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

API RECOMMENDED PRACTICE 1111
FOURTH EDITION, DECEMBER 2009

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Downstream Segment

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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.

API created an industry committee to develop appropriate uniform guidelines. The resulting first edition of API Recommended Practice 1111 was published in 1976. In 1989, the decision was made to create a revision that would provide industry with a more functional document. The resulting second edition was issued in November 1993. In 1997, a task force was formed to consider proposed changes to the RP based on a growing concern among pipeline engineers that existing codes lead to overly conservative designs for high-pressure pipelines having a low diameter to wall thickness (D/t) ratio. In fact, the second edition of the RP and the codes specifically excluded the pipelines categorized as flowlines which typically require these low D/t ratio (see ASME B31.4 and ASME B31.8). 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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Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the specification.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the specification.

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Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, NW, Washington, DC 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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1 Scope

1.1 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.

1.2 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.

1.3 Limit state design has been incorporated in this 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.

1.4 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.

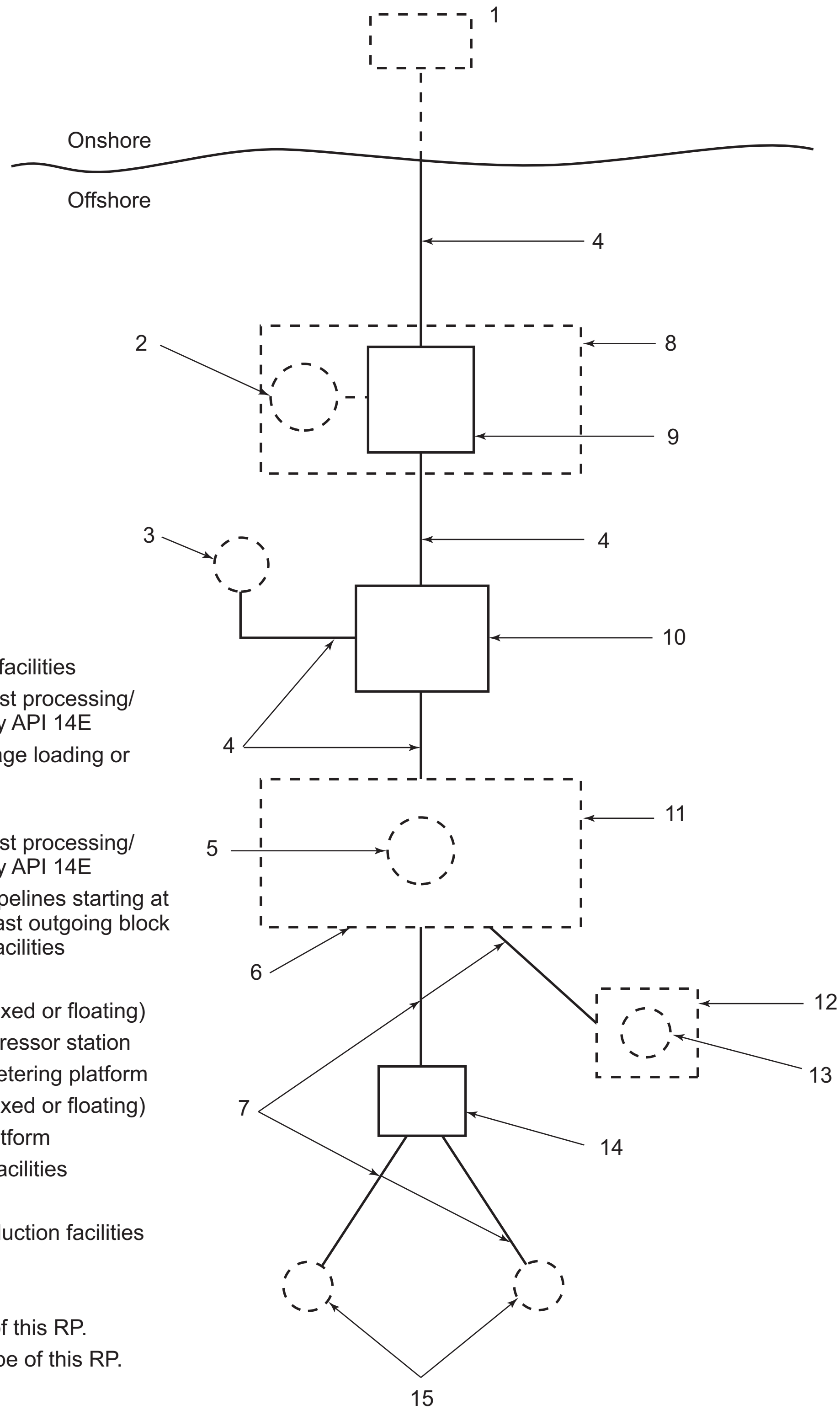
1.5 Design and construction practices other than those set forth in Section 4 and Section 7 may be employed when supported by adequate technical justification, including model or proof testing of involved components or procedures as appropriate. Nothing in this RP should be considered as a fixed rule 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.

1.6 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.

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



Key

1 onshore pipeline and facilities
2 production facilities first processing/ separation covered by API 14E
3 tanker, barge, or storage loading or unloading facilities
4 pipeline
5 production facilities first processing/ separation covered by API 14E
6 API 1111 applies to pipelines starting at the first incoming or last outgoing block valve on production facilities
7 flowlines
8 production platform (fixed or floating)
9 pump station or compressor station
10 pipeline junction or metering platform
11 production platform (fixed or floating)
12 remote production platform
13 wellhead production facilities
14 subsea manifold
15 subsea wellhead production facilities

NOTE
Solid lines = within scope of this RP.
Broken lines = outside scope of this RP.

Figure 1—Scope of API 1111

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, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*

API Recommended Practice 2RD, *Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms*

API Specification 5L/ISO 3183, *Specification for Line Pipe*

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

API Specification 6A/ISO 10423, *Specification for Wellhead and Christmas Tree Equipment*

API Specification 6D/ISO 14313, *Specification for Pipeline Valves*

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

API Recommended Practice 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*

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

API Recommended Practice 1110, *Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide*

API Publication 2200, *Repairing Crude Oil, Liquefied Petroleum Gas, and Product Pipelines*

API Recommended Practice 2201, *Safe Hot Tapping Practices in the Petroleum & Petrochemical Industries*

AGA [1], *Submarine Pipeline On-Bottom Stability Analysis and Design Guidelines*

ASME B16.5 [2], *Pipe Flanges and Flanged Fittings NPS 1/2 Through NPS 24 Metric/Inch Standard*

ASME B16.47, *Large Diameter Steel Flanges NPS 26 Through NPS 60*

ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines*

ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*

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

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

ASQC Z1.9:2003 [3], *Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming*

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1 American Gas Association, 1515 Wilson Boulevard, Arlington, Virginia 22209, www.aga.org.
2 American Society of Mechanical Engineers, 3 Park Avenue, New York, New York 10017, ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org..
3 American Society for Quality Control, 611 East Wisconsin Avenue, Milwaukee, Wisconsin 53202, www.asq.org.

AWS D3.6M [4], *Specification for Underwater Welding*

DNV-RP-F105:February 2006 [5], *Free Spanning Pipelines*

DOE [6], *Offshore Installations: Guidance on Design, Construction, and Certification*

MSS SP-44 [7], *Steel Pipeline Flanges*

NACE SP 0106:2006 [8], *Control of Internal Corrosion in Steel Pipelines and Piping Systems*

NACE SP 0607:2007/ISO 15589-2 (MOD)*, Petroleum and natural gas industries—Cathodic protection of pipeline transportation systems*

OMAE '85 [9], Murphey, C. E., and Langner C. G., "Ultimate Pipe Strength Under Bending, Collapse, and Fatigue," Proceedings, Vol. 1, pp. 467 to 477

Title 30 *Code of Federal Regulations* (*CFR*) Part 250, Subpart J [10], *Pipelines and Pipeline Rights-of-Way*

Title 49 *Code of Federal Regulations* (*CFR*) Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Safety Standards*

Title 49 *Code of Federal Regulations* (*CFR*) Part 195, *Transportation of Hazardous Liquids by Pipeline*

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
The 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
A hydrocarbon in a vapor phase.

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4 American Welding Society, Inc., P.O. Box 351040, 550 NW Le Jeune Road, Miami, Florida 33135, www.aws.org.
5 Det norske Veritas, Veritasveien, 1, N-1322 Hovik, Norway, www.dnv.com.
6 Department of Energy, Petroleum Engineering Division, 1 Palace St., London, SW1E 5HE, United Kingdom, www.hss.doe.gov.
7 Manufacturers Standardization Society of the Valve & Fittings Industry, Inc., 127 Park Street, NE, Vienna, Virginia 22180, www.mss-hq.com.
8 National Association of Corrosion Engineers International, 1440 South Creek Drive, Houston, Texas 77084, www.nace.org.
9 Offshore Mechanics and Arctic Engineering Symposium, ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.
10 The *Code of Federal Regulations* is available from the U.S. Government Printing Office, Washington, DC 20402.

3.1.4
offshore
The 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.

3.1.5
offshore pipeline riser
The 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 shall apply 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 should employ the "pipeline riser" design factor. Pipeline on the seabed connecting to a shallow-water fixed platform riser should employ the pipeline riser design factor for a horizontal offset distance of 300 ft.

3.1.6
oil
A hydrocarbon in liquid phase.

3.1.7
operational loads
Loads that may occur during normal operation of the pipeline.

3.1.8
pipeline
Piping that transports fluids between offshore production facilities or between a platform and a shore facility, often subclassified 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.).

3.1.9
pipeline component
Any part of a pipeline that may be subjected to pressure by the transported fluids.

3.1.10
pipeline system
A pipeline and its components, including compressor stations and pump stations that are subjected to internal pressure by the transported fluids.

3.1.11
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 shall be considered part of the pipeline from a design standpoint.

3.1.12
primary load
A load necessary for equilibrium with applied loads.

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

3.1.13
production platform
A 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.

3.1.14
splash zone
The area of the pipeline riser or other pipeline components that is intermittently wet and dry due to wave and tidal action.

3.1.15
surge pressure
The 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.)
DSAW	double submerged arc welded
d_{pipe}	outside steel pipe diameter
d_{reel}	reel or aligner diameter
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
OP	operating pressure
PIP	pipe-in-pipe
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)
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)

TLP	tension leg platform
T_a	axial tension in the pipe, in N (lb)
T_{eff}	effective tension in pipe, in N (lb)
T_{lay}	residual lay tension
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)
a	thermal coefficient of expansion of pipe
g	density (lb/ft^3)
δ	ovality
ε	bending strain in the pipe
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)
v	Poisson's ratio (0.3 for steel)

4 Design

4.1 Design Conditions

4.1.1 General

4.1.1.1 Offshore hydrocarbon pipelines, with the exceptions noted in Section 1, should comply with all sections of this RP.

4.1.1.2 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) fatigue affects during construction.

4.1.1.3 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 down hole 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

4.1.3.1 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.

4.1.3.2 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 nonburied 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]).

4.1.3.3 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.

4.1.3.4 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

4.1.4.1 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.

4.1.4.2 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.

4.1.4.3 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.

4.1.4.4 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.

4.1.4.5 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

4.1.6.1 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.

4.1.6.2 An 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 should be provided. Refer to NACE SP 0607 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 should 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).

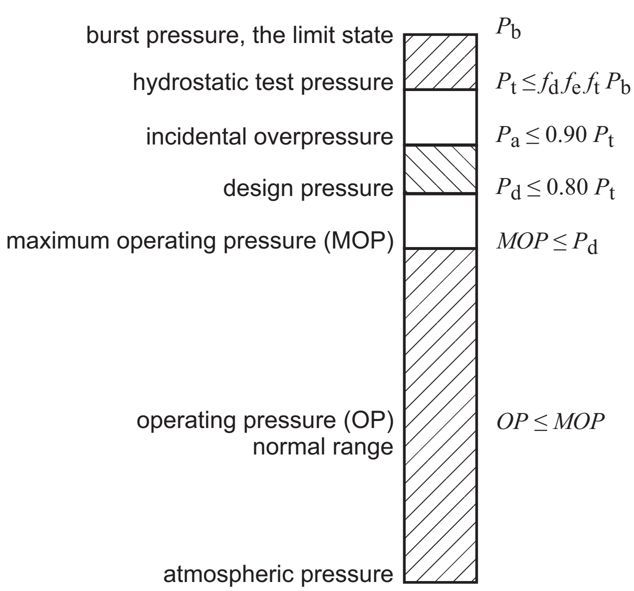
4.2.2 MOP

4.2.2.1 MOP Limits

4.2.2.1.1 The MOP should not exceed any of the following:

a) the design pressure of any component, including pipe, valves, and fittings;

b) 80 % of the applied hydrostatic test pressure in accordance with 8.2.



Max. Fraction of P_b	
Pipeline	Riser
1.000	1.000
0.900	0.750
0.810	0.675
0.720	0.600
0.000	0.000

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

Figure 2—Pressure Level Relations

4.2.2.1.2 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 topsides, 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

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):

$$P_t \leq f_d f_e f_t P_b \tag{1}$$

$$P_d \leq 0.80\ P_t \tag{2}$$

$$P_a \leq 0.90\ P_t \tag{3}$$

where

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

0.90 for pipelines;

0.75 for pipeline risers.

f_e 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/mm^2 (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:

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

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

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 shall be 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.

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.

4.3.1.1 Longitudinal Load Design

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

$$T_{eff} \leq 0.60\, T_y \tag{6}$$

where

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

$$T_a = \sigma_a A$$

$$T_y = SA$$

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

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 hangoff, 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:

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

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 hangoff 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.

4.3.1.2 Combined Load Design

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

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

4.3.1.3 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 nontensioned and free standing in the outer pipe during pipelay. All pipelay 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 pipelay 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

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.

4.3.2.1 Collapse Due to External Pressure

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

$$f_o P_c \geq (P_o - P_i) \tag{9}$$

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/mm^2 (psi).

The following equations can be used to approximate collapse pressure:

$$P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}} \tag{10}$$

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

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

where

E is the modulus of elasticity, in N/mm^2 (psi);

P_e is the elastic collapse pressure of the pipe, in N/mm^2 (psi);

P_y is the yield pressure at collapse, in N/mm^2 (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.

4.3.2.2 Buckling Due to Combined Bending and External Pressure

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

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

where

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

recommended value for f_c:

f_c = 0.6 for cold expanded pipe such as DSAW pipe;

f_c = 0.7 for seamless pipe.

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:

$$\varepsilon \geq f_1 \varepsilon_1 \tag{14}$$

$$\varepsilon \geq f_2 \varepsilon_2 \tag{15}$$

where

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

δ ovality $= \dfrac{D_{max} - D_{min}}{D_{max} + D_{min}}$;

ε is the bending strain in the pipe;

ε_b $\dfrac{t}{2D}$ = 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:

$$\varepsilon_{nom} = \frac{d_{pipe}}{d_{pipe} + d_{reel}} \tag{16}$$

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:

$$\varepsilon_1 = SAF \times \varepsilon_{nom} \tag{17}$$

where

SAF is the strain amplification factor (≥ 1.0)

For example, if the field joint coating stiffness for an insulated reeled flowline is less than the pipe insulation stiffness, the bending strain at the field joint will be larger than ε_{nom}. Similarly, mismatch of wall thickness and yield strength of adjacent pipe joints causes significant strain amplification at the field joint. Typically, more detailed analysis needs to be conducted to determine an appropriate value for the SAF. Abrupt changes in wall thickness of a reeled pipe should be avoided.

Safety factors f_1 and f_2 should be determined by the designer with appropriate consideration of the magnitude of increases that may occur for installation bending strain, ε_1, and in-place bending strain, ε_2. A value of 2.0 for safety factors f_1 and f_2 is suggested. Safety factor f_1 may be larger than 2.0 for cases where installation bending strain, ε_1, could increase significantly due to off-nominal conditions, or smaller than 2.0 for cases where bending strains are well-defined.

4.3.2.3 Propagating Buckles

4.3.2.3.1 A buckle resulting from excessive bending or another cause may propagate ("travel" along the pipe). Offshore hydrocarbon pipelines can fail by a propagating buckle caused by the hydrostatic pressure of seawater on a pipeline with a diameter-to-wall-thickness ratio that is too high. For submarine pipelines, since hydrostatic pressure is the force that causes a buckle to propagate, it is useful to estimate the buckle propagation pressure. If conditions are such that propagating buckles are possible, means to prevent or arrest them should be considered in the design.

4.3.2.3.2 Buckle arrestors may be used under the following condition:

$$P_o - P_i \geq f_p P_p \tag{18}$$

where

$$P_p = 24S\left[\frac{t}{D}\right]^{2.4}$$ f_p = propagating buckle design factor = 0.80.

Design of buckle arrestors is described in articles of the *International Journal of Mechanical Sciences* [4] and OTC 10711 [6]. A buckle arrestor is a device attached to or welded as an integral part of the pipeline, spaced at suitable intervals along the pipeline, and capable of confining a collapse failure to the interval between arrestors. Selection of proper buckle arrestor spacing is dependent on a number of parameters, such as the amount of spare pipe purchased for the project, installation methodology, buckle arrestor costs, and welding costs to install buckle arrestors in line pipe.

4.4 Marine Design

Design of an offshore pipeline should consider the forces and resulting stresses and strains imposed by the laying process and the longer-term stresses and strains imposed by the offshore environment. In many cases, such as installation by reeling, these strains may control selection of SMYS and wall thickness of the pipeline. Where dynamic loading is a factor, a fatigue analysis of pipelines and pipeline risers should be performed.

4.4.1 Installation of Pipeline and Riser

Normal lay methods include the following.

a) Conventional pipe-lay, also called S-lay, in which the pipe is laid from a near-horizontal position on a lay vessel using a combination of horizontal tension and a stinger (bend-limiting support).

b) Vertical (or near-vertical) pipe-lay, also called J-lay, in which the pipe is laid from an elevated tower on a lay vessel using longitudinal tension with or without a stinger so that no over bend is developed at the sea surface.

c) Reel barge lay, in which the pipe is made up at some remote location, spooled onto a large radius reel aboard a reel lay vessel, and then reeled off using longitudinal tension, with or without a stinger, and usually involving pipe straightening through reverse bending on the vessel.

d) Towed lay, in which the pipe is transported from a remote assembly location to the installation site by towing either on the water surface, at a controlled depth below the surface, or on the seabottom.

4.4.2 Hydrodynamic Stability

4.4.2.1 An offshore pipeline is subject to wave-induced and current-induced forces. For a pipeline resting on the seabed, lift and drag forces will be created. For that portion of a pipeline suspended between seabed irregularities, oscillation due to vortex shedding can occur. Evaluations of these forces should be performed by alternately assuming:

a) the pipe is empty (construction condition),

b) it is full of transported fluid (operating condition), or

c) pipe is full of seawater.

4.4.2.2 The lift and drag forces created by current-induced and wave-induced flow of water on the seabottom can result in excessive strains, fatigue from repeated lateral movements, encroachment on other pipelines, structures, bottom features, etc. of an offshore pipeline if not countered by a restraining force. Generally, a restraining force is supplied by on-bottom weight of the pipeline. Wall thickness of the pipe, thickness and density of the weight coating, or both are commonly used to control on-bottom weight. Where bottom conditions and water depths permit, anchors or weights may be viable alternatives. Burial, partially or completely below the seabed, is also an option for improved on-bottom stability.

4.4.2.3 The AGA Level 2 or Level 3 analysis for submarine pipeline on-bottom stability may be used for assessing on bottom stability requirements.

4.4.2.4 Specific geographic locations are subject to natural phenomena that can expose an offshore pipeline to unusual forces. The design of an offshore pipeline should consider such forces regarding stability and safety of the pipeline.

Examples of natural phenomena and their effect on offshore pipelines are as follows.

a) Earthquakes can liquefy some seabottom sediments. As a result, a pipeline could tend to either sink or float, depending on specific gravity relative to the liquefied bottom. An earthquake can also leave pipeline in a spanned condition due to surface uplifts on a fault line.

b) Hurricanes, cyclones, and typhoons can cause high currents and large cyclic wave action, which together or individually can cause liquefaction or weakening of some seabottom sediments. As a result, a pipeline may tend to sink, float, or move laterally.

c) Gross seabottom movement (such as mudslides or seabottom subsidence) may subject a pipeline to large lateral forces. As a result, a pipeline may tend to sink, float, or move laterally as the moving sediment is effectively liquefied.

d) Sediment transport or scour of susceptible soils due to bottom currents and or wave action may result in exposure of a buried or partially buried pipeline, loss of soil restraint, or increase in free spans.

In water depths where a pipeline is not buried out to approximately 200 m, severe bottom currents and potential soil instability should be evaluated in those areas to determine if additional measures should be taken in the design of the pipeline, such as additional weight coating, and added wall thickness, etc.

4.4.2.5 It may not be possible to quantify the effect of these natural phenomena for a specific offshore pipeline and location. Consideration should be given to modifying an otherwise optimum design to reroute around a potential seabottom movement zone. In those rare conditions where weight-coating or trenching methods may not represent a suitable solution (such as on a solid rock surface or in shallow-water zones of extremely high currents) the use of anchors or pipeline weights may be a viable addition or alternative.

4.4.3 Spans

The length of unsupported spans on an offshore pipeline should be controlled to avoid excessive loads or deformations in the pipeline.

4.4.3.1 Span Limitation Due to Weight, Pressure, and Temperature

See 4.1.4 and 4.6.3 for the static loads and limits on combined loads in determining the span limitation due to its own weight, pressures, temperature, and primary longitudinal loading.

4.4.3.2 Span Limitation Due to Vortex Shedding

4.4.3.2.1 Spans exposed to transverse flow of seawater due to currents and waves are subject to a phenomenon commonly referred to as *vortex shedding*. This can cause the pipeline to oscillate as shedding vortices alternately change the pressure above and below the pipe. Large amplitude oscillations may occur when the natural frequency of the span is near the frequency of vortex shedding.

4.4.3.2.2 Detailed procedures for vortex-induced vibration (VIV) are beyond the scope of this RP; detailed guidance on VIV analysis is available in DNV-RP-F105.

4.4.3.2.3 Stricter weld acceptance criteria for circumferential welds can be employed to increase the fatigue resistance of spanned sections in areas where spanning is predictable. VIV suppression devices such as strakes or fairings can be installed either during pipelay operations or post-lay installed on the identified span regions. “CP-porous” design of strake material should be employed when installing over fusion bonded epoxy (FBE) coated pipe to prevent shielding of the cathodic protection. Other methods, such as jetting pipe ends down to decrease span length, and supporting of pipe spans at discrete points to reduce the affected length, are also effective means to reduce VIV excitation of spans.

4.5 Fatigue Analysis

4.5.1 All pipeline components such as risers, flowlines, unsupported free spans, welds, J-lay collars, buckle arrestors, and flexjoints, should be assessed for fatigue. Potential cyclic loadings that cause fatigue damage include VIVs, wave-induced hydrodynamic loads, slug-induced vibration (SIV), internal flow-induced vibration (FIV), cyclic pressure and thermal expansion loads. The fatigue life of the component is defined as the time to develop a through-wall-thickness crack of the component. The design fatigue life, predicted by the Palmgren-Miner (S-N) methods, should be at least five times the service life for pipelines. Larger safe factors may be required for risers (refer to API

2RD). An S-N fatigue analysis to the stated criteria is sufficient to assure integrity for anticipated base metal components however a fracture mechanics crack growth analysis may be required for weldments.

Weld procedures developed for fatigue-sensitive sections of a pipeline may require full-scale fatigue testing of welded pipe specimens to demonstrate sufficient life. Adequate specimens should be tested to provide a 95 % probability that welds meet the mean S-N design performance criteria.

4.5.2 If a fracture mechanics crack growth analysis is employed, the initial flaw size should be the smallest rejectable flaw specified for the nondestructive testing during manufacture of the component in question.

4.5.3 Bending is an important consideration for fatigue. For instance, wave-induced bending moments in the splash zone are important for fatigue consideration.

4.5.4 For an SCR, the accumulated fatigue damage during 30 hours of exposure to a single occurrence of the 100-year hurricane should be less than 1.0 by the S-N method. This can be thought of as a 100-year design storm lasting three hours with a factor of safety of 10. The purpose of this check is to ensure that the riser does not fail in fatigue during a hurricane event. The riser should be analyzed for VIVs such as during a Gulf of Mexico 100-year loop current event. If vibrations are predicted, appropriate suppression devices such as fairings or helical strakes should be mounted on the riser throughout the section affected by VIV. Suppression devices will need to be periodically inspected and cleaned to maintain their effectiveness.

Fatigue damage from installation activities should be considered in the fatigue design of the riser. Further guidance is given in API 2RD.

4.6 Load Limits

4.6.1 Cold Bent Pipe

Field cold bends are acceptable provided that their radii are within the limits of Table 1 and the bent pipe meets the collapse and buckling criteria in 4.3.2.

Table 1—Minimum Radius of Field Cold Bends

Pipe Size (NPS)	Minimum Radius of Field Bends
≤12	18D
14	21D
16	24D
18	27D
≥20	30D
NOTE D = outside pipe diameter.	

4.6.2 Longitudinal Loads

Static primary longitudinal loads (e.g. top tension of a catenary riser) should be limited to 60 % of the yield tension of the pipe. Displacement controlled conditions, such as bending in a J-tube, bending in a catenary riser, and constraint loads, are not so limited; but the resulting strain should be within allowable limits. See API 2RD, ASME B31.4, and ASME B31.8 for design considerations.

4.6.3 Combined Loads

The combined load due to internal pressure and primary longitudinal loads should be limited to 90 % for functional loads, 96 % for extreme loads, and 96 % for hydrostatic test load [see Equation (8) in 4.3.1.2].

4.6.4 Test Pressure

See 8.2.4 for limitations on hydrostatic test pressure.

4.6.5 Expansion and Flexibility

The design and material criteria applicable to the expansion and flexibility of offshore hydrocarbon pipelines should be in accordance with 4.6.2 and 4.6.3.

4.7 Valves, Supporting Elements, and Piping

4.7.1 Valves, Fittings, Connectors, and Joints

4.7.1.1 If the wall thickness of the adjoining ends of pipe, valves, or fittings is unequal, the joint design for welding should be made as indicated in ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines. Transverse segments cut from factory-made bends and elbows may be used for changes in direction provided the arc distance measured along the crotch is at least 50.8 mm (2 in.) for pipe of nominal pipe size (NPS) 4 or larger.

4.7.1.2 Seal design for valves, fittings, and connectors should include consideration of external pressure. External pressure may exceed internal operating pressure for pipelines in deep water. Seal design should also consider operating conditions that may result in frequent changes in the internal operating pressures, which combined with high external water pressure, result in frequent pressure reversals on sealing mechanisms.

4.7.1.3 Where pigging devices are to be passed, all valves shall be of full-bore design.

4.7.1.4 Consideration should be given to the effects of erosion at locations where the flow changes direction.

4.7.2 Supporting Elements

4.7.2.1 Supports, braces, and anchors for pipelines should be designed in accordance with ASME B31.4 for liquid pipelines and ASME B31.8 for gas pipelines. In particular, the design and installation of a riser guard should be included for any riser that is subject to potential contact with floating vessels.

4.7.2.2 Riser guards should be installed to protect risers in areas exposed to potential impact of marine traffic. A riser guard should be designed to provide impact protection for an appropriate vessel size and impact velocity. Riser guard design should also consider the effects of transfer of riser guard loads to the platform structure. The platform structure can also serve as a riser guard in those instances where the riser is routed inside the platform structural members.

4.7.3 Design of Supports and Restraints

Design of supports and restraints should employ the latest edition of API 2A-WSD.

4.7.4 Auxiliary Piping

Auxiliary hydrocarbon and instrument piping containing pipeline fluids should be designed and constructed in a manner consistent with the provisions of ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines and with the provisions of this RP for offshore hydrocarbon pipelines.

4.8 Route Selection

4.8.1 Route of the Pipeline

The route of an offshore pipeline should be thoroughly analyzed using the data from available charts, maps, other sources of relevant information, and a field hazards survey as described in 4.8.2. Whenever practical, the selected route should avoid anchorage areas, existing underwater objects such as sunken vessels and pilings, active faults, rock outcrops, chemosynthetic communities, and mud slide areas. The selection of route should take into account the installation methods applicable and should minimize the resulting installation stresses. The route of the pipeline should be shown on maps of an appropriate scale.

4.8.2 Preliminary Environmental, Bathymetric, and Hydrographic Surveys

In selecting a satisfactory route for an offshore pipeline, a field hazards survey should be performed to identify potential hazards such as sunken vessels, piling, wells, geologic and man-made structures, potential mudslides and other pipelines. The bottom topographic and geologic features and soil characteristics should be determined. Data on normal and storm winds, waves, current, and marine activity in the area should be obtained where available. In areas where soil characteristics will be a factor in design and where previous operations or studies have not adequately defined the bottom soils, on-site samples should be acquired. Refer to the appropriate regulatory agencies for minimum requirements for conducting hazard surveys.

4.9 Flow Assurance

4.9.1 Flow assurance shall be considered in the design of offshore liquid, gas, and multiphase pipelines. Flow assurance refers to the facilities and operational procedures required to ensure that adequate flow can be sustained throughout the design life of a pipeline under all expected flow conditions for the range of pressure, temperatures, fluid properties and phase conditions existing during start-up, normal, shutdown and emergency operations. The considerations include test evaluation and behavior prediction of fluid properties, heat transfer, pressures, flow conditions, flow treatments with chemicals, and pigging operations. Some of the operational problems or failures encountered, which design efforts should strive to prevent or reduce, are:

a) formation of hydrates that may plug a pipeline,

b) paraffin and/or asphaltene deposition on pipeline walls resulting in flow restriction,

c) inefficient or reduced flow from multiphase flow regimes such as slugging,

d) pipeline liquid contents cooling to temperatures below the pour point forming solid gel phase,

e) drop-out of salt or sand that can cause restriction within the pipeline, and accelerated corrosion,

f) flows which produce emulsions detrimental to processing,

g) liquid slugging.

4.9.2 These considerations are increasingly important in pipeline system design for installations in colder environments as encountered, for example, in deeper waters off the continental shelf of the Gulf of Mexico. The higher operational risk associated with these conditions arises from the importance of maintaining temperatures above pour point, cloud point, and hydrate formation temperature. Designs such as PIP, vacuum-insulated pipes, electrically heated flowlines and chemical additives are examples of industry solutions currently in use or development to minimize the adverse affects of colder deep water.

4.10 Thermal Expansion Design

Deep water pipelines are installed to a seabed environment with temperatures of 3 °C to 5 °C (37 °F to 40 °F) and the pipeline will cool to that temperature before first production operations. Upon introduction of oil or gas production, the pipeline system will warm to operating temperatures ranging from 50 °C to 150 °C (120 °F to 300 °F). The increased temperature of the steel pipeline causes significant thermal expansion effects on the pipeline. The unrestrained ends of the pipeline may move significantly and the restrained portions of the pipeline may elastically (Euler) buckle at unplanned locations without specific design intervention to manage expansion. Buckling may take the form of upheaval buckling in a buried pipeline or lateral buckling of an unburied pipeline.

In some cases there have been complete failures of pipelines due to cyclic thermal expansion fatigue damage of buckles within relatively short periods after start-up. The cyclic strain range of unplanned, upheaval or lateral thermal expansion buckles can exceed 1 % leading to pipeline section collapse or high strain-low cycle fatigue and failure by cracking/rupture.

Any insulated pipeline should be evaluated for thermal expansion loading, however, thermal expansion fatigue considerations are not restricted to insulated oil/gas production pipelines. Water injection pipelines have suffered fatigue failures due to thermal and pressure-induced buckles.

Detailed guidance on thermal expansion design is outside the scope of this limit state design. Designers are directed to SAFEBUCK [9] and HOTPIPE [3] for additional information.

5 Materials and Dimensions

5.1 Materials

5.1.1 General

5.1.1.1 Materials and equipment that will become a permanent part of any piping system constructed under this RP should be suitable and safe for the conditions under which they are used. Materials and equipment should be qualified for the conditions of their use by compliance with specifications, standards, and special requirements of this RP, ASME B31.4 for liquid pipelines, or ASME B31.8 for gas pipelines. The design should consider the significance of temperature and other environmental conditions on the performance of the material, as indicated by such factors as toughness and ductility at the minimum operating temperature; the effect of corrosion (see Section 10); and the means that may be necessary to mitigate corrosion and other deterioration of the material in service. The maximum hydrostatic test pressure allowed in this RP can result in stresses exceeding yield near the inner surface of the pipe. The potential for growth of existing flaws under this loading should be considered.

5.1.1.2 Components constructed from composite materials that have been designed, tested, and recommended by the manufacturer may be considered for use. Pipe, valves, and fittings made of cast iron, bronze, brass, or copper shall not be used for primary service applications on hydrocarbon pipelines in cases where they are subjected to pipeline operating pressures or are in direct contact with the gas or liquid transported.

5.1.2 Pipe

Only steel pipes that conform to the requirements in ASME B31.4 and ASME B31.8 and have a weld joint factor of 1.0 are acceptable. Materials not listed should be qualified in accordance with ASME B31.4 or ASME B31.8, as appropriate, and Annex A of this RP.

5.1.3 Valves

Valves that conform to API 6D or API 6A, as appropriate, are acceptable and should be used in accordance with service recommendations of the manufacturer.

5.1.4 Flanges

Flanges that conform to ASME B16.5, ASME B16.47, MSS SP-44, or API 6A are acceptable.

5.1.5 Fittings Other Than Valves and Flanges

Components such as elbows, branch connections, closures, reducers, and gaskets, which comply with ASME B31.4, ASME B31.8, or API 6A as appropriate, are acceptable. Components not covered by the standards listed in ASME B31.4, ASME B31.8, or API 6A shall be qualified in accordance with ASME B31.4, ASME B31.8, or API 6A.

Riser hang-off support devices such tapered stress joints, riser tensioning systems, flexible hang-off elements shall be designed to withstand the design environment conditions, platform movements required for the production program, snag loads, pressure and temperature extreme conditions and the expected in-service pressure/ temperature fluctuations associated with the production profile. API 2RD should be consulted for additional information with regard to riser design parameters for design of risers from floating production systems and tension leg platforms (TLPs).

5.2 Dimensions

Dimensions used in offshore hydrocarbon pipelines should be in accordance with ASME dimensions specifications where practicable. Other dimensional criteria are acceptable, provided the design strength and test capabilities of the component equal or exceed those provided by a referenced component.

6 Safety Systems

6.1 General

For each pipeline system, a safety system should be provided that will prevent or minimize the consequences of overpressure, leaks, and failures in accordance with API 14C.

6.2 Liquid and Gas Transportation Systems on Nonproduction Platforms

6.2.1 Hydrocarbon Systems on Platforms with Liquid Pumps or Gas Compressors

Liquid and gas hydrocarbon pipeline facilities on nonproduction platforms on which liquid pumps or gas compressors are installed should be provided with a safety system in accordance with API 14C. The design of the safety system should also consider the need to limit surge pressures and other deviations from normal operations.

6.2.2 Hydrocarbon Systems on Platforms Without Liquid Pumps or Gas Compressors

Hydrocarbon pipeline facilities consisting only of junction piping, block valves, scraper traps, or measurement equipment on nonproduction platforms not equipped with liquid pumps, gas compressors, or other sources of flow input are not subject to 6.2.1, but should be equipped with check valves or other valves on each incoming line to prevent backflow.

6.3 Liquid and Gas Transportation Systems on Production Platforms

Liquid or gas pipeline facilities on production platforms should have a safety system in accordance with the requirements of the platform owner or operator, but in no case should the safety system be less than that which would be provided in 6.2.1.

6.4 Breakaway Connectors

In areas of potential mud slides, where the severity of the slide could cause a tensile pull on the pipeline of a magnitude that might cause damage to a platform or to a subsea connection, breakaway connectors or specialty design failure joints should be considered for protection of the platform or other pipelines. When conditions are such that an oil spill might result from breakaway, the design should include a built-in check-valve to minimize loss of fluid from the pipeline upon breakaway. Special consideration should be given to selection and installation of the check-valve to ensure timely positive closure. Breakaway devices can also be a weak piping link designed into a connection point.

7 Construction and Welding

7.1 Construction

7.1.1 General

Pipeline systems should be constructed in accordance with written specifications that are consistent with this RP. The lay methods described in 4.4.1 and other construction techniques are acceptable under this RP provided the pipeline meets all the criteria in this RP.

7.1.2 Construction Procedures

7.1.2.1 Construction of offshore pipelines requires careful control of the pipe as it is installed onto the sea floor. The installation system should be carefully designed, implemented, and monitored to ensure safe handling to protect the integrity of the pipeline system. A written construction procedure should be prepared. It should identify the allowable limits for the basic installation variables, including the following:

a) pipe tension,

b) pipe departure angle,

c) water depth during laying operations and temporary abandonment,

d) retrieval,

e) termination activities,

f) valve sled installation procedures,

g) riser transfer to host facility.

7.1.2.2 The construction procedure should reflect the allowable limits of continuous lay operations, the limits where correction or temporary abandonment is necessary, and the conditions that require supplemental inspection for suspected damage.

7.1.2.3 Construction workers should be advised of their safety-awareness responsibilities to protect themselves and the pipeline during construction.

7.1.3 Route Marking

The positioning of all construction vessels should be conducted with the use of an electronic tracking system (GPS-based survey system) to ensure that the pipeline is installed on the designated route. All hazards and areas of concern in the immediate vicinity of the pipelay activities should be appropriately highlighted on the surveyors tracking system. For shallow-water applications, it may also be necessary to physically mark pipelines or other physical structures with buoys to provide a visual indication.

7.1.4 Handling, Hauling, and Storing of Materials

7.1.4.1 Onshore

Materials stored onshore before loading for offshore construction should be handled as provided in ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines. Pipe transported by railroad enroute to the loading site should be transported in accordance with API 5L1. Additional line pipe inspection may be required if transported loads are subjected to severe conditions while enroute from the mill to coating site (e.g. rough sea states).

7.1.4.2 Offshore

Materials enroute to the offshore work site should be properly secured to minimize damage or deterioration in offshore transit. When stored at the offshore work location, materials should be secured and protected from damage.

7.1.5 Damage to Materials

Before being moved to the offshore work site, all materials should be inspected. Damaged materials should be replaced or repaired in accordance with ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines.

7.2 Welding

7.2.1 Atmospheric Welding

7.2.1.1 Welding and weld inspection of pipelines should be done in accordance with API 1104. The accepted welding procedure should be documented and retained. Welding practices should follow these procedures during construction.

7.2.1.2 Arc burns can cause serious stress concentrations and shall be prevented or eliminated. The metallurgical notch caused by arc burns shall be removed by grinding, provided the grinding does not reduce the remaining wall thickness to less than the minimum permitted by the material specifications governing manufacture and use of the pipe. The metallurgical notch created by an arc burn can be completely removed as follows.

a) Grind the arc burn area until no evidence of the arc burn is visible. Then swab the ground area with a 20 % solution of ammonium persulfate. A black spot is evidence of the metallurgical notch and indicates that additional grinding is necessary.

b) If after grinding the wall thickness is less than that permitted by the material specification, the cylindrical portion of pipe containing the arc burn shall be removed. Insert patching is prohibited.

7.2.2 Underwater Welding

7.2.2.1 General

AWS D3.6M should be used in conjunction with this RP to specify fabrication and quality assurance standards for underwater welding.

7.2.2.2 Underwater Welding Methods

7.2.2.2.1 One-atmosphere Welding

Welding in a pressure-vessel in which the pressure is reduced to approximately 1 atmosphere, independent of depth, is permitted.

7.2.2.2.2 Hyperbaric Welding

Three types of hyperbaric welding are permitted, as follows.

a) Habitat Welding—Welding at ambient pressure in a large chamber from which water has been displaced, with an atmosphere in which the welder-diver does not need to work in diving equipment.

b) Dry Chamber Welding—Welding at ambient pressure in a simple, open-bottomed, dry chamber that accommodates as a minimum the head and shoulders of the welder-diver in full diving equipment.

c) Dry Spot Welding—Welding at ambient pressure in a small, transparent, gas-filled enclosure with the welder-diver outside the enclosure, in the water, and in full diving equipment.

7.2.2.3 Hyperbaric Welding Requirements

Hyperbaric welding should conform to the following:

a) low-hydrogen processes should be used;

b) preheating to a suitable temperature should be performed for moisture removal and hydrogen diffusion;

c) for welding consumables, procedures should be specified on the following:

   1) storage and handling on the support vessel,

   2) storage and handling within the welding chamber,

   3) sealing in preparation for Item 4),

   4) transfer between the support vessel and the welding chamber.

7.2.2.4 Construction Welding Specification

Prior to the start of construction welding, a detailed procedure specification should be established and qualified by testing weldments produced under actual or simulated site conditions in a suitable testing facility. In addition to the requirements of API 1104, or ASME *Boiler and Pressure Vessel Code* Section IX, as applicable, the specification should include the following:

a) the chamber’s internal pressure range,

b) the range of water depths (ambient pressure),

c) the composition range of the gas inside the chamber,

d) the humidity range,

e) the range of temperature variation inside the chamber,

f) the temperature range of the pipe section to be welded.

7.2.2.5 Essential Variables

The essential variables specified in API 1104, or ASME *Boiler and Pressure Vessel Code* Section IX, shall be considered with the following:

a) pressure inside the chamber,

b) gas composition within the chamber,

c) humidity range.

7.2.2.6 Qualification of Welders

Underwater welding personnel should pass relevant welding tests above water before being permitted to qualify for welding underwater. Prior to the tests, the welders should be given sufficient training to familiarize them with the influence of pressure, temperature, and atmospheric changes on welding. AWS D3.6M may be used in conjunction with this RP to specify fabrication and quality assurance standards for underwater welding.

7.3 Other Components and Procedures

7.3.1 Installation of Underwater Pipelines and Risers

Installation procedures should safeguard the pipe materials, the pipe structure, and the pipeline in its final configuration. Criteria for handling pipe during installation should consider the installation technique, minimum pipe-bending radii, differential pressure, and pipe tension. Stress or strain limitations that have proven to be both safe and practical are acceptable.

7.3.2 On-bottom Protection

7.3.2.1 Trenching

7.3.2.1.1 Where trenching is specified during or after the installation of a pipeline, trenching equipment should be installed, operated, and removed to prevent pipe and coating damage.

7.3.2.1.2 The standard depth of trenching for a pipeline is the depth that will provide 0.9 m (3 ft) of elevation differential between the top of the pipe and the average seabottom. For those situations where additional protection is necessary or mandated, the hazards shall be evaluated to determine the total depth of trenching.

7.3.2.2 Cover

7.3.2.2.1 Cover material is not normally installed over the pipeline except where the pipeline will not acquire a natural cover or where more protection is required early in the pipeline's life.

7.3.2.2.2 In areas where backfill or riprap is specified, as in a surf zone, the backfill or riprap should be installed so that pipe and coating damage is prevented. Where pipeline-padding material is specified, the padding materials should be carefully placed to prevent pipe and coating damage.

7.3.2.3 Pipeline Crossings

Pipeline crossings should comply with the design, notification, installation, inspection, and as-built records requirements of the regulatory agencies and the owners or operators of the pipelines involved. A minimum separation of 12 in. typically using sand-cement bags or concrete-block mattresses should be provided.

7.3.2.4 Seabottom Protection of Valves and Manifolds

7.3.2.4.1 Pipeline valves, manifolds, and other miscellaneous equipment and structures installed on a subsea pipeline should be protected from fishing trawls and anchor lines. Very little protection from anchors themselves can be provided. However, damage caused by the lateral-sliding movement of anchor cables—the most prevalent cause of damage to valves and manifolds—can be minimized.

7.3.2.4.2 Usually, the burial and covering of valves and manifolds is mandated by regulatory agencies; however, exceptions will sometimes be requested and permitted. In such cases protective measures should be provided and maintained to prevent damage to the pipe and associated equipment. Such measures should be designed in a manner that will not obstruct trawling or other offshore operations.

7.3.3 Fabrication of Scraper Traps, Strainers, Filters, and Other Components

Whether fabricated in a shop or in the field, pipeline components, including pumping and compressor piping manifolds, storage fabricated from pipe, and auxiliary piping, should be fabricated so that they conform to the provisions of this standard.

8 Inspection and Testing

8.1 General

During construction, the operating company should make provisions for suitable inspection of the pipelines and related facilities by qualified inspectors to ensure compliance with the material, construction, welding, fabrication, testing, and recordkeeping provisions of this RP and of written specifications. Inspection of materials should also include transport surveys checking proper securing of loads with cribbing/tiedowns for vessel, rail or truck transport. Underwater inspection should be performed using methods and equipment that are suitable for the particular situation. Qualification of inspection personnel and the type and extent of inspection should be in accordance with the recommendations in this RP. Repairs required during new construction or replacement of existing systems should be in accordance with 7.1.5, 7.2.1, 7.2.2, and 9.2.9. Underwater inspection should be performed using methods and equipment that are suitable for the particular situation. Special emphasis on inspection may be needed for areas of unstable soils, trenched sections, pipeline/umbilical crossings, side taps, mechanical connections, J-tube entries, pipeline riser connections to platforms, VIV suppression installation and pipeline initiation/laydown.

8.1.1 Inspectors

8.1.1.1 Qualifications

Inspection personnel should be qualified by experience or training in the phase of construction they are to inspect. Inspection will be needed for pipeline routing, pipe condition, lineup, welding, coating, tie-in, pipelaying, trenching, and pressure testing.

8.1.1.2 Authority

The operating company should provide suitable inspection. The inspector should have the authority to order the repair or removal and replacement of any component that fails to meet the standards of the applicable design code or specification.

In certain situations, the governing permitting agency may require additional independent third-party inspection to review the riser design, fabrication and installation associated with deepwater risers. A certified verification agent (CVA) may be required to review the operating company's riser design, fabrication and installation program and sign-off on the three phases of the work.

8.1.2 Inspection Requirements

8.1.2.1 Inspection of Materials

8.1.2.1.1 Pipe should be cleaned sufficiently to permit proper inspection and to locate any defects that could impair its strength or serviceability. Prior to coating, pipe should be inspected for internal and external defects, including bends, buckles, ovality, and surface defects such as cracks, grooves, pits, gouges, dents, and arc burns. Where pipes of different grades or wall thickness are used, particular care should be taken to maintain proper identification during handling and installation.

8.1.2.1.2 All pipeline components should be inspected for evidence of mechanical damage.

8.1.2.1.3 Pipe coating should be inspected in accordance with 10.2 and with ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines. Externally coated pipe should be inspected prior to weight coating application.

8.1.2.1.4 Coating equipment should also be inspected to avoid harmful gouges or grooves in the pipe surface. The pipe coatings should be inspected for compliance with weight, dimension, and material specifications.

8.1.2.2 Inspection During and After Installation

8.1.2.2.1 Records should be maintained documenting the installation location of pipe by specification, grade, and wall thickness, manufacturing process, manufacturer, coating, anode location, and anode size. Pipe should be swabbed to provide a clean inside surface and examined for defects, damage-free bevels, and proper joint alignment. Pipe should be visually inspected just before the coating operation. Pipe coating, including field joint coatings, should be inspected. For proper application and freedom from defects, pipe beneath areas of damaged coating should be inspected prior to repair of the coating. Damaged or defective coating, pipe, and piping components should be repaired or replaced and inspected in accordance with Section 7 and Section 10 prior to laying.

8.1.2.2.2 All phases of the pipeline installation procedure identified in Section 7 should be monitored to maintain the installation operation within acceptable limits. Components that require supplemental inspection for suspected installation damage should be examined before the pipeline system is placed in operation. Field welds and shop welds, should be inspected for compliance with the procedures provided in 7.1, as applicable. All girth welds should be visually inspected. If practical, 100 % of the girth welds on the offshore pipeline should be inspected by radiographic, ultrasonic inspection, or other nondestructive methods prior to coating the weld area, but in no case should fewer than 90 % of those welds be inspected in that way. The inspection shall cover 100 % of the length of those inspected welds.

8.1.2.2.3 Where practical, the condition of the pipe on the seabottom should be inspected to verify its proper installation. When installed for the control of scouring, pipeline cover should be inspected where practical for the correct placement of material. Underwater inspection methods and equipment that are suitable for these tasks may include, but are not limited to, saturation diving, use of divers in atmospheric diving suits, remotely operated vehicles, submarines, sonar inspections, seismic inspections, and combinations of these methods and equipment.

8.1.2.2.4 Certified as-built surveys and drawings should be prepared during or after construction using acceptable methods of determining actual pipeline coordinates. As-built records and maps should cross reference preconstruction route survey data and should include such items as hazards, spans, trenching, soil, anomalies, pipeline crossings, existing and new facilities or appurtenances, pipe and coating properties.

8.1.3 Records

8.1.3.1 Construction reports should include inspection records of all material, including pipe, valves, and fabrications, for physical damage. Construction reports should also include inspection records of damaged external coating and of coating repair of the damaged areas.

8.1.3.2 Records should include welder qualifications and qualified welding procedures. At a minimum, records of the welds required in ASME B31.4 for liquid pipelines and in ASME B31.8 should be made and retained. The nondestructive inspection records should include qualification of the inspectors and qualified inspection procedures. These records should show the results of each test and the disposition of all rejected welds.

8.2 Testing

8.2.1 General

8.2.1.1 This RP in conjunction with API 1110 may be used for guidance on pressure testing. Pressure tests should be performed on completed systems and on all components not tested with the pipeline system or if the component requires a higher test pressure than the remainder of the pipeline. If leaks occur during tests, the leaking pipeline section or component should be:

a) repaired or replaced, and

b) retested in accordance with this RP.

8.2.1.2 Temporary repairs necessary to permit completion of tests are permissible, provided that the defective components are replaced after testing with suitable, pretested components and that the tie-in welds are nondestructively inspected in accordance with API 1104.

8.2.1.3 When this RP refers to tests or portions of tests described in other codes or specifications, they should be considered as parts of this RP.

8.2.2 Testing of Short Sections of Pipe and Fabrications

Short sections of pipe and fabrications such as risers, scraper traps, and manifolds may be tested separately from the pipeline. Where separate tests are used, these components should be tested to pressures equal to or greater than those used to test the pipeline system and should be tested in compliance with the requirements of 4.2.2.1 and the design factors in 4.3.1.

8.2.3 Testing After New Construction

8.2.3.1 Testing of Systems or Parts of Systems

8.2.3.1.1 Pipeline systems designed according to this RP should be pressure tested after construction in accordance with 8.2.4, except that fabricated items and components may be tested separately in accordance with 8.2.2 or pretested in accordance with 8.2.4. Hydrostatics pressure, both internal and external, should be fully taken into account in setting test pressure levels. This is especially important for deepwater pipelines that terminate with a pipeline riser.

8.2.3.1.2 During the testing of pipelines, care should be exercised to ensure that excessive pressure is not applied to valves, fittings, and other components. Test procedures should also specifically address the valve position and any differential pressure across the valve seat.

8.2.3.1.3 The pipeline should be inspected after construction for dents and out-of-roundness, and an assessment of any significant imperfections should be made to determine acceptability.

8.2.3.2 Testing of Tie-ins

Because it is sometimes necessary to divide a pipeline into test sections and install weld caps, connecting piping, and other test appurtenances, it is not always feasible to pressure-test all tie-in welds. Tie-in welds, which have not been subjected to a pressure test should be inspected by radiography or ultrasonic testing, in accordance with 7.2. After weld inspection, the field joint should be coated and inspected in accordance with 8.1.2 and Section 10. If the system is not pressure-tested after tie-in, additional pipe required for the tie-in should be pretested in accordance with this RP. Mechanical coupling devices used for tie-in should be installed and tested in accordance with the manufacturer's recommendations.

8.2.4 Pressure Testing

8.2.4.1 Test-pressure Levels

Except for fabricated items and components covered in 8.2.2, all parts of an offshore pipeline designed according to this RP should be subjected to an after-construction strength test of not less than 125 % of the pipeline MOP (see 4.2.2). Flowlines and flowline risers should be subjected to hydrostatic test of 125 % of the MOP or 111 % of shut-in pressure as defined in 4.1.2.1, whichever is greater. Hydrostatic test should not result in combined loads exceeding 96 % of capacity as described in 4.3.1.2. Gas lines regulated under 49 *Code of Federal Regulations* Part 192 require riser sections physically connected to a platform to be tested to 150 % of MOP. Regulatory agencies have indicated that SCRs connected to floating production systems can be considered an extension of the connecting pipeline, and thus for gas lines regulated under 49 *Code of Federal Regulations* Part 192, the SCR up to its hangoff point only needs to be tested to 125 % of MOP.

8.2.4.2 Test-medium Considerations

8.2.4.2.1 Pressure tests should be conducted using fresh water or seawater as the test medium. If use of water is impractical, however, a test may be conducted with air or gas, *provided a failure or rupture would not endanger personnel*. Testing with gas does present the risk of a release of a large amount of stored energy so appropriate precautions should be taken. Where water is the test medium, consideration should be given to adding corrosion inhibitor and biocide additives to the test water, particularly if the water is to remain in the pipeline for an extended period of time.

Caution—Precautions should be taken to prevent the development of an explosive mixture of air and hydrocarbons.

8.2.4.2.2 Where water is the test medium and where on-bottom stability of the pipeline is partially dependent on the liquid hydrocarbon to be transported, consideration should be given to leaving the test water in the pipeline until it is ready to be placed in service. If spans are present along the pipeline route, static loading of the pipeline for a flooded case should be evaluated to determine if the line will be overstressed when filling. Appropriate remediation measures such as lowering, or mid span supports should be incorporated into the design prior to flooding. Also, if applicable, all parts of the system exposed to freezing temperatures should be drained following hydrostatic test. Pipelines constructed for gas service should be purged in accordance with ASME B31.8. In some cases, the pipeline may need to be cleaned and dried prior to being placed in service.

8.2.4.2.3 If the testing medium in the system will be subject to thermal expansion during the test, provision should be made for the relief of excess pressure. Effects of temperature changes should be considered when interpretations are made of recorded test pressures.

8.2.4.2.4 Discharge permits may be required for disposal of the test medium.

8.2.4.3 Duration of Hydrostatic Tests

Piping systems are to be maintained continuously at maximum test pressure for a minimum of eight hours. For fabrications and short sections of pipe where all pressured components are visually inspected during proof-test to determine that there is no leakage, the maximum test pressure should be maintained continuously for a minimum of four hours.

8.2.4.4 Safety During Tests

Testing procedures for pipeline systems after construction should include precautions for the safety of personnel during the test.

8.2.5 Records

The operating company should maintain records of the testing of each pipeline system. The records shall include an accurate description, drawing, or sketch of the facility being tested. The records should also include the pressure gauge readings, the recording gauge charts, the dead weight pressure data, calibration records of test recording equipment and the reasons for and disposition of any failures during a test. Where the elevation differences in the section being tested exceed 30 m (100 ft), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section should be included. Records of pressure tests should contain the operator's name, the name of the test contractor, the date, the time, the duration of the test, the minimum test pressure, the test medium and its temperature, the weather conditions, a description of the facility tested, and an explanation of any pressure discontinuities.

9 Operation and Maintenance

9.1 System Guidelines

9.1.1 General

9.1.1.1 Each operating company should develop operation, inspection, and maintenance procedures based on the provisions of this RP, the company's experience and knowledge of its facilities, and the conditions under which its facilities are operated. Alternatives to the methods and procedures in this Standard may be justified based on local conditions such as the temperature, the characteristics of the fluids transported, the water depth, the line cover, and the seabottom conditions.

9.1.1.2 Standardization of plans and procedures is encouraged to the extent that it is practicable. Plans and procedures may cover a group of pipeline systems or a single pipeline, as appropriate. Plans and procedures should be reviewed at least once a year; and modifications should be made from time-to-time as experience dictates and as changes in operating conditions require.

9.1.2 Plans and Procedures

Each company operating an offshore hydrocarbon pipeline should develop and maintain the following plans and procedures for instruction of employees:

a) procedures for normal pipeline operation, inspection, maintenance, and repairs, including recommendations in 9.2;

b) procedures for the monitoring and mitigation of external and internal corrosion of pipeline facilities, including practices in Section 10;

c) procedures for inspecting pipelines in water depths less than 15 fsw, where required, to ensure they are not a hazard to navigation;

d) floating structure riser and support hang-off (flexible hang-off joint/stress joint) inspection procedures to ensure riser components are in working order and not experiencing deterioration that could lead to premature failure;

e) a plan to identify and review changes in conditions affecting the safety of the pipeline system;

f) an integrity management plan;

g) an emergency plan for implementation in the event of accidents, system failures, or other emergencies which includes features in 9.3;

h) procedures for abandoning pipeline systems that include provisions of 9.7.

9.2 Pipeline Operations

9.2.1 General

Written procedures for start-up, operation, and shutdown of pipeline facilities should be established, and the operating company should take appropriate steps to ensure these procedures are followed. Procedures should outline preventive measures and system checks to ensure the proper functioning of protective and shutdown devices and of safety, control, and alarm equipment.

9.2.2 Line Pressure

Pipeline systems should be operated to ensure the operating pressures set forth in this RP are not exceeded. Primary overpressure protection devices which shut-in the production facilities (wells, pumps, compressors, etc.) should be set above the normal operating pressure range but in no case shall it exceed the MOP of the pipeline. Secondary overpressure protection may be set above MOP but shall not exceed 90 % of hydrostatic test pressure. Such primary and secondary protection will protect the pipeline and allow for the orderly shut-in of the production facilities in case of an emergency or abnormal operating conditions. In some cases, other overpressure protection device settings for subsea well flowlines may be allowed since the well(s) will be shut-in in case of an emergency at the host facility by the emergency shutdown system.

9.2.3 Communications

Communications equipment should be installed and maintained as needed for proper pipeline operations under both normal and emergency conditions.

9.2.4 Markers

Permanent markers are not required for offshore pipelines.

9.2.5 Signs

Suitable signs should be posted on platforms to serve as hazard area warnings. Where appropriate, signs should display the operating company identification and emergency communication procedures.

9.2.6 Surveillance

Pipeline operators should maintain a pipeline surveillance program to observe indications of leaks, encroachments, and conditions along the pipeline route affecting the pipeline's safe operation. Conditions should be reviewed in accordance with the plan established in 9.1.2, Item e).

9.2.7 Safety Equipment

Pressure-limiting devices, relief valves, automatic shutdown valves (SDVs), and other safety devices should be tested at specified intervals dictated by field experience, operator's policy, and government regulations. Inspections should verify that each device is in good mechanical condition and properly performs the safety function for which it was installed.

9.2.8 Risers

Risers should be visually inspected annually for physical damage and corrosion in the splash zone and above. If damage is observed, the extent of the damage should be determined and the riser should be repaired or replaced, if necessary. Below water riser sections and other riser components should be inspected in accordance with the company's established asset integrity program.

9.2.9 Repairs

9.2.9.1 General

9.2.9.1.1 Repairs should be performed under qualified supervision by trained personnel aware of and familiar with the maintenance plan and operating conditions of the pipeline; the company's safety requirements; and the hazards to the public, employees, and the environment.

9.2.9.1.2 Special care and consideration should be given to limit the release of hydrocarbons into the environment during a repair operation. Pollution avoidance operations may include placing suitably designed external caps or internal plugs on the damaged pipe ends, elevating the pipe adjacent to the pipe location, using pollution domes to capture escaping liquids and releasing of pressure and/or removal of liquids at one or both ends of the pipeline.

9.2.9.1.3 Evacuation and repair operations should not result in imposed loads or deformations that would impair the serviceability of the pipe materials, weight coating, or protective coating. The configuration of the pipeline after the repair should meet the provisions of this RP.

9.2.9.1.4 The use of subsea equipment equipped with cutters, jets, or air suction systems should be carefully controlled and monitored to avoid damaging the pipeline, the external coating, and the cathodic protection system.

9.2.9.1.5 When pipe is lifted or supported during repair, the curvature of a pipe sag bend and overbend should be controlled and maintained so that its stress level does not exceed the limits outlined in 4.3.2. The lifting equipment should be selected to prevent pipe coating damage, overstressing, denting, and buckling during the repair.

9.2.9.1.6 Wave and current loads should be considered in determining total imposed stresses and cyclical loads in both surface and subsurface repairs.

9.2.9.1.7 Repair procedures may include appropriate considerations set forth in API 2200, API 1104, and API 2201. Personnel working on pipeline repairs should understand the need for careful job planning and the need to follow necessary precautionary measures and procedures; and should be briefed on procedures to be followed in accomplishing repairs. Special considerations should be made when working on lines/structures where hydrocarbons could be potentially trapped and hot work should be prohibited until the work area is deemed safe in all environments.

9.2.9.2 Welder and Welding Procedure Qualifications

Welders performing repair work should be qualified in accordance with API 1104 or ASME *Boiler and Pressure Vessel Code* Section IX, as appropriate. Repair welding should be performed in accordance with qualified welding and test procedures documented in accordance with 7.2.

9.2.9.3 Repair Methods

All repairs shall meet the requirements of ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines, as applicable. For offshore pipeline repair techniques may include, but are not limited to:

a) leak repair clamp for minor damage;

b) recovery and replacement of a portion of the line;

c) total on-bottom repair including mechanical connections;

d) surface lift and bottom connect repair including mechanical connections;

e) surface lifts, surface connect, and lateral layover.

9.2.9.4 Field Repair of Gouges, Grooves, and Dents

9.2.9.4.1 Gouges, grooves, and dents affecting the integrity of the pipeline should be repaired promptly with the pipeline pressure at a safe level. When prompt repair is impractical, safe pipeline operating pressures should be maintained until a repair is made. Injurious gouges, grooves, and dents are those exceeding the limits of ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines. These injurious features should be removed, where practical, by taking the pipeline out of service, cutting out a cylindrical piece of pipe, and replacing it with a length of pretested pipe of equal or greater design pressure, tested in accordance with 8.2.

9.2.9.4.2 Where it is not practical to take the pipeline out of service or to continue operation at a safe pressure, a full encirclement welded split sleeve or a mechanically secured fitting of appropriate design should be applied over injurious gouges, grooves, and dents. Consideration should be given to filling the annulus between the clamp and pipe with a hardenable material that will serve to limit movement in the dented area due to pressure fluctuations in the line pipe. By reinforcing the area and limiting its movement, the fatigue life of the defect can be dramatically improved. If a sleeve must be welded to the carrier pipe, special consideration should be given to the welding procedure, weld inspection, and support to prevent problems associated with hydrogen-induced cracking.

9.2.9.5 Field Repair of Weld Defects

9.2.9.5.1 Injurious weld defects should be repaired in accordance with 7.2.1.6, provided the pipeline can be taken out of service. In-service weld repairs may be made provided the weld is not leaking; the pressure in the pipeline is reduced to a level that will limit the hoop stress to not more than 20 % of the SMYS of the pipe; grinding of the defective weld area is limited to maintain at least 50 % of nominal wall thickness; and the completed repair is tested in accordance with 8.2.4.

9.2.9.5.2 Where injurious weld defects cannot be repaired and where removal of the defect from the pipeline by replacement is not practical, the defect may be repaired by the installation of a full-encirclement welded split sleeve or a mechanically secured fitting of appropriate design.

9.2.9.6 Field Repair of Leaks

9.2.9.6.1 Where practical, the pipeline should be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pretested pipe of equal or greater design pressure.

9.2.9.6.2 Repairs should be made by installing a full-encirclement welded split sleeve or a mechanical fitting of appropriate design where it is impractical to remove a cylindrical piece of pipe.

9.2.9.7 Field Repair of Corrosion Pitting

If corrosion has reduced the wall thickness of the pipe to less than that required by the MOP, the pipe should be repaired or replaced. The MOP, based on remaining pipe wall, should be determined by the criteria in ASME B31G.

9.2.9.8 Reduction in Operating Pressure

For pipe with corrosion pits that exceed the size limitations of ASME B31G, and for pipe with areas where the wall thickness has been reduced for any reason, operating pressure should be reduced to less than that allowed by remaining wall thickness at that point until repairs can be made. When leaks are repaired with a device that has a lower MOP than the pipeline system, the MOP of the system should be reduced to the MOP of the device.

9.2.9.9 Testing of Replacement Pipe Sections

When a repair to a pipeline is made by cutting out a section of the pipe as a cylinder and replacing it with another section of pipe, the replacement section of the pipe shall be pressure tested in accordance with 8.2. The test may be made on the replacement section prior to installation, provided that all tie-in welds are inspected by nondestructive means in accordance with API 1104.

9.2.9.10 Testing of Repaired Gouges, Grooves, Dents, Welds, and Pits

If gouges, grooves, dents, welds, and pits are repaired by welding in accordance with the provisions of API 1104, the welding shall be inspected by radiographic or other accepted nondestructive methods or inspected visually by a qualified inspector.

9.2.10 Investigation of Failures and Abnormal Occurrences

9.2.10.1 Accidents, abnormal occurrences, and significant material failures should be investigated to determine their causes. Failed material should be recovered for investigation where feasible. Evidence, records, and documents relating to the occurrence should be retained until the investigation is closed and a probable cause has been determined. Appropriate steps should be taken to prevent recurrence of accidents or significant material failures.

9.2.10.2 Pipeline failures and incidents that cause damage to the pipeline, surrounding structures, or environment should be reported to appropriate regulatory agencies and to operators of other facilities involved.

9.3 Emergency Plan

9.3.1 General

A written emergency plan should be established for implementation in the event of system failure, accident, or other emergency and should include procedures for prompt and expedient remedial action ensuring the following:

a) the safety of personnel,

b) minimization of property damage,

c) protection of the environment,

d) limitation of discharge from the pipeline system,

e) investigation of failures.

9.3.2 Training

The plan should provide for training of personnel responsible for the execution of emergency action. Personnel should be informed of the characteristics of the hydrocarbons in the pipeline, the safe practices for handling accidental discharge, and the procedures for the repair of the pipeline or related facility. The plan should provide for training and mock emergencies for operating personnel who might become involved in an emergency. Special emphasis should be given to the procedure for the evacuation of platforms in an emergency.

9.3.3 Communications

Procedures in the plan should include communication with appropriate government agencies and the notification of parties that should be involved in the emergency action, including other pipeline and platform operators.

9.3.4 Plan Provisions

The plan should include procedures to be implemented in case of a pipeline failure or leak and should establish measures to control pollution that might result from a liquid pipeline failure.

9.4 Records

The following records should be maintained for operation and maintenance purposes:

a) material and construction specifications;

b) route maps and alignment sheets;

c) coating and cathodic protection specifications;

d) pressure test data;

e) welding documentation and nondestructive inspection data;

f) necessary operational data;

g) pipeline surveillance records;

h) corrosion mitigation records recommended in 10.6;

i) records of repairs of welds, grooves, gouges, dents, and pits;

j) leak and break records and failure investigation records;

k) records of safety equipment inspection;

l) records of other inspections including such information as external or internal pipe conditions when a line is cut or hot tapped.

9.5 Qualification of the Pipeline System for Higher Operating Pressure

Existing pipeline systems may be qualified for higher operating pressures according to procedures set forth in ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines, subject to the provisions of this RP.

9.6 Change in Pipeline Use

A change in the product transported in the pipeline or a change in the direction of flow should not be made until the operator has made all technical modifications necessary to accommodate the change and has determined that the pipeline will be capable of handling the change without adverse safety or environmental effects.

9.7 Pipeline Abandonment

Pipelines to be abandoned in place should undergo the following steps:

a) the pipeline should be disconnected and isolated from all sources of hydrocarbons, such as other pipelines, meter stations, control lines, and other appurtenances;

b) the pipeline should be purged of hydrocarbons;

c) the pipeline should be filled with water, nitrogen, or another inert material;

d) the pipeline ends should be sealed and provided with appropriate cover to prevent obstruction at the mud line.

NOTE If water is used, inhibitors to prevent internal corrosion should be considered.

10 Corrosion Control

10.1 General

This section recommends guidelines for the establishment of corrosion mitigation procedures for offshore hydrocarbon pipelines. For liquid and gas pipelines, the following publications are incorporated by reference for the detection and mitigation of external and internal corrosion:

a) ASME B31.4 for liquid pipelines,

b) ASME B31.8 for gas pipelines,

c) NACE SP 0607.

10.2 External Coatings

10.2.1 Submerged

10.2.1.1 An external coating that is effective in the environment to which it is exposed should protect submerged steel pipelines. The design of external coating systems should include, but not be limited to, consideration of the following:

a) loading characteristics;

b) resistance to under-film water migration;

c) electrical resistance and degradation of resistance in service;

d) capability to withstand storage conditions;

e) resistance to disbonding, cold flow, embrittlement, and cracking;

f) capability to withstand installation stresses.

10.2.1.2 The welds and the pipe surface should be inspected for irregularities that could protrude through the pipe coating, and these irregularities should be removed. In conditions where there are significant shear loadings on the pipeline, cold wrap coatings and heat-shrink sleeves should be avoided due to potential disbondment issues. A corrosion cell can form under the disbonded area and the cathodic protection system will be ineffective in protecting the pipe.

10.2.1.3 Pipe coating should be inspected both visually and by a holiday detector set at the proper voltage before the pipe is lowered into the water or a weight coat (if used) is applied. Any holiday or other damage to the coating should be repaired and reinspected. Following inspection, pipe should be handled and lowered into the water so that damage to the coating is prevented.

10.2.2 Splash Zone

Exposed risers in the splash zone should be protected with an external splash zone coating that resists the effects of corrosion, sunlight, wave action, and mechanical damage. Heavy ice formations may indicate the need for other protective measures.

10.2.3 Atmospheric Zone

Valves and fittings exposed to the atmosphere should be protected with a suitable coating and should be visually inspected for corrosion at regular intervals.

10.3 Cathodic Protection

Design and installation of cathodic protection systems should be in accordance with NACE SP 0607. Cathodic protection may be provided by a galvanic anode system, an impressed current system, or both, capable of delivering sufficient current to adequately protect the pipeline. In the design and installation of cathodic protection systems, the following should be considered:

a) a galvanic anode system should use only alloys that have been successfully tested for offshore applications;

b) a galvanic anode system may be designed for the life of the pipeline or for periodic replacement;

c) the components of a cathodic protection system should be located and installed to minimize the possibility of damage;

d) design consideration should be given to minimizing interference of electrical currents from nearby pipelines or structures;

e) the design should take into account the water depth, the water temperature, pipe operating temperature, and the possibility of an increase in current requirements after installation;

f) isolating joints should be installed in the pipeline system where electrical isolation of portions of the system is necessary for proper cathodic protection;

NOTE isolating joints are most effective when they are installed above the splash zone in readily accessible locations and the electrical isolation is verified at intervals not to exceed 15 months, but at least once per year;

g) rectifiers or other impressed current sources should be inspected six times each year at intervals not exceeding 2.5 months in length.

10.4 Internal Corrosion Control

10.4.1 NACE SP 0106 guidelines should be followed for the design, the installation, and the evaluation of the results of an internal corrosion mitigation program. Where necessary, internal corrosion may be mitigated by one or more of the following:

a) the running of pipeline scrapers at regular intervals,

b) dehydration,

c) the use of corrosion inhibitors,

d) the use of a biocide,

e) the use of oxygen scavengers,

f) the use of an internal coating,

g) the use of corrosion-resistant alloys.

10.4.2 The variables and severity of each case will determine the preventive methods that should be used. A monitoring program should be established to evaluate the corrosiveness of the transported liquid or gas and the results of the internal corrosion mitigation systems or programs. Appropriate corrective measures should be taken when the results of monitoring indicate that protection against internal corrosion is required.

10.5 Maintenance of Cathodic Protection Systems

The cathodic protection system should be maintained in accordance with NACE SP 0607.

10.6 Records

Records including design, installation, and operational data of the corrosion control system should be maintained as outlined in NACE SP 0106 and NACE SP 0607.

Annex A
(normative)

Procedure for Determining Burst Design Criteria for Other Materials

A.1 General

A.1.1 The limit state design procedure in this RP is based on use of ductile materials. The pipe is assumed to be sufficiently ductile and have sufficient fracture toughness to have ductile failure modes in burst, tension, bending, collapse, and combined loading. Qualification of materials other than carbon steels, which have been demonstrated to have these properties, shall be tested in accordance with the qualification requirements in ASME B31.8 and the procedure in this annex.

A.1.2 The procedure described in this annex is intended for qualification for use of the limit state design procedure for a specific application. This procedure recommends a minimum of six burst tests be conducted. More testing will be required to qualify a class of pipe materials for limit state design, which would permit, e.g. ranges of D/t, S, and U to be used. This broader qualification should be part of a petition to the ASME Section Committee (see ASME B31.8).

A.2 Test Sample Selection

Pipe representative of that proposed for use shall be burst tested. The pipe selected for testing shall have the same pipe manufacturing process and grade and shall have dimensions similar to the dimensions for the given application.

A.3 Test Sample Description and Properties

A.3.1 The mechanical properties of pipe joints from which samples are to be made shall be determined. It is recommended that at least one tensile test from each end of each pipe joint be performed. The yield stress, the ultimate stress, and the elongation shall be recorded for each test. The tensile specimen shall be taken from the same pipe joint as the burst specimen. The yield stress and the ultimate stress for the pipe joint are defined as the average yield stress and the average ultimate stress from the tensile tests. Mechanical property tests for determining burst design criteria shall be conducted in a manner consistent with mechanical property tests performed during manufacturing.

A.3.2 The burst test sample shall have a length greater than six pipe diameters, not including end closures. Welded or mechanical end caps with pressure ports shall be used. The length of the sample shall be recorded.

A.3.3 The wall thickness of the test sample shall be measured using an ultrasonic measuring device. The measurements shall be taken around the circumference at mid-length and at quarter points of the sample, recording the minimum and four values of thickness at 90° intervals around the pipe at each cross section.

A.4 Test Procedure

A.4.1 Each sample shall be pressured until burst failure occurs. The test fluid may be either water or gas. The test should be conducted in a covered pit or pressure vessel to ensure safety of testing personnel.

A.4.2 Reference pressures for each sample shall be determined. The two values used for control of the test procedure are:

$$CEYP = \frac{SA}{A_o\sqrt{3}}\left(\frac{Y_{actual}}{S}\right)\left(\frac{t_{min}}{t}\right) \tag{A.1}$$

$$CEBP = \frac{2S}{\sqrt{3}}\ln\left(\frac{D}{D_i}\right)\left(\frac{Y_{actual}}{S}\right)\left(\frac{t_{min}}{t}\right) \tag{A.2}$$

where

$CEYP$ is the capped end yield pressure in N/mm^2 (psi);

$CEBP$ is the capped end burst pressure in N/mm^2 (psi);

t_{min} is the minimum measured wall thickness, in mm (in.);

Y_{actual} is the average measured yield strength of pipe, in N/mm^2 (psi).

A.4.3 The capped end burst pressure is close to, but usually less than, the actual burst pressure. The sample shall be pressured slowly to ensure an accurate determination of the burst pressure.

A.4.4 The recommended steps are as follows.

a) Increase pressure to $CEYP$ and hold to ensure stable deformation. A representative hold time is 15 minutes.

b) Increase the pressure from $CEYP$ to $CEBP$ slowly or in steps to ensure stable measurements. The recommended maximum step size for pressure increase is the minimum of 1000 psi or $(CEBP - CEYP)/4$. The recommended minimum elapsed time for this step is 20 min.

c) The pressure shall be held at $CEBP$ (if the sample has not burst) to ensure a stable pressure, e.g. 15 minutes.

d) Increase the pressure very slowly beyond $CEBP$ until the sample bursts.

A.4.5 The actual burst pressure, (P_{actual}), is the maximum pressure recorded in the test. It should be noted that the pressure might drop just prior to burst due to sample deformation.

A.4.6 Following each burst test, the failure surfaces shall be examined to verify that the failure mode is ductile. A ductile burst failure has a distinct bulge at the burst location. A longitudinal fracture extends over the length of the bulge and terminates near the end of the bulge. The end of fracture turns at roughly 45° from the pipe axis at each end. The failure surfaces have sharp edges and the surface has a similar appearance to the "cup-and-cone" surface observed in a tensile test. A typical ductile burst failure is illustrated in the Figure A.1. A typical brittle burst failure is illustrated in Figure A.2.

A.4.7 If the failure mode is not typical of a ductile burst, then the pipe is not suitable for use with the limit state design procedure in this RP.

A.4.8 For each test, calculate the ratio:

$$k = \frac{P_{actual}}{(Y_{actual} + U_{actual}) \ln\left(\frac{D}{D_i}\right)\left(\frac{t_{min}}{t}\right)} \qquad \text{(A.3)}$$

where

k computed burst factor;

P_{actual} is the actual measured burst pressure, in N/mm^2 (psi);

U_{actual} is the average measured ultimate tensile strength of pipe, in N/mm^2 (psi).

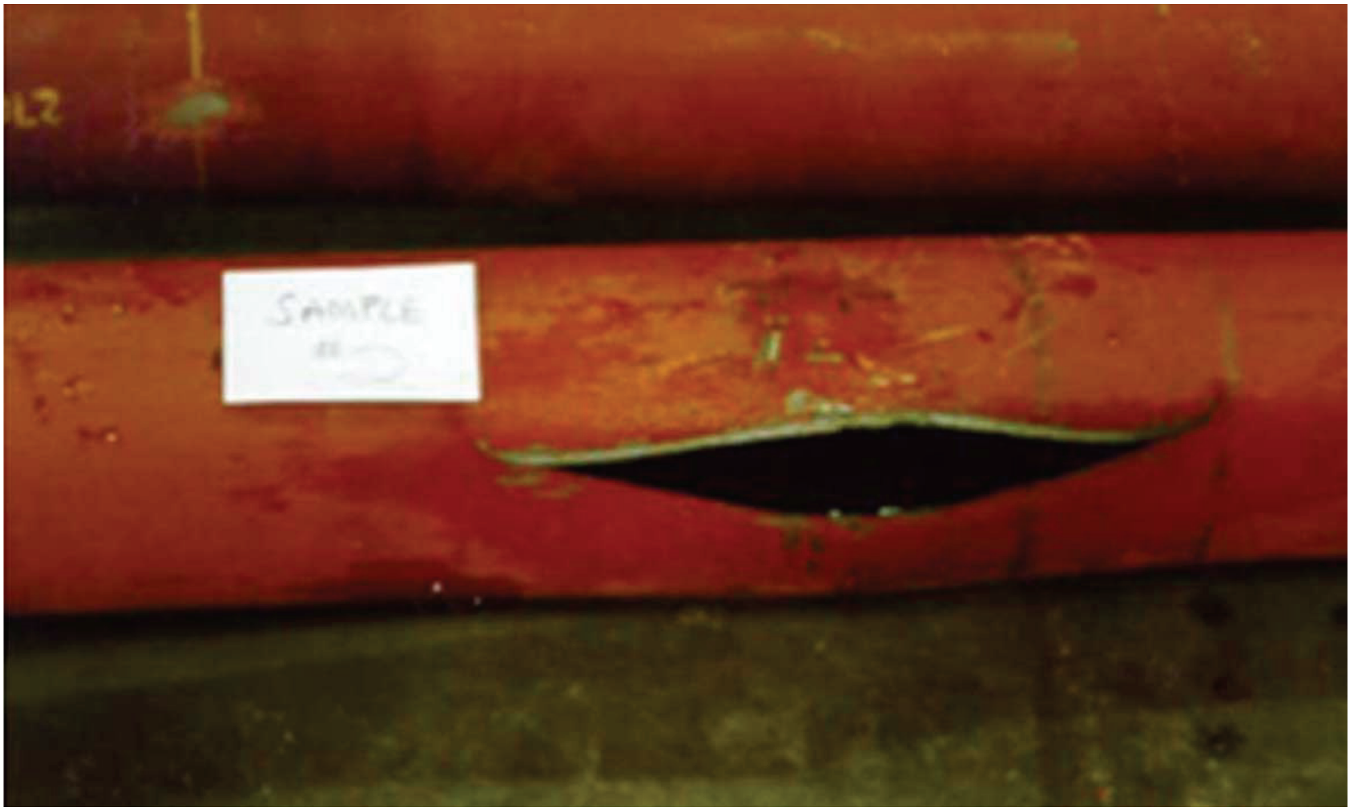


Figure A.1—Ductile Burst Sample

Figure A.2—Brittle Burst Sample

A.5 Determination of Specified Minimum Burst Pressure

A.5.1 The specified minimum burst pressure may be written in the form:

$$P_b = k(S + U)\ln\left(\frac{D}{D_i}\right) \tag{A.4}$$

The value of k is determined from the burst test data as: $k = \min\begin{cases} 0.875k_{avg} \\ 0.9k_{min} \\ 0.45 \end{cases}$

The specified minimum burst pressure so calculated shall be used for design.

NOTE The burst test is very repeatable. Therefore, very few samples are required to characterize the burst pressure. It is expected that the computed k values will all significantly exceed 0.45 based on extensive comparison with burst test data. The limitations based on the average k and on the minimum k are intended to account for materials whose strengths are not well represented by the mechanical tests.

Annex B
(normative)

Qualification of Increased Minimum Burst Pressure

B.1 General

B.1.1 Equation (4) and Equation (5) are suitable for estimation of the minimum burst pressure for pipe listed in 5.1.2. The coefficients in Equation (4) and Equation (5) (see 4.3.1) (0.45 and 0.90, respectively) include considerations of specification requirements, such as minimum wall thickness and mechanical testing frequency. Improved control of mechanical properties and dimensions can produce pipe with improved burst performance. The requirements in this Annex are intended to permit users to take advantage of improved manufacturing control, to increase the specified minimum burst pressure.

B.1.2 The recommended maximum value of the specified minimum burst pressure is:

$$P_{\mathrm{b}} = 0.50(S+U)\ln\left(\frac{D}{D_{\mathrm{i}}}\right) \tag{B.1}$$

or,

$$P_{\mathrm{b}} = 1.00(S+U)\ln\left(\frac{t}{D-t}\right) \tag{B.2}$$

B.1.3 The coefficients in Equation (4) and Equation (5) may be increased from 0.45 and 0.90 up to maximum values of 0.50 and 1.00, respectively.

B.1.4 To justify the increased burst pressure, supplementary specifications shall be included in the material specification. The recommended supplements are:

a) specified minimum burst pressure, up to the maximum defined in Equation (B.1) or Equation (B.2);

b) full-length helical ultrasonic inspection of each length, including ultrasonic wall thickness measurement with a minimum area coverage of 10 %;

c) specified minimum wall thickness greater than or equal to 90 % of nominal;

d) mechanical properties, including yield strength and ultimate strength, to be tested for compliance using ASQ Z1.9 with an acceptable quality level = 0.10 %;

e) burst testing as prescribed herein.

B.2 Burst Testing Requirements

B.2.1 Burst tests are conducted to ensure that compliance with strength and dimensional properties provides adequate evidence that the specified minimum burst pressure is also met. Burst tests shall be conducted for at least one lot, selected at random, and for each lot for which Tightened Inspection applies. Compliance shall be tested in accordance with ASQ Z1.9 with an acceptable quality level = 0.10 %. If, for the randomly selected lot(s), the mechanical property tests fail to meet the acceptability criterion, then the lot is rejected and an additional lot is selected at random for burst and mechanical property testing. If the burst pressure fails to meet the acceptability criterion and the mechanical property tests meet the acceptability criterion, then the lot is rejected and burst testing is required for all lots.

B.2.2 Each lot shall, as far as practicable, consist of units of pipe (pipe joints) of a single heat, heat-treatment batch, grade, diameter, and wall thickness, manufactured under the same conditions and essentially at the same time.

B.3 Test Sample Selection

A burst test sample shall be taken adjacent to each coupon taken for mechanical property tests.

B.4 Test Sample Description and Properties

B.4.1 The yield strength and the ultimate strength of the burst sample are the values to be obtained from the corresponding mechanical property test.

B.4.2 The burst test sample shall have a length greater than six pipe diameters, not including end closures. Welded or mechanical end caps with pressure ports shall be used. The length of the sample shall be recorded.

B.4.3 The wall thickness of the test sample shall be measured using an ultrasonic measuring device. The measurements shall be taken around the circumference at mid-length and at quarter points of the sample, recording the minimum and four values of thickness at 90° intervals around the pipe at each cross section.

B.5 Test Procedure

B.5.1 The burst tests shall be conducted as described in A.4. The burst pressure (P_{actual}) is the property to be checked for compliance using ASQ Z1.9. The minimum value is the specified minimum burst pressure.

B.5.2 If the failure mode of any burst test sample is not typical of a ductile burst, then the pipe is not suitable for use with the limit state design procedure in this RP.

B.5.3 For pipe that meets the requirements of this annex, the specified minimum burst pressure shall be used for design instead of the pressure calculated by Equation (4) or Equation (5).

Annex C
(informative)

Example Calculations for Internal Pressure (Burst) Design and Wall Thickness

C.1 Problem Statement

To illustrate application of the limit state design in accordance with 4.3.1, internal pressure (burst) design and wall thickness calculations are performed for two different insulated flowlines configured as “PIP” and “single pipe.” Consider a steel flowline and SCR connected to a subsea well at the deep end and connected to a floating platform (TLP) at the other end, as shown in Table C.1. Only British units are included to reduce clutter and allow comparison to previous editions of API 1111.

For calculation purposes, two different production cases of gas and crude oil are illustrated. Input data are assumed to be as follows:

Water depth at subsea well = 4000 ft

Water depth at platform = 3000 ft

Subsea well shut-in pressure, P_i = 10,000 psi

Specific gravity of fluid, gas production well = 0.30

Specific gravity of fluid, oil production well = 0.80

Internal corrosion allowance = 0 mm

Table C.1—Pipe Data

Pipe Data	Pipeline No. 1 PIP	Pipeline No. 2 Single Pipe
flowline/riser diameter, D, in.	8.625	8.625
flowline pipe SMYS, S, psi	70,000	70,000
flowline pipe ultimate strength, U, psi	82,000	82,000
riser pipe SMYS, S, psi	65,000	65,000
riser pipe ultimate strength, U, psi	78,000	78,000
PIP external pipe diameter, in.	12.75	—
PIP external pipe SMYS, psi	60,000	—
PIP external pipe ultimate strength, psi	75,000	—

C.2 Calculation Procedure

Calculation procedure described here is for two scenarios, depending on if the shut-in pressure is specified at the subsea wellhead, or at the top of the riser (surface). For all internal pressure design calculations based on this RP, ensure that the pressure difference ($P_i - P_o$) is used instead of P_i alone, where hydrostatic pressures both inside and outside the pipe vary with the water depth along the pipeline and riser. In the procedure described below the deepest water depth is assumed to be at the subsea wellhead location and the shallowest water depth is at the platform or riser location. Similar approaches should be taken to account for the pressure gains and losses due to changes in elevation in case the deep and shallow locations along the flowline and riser are different from the assumptions made here.

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. Specifically, these regulations may require that the internal test pressure shall exceed the maximum internal source pressure by a certain factor. The following provides a brief description of the difference in approach.

Assume the maximum source pressure (MSP) is equal to subsea well shut-in pressure (P_i = 10,000 psi in this calculation example). For this calculation example, the required minimum hydrostatic test pressure at the source (subsea wellhead) must be at least $1.25\ (P_i - P_o)$, where the hydrostatic test pressure P_t is a differential pressure. The actual minimum required internal test pressure at the subsea location, accounting for hydrostatic head, will then be at least equal to $1.25\ (P_i - P_o) + P_o$ or $1.25\ P_i - 0.25\ P_o$.

Some regulations, however, require the minimum required internal test pressure (not the differential test pressure) to be at least equal to a factor times the MSP, where the MSP is an internal source pressure. Assuming this factor also equals 1.25, this would lead to a minimum required internal test pressure of $1.25P_i$, regardless of local water depth.

As the calculation example in C.3 below will demonstrate, for flowlines tested via a riser from the surface, it will always be the test pressure at the surface that will determine the internal subsea test pressure, and this internal subsea test pressure will always exceed the minimum required internal subsea test pressure determined by either method above. However, there are two cases where it matters how the required test pressure is determined:

CASE 1 Surface testing of equipment for tie-in subsea, that may not be subjected to a subsequent full systems test offshore, for example, a subsea well jumper installed after the flowline system has been installed and tested.

CASE 2 Subsea hydrostatic testing of a flowline that is not connected to the surface via a riser, for example, a tie-in of a flowline to an existing flowline system, where the existing flowline system is not retested after the tie-in.

In Case 1, the design approach followed in this RP, would allow the jumper to be tested at the surface to a pressure equal to $1.25\ (P_i - P_o)$, with P_o being the external hydrostatic head at the subsea location for the jumper, provided the jumper does not see a higher test pressure during a subsequent systems hydrostatic test.

In Case 2, for the design approach followed in this RP, the internal test pressure to be applied subsea would equal $1.25\ P_i - 0.25\ P_o$ (for a PIP flowline, P_o would be 0).

The user of this RP is cautioned regarding Case 1 and Case 2, which are consistent with the design principles of this RP. This RP's methodology may not be allowed by some regulations, and in both cases, the required minimum internal hydrostatic test pressure may have to be equal to a factor times P_i, regardless of whether the component is tested at the surface or subsea.

C.2.1 Shut-in pressure is specified at subsea wellhead.

STEP 1 Obtain oil/gas production fluid density at shut-in pressure condition.

This information is generally known. If unknown, a fluid specific gravity of 0.30 (water referenced), representing a partially gas-filled line, may be assumed.

STEP 2 Calculate the internal shut-in pressure at the top of the riser.

Start at the subsea wellhead for which the internal shut-in pressure is known. Calculate the shut-in pressure at the top of the riser by subtracting the pressure loss due to elevation gain in the production fluid column, using the production fluid density from Step 1.

STEP 3 Calculate the hydrostatic test pressure at the top of the riser.

Calculate the hydrostatic test pressure at the top of the riser using Equation (2) if shut-ins of the wells through the flowline and riser are planned, or using Equation (3) if such shut-ins are incidental.

STEP 4 Calculate hydrostatic test pressure along the suspended riser and at the subsea wellhead.

Start with the hydrostatic test pressure at the top of the riser where the hydrostatic test pressure is known. Calculate the hydrostatic test pressure along the riser and at the subsea wellhead by adding the hydrostatic pressure due to the water column. For design purposes, calculate the differential pressure (the internal pressure minus the external pressure) at each point. For a single-pipe flowline, the differential hydrostatic test pressure is constant along the flowline and riser. For a PIP flowline, the controlling pressure is at the lowest point and for the riser it occurs at the base.

STEP 5 Determine the wall thickness for riser and flowline.

Calculate the wall thickness for a given pipe diameter and grade, using the test pressures from Step 4 and Equation (4) or Equation (5), as required to obtain the limit state design. Use the hydrostatic test pressure difference, which gives the thickest wall for both the flowline pipe and the riser pipe.

C.2.2 Shut-in pressure is specified at the top of the riser.

The calculation procedure for the shut-in pressure specified at the top of the riser is the same as, C.2.1, beginning with Step 3.

C.3 Calculations

For the example calculations, let $H1$, $H2$, P_s, γ, and SG be as follows:

$H1$ = 4000 ft;

$H2$ = 3000 ft;

P_s = 10,000 psi;

γ = seawater density, 64 lb/ft^3;

SG = specific gravity of produced fluid, 0.30 for gas, and 0.80 for crude oil.

Note that in "PIP" case, the internal pipe is not subjected to the external pressure due to water depth whereas the outer pipe (or jacket pipe) is affected. The pressure in the annular space between the two pipes is assumed to be atmospheric or negligible in this example of PIP flowline. For a single-pipe flowline, the external pressures at the riser base and at the subsea wellhead are given by:

P_o at riser base $= \gamma \times H2/144$

P_o at subsea well $= \gamma \times H1/144$

STEP 1 Produced fluid density or specific gravity.

Specific gravity of gas and oil production is given as 0.30 and 0.80 respectively.

STEP 2 Calculate internal pressure P_i at the top of the riser.

Using the subsea wellhead shut-in pressure, produced fluid density and water depth, calculate the internal pressure at the top of the riser.

P_i at subsea wellhead $= P_s = 10{,}000$ psi

P_i at top of the riser, $P_i = P_s - \gamma \times H1\ (SG)/144$

Calculated internal pressures are shown in Table C.2 for the example cases.

STEP 3 Calculate hydrostatic test pressure P_t at the top of the riser.

Using the shut-in pressure at the top of the riser from Step 2, calculate the hydrostatic test pressure at the top of the riser. Assume planned shut in of the system from the platform, thus requiring Equation (2).

$$P_t = (P_i - P_o)/0.8$$

$$P_t \text{ at riser top} = P_i/0.8$$

STEP 4 Calculate hydrostatic test pressure P_t along the riser and flowline.

Using the hydrostatic test pressure at the top of the riser, calculate the hydrostatic test pressures at the base of the riser and at the subsea wellhead.

$$P_t \text{ at riser base} = P_t + \gamma \times H2/144 - P_o \text{ at riser base}$$

For the single-pipe case, from the top of riser at the waterline to wellhead, external hydrostatic pressure will cancel out internal hydrostatic load, making resulting pressure during hydrostatic test constant.

$$P_t \text{ at subsea wellhead} = P_t + \gamma \times H1/144 - P_o \text{ at wellhead}$$

$$P_t \text{ at subsea wellhead} = (P_i - P_o)/0.8$$

See Table C.2 and Table C.3 for the calculated external pressure, shut-in pressure difference and the hydrostatic test pressure as per Step 3 and Step 4.

STEP 5 Calculate pipe wall thickness for riser and flowline.

Use Equation (1) to substitute P_t for P_b in Equation (4) or Equation (5) to determine pipe diameter to wall thickness ratio (D/t) for given pipe grades. Wall thickness is calculated knowing the pipe diameter and the D/t ratio. Equation (5) is modified and used for the example cases, as follows:

$$D/t = 1 + 0.90\ (S + U)\ /\ P_b$$

$$= 1 + 0.810\ (S + U)\ /\ P_t \text{ for flowline}$$

$$= 1 + 0.675\ (S + U)\ /\ P_t \text{ for riser}$$

Calculated pipe wall thickness as per Step 5 are shown in Table C.2 and Table C.3 for the example cases.

C.4 Limiting Riser to Within a Horizontal Distance of 300 ft from the Surface Facility

Section 3.1.5 of this RP specifies that for purposes of internal pressure design, the riser design factor applies to pipe within a horizontal distance of 300 ft from the surface facility and the pipeline design factor applies beyond that point. For this example it is assumed that at a 300 ft horizontal distance from the surface facility in the examples described herein, the riser extends to a 1000 ft depth below the water surface. Thus the section of pipe up to 1000 ft water depth and within 300 ft horizontal distance from the surface can be designed using the riser design factor for purpose of internal pressure design. And the pipe beyond that point can be designed using the pipeline design factor. This differentiation of the riser from pipeline provides additional safety of the riser based on third party damage and dropped object etc. Table C.4 and Table C.5 show the results of calculations using such criteria. The calculation procedure described in C.2 and C.3 remains the same.

C.5 Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

As per 4.3.1, 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. Assuming such criteria are met for pipe in the examples described considered here, Table C.6, Table C.7, Table C.8, and Table C.9 show the results of calculations based upon the calculation procedure described in C.2 to C.4 and Equation (B.2). Table C.6 and Table C.7 are for the riser and pipeline design factors that are similar to applied in calculations shown in Table C.2 and Table C.3. Table C.8 and Table C.9 are for the riser design factors applied to pipe within 300 ft horizontal distance from the surface facility. This scenario is similar to the ones described in C.4 and Table C.4 and Table C.5.

C.6 Comparison of Results

In order to further illustrate application of the limit state for the internal pressure design, flowline and riser pipe wall thickness as calculated and described in C.2 to C.5 were compared with the traditional design method. Refer to Table C.10. Results from Table C.2 to Table C.9 were taken and compared with the current design practice in compliance with 30 *Code of Federal Regulations* 250. PIP and single pipe for gas and oil production cases were taken. Four cases of limit state design were compared with the traditional design. The four cases are:

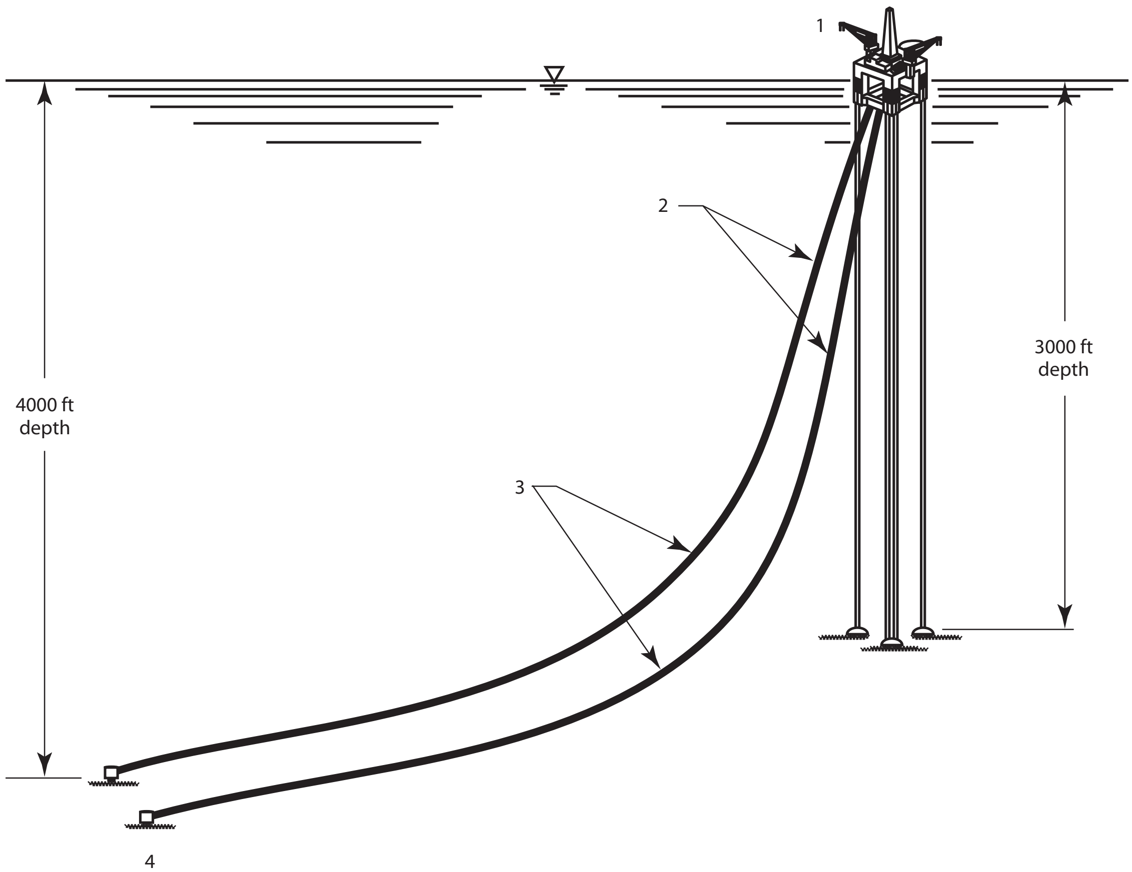
a) limit state design of flowline and riser (Table C.2 and Table C.3);

b) limit state design of a riser limited to within a 300 ft horizontal distance from the surface facility (Table C.4 and Table C.5);

c) limit state design of pipe material having improved control of mechanical properties and dimensions as per Annex B (Table C.6 and Table C.7);

d) limit state design of a riser limited to within a 300 ft horizontal distance from the surface facility, and pipe material having improved control of mechanical properties and dimensions as per Annex B (Table C.8 and Table C.9).

The comparison of results given in the Table C.10 shows that a material savings of 4.4 % to 21.2 % is possible to achieve by applying the limit state design as described in this RP to the example problem considered in this annex.



Key
1 TLP
2 catenary risers
3 insulated flowlines: pipe-in-pipe or single pipe
4 subsea production wells with 10,000 psi shut-in pressure

Figure C.1—Example Subsea Flowlines and Risers

Table C.2—PIP, Gas/Oil Production Flowline and Riser

Description	Flowline at Subsea Well	Bottom of Riser	Top of Riser
PIP, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	13,611	13,167	11,833
maximum pressure for calculating D/t ratio, psi	13,611	13,167	—
D/t ratio for hydrostatic test pressure	10.046	8.331	8.331
t, wall thickness, in.	0.859	1.035	1.035
PIP, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	12,500	12,056	—
maximum pressure for calculating D/t ratio, psi	12,500	12,056	12,056
D/t ratio for hydrostatic test pressure	10.850	9.007	9.007
t, wall thickness, in.	0.795	0.958	0.958

Table C.3—Single-pipe, Gas/Oil Production Flowline and Riser

Description	Flowline at Subsea Well	Bottom of Riser	Top of Riser
Single-pipe, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	1778	1333	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	11,833	11,833	11,833
maximum pressure for calculating D/t ratio, psi	11,833	11,833	—
D/t ratio for hydrostatic test pressure	11.405	9.157	9.157
t, wall thickness, in.	0.756	0.942	0.942
Single-pipe, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	1778	1333	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	10,722	10,722	10,722
maximum pressure for calculating D/t ratio, psi	10,722	10,722	—
D/t ratio for hydrostatic test pressure	12.483	10.002	10.002
t, wall thickness, in.	0.691	0.862	0.862

Table C.4—PIP, Gas/Oil Production Flowline and Riser Limiting Riser to Within a Horizontal Distance of 300 ft from the Surface Facility

Description	Flowline at Subsea Well	Bottom of Riser at 1000 ft	Top of Riser
PIP, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	13,611	12,278	11,833
maximum pressure for calculating D/t ratio, psi	13,611	12,278	—
D/t ratio for hydrostatic test pressure	10.046	8.862	8.862
t, wall thickness, in.	0.859	0.973	0.973
PIP, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8.578
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	12,500	11,167	10,722
maximum pressure for calculating D/t ratio, psi	12,500	11,167	—
D/t ratio for hydrostatic test pressure	10.850	9.644	9.644
t, wall thickness, in.	0.795	0.894	0.894

Table C.5—Single-pipe, Gas/Oil Production Flowline and Riser Limiting Riser to Within a Horizontal Distance of 300 ft from the Surface Facility

Description	Flowline at Subsea Well	Bottom of Riser at 1000 ft	Top of Riser
Single-pipe, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	1778	444	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	11,833	11,833	11,833
maximum pressure for calculating D/t ratio, psi	11,833	11,833	—
D/t ratio for hydrostatic test pressure	11.405	9.157	9.157
t, wall thickness, in.	0.756	0.942	0.942
Single-pipe, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	1778	444	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	10,722	10,722	10,722
maximum pressure for calculating D/t ratio, psi	10,722	10,722	—
D/t ratio for hydrostatic test pressure	12.483	10.002	10.002
t, wall thickness, in.	0.691	0.862	0.862

Table C.6—PIP, Gas/Oil Production Flowline and Riser
Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well	Bottom of Riser	Top of Riser
PIP, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	13,611	13,167	11,833
maximum pressure for calculating D/t ratio, psi	13,611	13,167	—
D/t ratio for hydrostatic test pressure	11.051	9.146	9.146
t, wall thickness, in.	0.780	0.943	0.943
PIP, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	12,500	12,056	12,056
maximum pressure for calculating D/t ratio, psi	12,500	12,056	—
D/t ratio for hydrostatic test pressure	11.944	9.896	9.896
t, wall thickness, in.	0.722	0.872	0.872

Table C.7—Single-pipe, Gas/Oil Production Flowline and Riser Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well	Bottom of Riser	Top of Riser
Single-pipe, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	1778	1333	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	11,833	11,833	11,833
maximum pressure for calculating D/t ratio, psi	11,833	11,833	—
D/t ratio for hydrostatic test pressure	12.561	10.063	10.063
t, wall thickness, in.	0.687	0.857	0.857
Single-pipe, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	1778	1333	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	10,722	10,722	10,722
maximum pressure for calculating D/t ratio, psi	10,722	10,722	—
D/t ratio for hydrostatic test pressure	13.759	11.003	11.003
t, wall thickness, in.	0.627	0.784	0.784

Table C.8—PIP, Gas/Oil Production Flowline and Riser Limiting Riser to Within a Horizontal Distance of 300 ft from the Surface Facility Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well	Bottom of Riser at 1000 ft	Top of Riser
PIP, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	13,611	12,278	11,833
maximum pressure for calculating D/t ratio, psi	13,611	12,278	—
D/t ratio for hydrostatic test pressure	11.051	9.735	9.735
t, wall thickness, in.	0.780	0.886	0.886
PIP, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8.578
P_o, external pressure, psi	0	0	0
$(P_i - P_o)$, shut-in pressure difference, psi	10,000	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	12,500	11,167	10,722
maximum pressure for calculating D/t ratio, psi	12,500	11,167	—
D/t ratio for hydrostatic test pressure	11.944	10.604	10.604
t, wall thickness, in.	0.722	0.813	0.813

Table C.9—Single-pipe, Gas/Oil Production Flowline and Riser Limiting Riser to Within a Horizontal Distance of 300 ft from the Surface Facility Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well	Bottom of Riser at 1000 ft	Top of Riser
Single-pipe, Gas Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	9467
P_o, external pressure, psi	1778	444	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	9467
P_t, test pressure at riser top, psi	—	—	11,833
resulting pressure during hydrostatic test, psi	11,833	11,833	11,833
maximum pressure for calculating D/t ratio, psi	11,833	11,833	—
D/t ratio for hydrostatic test pressure	12.561	10.063	10.063
t, wall thickness, in.	0.687	0.857	0.857
Single-pipe, Oil Production Flowline and Riser			
P_i, shut-in pressure, psi	10,000	—	8578
P_o, external pressure, psi	1778	444	0
$(P_i - P_o)$, shut-in pressure difference, psi	8222	—	8578
P_t, test pressure at riser top, psi	—	—	10,722
resulting pressure during hydrostatic test, psi	10,722	10,722	10,722
maximum pressure for calculating D/t ratio, psi	10,722	10,722	—
D/t ratio for hydrostatic test pressure	13.759	11.003	11.003
t, wall thickness, in.	0.627	0.784	0.784

Table C.10—Comparison of Results

Description	API 1111 Limit State, Table C.2 and Table C.3	API 1111 Limit State Table C.4 and Table C.5 (Riser Design Factor)	API 1111 Limit State, Table C.6 and Table C.7 (Annex B)	API 1111 Limit State, Table C.8 and Table C.9 (Riser Design Factor, and Annex B)	Title 30 *Code of Federal Regulations* 250 Traditional Design
PIP, Gas Production, 8.625 in. OD Inner Pipe					
flowline D/t ratio	10.046	10.046	11.051	11.051	9.768
flowline pipe wall, in.	0.859	0.859	0.780	0.780	0.883
weight in air, lb/ft	71.31	71.31	65.41	65.41	73.08
material savings, %	2.4	2.4	10.5	10.5	—
riser D/t ratio	8.331	8.862	9.146	9.735	7.905
riser pipe wall, in.	1.035	0.973	0.943	0.886	1.091
weight in air, lb/ft	83.98	79.59	77.44	73.30	87.87
material savings, %	4.4	9.4	11.9	16.6	—
PIP, Oil Production, 8.625 in. OD Inner Pipe					
flowline D/t ratio	10.850	10.850	11.944	11.944	10.080
flowline pipe wall, in.	0.795	0.795	0.722	0.722	0.856
weight in air, lb/ft	66.54	66.54	61.00	61.00	71.09
material savings, %	6.4	6.4	14.2	14.2	—
riser D/t ratio	9.007	9.644	9.896	10.604	8.088
riser pipe wall, in.	0.958	0.894	0.872	0.813	1.066
weight in air, lb/ft	78.52	73.88	72.27	67.89	86.14
material savings, %	8.9	14.2	16.1	21.2	—
Single-pipe, Gas Production, 8.625 in. OD Pipe					
flowline D/t ratio	11.405	11.405	12.561	12.561	11.245
flowline pipe wall, in.	0.756	0.756	0.687	0.687	0.767
weight in air, lb/ft	63.59	63.59	58.30	58.30	64.43
material savings, %	1.3	1.3	9.5	9.5	—
riser D/t ratio	9.157	9.157	10.063	10.063	8.239
riser pipe wall, in.	0.942	0.942	0.857	0.857	1.047
weight in air, lb/ft	77.37	77.37	71.17	71.17	84.82
material savings, %	8.8	8.8	16.1	16.1	—
Single-pipe, Oil Production, 8.625 in. OD Pipe					
flowline D/t ratio	12.483	12.483	13.759	13.759	12.131
flowline pipe wall, in.	0.691	0.691	0.627	0.627	0.711
weight in air, lb/ft	58.61	58.61	53.61	53.61	60.15
material savings, %	2.6	2.6	10.9	10.9	—
riser D/t ratio	10.002	10.002	11.003	11.003	9.093
riser pipe wall, in.	0.862	0.862	0.784	0.784	0.949
weight in air, lb/ft	71.53	71.53	65.72	65.72	77.87
material savings, %	8.1	8.1	15.6	15.6	—

Annex D
(informative)

External Pressure Design Example

D.1 Problem Statement

Perform external pressure (collapse) design validation per 4.3.2 for two flowlines with the following nominal specifications and design information (see Figure C.1). Only British units are included to reduce clutter and allow comparison to previous editions of API 1111.

Pipeline No. 1: 8 in. × 12 in. PIP flowline and SCR

Flowline Pipe: 8.625 in. × 0.875 in., API-5L X70, seamless, ultimate tensile = 80 ksi

Jacket Pipe: 12.75 in. × 0.562 in., API-5L X60, seamless, ultimate tensile = 75 ksi

SCR Pipe: 8.625 in. × 1.000 in., API-5L X65, seamless, ultimate tensile = 77 ksi

Jacket Pipe: 12.75 in. × 0.562 in., API-5L X60, seamless, ultimate tensile = 75 ksi

Pipeline No. 2: 8 in. flowline and SCR

Flowline Pipe: 8.625 in. × 0.875 in., API-5L X70, seamless, ultimate tensile = 80 ksi

SCR Pipe: 8.625 in. × 1.000 in., API-5L X65, seamless, ultimate tensile = 77 ksi

Maximum Flowline Water Depth: 4000 ft (1778 psi)

Maximum SCR Water Depth: 3000 ft (1333 psi)

Shut-in Pressure at Subsea Well: 10,000 psi

Maximum Product Specific Gravity: 0.80 (mainly oil)

Minimum Product Specific Gravity: 0.30 (mainly gas)

Young's Modulus, E: 29 × 106

Pipe Ovality, δ: 0.5 %

D.2 Collapse Due to External Pressure per 4.3.2.1

The Inequality (9) must be satisfied:

$$(P_o - P_i) \leq f_o P_c \tag{9}$$

The maximum ratio of ($P_o - P_i$) shall be determined for the installation and operating conditions. The hydrostatic test condition is ignored since the internal pressure exceeds the external pressure. P_o is the maximum external water pressure and P_i is the minimum internal pressure. Internal pressure has also been assumed as zero for both the installation and operating cases. Certain operating conditions such as blow down or gas lifting may reduce the internal pressure to negligible levels, consequently use of any nonzero internal pressure for the operating condition may not be realistic. Table D.1 summarizes the net external pressure loading for both installation and operation design cases.

Next, calculate the collapse pressure, P_c, for all six pipeline design cases from Table D.1. Equation (10), Equation (11), and Equation (12) are used to determine P_c.

Combining the results from Table D.1 and Table D.2, it can be established whether all the design cases satisfy inequality relation (9). The seamless pipe collapse factor, f_o, of 0.7 is utilized.

D.3 Results

Table D.3 demonstrates that all design cases for the pipelines meet the external pressure collapse resistance requirements of 4.3.2.1.

Table D.1—Net External Pressure Loading

Pressure in pounds per square inch

Design Case	P_o	P_i	$(P_o - P_i)$
P/L No. 1, flowline	0	0	0
P/L No. 1, jacket	1778	0	1778
P/L No. 1, riser	0	0	0
P/L No. 1, riser jacket	1333	0	1333
P/L No 2, flowline	1778	0	1778
P/L No. 2, riser	1333	0	1333

Table D.2—Collapse Pressure

Pressure in pounds per square inch

Design Case	P_y	P_e	P_c
P/L No. 1, flowline	14,202	66,548	13,889
P/L No. 1, jacket	5289	5458	3798
P/L No. 1, riser	15,072	99,337	14,901
P/L No. 1, riser jacket	5289	5458	3798
P/L No 2, flowline	14,202	66,548	13,889
P/L No. 2, riser	15,072	99,337	14,901

Table D.3—External Pressure Collapse Resistance

Pressure in pounds per square inch

Design Case	$(P_o - P_i)$	$f_o P_c$	Inequality (9) Satisfied? (Yes/No)
P/L No. 1, flowline	0	9722	yes
P/L No. 1, jacket	1778	2659	yes
P/L No. 1, riser	0	10,431	yes
P/L No. 1, riser jacket	1333	2659	yes
P/L No 2, flowline	1778	9722	yes
P/L No. 2, riser	1333	10,431	yes

D.4 Buckling Due to Combined Bending and External Pressure per 4.3.2.2

The inequality relations of Equation (13), Equation (14), and Equation (15) must be satisfied. There are different technical approaches to solving the inequalities dependent on whether the wall thickness is known or unknown in advance. The following solution path is based on the known pipe specifications of the example problem. In this case it is necessary to demonstrate that inequalities Equation (14), and Equation (15) are satisfied for the limit state, buckling bending strain determined by changing (13) from an inequality to an equation:

$$\varepsilon/\varepsilon_b + (P_o - P_i)/(f_c \times P_c) = g(\delta) \tag{13}$$

Solving Equation (13) for the buckling limit state bending strain, ε, yields:

$$\varepsilon = \{g(\delta) - (P_o - P_i)/(f_c \times P_c)\} \times \varepsilon_b$$

where

$g(\delta) = (1 + 20\delta)^{-1} = (1 + 20x0.005)^{-1} = 0.9091$ for all design cases

$\varepsilon_b = (t/2D)$

The term $(P_o - P_i)/(f_c \times P_c)$ is derived from Table D.2 and Table D.3 of the D.2 calculations. Assuming f_c = 0.7, this then yields the following buckling limit state bending strains, ε, shown in Table D.4.

Equation (14) and Equation (15) shall be satisfied to demonstrate adequate strength for the installation and operation design cases.

$$\varepsilon \geq f_1 \varepsilon_1 \tag{14}$$

$$\varepsilon \geq f_2 \varepsilon_2 \tag{15}$$

Following are examples of how the key load states and safety factors are defined:

$f_1 = 3.33$

The safety factor of 3.33 for installation allows for a large increase in the bending strain before the critical buckling bending strain is reached. This safety factor should be selected based on positional stability of the lay vessel during dynamic positioned pipelay and subjective degree of risk to be tolerated. Lower safety factors may be justified for exceptional conditions; for instance pipelay equipment limits, economic constraints, or other factors.

$e_1 = 0.0015$ or 0.15 %

The maximum installation bending strain is typically determined by installation analyses, contractor equipment limitations, and pipeline owner specifications. The selected value of 0.15 % has been used on numerous pipeline projects.

$f_2 = 2.0$

The safety factor of 2.0 for operation allows for a significant increase in the bending strain before the critical buckling bending strain is reached. This safety factor is reduced compared to the installation safety factor since the maximum

Table D.4—Buckling Limit State Bending Strains

Design Case	$\{g(\delta) - (P_o - P_i)/(f_c \times P_c)\}$	ε_b	ε
P/L No. 1, flowline	0.9091	0.0507	0.0461
P/L No. 1, jacket	0.2404	0.0220	0.0053
P/L No. 1, riser	0.9091	0.0580	0.0527
P/L No. 1, riser jacket	0.4078	0.0220	0.0090
P/L No 2, flowline	0.7261	0.0507	0.0368
P/L No. 2, riser	0.7813	0.0580	0.0453

Table D.5—Combined Bending and External Buckle Resistance

Design Case	Installation		Operation		Inequalities Satisfied (Yes/No)
	ε	$f_1\varepsilon_1$	ε	$f_2\varepsilon_2$	
P/L No. 1, flowline	0.0461	0.0050	0.0461	0.0030	yes
P/L No. 1, jacket	0.0053	0.0050	0.0053	0.0030	yes
P/L No. 1, riser	0.0527	0.0050	0.0527	0.0030	yes
P/L No. 1, riser jacket	0.0090	0.0050	0.0090	0.0030	yes
P/L No 2, flowline	0.0368	0.0050	0.0368	0.0030	yes
P/L No. 2, riser	0.0453	0.0050	0.0453	0.0030	yes

expected bending strains can be defined with higher precision due to the known boundary conditions. In many cases it can be demonstrated that operational or in-place bending strains are self-limiting due to the support geometry.

$$\varepsilon_2 = 0.0015 \text{ or } 0.15\ \%$$

In-place structural pipeline analyses and pipeline owner specifications typically determine the maximum operational bending strain. The selected value of 0.15 % is typical for pipeline projects.

D.5 Results

Table D.5 demonstrates that all design cases for the pipelines meet the combined bending and external pressure buckle resistance requirements of 4.3.2.2.

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