may exist in a well

3.2 Symbols and abbreviated terms

3.2.1 Symbols

A minimum pipe cross-sectional flow area required per unit volume flowrate, expressed in square millimetres per cubic metre per hour ($mm^2/m^3/h$)

B mean coefficient of thermal expansion at operating temperatures normally encountered, expressed in millimetres per kelvin (mm/K)

C empirical constant, dimensionless

C_e sum of corrosion, mechanical strength and thread allowance, expressed in millimetres (mm)

C_v valve coefficient, dimensionless

NOTE 1 This value is equal to the water flowrate in US gpm at 60 °F required to generate a pressure drop of 1 psi (US Customary units only are used in this instance to maintain alignment with other published data).

D_i pipe inside diameter, expressed in metres (m)

D_o pipe outside diameter, expressed in millimetres (mm)

d_i pipe inside diameter, expressed in millimetres (mm)

d_g gas relative density (air = 1), dimensionless

d_L liquid relative density (water = 1), dimensionless

E longitudinal weld joint factor, dimensionless

E_m modulus of elasticity of piping material in the cold condition, expressed in newtons per square millimetre (N/mm^2)

f Moody friction factor, dimensionless

g gravitational constant, expressed in metres per second per second (m/s^2)

h_a acceleration head, expressed in metres (m) of liquid

h_f friction head, expressed in metres (m) of liquid

h_p	absolute pressure head, expressed in metres (m) of liquid
h_{st}	static head, expressed in metres (m) of liquid
h_{vh}	velocity head, expressed in metres (m) of liquid
h_{vpa}	absolute vapour pressure, expressed in metres (m) of liquid
h_W	pressure loss, expressed in kilopascals (kPa)
K	acceleration factor, dimensionless
L	developed pipe length, expressed in metres (m)
L_m	pipe length, expressed in kilometres (km)
m	manufacturing wall thickness tolerance, expressed as a percentage (%)
$NPSH_a$	available net positive suction head, expressed in metres (m) of liquid
p	operating pressure, expressed in kilopascals [kPa (abs)]

NOTE 2 Also denoted in text as “flowing pressure”.

p_i	internal design pressure, expressed in kilopascals [kPa (ga)]
q_g	gas flow rate, expressed in cubic metres per hour (m ³ /h) at normal conditions
q_L	liquid flow rate, expressed in cubic metres per hour (m ³ /h)
q_m	total liquid plus vapour mass flowrate, expressed in kilograms per hour (kg/h)
R	gas/liquid volume ratio, dimensionless
Re	Reynolds number, dimensionless
R_p	pump speed, expressed in revolutions per minute (r/min)
S	allowable stress, expressed in newtons per square millimetre (N/mm ²)
T	operating temperature, expressed in kelvin (K)

NOTE 3 Also denoted in text as “flowing temperature”.

t	pressure design thickness, expressed in millimetres (mm)
t_{nom}	minimum nominal pipe wall thickness, expressed in millimetres (mm)
U	anchor distance (straight line distance between anchors), expressed in metres (m)
v_e	fluid erosional velocity, expressed in metres per second (m/s)
v_g	average gas velocity, expressed in metres per second (m/s)

NOTE 4 Also denoted in text as “gas velocity”

v_L	average liquid velocity, expressed in metres per second (m/s)
y	resultant of total displacement strains, expressed in millimetres (mm)

Y	temperature factor, dimensionless
Z	gas compressibility factor, dimensionless
ΔL	expansion to be absorbed by pipe, expressed in millimetres (mm)
Δp	pressure drop, expressed in kilopascals (kPa)
ρ_g	gas density at operating pressure and temperature, expressed in kilograms per cubic metre (kg/m ³)
ρ_L	liquid density at operating temperature, expressed in kilogram per cubic metre (kg/m ³)
ρ_m	gas/liquid mixture density at operating pressure and temperature, expressed in kilograms per cubic metre (kg/m ³)
ΔT	temperature change, expressed in kelvin (K)
μ_g	gas viscosity at flowing pressure and temperature, expressed in pascal seconds (Pa·s)
μ_L	liquid viscosity, expressed in pascal seconds (Pa·s)

3.2.2 Abbreviated terms

ERW	Electric Resistance Weld
PWHT	Post-Weld Heat Treatment
RF	Raised Face
RTJ	Ring Type Joint
SAW	Submerged Arc Weld
SMYS	Specified Minimum Yield Strength

4 General considerations

4.1 Materials

Carbon steel materials are suitable for many of the piping systems on production platforms, although stainless steels and other materials are also widely used. The following should be considered when selecting piping materials:

- type of service;
- compatibility with other materials;
- mechanical strength, ductility, elasticity and toughness;
- need for special welding procedures, or other jointing techniques;
- need for special inspections, tests, or quality control;
- possible misapplication in the field;
- corrosion and erosion caused by internal fluids and/or marine environments;
- need for performance in a fire situation.

4.2 Code of pressure piping

4.2.1 The design and installation of platform piping shall be in accordance with ASME B31.3, as modified by this International Standard. Risers for which ASME B31.3 is not applicable should be designed and installed in accordance with 4.2.2 to 4.2.6.

4.2.2 Design, construction, inspection and testing of risers shall be in accordance with ISO 13623 and governmental rules and regulations as appropriate to the application, using a design stress no greater than 0,6 times SMYS. Pipeline design codes may be used from pig trap to pig trap, except where precluded by national regulations.

4.2.3 One hundred percent radiography of welding should be performed on riser piping. The non-destructive testing of platform piping complying with ASME B31.3 should as a minimum satisfy Table 10 of this International Standard.

4.2.4 Impact tests shall be performed as specified by ASME B31.3. The design of high-pressure piping systems (i.e. above ASME class 2500) needs special consideration and shall be in accordance with the high-pressure piping requirements of ASME B31.3.

4.2.5 Valves, fittings and flanges should be manufactured in conformance with International and/or National Standards. Pressure/temperature ratings and material compatibility should be verified.

4.2.6 In determining the transition between risers and platform piping to which these practices apply, the first incoming and last outgoing valve that block pipeline flow are the limits of this International Standard's application, except for riser wall thickness calculations and material selection which may be to a pipeline code to permit a constant bore for pigging. Recommended practices included in this International Standard may be utilized for riser design when factors such as water depth, batter of platforms legs, potential bubbling area etc. are considered. National regulations may require the pipeline code to be continued to/from the pig launcher/receiver.

4.2.7 It is also common practice for a pipeline code to apply through the riser up to the pig trap and to include the piping and the first valve on each branch on the riser/pipeline.

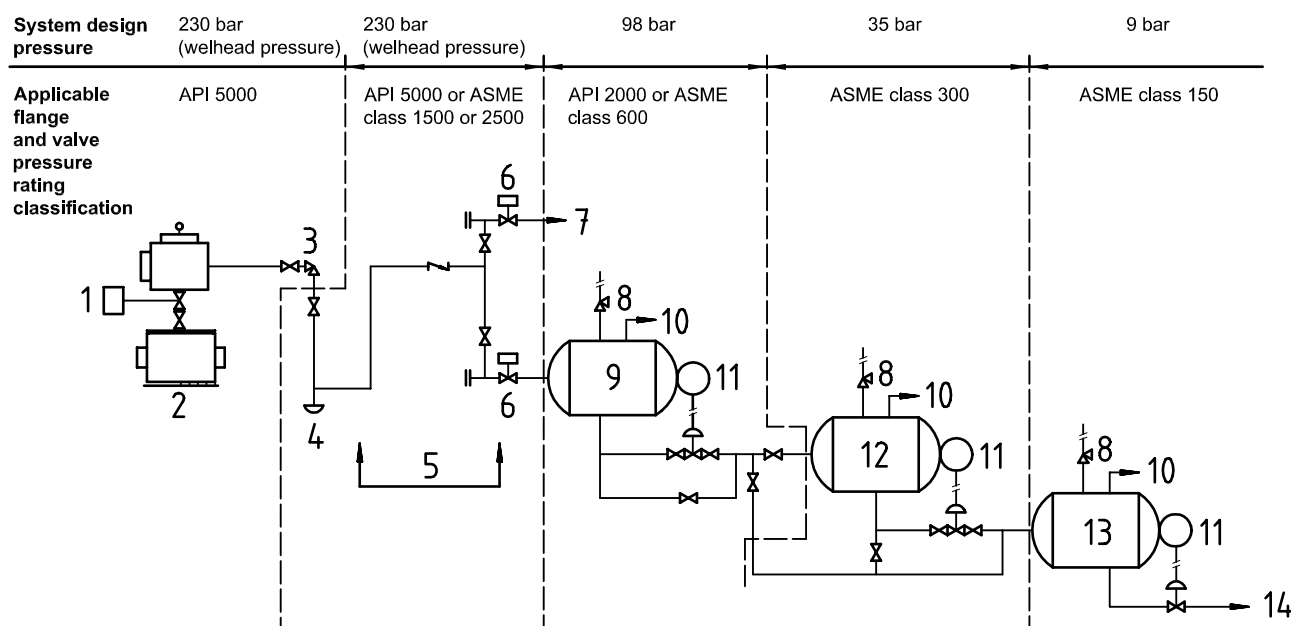
4.3 Demarcation between systems with different pressure ratings

4.3.1 Normally, after the well-stream leaves the wellhead the pressure is reduced in stages.

After the pressure is reduced, process components of lower pressure ratings may be used. A typical example is shown in Figure 1.

4.3.2 A pressure-containing process component shall either be designed to withstand the maximum internal pressure which can be exerted on it under any conditions, or shall be protected by a pressure-relieving device. In this case, a pressure-relieving device means a safety relief valve or a rupture disc. In general, when determining if pressure-relieving devices are needed, high-pressure shutdown valves, check valves, control valves or other such devices should not be considered as preventing overpressure of process components.

4.3.3 Pressure-rating boundaries shall be indicated on piping and instrument diagrams. Each system component (vessels, flanges, pipe or accessories) shall be designed to withstand the highest pressure to which it could be subjected under any foreseeable conditions, or it shall be protected by a pressure-relieving device. Abnormal pressure conditions shall be considered, e.g. start-up, shutdown, surge, etc.



NOTE 1 Design temperature is 65 °C throughout.

NOTE 2 Required shutdown sensors are not shown.

NOTE 3 Flowline and manifold are designed for wellhead pressure.

NOTE 4 System design pressures may be limited by factors other than the flange and valve pressure classifications (i.e. pipe wall thickness, separator design pressure, etc.).

NOTE 5 Only where spare relief valves are installed may upstream isolation valves be installed, and then it is essential that all isolation valves are interlocked to ensure that the pressurized system is protected at all times.

Key

- | | | |
|---------------------------|---------------------------|-------------------------------|
| 1 Upper master gate valve | 6 Shutdown valve | 11 Level controller |
| 2 Wellhead | 7 To other systems | 12 Medium pressure separator |
| 3 Wing choke | 8 Pressure safety valve | 13 Low pressure separator |
| 4 Flow tee | 9 High pressure separator | 14 Treating, storage or sales |
| 5 Manifold | 10 Gas outlet | |

Figure 1 — Example of a process system, denoting flange and valve pressure-rating changes

4.4 Corrosion considerations

4.4.1 General

Detailed corrosion-control practices for platform piping systems are outside the scope of this International Standard. Such practices should, in general, be developed by corrosion control specialists. Platform piping systems should, however, be designed to accommodate and be compatible with the corrosion control practices described below. Recommendations for corrosion-resistant materials and mitigation practices are given in the appropriate clauses of this International Standard.

The corrosivity of process streams may change over time. The possibility of changing conditions should be considered at the design stage.

4.4.2 Mass loss corrosion

Carbon steel platform piping systems may corrode under some process conditions. Production process streams containing water, brine, carbon dioxide (CO₂), hydrogen sulfide (H₂S) or oxygen (O₂), or combinations of these, may be corrosive to metals used in system components. The type of attack (uniform metal loss, pitting, corrosion-erosion, etc.) as well as the specific corrosion rate can vary in the same system, and can vary over time. The corrosivity of a process stream is a complex function of many variables, including:

- a) hydrocarbon, water, salt and corrosive gas content;
- b) hydrocarbon wettability;
- c) flow velocity, flow regime and piping configuration;
- d) temperature, pressure and pH;
- e) solids content (sand, mud, bacterial slime and microorganisms, corrosion products, and scale).

Corrosivity predictions are very qualitative and may be unique for each system. Some corrosivity information for corrosive gases found in production streams is shown in Table 1.

Table 1 is intended only as a general guide for corrosion mitigation considerations and not for specific corrosivity predictions. Corrosion inhibition is an effective mitigation procedure when corrosive conditions are predicted or anticipated (see 5.1.2).

Table 1 — Qualitative guideline for mass loss corrosion of steel

Corrosive gas	Solubility ^a ratio × 10 ⁻⁶	Limiting values in brine	
		Non-corrosive ratio × 10 ⁻⁶	Corrosive ratio × 10 ⁻⁶
Oxygen (O ₂)	8	< 0,005	> 0,025
Carbon dioxide (CO ₂)	1 700	< 600	> 1 200
Hydrogen sulfide (H ₂ S)	3 900	See Note	See Note
NOTE No limiting values for mass loss corrosion by hydrogen sulfide are shown in this table because the amount of carbon dioxide and/or oxygen greatly influences the metal loss corrosion rate. Hydrogen sulfide alone is usually less corrosive than carbon dioxide due to the formation of an insoluble iron sulfide film which tends to reduce metal mass loss corrosion.			
^a Solubility ratio by volume. Solubility at 20 °C in distilled water at 1 atm partial pressure. Oxygen (O ₂) is for 1 atm air pressure. Source: [3].			

4.4.3 Chloride stress-corrosion cracking

Careful consideration shall be given to the effect of stress and chlorides, if alloy and stainless steels are selected to prevent corrosion by hydrogen sulfide and/or carbon dioxide. Process streams that contain water with chlorides may cause cracking in susceptible materials, especially if oxygen is present and the temperature is above 60 °C. High alloy and stainless steels, such as the AISI 300-series austenitic stainless steels, precipitation-hardening stainless steels, and “A-286” (ASTM A 453 [2] grade 660), should not be used unless their suitability in the proposed environment has been adequately demonstrated. Consideration should also be given to the possibility that chlorides may be concentrated in localized areas in the system.

4.4.4 Sulfide stress-cracking

Process streams containing water and hydrogen sulfide may cause sulfide stress-cracking of susceptible materials. This phenomenon is effected by a complex interaction of parameters including metal chemical composition, hardness and microstructure, heat treatment condition and factors such as pH, hydrogen sulfide concentration, stress and temperature. Materials used for process streams containing hydrogen sulfide should be selected to accommodate these parameters.

Testing of these materials should be in accordance with NACE TM0177.

4.4.5 Application of NACE MR0175

Materials selected for resistance to sulfide stress-cracking should be in accordance with NACE MR0175. Corrosion-resistant alloys not listed in NACE MR0175 may exhibit such resistance and may be used if it can be demonstrated that they are resistant in the proposed environment of use (or in an equivalent laboratory environment). Caution should be exercised in the use of materials listed in NACE MR0175. The materials listed may be resistant to sulfide stress-cracking, but may not be suitable for use in chloride stress-corrosion cracking service.

4.4.6 Hydrogen-induced cracking

Process streams containing water and hydrogen sulfide may cause hydrogen-induced cracking (HIC) of susceptible materials, particularly to carbon steel plate fabrications or pipe made from plate. Consideration shall be given to HIC-testing such materials, which should be in accordance with NACE TM0284. Specialist advice should be sought in this area.

5 Piping design

5.1 Pipe material grades

5.1.1 Non-corrosive hydrocarbon service

The two most commonly used material grades of carbon steel pipe are ASTM A 106 [4] grade B, API 5L [5] grade B and ISO 3183-1 [6]. Seamless pipe is generally preferred due to its consistent quality. ASTM A 106 is only manufactured in seamless, while API 5L is available in seamless, ERW and SAW. If use of grade B requires excessive wall thickness, use of pipe with higher allowable design stress such as API 5L grade X52, may be required; however, special welding procedures and close supervision are necessary when using API 5L grade X46 or higher. It should be noted that the use of high yield materials such as 5L X-grades, will not result in a proportional increase in allowable stress values when used in accordance with ASME B31.3.

Many of the grades of pipe listed in ASME B31.3 are suitable for non-corrosive hydrocarbon service. The following types or grades of pipe are specifically excluded from hydrocarbon service in accordance with ASME B31.3:

- a) furnace lap-welded and furnace butt-welded;
- b) fusion-welded per ASTM A 134 [7] and ASTM A 139 [8];
- c) spiral-welded, except API 5L spiral-welded.

5.1.2 Corrosive hydrocarbon service

Design for corrosive hydrocarbon service should provide for one or more of the following corrosion-mitigating practices:

- a) chemical treatment;
- b) corrosion-resistant alloys;
- c) protective coatings (see 9.5.2).

Of these, chemical treatment of the fluid in contact with carbon steels has been common practice. Corrosion-resistant alloys that have proven successful in similar applications (or by suitable laboratory tests) may be used, however careful consideration should be given to welding procedures. Consideration shall also be given to the possibility of sulfide stress-cracking and chloride stress-corrosion cracking (see 4.4.3 and 4.4.4). Adequate provisions should be made for corrosion monitoring (coupons, probes, spools, etc.) and chemical treating.

Because welding can significantly alter the corrosion-resistance of otherwise resistant materials, careful consideration shall be given to the development of welding procedures.

5.1.3 Sulfide stress-cracking service

The following guidelines should be used when selecting pipe if sulfide stress-cracking is anticipated.

- a) Only seamless pipe should be used unless specifications and quality control applicable to this service have been exercised in manufacturing ERW or SAW pipe.
- b) Carbon and alloy steels and other materials that meet the property, hardness, heat treatment and other requirements of NACE MR0175 may be used in sulfide stress-cracking service.

The most commonly-used pipe grades that meet the above guidelines are ASTM A 106 grade B; ASTM A 333 [9] grade 6 and API 5L grade B seamless. API 5LX grades may also be used but their welding presents special problems.

5.1.4 Resistance to brittle fracture

To ensure adequate resistance to brittle fracture, the selected pipe material grade shall have adequate notch toughness at its design thickness and design temperature combination.

Non-impact-tested carbon steel pipe (materials) should at least be supplied normalized for services below 0 °C; and welded components may require PWHT depending on minimum (design) service temperature and thickness of weldment.

CAUTION — PWHT may reduce mechanical properties of API 5L X pipe material grades.

ASTM A 333 grade 6 is an impact-tested carbon steel suitable for cold service and should have adequate notch toughness down to – 46 °C. PWHT may be required for certain minimum design temperature and weldment thickness combinations.

5.1.5 Utilities services

Materials other than carbon steel are commonly used in utilities service. If, however, steel pipe is used that is of a type or grade not acceptable for hydrocarbon service in accordance with 5.1.1, some definite marking system should be established to prevent such pipe from accidentally being used in hydrocarbon service.

5.1.6 Tubing (instrumentation and hydraulic/air systems)

Solution-annealed austenitic stainless steel (AISI 316 or AISI 316L) tubing, either seamless or ERW, should be used in chloride environments and for all hydrocarbon service and air service.

5.2 Sizing criteria — General

5.2.1 In determining the diameter of pipe to be used in platform piping systems, both the flow velocity and pressure drop should be considered. 5.3, 5.4 and 5.5 present equations for calculating pipe diameters (and graphs for rapid approximation of pipe diameters) for liquid lines, single-phase gas lines, and gas/liquid two-phase lines, respectively. These equations may be used for preliminary sizing and for lines where pressure drop is not critical. For critical lines, more detailed calculations shall be performed. Many companies also use computer programs, often using the Colebrook equation, to facilitate piping sizing; see ref. [10] for further information.

5.2.2 When determining line sizes, consideration should be given to the range of conditions that give rise to the largest line size as well as just initial flow rates. These conditions may be higher liquid flow rates, or lower gas pressures, that may apply some time after facility start-up. It is often advisable to add a surge factor of between 20 % and 50 % to the anticipated normal flow rate, unless surge expectations have been more precisely determined by pulse pressure measurements in similar systems or by specific fluid hammer calculation. Table 2 presents some typical surge factors that may be used if more definite information is not available.

In large diameter flow lines producing liquid-vapour-phase fluids between platforms through riser systems, surge factors have been known to exceed 200 % due to slug flow. Liquid-vapour slug flow programs are generally available and may be consulted for the evaluation of slug flow.

Table 2 — Typical surge factors

Service	Surge factor
Facility handling primary production from its own platform	20 %
Facility handling primary production from another platform or remote well in less than 45 m (150 ft) of water	30 %
Facility handling primary production from another platform or remote well in greater than 45 m (150 ft) of water	40 %
Facility handling gas-lifted production from its own platform	40 %
Facility handling gas-lifted production from another platform or remote well	50 %

5.2.3 Determination of pressure drop in a line should include the effect of valves and fittings. Manufacturer's data or an equivalent length as given in Table 3 may be used.

5.2.4 Calculated line sizes may need to be adjusted in accordance with good engineering judgement.

5.3 Sizing methods for liquid lines

5.3.1 General

Single-phase liquid lines should be sized primarily on the basis of flow velocity. For lines transporting liquids in a single phase from one pressure vessel to another by pressure differential, the flow velocity should not exceed 5 m/s at maximum flow rates, to minimize flashing ahead of the control valve. Note that where "softer" materials are used, e.g. cupro-nickel, lower velocity limits apply. If practical, flow velocity should not be less than 1 m/s to minimize deposition of sand and other solids. At these flow velocities, the overall pressure drop in the piping will usually be small. Most of the pressure drop in liquid lines between two pressure vessels will occur in the liquid dump valve and/or choke.

Table 3 — Equivalent length of 100 % opening valves and fittings

Dimensions in metres

NPS	DN	Globe valve or ball check valve	Angle valve	Swing check valve	Plug valve, gate valve or ball valve	45° ell		Short radius ell		Long radius ell		Branch of tee		Run of tee		Enlargement						Contraction			
						Weld	Thread	Weld	Thread	Weld	Thread	Weld	Thread	Weld	Thread	Sudden	Standard reducer	Sudden	Standard reducer	Equivalent length in terms of small diameter					
																$d/D = 1/4$	$d/D = 1/2$	$d/D = 3/4$	$d/D = 1/2$	$d/D = 3/4$	$d/D = 1/2$	$d/D = 3/4$	$d/D = 1/2$	$d/D = 3/4$	
1½	40	16,8	7,92	3,96	0,305	0,610	0,914	1,52	0,914	2,49	2,74	0,610	0,914	1,22	0,610	1,52	0,914	0,305	1,22	0,305	0,914	0,610	0,305	10,305	$d/D = 3/4$
2	50	21,3	10,1	5,18	0,610	0,914	1,22	1,52	0,610	3,05	3,35	0,914	1,22	0,914	1,22	2,13	1,22	0,305	1,52	0,305	0,914	0,914	0,305	10,305	
2½	65	24,4	12,2	6,10	0,610	0,610	1,52		0,914	3,66		0,914		0,914	2,44	1,52	0,610	1,83	0,610	1,22	0,914	0,610	20,610		
3	80	30,5	15,2	7,62	0,610	0,610	1,83		1,22	4,17		1,22		1,22	3,05	1,83	0,610	2,44	0,610	1,52	1,22	0,610	20,610		
4	100	39,6	19,8	9,75	0,914	0,914	2,13		1,52	5,79		1,52		1,52	3,66	2,44	0,914	3,05	0,914	1,83	1,52	0,914	3,914	0,305	
6	150	61,0	30,5	14,6	1,22	1,22	3,35		2,44	8,53		2,44		2,44	5,49	3,66	1,22	4,27	1,22	2,74	2,13	1,22	1,22		
8	200	79,2	38,1	19,5	1,83	1,83	4,57		2,74	11,3		2,74		2,74	7,62	4,88	1,52	5,79	1,52	3,66	2,74	1,52	1,52	0,610	
10	250	101	48,8	24,4	2,13	2,13	5,49		3,66	14,3		3,66		3,66	9,45	6,10	2,13	7,32	2,13	4,57	3,66	1,83	1,83	0,610	
12	300	122	57,9	29,0	2,74	2,74	6,71		4,27	16,8		4,27		4,27	11,3	7,32	2,44	9,53	2,49	5,49	4,27	2,13	2,13	0,610	
14	350	137	64,0	32,0	3,05	3,05	7,92		4,88	18,9		4,88		4,88	12,8	7,92	2,74			6,10	4,88	2,44			
16	400	152	73,2	36,6	3,35	3,35	8,84		5,49	21,9		5,49		5,49	14,3	9,14	3,05			3,32	5,49	2,74			
18	450	168	85,3	42,7	3,66	3,66	10,1		6,10	25,0		6,10		6,10	16,2	10,7	3,35			7,92	6,10	3,05			
20	500	198	91,4	42,7	42,7	42,7	11,0		7,01	27,4		7,01		7,01	18,3	11,6	3,96			9,14	7,01	3,35			
22	550	210	102	51,8	45,7	45,7	12,2		7,62	30,5		7,62		7,62	19,8	12,8	4,27			9,75	7,62	3,66			
24	600	229	113	56,4	4,88	4,88	13,4		8,23	33,5		8,23		8,23	21,3	14,0	4,57			10,7	8,23	3,96			
30	750				6,40	6,40	16,8		12,2	42,7		12,2		12,2											
36	900				7,62	7,62	20,1		14,3	51,8		14,3		14,3											
42	1 050				9,14	9,14	23,5		16,8	61,0		16,8		16,8											
48	1 200				10,7	10,7	26,8		19,8	67,1		19,8		19,8											
54	1 350				12,2	12,2	30,2		21,3	76,2		21,3		21,3											
60	1 500				13,7	13,7	33,5		24,4	79,2		24,4		24,4											

NOTE 1

NOTE 2

Source: GPSA Data Book, 1987 Revision, ref. [11].
 d is inside diameter of small outlet. D is inside diameter of larger outlet.

5.3.1.1 Flow velocities in liquid lines may be read from Figure 2 or may be calculated using the following derived equation:

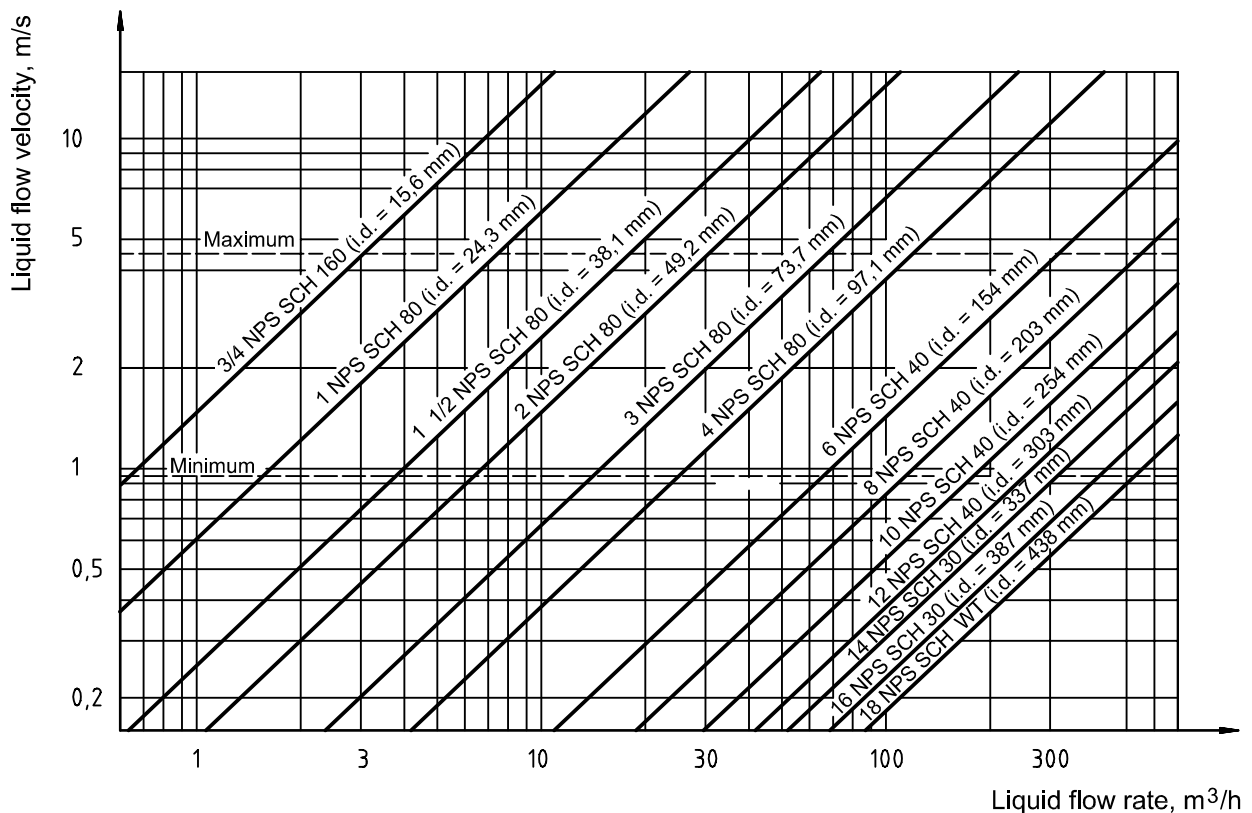
$$v_L = \frac{353,7 q_L}{d_i^2} \quad (1)$$

where

v_L is the liquid flow velocity, expressed in metres per second (m/s);

q_L is the liquid flow rate, expressed in cubic metres per hour (m³/h);

d_i is the pipe inside diameter, expressed in millimetres (mm).



NOTE These curves were determined using equation (2).

Figure 2 — Velocity in liquid lines

5.3.1.2 Pressure drop per 100 m pipe length for single-phase liquid lines may be calculated using the following (Fanning) equation:

$$\Delta p = \frac{6\,270 \times 10^6 f \cdot q_L^2 \cdot d_L}{d_i^5} \quad (2)$$

where

Δp is the pressure drop per 100 m of pipe, expressed in kilopascals (kPa);

f is the Moody friction factor, dimensionless;

q_L is the liquid flow rate, expressed in cubic metres per hour (m³/h);

d_L is the liquid relative density (water = 1), dimensionless;

d_i is the pipe inside diameter, expressed in millimetres (mm).

5.3.1.3 The Moody friction factor, f , is a function of the Reynolds number and the surface roughness of the pipe. The modified Moody diagram, Figure 3, can be used to determine the friction factor once the Reynolds number is known. The Reynolds number is determined by the following equation:

$$Re = \frac{\rho_L D_i v_L}{\mu_L} \quad (3)$$

where

Re is the Reynolds number, dimensionless;

ρ_L is the liquid density, expressed in kilograms per cubic metre (kg/m³);

D_i is the pipe inside diameter, expressed in metres (m);

v_L is the liquid flow velocity, expressed in metres per second (m/s);

μ_L is the liquid viscosity, expressed in pascal seconds (Pa·s), or

the quantity in centipoises divided by 1 000, or

the (quantity in centistokes × relative density) divided by 1 000.

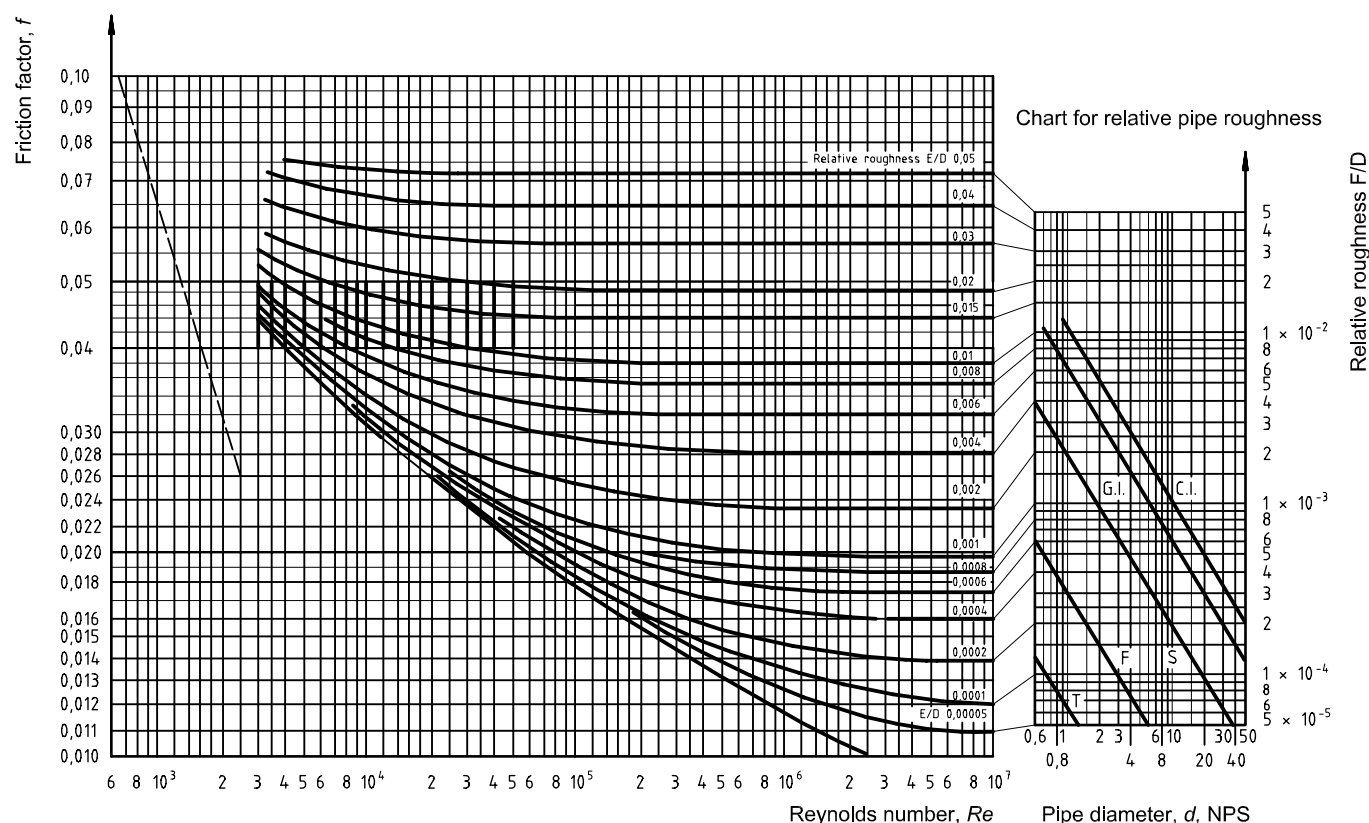


Figure 3 — Friction factor chart (modified Moody diagram)

5.3.2 Pump piping

5.3.2.1 Reciprocating, rotary and centrifugal pump suction piping systems should be designed so that the available net positive suction head ($NPSH_a$) at the pump inlet flange exceeds the NPSH required by the pump. Additionally, provision should be made in reciprocating pump suction piping to minimize pulsations. Satisfactory pump operation requires that essentially no vapour be flashed from the liquid as it enters the pump casing or cylinder.

5.3.2.2 In a centrifugal or rotary pump, the liquid pressure at the suction flange shall be high enough to overcome the pressure drop between the flange and the entrance to the impeller vane (or rotor) and maintain the pressure on the liquid above its vapour pressure, otherwise cavitation will occur. In a reciprocating unit, the pressure at the suction flange shall meet the same requirement but the pump's required NPSH is typically higher than for a centrifugal pump because of pressure drop across the valves and pressure drop caused by pulsation in the flow. Similarly, the available NPSH at the pump suction shall account for the acceleration in the suction piping caused by the pulsating flow, as well as the friction, velocity and static head.

5.3.2.3 The necessary available pressure differential over the pumped fluid vapour pressure may be defined as net positive suction head available ($NPSH_a$) which is the total head in metres absolute determined at the suction nozzle, minus the vapour pressure of the liquid in metres absolute. Available NPSH should always equal or exceed the pump's required NPSH. Available NPSH for most pump applications may be calculated using equation (4). It is normal practice to add a safety factor of up to 1 m to the NPSH calculated.

$$NPSH_a = h_p - h_{vpa} + h_{st} - h_f - h_{vh} - h_a \quad (4)$$

where

- h_p is the absolute pressure head due to pressure, atmospheric or otherwise, on surface of liquid going to suction, expressed in metres (m) of liquid;
- h_{vpa} is the absolute vapour pressure of the liquid at suction temperature, expressed in metres (m) of liquid;
- h_{st} is the static head, positive or negative, due to liquid level above or below datum line (centreline of pump), expressed in metres (m) of liquid;
- h_f is the friction head, or head loss due to flowing friction in the suction piping, including entrance and exit losses, expressed in metres (m) of liquid;
- h_{vh} is the velocity head, $v_L^2/2g$, expressed in metres (m) of liquid;
- h_a is the acceleration head, expressed in metres (m) of liquid;
- v_L is the velocity of liquid in piping, expressed in metres per second (m/s);
- g is the gravitational constant (usually 9,81 m/s²).

5.3.2.4 For a centrifugal or rotary pump, the acceleration head, h_a , is zero. For reciprocating pumps, the acceleration head is critical and may be determined by the following equation:

$$h_a = \frac{L v_L \cdot R_p \cdot C}{K \cdot g} \quad (5)$$

where

- h_a is the acceleration head, expressed in metres (m) of liquid;
- L is the length of suction line (actual length, not equivalent length), expressed in metres (m);
- v_L is the average liquid velocity in suction line, expressed in metres per second (m/s);
- R_p is the pump speed, expressed in revolutions per min (r/min);
- C is the empirical constant for the type of pump:
 - $C = 0,200$ for simplex double-acting;
 - $C = 0,200$ for duplex single-acting;
 - $C = 0,115$ for duplex double-acting;
 - $C = 0,066$ for triplex single- or double-acting;
 - $C = 0,040$ for quintuplex single- or double-acting;
 - $C = 0,028$ for septuplex single- or double-acting;

NOTE The constant C varies from these values for unusual ratios of connecting rod length to crank radius.

K is the liquid compressibility factor representing the reciprocal of the fraction of the theoretical acceleration head which shall be provided to avoid a noticeable disturbance in the suction piping:

$K = 1,4$ for liquid with almost no compressibility (deaerated water);

$K = 1,5$ for amine, glycol, water;

$K = 2,0$ for most hydrocarbons;

$K = 2,5$ for relatively compressible liquid (hot oil or ethane);

g is the gravitational constant (usually $9,81 \text{ m/s}^2$).

It should be noted that there is not universal acceptance of equation (5) or the effect of acceleration head (see [12], [13] and [14] for further information). However, equation (5) is believed to be a conservative basis that will assure adequate provision for acceleration head.

5.3.2.5 When more than one reciprocating pump is operated simultaneously on a common feed line, all crankshafts are at times in phase and, to the feed system, the multiple pumps act as one pump of that type with a capacity equal to that of all pumps combined. In this case, the maximum instantaneous velocity in the feed line would be equal to that created by one pump having a capacity equal to that of all the pumps combined.

5.3.2.6 If the acceleration head is determined to be excessive, the following should be evaluated.

- a) Shorten the suction line. Acceleration head is directly proportional to line length, L .
- b) Use a larger suction pipe to reduce velocity. This is very helpful since velocity varies inversely with the square of pipe inside diameter. Acceleration head is directly proportional to fluid velocity, v_L .
- c) Reduce the required pump speed by using a larger-size piston or plunger, if permitted by the pump rating. Speed required is inversely proportional to the square of piston diameter. Acceleration head is directly proportional to pump speed, R_p .
- d) Consider using a pump with more plungers. For example:
 $C = 0,040$ for a quintuplex pump. This is about 40 % less than a triplex pump;
 $C = 0,066$ for a triplex pump. Acceleration head is directly proportional to C .
- e) Consider using a pulsation dampener if the above remedies are unacceptable. The results obtainable by using a dampener in the suction system depend on the size, type, location and charging pressure used. A good, properly-located dampener, if kept properly charged, may reduce L , the length of pipe used in the acceleration head equation, to a value of 5 to 15 nominal pipe diameters. Dampeners should be located as close to the pump suction as possible.
- f) Use a centrifugal booster pump to charge the suction of the reciprocating pump.

5.3.2.7 The following guidelines may be useful in designing suction piping:

- a) suction piping may be one or two pipe sizes larger than the pump inlet connection;
- b) suction lines should be short with a minimum number of elbows and fittings, and should fall continuously to the pump suction nozzle;
- c) eccentric reducers should be used near the pump, with the flat side on top, to keep the top of the line level. This eliminates the possibility of gas pockets being formed in the suction piping. If potential for accumulation of debris is a concern, means for removal should be provided;

- d) for reciprocating pumps, provide a suitable pulsation dampener (or make provisions for adding a dampener at a later date) as close to the pump suction as possible;
- e) in multi-pump installations, size the common feed line so that the velocity will be as close as possible to the velocity in the laterals going to the individual pumps. This avoids velocity changes and thereby minimizes acceleration head effects.

5.3.2.8 Reciprocating, centrifugal and rotary pump discharge piping should be sized on an economical basis. Additionally, reciprocating pump discharge piping should be sized to minimize pulsations. Pulsations in reciprocating pump discharge piping are also related to the acceleration head, but are more complex than suction piping pulsations. The following guidelines may be useful in designing discharge piping:

- a) discharge piping should be as short and direct as possible;
- b) discharge piping may be one or two pipe sizes larger than pump discharge connection;
- c) the velocity in discharge piping should not exceed three times the velocity in the suction piping. This velocity will normally result in an economical line size for all pumps, and will minimize pulsations in reciprocating pumps;
- d) for reciprocating pumps, include a suitable pulsation dampener (or make provisions for adding a dampener at a later date) as close to the pump discharge as possible.

5.3.2.9 Table 4 may be used to determine preliminary suction and discharge line sizes.

Table 4 — Typical flow velocities

Type of pump	Suction velocity m/s	Discharge velocity m/s
Reciprocating		
Speeds up to 250 r/min	0,6	1,8
Speeds 251 r/min to 330 r/min	0,45	1,4
Speeds above 330 r/min	0,3	1,0
Centrifugal	0,6 to 1	1,8 to 2,7

5.4 Sizing criteria for single-phase gas lines

5.4.1 Sizing considerations

Single-phase gas lines should be sized so that the resulting end pressure is high enough to satisfy the requirements of the next piece of equipment. Excessive noise may result from restrictions such as control valves, orifices etc. or from velocities exceeding 25 m/s; however, the velocity of 25 m/s should not be interpreted as an absolute criteria. Higher velocities are acceptable if pipe routing, valve choice and placement are done to minimize or isolate noise.

The design of any piping system where corrosion inhibition is expected to be utilized shall consider the installation of additional wall thickness in piping design and/or reduction of velocity to less than 15 m/s to reduce the effect of stripping inhibitor film from the pipe wall. In such systems, a wall thickness monitoring method should be instituted.

5.4.2 General pressure drop equation

$$p_1^2 - p_2^2 = 6 \times 10^4 \left(\frac{S_g \cdot q_g^2 \cdot Z \cdot T_1 \cdot f \cdot L}{d_i^5} \right) \quad (6)$$

where

- p_1 is the upstream pressure, expressed in kilopascals [kPa (abs)];
- p_2 is the downstream pressure, expressed in kilopascals [kPa (abs)];
- d_g is the gas relative density (air = 1,0), dimensionless;
- q_g is the gas flow rate, expressed in cubic metres per hour (m³/h) at normal conditions;
- Z is the compressibility factor for gas (see [11] for further information);
- T_1 is the flowing temperature, expressed in kelvin (K);
- f is the Moody friction factor, dimensionless (refer to Figure 3);
- d_i is the pipe inside diameter, expressed in millimetres (mm);
- L is the length, expressed in metres (m).

Rearranging equation (6) and solving for q_g :

$$q_g = 0,004\ 08 \left[\frac{d_i^5 (p_1^2 - p_2^2)}{Z \cdot T_1 \cdot f \cdot L \cdot d_g} \right]^{1/2} \quad (7)$$

An approximation of equation (6) can be made when the change in pressure is less than 10 % of the inlet pressure. If this is true, the assumption can be made:

$$p_1^2 - p_2^2 \cong 2p_1 (p_1 - p_2) \quad (8)$$

Substituting in equation (6):

$$\Delta p = 300 \frac{d_g \cdot q_g^2 \cdot Z \cdot T_1 \cdot f \cdot L}{p_1 \cdot d_i^5} \quad (9)$$

5.4.3 Empirical pressure drop

5.4.3.1 Equation assumptions

Several empirical equations have been developed so as to avoid solving for the Moody friction factor. All equations are patterned after the general flow equation with various assumptions relative to the Reynolds number. The most common empirical pressure-drop equation for gas flow in production facility piping is the Weymouth equation described below.