

Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

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Foreword

This recommended practice (RP) sets out criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons, that is, the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water.

The criteria contained in this document are intended to permit the economical transportation of hydrocarbons while providing for the safety of life and property and the protection of the environment. The general adoption of these criteria should assure that offshore hydrocarbon pipelines possess the requisite structural integrity for their safe and efficient operation.

This RP includes a “limit state design” methodology. Safety margins similar to existing levels are obtained for the lower D/t ratio by changing to a limit state design based on the actual burst strength of pipe. The burst pressure formula in the document is based on theoretical considerations and confirmed by more than 250 burst tests of full-size pipe specimens that cover a wide range of pipe grade, diameter, and wall thickness.

Portions of this publication have changed from the previous editions, which have been an RP, but the changes are too numerous to use bar notations in this edition. In some cases, the changes are significant, while in other cases the changes reflect minor editorial adjustments.

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Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC, 20001, standards@api.org.

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Introduction

Limit state design has been incorporated in this recommended practice (RP) to provide a uniform factor of safety with respect to rupture or burst failure as the primary design condition independent of the pipe diameter, wall thickness, and grade. Background on theory and practice of limit states for pressure-containing cylinders may be found in Hill [2] and in Crossland and Jones [1], as listed in the Bibliography at the end of the RP. Burst design criteria within this practice are presently defined for carbon steel line pipe. Application of the proposed design criteria to other materials requires determination by the user of the minimum burst criteria using the procedure set forth in Annex A.

Design and construction practices other than those set forth in Section 4 and Section 7 may be employed when supported by adequate technical justification, including model or proof testing of involved components or procedures as appropriate. Nothing in this RP should be considered as a fixed rule for application without regard to sound engineering judgment.

NOTE Certain governmental requirements or company specifications may differ from the criteria set forth in this RP, and this RP does not supersede or override those differing requirements or specifications.

This publication has incorporated by reference all or parts of several existing codes, standards, and RPs that have been found acceptable for application to offshore hydrocarbon pipelines.

Caution—Users shall use the most recent editions of all reference documents in this RP. For ASME B31.4 and ASME B31.8 specifically, the 2006 edition and the 2007 edition, respectively, of the documents were used as the basis for determining the requirements. However, the reference is meant to be to the corresponding part in the latest revision or edition of the publication.

Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

1 Scope

This recommended practice (RP) sets criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons; that is, the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water. This RP may also be utilized for water injection pipelines offshore.

The RP also applies to any transportation piping facilities located on a production platform downstream of separation and treatment facilities, including meter facilities, gas compression facilities, liquid pumps, associated piping, and appurtenances.

The design, construction, inspection, and testing provisions of this RP may not apply to offshore hydrocarbon pipelines designed or installed before this latest revision of the RP was issued. The operation and maintenance provisions of this RP are suitable for application to existing facilities.

For a graphic representation of the scope of this RP, see Figure 1.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 2A-WSD, *Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design*

API Standard 2RD, *Dynamic Risers for Floating Production Systems*

API Specification 5L, *Specification for Line Pipe*

API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe*

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Specification 6D, *Specification for Pipeline and Piping Valves*

API Recommended Practice 14C, *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*

API Standard 1104, *Welding of Pipelines and Related Facilities*

ASME B31G¹, *Manual for Determining the Remaining Strength of Corroded Pipelines*

ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*

ASME B31.8, *Gas Transmission and Distribution Piping Systems*

ASME Boiler and Pressure Vessel Code (BPVC), Section IX: *Welding, Brazing, and Fusing Qualifications*

¹ ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

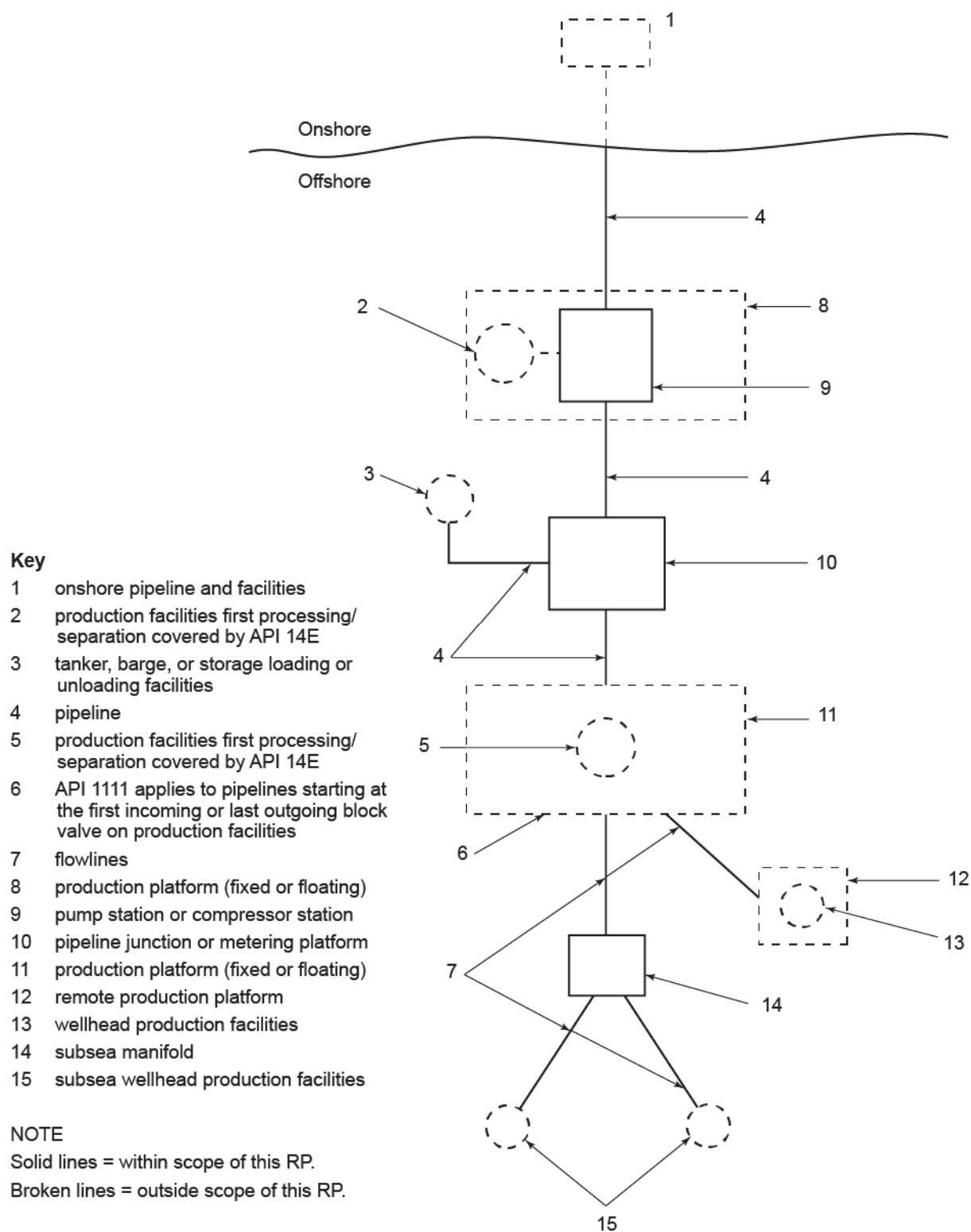


Figure 1—Scope of API 1111

ASQ Z1.9-2003 ², *Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming*

AWS D3.6M ³, *Underwater Welding Code*

MSS SP-44 ⁴, *Steel Pipeline Flanges*

NACE SP0106 ⁵, *Control of Internal Corrosion in Steel Pipelines and Piping Systems*

ANSI/NACE SP0115-2015/ISO 15589-2, *Petroleum, petrochemical and natural gas industries—Cathodic protection of pipeline transportation systems—Part 2: Offshore pipelines*

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1

design pressure

Maximum difference, at each cross section, between internal pressure and external pressure during operating conditions.

NOTE Section 4.3.1 sets limits on design pressure.

3.1.2

extreme loads

Loads that are unlikely to be exceeded during the lifetime of the pipeline.

3.1.3

gas

Hydrocarbon in a vapor phase.

3.1.4

limit state design

Condition of a structure such as a pipeline, beyond which it no longer fulfills the relevant design criteria

NOTE The condition may refer to a degree of loading or other actions on the structure, while the criteria refer to structural integrity, fitness for use, durability or other design requirements.

3.1.5

non-shielded coating

Coating system with a failure mode (loss of adhesion etc.) that does not prevent distribution of cathodic protection current to the metal substrate

3.1.6

offshore

Area seaward of the established coastline that is in direct contact with the open sea, and seaward of the line marking the seaward limit of inland coastal waters.

² American Society for Quality Control, 611 East Wisconsin Avenue, Milwaukee, Wisconsin 53202, www.asq.org.

³ American Welding Society, 8669 NW 36 Street, #130, Miami, Florida 33166-6672, www.aws.org.

⁴ Manufacturers Standardization Society of the Valve and Fittings Industry, Inc., 127 Park Street, NE, Vienna, Virginia 22180-4602, www.mss-hq.com.

⁵ NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org.

3.1.7

offshore pipeline riser

Vertical or near-vertical portion of an offshore pipeline between the platform piping and the pipeline at or above the seabed, differentiated from a pipeline to provide additional personnel safety factor for third-party damage, dropped objects, etc.

NOTE For purposes of internal pressure design, the “pipeline riser” design factor applies to the riser pipe within an appropriate horizontal distance from the surface facility, and the “pipeline” design factor applies beyond that point.

- a) A minimum horizontal offset distance of 300 ft for use of the pipeline riser design factor is recommended for deepwater suspended risers (e.g. SCRs). Offset begins at the hang-off point of the riser.
- b) For shallow-water fixed platforms, the entire riser attached to the facility typically employs the “pipeline riser” design factor. Pipeline on the seabed connecting to a shallow-water fixed platform riser typically employs the pipeline riser design factor for a horizontal offset distance of 300 ft.

3.1.8

oil

Hydrocarbon in liquid phase.

3.1.9

operational loads

Loads that may occur during normal operation of the pipeline.

3.1.10

pipeline

Piping that transports fluids between offshore production facilities or between a platform and a shore facility, often sub-classified into the three categories: flowlines, injection lines, and export lines.

NOTE The use of the word pipeline in this RP applies to all three categories defined below, unless otherwise specifically noted in the RP.

- a) **Export Line**—A pipeline that transports processed oil and/or gas fluids between platforms or between a platform and a shore facility.
- b) **Flowline**—A pipeline that transports the well fluids from the wellhead to the first downstream process component. Flowlines covered by this RP originate at a subsea wellhead, subsea manifold, or a remote wellhead platform. Flowlines that are confined to a single platform are not covered by this RP (see API 14E).
- c) **Injection Line**—A pipeline that directs liquids or gases into a formation, wellhead, or riser, to support hydrocarbon production activity (i.e. water or gas injection, gas lift, or chemical injection lines, etc.).

3.1.11

pipeline component

Any part of a pipeline that may be subjected to pressure as a result of the process, environment, or intervention activities.

3.1.12

pipeline system

Pipeline and its components, including compressor stations and pump stations that are subjected to internal pressure by the transported fluids.

3.1.13

platform piping

Piping restricted to a production or transportation hub platform, confined to the platform or is located between launching and receiving traps or the first boarding SDV and the last out-going block valve if no traps are present.

NOTE 1 See API 14E for platform piping RPs.

NOTE 2 Launching and receiving facilities inclusive of the associated valves for pipeline cleaning/inspection devices are considered part of the pipeline from a design standpoint.

3.1.14**primary load**

Primary force necessary for equilibrium with applied loads and acting on a structure such as internal pressure or tension loading which drive the design considerations, materials, and final results

NOTE A primary load is not self-limiting; thus if a primary load substantially exceeds the yield strength, either failure or gross structural yielding occurs.

3.1.15**production platform**

Facility that is operated to produce liquid or gas hydrocarbons and that includes such items as wells, wellhead assemblies, completion assemblies, platform piping, separators, dehydrators, and heater treaters.

3.1.16**splash zone**

Area of the pipeline riser or other pipeline components that is intermittently wet and dry due to wave and tidal action.

3.1.17**surge pressure**

Pressure produced by sudden changes in the velocity of the moving stream of hydrocarbons inside the pipeline or riser.

3.2 Acronyms, Abbreviations, and Symbols

For the purposes of this document, the following acronyms, abbreviations, and symbols apply.

A	cross-sectional area of pipe steel, in mm^2 (in.^2)
A_i	internal cross-sectional area of the pipe, in mm^2 (in.^2)
A_o	external cross-sectional area of the pipe, in mm^2 (in.^2)
$CEBP$	capped end burst pressure in N/mm^2 (psi)
$CEYP$	capped end yield pressure in N/mm^2 (psi)
CVA	certified verification agent
D	outside diameter of pipe (equation dependent)
D_i	inside diameter of pipe, in mm (in.) = $(D - 2t)$
$D_{\max}$	maximum diameter at any given cross section, in mm (in.)
$D_{\min}$	minimum diameter at any given cross section, in mm (in.)
d_{pipe}	outside steel pipe diameter
d_{reel}	reel or aligner diameter
DSAW	double submerged arc welded
E	Young's modulus of elasticity, in N/mm^2 (psi)
ERW	electric resistance welded
FBE	fusion bonded epoxy
FIV	flow-induced vibration
f_c	collapse factor for use with combined pressure and bending loads
f_d	internal pressure (burst) design factor
f_e	weld joint factor, longitudinal or spiral seam welds

f_o	collapse factor
f_p	propagating buckle design factor
fsw	feet of saltwater
f_t	temperature derating factor
f_1	bending safety factor for installation bending plus external pressure
f_2	bending safety factor for in-place bending plus external pressure
$g(\delta)$	collapse reduction factor
k	computed burst factor
ln	natural log
MOP	maximum operating pressure
MSP	maximum source pressure
N	newtons
NPS	nominal pipe size
P_a	incidental overpressure (internal minus external pressure), in N/mm ² (psi)
P_{actual}	actual measured burst pressure, in N/mm ² (psi)
P_b	specified minimum burst pressure of pipe, in N/mm ² (psi)
P_c	collapse pressure of the pipe, in N/mm ² (psi)
P_d	design pressure of the pipeline, (internal minus external pressure) in N/mm ² (psi)
P_e	elastic collapse pressure of the pipe, in N/mm ² (psi)
PIP	pipe-in-pipe
P_i	internal pressure in the pipe, in N/mm ² (psi)
P_o	external hydrostatic pressure, in N/mm ² (psi)
P_p	buckle propagation pressure, in N/mm ² (psi)
P_s	shut-in pressure (psi)
P_t	hydrostatic test pressure (internal minus external pressure), in N/mm ² (psi)
P_y	yield pressure at collapse, in N/mm ² (psi)
S	SMYS of pipe, in N/mm ² (psi)
SAF	strain amplification factor
SCR	steel catenary riser
SDV	shutdown valve
SG	specific gravity
SIV	slug-induced vibration
SMYS	specified minimum yield strength (see S)
T_a	axial tension in the pipe, in N (lb)
T_{eff}	effective tension in pipe, in N (lb)
T_{lay}	residual lay tension
TLP	tension leg platform

T_y	yield tension of the pipe, in N (lb)
t	nominal wall thickness of pipe, in mm (in.)
$t_{\min}$	minimum measured wall thickness, in mm (in.)
U	specified minimum ultimate tensile strength of pipe, in N/mm ² (psi)
U_{actual}	average measured ultimate tensile strength of pipe, in N/mm ² (psi)
VIV	vortex-induced vibration
Y_{actual}	average measured yield strength of pipe, in N/mm ² (psi)
α	thermal coefficient of expansion of pipe
ρ	density (lb/ft ³)
δ	ovality
ϵ	allowable bending strain in the pipe [in the presence of external pressure]
ϵ_b	buckling strain under pure bending
ϵ_{nom}	nominal bending strain in pipe
ϵ_1	maximum installation bending strain
ϵ_2	maximum in-place bending strain
σ_a	axial stress in the pipe wall, in N/mm ² (psi)
ν	Poisson's ratio (0.3 for steel)

4 Design

4.1 Design Conditions

4.1.1 General

Offshore hydrocarbon pipelines, with the exceptions noted in Section 1, should conform to all sections of this recommended practice (RP).

Pipe selection for most offshore pipelines is determined by considering installation and operation loads in addition to the stresses resulting from internal pressure. Design should begin with material selection and pipe sizing for flow considerations and be modified later as a result of design cycles that include the following:

- a) burst due to net internal pressure;
- b) combined bending and tension during installation and operation;
- c) collapse due to external pressure, with the pipe either empty or filled;
- d) buckling and collapse due to combined bending and external pressure;
- e) pipeline stability against horizontal or vertical displacement during construction and operation;
- f) effects of thermal expansion and contraction;
- g) in-place and in-service pipeline repair capabilities;
- h) fatigue due to hydrodynamic and operational loading;
- i) spanning impacts due to route selection;

- j) pipeline/umbilical crossing requirements;
- k) internal/external mechanical damage such as corrosion and erosion;
- l) fatigue affects during construction.

This document is a limit state design practice because design is based on the strength of the pipe for each of the above limit states.

4.1.2 Design for Internal and External Pressures

4.1.2.1 Design for Internal Pressure

Pipeline components at any point in a pipeline system should be designed for or selected to withstand the maximum differential pressure between internal and external pressures to which the components will be exposed during construction and under operating conditions.

NOTE Design equations in this section using differential pressure apply to pipe or other round cylindrical shells only and may not be suitable for valves and similar components.

For such components, more detailed analysis is required to assess the combined effect of internal and external pressure, which is beyond the scope of this RP.

The maximum differential pressure for a flowline may be due to a shut-in pressure condition. This condition may result from closure of a valve at the production facility without closing the valves at the tree, manifold, or downhole safety valve. The condition may also occur due to leakage of these same valves or due to plugging of the flowline. The shut-in pressure condition should be considered unless an overpressure protection device or system is installed (refer to API 14C).

4.1.2.2 Design for External Pressure

An important consideration in offshore pipeline design is external pressure on all undersea pipeline systems. The significance of external pressure has been demonstrated by the buckling of large pipelines subjected to severe bending and external pressure.

4.1.3 Thermal Influences

The design should consider the effects of thermal expansion and contraction of the pipeline system. When temperature changes are anticipated, the pipeline approach to a platform or subsea junction should have additional flexibility for expansion and contraction using measures such as slack curves, pipeline bends, and thermal expansion devices.

Adequate measures should be taken to prevent excessive strains or fatigue damage due to thermally induced upheaval buckling of buried pipelines or lateral buckling of non-buried pipelines. Design considerations for upheaval and lateral buckling should account for fatigue, longitudinal, and combined loads as described in 4.5 and 4.6.5 (more information can be found in the reference paper OTC 6335^[5]).

High production temperatures may lead to thermal expansion of production casing and elevation increases of subsea wellheads. Such elevation changes will induce displacements and loads in attached equipment such as jumpers and flowlines.

Thermal expansion of subsea flowlines may result in the movement of mat foundations supporting piping and valve equipment. The mat foundation should be designed to accommodate repeated expansion movements and prevent excessive rotation or settlement as a result of soil being displaced from beneath it.

4.1.4 Static Loads

The design should consider static loads imposed on the pipeline. These include the weight of the pipe, coating, appurtenances, and attachments; external and internal hydrostatic pressure and thermal expansion loads; and the static forces due to bottom subsidence and differential settlement.

The weight-related forces are of special concern where the pipeline is not continuously supported, that is, where spans are expected to occur. Spans are also of concern where seismic liquefaction of the supporting bottom could occur, and where mudslides could occur, such as some areas around the Mississippi River delta.

The weight of the submerged pipeline can be controlled through the combination of the pipe wall thickness and the density and thickness of the external (concrete) weight coating. Weight calculations should consider stability when empty (the usual as-laid condition), full of the fluid to be transported, and flooded with seawater.

Consideration should be given to preventing unacceptably long unsupported lengths by use of dumped gravel, anchor supports, concrete mattresses, sand bagging, or other suitable means.

Thermal expansion loads are not considered primary loads unless they can lead to buckling or axial collapse of the pipeline (see 4.3.1.3).

4.1.5 Dynamic Loads

The design should consider dynamic loads and the resulting stresses imposed on the pipeline. These may include stresses induced by impact, vibration due to current-induced vortex shedding and other hydrodynamic loading, seismic activity, soil movement, and other natural phenomena. Forces imposed during construction induce bending, compressive, and tensile stresses, which, in combination with other stresses, can cause pipeline failure.

4.1.6 Relative Movement of Connected Components

The design should consider the effect of the movement of one component relative to another and the movement of pipe-supporting elements relative to the pipe.

A steel catenary riser (SCR) shall be designed to meet the requirements of API 2RD. Design should include allowable movement of the catenary risers and avoidance of interference with other risers and mooring lines suspended from the structure. The catenary riser touchdown point is expected to reposition itself from time-to-time during its service life, which should be acceptable provided the requirements of strain limits and fatigue life are adequately met. The seafloor in any potential area of SCR touchdown movement should be clear of all debris.

4.1.7 Corrosion Allowances

4.1.7.1 Allowance for External Corrosion

Adequate anticorrosion coating and cathodic protection shall be provided. Refer to ISO 15589-2 as a guideline for the control of external corrosion. A corrosion allowance for external corrosion is not required where cathodic protection is provided.

4.1.7.2 Allowance for Internal Corrosion

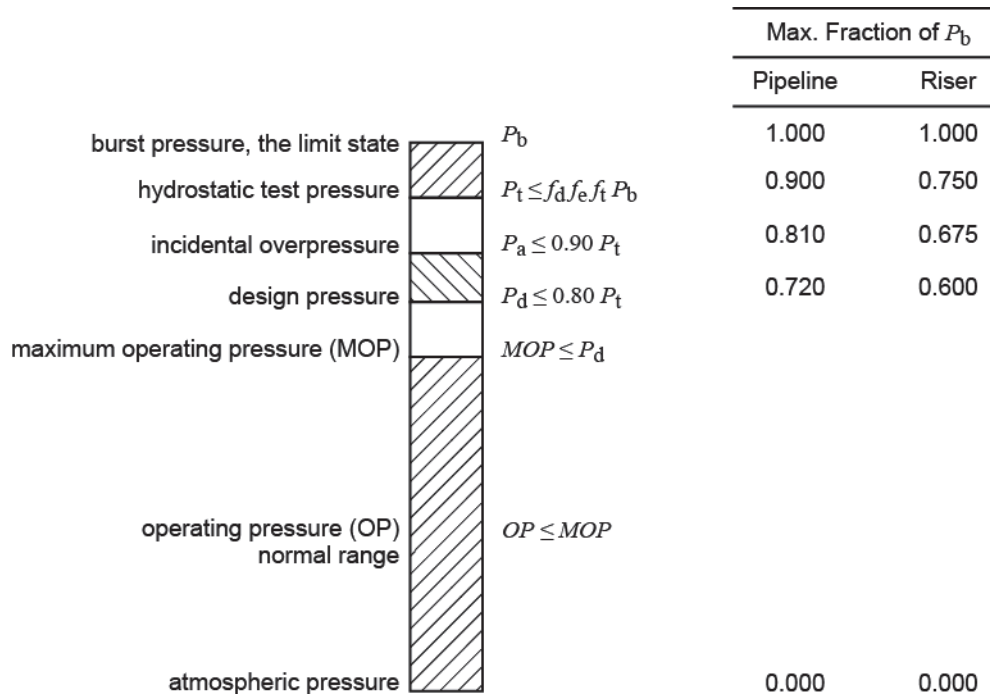
Adequate measures shall be taken to protect against internal corrosion. Proper selection of pipe material, internal coating, injection of a corrosion inhibitor, or a combination of such options should be considered. The selected pipe wall thickness may require a corrosion allowance. Determination of the required corrosion allowance is outside the scope of this RP.

The effectiveness of the corrosion mitigation system should be evaluated periodically to ensure the system is functioning as intended. In-service monitoring devices should be designed into the original mitigation system.

4.2 Design Criteria

4.2.1 General

This subsection provides design factors governing the maximum operating pressure (MOP) and the maximum incidental pressure of a pipeline system, and how these pressure levels relate (see Figure 2).



NOTE See 9.2.2 for primary and secondary overpressure protection device settings.

Figure 2—Pressure Level Relations

4.2.2 MOP

4.2.2.1 MOP Limits

The MOP should not exceed any of the following:

- the design pressure of any component, including pipe, valves, and fittings;
- 80 % of the applied hydrostatic test pressure in accordance with 8.2.

For purposes of design, pressure shall be interpreted as the difference between internal pressure and external pressure acting on the pipeline.

NOTE Some regulations relate MOP to a maximum internal source pressure. While these regulations may still allow for consideration of external pressure, the definition of, for example, the required hydrostatic test pressure may differ from the definition in this RP. See the note in C.2.

4.2.2.2 Incidental Overpressure

Incidental overpressure includes the situation where the pipeline is subject to surge pressure, unintended shut-in pressure, or any temporary incidental condition. The incidental overpressure should not exceed 90 % of the hydrostatic test pressure. The incidental pressure may exceed MOP temporarily, but the normal shut-in pressure condition should not be allowed to exceed MOP.

4.2.3 Pressure Ratings for Pipeline Components

4.2.3.1 Components

Valves, flanges, and other components should have pressure ratings that are equal to or exceed the requirements for the pipeline or flowline. See note in 4.1.2.1.

4.2.3.2 Components Without Specific Ratings

Components not manufactured to a standard specification may be qualified for use as specified in ASME B31.4 or ASME B31.8. Nonmetallic trim, packing, seals, and gaskets should be made of materials compatible with the fluid the pipeline and with the offshore environment.

4.2.3.3 Segmentation for Different MOPs

Pipelines that are segmented to operate at different MOPs should have an isolation valve (and any associated components) rated to the higher MOP installed at the point of pressure segmentation. The lower MOP segment should be protected from overpressure by high-pressure shutdown devices at the appropriate connected platforms or by a relief system if the segment terminates on shore. Automatic or remote operation of the valve at the point of pressure segmentation should be considered only if reliability of communication and actuating power to the valve is appropriately ensured.

For lines where there is a pressure break topside, a redundant shutdown system consisting of two independent isolation valves with independent pressure shutdown switches should be considered.

4.3 Pressure Design of Components

4.3.1 Internal Pressure (Burst) Design

4.3.1.1 General

The hydrostatic test pressure, the pipeline design pressure, and the incidental overpressure, including both internal and external pressures acting on the pipelines, shall not exceed that determined by the equations (see Figure 2):

$$P_t \leq f_d f_c f_t P_b \quad (1)$$

$$P_d \leq 0.80 P_t \quad (2)$$

$$P_a \leq 0.90 P_t \quad (3)$$

where

f_d is the internal pressure (burst) design factor, applicable to all pipelines;

0.90 for pipelines;

0.75 for pipeline risers;

f_c is the weld joint factor, longitudinal or spiral seam welds. See ASME B31.4 or ASME B31.8. Only materials with a factor of 1.0 are acceptable;

f_t is the temperature derating factor, as specified in ASME B31.8 [1.0 for temperatures less than 121 °C (250 °F)];

P_a is the incidental over pressure (internal minus external pressure), in N/mm² (psi);



P_b is the specified minimum burst pressure of pipe, in N/mm^2 (psi);

P_d is the pipeline design pressure, in N/mm^2 (psi);

P_t is the hydrostatic test pressure (internal minus external pressure), in N/mm^2 (psi).

The specified minimum burst pressure (P_b) is determined by one of the following equations:

$$P_b = 0.45(S + U) \ln \frac{D}{D_i}, \text{ or} \quad (4)$$

$$P_b = 0.90(S + U) \frac{t}{D - t} \quad (5)$$

where

D is the outside diameter of pipe, in mm (in.);

D_i is $D - 2t$ = inside diameter of pipe, in mm (in.);

S is the specified minimum yield strength (SMYS) of pipe, in N/mm^2 (psi) (see API 5L, ASME B31.4, or ASME B31.8 as appropriate);

t is the nominal wall thickness of pipe, in mm (in.);

U is the specified minimum ultimate tensile strength of pipe, in N/mm^2 (psi);

$\ln$ is the natural log.

NOTE 1 The two equations, Equation (4) and Equation (5), for the burst pressure are equivalent for $D/t > 15$. For low D/t pipe ($D/t < 15$), Equation (4) is recommended.

NOTE 2 Determination of specified minimum burst pressure for unlisted materials is in accordance with Annex A.

NOTE 3 Improved control of mechanical properties and dimensions can produce pipe with improved burst performance. The specified minimum burst pressure may be increased in accordance with Annex B.

NOTE 4 See Annex C for example calculations of internal pressure (burst) and Annex D for example calculations of external pressure (collapse).

When a corrosion allowance is required, the design process should consider the following adjustment to the wall thickness used in the design equations:

- 1) the hydrostatic test pressure prior to first placing the pipeline in service shall not exceed the code test limit where the wall thickness includes the corrosion allowance;
- 2) the MOP (usually equal to the shut-in pressure for a flowline) shall not exceed the code operating limit where the wall thickness does not include the corrosion allowance.

4.3.1.2 Longitudinal Load Design

The effective tension due to static primary longitudinal loads (see 4.6.2) shall not exceed the value given by:

$$T_{\text{eff}} \leq 0.60 T_y \quad (6)$$

where

$$T_{\text{eff}} = T_a - P_i A_i + P_o A_o$$

$$T_a = \sigma_a A$$

$$T_y = SA$$

$$A = A_o - A_i = \frac{\pi}{4}(D^2 - D_i^2)$$

A is the cross-sectional area of pipe steel, in mm^2 (in.^2);

A_i is the internal cross-sectional area of the pipe, mm^2 (in.^2);

A_o is the external cross-sectional area of the pipe, mm^2 (in.^2);

P_i is the internal pressure in the pipe, in N/mm^2 (psi);

P_o is the external hydrostatic pressure, in N/mm^2 (psi);

T_a is the axial (material) tension in pipe, in N (lb);

T_{eff} is the effective tension in pipe, in N (lb);

T_y is the yield tension of the pipe, in N (lb);

σ_a is the axial stress in the pipe wall, in N/mm^2 (psi).

The physical meaning of the term “effective” tension relates to the interaction between the pipe and other structures (sleds, anchor points, lay barge hang off, etc.). The applied force at a boundary condition is always the effective tension. For the on-bottom portion of a pipeline, the effective tension will vary as loading conditions change. Typically, when a pipeline is just installed on the seabed, the effective tension is equal to the residual horizontal lay tension. For a single pipeline under fully restrained condition (i.e. far from the end), the effective tension T_{eff} is given by:

$$T_{\text{eff}} = T_{\text{lay}} - (1 - 2\nu)\Delta P_i A_i - AE\alpha\Delta T \quad (7)$$

where

T_{lay} is the residual lay tension;

in the case of a pipe-in-pipe (PIP) installed with the inner pipe free-standing inside the outer pipe during construction, the term T_{lay} will be negative (without mitigation) and additive to pressure and temperature loading (see 4.3.1.3);

ΔP_i is the internal pressure change since laydown of the pipe;

E is Young’s modulus of elasticity;

α is the thermal coefficient of expansion of the pipe;

ΔT is the temperature change in the pipe since laydown;

ν is the Poisson ratio.

In an SCR, the effective tension at the surface is equal to the hang off load at the end fixture, and to compute the axial material tension in the pipe, proper consideration needs to be given to internal and external pressure loads.

4.3.1.3 Combined Load Design

The combination of primary longitudinal load (static and dynamic) and differential pressure load shall not exceed that given by:

$$\sqrt{\left(\frac{P_i - P_o}{P_b}\right)^2 + \left(\frac{T_{\text{eff}}}{T_y}\right)^2} \leq \begin{cases} 0.90 & \text{For operational loads} \\ 0.96 & \text{For extreme loads} \\ 0.96 & \text{For hydrotest loads} \end{cases} \quad (8)$$

4.3.1.4 Axial Collapse/Burst Due to Combined Axial Compressive Load and Internal Pressure

Axial compressive load can combine with internal pressure loading to result in material stresses exceeding the yield strength of the pipe, with potential for axial collapse/burst failure due to overload and strain localization. This combination is a particular risk for deepwater PIP construction by the J-lay or S-lay methods (see 4.4.1) where the internal and external pipes are not continuously structurally linked. For these PIP installation methods, the inner pipe may be non-tensioned and free standing in the outer pipe during pipe lay. All pipe lay tension loads are carried by the outer pipe. The inner pipe must support its own weight with a resultant compressive stress at touchdown on the seabed. Consequently, as the PIP is progressively laid to the seabed, the inner pipe compressive load is permanently captured by contact friction with the outer pipe. At the completion of pipe lay, virtually the entire inner pipe will have a permanent compressive stress approximately equal to (water depth × inner pipe unit weight/inner pipe steel area). In deep water (>1500 m), this stress can be 25 % to 50 % of the axial compressive yield load.

Combined with the axial stress arising from high operating temperatures, the axial stress may exceed the yield strength of the pipe and an inner pipe weak section may accumulate excessive strains (strain localization) leading to failure by axial collapse/burst when pipe wall strains exceed material capacity. For further details, refer to OTC 18063^[7].

4.3.2 External Pressure (Collapse) Design

4.3.2.1 General

During construction and operation, offshore hydrocarbon pipelines may be subject to conditions where the external pressure exceeds the internal pressure. The differential pressure acting on the pipe wall due to hydrostatic head can cause collapse of the pipe. The pipe selection should provide a pipe of adequate strength to prevent collapse, taking into consideration the physical property variations, ovality, bending stresses, and external loads. The combined application of Equation (9) through Equation (17) in the following sections shall be used in all external pressure design calculations.

4.3.2.2 Collapse Due to External Pressure

The collapse pressure of the pipe shall exceed the net external pressure everywhere along the pipeline as follows:

$$f_o P_c \geq (P_o - P_i) \quad (9)$$

where

f_o is the collapse factor;

= 0.7 for seamless or electric resistance welded (ERW) pipe;

= 0.6 for cold expanded pipe, such as double submerged arc welded (DSAW) pipe;

Under some circumstances in cold expanded pipe, credit can be taken for partial recovery of compressive yield strength by heat treatment to at least 233 °C (450 °F) for several minutes. Such heat treatment may be provided during the fusion bond epoxy coating process of the pipe, provided temperature and duration of heating is carefully controlled. In such cases, the collapse factor of 0.6 may be raised to no more than 0.7. The proposed increase in design factor should be validated through a testing program;

P_c is the collapse pressure of the pipe, in N/mm² (psi).

The following equations can be used to approximate collapse pressure:

$$P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}} \quad (10)$$

$$P_y = 2S \left(\frac{t}{D} \right) \quad (11)$$

$$P_e = 2E \frac{\left(\frac{t}{D} \right)^3}{(1 - \nu^2)} \quad (12)$$

where

E is the modulus of elasticity, in N/mm² (psi);

P_e is the elastic collapse pressure of the pipe, in N/mm² (psi);

P_y is the yield pressure at collapse, in N/mm² (psi).

The collapse pressure predicted by these or other equations should be compared to the hydrostatic pressure due to water depth to ensure adequate wall thickness is chosen for the range of water depths to be encountered.

4.3.2.3 Buckling Due to Combined Bending and External Pressure

Combined bending strain and external pressure load should satisfy the following:

$$\frac{\varepsilon}{\varepsilon_b} + \frac{(P_o - P_i)}{f_c P_c} \leq g(\delta) \quad (13)$$

where

f_c is the collapse factor for use with combined pressure and bending loads;

recommended value for f_c : $f_c = f_o/g(\delta)$.

For installation conditions, consideration can be given to higher collapse factors up to 1.0. Regardless of the selection of the value for f_c , the conditions for collapse in Equation (9) need to be satisfied.

NOTE The collapse factor f_c was absent from Equation (13) in previous editions of this practice. This factor has been added to reflect consistency between DNV design codes, this practice, and API 2RD (refer to OTC 13013^[8]).

To avoid buckling, bending strains should be limited as follows:

$$\varepsilon \geq f_1 \varepsilon_1 \quad (14)$$

$$\varepsilon \geq f_2 \varepsilon_2 \quad (15)$$

where

$g(\delta)$ collapse reduction factor = $(1 + 20\delta)^{-1}$;

$$\delta \quad \text{ovality} = \frac{D_{\max} - D_{\min}}{D_{\max} + D_{\min}};$$

ε is the allowable bending strain in the pipe [in the presence of external pressure];

$$\varepsilon_b \quad \frac{t}{2D} = \text{buckling strain under pure bending};$$

ε_1 is the maximum installation bending strain;

ε_2 is the maximum in-place bending strain;

f_1 is the bending safety factor for installation bending plus external pressure;

f_2 is the bending safety factor for in-place bending plus external pressure;

$D_{\max}$ is the maximum diameter at any given cross section, in mm (in.);

$D_{\min}$ is the minimum diameter at any given cross section, in mm (in.).

NOTE Equation (13) is acceptable for a maximum $D/t = 50$. Refer to the OMAE article for utilizing ratios higher than 50.

Bending strains ε_1 and ε_2 are not simply nominal (global) bending strains and shall include an allowance for possible strain concentrations. For example, if a pipe is reeled, the nominal bending strain in the pipe on the reel or aligner is given by:

$$\varepsilon_{\text{nom}} = \frac{d_{\text{pipe}}}{d_{\text{pipe}} + d_{\text{reel}}} \quad (16)$$

where

d_{pipe} is the outside steel pipe diameter;

d_{reel} is the reel or aligner diameter.

The maximum installation bending strain is then given by:

$$\varepsilon_1 = SAF \times \varepsilon_{\text{nom}} \quad (17)$$

where

SAF is the strain amplification factor (≥ 1.0).