ASME B31.8-2016
(Revision of ASME B31.8-2014)

Gas Transmission and Distribution Piping Systems

ASME Code for Pressure Piping, B31

AN INTERNATIONAL PIPING CODE®

The American Society of Mechanical Engineers

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Two Park Avenue • New York, NY • 10016 USA

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The next edition of this Code is scheduled for publication in 2018. This Code will become effective 6 months after the Date of Issuance.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Code. Interpretations are published on the Committee Web page and under go.asme.org/Interpretations. Periodically certain actions of the ASME B31 Committee may be published as Cases. Cases are published on the ASME Web site under the B31 Committee Page at go.asme.org/B31committee as they are issued.

Errata to codes and standards may be posted on the ASME Web site under the Committee Pages of the associated codes and standards to provide corrections to incorrectly published items, or to correct typographical or grammatical errors in codes and standards. Such errata shall be used on the date posted.

The B31 Committee Page can be found at go.asme.org/B31committee. The associated B31 Committee Pages for each code and standard can be accessed from the main page. There is an option available to automatically receive an e-mail notification when errata are posted to a particular code or standard. This option can be found on the appropriate Committee Page after selecting "Errata" in the "Publication Information" section.

The American Society of Mechanical Engineers
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CONTENTS

FOREWORD

The need for a national code for pressure piping became increasingly evident from 1915 to 1925. To meet this need, the American Engineering Standards Committee [later changed to the American Standards Association, now the American National Standards Institute (ANSI)] initiated Project B31 in March 1926 at the request of the American Society of Mechanical Engineers and with that Society as sole sponsor. After several years of work by Sectional Committee B31 and its subcommittees, a first Edition was published in 1935 as an American Tentative Standard Code for Pressure Piping.

A revision of the original tentative standard began in 1937. Several more years of effort were given to securing uniformity among sections, eliminating divergent requirements and discrepancies, keeping the Code abreast of current developments in welding technique, calculating stress computations, and including reference to new dimensional and material standards. During this period, a new section on refrigeration piping was prepared in cooperation with the American Society of Refrigeration Engineers and complemented the American Standard Code for Mechanical Refrigeration. This work culminated in the 1942 American Standard Code for Pressure Piping.

Supplements 1 and 2 of the 1942 Code, which appeared in 1944 and 1947, respectively, introduced new dimensional and material standards, a new formula for pipe wall thickness, and more comprehensive requirements for instrument and control piping. Shortly after the 1942 Code was issued, procedures were established for handling inquiries requiring explanation or interpretation of Code requirements and for publishing such inquiries and answers in *Mechanical Engineering* for the information of all concerned.

By 1948, continuing increases in the severity of service conditions combined with the development of new materials and designs to meet these higher requirements warranted more extensive changes in the Code than could be provided from supplements alone. The decision was reached by the American Standards Association and the sponsor to reorganize the sectional committee and its several subcommittees and to invite the various interested bodies to reaffirm their representatives or to designate new ones.

Because of the wide field involved, between 30 and 40 different engineering societies, government bureaus, trade associations, institutes, and similar organizations had one or more representatives on the sectional committee, plus a few "members-at-large" to represent general interests. Code activities were subdivided according to the scope of the several sections. General direction of Code activities rested with the Standards Committee officers and an executive committee, membership of which consisted principally of Standards Committee officers and section chairmen.

Following its reorganization in 1948, Standards Committee B31 made an intensive review of the 1942 Code that resulted in

(a) a general revision and extension of requirements to agree with present-day practice

(b) the revision of references to existing dimensional standards and material specifications and the addition of references to the new ones

(c) the clarification of ambiguous or conflicting requirements

A revision was presented for letter ballot vote of Standards Committee B31. Following approval by this body, the project was approved by the sponsor organization and by the American Standards Association. It was finally designated as an American Standard in February 1951, with the designation B31.1-1951.

Standards Committee B31 at its annual meeting of November 29, 1951, authorized the separate publication of a section of the Code for Pressure Piping addressing gas transmission and distribution piping systems, to be complete with the applicable parts of Section 2, Gas and Air Piping Systems; Section 6, Fabrication Details; and Section 7, Materials — Their Specifications and Identification. The purpose was to provide an integrated document for gas transmission and distribution piping that would not require cross-referencing to other sections of the Code.

The first Edition of this integrated document, known as American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems, was published in 1952 and consisted almost entirely of material taken from Sections 2, 6, and 7 of the 1951 Edition of the Pressure Piping Code.

A new section committee was organized in 1952 to update Section 8 as necessary to address modern materials and methods of construction and operation.

After a review by B31 Executive and Standards Committees in 1955, a decision was made to develop and publish industry sections as separate Code documents of the American Standard B31 Code for Pressure Piping. The 1955 Edition constituted a general revision of the 1952 Edition with a considerably expanded scope. Further experience in the application of the Code resulted in revisions in 1958, 1963, 1966, 1967, 1968, 1969, 1975, and 1982.

In December 1978, the American National Standards Committee B31 was reorganized as the ASME Code for Pressure Piping, B31 Committee. The code designation was also changed to ANSI/ASME B31.

The 1989 Edition of the Code was a compilation of the 1986 Edition and the subsequent addenda issued to the 1986 Edition.

The 1992 Edition of the Code was a compilation of the 1989 Edition, the subsequent three addenda, and the two special Errata issued to the 1989 Edition.

The 1995 Edition of the Code was a compilation of the 1992 Edition and the subsequent three addenda issued to the 1992 Edition.

The 1999 Edition of the Code was a compilation of the 1995 Edition and the revisions that occurred following the issuance of the 1995 Edition.

The 2003 Edition of the Code was a compilation of the 1999 Edition and revisions that occurred following the issuance of the 1999 Edition.

The 2007 Edition of the Code was a compilation of the 2003 Edition and revisions that occurred following the issuance of the 2003 Edition.

The 2010 Edition of the Code was a compilation of the 2007 Edition and revisions that occurred folowing the issuance of the 2007 Edition.

The 2012 Edition of the Code was a compilation of the 2010 Edition and revisions that occurred following the issuance of the 2010 Edition.

The 2014 Edition of the Code was a compilation of the 2012 Edition and revisions that occurred following the issuance of the 2012 Edition.

The 2016 Edition of the Code is a compilation of the 2014 Edition and revisions that have occurred since the issuance of the 2014 Edition. This Edition was approved by ANSI on August 26, 2016.

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Code for Pressure Piping

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(16)

INTRODUCTION

The ASME Code for Pressure Piping consists of many individually published sections, each an American National Standard. Hereafter, in this Introduction and in the text of this Code Section, B31.8, when the word "Code" is used without specific identification, it means this Code Section.

The Code specifies engineering requirements deemed necessary for the safe design and construction of pressure piping. While safety is the primary consideration, this factor alone will not necessarily govern the final specifications of any piping installation or operation. The Code is not a design handbook. Many decisions that must be made to produce a sound piping installation and maintain system integrity during operation are not specified in detail within this Code. The Code does not serve as a substitute for sound engineering judgement by the operating company and designer.

To the greatest possible extent, Code requirements for design are stated in terms of basic design principles and formulas. These are supplemented as necessary with specific requirements to ensure uniform application of principles and to guide selection and application of piping elements. The Code prohibits designs and practices known to be unsafe and contains warnings where caution, but not prohibition, is warranted.

This Code Section includes

(a) references to acceptable material specifications and component standards, including dimensional and mechanical property requirements

(b) requirements for designing components and assemblies

(c) requirements and data for evaluating and limiting stresses, reactions, and movements associated with pressure, temperature changes, and other forces

(d) guidance and limitations on selecting and applying materials, components, and joining methods

(e) requirements for fabricating, assembling, and installing piping

(f) requirements for examining, inspecting, and testing piping

(g) procedures for operation and maintenance that are essential to public safety

(h) provisions for protecting pipelines from external and internal corrosion

It is intended that this Edition of Code Section B31.8 not be retroactive. The latest edition issued at least 6 months before the original contract date for the first phase of activity covering a piping system or systems shall be the governing document, unless agreement is specifically made between contracting parties to use another issue, or unless the regulatory body having jurisdiction imposes the use of another issue or different requirements.

Users of this Code are cautioned against making use of revisions without assurance that they are acceptable to any authorities of jurisdiction where the piping is to be installed.

The Code is under the direction of ASME Committee B31, Code for Pressure Piping, which is organized and operates under procedures of The American Society of Mechanical Engineers that have been accredited by the American National Standards Institute. The Committee is a continuing one and keeps all Code Sections current with new developments in materials, construction, and industrial practice.

When no Section of the ASME Code for Pressure Piping specifically covers a piping system, the user has discretion to select any Section determined to be generally applicable; however, it is cautioned that supplementary requirements to the Section chosen may be necessary to provide for a safe piping system for the intended application. Technical limitations of the various Sections, legal requirements, and possible applicability of other Codes or Standards are some of the factors to be considered by the user in determining the applicability of any Section of this Code.

Appendices

This Code contains two kinds of appendices: mandatory and nonmandatory. Mandatory appendices contain materials the user needs to carry out a requirement or recommendation in the main text of the Code. Nonmandatory appendices, which are written in mandatory language, are offered for application at the user's discretion.

Interpretations and Revisions

The Committee has established an orderly procedure to consider requests for interpretation and revision of Code requirements. To receive consideration, inquiries must be in writing and must give full particulars. (See Nonmandatory Appendix O covering preparation of technical inquiries.)

The approved reply to an inquiry will be sent directly to the inquirer. In addition, the question and reply will be published as part of an Interpretation Supplement to the Code Section, issued with the revisions.

Requests for interpretation and suggestions for revision should be addressed to the Secretary, ASME B31 Committee, The American Society of Mechanical Engineers, Two Park Avenue, New York, NY 10016-5990.

Cases

A Case is the prescribed form of reply to an inquiry when study indicates that the Code wording needs clarification or when the reply modifies existing requirements of the Code or grants permission to use new materials or alternative constructions. The Case will be published on the B31.8 Committee Page at http://cstools.asme.org/.

A Case is normally issued for a limited period, after which it may be renewed, incorporated in the Code, or allowed to expire if there is no indication of further need for the requirements covered by the Case. The provisions of a Case, however, may be used after its expiration or withdrawal, provided the Case was effective on the original contract date or was adopted before completion of the work, and the contracting parties agree to its use.

Materials are listed in the Stress Tables only when sufficient usage in piping within the scope of the Code has been shown. Materials may be covered by a Case. Requests for listing shall include evidence of satisfactory usage and specific data to permit establishment of allowable stresses or pressure rating, maximum and minimum temperature limits, and other restrictions. Additional criteria can be found in the guidelines for addition of new materials in the ASME Boiler and Pressure Vessel Code, Section II. (To develop usage and gain experience, unlisted materials may be used in accordance with para. 811.2.2.)

Effective Date

This Edition, when issued, contains new Code provisions. It is a compilation of the 2014 Edition and revisions to the 2014 Edition.

ASME B31.8-2016
SUMMARY OF CHANGES

Following approval by the B31 Committee and ASME, and after public review, ASME B31.8-2016 was approved by the American National Standards Institute on August 26, 2016.

ASME B31.8-2016 consists of editorial changes, revisions, and corrections identified by a margin note, **(16)**, placed next to the affected area.

Page	*Location*	*Change*
xiv, xv	Introduction	Updated
1	802.1	Subparagraph (b)(2) revised
2	802.2	New para. 802.2.2 added, and remaining paragraphs redesignated
3	803.4	Definition of *gathering system* revised in its entirety
8	805.2.3	Definition of *hoop stress, S_H [psi (MPa)]* revised
15	813.3	Added
16	814.1.3	Subparagraph (a)(2) revised
18	817.3	Subparagraph (a) revised
20	823.2.1	Revised
25, 26	831.3.1	Subparagraph (f) revised
27	831.4.1	Subparagraphs (b) and (e) revised
34	834.5	Subparagraph (b) revised
37, 38	841.1.2	Subparagraph (c) revised in its entirety
39	841.1.5	Subparagraph (a) revised
40	Table 841.1.6-2	"Pressure/flow control and metering facilities" row revised
49	Table 841.3.2-1	General Note (b) revised
52	Table 842.1.1-1	Last row revised
53	842.2.1	Definition for *S* revised
	842.2.2	(1) Subparagraph (c) revised (2) Table 842.2.2-1 deleted
54	842.2.3	(1) Subparagraph (c) revised (2) Table 842.2.3-1 deleted
	842.2.9	(1) Subparagraphs (b)(5) and (c)(3) revised (2) Subparagraph (b)(5)(-c) added
56, 57	Table 842.2.9-1	Second row added
	842.3.3	Former subpara. (d)(1) deleted, and remaining subparagraphs redesignated

Page	*Location*	*Change*
59	843.3.1	Subparagraph (b) revised
61	843.4.6	Revised
67	845.4.1	Subparagraphs (a)(1), (a)(2), and (a)(3) revised
103, 104	A801	Revised
	A803	Definitions for *minimum wall thickness*, t_{min}; *prefabricated piping*; and *special assembly* added
109–111	A842.1.6	Revised
	A842.2.2	Revised in its entirety
	Table A842.2.2-1	Note (1) revised
	A842.2.10	First sentence revised
121	B842.2.2	Subparagraph (g) revised
	B842.2.9	Subparagraph (b) revised
125–129	Mandatory Appendix A	Updated
131–133	Nonmandatory Appendix C	Updated
136	Table D-2	(1) Headers revised (2) Second row added
138–141	Table E-1	"Tapered transition per ASME B16.25" sketch and Note (1) revised
143, 145, 147	F-2.1	Last sentence revised
	F-2.1.5	Last sentence revised
	F-2.1M	Last sentence revised
	F-2.1.5M	Last sentence revised
175	N-1	Last sentence revised
183–191	Index	Updated

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GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS

General Provisions and Definitions

801 GENERAL

801.1 Approved Standards and Specifications

Standards and specifications approved for use under this Code and the names and addresses of the sponsoring organizations are shown in Mandatory Appendix A. It is not considered practicable to refer to a specific edition of each of the standards and specifications in the individual Code paragraphs.

801.2 Use of Standards and Specifications Incorporated by Reference

Some standards and specifications cited in Mandatory Appendix A are supplemented by specific requirements elsewhere in this Code. Users of this Code are advised against attempting direct application of any of these standards without carefully observing the Code's reference to that standard.

801.3 Standard Dimensions

Adherence to American National Standards Institute (ANSI) dimensions is strongly recommended wherever practicable. Paragraphs or notations specifying these and other dimensional standards in this Code, however, shall not be mandatory, provided that other designs of at least equal strength and tightness, capable of withstanding the same test requirements, are substituted.

801.4 SI (Metric) Conversion

For factors used in converting U.S. Customary units to SI units, see Nonmandatory Appendix J.

802 SCOPE AND INTENT

(16) 802.1 Scope

(a) This Code covers the design, fabrication, installation, inspection, and testing of pipeline facilities used for the transportation of gas. This Code also covers safety aspects of the operation and maintenance of those facilities. (See Mandatory Appendix Q for scope diagrams.)

This Code is concerned only with certain safety aspects of liquefied petroleum gases when they are vaporized and used as gaseous fuels. All of the requirements of NFPA 58 and NFPA 59 and of this Code concerning design, construction, and operation and maintenance of piping facilities shall apply to piping systems handling butane, propane, or mixtures of these gases.

(b) This Code does not apply to

(1) design and manufacture of pressure vessels covered by the BPV Code[1]

(2) piping with metal temperatures above 450°F (232°C) (For low-temperature considerations, see para. 812.)

(3) piping beyond the outlet of the customer's meter set assembly (Refer to ANSI Z223.1/NFPA 54.)

(4) piping in oil refineries or natural gasoline extraction plants, gas treating plant piping other than the main gas stream piping in dehydration, and all other processing plants installed as part of a gas transmission system, gas manufacturing plants, industrial plants, or mines (See other applicable sections of the ASME Code for Pressure Piping, B31.)

(5) vent piping to operate at substantially atmospheric pressures for waste gases of any kind

(6) wellhead assemblies, including control valves, flow lines between wellhead and trap or separator, offshore platform production facility piping, or casing and tubing in gas or oil wells (For offshore platform production facility piping, see API RP 14E.)

(7) the design and manufacture of proprietary items of equipment, apparatus, or instruments

(8) the design and manufacture of heat exchangers (Refer to appropriate TEMA[2] standard.)

(9) liquid petroleum transportation piping systems (Refer to ASME B31.4.)

(10) liquid slurry transportation piping systems (Refer to ASME B31.4.)

(11) carbon dioxide transportation piping systems

[1] BPV Code references here and elsewhere in this Code are to the ASME Boiler and Pressure Vessel Code.

[2] Tubular Exchanger Manufacturers Association, 25 North Broadway, Tarrytown, NY 10591.

(12) liquefied natural gas piping systems (Refer to NFPA 59A and ASME B31.3.)

(13) cryogenic piping systems

(16) 802.2 Intent

802.2.1 Adequacy for Normal Conditions. The requirements of this Code are adequate for safety under conditions usually encountered in the gas industry. Requirements for all unusual conditions cannot be specifically provided for, nor are all details of engineering and construction prescribed; therefore, activities involving the design, construction, operation, or maintenance of gas transmission, gathering, or distribution pipelines should be undertaken using supervisory personnel having the experience or knowledge to make adequate provision for such unusual conditions and specific engineering and construction details. All work performed within the scope of this Code shall meet or exceed the safety standards expressed or implied herein.

802.2.2 More Complete Analysis. The Code generally specifies a simplified approach for many of its requirements.

(a) For design and construction, a designer may choose to use a more rigorous analysis to develop design and construction requirements. When the designer decides to take this approach, the designer shall provide to the operating company details and calculations demonstrating that design, construction, examination, and testing are consistent with the criteria of this Code. These details shall be adequate for the operating company to verify the validity of the approach and shall be approved by the operating company. The details shall be documented in the engineering design.

(b) For operation and maintenance, an operating company may choose to use a more rigorous analysis to develop operation and maintenance requirements. When the operating company decides to take this approach, the operating company shall provide details and calculations demonstrating that such alternative practices are consistent with the objectives of this Code. The details shall be documented in the operating records and retained for the lifetime of the facility.

802.2.3 Safety. This Code is concerned with

(a) safety of the general public.

(b) employee safety to the extent that it is affected by basic design, quality of materials and workmanship, and requirements for testing, operations, and maintenance of gas transmission and distribution facilities. Existing industrial safety procedures pertaining to work areas, safety devices, and safe work practices are not intended to be supplanted by this Code.

802.2.4 Retroactive Applications. It is not intended that this Code be applied retroactively to such aspects of existing installations as design, fabrication, installation, and testing at the time of construction. Further, it is not intended that this Code be applied retroactively to established operating pressures of existing installations, except as provided for in Chapter V.

802.2.5 Application to Existing Facilities. Provisions of this Code shall be applicable to operating and maintenance procedures of existing installations, and when existing installations are uprated.

802.2.6 Qualification of Those Performing Inspections. Individuals who perform inspections shall be qualified by training and/or experience to implement the applicable requirements and recommendations of this Code.

802.2.7 Further Information. For further information concerning pipeline integrity, see the nonmandatory supplement ASME B31.8S, Managing System Integrity of Gas Pipelines.

802.3 Offshore Gas Transmission

See Chapter VIII for additional requirements and definitions applicable to offshore gas transmission systems.

803 PIPING SYSTEMS DEFINITIONS

803.1 General Terms and Definitions

carbon dioxide: a heavy, colorless gas that does not support combustion, dissolves in water to form carbonic acid, and is found in some natural gas streams.

environment: the surroundings or conditions (physical, chemical, mechanical) in which a material exists.

gas: as used in this Code, is any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air.

hot taps: branch piping connections made to operating pipelines, mains, or other facilities while they are in operation. The branch piping is connected to the operating line, and the operating line is tapped while it is under pressure.

liquefied natural gas: natural gas liquefied by refrigeration or pressure.

liquefied petroleum gases (LPG): composed predominantly of the following hydrocarbons (either by themselves or as mixtures): butane (normal butane or isobutene), butylene (including isomers), propane, propylene, and ethane. LPG can be stored as liquids under moderate pressures [approximately 80 psig (550 kPa) to 250 psig (1 720 kPa)] at ambient temperatures.

listed specification: a specification listed in Mandatory Appendix A.

operating company or *operator:* as used herein, is the individual, partnership, corporation, public agency, owner, agent, or other entity responsible for the design, construction, inspection, testing, operation, and maintenance of the pipeline facilities.

parallel encroachment: as used in this Code, is the portion of the route of a pipeline or main that lies within, runs in a generally parallel direction to, and does not necessarily cross the rights-of-way of a road, street, highway, or railroad.

petroleum: crude oil, condensate, natural gasoline, natural gas liquids, liquefied petroleum gas, and liquid petroleum products.

pipeline: all parts of physical facilities through which gas moves in transportation, including pipe, valves, fittings, flanges (including bolting and gaskets), regulators, pressure vessels, pulsation dampeners, relief valves, appurtenances attached to pipe, compressor units, metering facilities, pressure-regulating stations, pressure-limiting stations, pressure relief stations, and fabricated assemblies. Included within this definition are gas transmission and gathering lines, which transport gas from production facilities to onshore locations, and gas storage equipment of the closed pipe type that is fabricated or forged from pipe or fabricated from pipe and fittings.

private rights-of-way: as used in this Code, are rights-of-way not located on roads, streets, or highways used by the public, or on railroad rights-of-way.

system or pipeline system: either the operator's entire pipeline infrastructure or large portions of that infrastructure that have definable starting and stopping points.

transportation of gas: gathering, transmission, or distribution of gas by pipeline or the storage of gas.

vault: an underground structure that may be entered and that is designed to contain piping and piping components (such as valves or pressure regulators).

803.2 Piping Systems

component or pipeline component: an individual item or element fitted in line with pipe in a pipeline system, such as, but not limited to, valves, elbows, tees, flanges, and closures.

pipeline facility: new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

pipeline section: a continuous run of pipe between adjacent compressor stations, between a compressor station and a block valve, or between adjacent block valves.

segment: a length of pipeline or part of the system that has unique characteristics in a specific geographic location.

storage field: a geographic field containing a well or wells that are completed for and dedicated to subsurface storage of large quantities of gas for later recovery, transmission, and end use.

transmission line: a segment of pipeline installed in a transmission system or between storage fields.

transmission system: one or more segments of pipeline, usually interconnected to form a network, that transports gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high- or low-pressure distribution system, a large-volume customer, or another storage field.

803.3 Distribution Systems

gas main or distribution main: a segment of pipeline in a distribution system installed to convey gas to individual service lines or other mains.

gas service line: the piping installed between a main, pipeline, or other source of supply and the meter set assembly. [See para. 802.1(b)(3).]

high-pressure distribution system: a gas distribution piping system that operates at a pressure higher than the standard service pressure delivered to the customer. In such a system, a service regulator is required on each service line to control the pressure delivered to the customer.

low-pressure distribution system: a gas distribution piping system in which the gas pressure in the mains and service lines is substantially the same as that delivered to the customer's appliances. In such a system, a service regulator is not required on the individual service lines.

803.4 Gathering Systems (16)

gas storage line: a pipeline used for conveying gas between a compressor station and a gas well used for storing gas underground.

gathering line: a segment of pipeline installed in a gathering system.

gathering system: one or more segments of pipeline, usually interconnected to form a network, that meets one or more of the following criteria:

(a) transports gas from one or more production facilities to the inlet of a gas processing plant. If no gas processing plant exists, the gas is transported to the most downstream of one of the following:

(1) the point of custody transfer of gas suitable for delivery to a distribution system

(2) the point where accumulation and preparation of gas from separate geographic production fields in reasonable proximity has been completed

(b) transports gas within the gathering system for production or gathering uses such as compressor fuel gas, gas lift, heating, or other processes, the source of which is within the gathering system (i.e., upstream of a transmission system).

(c) is in conformance with the definition for onshore gathering lines as defined in API RP 80.

Refer to Mandatory Appendix Q, Figs. Q-1 and Q-2 for additional clarifications.

803.5 Miscellaneous Systems

control piping: all piping, valves, and fittings used to interconnect air, gas, or hydraulically operated control apparatus or instrument transmitters and receivers.

gas processing plant: a facility used for extracting commercial products from gas.

instrument piping: all piping, valves, and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.

production facility: piping or equipment used in production, extraction, recovery, lifting, stabilization, separation, treating, associated measurement, field compression, gas lift, gas injection, or fuel gas supply. Production facility piping or equipment must be used in extracting petroleum liquids or natural gas from the ground and preparing it for transportation by pipeline.

sample piping: all piping, valves, and fittings used to collect samples of gas, steam, water, or oil.

803.6 Meters, Regulators, and Pressure Relief Stations

customer's meter: a meter that measures gas delivered to a customer for consumption on the customer's premises.

meter set assembly: the piping and fittings installed to connect the inlet side of the meter to the gas service line and the outlet side of the meter to the customer's fuel line.

monitoring regulator: a pressure regulator installed in series with another pressure regulator that automatically assumes control of the pressure downstream of the station, in case that pressure exceeds a set maximum.

pressure-limiting station: consists of equipment that under abnormal conditions will act to reduce, restrict, or shut off the supply of gas flowing into a system to prevent the gas pressure from exceeding a predetermined value. While normal pressure conditions prevail, the pressure-limiting station may exercise some degree of control of the flow of the gas or may remain in the wide open position. Included in the station are piping and auxiliary devices, such as valves, control instruments, control lines, the enclosure, and ventilating equipment, installed in accordance with the pertinent requirements of this Code.

pressure-regulating station: consists of equipment installed for automatically reducing and regulating the pressure in the downstream pipeline or main to which it is connected. Included are piping and auxiliary devices such as valves, control instruments, control lines, the enclosure, and ventilation equipment.

pressure relief station: consists of equipment installed to vent gas from a system being protected to prevent the gas pressure from exceeding a predetermined limit. The gas may be vented into the atmosphere or into a lower pressure system capable of safely absorbing the gas being discharged. Included in the station are piping and auxiliary devices, such as valves, control instruments, control lines, the enclosure, and ventilating equipment, installed in accordance with the pertinent requirements of this Code.

service regulator: a regulator installed on a gas service line to control the pressure of the gas delivered to the customer.

803.7 Valves

block or *stop valve:* a valve installed for the purpose of blocking or stopping the flow of gas in a pipe.

check valve: a valve designed to permit flow in one direction and to close automatically to prevent flow in the reverse direction.

curb valve: a stop valve installed below grade in a service line at or near the property line, accessible through a curb box or standpipe, and operable by a removable key or wrench for shutting off the gas supply to a building. This valve is also known as a *curb shutoff* or *curb cock*.

service line valve: a stop valve readily operable and accessible for the purpose of shutting off the gas to the customer's fuel line. The stop valve should be located in the service line ahead of the service regulator or ahead of the meter, if a regulator is not provided. The valve is also known as a *service line shutoff*, *service line cock*, or *meter stop*.

803.8 Gas Storage Equipment

bottle: as used in this Code, is a gas-tight structure completely fabricated from pipe with integral drawn, forged, or spun end closures and tested in the manufacturer's plant.

bottle-type holder: any bottle or group of interconnected bottles installed in one location and used only for storing gas.

pipe-type holder: any pipe container or group of interconnected pipe containers installed at one location and used only for storing gas.

804 PIPING SYSTEMS COMPONENT DEFINITIONS

804.1 Plastic Terms and Definitions

plastic (noun): a material that contains as an essential ingredient an organic substance of high to ultrahigh molecular weight, is solid in its finished state, and at some stage of its manufacture or processing, can be shaped by flow. The two general types of plastic referred to in this Code are thermoplastic and thermosetting.

thermoplastic: a plastic that is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature.

thermosetting plastic: plastic that is capable of being changed into a substantially infusible or insoluble product when cured under application of heat or chemical means.

804.2 Iron Terms and Definitions

cast iron: shall apply to gray cast iron, that is, a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed throughout the metal.

ductile iron: sometimes called nodular iron, a cast ferrous material in which the free graphite present is in a spheroidal form, rather than a flake form. The desirable properties of ductile iron are achieved by chemistry and a ferritizing heat treatment of the castings.

804.3 General Terms and Definitions

pipe container: a gas-tight structure assembled in a shop or in the field from pipe and end closures.

proprietary items: items made and marketed by a company having the exclusive or restricted right to manufacture and sell them.

804.4 Pipe Terms and Definitions

cold expanded pipe: seamless or welded pipe that is formed and then cold expanded while in the pipe mill so that the circumference is permanently increased by at least 0.50%.

miter: two or more straight sections of pipe matched and joined on a line bisecting the angle of junction so as to produce a change in direction.

pipe: a tubular product, including tubing, made for sale as a production item, used primarily for conveying a fluid and sometimes for storage. Cylinders formed from plate during the fabrication of auxiliary equipment are not pipe as defined herein.

804.5 Dimensional Terms and Definitions

diameter or *nominal outside diameter:* the as-produced or as-specified outside diameter of the pipe, not to be confused with the dimensionless NPS (DN). For example, NPS 12 (DN 300) pipe has a specified outside diameter of 12.750 in. (323.85 mm), NPS 8 (DN 200) has a specified outside diameter of 8.625 in. (219.08 mm), and NPS 24 (DN 600) pipe has a specified outside diameter of 24.000 in. (609.90 mm).

length: a piece of pipe of the length delivered from the mill. Each piece is called a length, regardless of its actual dimension. This is sometimes called *joint*, but *length* is preferred.

nominal pipe size (NPS) or *diameter nominal (DN):* a dimensionless designator of pipe. It indicates a standard pipe size when followed by the appropriate number [e.g., NPS 1½ (DN 40), NPS 12 (DN 300)]. See ASME B36.10M, page 1 for additional information on NPS.

nominal wall thickness, t: the wall thickness computed by or used in the design equation in para. 841.1.1 or A842.2.2(a) in Chapter VIII. Under this Code, pipe may be ordered to this computed wall thickness without adding allowance to compensate for the underthickness tolerance permitted in approved specifications.

804.6 Mechanical Properties

specified minimum elongation: the minimum elongation (expressed in percent of the gage length) in the tensile test specimen, prescribed by the specifications under which the material is purchased from the manufacturer.

specified minimum tensile strength: expressed in pounds per square inch (MPa), the minimum tensile strength prescribed by the specification under which pipe is purchased from the manufacturer.

specified minimum yield strength (SMYS): expressed in pounds per square inch (MPa), the minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer.

tensile strength: expressed in pounds per square inch (MPa), the highest unit tensile stress (referred to the original cross section) a material can sustain before failure.

yield strength: expressed in pounds per square inch (MPa), the strength at which a material exhibits a specified limiting permanent set or produces a specified total elongation under load. The specified limiting set or elongation is usually expressed as a percentage of gage length. Its values are specified in the various material specifications acceptable under this Code.

804.7 Steel Pipe

804.7.1 Carbon Steel.[3] By common custom, steel is considered to be carbon steel when no minimum content is specified or required for aluminum, boron, chromium, cobalt, molybdenum, nickel, niobium, titanium, tungsten, vanadium, zirconium, or any other element added to obtain a desired alloying effect; when the specified minimum for copper does not exceed 0.40%; or when the maximum content specified for any of the following elements does not exceed the following percentages:

Element	Percentage
Copper	0.60
Manganese	1.65
Silicon	0.60

In all carbon steels, small quantities of certain residual elements unavoidably retained from raw materials are sometimes found but are not specified or required, such as copper, nickel, molybdenum, chromium, etc. These

[3] From *Steel Products Manual*, Section 6, American Iron and Steel Institute, August 1952, pp. 5 and 6.

elements are considered as incidental and are not normally determined or reported.

804.7.2 Alloy Steel.[4] By common custom, steel is considered to be alloy steel when the maximum of the range given for the content of alloying elements exceeds one or more of the following limits:

Element	Percentage
Copper	0.60
Manganese	1.65
Silicon	0.60

or in which a definite range or a definite minimum quantity of any of the following elements is specified or required within the limits of the recognized field of constructional alloy steels:

(a) aluminum
(b) boron
(c) chromium (up to 3.99%)
(d) cobalt
(e) columbium
(f) molybdenum
(g) nickel
(h) titanium
(i) tungsten
(j) vanadium
(k) zirconium

or any other alloying element added to obtain a desired alloying effect.

Small quantities of certain elements are unavoidably present in alloy steels. In many applications, these are not considered to be important and are not specified or required. When not specified or required, they should not exceed the following amounts:

Element	Percentage
Chromium	0.20
Copper	0.35
Molybdenum	0.06
Nickel	0.25

804.7.3 Pipe Manufacturing Processes. Types and names of welded joints are used herein according to their common usage as defined in AWS A3.0, or as specifically defined as follows:

(a) double submerged-arc-welded pipe: pipe having a longitudinal or helical butt joint produced by at least two passes, one of which is on the inside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding is shielded by a blanket of granular, fusible material on the work. Pressure is not used, and filler metal for the inside and outside welds is obtained from the electrode or electrodes. Typical specifications are ASTM A381, ASTM A1005, and API 5L.

(b) electric-flash-welded pipe: pipe having a longitudinal butt joint wherein coalescence is produced simultaneously over the entire area of abutting surfaces by the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by expulsion of metal from the joint. A typical specification is API 5L.

(c) electric-fusion-welded pipe: pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc welding. The weld may be single or double and may be made with or without the use of filler metal. Typical specifications are ASTM A134 and ASTM A139, which permit single or double weld with or without the use of filler metal. Additional typical specifications are ASTM A671 and ASTM A672, which require both inside and outside welds and the use of filler metal.

(1) spiral-welded pipe: also made by the electric-fusion-welded process with either a butt joint, a lap joint, or a lock-seam joint. Typical specifications are ASTM A134, ASTM A139 (butt joint), API 5L, and ASTM A211 (butt joint, lap joint, or lock-seam joint).

(d) electric-resistance-welded pipe: pipe produced in individual lengths or in continuous lengths from coiled skelp and subsequently cut into individual lengths. The resulting lengths have a longitudinal butt joint wherein coalescence is produced by the heat obtained from resistance of the pipe to the flow of electric current in a circuit of which the pipe is a part, and by the application of pressure. Typical specifications are ASTM A53, ASTM A135, ASTM A984, and API 5L.

(e) furnace buttwelded pipe

(1) bell-welded: furnace-welded pipe produced in individual lengths from cut-length skelp. The pipe's longitudinal butt joint forge welded by the mechanical pressure is developed in drawing the furnace-heated skelp through a cone-shaped die (commonly known as a *welding bell*), which serves as a combined forming and welding die. Typical specifications are ASTM A53 and API 5L.

(2) continuous-welded: furnace-welded pipe produced in continuous lengths from coiled skelp and subsequently cut into individual lengths. The pipe's longitudinal butt joint is forge-welded by the mechanical pressure developed in rolling the hot-formed skelp through a set of round pass welding rolls. Typical specifications are ASTM A53 and API 5L.

(f) laser beam welded pipe: pipe having a longitudinal butt joint made with a welding process that utilizes a laser beam to produce melting of full thickness of edges to be welded, followed by the fusion of those edges. A typical specification is ASTM A1006.

(g) seamless pipe: a wrought tubular product made without a welded seam. It is manufactured by hot-working steel and, if necessary, by subsequently cold-finishing the hot-worked tubular product to produce

[4] From *Steel Products Manual*, Section 6, American Iron and Steel Institute, January 1952, pp. 6 and 7.

the desired shape, dimensions, and properties. Typical specifications are ASTM A53, ASTM A106, and API 5L.

804.8

For plastic pipe, see para. 805.1.3.

805 DESIGN, FABRICATION, OPERATION, AND TESTING TERMS AND DEFINITIONS

805.1 General

805.1.1 Area

location class or class location: a geographic area along the pipeline classified according to the number and proximity of buildings intended for human occupancy and other characteristics that are considered when prescribing design factors for construction, operating pressures, and methods of testing pipelines and mains located in the area and applying certain operating and maintenance requirements.

right-of-way (ROW): a strip of land on which pipelines, railroads, power lines, roads, highways, and other similar facilities are constructed. The ROW agreement secures the right to pass over property owned by others. ROW agreements generally allow the right of ingress and egress for the operation and maintenance of the facility, and the installation of the facility. The ROW width can vary with the construction and maintenance requirements of the facility's operator and is usually determined based on negotiation with the affected landowner by legal action, or by permitting authority.

805.1.2 Leakage Investigative Terms and Definitions. For definitions of *gas leakage control criteria investigation terms,* see Nonmandatory Appendix M.

805.1.3 Plastic Terms and Definitions

adhesive joint: a joint made in plastic piping by the use of an adhesive substance that forms a continuous bond between the mating surfaces without dissolving either one of them.

dimension ratio (DR): the ratio of outside pipe diameter to wall thickness of thermoplastic pipe. It is calculated by dividing the specified outside diameter of the pipe by the specified minimum wall thickness.

heat fusion joint: a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

hydrostatic design basis (HDB): one of a series of established stress values (specified in ASTM D2837) for a plastic compound obtained by categorizing the long-term hydrostatic strength determined in accordance with ASTM D2837. Established HDBs are listed in PPI TR-4.

long-term hydrostatic strength: the estimated hoop stress in pounds per square inch (MPa) in a plastic pipe wall that will cause failure of the pipe at an average of 100,000 hr when subjected to a constant hydrostatic pressure. (See Mandatory Appendix D.)

solvent cement joint: a joint made in thermoplastic piping by the use of a solvent or solvent cement that forms a continuous bond between the mating surfaces.

standard dimension ratio (SDR): the ratio of outside pipe diameter to wall thickness of thermoplastic pipe. It is calculated by dividing the specified outside diameter of the pipe by the specified wall thickness.

805.1.4 Fabrication Terms and Definitions

arc welding or arc weld: a group of welding processes that produces coalescence of metals by heating them with an arc. The processes are used with or without the application of pressure and with or without filler metal.

butt joint: a joint between two members aligned approximately in the same plane. See Figs. 1(A), 2(A), 3, 51(A), and 51(B) in AWS A3.0.

butt weld: a nonstandard term for a weld in a butt joint.

cold-springing: where used in the Code, the fabrication of piping to an actual length shorter than its nominal length and forcing it into position so that it is stressed in the erected condition, thus compensating partially for the effects produced by the expansion due to an increase in temperature. Cold-spring factor is the ratio of the amount of cold spring provided to the total computed temperature expansion.

fillet weld: a weld of approximately triangular cross section joining two surfaces approximately at right angles to each other in a lap joint, tee joint, or corner joint.

girth weld: a complete circumferential butt weld joining pipe or components.

heat treatment: heating and cooling a solid metal or alloy in such a way as to obtain desired properties. Heating for the sole purpose of hot working is not considered heat treatment. If a weldment is heated and cooled in a controlled manner, then the term *postweld heat treatment* is used.

seam weld: the longitudinal or helical seam in pipe, made in the pipe mill for the purpose of making a complete circular cross section.

stress relieving: heating a metal to a suitable temperature, holding at that temperature long enough to reduce residual stresses, and then cooling slowly enough to minimize the development of new residual stresses.

submerged arc welding: an arc welding process that uses an arc or arcs between a bare metal electrode or electrodes and the weld pool. The arc and molten metal are shielded by a blanket of granular flux on the workpieces. The process is used without pressure and with filler metal from the electrode and sometimes from a supplemental source (welding rod, flux, or metal granules).

tie-in: a connection where a gap is left to divide a pipeline into test sections, or to install a pretested replacement section, or in the continuous line construction at a location such as a river or highway crossing.

tie-in weld: a tie-in connection using a weld, typically a girth weld.

weld: a localized coalescence of metals or nonmetals produced either by heating the materials to the welding temperature, with or without the application of pressure, or by the application of pressure alone and with or without the use of filler material.

welder: one who performs manual or semiautomatic welding.

welding operator: one who operates adaptive control, automatic, mechanized, or robotic welding equipment.

welding procedures: the detailed methods and practices involved in the production of a weldment.

wrinkle bend: a pipe bend produced by a field machine or controlled process that may result in prominent contour discontinuities on the inner radius. The wrinkle is deliberately introduced as a means of shortening the inside meridian of the bend. Note that this definition does not apply to a pipeline bend in which incidental minor, smooth ripples are present.

wrought: metal in the solid condition that is formed to a desired shape by working (rolling, extruding, forging, etc.), usually at an elevated temperature.

805.2 Design

805.2.1 Pressure Terms and Definitions

design pressure or internal design pressure: the maximum pressure permitted by this Code, as determined by the design procedures applicable to the materials and locations involved. It is used in calculations or analysis for pressure design of a piping component.

hydrostatic test or hydrotest: a pressure test using water as the test medium.

maximum allowable operating pressure (MAOP): the maximum pressure at which a pipeline system may be operated in accordance with the provisions of this Code.

maximum allowable test pressure: the maximum internal fluid pressure permitted by this Code for a pressure test based upon the material and location involved.

maximum operating pressure (MOP): sometimes referred to as maximum actual operating pressure, the highest pressure at which a piping system is operated during a normal operating cycle.

normal operating pressure: the predicted pressure (sum of static head pressure, pressure required to overcome friction losses, and any backpressure) at any point in a piping system when the system is operating under a set of predicted steady-state conditions.

overpressure protection: the prevention of the pressure in the system or part of the system from exceeding a predetermined value and is typically provided by a device or equipment installed in a gas piping system.

pressure: unless otherwise stated, expressed in pounds per square inch (kilopascals) above atmospheric pressure (i.e., gage pressure) and is abbreviated as psig (kPa).

pressure test: a means by which the integrity of a piece of equipment (pipe) is assessed, in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.

standard service pressure: sometimes called the normal utilization pressure, the gas pressure a utility undertakes to maintain at its domestic customers' meters.

standup pressure test: a procedure used to demonstrate the leak tightness of a low-pressure, gas service line, using air or gas as the test medium.

805.2.2 Temperature Terms and Definitions

ambient temperature: the temperature of the surrounding medium, usually used to refer to the temperature of the air in which a structure is situated or a device operates.

ground temperature: the temperature of the earth at pipe depth.

minimum design temperature: the lowest anticipated material temperature during service. The user of this Code is cautioned that ambient and operating temperature conditions may exist during construction, start-up, or shutdown that require special design considerations or operating restrictions.

temperature: expressed in degrees Fahrenheit (°F) [degrees Celsius (°C)].

805.2.3 Stress Terms and Definitions (16)

bending stress: the force per unit area acting at a point along the length of a member resulting from the bending moment applied at that point.

compressive stress: the applied pushing force divided by the original cross-sectional area.

hoop stress, S_H [psi (MPa)]: the stress in a pipe of wall thickness, t [in. (mm)], acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, produced by the pressure, P [psig (kPa)], of the fluid in a pipe of diameter, D [in. (mm)], and is determined by Barlow's formula:

(U.S. Customary Units)

$$S_H = \frac{PD}{2t}$$

(SI Units)

$$\left(S_H = \frac{PD}{2\,000t}\right)$$

maximum allowable hoop stress: the maximum hoop stress permitted by this Code for the design of a piping system. It depends on the material used, the location of the pipe, the operating conditions, and other limitations imposed by the designer in conformance with this Code.

operating stress: the stress in a pipe or structural member under normal operating conditions.

residual stress: stress present in an object in the absence of any external loading, typically resulting from manufacturing or construction processes.

secondary stress: stress created in the pipe wall by loads other than internal fluid pressure, such as backfill loads, traffic loads, loads caused by natural hazards (see para. 841.1.10), beam action in a span, loads at supports, and at connections to the pipe.

stress: the internal resistance of a body to an externally applied force, expressed in units of force per unit area (psi or MPa). It may also be termed *unit stress*.

stress concentrator or *stress concentration:* a discontinuity in a structure or change in contour that causes a local increase in stress.

stress level: the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

tensile stress: the applied pulling force divided by the original cross-sectional area.

805.2.4 Construction, Operation, and Maintenance Terms and Definitions

abandoned: permanently removed from service.

actionable anomaly: an anomaly that may exceed acceptable limits based on the operator's anomaly and pipeline data analysis.

anomaly: an unexamined deviation from the norm in pipe material, coatings, or welds.

anomaly and pipeline data analysis: the process through which anomaly and pipeline data are integrated and analyzed to further classify and characterize anomalies.

backfill: material placed in a hole or trench to fill excavated space around a pipeline or other appurtenances.

certification: written testimony of qualification.

consequence: the impact that a pipeline failure could have on the public, employees, property, and the environment.

crack: very narrow, elongated defect caused by mechanical splitting into parts.

defect: a physically examined anomaly with dimensions or characteristics that exceed acceptable limits.

dent: a permanent deformation of the circular cross-section of the pipe that produces a decrease in the diameter and is concave inward.

discontinuity: an interruption of the typical structure of a material, such as a lack of homogeneity in its mechanical, metallurgical, or physical characteristics. A discontinuity is not necessarily a defect.

evaluation: a review following the characterization of an actionable anomaly to determine whether the anomaly meets specified acceptance criteria.

examination: the direct physical inspection of a pipeline, which may include the use of nondestructive examination (NDE) techniques or methods.

experience: work activities accomplished in a specific nondestructive testing (NDT) method under the direction of qualified supervision including the performance of the NDT method and related activities but not including time spent in organized training programs.

failure: a general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use.

fatigue: the process of development of, or enlargement of, a crack as a result of repeated cycles of stress.

fracture toughness: the resistance of a material to fail from the extension of a crack.

gouge: mechanically induced metal loss that causes localized elongated grooves or cavities in a metal pipeline.

grinding: removal of material by abrasion, usually utilizing a rigid abrasive carrier, such as a disk.

imperfection: an anomaly with characteristics that do not exceed acceptable limits.

inclusion: a nonmetallic phase such as an oxide, sulfide, or silicate particle in a metal pipeline.

indication: a finding of a nondestructive testing technique or method that deviates from the expected. It may or may not be a defect.

in-line inspection (ILI): a steel pipeline inspection technique that uses devices known in the industry as intelligent or smart pigs. These devices run inside the pipe and provide indications of metal loss, deformation, and other defects.

in-service pipeline: a pipeline that contains natural gas to be transported. The gas may or may not be flowing.

inspection: the use of a nondestructive testing technique or method.

integrity: the capability of the pipeline to withstand all anticipated loads (including hoop stress due to operating pressure) plus the margin of safety established by this section.

integrity assessment: a process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis.

leak: an unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks (including propagating and non-propagating, longitudinal, and circumferential), separation or pull-out, and loose connections.

mechanical damage: a type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, puncturing, and residual stresses.

mitigation: the limitation or reduction of the probability of occurrence or expected consequence for a particular event.

nondestructive examination (NDE) or nondestructive testing (NDT): a testing method, such as radiography, ultrasonic, magnetic testing, liquid penetrant, visual, leak testing, eddy current, and acoustic emission, or a testing technique, such as magnetic flux leakage, magnetic particle inspection, shear-wave ultrasonic, and contact compression-wave ultrasonic.

pig: a device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.

pig trap or scraper trap: an ancillary item of pipeline equipment, such as a launcher or receiver, with associated pipework and valves, for introducing a pig into a pipeline or removing a pig from a pipeline.

pigging: the use of any independent, self-contained device, tool, or vehicle that moves through the interior of the pipeline for inspecting, dimensioning, cleaning, or drying.

qualification: demonstrated and documented knowledge, skills, and abilities, along with documented training, experience, or both, required for personnel to properly perform the duties of a specific job or task.

rupture: a complete failure of any portion of the pipeline that allows the product to escape to the environment.

slug: a volume of liquid or gas, completely filling the cross section of the pipe.

survey: measurements, inspections, or observations intended to discover and identify events or conditions that indicate a departure from normal operation or undamaged condition of the pipeline.

training: an organized program developed to impart the knowledge and skills necessary for qualification.

ultrasonic: high-frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

uprating: the qualifying of an existing pipeline or main for a higher maximum allowable operating pressure.

805.2.5 Corrosion Control Terms and Definitions

anode: the electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

bracelet anodes: galvanic anodes with geometry suitable for direct attachment around the circumference of a pipeline. These may be half-shell bracelets consisting of two semicircular sections or segmented bracelets consisting of a large number of individual anodes.

cathodic protection (CP): a technique to reduce the corrosion of a metal surface by making that surface the cathode of an electromechanical cell.

cell or electrochemical cell: a system consisting of an anode and a cathode immersed in an electrolyte so as to create an electrical circuit. The anode and cathode may be different metals or dissimilar areas on the same metal surface.

coating: a liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film. Coating also includes tape wrap.

coating system: the complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.)

corrosion: the deterioration of a material, usually a metal, that results from an electrochemical reaction with its environment.

corrosion fatigue: fatigue-type cracking of metal caused by repeated or fluctuating stresses in a corrosive environment and is characterized by shorter life than would be encountered as a result of either the repeated or fluctuating stress alone or the corrosive environment alone.

corrosion inhibitor: a chemical substance or combination of substances that, when present in the environment or on a surface, prevents or reduces corrosion.

corrosion rate: the rate at which corrosion proceeds.

corrosiveness: the tendency of an environment to cause corrosion or the degree to which or rate at which it causes corrosion.

crevice corrosion: localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment because of close proximity of the metal to the surface of another material.

curing: a chemical process of developing the intended properties of a coating or other material (e.g., resin) over a period of time.

current: a flow of electric charge.

current density: the current to or from a unit area of an electrode surface or through a unit area of a conductor or electrolyte.

depolarization: the removal of factors resisting the current in an electrochemical cell.

dielectric coating: a coating that does not conduct electricity.

dissimilar metals: different metals that could form an anode–cathode relationship in an electrolyte when connected by a metallic path.

electric potential: a voltage difference existing between two points, such as the pipe and its environment.

electrical interference: any electrical disturbance on a metallic structure in contact with an electrolyte caused by stray current(s).

electrical isolation: the condition of being electrically separated from other metallic structures or the environment.

electrode: a conductor used to establish contact with an electrolyte and through which current is transferred to or from an electrolyte.

electrolyte: a medium containing ions that migrate in an electric field.

epoxy: type of resin formed by the reaction of aliphatic or aromatic polyols (like bisphenol) with epichlorohydrin and characterized by the presence of reactive oxirane end groups.

erosion: the progressive loss of material from a solid surface due to mechanical interaction between that surface and a fluid, a multicomponent fluid, or solid particles carried with the fluid.

fault current: a current that flows from one conductor to ground or to another conductor due to an abnormal connection (including an arc) between the two. A fault current flowing to ground may be called a ground fault current.

film: a thin, not necessarily visible layer of material.

foreign structure: any metallic structure that is not intended as a part of a system under cathodic protection.

galvanic anode: a metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of cathodic protection.

galvanic corrosion: accelerated corrosion of a metal because of an electrical contact with a more noble metal and/or a more noble localized section of the metal or nonmetallic conductor in a corrosive electrolyte.

graphitization: the formation of graphite in iron or steel, usually from decomposition of iron carbide at elevated temperatures. This should not be used as a term to describe graphitic corrosion.

holiday: a discontinuity in a protective coating that exposes unprotected surface to the environment.

hydrogen embrittlement: a loss of ductility of a metal resulting from absorption of hydrogen.

hydrogen stress cracking: cracking that results from the presence of hydrogen in a metal in combination with tensile stress. It occurs most frequently with high-strength alloys.

impressed current: an electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

impressed current anode: an electrode suitable for use as an anode when connected to a source of impressed current, which is generally composed of a substantially inert material that conducts by oxidation of the electrolyte and, for this reason, is not corroded appreciably.

intergranular corrosion: preferential corrosion at or along the grain boundaries of a metal (also known as intercrystalline corrosion).

ion: an electrically charged atom or group of atoms.

metal loss: any of a number of types of anomalies in pipe in which metal has been removed from the pipe surface, usually due to corrosion or gouging.

noble: the positive direction of electrode potential, thus resembling noble metals such as gold and platinum.

overvoltage: the change in potential of an electrode from its equilibrium or steady-state value when current is applied.

paint: a pigmented liquid or resin applied to a substrate as a thin layer that is converted to an opaque solid film after application. It is commonly used as a decorative or protective coating.

pipe-to-soil potential: the electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

pitting: localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits.

polarization: the change from the open-circuit potential as a result of current across the electrode/electrolyte interface.

protective coating: a coating applied to a surface to protect the substrate from corrosion or other damage.

resistivity:

(a) the resistance per unit length of a substance with uniform cross section.

(b) a measure of the ability of an electrolyte (e.g., soil) to resist the flow of electric charge (e.g., cathodic protection current). Resistivity data are used to design a groundbed for a cathodic protection system.

rust: corrosion product consisting of various iron oxides and hydrated iron oxides. (This term properly applies only to iron and ferrous alloys.)

shielding: preventing or diverting the flow of cathodic protection current from its natural path.

stray current: current through paths other than the intended circuit.

stress corrosion cracking (SCC): a form of environmental attack of the metal involving an interaction of a local corrosive environment and tensile stresses in the metal, resulting in formation and growth of cracks.

805.2.6 Engineering Terms and Definitions

brittle fracture: fracture with little or no plastic deformation.

design life: a period of time used in design calculations, selected for the purpose of verifying that a replaceable or permanent component is suitable for the anticipated period of service. Design life may not pertain to the life of a pipeline system because a properly maintained and protected pipeline system can provide service indefinitely.

ductility: a measure of the capability of a material to be deformed plastically before fracturing.

elastic distortion: changes of dimensions of a material upon the application of a stress within the elastic range. Following the release of an elastic stress, the material returns to its original dimensions without any permanent deformation.

elastic limit: the maximum stress to which a material may be subjected without retention of any permanent deformation after the stress is removed.

elasticity: the property of a material that allows it to recover its original dimensions following deformation by a stress below its elastic limit.

engineering assessment: a documented assessment using engineering principles of the effect of relevant variables upon service or integrity of a pipeline system and conducted by or under supervision of a competent person with demonstrated understanding of and experience in the application of engineering and risk management principles related to the issue being assessed.

engineering critical assesment: an analytical procedure based upon fracture mechanics that allows determination of the maximum tolerable sizes for imperfections, and conducted by or under supervision of a competent person with demonstrated understanding of and experience in the application of the engineering principles related to the issue being assessed.

modulus of elasticity: a measure of the stiffness or rigidity of a material. It is actually the ratio of stress to strain in the elastic region of a material. If determined by a tension or compression test, it is also called Young's Modulus or the coefficient of elasticity.

probability: the likelihood of an event occurring.

risk: a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

span: a section of the pipe that is unsupported.

strain: the change in length of a material in response to an applied force, expressed on a unit length basis (e.g., inches per inch or millimeters per millimeter).

805.2.7 Miscellaneous Terms and Definitions

shall or *shall not:* used to indicate that a provision is mandatory.

should, should not, or *it is recommended:* used to indicate that a provision is not mandatory but recommended as good practice.

806 QUALITY ASSURANCE

Quality Control systems consist of those planned, systematic, and preventative actions that are required to ensure that materials, products, and services will meet specified requirements. Quality Assurance systems and procedures consist of periodic audits and checks that ensure the Quality Control system will meet all of its stated purposes.

The integrity of a pipeline system may be improved by the application of Quality Assurance systems. These systems should be applied to the design, procurement, construction, testing, operating, and maintenance activities in the applications of this Code.

Organizations performing design, fabrication, assembly, erection, inspection, examination, testing, installation, operation, and maintenance application for B31.8 piping systems should have a written Quality Assurance system in accordance with applicable documents. Registration or certification of the Quality Assurance system should be by agreement between the contracting parties involved.

807 TRAINING AND QUALIFICATION OF PERSONNEL

807.1 Program

Each operating company shall have a program to manage the qualification of personnel who perform operating, maintenance, and construction activities that could impact the safety or integrity of a pipeline. The program shall address, at a minimum, the following elements:

(a) Identify those tasks for which the qualification provisions of the program apply. The tasks shall include operating, maintenance, and construction activities that could impact the safety or integrity of a pipeline.

(b) For each task covered by the program, identify abnormal operating conditions, and describe the process used to ensure that individuals who perform these tasks are able to recognize and react to such conditions. An *abnormal operating condition* is defined in ASME B31Q as a condition that may indicate a malfunction of a component or deviation from normal operations that may

(1) indicate a condition exceeding design limits

(2) result in hazard(s) to persons, property, or the environment

(c) Identify training requirements for personnel involved in performing tasks covered by the program.

(d) Describe the evaluation process and critera used to determine

(1) initial qualification

(2) subsequent or ongoing qualification

(3) suspension or revocation of qualifications

(4) reinstatement of qualifications

(e) Establish organizational responsibilities for carrying out each program element.

(f) Establish a process to periodically evaluate the effectiveness of the qualification program, including provisions for updating the program based on the results of effectiveness appraisals.

(g) Describe how program requirements are communicated to affected individuals and how changes to program requirements are managed and communicated.

(h) Identify the documentation requirements needed to adequately manage the program.

807.2 Operating and Maintenance Functions

In addition to the requirements in para. 807.1, each operating company shall provide training for employees in procedures established for operating and maintenance functions. The training shall be comprehensive and designed to prepare employees for service in their area of responsibility.

807.3 Reference

A useful reference for managing personnel qualifications is ASME B31Q, Pipeline Personnel Qualification.

Chapter I
Materials and Equipment

810 MATERIALS AND EQUIPMENT

It is intended that all materials and equipment that will become a permanent part of any piping system constructed under this Code shall be suitable and safe for the conditions under which they are used. All such materials and equipment shall be qualified for the conditions of their use by compliance with certain specifications, standards, and special requirements of this Code, or otherwise as provided herein.

811 QUALIFICATION OF MATERIALS AND EQUIPMENT

811.1 Categories

Materials and equipment fall into the following six categories pertaining to methods of qualification for use under this Code:

(a) items that conform to standards or specifications referenced in this Code

(b) items that are important from a safety standpoint, of a type for which standards or specifications are referenced in this Code but specifically do not conform to a referenced standard (e.g., pipe manufactured to a specification not referenced in this Code)

(c) items of a type for which standards or specifications are referenced in this Code, but that do not conform to the standards and are relatively unimportant from a safety standpoint because of their small size or because of the conditions under which they are to be used

(d) items of a type for which no standard or specification is referenced in this Code (e.g., gas compressor)

(e) proprietary items (see definition, para. 804.3)

(f) unidentified or used pipe

811.2 Procedures for Qualification

Prescribed procedures for qualifying each of these six categories are given in the following paragraphs.

811.2.1 Conformance. Items that conform to standards or specifications referenced in this Code [para. 811.1(a)] may be used for appropriate applications, as prescribed and limited by this Code without further qualification. (See section 814.)

811.2.2 Nonconformance (Important Items). Important items of a type for which standards or specifications are referenced in this Code, such as pipe, valves, and flanges, but that do not conform to standards or specifications referenced in this Code [para. 811.1(b)] shall be qualified as described in (a) or (b) below:

(a) A material conforming to a written specification that does not vary substantially from a referenced standard or specification and that meets the minimum requirements of this Code with respect to quality of materials and workmanship may be used. This paragraph shall not be construed to permit deviations that would tend to affect weldability or ductility adversely. If the deviations tend to reduce strength, full allowance for the reduction shall be provided for in the design.

(b) When petitioning the Section Committee for approval, the following requirements shall be met. If possible, the material shall be identified with a comparable material, and it should be stated that the material will comply with that specification, except as noted. Complete information as to chemical composition and physical properties shall be supplied to the Section Committee, and its approval shall be obtained before this material is used.

811.2.3 Nonconformance (Unimportant Items). Relatively unimportant items that do not conform to a standard or specification [para. 811.1(c)] may be used, provided that

(a) they are tested or investigated and found suitable for the proposed service

(b) they are used at unit stresses not greater than 50% of those allowed by this Code for comparable materials

(c) their use is not specifically prohibited by this Code

811.2.4 No Standards or Specifications Referenced. Items of a type for which no standards or specifications are referenced in this Code [para. 811.1(d)] and proprietary items [para. 811.1(e)] may be qualified by the user provided

(a) the user conducts an investigation and tests (if needed) that demonstrate that the item of material or equipment is suitable and safe for the proposed service (e.g., clad or duplex stainless steel pipe); or

(b) the manufacturer affirms the safety of the item recommended for that service (e.g., gas compressors and pressure relief devices)

811.3 Unidentified or Used Pipe

Unidentified or used pipe [para. 811.1(f)] may be used and is subject to the requirements of section 817.

812 MATERIALS FOR USE IN LOW-TEMPERATURE APPLICATIONS

Some of the materials conforming to specifications referenced for use under this Code may not have properties suitable for operation at low temperatures. Users of this Code are cautioned to consider the effects of low temperature and the potential impact on fracture performance at low temperatures.

Whenever the minimum design temperature is below −20°F (−29°C), a fracture control program shall be established. The program shall address parent materials, the parent material seam weld (if present), circumferential butt welds, attachment welds, and any weld heat-affected zone (HAZ).

Of primary importance in the fracture control program is the prevention of brittle fracture initiation that can occur at small stress concentrations. As a minimum, the fracture control program shall require Charpy impact energy testing at or below the minimum design temperature. The specific energy requirement is a function of the strength of the material, its thickness, and the design stress. See para. 841.1.2 for additional requirements relative to fracture control for pipe.

Provided the manufacturer's fracture toughness testing of reference material (material standards and specifications referenced in Mandatory Appendix A or Nonmandatory Appendix C) is performed at or below the pipeline minimum design temperature and meets the requirements of the fracture control plan, additional toughness testing of the material is not required. The welding procedure for circumferential welds shall be qualified as conforming to the fracture control program by Charpy testing at or below the minimum design temperature.

813 MARKING

813.1 Scope

All valves, fittings, flanges, bolting, pipe, and tubing shall be marked in accordance with the marking sections of the standards and specifications to which the items were manufactured or in accordance with the requirements of MSS SP-25.

813.2 Die Stamping

Die stamping, if used, shall be done with dies having blunt or rounded edges to minimize stress concentrations.

(16) 813.3 Multiple Marking of Materials or Components

Materials or components marked as meeting the requirements for two or more specifications (or grades, classes, or types) are acceptable, provided

(a) At least one or more of the multiple markings include a material specification (or grade, class, or type) that is permitted by this Code, and the material meets all the requirements of that specification.

(b) The appropriate design values and material properties from only the selected applicable specification (or grade, class, or type) shall be used. Design values and material properties from other specifications, grades, classes, or types for which the material is marked, including those acceptable to this Code, shall not be used or substituted for those in the selected specification.

(c) All other requirements of this Code are satisfied for the material selected.

Multiple marking shall be in accordance with the material specification, if allowed. Otherwise, multiple marking shall be in accordance with the guidelines set out in BPV Code, Section II, Part D, Appendix 7.

814 MATERIAL SPECIFICATIONS

For a listing of all referenced material specifications, see Mandatory Appendix A. For a listing of standards for other commonly used materials that are not referenced, see Nonmandatory Appendix C.

814.1 Pipe Conforming to Referenced Standards and Specifications

Pipe that is qualified under para. 811.1(a) may be used.

814.1.1 Steel Pipe

(a) Steel pipe manufactured in accordance with the following standards may be used:

API 5L [Note (1)]	Line Pipe
ASTM A53/A53M	Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless Pipe
ASTM A106/A106M	Seamless Carbon Steel Pipe for High-Temperature Service
ASTM A134	Steel, Electric-Fusion (Arc)-Welded Pipe (Sizes NPS 16 and Over)
ASTM A135/A135M	Electric-Resistance-Welded Steel Pipe
ASTM A139/A139M	Electric-Fusion (Arc)-Welded Steel Pipe (Sizes NPS 4 and Over)
ASTM A333/A333M	Seamless and Welded Steel Pipe for Low-Temperature Service
ASTM A381	Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems
ASTM A671	Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures
ASTM A672	Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures
ASTM A691	Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures
ASTM A984	Electric-Resistance-Welded Steel Line Pipe

ASTM A1005	Longitudinal and Helical Double Submerged-Arc Welded Steel Line Pipe
ASTM A1006	Laser Beam Welded Steel Line Pipe

NOTE:
(1) The provisions of API 5L, 45th edition, apply unless otherwise provided for, prohibited by, or limited by this edition of ASME B31.8.

(b) Cold expanded pipe shall meet the mandatory requirements of API 5L.

814.1.2 Ductile Iron Pipe. Ductile iron pipe manufactured in accordance with ANSI A21.52, titled Ductile-Iron Pipe, Centrifugally Cast, for Gas, may be used.

(16) **814.1.3 Plastic Pipe and Components**

(a) Plastic pipe and components manufactured in accordance with the following standards may be used:

(1) For polyethylene (PE) pipe, use

ASTM D2513	Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings

(2) For polyamide-11 (PA-11) pipe, use

ASTM D2517	Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
ASTM F2945	Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings

(b) Thermoplastic pipe, tubing, fittings, and cements conforming to ASTM D2513 shall be produced in accordance with the in-plant quality control program recommended in Annex A3 of that specification.

814.1.4 Qualification of Plastic Piping Materials

(a) In addition to complying with the provisions of para. 814.1.3, the user shall thoroughly investigate the specific plastic pipe, tubing, or fitting to be used and shall determine material serviceability for the conditions anticipated. The selected material shall be adequately resistant to the liquids and chemical atmospheres that may be encountered.

(b) When plastic pipe, tubing, or fittings of different material specifications are joined, a thorough investigation shall be made to determine that the materials are compatible with each other. See para. 842.2.9 for joining requirements.

814.2 Steel, Cast Iron, and Ductile Iron Piping Components

Specific requirements for these piping components that qualify under para. 811.1(a) are found in Chapter III.

815 EQUIPMENT SPECIFICATIONS

Except for the piping components and structural materials listed in Mandatory Appendix A and Nonmandatory Appendix C, it is not intended to include in this Code complete specifications for equipment. Certain details of design and fabrication, however, necessarily refer to equipment, such as pipe hangers, vibration dampeners, electrical facilities, engines, compressors, etc. Partial specifications for such equipment items are given herein, particularly if they affect the safety of the piping system in which they are to be installed. In other cases where this Code gives no specifications for the particular equipment item, the intent is that the safety provisions of this Code shall govern, insofar as they are applicable. In any case, the safety of equipment installed in a piping system shall be equivalent to that of other parts of the same system.

816 TRANSPORTATION OF LINE PIPE

Provisions should be made to protect the pipe, bevels, corrosion coating, and weight coating (if applicable) from damage during any transportation (highway, rail, and/or water) of line pipe.

Any line pipe to be transported by railroad, inland waterway, or by marine transportation shall be loaded and transported in accordance with API RP 5L1 or API RP 5LW. Where it is not possible to establish that pipe was loaded and transported in accordance with the above referenced recommended practice, the pipe shall be hydrostatically tested for at least 2 hr to at least 1.25 times the maximum allowable operating pressure if installed in a Class 1 Location, or to at least 1.5 times the maximum allowable operating pressure if installed in a Class 2, 3, or 4 Location.

817 CONDITIONS FOR THE REUSE OF PIPE

817.1 Reuse of Steel Pipe

817.1.1 Equivalent Service Level. Removal of a portion of an existing steel line and reuse of the pipe, in the same line or in a line operating at the same or lower rated pressure, is permitted, provided that the fracture toughness of the removed pipe is commensurate with or exceeds that of the line operating at the same or lower rated pressure and the used pipe meets the restrictions of paras. 817.1.3(a), (f), and (i). Reuse of the pipe in the same line or in a line operating at the same or lower pressure and the same or higher temperature is permitted subject to the same para. 817.1.3 restrictions above and any derations as required by Table 841.1.8-1. Removed pipe that is reinstalled in the same location need not be retested. Used pipe installed elsewhere is subject to paras. 817.1.3(i) and (j).

817.1.2 Low Hoop Stress Service Level [Less Than 6,000 psi (41 MPa)]. Used steel pipe and unidentified new steel pipe may be used for low-stress [hoop stress less than 6,000 psi (41 MPa)] level service where no close coiling or close bending is to be done, provided that

(a) careful visual examination indicates that it is in good condition and free from split seams or other defects that would cause leakage

(b) if the pipe is to be welded and is of unknown specification, it shall satisfactorily pass weldability tests prescribed in para. 817.1.3(e)

817.1.3 Midrange Hoop Stress Service Level [Greater Than 6,000 psi (41 MPa) but Less Than 24,000 psi (165 MPa)]. Unidentified steel pipe and unidentified new steel pipe may be qualified for use at hoop stress levels above 6,000 psi (41 MPa) or for service involving close coiling or close bending by the procedures and within the limits outlined below:

(a) Inspection. All pipe shall be cleaned inside and outside, if necessary, to permit good inspection. All pipe shall be visually inspected to determine that it is reasonably round and straight and to discover any defects that might impair its strength or tightness.

(b) Bending Properties. For pipe NPS 2 (DN 50) and smaller, a sufficient length of pipe shall be bent cold through 90 deg around a cylindrical mandrel, the diameter of which is 12 times the nominal diameter of the pipe, without developing cracks at any portion and without opening the weld.

For pipe larger than NPS 2 (DN 50), flattening tests as prescribed in Mandatory Appendix H shall be made. The pipe shall meet the requirements in this test, except that the number of tests required to determine flattening properties shall be the same as required in (g) below to determine yield strength.

(c) Determination of Wall Thickness. Unless the nominal wall thickness is known with certainty, it shall be determined by measuring the thickness at quarter points on one end of each piece of pipe. If the lot of pipe is known to be of uniform grade, size, and nominal thickness, measurement shall be made on not less than 10% of the individual lengths, but not less than 10 lengths; thickness of the other lengths may be verified by applying a gage set to the minimum thickness. Following such measurement, the nominal wall thickness shall be taken as the next commercial wall thickness below the average of all the measurements taken, but in no case greater than 1.14 times the least measured thickness for all pipe smaller than NPS 20 (DN 500), and no greater than 1.11 times the least measured thickness for all pipe NPS 20 (DN 500) and larger.

(d) Longitudinal Joint Factor. If the type of longitudinal joint can be determined with certainty, the corresponding longitudinal joint factor, E (Table 841.1.7-1 in Chapter IV), may be used. Otherwise, E shall be taken as 0.60 for pipe NPS 4 (DN 100) and smaller, or 0.80 for pipe larger than NPS 4 (DN 100).

(e) Weldability. Weldability shall be determined as follows. A qualified welder shall make a girth weld in the pipe. The weld shall then be tested in accordance with requirements of API 1104. The qualifying weld shall be made under the most severe conditions under which welding will be permitted in the field and using the same procedure as to be used in the field. The pipe shall be considered weldable if the requirements set forth in API 1104 are met. At least one such test weld shall be made for each 100 lengths of pipe on sizes larger than NPS 4 (DN 100). On sizes NPS 4 (DN 100) and smaller, one test will be required for each 400 lengths of pipe. If in testing the weld the requirements of API 1104 cannot be met, the weldability may be established by making chemical tests for carbon and manganese (see para. 823.2.3), and proceeding in accordance with the provisions of the BPV Code, Section IX. The number of chemical tests shall be the same as required for circumferential weld tests stated above.

Table 817.1.3-1 Tensile Testing

Lot	Number of Tensile Tests, All Sizes
10 lengths or less	1 set of tests from each length
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10
Greater than 100 lengths	1 set of tests for each 10 lengths, but not less than 20

(f) Surface Defects. All pipe shall be examined for gouges, grooves, and dents and shall be qualified in accordance with the provisions of para. 841.2.4.

(g) Determination of Yield Strength. When the manufacturer's specified minimum yield strength, tensile strength, or elongation for the pipe is unknown, and no physical tests are made, the minimum yield strength for design shall be taken as not more than 24,000 psi (165 MPa). Alternatively, the tensile properties may be established as follows:

(1) Perform all tensile tests prescribed by API 5L, except that the number of such tests shall be as shown in Table 817.1.3-1.

(2) All test specimens shall be selected at random.

(3) If the yield–tensile ratio exceeds 0.85, the pipe shall not be used, except as provided in para. 817.1.2.

(h) S Value. For pipe of unknown specification, the yield strength, to be used as S in the formula of para. 841.1.1, in lieu of the specified minimum yield strength, shall be 24,000 psi (165 MPa), or determined as follows.

Determine the average value of all yield strength tests for a uniform lot. The value of S shall then be taken as the lesser of the following:

(1) 80% of the average value of the yield strength tests

(2) the minimum value of any yield strength test, provided, however, that in no case shall S be taken as greater than 52,000 psi (359 MPa)

(i) Hydrostatic Test. New or used pipe of unknown specification and all used pipe, the strength of which is

impaired by corrosion or other deterioration, shall be retested hydrostatically either length by length in a mill-type test or in the field after installation before being placed in service. The test pressure used shall establish the maximum allowable operating pressure, subject to limitations described in para. 841.1.3.

(j) Fracture Control and Arrest. Without fracture toughness testing per para. 841.1.2, unidentified steel pipe and new or used pipe of unknown specification shall not be used in the following applications:

(1) where the operating hoop stress exceeds 40% SMYS for NPS 16 and larger

(2) where the operating hoop stress exceeds 72% SMYS for sizes smaller than NPS 16 (Class 1 Division 1 locations)

(3) where the minimum design temperature is below −20°F (−29°C)

817.2 Reuse of Ductile Iron Pipe

817.2.1 Equivalent Service Level. The removal of a portion of an existing line of unknown specifications and the reuse of the pipe in the same line or in a line operating at the same or lower pressure is permitted, provided careful inspection indicates that the pipe is sound, permits the makeup of tight joints, and has an actual net wall thickness equal to or exceeding the requirements of para. 842.1.1(d). The pipe shall be leak-tested in accordance with para. 841.3.4 or 841.3.5.

817.2.2 Known Specifications. Used pipe of known specifications may be reused in accordance with the provisions and specifications of para. 842.1 provided a careful inspection indicates the pipe is sound and permits the makeup of tight joints.

817.3 Reuse of Plastic Piping (16)

Used plastic pipe and tubing of known specifications and dimensions that have been used in natural gas service only may be reused, provided that all of the following are true:

(a) It meets the requirements of ASTM D2513 or ASTM F2945 for new thermoplastic pipe or tubing, or ASTM D2517 for new thermosetting pipe.

(b) A careful inspection indicates that it is free of visible defects.

(c) It is installed and tested in accordance with the requirements of this Code for new pipe.

Chapter II
Welding

820 WELDING

821 GENERAL

821.1 General Requirements

This Chapter addresses the welding of pipe joints in both wrought and cast steel materials and covers butt and fillet welded joints in pipe, valves, flanges, and fittings and fillet weld joints in pipe branches, slip-on flanges, socket weld fittings, etc., as applied in pipelines and connections to apparatus or equipment. When valves or equipment are furnished with welding ends suitable for welding directly into a pipeline, the design, composition, welding, and stress relief procedures must be such that no significant damage will result from the welding or stress relieving operation. This Chapter does not apply to the welding of the seam in the manufacture of pipe.

821.2 Welding Processes

The welding may be done by any process or combination of processes that produce welds that meet the procedure qualification requirements of this Code. The welds may be produced by position welding or roll welding, or a combination of position and roll welding.

821.3 Welding Procedure

Prior to welding of any pipe, piping components, or related equipment covered by this Code, a welding procedure shall be established and qualified. Each welder or welding operator shall be qualified for the established procedure before performing any welding on any pipe, piping components, or related equipment installed in accordance with this Code.

821.4 Weld Acceptance

The standards of acceptability for welds of piping systems to operate at hoop stress levels of 20% or more of specified minimum yield strength as established in API 1104 shall be used.

821.5 Welding Qualifications

All welding done under this Code shall be performed under a standard referenced in para. 823.1.1 or 823.2.1, whichever is applicable.

821.6 Welding Safety

Prior to welding in or around a structure or area containing gas facilities, a thorough check shall be made to determine the possible presence of a combustible gas mixture. Welding shall begin only when safe conditions are indicated.

821.7 Welding Terms

Definitions pertaining to welding as used in this Code conform to the standard definitions established by the American Welding Society and contained in AWS A3.0.

822 PREPARATION FOR WELDING

822.1 Butt Welds

(a) Some acceptable end preparations are shown in Mandatory Appendix I, Fig. I-4.

(b) Mandatory Appendix I, Fig. I-5 shows acceptable end preparations for buttwelding of pieces having either unequal thickness or unequal yield strength, or both.

822.2 Fillet Welds

Minimum dimensions for fillet welds used in the attachment of slip-on flanges and for socket welded joints are shown in Mandatory Appendix I, Fig. I-6. Similar minimum dimensions for fillet welds used in branch connections are shown in Mandatory Appendix I, Figs. I-1 and I-2.

822.3 Seal Welds

Seal welding shall be done by qualified welders. Seal welding of threaded joints is permitted, but the seal welds shall not be considered as contributing to the strength of joints.

823 QUALIFICATION OF PROCEDURES AND WELDERS

823.1 Requirements for Qualifying Welders on Piping Systems Operating at Hoop Stresses of Less Than 20% of the Specified Minimum Yield Strength

Welders whose work is limited to piping operating at hoop stress levels of less than 20% of the specified minimum yield strength shall be qualified under any of the references given in para. 823.2.1 or in accordance with Mandatory Appendix G.

823.2 Requirements for Qualifying Procedures and Welders on Piping Systems Operating at Hoop Stresses of 20% or More of the Specified Minimum Yield Strength

(16) **823.2.1 Qualifying Standards.** Welding procedures and welders performing work for new construction and out-of-service pipelines shall be qualified under Section IX of the BPV Code or API 1104. For in-service welding, welding procedures and welders shall be qualified under Appendix B of API 1104. Procedures qualified under Appendix B are suitable for weld deposition repair, provided the procedure is appropriate for the remaining wall thickness to which it is being applied.

823.2.2 Compressor Station Piping. When welders qualified under API 1104 are employed on compressor station piping, their qualification shall have been based on the destructive mechanical test requirements of API 1104.

823.2.3 Variables for the Separate Qualification of Welders. The references given in para. 823.2.1 contain sections titled "Essential Variables" applicable to welder qualification. These shall be followed, except that for purposes of this Code, all carbon steels that have a carbon content not exceeding 0.32% by heat analysis and a carbon equivalent (C + $\frac{1}{4}$ Mn) not exceeding 0.65% by heat analysis are considered to come under material grouping P-No. 1. Alloy steels having weldability characteristics demonstrated to be similar to these carbon steels shall be welded, preheated, and stress relieved as prescribed herein for such carbon steel. There may be significant differences in the base metal strength encompassed by these P-No. 1 materials, and although it is not an essential variable to welder qualification, it may require separate procedure qualification in accordance with para. 823.2.1.

823.3 Welder Requalification Requirements

Welder requalification tests shall be required if there is some specific reason to question a welder's ability or if the welder is not engaged in a given process of welding for 6 months or more. All welders shall be requalified at least once each year.

823.4 Qualification Records

Records of the tests that establish the qualification of a welding procedure shall be maintained as long as that procedure is in use. The operating company or contractor shall, during the construction involved, maintain a record of the welders qualified, showing the dates and results of tests.

824 PREHEATING

824.1 Carbon Steels

Carbon steels having a carbon content in excess of 0.32% (ladle analysis) or a carbon equivalent (C + $\frac{1}{4}$ Mn) in excess of 0.65% (ladle analysis) shall be preheated to the temperature indicated by the welding procedure. Preheating shall also be required for steels having lower carbon content or carbon equivalents when the welding procedure indicates that chemical composition, ambient and/or metal temperature, material thickness, or weld-end geometry require such treatment to produce satisfactory welds.

824.2 Dissimilar Materials

When welding dissimilar materials having different preheating requirements, the material requiring the higher preheat shall govern.

824.3 Suitable Methods

Preheating may be accomplished by any suitable method, provided that it is uniform and that the temperature does not fall below the prescribed minimum during the actual welding operations.

824.4 Temporary Monitoring

The preheating temperature shall be checked by the use of temperature-indicating crayons, thermocouple pyrometers, or other suitable methods to ensure that the required preheat temperature is obtained prior to and maintained during the welding operation.

825 STRESS RELIEVING

825.1 Carbon Steels

Welds in carbon steels having a carbon content in excess of 0.32% (ladle analysis) or a carbon equivalent (C + $\frac{1}{4}$ Mn) in excess of 0.65% (ladle analysis) shall be stress relieved as prescribed in the BPV Code, Section VIII. Stress relieving may also be advisable for welds in steel having lower carbon content or carbon equivalent when adverse conditions cool the weld too rapidly.

825.2 Wall Thickness

Welds in all carbon steels shall be stress relieved when the nominal wall thickness exceeds $1\frac{1}{4}$ in. (32 mm).

825.3 Different Wall Thicknesses

When the welded joint connects parts that are of different thicknesses but of similar materials, the thickness to be used in applying the rules in paras. 825.1 and 825.2 shall be

(a) the thicker of the two parts being joined, measured at the weld joint

(b) the thickness of the pipe run or header in case of branch connections, slip-on flanges, or socket weld fittings

825.4 Dissimilar Materials

If either material in welds between dissimilar materials requires stress relieving, the joint shall require stress relieving.

825.5 Connections and Attachments

All welding of connections and attachments shall be stress relieved when the pipe is required to be stress relieved by the rules of para. 825.3, with the following exceptions:

(a) fillet and groove welds not over ½ in. (13 mm) leg size that attach connections not over NPS 2 (DN 50) pipe size

(b) fillet and groove welds not over ⅜ in. (10 mm) groove size that attach supporting members or other nonpressure attachments

825.6 Stress Relieving Temperature

(a) Stress relieving shall be performed at a temperature of 1,100°F (593°C) or greater for carbon steels, and 1,200°F (649°C) or greater for ferritic alloy steels. The exact temperature range shall be stated in the procedure specification.

(b) When stress relieving takes place in a joint between dissimilar metals having different stress relieving requirements, the material requiring the higher stress relieving temperature shall govern.

(c) The parts heated shall be brought slowly to the required temperature and held at that temperature for a period of time proportioned on the basis of at least 1 hr/in. (1 h/25 mm) of pipe wall thickness, but in no case less than ½ hr, and shall be allowed to cool slowly and uniformly.

825.7 Methods of Stress Relieving

(a) Heat the complete structure as a unit.

(b) Heat a complete section containing the weld or welds to be stress relieved before attachment to other sections of work.

(c) Heat a part of the work by slowly heating a circumferential band containing the weld at the center. The width of the band that is heated to the required temperature shall be at least 2 in. (51 mm) greater than the width of the weld reinforcement. Care should be taken to obtain a uniform temperature around the entire circumference of the pipe. The temperature shall diminish gradually outward from the edges of this band.

(d) Branches or other welded attachments for which stress relief is required may be locally stress relieved by heating a circumferential band around the pipe on which the branch or attachment is welded with the attachment at the middle of the band. The width of the band shall be at least 2 in. (51 mm) greater than the diameter of the weld joining the branch or attachment to the header. The entire band shall be brought up to the required temperature and held for the time specified.

825.8 Equipment for Local Stress Relieving

(a) Stress relieving may be accomplished by electric induction, electric resistance, fuel-fired ring burners, fuel-fired torches, or other suitable means of heating, provided that a uniform temperature is obtained and maintained during the stress relieving.

(b) The stress relieving temperature shall be checked by the use of thermocouple pyrometers or other suitable equipment to ensure that the proper stress relieving cycle has been accomplished.

826 WELD INSPECTION REQUIREMENTS

826.1 Visual Inspection

Visual inspection of welds must be conducted by a person qualified by appropriate training and experience.

826.2 Inspection of Welds on Piping Systems Intended to Operate at Hoop Stress Levels of Less Than 20% of the Specified Minimum Yield Strength

The quality of welds shall be checked visually on a sampling basis, and defective welds shall be repaired or removed from the line.

826.3 Inspection and Tests for Quality Control of Welds on Piping Systems Intended to Operate at Hoop Stress Levels of 20% or More of the Specified Minimum Yield Strength

(a) The quality of each weld shall be examined by visual inspection.

(b) In addition, a certain percentage of the welds shall be examined through radiographic examination, ultrasonic testing, magnetic particle testing, or other comparable and acceptable methods of nondestructive testing. The trepanning method of nondestructive testing is prohibited.

The following minimum number of field butt welds shall be selected on a random basis by the operating company from each day's construction for examination. Each weld so selected shall be examined over its entire circumference or else the equivalent length of welds shall be examined if the operating company chooses to examine only a part of the circumference of each. The same minimum percentages shall be examined for double ending at railhead or yard.

(1) 10% of welds in Location Class 1.
(2) 15% of welds in Location Class 2.
(3) 40% of welds in Location Class 3.
(4) 75% of welds in Location Class 4.

(5) 100% of the welds in compressor stations, and at major or navigable river crossings, major highway crossings, and railroad crossings, if practical, but in no case less than 90%. All tie-in welds not subjected to a pressure proof test shall be examined.

(c) All welds that are inspected must either meet the standards of acceptability of API 1104 or be appropriately repaired and reinspected. The results of the inspection shall be used to control the quality of welds.

(d) When radiographic examination is employed, a procedure meeting the requirements of API 1104 shall be followed.

(e) When pipe size is less than NPS 6 (DN 150), or when the construction project involves such a limited number of welds that nondestructive inspection would be impractical, and the pipe is intended to operate at hoop stress levels of 40% or less of the specified minimum yield strength, then provisions (b) and (c) above are not mandatory, provided the welds are inspected visually and approved by a qualified welding inspector.

(f) In addition to the nondestructive inspection requirements outlined above, the quality of welds shall be continually controlled by qualified personnel.

827 REPAIR OR REMOVAL OF DEFECTIVE WELDS IN PIPING INTENDED TO OPERATE AT HOOP STRESS LEVELS OF 20% OR MORE OF THE SPECIFIED MINIMUM YIELD STRENGTH

Defective welds shall be repaired or removed. If a repair is made, it shall be in accordance with API 1104. Welders performing repairs shall be qualified in accordance with para. 823.2.

Chapter III
Piping System Components and Fabrication Details

830 PIPING SYSTEM COMPONENTS AND FABRICATION DETAILS

830.1 General

(a) The purpose of this Chapter is to provide a set of standards for piping systems covering

(1) specifications for and selection of all items and accessories that are a part of the piping system, other than the pipe itself

(2) acceptable methods of making branch connections

(3) provisions to care for the effects of temperature changes

(4) approved methods for support and anchorage of exposed and buried piping systems

(b) This Chapter does not include

(1) pipe materials (see Chapter I)

(2) welding procedures (see Chapter II)

(3) design of pipe (see Chapter IV)

(4) installation and testing of piping systems (see Chapter IV)

(5) special conditions for offshore application (see Chapter VIII)

(6) special conditions for sour gas application (see Chapter IX)

831 PIPING SYSTEM COMPONENTS

All components of piping systems, including valves, flanges, fittings, headers, special assemblies, etc., shall be designed in accordance with the applicable requirements of this section and recognized engineering practices to withstand operating pressures and other specified loadings.

Components shall be selected that can withstand the design, operating, and test conditions of the system in which the component is to be used without failure or leakage and without impairment of their serviceability.

831.1 Valves and Pressure-Reducing Devices

831.1.1 Valves Without Threads. Valves shall conform to standards and specifications referenced in this Code and shall be used only in accordance with the service recommendations of the manufacturer.

(a) Valves manufactured in accordance with the following standards may be used:

API 6A	Specification for Wellhead and Christmas Tree Equipment
API 6D/ISO 14313	Specification for Pipeline Valves
ASME B16.33	Manually Operated Metallic Gas Valves for Use in Gas Piping Systems up to 175 psi (Sizes NPS ½ Through NPS 2)
ASME B16.34	Valves — Flanged, Threaded, and Welding End
ASME B16.38	Large Metallic Valves for Gas Distribution: Manually Operated, NPS 2½ (DN 65) to NPS 12 (DN 300), 125 psig (8.6 bar) Maximum
ASME B16.40	Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems
MSS SP-70	Gray Iron Gate Valves, Flanged and Threaded Ends
MSS SP-71	Gray Iron Swing Check Valves, Flanged and Threaded Ends
MSS SP-78	Gray Iron Plug Valves, Flanged and Threaded Ends

(b) Valves having shell (body, bonnet, cover, and/or end flange) components made of cast ductile iron in compliance with ASTM A395 and having dimensions conforming to ASME B16.1, ASME B16.33, ASME B16.34, ASME B16.38, ASME B16.40, or API 6D/ISO 14313 may be used at pressures not exceeding 80% of the pressure ratings for comparable steel valves at their listed temperature, provided the pressure does not exceed 1,000 psig (6 900 kPa), and welding is not employed on any ductile iron component in the fabrication of the valve shells or their assembly as part of the piping system.

(c) Valves having shell components made of cast iron shall not be used in gas piping components for compressor stations.

831.1.2 Threaded Valves. Threaded valves shall be threaded according to ASME B1.20.1, API 5L, or API 6A.

831.1.3 Pressure-Reducing Devices. Pressure-reducing devices shall conform to the requirements of this Code for valves in comparable service conditions.

831.2 Flanges

831.2.1 Flange Types and Facings

(a) The dimensions and drilling for all line or end flanges shall conform to one of the following standards:

ASME B16.1	Gray Iron Pipe Flanges and Flanged Fittings: Classes 25, 125, and 250

ASME B16.5	Pipe Flanges and Flanged Fittings: NPS $\frac{1}{2}$ Through NPS 24 Metric/Inch Standard
ASME B16.24	Cast Copper Alloy Pipe Flanges and Flanged Fittings: Classes 150, 300, 600, 900, 1500, and 2500
ASME B16.42	Ductile Iron Pipe Flanges and Flanged Fittings: Classes 150 and 300
ASME B16.47	Large Diameter Steel Flanges: NPS 26 Through NPS 60 Metric/Inch Standard
ASME B31.8, Mandatory Appendix I, Table I-1	Lightweight Flanges
MSS SP-44	Steel Pipeline Flanges

Flanges cast or forged integral with pipe, fittings, or valves are permitted in sizes and the pressure classes covered by the standards listed above, subject to the facing, bolting, and gasketing requirements of this paragraph and paras. 831.2.2 and 831.2.3.

(b) Threaded companion flanges that comply with the B16 group of ASME standards are permitted in sizes and pressure classes covered by these standards.

(c) Lapped flanges are permitted in sizes and pressure classes established in ASME B16.5.

(d) Slip-on welding flanges are permitted in sizes and pressure classes established in ASME B16.5. Slip-on flanges of rectangular section may be substituted for hubbed slip-on flanges, provided the thickness is increased as required to produce equivalent strength as determined by calculations made in accordance with Section VIII of the BPV Code.

(e) Welding neck flanges are permitted in sizes and pressure classes established in ASME B16.5, ASME B16.47, and MSS SP-44. The bore of the flange should correspond to the inside diameter of the pipe used. For permissible welding end treatment, see Mandatory Appendix I, Fig. I-5.

(f) Cast iron, ductile iron, and steel flanges shall have contact faces finished in accordance with MSS SP-6.

(g) Nonferrous flanges shall have contact faces finished in accordance with ASME B16.24.

(h) Class 25 and 125 cast iron integral or threaded companion flanges may be used with a full-face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. When using a full-face gasket, the bolting may be of alloy steel (ASTM A193). When using a ring gasket, the bolting shall be of carbon steel, equivalent to ASTM A307 Grade B, without heat treatment other than stress relief.

(i) When bolting together two Class 250 integral or threaded companion cast iron flanges having $\frac{1}{16}$-in. (1.6-mm) raised faces, the bolting shall be of carbon steel equivalent to ASTM A307 Grade B, without heat treatment other than stress relief.

(j) Class 150 steel flanges may be bolted to Class 125 cast iron flanges. When such construction is used, the $\frac{1}{16}$-in. (1.6-mm) raised face on the steel flange shall be removed. When bolting such flanges together using a flat ring gasket extending to the inner edge of the bolt holes, the bolting shall be of carbon steel equivalent to ASTM A307 Grade B, without heat treatment other than stress relief. When bolting such flanges together using a full-face gasket, the bolting may be alloy steel (ASTM A193).

(k) Class 300 steel flanges may be bolted to Class 250 cast iron flanges. Where such construction is used, the bolting shall be of carbon steel, equivalent to ASTM A307 Grade B, without heat treatment other than stress relief. Good practice indicates that the raised face on the steel flange should be removed, but also in this case, bolting shall be of carbon steel equivalent to ASTM A307 Grade B.

(l) Forged steel welding neck flanges having an outside diameter and drilling the same as that of ASME B16.1, but with modified flange thickness, hub dimensions, and special facing details, may be used to bolt against flat-faced cast iron flanges and may operate at the pressure–temperature ratings given in ASME B16.1 for Class 125 cast iron pipe flanges, provided

(1) the minimum flange thickness, T, is not less than that specified in Mandatory Appendix I for lightweight flanges

(2) flanges are used with nonmetallic full-face gaskets extending to the periphery of the flange

(3) the joint design has been proven by test to be suitable for the ratings

(m) Flanges made of ductile iron shall conform to the requirements of ASME B16.42. Bolting requirements for ductile iron flange joints shall be the same as those for carbon and low alloy steel flanges as specified in para. 831.2.2.

831.2.2 Bolting

(a) For all flange joints, the bolts or stud bolts used shall extend completely through the nuts.

(b) For all flange joints other than those described in paras. 831.21(h) through (k), the bolting shall be made of alloy steel conforming to ASTM A193, ASTM A320, or ASTM A354, or of heat treated carbon steel conforming to ASTM A449. Bolting, however, for ASME B16.5, Class 150 and 300 flanges at temperatures between −20°F and 400°F (−29°C and 204°C) may be made of ASTM A307 Grade B material.

(c) Alloy-steel bolting material conforming to ASTM A193 or ASTM A354 shall be used for insulating flanges if such bolting is made $\frac{1}{8}$-in. (3.2-mm) undersized.

(d) The materials used for nuts shall conform to ASTM A194 and ASTM A307. ASTM A307 nuts may be used only with ASTM A307 bolting.

(e) All carbon and alloy-steel bolts, stud bolts, and their nuts shall be threaded in accordance with the following thread series and dimension classes as required by ASME B1.1.

(1) Carbon Steel. All carbon-steel bolts and stud bolts shall have coarse threads having Class 2A dimensions, and their nuts shall have Class 2B dimensions.

(2) Alloy Steel. All alloy-steel bolts and stud bolts of 1-in. (25-mm) and smaller nominal diameter shall be of the coarse-thread series; nominal diameters $1\frac{1}{8}$ in. (29 mm) and larger shall be of the 8-thread series (8 threads per 25.4 mm). Bolts and stud bolts shall have a Class 2A dimension; their nuts shall have Class 2B dimension.

(f) Bolts shall have ASME Standards regular square heads or heavy hexagonal heads and shall have ASME Standards heavy hexagonal nuts conforming to the dimensions of ASME B18.2.1 and ASME B18.2.2.

(g) Nuts cut from bar stock in such a manner that the axis will be parallel to the direction of rolling of the bar may be used in all sizes for joints in which one or both flanges are cast iron and for joints with steel flanges where the pressure does not exceed 250 psig (1 720 kPa). Such nuts shall not be used for joints in which both flanges are steel and the pressure exceeds 250 psig (1 720 kPa), except that for nut sizes $\frac{1}{2}$ in. (12.7 mm) and smaller, these limitations do not apply.

831.2.3 Gaskets

(a) General

(1) Gasket materials shall be capable of maintaining their serviceability once installed and exposed to the gases and fluids contained in the piping system.

(2) ASME B16.20 and ASME B16.21 are standards that provide guidance for applicable gaskets and materials.

(b) Pressure

(1) Gaskets shall be made of materials suitable for the design and test pressures of the systems in which they are installed.

(2) Metallic gaskets other than ring-type or spirally wound metal gaskets shall not be used with ASME Class 150 or lighter flanges. Metallic gaskets shall not be used for flanges lighter than Class 150, or when ASTM A307 Grade B bolts or equivalent are used.

(c) Temperature

(1) Gasket materials shall be capable of maintaining their desired mechanical and chemical properties for the full range of temperatures to which they will be exposed.

(2) Consideration should be given to the use of fire-safe materials to withstand emergency conditions.

(d) Types

(1) The use of metal or metal-jacketed gaskets (either plain or corrugated) is not pressure limited, except as noted in (b)(2), provided that the gasket material is suitable for the service temperature. These types of gaskets are recommended for use with the small male and female or the small tongue-and-groove facings. They may also be used with steel flanges with lapped, large male and female, large tongue-and-groove, or raised-face facings.

(2) Full-face gaskets should be used with all bronze (or copper alloy) flanges and with Class 25 and Class 125 cast iron flanges. Flat ring gaskets with an outside diameter extending to the inside of the bolt holes may be used with cast iron flanges, with raised-face steel flanges, or with lapped steel flanges, provided that the bolting requirements of ASME B16.5, para. 5.3.5 are followed.

(3) For steel flanges to secure higher unit compression on the gasket, metallic gaskets of a width less than the full male face of the flange may be used with raised face, lapped, or large male and female facings. The width of the gasket for small male and female or for tongue-and-groove joints shall be equal to the width of the male face or tongue.

(4) Rings for ring joints shall be of dimensions established in ASME B16.20. The material for these rings shall be suitable for the service conditions encountered and shall be softer than the flanges.

(5) Special Gaskets. Special gaskets, including insulating gaskets, may be used, provided they are suitable for the temperatures, pressures, gas composition, fluids, and other conditions to which they may be subjected.

831.3 Fittings Other Than Valves and Flanges

831.3.1 Standard Fittings (16)

(a) The minimum metal thickness of flanged or threaded fittings shall not be less than specified for the pressures and temperatures in the applicable ASME standards or the MSS standard practice.

(b) Steel buttwelding fittings shall comply with either ASME B16.9 or MSS SP-75 and shall have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. For adequacy of fitting design, the actual bursting strength of fittings shall at least equal the computed bursting strength of pipe of the designated material and wall thickness. Mill hydrostatic testing of factory-made steel buttwelding fittings is not required, but all such fittings shall be capable of withstanding a field test pressure equal to the test pressure established by the manufacturer, without failure or leakage, and without impairment of their serviceability.

(c) Factory-made wrought steel buttwelding induction bends or hot bends shall comply with ASME B16.49.

(d) Steel socket-welding fittings shall comply with ASME B16.11.

(e) Ductile iron flanged fittings shall comply with the requirements of ASME B16.42 or ANSI A21.14.

(f) Thermoplastic fittings shall comply with ASTM D2513 or ASTM F2945.

(g) Reinforced thermosetting plastic fittings shall comply with ASTM D2517.

831.3.2 Special Fittings. When special cast, forged, wrought, or welded fittings are required to dimensions differing from those of regular shapes specified in the applicable ASME and MSS standards, the provisions of para. 831.3.6 shall apply.

831.3.3 Branch Connections

(a) Welded branch connections on steel pipe must meet the design requirements of paras. 831.4 and 831.5.

(b) Threaded taps in cast iron pipe for branch connections are permitted without reinforcement to a size not more than 25% of the nominal diameter of the pipe; however, where climate service conditions or soil conditions create abnormal or unusual external loadings on cast iron pipe, unreinforced threaded taps for branch connections are permitted only on cast iron pipe NPS 8 (DN 200) and larger in diameter, provided that the tap size is no greater than 25% of the nominal pipe diameter.

(c) Existing threaded taps in cast iron pipe may be used for replacement branch connections when careful inspection shows there are no cracks or other deterioration in the main immediately surrounding the opening.

(d) Threaded taps in ductile iron pipe are permitted without reinforcement to a size not more than 25% of the nominal diameter of the pipe, except that $1\frac{1}{4}$-in. (DN 32) taps are permitted in NPS 4 (DN 100) pipe having a nominal wall thickness of not less than 0.380 in. (9.65 mm).

(e) Mechanical fittings may be used for making hot taps on pipelines and mains, provided they are designed for the operating conditions of the pipeline or main and are suitable for that purpose.

831.3.4 Openings for Gas Control Equipment in Cast Iron Pipe. Threaded taps used for gas control equipment in cast iron pipe (i.e., bagging off a section of main) are permitted without reinforcement to a size not more than 25% of the nominal diameter of the pipe, except that $1\frac{1}{4}$-in. (DN 32) taps are permitted in NPS 4 (DN 100) pipe. Taps larger than those permitted above shall use a reinforcing sleeve.

831.3.5 Special Components Fabricated by Welding

(a) This section covers piping system components other than assemblies consisting of pipe and fittings joined by circumferential welds.

(b) All welding shall be performed using procedures and operators that are qualified in accordance with the requirements of section 823.

(c) Branch connections shall meet the design requirements of paras. 831.4, 831.5, and 831.6.

(d) Prefabricated units, other than regularly manufactured buttwelding fittings, that employ plate and longitudinal seams as contrasted with pipe that has been produced and tested under one of the specifications listed in this Code, shall be designed, constructed, and tested under requirements of the BPV Code. BPV Code requirements are not intended to apply to such partial assemblies as split rings or collars or to other field welded details.

(e) Every prefabricated unit produced under this section of the Code shall successfully withstand a pressure test without failure, leakage, distress, or distortion other than elastic distortion at a pressure equal to the test pressure of the system in which it is installed, either before installation or during the system test. When such units are to be installed in existing systems, they shall be pressure tested before installation, if feasible; otherwise, they shall withstand a leak test at the operating pressure of the line.

831.3.6 Pressure Design of Other Pressure-Containing Components. Pressure-containing components that are not covered by the standards listed in Mandatory Appendix A and for which design equations or procedures are not given herein may be used where the design of similarly shaped, proportioned, and sized components has been proven satisfactory by successful performance under comparable service conditions. (Interpolation may be made between similarly shaped components with small differences in size or proportion.) In the absence of such service experience, the pressure design shall be based on an analysis consistent with the general design philosophy embodied in this Code and substantiated by at least one of the following:

(a) proof tests, as described in UG-101 of Section VIII, Division 1 of the BPV Code

(b) experimental stress analysis, as described in Annex 5.F of Section VIII, Division 2 of the BPV Code

(c) engineering calculations

831.3.7 Closures

(a) Quick Opening Closures. A quick opening closure is a pressure-containing component (see para. 831.3.6) used for repeated access to the interior of a piping system. It is not the intent of this Code to impose the requirements of a specific design method on the designer or manufacturer of a quick opening closure.

Quick opening closures shall have pressure and temperature ratings equal to or in excess of the design requirements of the piping system to which they are attached.

Quick opening closures shall be equipped with safety locking devices in compliance with Section VIII, Division I, UG-35.2 of the BPV Code.

Weld end preparation shall be in accordance with Mandatory Appendix I, Fig. I-4.

(b) Closure Fittings. Closure fittings commonly referred to as "weld caps" shall be designed and manufactured in accordance with ASME B16.9 or MSS SP-75. [See para. 831.3.1(b).]

(c) Closure Heads. Closure heads such as flat, ellipsoidal [other than in (b)], spherical, or conical heads are allowed for use under this Code. Such items may be designed in accordance with Section VIII, Division 1 of the BPV Code. For closure heads not designed to Section VIII, Division 1 of the BPV Code, the maximum allowable stresses for materials used in these closure heads shall be established under the provisions of section 841 and shall not exceed a hoop stress level of 60% SMYS.

If welds are used in the fabrication of these heads, they shall be inspected in accordance with the provisions of Section VIII, Division 1 of the BPV Code.

Closure heads shall have pressure and temperature ratings equal to or in excess of the design requirement of the piping system to which they are attached.

(d) Fabricated Closures. Orange-peel bull plugs and orange-peel swages are prohibited on systems operating at hoop stress levels of 20% or more of the specified minimum yield strength of the pipe material. Fish tails and flat closures are permitted on pipe NPS 3 (DN 75) and smaller operating at less than 100 psi (690 kPa). Fish tails on pipe larger than NPS 3 (DN 75) are prohibited. Flat closures on pipe larger than NPS 3 shall be designed according to Section VIII, Division 1 of the BPV Code. [See (c).]

(e) Bolted Blind Flange Connections. Bolted blind flange connections shall conform to para. 831.2.

831.4 Reinforcement of Welded Branch Connections

(16) **831.4.1 General Requirements.** All welded branch connections shall meet the following requirements:

(a) When branch connections are made to pipe in the form of a single connection or in a header or manifold as a series of connections, the design must be adequate to control the stress levels in the pipe within safe limits. The construction shall accommodate the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, vibration, etc. The following paragraphs provide design rules for the usual combinations of the above loads, except for excessive external loads.

(b) The reinforcement required in the crotch section of a welded branch connection shall be determined by the rule that the metal area available for reinforcement shall be equal to or greater than the required area as defined in this paragraph as well as in Mandatory Appendix F, Fig. F-5.

(c) The required cross-sectional area, A_R, is defined as the product of d times t:

$$A_R = dt$$

where

d = the greater of the length of the finished opening in the header wall measured parallel to the axis of the run or the inside diameter of the branch connection

t = the nominal header wall thickness required by para. 841.1.1 for the design pressure and temperature

When the pipe wall thickness includes an allowance for corrosion or erosion, all dimensions used shall result after the anticipated corrosion or erosion has taken place.

(d) The area available for reinforcement shall be the sum of

(1) the cross-sectional area that results from any excess thickness available in the header thickness over the minimum required for the header as defined in (c) and that lies within the reinforcement area as defined in (e)

(2) the cross-sectional area that results from any excess thickness available in the branch wall thickness over the minimum thickness required for the branch and that lies within the reinforcement area as defined in (e)

(3) the cross-sectional area of all added reinforcing metal that lies within the reinforcement area, as defined in (e), including that of solid weld metal that is conventionally attached to the header and/or branch

(e) The area of reinforcement, shown in Mandatory Appendix F, Fig. F-5, is defined as a rectangle whose length shall extend a distance, d, on each side of the transverse centerline of the finished opening and whose width shall extend a distance of $2\frac{1}{2}$ times the header wall thickness on each side of the surface of the header wall. In no case, however, shall it extend more than $2\frac{1}{2}$ times the thickness of the branch wall from the outside surface of the header or of the reinforcement, if any.

(f) The material of any added reinforcement shall have an allowable working stress at least equal to that of the header wall, except that material of lower allowable stress may be used if the area is increased in direct ratio of the allowable stress for header and reinforcement material, respectively.

(g) The material used for ring or saddle reinforcement may be of specifications differing from those of the pipe, provided the cross-sectional area is made in direct proportion to the relative strength of the pipe and reinforcement materials at the operating temperatures, and provided it has welding qualities comparable to those of the pipe. No credit shall be taken for the additional strength of material having a higher strength than that of the part to be reinforced.

(h) When rings or saddles cover the weld between branch and header, a vent hole shall be provided in the ring or saddle to reveal leakage in the weld between branch and header and to provide venting during welding and heat treating operations. Vent holes should be plugged during service to prevent crevice corrosion between pipe and reinforcing member, but no plugging material that would be capable of sustaining pressure within the crevice should be used.

(i) The use of ribs or gussets shall not be considered as contributing to reinforcement of the branch connection. This does not prohibit the use of ribs or gussets for purposes other than reinforcement, such as stiffening.

(j) The branch shall be attached by a weld for the full thickness of the branch or header wall plus a fillet weld, W_1, as shown in Mandatory Appendix I, Figs. I-1 and I-2. The use of concave fillet welds is preferred to further minimize corner stress concentration. Ring or saddle reinforcement shall be attached as shown by Fig. I-2. When a full fillet is not used, it is recommended that the edge of the reinforcement be relieved or chamfered at approximately 45 deg to merge with the edge of the fillet.

(k) Reinforcement rings and saddles shall be accurately fitted to the parts to which they are attached. Mandatory Appendix I, Figs. I-2 and I-3 illustrate some acceptable forms of reinforcement.

(l) Branch connections attached at an angle less than 85 deg to the run become progressively weaker as the angle decreases. Any such design must be given individual study, and sufficient reinforcement must be provided to compensate for the inherent weakness of such construction. The use of encircling ribs to support the flat or re-entering surfaces is permissible and may be included in the strength calculations. The designer is cautioned that stress concentrations near the ends of partial ribs, straps, or gussets may defeat their reinforcing value.

831.4.2 Special Requirements. In addition to the requirements of para. 831.4.1, branch connections must meet the special requirements of the following paragraphs as given in Table 831.4.2-1:

(a) Smoothly contoured wrought steel tees of proven design are preferred. When tees cannot be used, the reinforcing member shall extend around the circumference of the header. Pads, partial saddles, or other types of localized reinforcement are prohibited.

(b) Smoothly contoured tees of proven design are preferred. When tees are not used, the reinforcing member should be of the complete encirclement type, but may be of the pad type, saddle type, or a welding outlet fitting type.

(c) The reinforcement member may be of the complete encirclement type, pad type, saddle type, or welding outlet fitting type. The edges of reinforcement members should be tapered to the header thickness. It is recommended that legs of fillet welds joining the reinforcing member and header do not exceed the thickness of the header.

Table 831.4.2-1 Reinforcement of Welded Branch Connections, Special Requirements

Ratio of Design Hoop Stress to Minimum Specified Yield Strength in the Header	Ratio of Nominal Branch Diameter to Nominal Header Diameter		
	25% or Less	More Than 25% Through 50%	More Than 50%
20% or less	(g), (j)	(g), (j)	(h), (j)
More than 20% through 50%	(d), (i), (j)	(i), (j)	(h), (i), (j)
More than 50%	(c), (d), (e), (j)	(b), (e), (j)	(a), (e), (f), (j)

GENERAL NOTE: The letters in the table correspond to the subparagraphs of para. 831.4.2.

(d) Reinforcement calculations are not required for openings 2 in. (51 mm) and smaller in diameter; however, care should be taken to provide suitable protection against vibrations and other external forces to which these small openings are frequently subjected.

(e) All welds joining the header, branch, and reinforcing member shall be equivalent to those shown in Mandatory Appendix I, Figs. I-1, I-2, and I-3.

(f) The inside edges of the finished opening shall, whenever possible, be rounded to a $\frac{1}{8}$ in. (3.2 mm) radius. If the encircling member is thicker than the header and is welded to the header, the ends shall be tapered down to the header thickness, and continuous fillet welds shall be made. In the case of hot tap or plugging fittings, use special requirement (j).

(g) Reinforcement of openings is not mandatory; however, reinforcement may be required for special cases involving pressures over 100 psig (690 kPa), thin wall pipe, or severe external loads.

(h) If a reinforcement member is required, and the branch diameter is such that a localized type of reinforcement member would extend around more than half the circumference of the header, then a complete encirclement type of reinforcement member shall be used, regardless of the design hoop stress, or a smoothly contoured wrought steel tee of proven design may be used.

(i) The reinforcement may be of any type meeting the requirements of para. 831.4.1.

(j) For hot tap or plugging fittings of tee-type configurations (see Fig. I-3.1), where the reinforcing sleeve is pressurized and thicker than the header, and the application results in additional loading such as that from hot tapping and plugging equipment, the following requirements apply:

(1) The minimum leg dimension of the fillet weld at the ends of the sleeve shall be 1.0t plus the gap observed or measured between the inside of the fitting and the outside of the pipe on installation, where t is

the actual wall thickness of the pipe. This will result in a minimum effective weld throat of $0.7t$.

(2) The maximum leg dimension of the end fillet welds shall be $1.4t$ plus the gap observed or measured between the inside of the fitting and the outside of the pipe on installation, resulting in an effective weld throat not to exceed $1.0t$.

(3) If necessary, the fittings shall be tapered, beveled, or chamfered at their ends to a minimum approximate angle of 45 deg (with respect to the end face). Tapering, beveling, or chamfering should provide at least a nominal face to accommodate the fillet weld, but the face dimension should not exceed 1.4 times the calculated thickness required to meet the maximum hoop stress of the pressurized sleeve. The leg of the fillet deposited on the end face need not be carried out fully to the shoulder of the face if doing so would result in an oversized fillet weld.

(4) Because each installation may be unique, the taper or chamfer shall be the responsibility of the user or otherwise by agreement between user and manufacturer.

831.5 Reinforcement of Multiple Openings

(a) When two or more adjacent branches are spaced at less than two times their average diameter (so that their effective areas of reinforcement overlap), the group of openings shall be reinforced in accordance with para. 831.4. The reinforcing metal shall be added as a combined reinforcement, the strength of which shall equal the combined strengths of the reinforcements that would be required for the separate openings. In no case shall any portion of a cross section be considered to apply to more than one opening or be evaluated more than once in a combined area.

(b) When more than two adjacent openings are to be provided with a combined reinforcement, the minimum distance between centers of any two of these openings shall preferably be at least $1\frac{1}{2}$ times their average diameter, and the area of reinforcement between them shall be at least equal to 50% of the total required for these two openings on the cross section being considered.

(c) When the distance between centers of two adjacent openings is less than $1\frac{1}{3}$ times their average diameter, as considered under (b), no credit for reinforcement shall be given for any of the metal between these two openings.

(d) Any number of closely spaced adjacent openings in any arrangement may be reinforced as if the group were treated as one assumed opening of a diameter enclosing all such openings.

831.6 Extruded Outlets

(a) The rules in this paragraph apply to steel extruded outlets in which the reinforcement is integral.

An extruded outlet is defined as an outlet in which the extruded lip at the outlet has a height above the surface of the run that is equal to or greater than the radius of curvature of the external contoured portion of the outlet. (See Mandatory Appendix F, Figs. F-1 through F-4 and nomenclature.)

(b) These rules do not apply to any nozzles or branch connections in which additional nonintegral material is applied in the form of rings, pads, or saddles.

(c) These rules apply only to cases where the axis of the outlet intersects and is perpendicular to the axis of the run.

(d) Figures F-1 through F-4 define the pertinent dimensions and limiting conditions.

(e) *Required Area.* The required area is defined as

$$A = K t_r D_o$$

where

K = 1.00 when $d/D > 0.60$
= $0.6 + \frac{2}{3} d/D$ when $d/D > 0.15$ and not exceeding 0.60
= 0.70 when $d/D \le 0.15$

The design must meet the criterion that the reinforcement area defined in (f) below is not less than the required area.

(f) *Reinforcement Area.* The reinforcement area shall be the sum of areas $A_1 + A_2 + A_3$ as defined below:

(1) Area A_1 is the area lying within the reinforcement zone resulting from any excess thickness available in the run wall, i.e.,

$$A_1 = D_o (T_r - t_r)$$

(2) Area A_2 is the area lying within the reinforcement zone resulting from any excess thickness available in the branch pipe wall, i.e.,

$$A_2 = 2L (T_b - t_b)$$

(3) Area A_3 is the area lying within the reinforcement zone resulting from excess thickness available in the extruded outlet lip, i.e.,

$$A_3 = 2r_o (T_o - t_b)$$

(g) *Reinforcement of Multiple Openings.* The rules in para. 831.5 shall be followed, except that the required area and reinforcement area shall be as given in para. 831.6.

(h) In addition to the above, the manufacturer shall be responsible for establishing and marking on the section containing extruded outlets the following: the design pressure and temperature, and that these were established under provisions of this Code. The manufacturer's name or trademark shall be marked on the section.

Table 832.2-1 Thermal Expansion or Contraction of Piping Materials Carbon and Low Alloy High Tensile Steel and Wrought Iron

Temperature, °F (°C)	Approximate Expansion or Contraction, in./100 ft (mm/m) Above or Below 32°F (0°C)
−125 (−87)	1.2 (1.0)
−100 (−74)	1.0 (0.8)
−75 (−60)	0.8 (0.7)
−50 (−45)	0.6 (0.5)
0 (−18)	0.2 (0.2)
32 (0)	0.0 (0.0)
60 (16)	0.2 (0.2)
100 (38)	0.5 (0.4)
125 (52)	0.7 (0.6)
150 (66)	0.9 (0.8)
175 (79)	1.1 (0.9)
200 (93)	1.3 (1.1)
225 (107)	1.5 (1.3)
250 (121)	1.7 (1.4)
300 (149)	2.2 (1.8)
350 (177)	2.6 (2.2)
400 (204)	3.0 (2.5)
450 (232)	3.5 (2.9)

832 EXPANSION AND FLEXIBILITY

832.1 Application

Section 832 is applicable to piping meeting the definition of unrestrained piping in para. 833.1(c).

832.2 Amount of Expansion or Contraction

The thermal expansion and contraction of the more common carbon and low alloy steels may be calculated using 6.5×10^{-6} in./in./°F (1.17×10^{-5} cm/cm/°C) as the coefficient of thermal expansion. The expansion or contraction to be considered is the difference between the maximum or minimum design temperatures and the expected average installation temperature. For more precise thermal expansion coefficients for specific materials, refer to authoritative source data, such as publications of the National Institute of Standards and Technology. A table containing approximate amounts of expansion or contraction per unit length for selected temperatures is provided in Table 832.2-1.

832.3 Flexibility Requirements

(a) Piping systems shall be designed to have sufficient flexibility to prevent thermal expansion or contraction from causing excessive stresses in the piping material, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment or at anchorage or guide points. Formal calculations shall be performed where reasonable doubt exists as to the adequate flexibility of the system. See para. 833.7 for further guidance.

(b) Flexibility shall be provided by the use of bends, loops, or offsets, or provision shall be made to absorb thermal changes by the use of expansion joints or couplings of the lip joints type or expansion joints of the bellows type. If expansion joints are used, anchors or ties of sufficient strength and rigidity shall be installed to provide for end forces due to fluid pressure and other causes.

(c) In calculating the flexibility of a piping system, the system shall be treated as a whole. The significance of all parts of the line and all restraints, such as rigid supports or guides, shall be considered.

(d) Calculations shall take into account stress intensification factors found to exist in components other than plain straight pipe. Credit may be taken for the extra flexibility of such components. The flexibility factors and stress intensification factors shown in Table E-1 may be used.

(e) Properties of pipe and fittings for these calculations shall be based on nominal dimensions, and the joint factor E shall be taken as 1.00.

(f) The total range in temperature from minimum design temperature to the maximum design temperature shall be considered in all expansion stress calculations, whether piping is cold-sprung or not. Should installation, start-up, or shutdown temperatures be outside of the design temperature range, the maximum possible temperature range shall be considered. In addition to the expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall be considered.

(g) Flexibility calculations shall be based on the modulus of elasticity corresponding to the lowest temperature of the operational cycle.

(h) In order to modify the effect of expansion and contraction, runs of pipe may be cold-sprung. Cold-spring may be taken into account in the calculations of the reactions, provided an effective method of obtaining the designed cold-spring is specified and used.

832.4 Reactions

(a) Reaction forces and moments to be used in the design of restraints and supports for a piping system, and in evaluating the effects of piping displacements on connected equipment shall consider the full range of thermal displacement conditions plus weight and external loads. Cold-spring may be useful for maintaining reactions within acceptable limits.

(b) The reactions for thermal displacements shall be calculated using the elastic modulus corresponding to the lowest temperature of an operational cycle.

(c) Consideration shall be given to the load-carrying capacity of attached rotating and pressure-containing equipment and the supporting structure.

Table 832.5-1 Modulus of Elasticity for Carbon and Low Alloy Steel

Temperature, °F (°C)	Modulus of Elasticity, psi × 10^6 (GPa)
−100 (−73)	30.2 (208)
70 (21)	29.5 (203)
200 (93)	28.8 (198)
300 (149)	28.3 (195)
400 (204)	27.7 (191)
500 (260)	27.3 (188)

832.5 Modulus of Elasticity

The modulus of elasticity for carbon and low alloy steel at various temperatures is given in Table 832.5-1. Values between listed temperatures may be linearly interpolated.

833 DESIGN FOR LONGITUDINAL STRESS

833.1 Restraint

(a) The restraint condition is a factor in the structural behavior of the pipeline. The degree of restraint may be affected by aspects of pipeline construction, support design, soil properties, and terrain. Section 833 is applicable to all steel piping within the scope of ASME B31.8. For purposes of design, this Code recognizes two axial restraint conditions, "restrained" and "unrestrained." Guidance in categorizing the restraint condition is given below.

(b) Piping in which soil or supports prevent axial displacement or flexure at bends is "restrained." Restrained piping may include the following:

(1) straight sections of buried piping

(2) bends and adjacent piping buried in stiff or consolidate soil

(3) sections of aboveground piping on rigid supports

(c) Piping that is freed to displace axially or flex at bends is "unrestrained." Unrestrained piping may include the following:

(1) aboveground piping that is configured to accommodate thermal expansion or anchor movements through flexibility

(2) bends and adjacent piping buried in soft or unconsolidated soil

(3) an unbackfilled section of otherwise buried pipeline that is sufficiently flexible to displace laterally or that contains a bend

(4) pipe subject to an end cap pressure force

833.2 Calculation of Longitudinal Stress Components

(a) The longitudinal stress due to internal pressure in restrained pipelines is

$$S_p = 0.3S_H$$

where S_H is the hoop stress, psi (MPa)

(b) The longitudinal stress due to internal pressure in unrestrained pipeline is

$$S_p = 0.5S_H$$

where S_H is the hoop stress, psi (MPa)

(c) The longitudinal stress due to thermal expansion in restrained pipe is

$$S_T = E\alpha(T_1 - T_2)$$

where

E = the elastic modulus, psi (MPa), at the ambient temperature

T_1 = the pipe temperature at the time of installation, tie-in, or burial, °F (°C)

T_2 = the warmest or coldest pipe operating temperature, °F (°C)

α = the coefficient of thermal expansion, 1/°F (1/°C)

If a section of pipe can operate either warmer or colder than the installed temperature, both conditions for T_2 may need to be examined.

(d) The nominal bending stress in straight pipe or large-radius bends due to weight or other external loads is

$$S_B = M/Z$$

where

M = the bending moment across the pipe cross section, lb-in. (N·m)

Z = the pipe section modulus, in.^{3} (cm^3)

(e) The nominal bending stress in fittings and components due to weight or other external loads is

$$S_B = M_R/Z$$

where M_R is the resultant intensified moment across the fitting or component. The resultant moment shall be calculated as

$$M_R = [(0.75i_i\,M_i)^2 + (0.75i_o\,M_o)^2 + M_t^2]^{1/2}, \text{ lb-in. (N·m)}$$

where

i_i = in-plane stress intensification factor from Mandatory Appendix E

i_o = out-of-plane stress intensification factor from Mandatory Appendix E

M_i = in-plane bending moment, lb-in. (N·m)

M_o = out-of-plane bending moment, lb-in. (N·m)
M_t = torsional moment, lb-in. (N·m)

The product $0.75i \geq 1.0$

(f) The stress due to axial loading other than thermal expansion and pressure is

$$S_X = R/A$$

where
A = pipe metal cross-sectional area, in.^{2} (mm^2)
R = external force axial component, lb (N)

833.3 Summation of Longitudinal Stress in Restrained Pipe

(a) The net longitudinal stresses in restrained pipe are

$$S_L = S_P + S_T + S_X + S_B$$

Note that S_B, S_L, S_T, or S_X can have negative values.

(b) The maximum permitted value of $|S_L|$ is $0.9ST$, where S is the specified minimum yield strength, psi (MPa), per para. 841.1.1(a), and T is the temperature derating factor per para. 841.1.8.

(c) Residual stresses from construction are often present; for example, bending in buried pipelines where spanning or differential settlement occurs. These stresses are often difficult to evaluate accurately, but can be disregarded in most cases. It is the engineer's responsibility to determine whether such stresses should be evaluated.

833.4 Combined Stress for Restrained Pipe

(a) The combined biaxial stress state of the pipeline in the operating mode is evaluated using the calculation in either (1) or (2) below:

(1) max. $\{|S_H - S_L|, |S_H|, |S_L|\}$ or

(2) $[S_L^2 - S_L S_H + S_H^2]^{1/2}$

The maximum permitted value for the combined biaxial stress is kST where S is the specified minimum yield strength, psi (MPa), per para. 841.1.1(a), T is the temperature derating factor per para. 841.1.8, and k is defined in (b) and (c) below.

(b) For loads of long duration, the value of k shall not exceed 0.90.

(c) For occasional nonperiodic loads of short duration, the value of k shall not exceed 1.0.

(d) S_L in (a) above is calculated considering both the tensile and compressive values of S_B.

(e) Stresses induced by loads that do not occur simultaneously need not be considered to be additive.

(f) The biaxial stress evaluation described above applies only to straight sections of pipe.

833.5 Design for Stress Greater Than Yield

(a) The limits in paras. 833.3 and 833.4 may be exceeded where due consideration is given to the ductility and strain capacity of seam weld, girth weld, and pipe body materials; and to the avoidance of buckles, swelling, or coating damage.

(b) The maximum permitted strain is limited to 2%.

833.6 Summation of Longitudinal Stresses in Unrestrained Pipe

(a) The net longitudinal stress in unrestrained pipe is

$$S_L = S_P + S_X + S_B, \text{ psi}$$

(b) The maximum permitted longitudinal stress in unrestrained pipe is $S_L \leq 0.75ST$, where S is the specified minimum yield strength, psi (MPa), per para. 841.1.1(a), and T is the temperature derating factor per para. 841.1.8.

833.7 Flexibility Analysis for Unrestrained Piping

(a) There is no need for formal flexibility analysis for an unrestrained piping system that

(1) duplicates or replaces without significant change a system operating with a successful record

(2) can be readily judged adequate by comparison with previously analyzed systems

(3) is of uniform size, has no more than two points of fixation and no intermediate restraints, and falls within the limitations of the following empirical equation

$$\frac{DY}{(L - U)^2} \leq K$$

where
D = nominal outside diameter of pipe, in. (mm)
K = 0.03, for U.S. Customary units (208, for SI units) listed in the equation above
L = developed length of piping between anchors, ft (m)
U = straight line separation between anchors, ft (m)
Y = resultant of total displacement strains, in. (mm), to be absorbed by the system

NOTE: No general proof can be offered that this empirical equation always yields conservative results. It is not applicable to systems used in severe cyclic conditions. It should be used with caution in configurations such as unequal leg U-bends having $L/U > 2.5$; or nearly-straight "saw-tooth" runs; or where $i \geq 5$ due to thin-walled design; or where displacements not in the direction connecting anchor points constitute a large part of the total displacement. There is no assurance that terminal reactions will be acceptably low even if a piping system falls within the limitations of (a)(3).

(b) Any piping system that does not meet one of the criteria in (a) should undergo a flexibility stress analysis by a simplified, approximate, or comprehensive method as deemed appropriate.

833.8 Flexibility Stresses and Stresses Due to Periodic or Cyclic Fatigue Loading

(a) The stress range in unrestrained piping due to thermal expansion and periodic, vibrational, or cyclic displacements or loads shall be computed as

$$S_E = M_E/Z$$

where M_E is the resultant intensified moment range from one stress state to another. The resultant intensified moment shall be calculated as

$$M_E = [(i_iM_i)^2 + (i_oM_o)^2 + M_t^2]^{1/2}, \text{ lb-in. (N·m)}$$

(b) The cyclic stress range $S_E \leq S_A$, where

$$S_A = f\,[1.25\,(S_c + S_h) - S_L]$$

$$f = 6N^{-0.2} \leq 1.0$$

N = equivalent number of cycles during the expected service life of the piping system
S_c = 0.33 S_uT at the minimum installed or operating temperature
S_h = 0.33 S_uT at the maximum installed or operating temperature
S_L = longitudinal stress calculated according to para. 833.6(a), psi (MPa)
S_u = specified minimum ultimate tensile strength, psi (MPa)
T = temperature derating factor per para. 841.1.8

(c) When the computed stress range varies, S_E is defined as the greatest computed stress range. The value of N in such cases can be calculated as

$$N = N_E + \Sigma\,[r_i^5 N_i] \text{ for } i = 1, 2, \ldots n$$

where
N_E = number of cycles of maximum computed stress range, S_E
N_i = number of cycles associated with stress range, S_i
r_i = S_i/S_E
S_i = any computed stress range smaller than S_E, psi (MPa)

833.9 Local Stresses

(a) High local stresses are usually generated at structural discontinuities and sites of local loadings. Although they may exceed the material yield strength, such stresses may often be disregarded because they are localized in influence and may be self-limiting or relieved by local deformation. Examples include stresses in branch connections caused by pressure or external loads, or stresses at structural discontinuities. This Code does not fully address the maximum allowable value for local stresses. It is the engineer's responsibility to determine whether such stresses must be evaluated.

(b) The maximum allowable sum of circumferential stress due to internal pressure and circumferential through-wall bending stress caused by surface vehicle loads or other local loads is 0.9ST, where S is the specified minimum yield strength, psi (MPa), per para. 841.1.1(a), and T is the temperature derating factor per para. 841.1.8.

(c) Local stresses in (a) or (b) caused by periodic or repetitive loads may require further limitations in consideration of fatigue.

833.10 Buckling and Lateral Instability

In order to prevent buckling in the form of wrinkling of the pipe wall or lateral instability, the maximum allowable net compressive stress is ⅔ of the critical buckling stress estimated using a suitable stability criterion.

834 SUPPORTS AND ANCHORAGE FOR EXPOSED PIPING

834.1 General

Piping and equipment shall be supported in a substantial and workmanlike manner, so as to prevent or reduce excessive vibration, and shall be anchored sufficiently to prevent undue strains on connected equipment.

834.2 Provision for Expansion

Supports, hangers, and anchors should be so installed as not to interfere with the free expansion and contraction of the piping between anchors. Suitable spring hangers, sway bracing, etc., shall be provided where necessary.

834.3 Materials, Design, and Installation

All permanent hangers, supports, and anchors shall be fabricated from durable incombustible materials and designed and installed in accordance with good engineering practice for the service conditions involved. All parts of the supporting equipment shall be designed and installed so that they will not be disengaged by movement of the supported piping.

834.4 Forces on Pipe Joints

(a) All exposed pipe joints shall be able to sustain the maximum end force, lb (N), due to the internal pressure, i.e., the design pressure, psig (kPa), times the internal area of the pipe, in.^{2} (mm^2), as well as any additional forces due to temperature expansion or contraction or to the weight of pipe and contents.

(b) If compression or sleeve-type couplings are used in exposed piping, provision shall be made to sustain the longitudinal forces noted in (a) above. If such provision is not made in the manufacture of the coupling, suitable bracing or strapping shall be provided, but such design must not interfere with the normal performance of the coupling nor with its proper maintenance. Attachments must meet the requirements of para. 834.5.

(16) ### 834.5 Attachment of Supports or Anchors

(a) If the pipe is designed to operate at a hoop stress of less than 50% of the specified minimum yield strength, structural supports or anchors may be welded directly to the pipe. Proportioning and welding strength requirements of such attachments shall conform to standard structural practice.

(b) If the pipe is designed to operate at a hoop stress of 50% or more of the specified minimum yield strength, structural supports or anchors shall not be welded directly to the pipe. Where it is necessary to provide a welded attachment, structural supports or anchors shall be welded to a member that fully encircles the pipe. The connection of the pipe to the encircling member shall be by continuous, rather than intermittent, welds or by use of a bolted or clamped mechanical connection.

835 ANCHORAGE FOR BURIED PIPING

835.1 General

Bends or offsets in buried pipe cause longitudinal forces that must be resisted by anchorage at the bend, by restraint due to friction of the soil, or by longitudinal stresses in the pipe.

835.2 Anchorage at Bends

If the pipe is anchored by bearing at the bend, care shall be taken to distribute the load on the soil so that the bearing pressure is within safe limits for the soil involved.

835.3 Restraint Due to Soil Friction

Where there is doubt as to the adequacy of restraint friction, calculations shall be made, and indicated anchoring shall be installed.

835.4 Forces on Pipe Joints

If anchorage is not provided at the bend (see para. 835.2), pipe joints that are close to the points of thrust origin shall be designed to sustain the longitudinal pullout force. If such provision is not made in the manufacture of the joints, suitable bracing or strapping shall be provided.

835.5 Supports for Buried Piping

(a) In pipelines, especially those that are highly stressed from internal pressure, uniform and adequate support of the pipe in the trench is essential. Unequal settlements may produce added bending stresses in the pipe. Lateral thrusts at branch connections may greatly increase the stresses in the branch connection itself, unless the fill is thoroughly consolidated or other provisions are made to resist the thrust.

(b) Rock shield shall not be draped over the pipe unless suitable backfill and padding are placed in the ditch to provide a continuous and adequate support of the pipe in the trench.

(c) When openings are made in a consolidated backfill to connect new branches to an existing line, care must be taken to provide firm foundation for both the header and the branch to prevent vertical and lateral movements.

835.6 Interconnection of Underground Lines

Underground lines are subjected to longitudinal stresses due to changes in pressure and temperature. For long lines, the friction of the earth will prevent changes in length from these stresses, except for several hundred feet adjacent to bends or ends. At these locations, the movement, if unrestrained, may be of considerable magnitude. If connections are made at such a location to a relatively unyielding line or other fixed object, it is essential that the interconnection shall have ample flexibility to compensate for possible movement, or the line shall be provided with an anchor sufficient to develop the forces necessary to limit the movement.

Chapter IV
Design, Installation, and Testing

840 DESIGN, INSTALLATION, AND TESTING

840.1 General Provisions

(a) The design requirements of this Code are intended to be adequate for public safety under all conditions encountered in the gas industry. Conditions that may cause additional stress in any part of a line or its appurtenances shall be provided for, using good engineering practice. Examples of such conditions include long self-supported spans, unstable ground, mechanical or sonic vibration, weight of special attachments, earthquake-induced stresses, stresses caused by temperature differences, and the soil and temperature conditions found in the Arctic. Temperature differences shall be taken as the difference between the lowest and highest expected metal temperature during pressure test and/or operating services having due regard to past recorded temperature data and the possible effects of lower or higher air and ground temperature.

(b) The quality of the gas to be transported in the pipeline, or by the pipeline system, shall be considered when designing facilities. Measures shall be taken to control or minimize adverse effects of the gas properties or gas composition when any of the following may be a concern:

(1) Gas Composition. Uncontrolled or unexpected variations in heating value may result in problems at the end user's burner tip or process. Noncombustible compounds (e.g., nitrogen, nitrogen compounds, carbon dioxide, etc.) may reduce the heating value and increase the specific gravity of the gas stream. Carbon dioxide contributes to internal corrosion in the presence of free water. Increased specific gravity of the gas stream may foretell the condensing of heavy hydrocarbons at cooler temperatures which may negatively affect operations. A change in specific gravity may affect pipeline and compressor capacity calculations. For effects of heavy hydrocarbons on the design of pipe for ductile fracture arrest, see the "Caution" at the end of para. 841.1.1.

(2) Hydrogen Sulfide Content. Hydrogen sulfide is highly toxic and contributes to corrosion in the presence of water. Refer to Chapter IX, Sour Gas Service, for specific provisions related to hydrogen sulfide.

(3) Oxygen Content. Oxygen contributes to corrosion problems in the presence of free water at certain temperatures. Certain mixtures of oxygen and gas above the lower explosive limit can create an explosive condition. (See section 864 and paras. 841.2.7 and 850.6.)

(4) Water Vapor Content and Free Liquids. Free water and hydrocarbons at certain combinations of pressures and temperatures may produce hydrates, which are crystalline solids that may cause partial or complete pipeline blockages, that may lead to a disruption of pipeline operations.

Based on the characteristics of the gas stream (i.e., heating value, specific gravity, temperature, free liquid, odorization, impurities, and other objectionable substances), appropriate precautions shall be considered to address any problems that might adversely affect the pipeline system or the end user.

(c) The most significant factor contributing to the failure of a gas pipeline is damage to the line caused by the activities of people along the route of the line. Damage will generally occur during construction of other facilities associated with providing the services associated with human dwellings and commercial or industrial enterprises. These services, such as water, gas and electrical supply, sewage systems, drainage lines and ditches, buried power and communication cables, streets and roads, etc., become more prevalent and extensive, and the possibility of damage to the pipeline becomes greater with larger concentrations of buildings intended for human occupancy. Determining the Location Class provides a method of assessing the degree of exposure of the line to damage.

(d) A pipeline designed, constructed, and operated in accordance with the requirements of Location Class 1 [see para. 840.2.2(a)] is basically safe for pressure containment in any location; however, additional measures are necessary to protect the integrity of the line in the presence of activities that might cause damage. One of the measures required by this Code is to lower the stress level in relation to increased public activity. This activity is quantified by determining Location Class and relating the design of the pipeline to the appropriate design factor.

(e) Early editions of this Code used the term "population density index" to determine design, construction, testing, and operation requirements. They also used the term "Location Class" in prescribing design pressure, type of construction, and maximum allowable operating pressure. To simplify use of this Code, the term "population density index" was eliminated. Construction Types A, B, C, and D were eliminated and replaced with the same terminology used for design–location class.

(f) The requirements based on Location Class were such that there were no significant changes in the design, installation, testing, and operation of piping systems due to changes in terminology.

(g) Pipelines constructed prior to the publication of this Edition and designed in accordance with Location Classes established in compliance with previous editions of this Code may continue to use the Location Classes so determined, provided that when observed increases in the number of buildings intended for human occupancy occur, the Location Class determination shall be as presented in para. 840.2.

840.2 Buildings Intended for Human Occupancy

840.2.1 General

(a) To determine the number of buildings intended for human occupancy for an onshore pipeline, lay out a zone $\frac{1}{4}$-mi (0.4-km) wide along the route of the pipeline with the pipeline on the centerline of this zone, and divide the pipeline into random sections 1 mi (1.6 km) in length such that the individual lengths will include the maximum number of buildings intended for human occupancy. Count the number of buildings intended for human occupancy within each 1-mi (1.6-km) zone. For this purpose, each separate dwelling unit in a multiple dwelling unit building is to be counted as a separate building intended for human occupancy.

(b) It is not intended here that a full 1 mi (1.6 km) of lower stress level pipeline shall be installed if there are physical barriers or other factors that will limit the further expansion of the more densely populated area to a total distance of less than 1 mi (1.6 km). It is intended, however, that where no such barriers exist, ample allowance shall be made in determining the limits of the lower stress design to provide for probable further development in the area.

(c) When a cluster of buildings intended for human occupancy indicates that a basic 1 mi (1.6 km) of pipeline should be identified as a Location Class 2 or Location Class 3, the Location Class 2 or Location Class 3 may be terminated 660 ft (200 m) from the nearest building in the cluster.

(d) For pipelines shorter than 1 mi (1.6 km) in length, a Location Class that is typical of the Location Class that would be required for 1 mi (1.6 km) of pipeline traversing the area shall be assigned.

840.2.2 Location Classes for Design and Construction

(a) *Location Class 1.* A Location Class 1 is any 1-mi (1.6-km) section that has 10 or fewer buildings intended for human occupancy. A Location Class 1 is intended to reflect areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.

(1) *Class 1, Division 1.* This Division is a Location Class 1 where the design factor of the pipe is greater than 0.72 but equal to or less than 0.80. (See Table 841.1.6-2 for exceptions to design factor.)

(2) *Class 1, Division 2.* This Division is a Location Class 1 where the design factor of the pipe is equal to or less than 0.72. (See Table 841.1.6-2 for exceptions to design factor.)

(b) *Location Class 2.* A Location Class 2 is any 1-mi (1.6-km) section that has more than 10 but fewer than 46 buildings intended for human occupancy. A Location Class 2 is intended to reflect areas where the degree of population is intermediate between Location Class 1 and Location Class 3, such as fringe areas around cities and towns, industrial areas, ranch or country estates, etc.

(c) *Location Class 3.* A Location Class 3 is any 1-mi (1.6-km) section that has 46 or more buildings intended for human occupancy except when a Location Class 4 prevails. A Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.

(d) *Location Class 4.* Location Class 4 includes areas where multistory buildings are prevalent, where traffic is heavy or dense, and where there may be numerous other utilities underground. Multistory means four or more floors aboveground including the first or ground floor. The depth of basements or number of basement floors is immaterial.

840.3 Considerations Necessary for Concentrations of People in Location Class 1 or 2

(a) In addition to the criteria contained in para. 840.2, additional consideration must be given to the possible consequences of a failure near areas where a concentration of people is likely, such as a church, school, multiple dwelling unit, hospital, or recreational area of an organized character in Location Class 1 or 2.

If the facility is used infrequently, the requirements of (b) need not be applied.

(b) Pipelines near places of public assembly or concentrations of people, such as churches, schools, multiple dwelling unit buildings, hospitals, or recreational areas of an organized nature in Location Class 1 or 2 shall meet requirements for Location Class 3.

(c) Concentrations of people referred to in (a) and (b) above are not intended to include groups of fewer than 20 people per instance or location but are intended to cover people in an outside area as well as in a building.

840.4 Intent

(a) It should be emphasized that Location Class (1, 2, 3, or 4) as described in the previous paragraphs is defined as the general description of a geographic area having certain characteristics as a basis for prescribing the types of design, construction, and methods of testing to be used in those locations or in areas that are comparable. A numbered Location Class, such as Location Class 1, refers only to the geography of that location or a similar area and does not necessarily indicate that a design factor of 0.72 will suffice for all construction in that particular location or area [e.g., in Location Class 1, all aerial crossings require a design factor of 0.6; see para. 841.1.9(b)].

(b) When classifying locations for determining the design factor for pipeline construction and testing that should be prescribed, due consideration shall be given to the possibility of future development of the area. If at the time of planning a new pipeline this future development appears likely to be sufficient to change the Location Class, this shall be taken into consideration in the design and testing of the proposed pipeline.

841 STEEL PIPE

841.1 Steel Piping Systems Design Requirements

841.1.1 Steel Pipe Design Formula

(a) The design pressure for steel gas piping systems or the nominal wall thickness for a given design pressure shall be determined by the following formula (for limitations, see para. 841.1.3):

(U.S. Customary Units)

$$P = \frac{2St}{D} FET$$

(SI Units)

$$\left(P = \frac{2\,000St}{D} FET\right)$$

where

D = nominal outside diameter of pipe, in. (mm)
E = longitudinal joint factor obtained from Table 841.1.7-1 [see also para. 817.1.3(d)]
F = design factor obtained from Table 841.1.6-1. In setting the values of the design factor, F, due consideration has been given and allowance has been made for the various underthickness tolerances provided for in the pipe specifications listed and approved for usage in this Code.
P = design pressure, psig (kPa) (see also para. 841.1.3)
S = specified minimum yield strength, psi (MPa), stipulated in the specifications under which the pipe was purchased from the manufacturer or determined in accordance with paras. 817.1.3(h) and 841.1.4. The specified minimum yield strengths of some of the more commonly used piping steels whose specifications are incorporated by reference herein are tabulated for convenience in Mandatory Appendix D.
T = temperature derating factor obtained from Table 841.1.8-1
t = nominal wall thickness, in. (mm)

CAUTION: This cautionary note is nonmandatory. Steel pipe may exhibit pronounced differences in strength between the longitudinal and circumferential directions. The orientation of the strength test is established by the pipe product specification depending on pipe size and method of pipe making. Consequently, pipe may have a qualified strength in an axis orientation that does not conform to the orientation of the principal loading or stress. The user is alerted to be aware of the standard test orientation used to determine conformance of pipe to the minimum strength requirement of the selected grade, and to consider whether the intended uses or anticipated service conditions of the pipeline system warrant supplemental testing of the strength properties in other orientations.

(b) The design factor for pipelines in Location Class 1, Division 1 is based on gas pipeline operational experience at operation levels in excess of those previously recommended by this Code.

It should be noted that the user may be required to change out such pipe or reduce pressure to 0.72 SMYS maximum in accordance with para. 854.2.

841.1.2 Fracture Control and Arrest (16)

(a) Fracture Toughness Criterion. A fracture toughness criterion or other method shall be specified to control fracture propagation when one of the following is true:

(1) a pipeline is designed to operate either at a hoop stress over 40% through 80% of SMYS in sizes NPS 16 (DN 400) or larger

(2) a pipeline is designed to operate at a hoop stress over 72% through 80% of SMYS in sizes smaller than NPS 16 (DN 400)

(3) a pipeline is designed with a minimum design temperature below −20°F (−29°C) as outlined in section 812

When a fracture toughness criterion is used, control can be achieved by ensuring that the pipe has adequate ductility and by either specifying adequate toughness or installing crack arrestors on the pipeline to stop propagation.

(b) Brittle Fracture Control. To ensure that the pipe has adequate ductility, fracture toughness testing shall be performed in accordance with the testing procedures of supplementary requirements SR5 or SR6 of API 5L (43rd edition) or Annex G of API 5L (45th edition), or other equivalent alternatives. If the operating temperature is below 50°F (10°C), an appropriate lower test temperature shall be used when determining adherence to the minimum impact values in (c) and shear appearance as outlined below. The appropriate lower test temperature shall be taken to be at or below the lowest expected metal temperature during pressure testing (if with air or gas) and during service, having regard to past recorded temperature data and possible effects of lower air and ground temperatures. The average shear value of the fracture appearance of three Charpy specimens from

each heat shall not be less than 60%, and the all-heat average for each order per diameter, size, and grade shall not be less than 80%. Alternatively, when drop-weight tear testing is specified, at least 80% of the heats shall exhibit a fracture appearance shear area of 40% or more at the specified test temperature.

(c) Ductile Fracture Arrest. To ensure that the pipeline has adequate toughness to arrest a ductile fracture, the pipe shall be tested in accordance with the procedures of supplementary requirements SR5 of API 5L (43rd edition) or Annex G of API 5L (45th edition). The all-heat average of the Charpy energy values shall meet or exceed the energy value calculated using one of the following equations that have been developed in various pipeline research programs:

(U.S. Customary Units)

(1) Battelle Columbus Laboratories (BCL) (AGA)

$$CVN = 1.08 \times 10^{-2} \sigma^2 R^{1/3} t^{1/3}$$

(2) American Iron and Steel Institute (AISI)

$$CVN = 3.39 \times 10^{-2} \sigma^{3/2} R^{1/2}$$

(SI Units)

(3) Battelle Columbus Laboratories (BCL) (AGA)

$$CVN = 3.57 \times 10^{-5} \sigma^2 R^{1/3} t^{1/3}$$

(4) American Iron and Steel Institute (AISI)

$$CVN = 5.04 \times 10^{-4} \sigma^{3/2} R^{1/2}$$

where

CVN = full-size Charpy V-notch absorbed energy, ft-lb (J)

R = pipe radius, in. (mm)

t = nominal wall thickness, in. (mm)

σ = maximum allowable hoop stress, ksi (MPa)

For API 5L pipe, the minimum impact values shall be the greater of those given by the equations above or those required by API 5L for PSL 2 pipe. Annex G of API 5L (45th edition) contains additional acceptable methodologies for establishing minimum or all heat average Charpy energy values.

For pipe manufactured to other standards where the minimum impact values are specified within that standard, those minimum requirements shall be maintained. In cases where the pipe manufacturing standard does not specify the minimum impact requirements, the minimum impact requirements of API 5L (45th edition) shall be utilized.

(d) Mechanical Crack Arrestors. Mechanical crack arrestors consisting of sleeves, wire-rope wrap, heavy-wall pipe, or other suitable types have been shown to provide reliable methods of arresting ductile fracture. The mechanical crack arrestors shall be placed at intervals along the pipeline.

CAUTION: The requirements specified in (c), Ductile Fracture Arrest, assume the pipeline is transporting essentially pure methane and the pipe is similar in fracture behavior to that used to develop the empirical equations above. The presence of heavier hydrocarbons can cause the gas to exhibit two-phase behavior on sudden decompression and thus requires a greater Charpy energy to arrest propagating pipe fracture. Likewise, pipe with heavy wall thickness greater than 1.25 in. (32 mm) or that has been control rolled or quench and tempered may not behave as indicated by the equations and may also require a greater Charpy energy to arrest a propagating fracture. Calculations must be performed to determine if the decompression exhibits two-phase behavior, and an assessment must be made as to the applicability of the arrest equations where additional toughness may be required. Otherwise, mechanical crack arrestors [see (d) above] should be installed, or the Charpy toughness requirements for arrest should be verified through experiments or additional calculations.

NOTE: The empirical equations specified in (c), Ductile Fracture Arrest, were developed utilizing conventional line pipe wall thicknesses. The user of this Code is advised that lowering of the test temperature to below the minimum design temperature is sometimes necessary to accurately simulate the performance of materials when the pipe wall thickness is significantly greater than the size of the test specimens.

841.1.3 Limitations on Design Pressure, *P*, in Para. 841.1.1. The design pressure obtained by the formula in para. 841.1.1 shall be reduced to conform to the following:

(a) P for furnace buttwelded pipe shall not exceed the restrictions of para. 841.1.1 or 60% of mill test pressure, whichever is the lesser.

(b) P shall not exceed 85% of the mill test pressure for all other pipes provided; however, that pipe, mill tested to a pressure less than 85% of the pressure required to produce a hoop stress equal to the specified minimum yield, may be retested with a mill type hydrostatic test or tested in place after installation. In the event the pipe is retested to a pressure in excess of the mill test pressure, then P shall not exceed 85% of the retest pressure rather than the initial mill test pressure. It is mandatory to use a liquid as the test medium in all tests in place after installation where the test pressure exceeds the mill test pressure. This paragraph is not to be construed to allow an operating pressure or design pressure in excess of that provided for by para. 841.1.1.

841.1.4 Limitations on Specified Minimum Yield Strength, *S*, in Para. 841.1.1

(a) If the pipe under consideration is not new pipe purchased under a specification approved and listed in this Code, the value of S may be determined in accordance with one of the following:

(1) S value for new pipe qualified under para. 811.2.2(a) or 811.2.2(b)

(2) S value for reuse of steel pipe qualified under one of the provisions of para. 817.1

(3) S value for pipe of unknown specification as determined by para. 817.1.3(h)

Table 841.1.6-1 Basic Design Factor, *F*

Location Class	Design Factor, *F*
Location Class 1, Division 1	0.80
Location Class 1, Division 2	0.72
Location Class 2	0.60
Location Class 3	0.50
Location Class 4	0.40

(b) When pipe that has been cold worked for meeting the specified minimum yield strength is subsequently heated to a temperature higher than 900°F (482°C) for any period of time or over 600°F (316°C) for more than 1 hr, the maximum allowable pressure at which it can be used shall not exceed 75% of the value obtained by use of the steel pipe design formula given in para. 841.1.1.

(c) In no case where the Code refers to the specified minimum value of a mechanical property shall the higher actual value of a property be substituted in the steel pipe design formula given in para. 841.1.1. If the actual value is less than the specified minimum value of a mechanical property, the actual value may be used where it is permitted by the Code, such as in para. 817.1 regarding the reuse of steel pipe.

(16) **841.1.5 Additional Requirements for Nominal Wall Thickness, *t*, in Para. 841.1.1**

(a) The nominal wall thickness, *t*, required for pressure containment as determined by para. 841.1.1 may not be adequate for other forces to which the pipeline may be subjected. [See para. 840.1(a).] Consideration shall also be given to loading due to transportation or handling of the pipe during construction, weight of water during testing, and soil loading and other secondary loads during operation. [See para. 841.1.11(e) for suggested methods to provide additional protection.] Consideration should also be given to welding or mechanical joining requirements. Standard wall thickness, as prescribed in ASME B36.10M, shall be the least nominal wall thickness used for threaded and grooved pipe.

(b) Transportation, installation, or repair of pipe shall not reduce the wall thickness at any point to a thickness less than 90% of the nominal wall thickness as determined by para. 841.1.1 for the design pressure to which the pipe is to be subjected.

841.1.6 Design Factors, *F*, and Location Classes. The design factor in Table 841.1.6-1 shall be used for the designated Location Class. All exceptions to basic design factors to be used in the design formula are given in Table 841.1.6-2.

841.1.7 Longitudinal Joint Factor. The longitudinal joint factor shall be in accordance with Table 841.1.7-1.

841.1.8 Temperature Derating Factor. The temperature derating factor shall be in accordance with Table 841.1.8-1.

841.1.9 Additional Design Information or Instructions

(a) Fabricated Assemblies. When fabricated assemblies, such as connections for separators, main line valve assemblies, cross connections, river crossing headers, etc., are to be installed in areas defined in Location Class 1, a design factor of 0.6 is required throughout the assembly and for a distance equal to the lesser of 5 diameters or 10 ft (3 m) in each direction beyond the last fitting. A shorter distance may be used provided that combined stresses are considered in the design of the installation. Transition pieces at the end of an assembly and elbows used in place of pipe bends are not considered fittings under the requirements of this paragraph. Also see section 822.

(b) Pipelines or Mains on Bridges. The design factor for pipelines or mains supported by railroad, vehicular, pedestrian, or pipeline bridges shall be determined in accordance with the Location Class prescribed for the area in which the bridge is located. In Location Class 1, however, a design factor of 0.6 shall be used.

(c) Decompression Cooling. When reduction of pressure due to depressurization is anticipated to result in a significant reduction in the temperature of the piping system or any portion thereof, the user of this Code is cautioned to evaluate the effects of decompression and associated cooling on material serviceability and induced stresses.

(d) Design of Metering and Pressure/Flow Control

(1) All piping and piping components, up to and including the outlet stop valve(s) of individual meter and pressure/flow control runs, shall meet or exceed the maximum design pressure of the inlet piping system. Threaded reducing bushings should not be used in pressure/flow control facilities where they are subject to high frequency piping vibrations. The design requirements of para. 840.3 and Table 841.1.6-2 apply to the design requirements of this section.

(2) All piping shall be tested in accordance with para. 841.3 and the Location Class requirements of Table 841.1.6-2. Instrumentation devices such as transmitters, recorders, controllers, etc., excluding testing instrumentation, should be isolated from the piping during the test. Test fluids shall be removed from piping and piping components and the piping purged with natural gas before placing the facilities in service.

(3) The corrosion control measures in Chapter VI, as appropriate, must be applied to meter and pressure/flow control piping.

(e) Metering Facilities. Particular consideration and attention shall be given to sizing meter run blowdowns and/or flow-restricting plates for turbine and positive displacement meters. Rapid depressurization of meter

(16)

Table 841.1.6-2 Design Factors for Steel Pipe Construction

Facility	Location Class 1 Div. 1	Location Class 1 Div. 2	Location Class 2	Location Class 3	Location Class 4
Pipelines, mains, and service lines [see para. 840.2.2]	0.80	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surface and railroads	0.60	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surface and railroads	0.72	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:					
(a) Private roads	0.80	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.80	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surface and railroads	0.60	0.60	0.60	0.50	0.40
Fabricated assemblies [see para. 841.1.9(a)]	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges [see para. 841.1.9(b)]	0.60	0.60	0.60	0.50	0.40
Pressure/flow control and metering facilities [see para. 841.1.9(d)]	0.60	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.50	0.40
Liquid separators constructed of pipe and fittings without internal welding [see para. 843.3.1(b)]	0.40	0.40	0.40	0.40	0.40
Near concentration of people in Location Classes 1 and 2 [see para. 840.3(b)]	0.50	0.50	0.50	0.50	0.40

Table 841.1.7-1 Longitudinal Joint Factor, *E*

Spec. No.	Pipe Class	*E* Factor
ASTM A53	Seamless	1.00
	Electric-resistance-welded	1.00
	Furnace-buttwelded, continuous weld	0.60
ASTM A106	Seamless	1.00
ASTM A134	Electric-fusion arc-welded	0.80
ASTM A135	Electric-resistance-welded	1.00
ASTM A139	Electric-fusion arc-welded	0.80
ASTM A333	Seamless	1.00
	Electric-resistance-welded	1.00
ASTM A381	Submerged-arc-welded	1.00
ASTM A671	Electric-fusion-welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
ASTM A672	Electric-fusion-welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
ASTM A691	Electric-fusion-welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
ASTM A984	Electric-resistance-welded	1.00
ASTM A1005	Double submerged-arc-welded	1.00
ASTM A1006	Laser beam welded	1.00
API 5L	Electric welded	1.00
	Seamless	1.00
	Submerged-arc-welded (longitudinal seam or helical seam)	1.00
	Furnace-buttwelded, continuous weld	0.60

GENERAL NOTE: Definitions for the various classes of welded pipe are given in para. 804.7.3.

Table 841.1.8-1 Temperature Derating Factor, *T*, for Steel Pipe

Temperature, °F (°C)	Temperature Derating Factor, *T*
250 (121) or lower	1.000
300 (149)	0.967
350 (177)	0.933
400 (204)	0.900
450 (232)	0.867

GENERAL NOTE: For intermediate temperatures, interpolate for derating factor.

runs can damage or destroy meters due to meter overspin and high differentials and can endanger personnel.

(f) Other (Nonmandatory) Considerations for Metering Facilities

(1) Meter proving reduces measurement uncertainty. Where meter design, size, and flow rate allows, consider installing meter proving taps.

(2) Upstream dry gas filter(s) should be considered when installing rotary or turbine meters. Particulates and pipeline dust can contaminate meter lubricating oil and damage bearings and other internal meter components.

(g) Pressure/Flow Control Facilities

(1) Overpressure protection shall be provided by the use of

(-a) a monitor regulator in series with a controlling regulator (each regulator run).

(-b) adequately sized relief valve(s) downstream of the controlling regulator(s).

(-c) overpressure shutoff valve(s) *upstream* or downstream of the controlling regulator(s). Installation of alarm devices that indicate primary (controlling) regulator failure is useful and should be considered for monitoring regulator systems.

(2) Each regulator supply, control, and sensing line shall have a separate isolation valve for isolation purposes during regulator setup and maintenance and to prevent a safety device (i.e., monitor, regulator) from becoming unintentionally inoperable due to plugging or freezing of instrument lines.

(3) Steps shall be taken to prevent the freezing-up (internal and external) of regulators, control valves, instrumentation, pilot controls, and valve actuation equipment caused by moisture saturated instrument air or gas, pipeline gas, or external ambient conditions.

(4) Sound pressure levels of 110 dBA and greater shall be avoided to prevent damage to control equipment and piping.

(5) Gas velocities in piping should not exceed 100 ft/sec (30 m/s) at peak conditions. Lower velocities are recommended. High gas velocities in piping increase turbulence and pressure drop and contribute to excessive sound pressure levels (aerodynamic noise) and can cause internal piping erosion.

(h) Other (Nonmandatory) Considerations for Pressure/Flow Control Facilities

(1) Filtration of gas, particularly for instrumentation, instrument regulators, etc., should be considered where particulate contaminants are a present or potential problem.

(2) Installation of conical reducers immediately downstream of a regulator or control valve will allow a more gradual expansion of gas to larger piping and reduce turbulence and pressure drop during gas expansion.

(i) Electrical Facilities and Electronic Equipment for Pressure/Flow Control and Metering Facilities

(1) All electrical equipment and wiring installed in pressure/flow control facilities and metering facilities shall conform to the requirements of NFPA 70 and other applicable electrical codes. Additional API and AGA references are listed in Nonmandatory Appendix C.

(2) Electronic control, monitoring, and gas measurement equipment shall be properly grounded and isolated from piping to help prevent overpressure/accidental shutoff situations caused by equipment failure due to lightning strikes and electrical transients and to prevent safety hazards caused by fault currents. Electrical isolation equipment for corrosion control purposes should not be installed in buildings unless specifically designed to be used in combustible atmospheres.

(3) Uninterruptible power sources or redundant backup systems should be considered to help prevent overpressure/unintentional shutoff situations caused by power outages.

(4) A useful reference for electronic gas measurements is API Manual of Petroleum Measurement Standards, Chapter 21 — Flow Measurement Using Electronic Metering Systems, Section 1 — Electronic Gas Measurement.

(j) Pipeline Installation by Directional Drilling

(1) Qualifications. Drilling contractors shall maintain written design and installation procedures addressing crossings to be completed by the directional drilling method. Drilling equipment operators and personnel responsible for establishing the location of the pilot head and reamer during drilling operations shall be qualified by training and experience in the implementation of the contractor's procedures.

(2) Geotechnical Evaluations. Geotechnical evaluations should be considered at the crossing location to establish subsurface conditions.

(3) Installation Forces and Stresses. Loads on, and stresses in, the pipe string during installation shall be evaluated to ensure protection of the pipe against yielding, buckling, collapse, and undesired movement of the pipe string due to the combined effects of external pressure, friction, axial forces, and bending. (See directional drilling references in Nonmandatory Appendix C.)

(4) Protective Coating. The frictional and abrasive forces that may be exerted on the pipe coating during installation shall be considered when specifying the type of coating system to be applied to the pipe and weld joints. During installation, care shall be taken to protect the quality and integrity of the external corrosion coating.

(5) Additional Evaluation Measures. In addition to the minimum inspection and post-inspection testing requirements of this Code, consideration shall be given to performing the following additional measures on the pipe string:

(-a) nondestructive examination of 100% of all circumferential welds prior to installation

(-b) pressure testing (pretest) of the fabricated pipe string prior to installation

(-c) passing an internal sizing plate, caliper tool, or instrumented inspection device through the pipe string following installation

(6) Damage Prevention. To minimize the potential for damage to existing surface or subsurface structures, design of the crossing plan and profile shall consider the accuracy of the methods to be employed in locating existing structures, maintaining required clearances from existing structures, tracking the position of the pilot head and reamer during drilling operations, and tracking of the reamer during pullback.

Prior to the commencement of drilling operations, the location of all subsurface structures in near proximity to the design drill path shall, where practical, be exposed to permit a visual confirmation of the structure's location.

Prior to initiating the reaming operation, consideration shall be given to the potential impact of the operation on all adjacent structures due to any realized deviations from the design path.

(k) Other (Nonmandatory) Considerations for Pressure Cycle Fatigue of Longitudinal Pipe Seams. Line pipe longitudinal seams are not generally regarded as susceptible to fatigue due to operational pressure cycles in most natural gas service. Evaluation of the potential for fatigue crack growth due to pressure cycles is recommended for pipe containing longitudinal seams where the expected lifetime accumulation of full MAOP cycles may exceed the following number of occurrences:

(U.S. Customary Units)

$$N = \frac{6.0 \times 10^{17}}{(F \times S)^3 \times t^{0.5}}$$

(SI Units)

$$\left(N = \frac{9.8 \times 10^{11}}{(F \times S)^3 \times t^{0.5}} \right)$$

where

F = design factor from Table 841.1.6-1

N = equivalent number of cycles during the expected service life of the piping system

S = specified minimum yield strength, psi (MPa), stipulated in the specification under which the pipe was purchased from the manufacturer or determined in accordance with paras. 817.1.3(h) and 841.1.4

t = nominal wall thickness, in. (mm)

The pipeline is considered not susceptible to fatigue in the longitudinal seams due to pressure cycles if the pipeline has been exposed to a hydrostatic test at a pressure level at least 1.25 times the MAOP, and the expected lifetime accumulation of full-MAOP cycles is

N or fewer, or the design factor, *F*, is 0.4 or less. For purposes of applying this screening criterion, pressure cycles larger than 50% of the MAOP in magnitude should be counted as full-MAOP cycles. Seam welds that are not oriented parallel to the longitudinal axis of the pipe are exempt from the evaluation.

841.1.10 Protection of Pipelines and Mains From Hazards

(a) When pipelines and mains must be installed where they will be subject to natural hazards, such as washouts, floods, unstable soil, landslides, earthquake-related events (such as surface faulting, soil liquefaction, and soil and slope instability characteristics), or other conditions that may cause serious movement of, or abnormal loads on, the pipeline, reasonable precautions shall be taken to protect the pipeline, such as increasing the wall thickness, constructing revetments, preventing erosion, and installing anchors.

(b) Where pipelines and mains cross areas that are normally under water or subject to flooding (i.e., lakes, bays, or swamps), sufficient weight or anchorage shall be applied to the line to prevent flotation.

(c) Because submarine crossings may be subject to washouts due to the natural hazards of changes in the waterway bed, water velocities, deepening of the channel, or changing of the channel location in the waterway, design consideration shall be given to protecting the pipeline or main at such crossings. The crossing shall be located in the more stable bank and bed locations. The depth of the line, location of the bends installed in the banks, wall thickness of the pipe, and weighting of the line shall be selected based on the characteristics of the waterway.

(d) Where pipelines and mains are exposed, such as at spans, trestles, and bridge crossings, the pipelines and mains shall be reasonably protected by distance or barricades from accidental damage by vehicular traffic or other causes.

841.1.11 Cover, Clearance, and Casing Requirements for Buried Steel Pipelines and Mains

(a) Cover Requirements for Mains. Buried mains shall be installed with a cover not less than 24 in. (610 mm). Where this cover provision cannot be met, or where external loads may be excessive, the main shall be encased, bridged, or designed to withstand any such anticipated external loads. Where farming or other operations might result in deep plowing, in areas subject to erosion, or in locations where future grading is likely, such as road, highway, railroad, and ditch crossings, additional protection shall be provided. [See (e) for suggested methods to provide additional protection.]

(b) Cover Requirements for Pipelines. Except for offshore pipelines, buried pipelines shall be installed with a cover not less than that shown in Table 841.1.11-1.

Table 841.1.11-1 Pipeline Cover Requirements

Location	Cover, in. (mm)		
		For Rock Excavation [Note (1)]	
	For Normal Excavation	Pipe Size NPS 20 (DN 500) and Smaller	Pipe Size Larger Than NPS 20 (DN 500)
Class 1	24 (610)	12 (300)	18 (460)
Class 2	30 (760)	18 (460)	18 (460)
Classes 3 and 4	30 (760)	24 (610)	24 (610)
Drainage ditch at public roads and railroad crossings (all locations)	36 (910)	24 (610)	24 (610)

NOTE:
(1) Rock excavation is excavation that requires blasting.

Where these cover provisions cannot be met or where external loads may be excessive, the pipeline shall be encased, bridged, or designed to withstand any such anticipated external loads. In areas where farming or other operations might result in deep plowing, in areas subject to erosion, or in locations where future grading is likely, such as at roads, highways, railroad crossings, and ditch crossings, additional protection shall be provided. [See (e) for suggested methods to provide additional protection.]

(c) Clearance Between Pipelines or Mains and Other Underground Structures

(1) There shall be at least 6 in. (150 mm) of clearance wherever possible between any buried pipeline and any other underground structure not used in conjunction with the pipeline. When such clearance cannot be attained, precautions to protect the pipe shall be taken, such as the installation of casing, bridging, or insulating material.

(2) There shall be at least 2 in. (50 mm) of clearance wherever possible between any buried gas main and any other underground structure not used in conjunction with the main. When such clearance cannot be attained, precautions to protect the main shall be taken, such as the installation of insulating material or casing.

(d) Casing Requirements Under Railroads, Highways, Roads, or Streets. Casings shall be designed to withstand the superimposed loads. Where there is a possibility of water entering the casing, the ends of the casing shall be sealed. If the end sealing is of a type that will retain the maximum allowable operating pressure of the carrier pipe, the casing shall be designed for this pressure and at least to the design factor of 0.72. Venting of sealed casings is not mandatory; however, if vents are installed they should be protected from the weather to prevent

water from entering the casing. (Requirements for crossings within casing of railroads and highways are shown in Table 841.1.6-2.)

(e) Additional Underground Pipe Protection. The pipe design factor, *F*, shall be in accordance with Table 841.1.6-2 for the crossing of roads and railroads. The guidance provided by API RP 1102, Steel Pipelines Crossing Railroads and Highways; or GRI Report No. 91/0284, Guidelines for Pipelines Crossing Highways; or Gas Piping Technology Committee's Guide Material Appendix G-15, Design of Uncased Pipelines Crossing of Highways and Railroads, may be considered for design and installation of pipeline crossing. The pipeline operator shall evaluate the need for extending additional pipe protection over the pipeline when the road or railroad right-of-way width is undefined based on anticipated loading from traffic or heavy equipment performing maintenance activities adjacent to the road or railroad.

Varying degrees of additional protection from third-party damage to a buried main or pipeline crossing within (or parallel to) the right-of-way of road or railroad may be achieved using the following techniques, or variants thereof, singly or in combination:

(1) A physical barrier or marker may be installed above or around the pipe (see para. 851.7). If a physical barrier is used, the potential conflict with the right-of-way maintenance activities should be recognized. Physical barrier or marker methods include

(-a) a concrete or steel barrier placed above the pipe

(-b) a concrete slab placed vertically adjacent to the pipe on each side and extended above the top of pipe elevation

(-c) damage-resistant coating material, such as concrete

(-d) extra depth of cover additional to that required in (b)

(-e) buried high-visibility warning tape placed parallel to and above the pipe

(-f) pipe casing [see (d) and para. 861.1.6]

(2) A heavier wall thickness than is required by the pipe design factor, *F*, in accordance with Table 841.1.6-1 or Table 841.1.6-2.

(3) Pipeline alignment should be as straight and perpendicular to the road or railroad alignment as possible to promote reliable marking of the pipe location through the right-of-way and at the right-of-way limits.

Additional underground pipe protection shall be used in conjunction with an effective educational program (para. 850.4.4), periodic surveillance of pipelines (para. 851.1), pipeline patrolling (para. 851.2), and utilization of programs that provide notification to operators regarding impending excavation activity, if available.

841.1.12 Design Factors Summary. Design factors are summarized in Table 841.1.6-2.

841.2 Installation of Steel Pipelines and Mains

841.2.1 Construction Specifications. All construction work performed on piping systems in accordance with the requirements of this Code shall be done under construction specifications. The construction specifications shall cover all phases of the work and shall be in sufficient detail to cover the requirements of this Code.

841.2.2 Inspection Provisions

(a) The operating company shall provide suitable inspection. Inspectors shall be qualified either by experience or training. The inspector shall have the authority to order the repair or removal and replacement of any component found that fails to meet the standards of this Code.

(b) The installation inspection provisions for pipelines and other facilities to operate at hoop stresses of 20% or more of the specified minimum yield strength shall be adequate to make possible at least the following inspections at sufficiently frequent intervals to ensure good quality of workmanship:

(1) Inspect the surface of the pipe for serious surface defects just prior to the coating operation. [See para. 841.2.4(b)(1).]

(2) Inspect the surface of the pipe coating as it is lowered into the ditch to find coating lacerations that indicate the pipe might have been damaged after being coated.

(3) Inspect the fitup of the joints before the weld is made.

(4) Visually inspect the stringer beads before subsequent beads are applied.

(5) Inspect the completed welds before they are covered with coating.

(6) Inspect the condition of the ditch bottom just before the pipe is lowered in, except for offshore pipelines.

(7) Inspect the fit of the pipe to the ditch before backfilling, except for offshore pipelines.

(8) Inspect all repairs, replacements, or changes ordered before they are covered.

(9) Perform such special tests and inspections as are required by the specifications, such as nondestructive testing of welds and electrical testing of the protective coating.

(10) Inspect backfill material prior to use and observe backfill procedure to ensure no damage occurs to the coating in the process of backfilling.

841.2.3 Bends, Miters, and Elbows in Steel Pipelines and Mains. Changes in direction may be made by the use of bends, miters, or elbows under the limitations noted below:

(a) Bends

(1) A bend shall be free from buckling, cracks, or other evidence of mechanical damage.

Table 841.2.3-1 Pipeline Field Cold Bend Requirements

Nominal Pipe Size	Deflection of Longitudinal Axis, deg	Minimum Radius of Bend in Pipe Diameters [see 841.2.3(a)(3)]
Smaller than NPS 12 (DN 300)	841.2.3(a)(4)	18*D*
NPS 12 (DN 300)	3.2	18*D*
NPS 14 (DN 350)	2.7	21*D*
NPS 16 (DN 400)	2.4	24*D*
NPS 18 (DN 450)	2.1	27*D*
NPS 20 (DN 500) and larger	1.9	30*D*

(2) The maximum degree of bending on a field cold bend may be determined by either method in Table 841.2.3-1. The first column expresses the maximum deflection in an arc length equal to the nominal outside diameter, and the second column expresses the minimum radius as a function of the nominal outside diameter.

(3) A field cold bend may be made to a shorter minimum radius than permitted in (2) above, provided the completed bend meets all other requirements of this section, and the wall thickness after bending is not less than the minimum permitted by para. 841.1.1. This may be demonstrated through appropriate testing.

(4) For pipe smaller than NPS 12 (DN 300), the requirements of (1) above must be met, and the wall thickness after bending shall not be less than the minimum permitted by para. 841.1.1. This may be demonstrated through appropriate testing.

(5) Except for offshore pipelines, when a circumferential weld occurs in a bend section, it shall be subjected to radiography examination after bending.

(6) All hot bends shall be made in accordance with ASME B16.49.

(7) Wrinkle bends shall be permitted only on systems operating at hoop stress levels of less than 30% of the specified minimum yield strength. When wrinkle bends are made in welded pipe, the longitudinal weld shall be located on or near to the neutral axis of the bend. Wrinkle bends with sharp kinks shall not be permitted. Spacing of wrinkles shall be measured along the crotch of the pipe bend, and the peak-to-peak distance between the wrinkles shall exceed the diameter of the pipe. On pipe NPS 16 (DN 400) and larger, the wrinkle shall not produce an angle of more than $1\frac{1}{2}$ deg per wrinkle.

(8) Incidental ripples in the pipe surface may occur along the inside radius during the forming of cold field bends in some pipe. Ripples having a dimension measured from peak to valley not exceeding 1% of the pipe outside diameter are considered acceptable for all gas service. Larger ripples may be permitted based on an engineering analysis that considers the effects of pipeline construction and operation on the reliability of pipe affected by such features. In addition, the bend shall meet all other provisions of this section.

(b) Miters. Mitered bends are permitted, provided the following limitations are met:

(1) In systems intended to operate at hoop stress levels of 40% or more of the specified minimum yield strength, mitered bends are not permitted. Deflections caused by misalignment up to 3 deg are not considered as miters.

(2) In systems intended to operate at hoop stress levels of 10% or more but less than hoop stress levels of 40% of the specified minimum yield strength, the total deflection angle at each miter shall not exceed $12\frac{1}{2}$ deg.

(3) In systems intended to operate at hoop stress levels of less than 10% of the specified minimum yield strength, the total deflection angle at each miter shall not exceed 90 deg.

(4) In systems intended to operate at hoop stress levels of 10% or more of the specified minimum yield strength, the minimum distance between miters measured at the crotch shall not be less than one pipe diameter.

(5) Care shall be taken in making mitered joints to provide proper spacing and alignment and full penetration.

(c) Elbows. Factory-made, wrought-steel welding elbows or transverse segments cut therefrom may be used for changes in direction, provided that the arc length measured along the crotch is at least 1 in. (25 mm) on pipe sizes NPS 2 (DN 50) and larger.

841.2.4 Pipe Surface Requirements Applicable to Pipelines and Mains to Operate at a Hoop Stress of 20% or More of the Specified Minimum Yield Strength. Gouges, grooves, and notches have been found to be an important cause of pipeline failures, and all harmful defects of this nature must be prevented, eliminated, or repaired. Precautions shall be taken during manufacture, hauling, and installation to prevent the gouging or grooving of pipe.

(a) Detection of Gouges and Grooves

(1) The field inspection provided on each job shall be suitable to reduce to an acceptable minimum the chances that gouged or grooved pipe will get into the finished pipeline or main. Inspection for this purpose just ahead of the coating operation and during the lowering-in and backfill operation is required.

(2) When pipe is coated, inspection shall be made to determine that the coating machine does not cause harmful gouges or grooves.

(3) Lacerations of the protective coating shall be carefully examined prior to the repair of the coating to determine if the pipe surface has been damaged.

(b) Field Repair of Gouges and Grooves

(1) Injurious gouges or grooves shall be removed.

(2) Gouges or grooves may be removed by grinding to a smooth contour, provided that the resulting wall thickness is not less than the minimum prescribed by this Code for the conditions of usage. [See para. 841.1.5(b).]

(3) When the conditions outlined in (b)(2) cannot be met, the damaged portion of pipe shall be cut out as a cylinder and replaced with a good piece. Insert patching is prohibited.

(c) Dents

(1) A dent may be defined as a depression that produces a gross disturbance in the curvature of the pipe wall (as opposed to a scratch or gouge, which reduces the pipe wall thickness). The depth of a dent shall be measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe in any direction.

(2) A dent, as defined in (c)(1), that contains a stress concentrator such as a scratch, gouge, groove, or arc burn shall be removed by cutting out the damaged portion of the pipe as a cylinder.

(3) All dents that affect the curvature of the pipe at the longitudinal weld or any circumferential weld shall be removed. All dents that exceed a maximum depth of $\frac{1}{4}$ in. (6 mm) in pipe NPS 12 (DN 300) and smaller or 2% of the nominal pipe diameter in all pipe greater than NPS 12 (DN 300) shall not be permitted in pipelines or mains intended to operate at hoop stress levels of 40% or more of the specified minimum yield strength. When dents are removed, the damaged portion of the pipe shall be cut out as a cylinder. Insert patching and pounding out of the dents is prohibited.

(d) Notches

(1) Notches on the pipe surface can be caused by mechanical damage in manufacture, transportation, handling, or installation, and when determined to be mechanically caused, shall be treated the same as gouges and grooves [see (a) above].

(2) Stress concentrations that may or may not involve a geometrical notch may also be created by a process involving thermal energy in which the pipe surface is heated sufficiently to change its mechanical or metallurgical properties. These imperfections are termed "metallurgical notches." Examples include an arc burn produced by accidental contact with a welding electrode or a grinding burn produced by excessive force on a grinding wheel. Metallurgical notches may result in even more severe stress concentrations than a mechanical notch and shall be prevented or eliminated in all pipelines intended to operate at hoop stress levels of 20% or more of the specified minimum yield strength.

(e) Elimination of Arc Burns. 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 prescribed by this Code for the conditions of use.[1] In all other cases, repair is prohibited, and the portion of pipe containing the arc burn must be cut out as a cylinder and replaced with a good piece. Insert patching is prohibited. Care shall be exercised to ensure that the heat of grinding does not produce a metallurgical notch.

841.2.5 Miscellaneous Operations Involved in the Installation of Steel Pipelines and Mains

(a) Handling, Hauling, and Stringing. Care shall be taken in the selection of the handling equipment and in handling, hauling, unloading, and placing the pipe so as not to damage the pipe.

(b) Installation of Pipe in the Ditch. On pipelines operating at hoop stress levels of 20% or more of the specified minimum yield strength, it is important that stresses imposed on the pipeline by construction be minimized. Except for offshore pipelines, the pipe shall fit the ditch without the use of external force to hold it in place until the backfill is completed. When long sections of pipe that have been welded alongside the ditch are lowered in, care shall be exercised so as not to jerk the pipe or impose any strains that may kink or put a permanent bend in the pipe. Slack loops are not prohibited by this paragraph where laying conditions render their use advisable.

(c) Backfilling

(1) Backfilling shall be performed in a manner to provide firm support under the pipe.

(2) If there are large rocks in the material to be used for backfill, care shall be used to prevent damage to the coating by such means as the use of rock shield material, or by making the initial fill with rock-free material sufficient to prevent damage.

(3) Where the trench is flooded to consolidate the backfill, care shall be exercised to see that the pipe is not floated from its firm bearing on the trench bottom.

841.2.6 Hot Taps. All hot taps shall be installed by trained and experienced crews.

841.2.7 Precautions to Avoid Explosions of Gas–Air Mixtures or Uncontrolled Fires During Construction Operations

(a) Operations such as gas or electric welding and cutting with cutting torches can be safely performed on pipelines, mains, and auxiliary equipment, provided that they are completely full of gas or air that is free from combustible material. Steps shall be taken to prevent a mixture of gas and air at all points where such operations are to be performed.

[1] Complete removal of the metallurgical notch created by an arc burn can be determined as follows: After visible evidence of the arc burn has been removed by grinding, swab the ground area with a 20% solution of ammonium persulfate. A blackened spot is evidence of a metallurgical notch and indicates that additional grinding is necessary.

(b) When a pipeline or main can be kept full of gas during a welding or cutting operation, the following procedures are recommended:

(1) Keep a slight flow of gas moving toward the point where cutting or welding is being done.

(2) Control the gas pressure at the site of the work by a suitable means.

(3) After a cut is made, immediately close all slots or open ends with tape, tightly fitted canvas, or other suitable materials.

(4) Do not permit two openings to remain uncovered at the same time. This is doubly important if the two openings are at different elevations.

(c) Welding, cutting, or other operations that could be a source of ignition shall not be done on a pipeline, main, or auxiliary apparatus that contains air, if it is connected to a source of gas, unless a suitable means has been provided to prevent the formation of an explosive mixture in the work area.

(d) In situations where welding or cutting must be done on facilities that are filled with air and connected to a source of gas, and the precautions recommended above cannot be taken, one or more of the following precautions, depending on circumstances at the jobsite, are suggested:

(1) purging of the pipe or equipment upon which welding or cutting is to be done with an inert gas or continuous purging with air in such a manner that a combustible mixture does not form in the facility at the work area

(2) testing of the atmosphere in the vicinity of the zone to be heated before the work is started and at intervals as the work progresses with a combustible gas indicator or by other suitable means

(3) careful verification before and during the work ensuring that the valves that isolate the work from a source of gas do not leak

(e) *Purging of Pipelines and Mains*

(1) When a pipeline or main is to be placed in service, the air in it shall be displaced. The following are some acceptable methods:

(-a) *Method 1.* Introduce a moderately rapid and continuous flow of gas into one end of the line and vent the air out the other end. The gas flow shall be continued without interruption until the vented gas is free of air.

(-b) *Method 2.* If the vent is in a location where the release of gas into the atmosphere may cause a hazardous condition, then a slug of inert gas shall be introduced between the gas and air. The gas flow shall then be continued without interruption until all of the air and inert gas have been removed from the facility. The vented gases shall be monitored and the vent shall be closed before any substantial quantity of combustible gas is released to the atmosphere.

(2) In cases where gas in a pipeline or main is to be displaced with air and the rate at which air can be supplied to the line is too small to make a procedure similar to but the reverse of that described in (1) above feasible, a slug of inert gas should be introduced to prevent the formation of an explosive mixture at the interface between gas and air. Nitrogen or carbon dioxide can be used for this purpose.

(3) If a pipeline or main containing gas is to be removed, the operation may be carried out in accordance with (b), or the line may be first disconnected from all sources of gas and then thoroughly purged with air, water, or inert gas before any further cutting or welding is done.

(4) If a gas pipeline, main, or auxiliary equipment is to be filled with air after having been in service, and there is a reasonable possibility that the inside surfaces of the facility are wetted with volatile inflammable liquid, or if such liquids might have accumulated in low places, purging procedures designed to meet this situation shall be used. Steaming of the facility until all combustible liquids have been evaporated and swept out is recommended. Filling of the facility with an inert gas and keeping it full of such gas during the progress of any work that may ignite an explosive mixture in the facility is an alternative recommendation. The possibility of striking static sparks within the facility must not be overlooked as a possible source of ignition.

(f) Whenever the accidental ignition in the open air of gas–air mixture may be likely to cause personal injury or property damage, precautions, such as the following, shall be taken:

(1) Prohibit smoking and open flames in the area.

(2) Install a metallic bond around the location of cuts in gas pipes to be made by means other than cutting torches.

(3) Take precautions to prevent static electricity sparks.

(4) Provide a fire extinguisher of appropriate size and type, in accordance with NFPA 10.

841.3 Testing After Construction

841.3.1 General Provisions. All piping systems shall be tested after construction to the requirements of this Code except for pre-tested fabricated assemblies and welded tie-in connections where post construction tie-in testing is not practical.

Additionally, single *lengths* or multiple welded *lengths* of pipe previously tested in accordance with this Code for the purposes of repair or replacement do not require a post construction retest.

(a) The circumferential welds associated with connecting pretested assemblies, pretested repair pipe *lengths* or sections, and welded tie-in connections not pressure tested after construction shall be inspected by radiographic or other accepted nondestructive methods in accordance with para. 826.2.

(b) Nonwelded tie-in connections not pressure tested after construction shall be leak tested at not less than

the pressure available when the tie-in is placed into service.

(c) Pressure testing with water is recommended whenever possible. However, it is recognized that certain conditions may require testing with gases. When a gas is used as the test medium, the test pressure shall not exceed the maximum values stated in Tables 841.3.2-1 and 841.3.3-1.

The user is cautioned that the release of stored energy in a gas test failure can be significantly more hazardous than a similar failure with water. When testing with gas, a formal risk assessment is recommended, wherein risks are identified, and appropriate mitigating measures and practices are identified and implemented to minimize these additional risks.

(d) When pipeline systems are installed in unstable soils *or* the mass of the test medium contributes to additional stresses in the pipeline system, the stresses and reactions due to expansion, longitudinal pressure, and longitudinal bending shall be investigated prior to testing. This investigation shall confirm that the test pressures and loads do not produce unacceptable stresses, strains, deflections, or other conditions that could adversely impact the ability of the system to perform as required.

(e) Test planning shall consider pressure test medium temperatures and duration of testing operations to limit damage to pipe from freezing of the test medium and prevent detrimental pipeline deformation due to destabilization of permafrost soils.

(f) Each test assembly (a fabrication that is not part of the permanent facility used for filling, pressuring and monitoring the test) shall be designed, fabricated, and installed in accordance with the provisions of this Code. Each test assembly shall be designed to operate at the anticipated maximum test pressure. The operator is encouraged to consider pretesting of the test assembly prior to its use to reduce risk to testing personnel. Pretesting of the test assembly is required when the pressure test is to be conducted with a sour gas medium. Subsequent retesting prior to reuse should be considered if the test assembly is suspected to have undergone damage during or between tests.

(g) Test assemblies should be located considering accessibility, sources of test medium, and the elevation profile of the test segment. Selected locations should provide testing flexibility while limiting test pressures between the minimum test pressure and the selected maximum test pressure.

841.3.2 Pressure Test Requirements to Prove Strength of Pipelines and Mains to Operate at Hoop Stresses of 30% or More of the Specified Minimum Yield Strength of the Pipe. The following are pressure test requirements to prove strength of pipelines and mains to operate at hoop stresses of 30% or more of the specified minimum yield strength of the pipe:

(a) The permissible pressure test media are stated in Table 841.3.2-1. The recommended test medium is water. Sour gas as defined in para. B803 and flammable gas may only be used for testing purposes in Location Class 1, Division 2 locations. When either of these media are utilized, the public shall be removed to a safe distance during the test and testing personnel shall be equipped with appropriate personal protective equipment. Both sour gas and flammable gas tests must meet the test pressure limitations per Table 841.3.3-1.

(b) The pressure test medium requirements of Table 841.3.2-1 for the pressure testing of pipelines in Class Locations 3 and 4 need not apply if, at the time the pipelines are first ready for pressure testing, one or both of the following conditions exist:

(1) Ground temperature at pipe depths is sufficiently low during the test to cause the test medium to change state and cause damage or blockage that would damage the pipe or invalidate the test, and use of chemical freeze depressants is not possible.

(2) Approved water of satisfactory quality is not reasonably available in sufficient quantity.

(c) Where one or both of the conditions in (b) exist, it is permissible to pressure test using air or nonflammable, nontoxic gases as the pressure test medium provided that all of the following conditions exist:

(1) The maximum hoop stress during pressure testing is less than 50% of the specified minimum yield strength in Class 3 Locations, and less than 40% of the specified minimum yield strength in Class 4 Locations.

(2) The maximum pressure at which the pipeline is to be operated does not exceed 80% of the maximum field test pressure.

(3) The pipe involved has been confirmed to be fit for service and has a longitudinal joint factor of 1.00 (see Table 841.1.7-1).

(d) Before being placed in service, a newly constructed pipeline system shall be strength tested for a minimum period of 2 hr at a minimum pressure equal to or greater than that specified in Table 841.3.2-1 after stabilization of temperatures and surges from pressuring operations has been achieved. The minimum pressure shall be obtained and held at the highest elevation in the pipeline system.

(e) Test requirements as a function of Location Class are summarized in Table 841.3.2-1.

(f) In selecting the test pressure, the designer or operating company should be aware of the provisions of section 854 and the relationship between test pressure and operating pressure when the pipeline experiences a future increase in the number of dwellings intended for human occupancy.

(g) Other provisions of this Code notwithstanding, pipelines and mains crossing highways and railroads may be pretested independently or tested in conjunction

Table 841.3.2-1 Test Requirements for Steel Pipelines and Mains to Operate at Hoop Stresses of 30% or More of the Specified Minimum Yield Strength of the Pipe (16)

1	2	3	4	5	6
Location Class	Maximum Design Factor, *F*	Permissible Test Medium	Pressure Test Prescribed: Minimum	Pressure Test Prescribed: Maximum	Maximum Allowable Operating Pressure, the Lesser of
1, Division 1	0.8	Water	1.25 × MOP	None	TP ÷ 1.25 or DP
1, Division 2	0.72	Water	1.25 × MOP	None	TP ÷ 1.25 or DP
	0.72	Air or Gas [Note (1)]	1.25 × MOP	1.25 × DP	TP ÷ 1.25 or DP
2	0.6	Water	1.25 × MOP	None	TP ÷ 1.25 or DP
	0.6	Air [Note (1)]	1.25 × MOP	1.25 × DP	TP ÷ 1.25 or DP
3 [Note (2)]	0.5	Water [Note (3)]	1.50 × MOP	None	TP ÷ 1.5 or DP
4	0.4	Water [Note (3)]	1.50 × MOP	None	TP ÷ 1.5 or DP

LEGEND:
DP = design pressure
MOP = maximum operating pressure (not necessarily the maximum allowable operating pressure)
TP = test pressure

GENERAL NOTES:
(a) This Table defines the relationship between test pressures and maximum allowable operating pressures subsequent to the test. If an operating company decides that the maximum operating pressure will be less than the design pressure, a corresponding reduction in the prescribed test pressure may be made as indicated in the Pressure Test Prescribed, Minimum column. If this reduced test pressure is used, however, the maximum operating pressure cannot later be raised to the design pressure without retesting the line to a higher test pressure. See paras. 805.2.1(d), 845.2.2, and 845.2.3.
(b) Gas piping within gas pipeline facilities (e.g., meter stations, regulator stations, etc.) is to be tested and the maximum allowable operating pressure qualified in accordance with para. 841.3 and Tables 841.3.2-1 and 841.3.3-1 subject to the appropriate location class, design factor, and test medium criteria.
(c) When an air or gas test is used, the user of this Code is cautioned to evaluate the ability of the piping system to resist propagating brittle or ductile fracture at the maximum stress level to be achieved during the test.

NOTES:
(1) When pressure testing with air or gas, see paras. 841.3.1(c) and 841.3.2(a) through (c), and Table 841.3.3-1.
(2) Compressor station piping shall be tested with water to Location Class 3 pipeline requirements as indicated in para. 843.5.1(c).
(3) For exceptions, see paras. 841.3.2(b) and (c).

with the adjoining pipeline segments in the same manner and to the same pressure as the pipeline on each side of the crossing.

(h) Other provisions of this Code notwithstanding, fabricated assemblies, including main line valve assemblies, cross connections, river crossing headers, etc., installed in pipelines in Location Class 1 and designed in accordance with a design factor of 0.60 as required in para. 841.1.9(a), may be pretested independently or tested in conjunction with the adjoining pipeline segments as required for Location Class 1.

(i) Operating companies shall retain, in their files, for the useful life of each pipeline and main, records showing the procedures used and the data developed in establishing the maximum allowable operating pressure of that pipeline or main. Refer to section N-7 of Nonmandatory Appendix N for a list of suggested records for retention.

841.3.3 Tests Required to Prove Strength for Pipelines and Mains to Operate at Hoop Stress Levels of Less Than 30% of the Specified Minimum Yield Strength of the Pipe, but in Excess of 100 psig (690 kPa). Steel piping that is to operate at hoop stress levels of less than 30% of the specified minimum yield strength in Class 1 Locations shall at least be tested in accordance with para. 841.3.4. In Class 2, 3, and 4 Locations, such piping shall be tested in accordance with Table 841.3.2-1, except that gas or air may be used as the test medium within the maximum limits set in Table 841.3.3-1.

841.3.4 Leak Tests for Pipelines or Mains to Operate at 100 psig (690 kPa) or More

(a) Each pipeline and main shall be tested after construction and before being placed in operation to demonstrate that it does not leak. If the test indicates that a leak exists, the leak or leaks shall be located and eliminated, unless it can be determined that no undue hazard to public safety exists.

(b) The test procedure used shall be capable of disclosing all leaks in the section being tested and shall be selected after giving due consideration to the volumetric content of the section and to its location. This requires the exercise of responsible and experienced judgement, rather than numerical precision.

(c) In all cases where a line is to be stressed in a strength proof test to a hoop stress level of 20% or more of the specified minimum yield strength of the pipe, and gas or air is the test medium, a leak test shall be made at a pressure in the range from 100 psig (690 kPa) to that required to produce a hoop stress of 20% of the minimum specified yield, or the line shall be walked while the hoop stress is held at approximately 20% of the specified minimum yield.

Table 841.3.3-1 Maximum Hoop Stress Permissible During an Air or Gas Test

Test Medium	Location Class, Percent of Specified Minimum Yield Strength		
	2	3	4
Air or nonflammable nontoxic gas	75	50	40
Flammable gas	30	30	30

GENERAL NOTE: Refer to para. 841.3.2(c).

841.3.5 Leak Tests for Pipelines and Mains to Operate at Less Than 100 psig (690 kPa)

(a) Each pipeline, main, and related equipment that will operate at less than 100 psi (690 kPa) shall be tested after construction and before being placed in operation to demonstrate that it does not leak.

(b) Gas may be used as the test medium at the maximum pressure available in the distribution system at the time of the test. In this case, the soap bubble test may be used to locate leaks if all joints are accessible during the test.

(c) Testing at available distribution system pressures as provided for in (b) may not be adequate if substantial protective coatings are used that would seal a split pipe seam. If such coatings are used, the leak test pressure shall be 100 psig (690 kPa).

841.3.6 Safety During Tests. All testing of pipelines and mains after construction shall be done with due regard for the safety of employees and the public during the test. When air or gas is used, suitable steps shall be taken to keep persons not working on the testing operations out of the testing area when the hoop stress is first raised from 50% of the specified minimum yield to the maximum test stress, and until the pressure is reduced to the maximum operating pressure.

841.4 Commissioning of Facilities

841.4.1 General. Written procedures shall be established for commissioning. Procedures shall consider the characteristics of the gas to be transported, the need to isolate the pipeline from other connected facilities, and the transfer of the constructed pipeline to those responsible for its operation.

Commissioning procedures, devices, and fluids shall be selected to ensure that nothing is introduced into the pipeline system that will be incompatible with the gas to be transported, or with the materials in the pipeline components.

841.4.2 Cleaning and Drying Procedures. Consideration shall be given to the need for cleaning and drying the pipe and its components beyond that required for removal of the test medium.

841.4.3 Functional Testing of Equipment and Systems. As a part of commissioning, all pipeline and compressor station monitor and control equipment and systems shall be fully function-tested, especially including safety systems such as pig trap interlocks, pressure and flow-monitoring systems, and emergency pipeline shutdown systems. Consideration should also be given to performing a final test of pipeline valves before the gas is introduced to ensure that each valve is operating correctly.

841.4.4 Start-Up Procedures and Introduction of Transported Gas. Written start-up procedures shall be prepared before introducing the transported gas into the system and shall require the following:

(a) the system be mechanically complete and operational

(b) all functional tests be performed and accepted

(c) all necessary safety systems be operational

(d) operating procedures be available

(e) a communications system be established

(f) transfer of the completed pipeline system to those responsible for its operation

841.4.5 Documentation and Records. The following commissioning records shall be maintained as permanent records:

(a) cleaning and drying procedures

(b) cleaning and drying results

(c) function-testing records of pipeline monitoring

(d) control equipment systems

(e) completed prestart checklist

842 OTHER MATERIALS

842.1 Ductile Iron Piping Systems Requirements

842.1.1 Ductile Iron Pipe Design

(a) Determination of Required Wall Thickness. Ductile iron pipe shall be designed in accordance with the methods set forth in ANSI/AWWA C150/A21.50.

(b) Allowable Values of s and f. The values of design hoop stress, s, and design bending stress, f, at the bottom of the pipe, to be used in the equations given in ANSI/AWWA C150/A21.50, are

$$s = 16{,}800 \text{ psi (116 MPa)}$$
$$f = 36{,}000 \text{ psi (248 MPa)}$$

(c) Standard Ductile Iron Strength and Conformance to ANSI A21.52. Ductile iron pipe shall be (60-42-10) grade and shall conform to all requirements of ANSI A21.52. Grade (60-42-10) ductile iron has the following mechanical properties:

Minimum tensile strength	60,000 psi (414 MPa)
Minimum yield strength	42,000 psi (290 MPa)
Minimum elongation	10%

(d) Allowable Thickness for Ductile Iron Pipe. The least ductile iron pipe thicknesses permitted are the lightest standard class for each nominal pipe size as shown in ANSI A21.52. Standard wall thicknesses for 250 psig (1 720 kPa) maximum working pressure and standard laying conditions at several depths of cover are shown in Table 842.1.1-1.

(e) Ductile Iron Pipe Joints

(1) Mechanical Joints. Ductile iron pipe with mechanical joints shall conform to the requirements of ANSI A21.52 and ANSI/AWWA C111/A21.11. Mechanical joints shall be assembled in accordance with "Notes on Installation of Mechanical Joints" in ANSI/AWWA C111/A21.11.

(2) Other Joints. Ductile iron pipe may be furnished with other types of joints provided they are properly qualified and meet the appropriate provisions of this Code. Such joints shall be assembled in accordance with applicable standards or in accordance with the manufacturer's written recommendations.

(3) Threaded Joints. The use of threaded joints to couple lengths of ductile iron pipe is not recommended.

842.1.2 Installation of Ductile Iron Pipe

(a) Laying. Ductile iron pipe shall be laid in accordance with the applicable field conditions described in ANSI/AWWA C150/A21.50.

(b) Cover. Underground ductile iron pipe shall be installed with a minimum cover of 24 in. (610 mm) unless prevented by other underground structures. Where sufficient cover cannot be provided to protect the pipe from external loads or damage and the pipe is not designed to withstand such external loads, the pipe shall be cased or bridged to protect the pipe.

(c) Joint Restraint. Suitable harnessing or buttressing shall be provided at points where the main deviates from a straight line and the thrust, if not restrained, would separate the joints.

(d) Making Ductile Iron Field Joints. Ductile iron pipe joints shall conform to para. 842.1.1(e) and shall be assembled according to recognized American National Standards or in accordance with the manufacturer's written recommendations.

842.1.3 Testing Ductile Iron Field Joints. Ductile iron pipe joints shall be leak tested in accordance with para. 841.3.4 or 841.3.5.

842.2 Design of Plastic Piping

General Provisions. The design requirements of this section are intended to limit the use of plastic piping primarily to mains and service lines in typical PVC (polyvinyl chloride) distribution systems[2] operating at a pressure of 100 psig (690 kPa) or less, PE (polyethylene)

[2] Under ASTM D2513, PVC piping may be used only for repair and maintenance of existing PVC installations.

(16)

Table 842.1.1-1 Standard Thickness Selection Table for Ductile Iron Pipe

Nominal Pipe Size, NPS (DN)	Laying Condition	Thickness, in. (mm), for Depth of Cover, ft (m)							
		$2^1/_2$	$3^1/_2$	5	8	12	16	20	24
3 (75)	A	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)
	B	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)	0.28 (7.1)
4 (100)	A	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)
	B	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)	0.29 (7.4)
6 (150)	A	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)
	B	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)	0.31 (7.9)
8 (200)	A	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)
	B	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)	0.33 (8.4)
10 (250)	A	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.38 (9.7)	0.38 (9.7)
	B	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.35 (8.9)	0.38 (9.7)	0.38 (9.7)
12 (300)	A	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.40 (10.2)	0.43 (10.9)
	B	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.40 (10.2)	0.40 (10.2)
14 (350)	A	0.36 (9.1)	0.36 (9.1)	0.36 (9.1)	0.36 (9.1)	0.39 (9.9)	0.42 (10.7)	0.45 (11.4)	0.45 (11.4)
	B	0.36 (9.1)	0.36 (9.1)	0.36 (9.1)	0.36 (9.1)	0.36 (9.1)	0.42 (10.7)	0.42 (10.7)	0.45 (11.4)
16 (400)	A	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.40 (10.2)	0.43 (10.9)	0.46 (11.7)	0.49 (12.4)
	B	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.37 (9.4)	0.40 (10.2)	0.43 (10.9)	0.46 (11.7)	0.49 (12.4)
18 (450)	A	0.38 (9.7)	0.38 (9.7)	0.38 (9.7)	0.38 (9.7)	0.41 (10.4)	0.47 (11.9)	0.50 (12.7)	0.53 (13.5)
	B	0.38 (9.7)	0.38 (9.7)	0.38 (9.7)	0.38 (9.7)	0.41 (10.4)	0.44 (11.2)	0.47 (11.9)	0.53 (13.5)
20 (500)	A	0.39 (9.9)	0.39 (9.9)	0.39 (9.9)	0.39 (9.9)	0.45 (11.4)	0.48 (12.2)	0.54 (13.7)	. . .
	B	0.39 (9.9)	0.39 (9.9)	0.39 (9.9)	0.39 (9.9)	0.42 (10.7)	0.48 (12.2)	0.51 (13.0)	. . .
24 (600)	A	0.44 (11.2)	0.41 (10.4)	0.41 (10.4)	0.44 (11.2)	0.50 (12.7)	0.56 (14.2)	. . .	. . .
	B	0.41 (10.4)	0.41 (10.4)	0.41 (10.4)	0.41 (10.4)	0.47 (11.9)	0.53 (13.5)	. . .	. . .

GENERAL NOTES:

(a) This Table is taken from ANSI A21.52.

(b) Laying Condition A: flat-bottom trench without blocks, untamped backfill.

(c) Laying Condition B: flat-bottom trench without blocks, tamped backfill.

(d) The thicknesses in this Table are equal to or in excess of those required to withstand 250 psi (1 720 kPa) working pressure.

(e) All thicknesses shown in this Table for the depths of cover indicated are adequate for trench loads, including truck superloads.

(f) For the basis of design, see ANSI/AWWA C150/A21.50.

(g) Thread engagement in taps for service connections and bag holes may require consideration in selecting pipe thicknesses. See Appendix of ANSI A21.52.

distribution systems operating at a pressure of 125 psig (860 kPa) or less, and PA-11 (polyamide 11) distribution systems operating at pressures up to the design pressure of the material as determined by the formulas in para. 841.2.1. For other applications in Class 1 or 2 Locations, plastic piping may be used within the limitations prescribed in this Code. Plastic piping shall meet the requirements of a specification listed in Mandatory Appendix A.

(16) **842.2.1 Plastic Pipe and Tubing Design Formula.** The design pressure for plastic gas piping systems or the nominal wall thickness for a given design pressure (subject to the limitations in para. 842.2.2) shall be determined by the following formulas:

(U.S. Customary Units)

$$P = \frac{2S}{(SDR) - 1} \times D_f$$

or

$$P = \frac{2St}{D - t} \times D_f$$

(SI Units)

$$\left(P = \frac{2\,000S}{(SDR) - 1} \times D_f\right)$$

or

$$\left(P = \frac{2\,000St}{D - t} \times D_f\right)$$

where

D = specified outside diameter, in. (mm), in the case of reinforced thermosetting plastic (RTP) pipe, the specified outside diameter of the reinforced thermoset layer

D_f = design factor = 0.32 or 0.40 for PA-11. The design factor is a number less than or equal to 1 that is multiplied by the calculated maximum pressure to obtain the design pressure.

DR = dimension ratio, the ratio of the average specified outside diameter to the specified minimum wall thickness

P = design pressure, gage, psig (kPa)

S = for thermoplastic pipe, hydrostatic design basis (HDB) determined in accordance with ASTM D2837 at a temperature equal to 73°F (23°C), 100°F (38°C), 120°F (49°C), 140°F (60°C), or 180°F (82°C). In the absence of a HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3. For RTP pipe NPS 6 (DN 150) and below, used in Class 1 and 2 locations, the HDB determined in accordance with the listed specification. For all other RTP pipe, use 11,000 psi (76 MPa).

SDR = standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10. In the case of RTP pipe, SDR is the ratio of the average outside diameter of the reinforced thermoset layer to the minimum specified wall thickness of the reinforced thermoset layer. DR may be substituted for SDR in this calculation when the dimension ratio is not an above defined "standard" dimension ratio.

t = specified wall thickness, in. (mm), in the case of RTP pipe, the specified wall thickness of the reinforced thermoset layer

NOTE: Long-term hydrostatic strength at 73°F (23°C) for the plastic materials whose specifications are incorporated by reference herein are given in Mandatory Appendix D.

842.2.2 Thermoplastic Design Limitations (16)

(a) Except as provided in (e) and (f), the design pressure may not exceed a gage pressure of 100 psig (689 kPa) for plastic pipe used in

(1) distribution systems

(2) Location Classes 3 and 4

(b) Plastic pipe shall not be used where the design temperature of the pipe will be

(1) below −40°F (−40°C). In no case shall the pipe or piping components be used in applications beyond the manufacturer's recommended ratings for the pipe or piping component.

(2) above the temperature at which the HDB used in the design formula is determined.

(c) The value of t for thermoplastic pipe shall not be less than that specified in ASTM D2513.

(d) For saddle-type service connections made by heat fusion techniques, it may be necessary for some materials that are intended for use at high operating pressures to require a heavier wall thickness than defined by the pressure design formula for sizes NPS 2 (DN 50) and smaller. Manufacturers of the specific pipe material should be contacted for recommendations or a qualified procedure shall be used.

(e) The design pressure for PE pipe may exceed a gage pressure of 100 psig (689 kPa), provided that

(1) the design pressure does not exceed 125 psig (862 kPa)

(2) the material is a PE material as specified within ASTM D2513

(3) the pipe size is NPS 12 (DN 300) or smaller

(4) the design pressure is determined in accordance with the design equation defined in para. 842.2.1

(f) Polyamide-11 (PA-11) pipe may be operated at pressures up to its design pressure as determined in accordance with the design equation defined in para. 842.2.1.

(16) **842.2.3 Reinforced Thermosetting Plastic (RTP) Design Limitations**

(a) The value of *P* for RTP mains and service lines in distribution systems in Class 3 and 4 Locations shall not exceed 100 psig (689 kPa) except as prescribed in (d).

(b) Reinforced thermosetting plastic pipe and fittings shall not be used where operating temperatures will be below −20°F (−29°C), or above 150°F (66°C), and if recommended by the manufacturer, up to 180°F (82°C).

(c) The wall thickness for RTP pipe shall not be less than that specified in ASTM D2517.

(d) RTP pipe may be operated at pressures up to its design pressure as determined in accordance with the equation in para. 842.2.1.

842.2.4 Design Pressure of Plastic Fittings. The maximum pressure rating for fittings shall be the same value as the maximum design pressure of the corresponding pipe size and wall thickness as indicated in the referenced standard for the fittings and as determined in paras. 842.2.1 and 842.2.2. The manufacturer should be consulted for advice on maximum pressure ratings for fittings not covered by referenced standards.

842.2.5 Valves in Plastic Piping

(a) Valves in plastic piping may be made of any suitable material and design permitted by this Code. Thermoplastic valves shall comply with ASTM D2513 and ASME B16.40.

(b) Valve installations in plastic piping shall be so designed as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

842.2.6 Protection From Hazards. Plastic piping shall conform to the applicable provisions of para. 841.1.10.

842.2.7 Cover and Casing Requirements Under Railroads, Roads, Streets, or Highways. Plastic piping shall conform to the applicable requirements of paras. 841.1.11(a) and (d). Where plastic piping must be cased or bridged, suitable precautions shall be taken to prevent crushing or shearing of the piping. (See also para. 842.3.3.)

842.2.8 Clearance Between Mains and Other Underground Structures. Plastic piping shall conform to the applicable provisions of para. 841.1.11(c). Sufficient clearance shall be maintained between plastic piping and steam, hot water, or power lines and other sources of heat to prevent operating temperatures in excess of the limitations of para. 842.2.2(b) or 842.2.3(b).

842.2.9 Plastic Pipe and Tubing Joints and Connections (16)

(a) General Provisions. Plastic pipe, tubing, and fittings may be joined by the solvent cement method, adhesive method, heat-fusion method, or by means of compression couplings or flanges. The method used must be compatible with the materials being joined. The recommendations of the manufacturer shall be considered when determining the method to be used.

(b) Joint Requirements

(1) Pipe or tubing shall not be threaded.

(2) Solvent cement joints, adhesive joints, and heat-fusion joints shall be made in accordance with qualified procedures that have been established and proven by test to produce gas-tight joints at least as strong as the pipe or tubing being joined.

(3) Joints shall be made by personnel qualified by training or experience in the proper procedures required for the type of joint involved.

(4) Solvent cement shall be used only on PVC joints.

(5) Heat-fusion or mechanical joints shall be used when joining polyethylene or polyamide 11 pipe, tubing, or fittings. PA-11 components may be joined to PA-11 components, and PE components may be joined to PE components. PE and PA-11 components shall not be heat-fused to each other. Polyethylene components made of different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific components are used. Any combination of PE materials with an ASTM D2513, Table 4, Pipe Category, melt index category C may be joined by heat fusion procedures such as those detailed in PPI TR-33. The Plastics Pipe Institute (PPI) publishes the following generic heat-fusion procedures:

(-a) TR-33, Generic Butt Fusion Joining Procedure for Polyethylene Gas Piping

(-b) TR-41, Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping

(-c) TR-45, Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe

Fusion of PE components with different melt categories may require "dissimilar fusion" procedures provided by the manufacturer.

(6) Flanges or special joints may be used provided they are properly qualified and used in accordance with the appropriate provisions of this Code.

(c) Solvent Cement Joints

(1) Square cut ends free of burrs are required for a proper socket joint.

(2) Proper fit between the pipe or tubing and mating socket or sleeve is essential to a good joint. Sound joints cannot normally be made between loose or very tight-fitting components.

(3) The mating surfaces must be clean, dry, and free of material that may be detrimental to the joint.

(4) Solvent cements that conform to ASTM D2513 and are recommended by the pipe or tubing manufacturer shall be used to make cemented joints.

(5) A uniform coating of the solvent cement is required on both mating surfaces. After the joint is made, excess cement shall be removed from the outside of the joint. The joint shall not be disturbed until it has properly set.

(6) The solvent cement and piping components to be joined may be conditioned prior to assembly by warming if done in accordance with the manufacturer's recommendations.

(7) A solvent cement joint shall not be heated to accelerate the setting of the cement.

(8) Safety requirements in Appendix A of ASTM D2513 shall be followed when solvent cements are used.

(d) Heat-Fusion Joints

(1) Sound butt heat-fusion joints require the use of a jointing device that holds the heater element square to the ends of the piping, can compress the heated ends together, and holds the piping in proper alignment while the plastic hardens.

(2) Sound socket heat-fusion joints require the use of a jointing device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature. The completed joint must not be disturbed until properly set.

(3) Care must be used in the heating operation to prevent damage to the plastic material from overheating or having the material not sufficiently heated to ensure a sound joint. Direct application of heat with a torch or other open flame is prohibited.

(4) When connecting saddle-type fittings to pipe NPS 2 (DN 50) and smaller, see para. 842.2.2(e) to minimize the possibility of failures.

(e) Adhesive Joints

(1) Adhesives that conform to ASTM D2517 and are recommended by the pipe, tubing, or fitting manufacturer shall be used to make adhesive bonded joints.

(2) When dissimilar materials are bonded together, a thorough investigation shall be made to determine that the materials and adhesive used are compatible with each other.

(3) An adhesive bonded joint may be heated in accordance with the pipe manufacturer's recommendation to accelerate cure.

(4) Provisions shall be made to clamp or otherwise prevent the joined materials from moving until the adhesive is properly set.

(f) Mechanical Joints[3]

(1) When compression-type mechanical joints are used, the elastomeric gasket material in the fitting shall be compatible with the plastic (i.e., the plastic and the elastomer shall not cause deterioration in one another's chemical and physical properties over a long period).

(2) The tubular stiffener required to reinforce the end of the pipe or tubing shall extend at least under that section of the pipe being compressed by the gasket or gripping material. The stiffener shall be free of rough or sharp edges and shall not be a force fit in the pipe or tube. Split tubular fittings shall not be used.

(3) Since pull-out resistance of compression-type fittings varies with type and size, all mechanical joints shall be designed and installed to effectively sustain the longitudinal pull-out forces caused by contraction of the piping or by maximum anticipated external loading. The installation shall be designed and made to minimize these forces as follows:

(-a) In the case of direct burial when the pipe is sufficiently flexible, the pipe may be snaked in the ditch.

(-b) In the case of pipe installed by insertion in casing, the pipe shall be pushed rather than pulled into place so as to place it in compression rather than tension.

(-c) Allowance shall be made for thermal expansion and contraction due to seasonal changes in temperature of installed pipe. The importance of this allowance increases as the length of the installation increases. Such allowance is of paramount importance when the plastic pipe is used for insertion renewal inside another pipe, because it is not restrained by earth loading. This allowance may be accomplished by appropriate combinations of

(-1) offsets

(-2) anchoring

(-3) aligning the pipe and fitting

(-4) in the case of compression, fittings by the use of long-style types and placement of the pipe in slight axial compression

(-5) expansion–contraction devices, or

(-6) fittings designed to prevent pull-out

Typical coefficients of thermal expansion, which may be used to make calculations, are given in Table 842.2.9-1.

842.3 Installation of Plastic Piping

842.3.1 Construction Specifications. All construction work performed on piping systems in accordance with the requirements of this Code shall be done using construction specifications. The construction specifications shall cover the requirements of this Code and shall be in sufficient detail to ensure proper installation.

842.3.2 Inspection and Handling Provisions. Plastic piping components are susceptible to damage by mishandling. Gouges, cuts, kinks, or other forms of damage may cause failure. Care shall be exercised during handling and installation to prevent such damage.

[3] Refer to the current editions of the AGA Catalog No. XR0104, *Plastic Pipe Manual for Gas Service*; ASTM D2513; ANSI/GPTC Z380.1, *Guide for Gas Transmission and Distribution Piping Systems*; and technical publications of plastic pipe and fitting manufacturers.

(16) **Table 842.2.9-1 Nominal Values for Coefficients of Thermal Expansion of Thermoplastic Pipe Materials**

General Material Designation	Nominal Coefficients of Thermal Expansion ASTM D696, × 10^{-5} in./in./°F (× 10^{-5} mm/mm/°C)
PA 32312 (PA-11)	8.5 (4.3)
PA 32316 (PA-11)	8.5 (4.3)
PE 2406	9.0 (5.0)
PE 2606	10.0 (5.6)
PE 2706	10.0 (5.6)
PE 2708	10.0 (5.6)
PE 3408	9.0 (5.0)
PE 3608	9.0 (5.0)
PE 3708	9.0 (5.0)
PE 3710	9.0 (5.0)
PE 4708	9.0 (5.0)
PE 4710	9.0 (5.0)
PVC 1120	3.0 (1.7)
PVC 1220	3.5 (1.9)
PVC 2116	4.0 (2.2)

GENERAL NOTES:
(a) Individual compounds may differ from values in this Table as much as ±10%. More exact values for specific commercial products may be obtained from the manufacturers.
(b) Abbreviations: PA-11 = polyamide 11, PE = polyethylene, PVC = polyvinyl chloride.

(a) Plastic pipe and tubing shall be carefully inspected for cuts, scratches, gouges, and other imperfections before use, and any pipe or tubing containing harmful imperfections shall be rejected.

(b) Each installation shall be field inspected to detect harmful imperfections. Any such imperfections found shall be eliminated.

(c) Skillful application of qualified techniques and the use of proper materials and equipment in good condition are required to achieve sound joints in plastic piping by the solvent cement, adhesive, or heat fusion methods. Inspection provisions shall be checked visually. If there is any reason to believe the joint is defective, it shall be removed and replaced.

(d) Care shall be exercised to avoid rough handling of plastic pipe and tubing. It shall not be pushed or pulled over sharp projections or dropped, or it shall not have other objects dropped on it. Care shall be taken to prevent kinking or buckling, and any kinks or buckles that occur shall be removed by cutting out as a cylinder.

(e) Care shall be exercised at all times to protect the plastic material from fire, excessive heat, or harmful chemicals.

(f) Plastic pipe and tubing shall be adequately supported during storage. Thermoplastic pipe, tubing, and fittings shall be protected from long-term exposure to direct sunlight.

842.3.3 Installation Provisions (16)

(a) Aboveground Installation. Plastic piping may be installed aboveground if it is one of the following:

(1) encased in metal pipe that is protected against atmospheric corrosion; protected against deterioration (e.g., high-temperature degradation); and protected against external damage

(2) installed on a bridge in accordance with GRI Report 00/0154, Design Guide for Pipes Across Bridges

(3) installed for plastic service lines as permitted in para. 849.4.2(b)

Plastic pipe shall not be used to support external loads. Encased plastic pipe shall be able to withstand anticipated temperatures without deteriorating or decreasing in strength below the design limitations stated in paras. 842.2.2 and 842.2.3. When protecting against external damage, consideration shall be given to the need to isolate the encased segment and to safely vent or contain gas that may escape the plastic pipe in the event of a leak or rupture.

(b) Belowground Installation. Plastic piping shall not be installed in vaults or any other below-grade enclosure unless it is completely encased in gas-tight metal pipe and metal fittings having adequate corrosion protection.

(c) Stresses. Plastic piping shall be installed in such a way that shear or tensile stresses resulting from construction, backfill, thermal contraction, or external loading are minimized. [See para. 842.2.9(f).]

(d) Direct Burial

(1) Plastic piping shall be laid on undisturbed or well-compacted soil. If plastic piping is to be laid in soils that may damage it, the piping shall be protected by suitable rock-free materials before backfilling is completed. Plastic piping shall not be supported by blocking. Well-tamped earth or other continuous support shall be used.

(2) The piping shall be installed with sufficient slack to provide for possible contraction. Cooling may be necessary before the last connection is made under extremely high-temperature conditions. [See para. 842.2.9(f).]

(3) When long sections of piping that have been assembled alongside the ditch are lowered in, care shall be exercised to avoid any strains that may overstress or buckle the piping or impose excessive stress on the joints.

(4) Backfilling shall be performed in a manner to provide firm support around the piping. The material used for backfilling shall be free of large rocks, pieces of pavement, or any other materials that might damage the pipe.

(5) Where flooding of the trench is done to consolidate the backfill, care shall be exercised to see that the

piping is not floated from its firm bearing on the trench bottom.

(6) A positive method of locating plastic piping systems is required. A common method is the installation of electrically conductive material, such as tracer wire or plastic coated metallic tape with the plastic pipe to facilitate locating it with an electronic pipe locator. Alternative proven locating methods may be used.

(e) Insertion of Casing

(1) The casing pipe shall be prepared to the extent necessary to remove any sharp edges, projections, or abrasive material that could damage the plastic during and after insertion.

(2) Plastic pipe or tubing shall be inserted into the casing pipe in such a manner so as to protect the plastic during the installation. The leading end of the plastic shall be closed before insertion. Care shall be taken to prevent the plastic piping from bearing on the end of the casing.

(3) The portion of the plastic piping exposed due to the removal of a section of the casing pipe shall be of sufficient strength to withstand the anticipated external loading, or it shall be protected with a suitable bridging piece capable of withstanding the anticipated external loading.

(4) The portion of the plastic piping that spans disturbed earth shall be adequately protected by a bridging piece or other means from crushing or shearing from external loading or settling of backfill.

(5) The piping shall be installed to provide for possible contraction. Cooling may be necessary before the last connection is made when the pipe has been installed in hot or warm weather. [See para. 842.2.9(f).]

(6) If water accumulates between the casing and the carrier pipe where it may be subjected to freezing temperatures, the carrier pipe can be constricted to the point where the capacity is affected or the pipe wall could be crushed and leak. To avoid this, one or more of the following steps shall be taken:

(-a) The annulus between the carrier pipe and casing shall be kept to a minimum so that the increased volume of water changing to ice will be insufficient to crush the carrier pipe.

(-b) Adequate draining for the casing shall be provided.

(-c) Filler such as foam shall be inserted into the annulus between the casing and the carrier pipe.

(f) Trenchless Installations — Plastic Pipe. For general installation requirements, see para. 841.1.9(j). In addition, the following measures shall also be taken for trenchless installations of plastic pipe:

(1) Protecting Pipe

(-a) Precautions shall be taken to avoid pushing or pulling the exposed pipe string over sharp objects or abrasive surfaces that may damage the pipe during installation.

(-b) Visual inspection of the exposed pipe surface shall be performed before and after installation. This would include any exposed pipe sections at the pulling head and at holes dug for test pits, tie-ins, and branch or service connections. If damage (e.g., scratches, gouges, etc.) exceeds 10% of the nominal wall thickness, then the pipe shall be replaced in its entirety.

(-c) Measures shall be taken to prevent overstressing plastic pipe during trenchless installations. These measures may include monitoring of the pulling force, use of a weak link at the pulling head, or other methods. For further information, see Handbook of Polyethylene Pipe.

(-d) For locating the pipe with an electronic pipe locator, a tracer wire shall be pulled in with the piping, but with minimal physical contact with the pipe.

(2) Additional Evaluation Measures. The minimum inspection and post-inspection testing requirements elsewhere in this Code shall be employed.

842.3.4 Bends and Branches. Changes in direction of plastic piping may be made with bends, tees, or elbows under the following limitations:

(a) Plastic pipe and tubing may be deflected to a radius not less than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness, and diameter of the particular plastic used.

(b) The bends shall be free of buckles, cracks, or other evidence of damage.

(c) Changes in direction that cannot be made in accordance with (a) above shall be made with elbow-type fittings.

(d) Field-fabricated miter fittings are not permitted.

(e) Branch connections shall be made only with socket-type tees or other suitable fittings specifically designed for the purpose.

842.3.5 Field Repairs of Gouges and Punctures. Injurious gouges or punctures shall be removed by cutting out and replacing the damaged portion as a cylinder or repaired in accordance with para. 852.5.2.

842.3.6 Hot Taps. All hot taps shall be installed by trained and experienced crews.

842.3.7 Purging. Purging of plastic mains and service lines shall be done in accordance with the applicable provisions of paras. 841.2.7(e) and (f).

842.4 Testing Plastic Piping After Construction

842.4.1 General Provisions

(a) Pressure Testing. All plastic piping shall be pressure tested after construction and before being placed in operation to demonstrate that it does not leak.

(b) Tie-Ins. Because it is sometimes necessary to divide a pipeline or main into sections for testing, and to install test heads, connecting piping, and other necessary appurtenances, it is not required that the tie-in

sections of piping be tested. The tie-in joints, however, shall be tested for leaks at line pressure.

842.4.2 Test Requirements

(a) The test procedure used, including the duration of the test, shall be capable of disclosing all leaks in the section being tested and shall be selected after giving due consideration to the volumetric content of the section and its location.

(b) Thermoplastic piping shall not be tested at material temperatures above 140°F (60°C), and reinforced thermosetting plastic piping shall not be tested at material temperatures above 150°F (66°C). The duration of the test of thermoplastic piping above 100°F (38°C), however, shall not exceed 96 hr.

(c) Sufficient time for joints to "set" properly must be allowed before the test is initiated.

(d) Plastic pipelines and mains shall be tested at a pressure not less than 1.5 times the maximum operating pressure or 50 psig (340 kPa), whichever is greater, except that

(1) the test pressure for reinforced thermosetting plastic piping shall not exceed 3.0 times the design pressure of the pipe

(2) the test pressure for thermoplastic piping shall not exceed 3.0 times the design pressure of the pipe at temperatures up to and including 100°F (38°C) or 2.0 times the design pressure at temperatures exceeding 100°F (38°C)

(e) Gas, air, or water may be used as the test medium.

842.4.3 Safety During Tests. All testing after construction shall be done with due regard for the safety of employees and the public during the test.

842.5 Copper Mains

842.5.1 Design of Copper Mains

(a) Requirements. When used for gas mains, copper pipe or tubing shall conform to the following requirements:

(1) Copper pipe or tubing shall not be used for mains where the pressure exceeds 100 psig (690 kPa).

(2) Copper pipe or tubing shall not be used for mains where the gas carried contains more than an average of 0.3 grains of hydrogen sulfide per 100 standard cubic feet (2.8 m^3) of gas. This is equivalent to a trace as determined by a lead acetate test.

(3) Copper tubing or pipe for mains shall have a minimum wall thickness of 0.065 in. (1.65 mm) and shall be hard drawn.

(4) Copper pipe or tubing shall not be used for mains where strain or external loading may damage the piping.

(b) Valves in Copper Piping. Valves installed in copper lines may be made of any suitable material permitted by this Code.

(c) Fittings in Copper Piping. It is recommended that fittings in copper piping and exposed to the soil, such as service tees, pressure control fittings, etc., be made of bronze, copper, or brass.

(d) Joints in Copper Pipe and Tubing. Copper pipe shall be joined using either a compression-type coupling or a brazed or soldered lap joint. The filler material used for brazing shall be a copper–phosphorus alloy or silver base alloy. Butt welds are not permissible for joining copper pipe or tubing. Copper tubing shall not be threaded, but copper pipe with wall thickness equivalent to the comparable size of Schedule 40 steel pipe, i.e., ranging from 0.068 in. (1.73 mm) for NPS ⅛ (DN 6) to 0.406 in. (10.31 mm) for NPS 12 (DN 300), may be threaded and used for connecting screwed fittings or valves.

(e) Protection Against Galvanic Corrosion. Provision shall be made to prevent harmful galvanic action where copper is connected underground to steel. [See para. 861.1.3(a).]

842.5.2 Testing of Copper Mains After Construction. All copper mains shall be tested after construction in accordance with the provisions of para. 841.3.5.

843 COMPRESSOR STATIONS

843.1 Compressor Station Design

843.1.1 Location of Compressor Building. Except for offshore pipelines, the main compressor building for gas compressor stations should be located at such clear distances from adjacent property not under control of the operating company as to minimize the hazard of communication of fire to the compressor building from structures on adjacent property. Sufficient open space should be provided around the building to permit the free movement of firefighting equipment.

843.1.2 Building Construction. All compressor station buildings that house gas piping in sizes larger than NPS 2 (DN 50) or equipment handling gas (except equipment for domestic purposes) shall be constructed of noncombustible or limited combustible materials as defined in NFPA 220.

843.1.3 Exits. A minimum of two exits shall be provided for each operating floor of a main compressor building, basements, and any elevated walkway or platform 10 ft (3 m) or more above ground or floor level. Individual engine catwalks shall not require two exits. Exits of each such building may be fixed ladders, stairways, etc. The maximum distance from any point on an operating floor to an exit shall not exceed 75 ft (23 m), measured along the centerline of aisles or walkways. Exits shall be unobstructed doorways located so as to provide a convenient possibility of escape and shall provide unobstructed passage to a place of safety. Door latches shall be of a type that can be readily opened from the inside without a key. All swinging doors located in an exterior wall shall swing outward.

843.1.4 Fenced Areas. Any fence that may hamper or prevent escape of persons from the vicinity of a compressor station in an emergency shall be provided with a minimum of two gates. These gates shall be located so as to provide a convenient opportunity for escape to a place of safety. Any such gates located within 200 ft (61 m) of any compressor plant building shall open outward and shall be unlocked (or capable of being opened from the inside without a key) when the area within the enclosure is occupied. Alternatively, other facilities affording a similarly convenient exit from the area may be provided.

843.2 Electrical Facilities

All electrical equipment and wiring installed in gas transmission and distribution compressor stations shall conform to the requirements of NFPA 70, insofar as the equipment commercially available permits.

Electrical installations in hazardous locations as defined in NFPA 70 and that are to remain in operation during compressor station emergency shutdown as provided in para. 843.3.3(a)(1) shall be designed to conform to NFPA 70 for Class I, Division 1 requirements.

843.3 Compressor Station Equipment

(16) **843.3.1 Gas Treating Facilities**

(a) Liquid Removal. When condensable vapors are present in the gas stream in sufficient quantity to liquefy under the anticipated pressure and temperature conditions, the suction stream to each stage of compression (or to each unit for centrifugal compressors) shall be protected against the introduction of dangerous quantities of entrained liquids into the compressor. Every liquid separator used for this purpose shall be provided with manually operated facilities for removal of liquids therefrom. In addition, automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm shall be used where slugs of liquid might be carried into the compressors.

(b) Liquid Removal Equipment. Liquid separators shall be manufactured in accordance with Section VIII of the BPV Code, except that those constructed of pipe and fittings without any components welded to the inside of the pipe may be constructed in accordance with ASME B31.8 utilizing a design factor of 0.4. The designer of the liquid removal equipment shall apply an appropriate corrosion allowance and shall address all liquid and water hammer loads so that Code-allowable stresses are not exceeded.

843.3.2 Fire Protection. Fire protection facilities should be provided in accordance with the American Insurance Association's recommendations. If the fire pumps are a part of such facilities, their operation shall not be affected by emergency shutdown facilities.

843.3.3 Safety Devices

(a) Emergency Shutdown Facilities

(1) Except as noted or clarified in (a)(2) through (a)(4), compressor station shall be provided with an emergency shutdown system by means of which the gas can be blocked out of the station and the station gas piping blown down. Operation of the emergency shutdown system also shall cause the shutdown of all gas compressing equipment and all gas-fired equipment. Operation of this system shall de-energize the electrical facilities located in the vicinity of gas headers and in the compressor room, except those that provide emergency lighting for personnel protection and those that are necessary for protection of equipment. The emergency shutdown system shall be operable from any one of at least two locations outside the gas area of the station, preferably near exit gates in the station fence, but not more than 500 ft (150 m) from the limits of the stations. Blowdown piping shall extend to a location where the discharge of gas is not likely to create a hazard to the compressor station or surrounding area.

(2) Unattended field compressor stations of 1,000 hp (746 kW) and less are excluded from the provisions of (a)(1).

(3) Each compressor station supplying gas directly to a distribution system shall be provided with emergency shutdown facilities located outside the compressor station buildings by means of which all gas can be blocked out of the station, provided there is another adequate source of gas for the distribution system. These shutdown facilities can be either automatic or manually operated as local conditions designate. When no other gas source is available, no shutdown facilities that might function at the wrong time and cause an outage on the distribution system shall be installed.

(4) Notwithstanding the exceptions in (a)(2) and (a)(3), each compressor station handling gas that contains quantities or concentrations of hydrogen sulfide and/or liquids sufficient to present an environmental or safety hazard shall be provided with an emergency shutdown system. The emergency shutdown system and automatic or manual blowdown processes and equipment must be designed to prevent the automatic release of hydrogen sulfide, condensable vapors, or free liquids into the atmosphere in concentrations that may be hazardous to the operator or the general public.

(b) Engine Overspeed Stops. Every compressor prime mover, except electrical induction or synchronous motors, shall be provided with an automatic device that is designed to shut down the unit before the maximum safe speed of either the prime mover or driven unit, as established by the respective manufacturers, is exceeded.

843.3.4 Pressure-Limiting Requirements in Compressor Stations

(a) Pressure Relief. Pressure relief or other suitable protective devices of sufficient capacity and sensitivity shall be installed and maintained to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10%.

(b) Pressure Relief Valves. A pressure relief valve or pressure-limiting device, such as a pressure switch or unloading device, shall be installed in the discharge line of each positive displacement transmission compressor between the gas compressor and the first discharge block valve. If a pressure relief valve is the primary overprotection device, then the relieving capacity shall be equal to or greater than the capacity of the compressor. If the relief valves on the compressor do not prevent the possibility of overpressuring the pipeline as specified in section 845, a relieving or pressure-limiting device shall be installed on the pipeline to prevent it from being overpressured beyond the limits prescribed by this Code.

(c) Venting. Vent lines provided to exhaust the gas from the pressure relief valves to atmosphere shall be extended to a location where the gas may be discharged without undue hazard. Vent lines shall have sufficient capacity so that they will not inhibit the performance of the relief valve. For additional design considerations, see para. 841.1.9(d).

843.3.5 Fuel Gas Control. An automatic device designed to shut off the fuel gas when the engine stops shall be provided on each gas engine operating with pressure gas injection. The engine distribution manifold shall be automatically vented simultaneously.

843.3.6 Cooling and Lubrication Failures. All gas compressor units shall be equipped with shutdown or alarm devices to operate in the event of inadequate cooling or lubrication of the units.

843.3.7 Explosion Prevention

(a) Mufflers. The external shell of mufflers for engines using gas as fuel shall be designed in accordance with good engineering practice and shall be constructed of ductile materials. It is recommended that all compartments of the muffler be manufactured with vent slots or holes in the baffles to prevent gas from being trapped in the muffler.

(b) Building Ventilation. Ventilation shall be ample to ensure that employees are not endangered under normal operating conditions (or such abnormal conditions as a blown gasket, packing gland, etc.) by accumulations of hazardous concentrations of flammable or noxious vapors or gases in rooms, sumps, attics, pits, or similarly enclosed places, or in any portion thereof.

(c) LPG Ventilation. All liquefied petroleum gases are heavier than air; hence, structures aboveground for housing regulators, meters, etc., shall have open vents near the floor level. Such equipment shall not be installed in pits or in underground vaults, except in cases where suitable provisions for forced ventilation are made.

(d) LPG Special Precautions. Special care is required in the location of relief valve discharge vents releasing LPG to the atmosphere to prevent accumulation of the heavy gases at or below ground level. Likewise, special precautions are necessary for adequate ventilation where excavations are made for the repair of leaks in an underground LPG distribution system.

843.3.8 Gas Detection and Alarm Systems

(a) Each compressor building in a compressor station where hazardous concentrations of gas may accumulate shall have a fixed gas detection and alarm system unless the building is

(1) constructed so that at least 50% of its upright side area is permanently open to the atmosphere or adequately ventilated by forced or natural ventilation, or

(2) in an unattended field compressor station location of 1,000 hp (746 kW) or less and adequately ventilated

(b) Except when shutdown of the system is necessary for maintenance (see para. 853.1.6), each gas detection and alarm system required by this section shall

(1) continuously monitor the compressor building for a concentration of gas in air of not more than 25% of the lower explosive limit

(2) warn persons about to enter the building and persons inside the building of the danger if that concentration of gas is exceeded

(c) The compressor building configuration shall be considered in selecting the number, type, and placement of detectors and alarms.

(d) Alarm signals shall be unique and immediately recognizable, considering background noise and lighting, to personnel who are inside or immediately outside each compressor building.

843.4 Compressor Station Piping

843.4.1 Gas Piping. The following are general provisions applicable to all gas piping:

(a) Specifications for Gas Piping. All compressor station gas piping, other than instrument, control, and sample piping, up to and including connections to the main pipeline shall be of steel and shall use a design factor, *F*, per Table 841.1.6-2. Valves having shell components made of ductile iron may be used subject to the limitations in para. 831.1.1(b).

(b) Installation of Gas Piping. The provisions of para. 841.2 shall apply where appropriate to gas piping in compressor stations.

(c) Testing of Gas Piping. All gas piping within a compressor station shall be tested after installation in accordance with the provisions of para. 841.3 for pipelines and

mains in Location Class 3, except that small additions to operating stations need not be tested where operating conditions make it impractical to test.

(d) Identification of Valves and Piping. All emergency valves and controls shall be identified by signs. The function of all important gas pressure piping shall be identified by signs or color codes.

843.4.2 Fuel Gas Piping. The following are specific provisions applicable to compressor station fuel gas piping only:

(a) All fuel gas lines within a compressor station that serve the various buildings and residential areas shall be provided with master shutoff valves located outside of any building or residential area.

(b) The pressure-regulating facilities for the fuel gas system for a compressor station shall be provided with pressure-limiting devices to prevent the normal operating pressure of the system from being exceeded by more than 25%, or the maximum allowable operating pressure by more than 10%.

(c) Suitable provision shall be made to prevent fuel gas from entering the power cylinders of an engine and actuating moving parts while work is in progress on the engine or on equipment driven by the engine.

(d) All fuel gas used for domestic purposes at a compressor station that has an insufficient odor of its own to serve as a warning in the event of its escape shall be odorized as prescribed in section 856.

843.4.3 Air Piping System

(a) All air piping within gas compressing stations shall be constructed in accordance with ASME B31.3.

(b) The starting air pressure, storage volume, and size of connecting piping shall be adequate to rotate the engine at the cranking speed and for the number of revolutions necessary to purge the fuel gas from the power cylinder and muffler. The recommendations of the engine manufacturer may be used as a guide in determining these factors. Consideration should be given to the number of engines installed and to the possibility of having to start several of these engines within a short period of time.

(c) A check valve shall be installed in the starting air line near each engine to prevent backflow from the engine into the air piping system. A check valve shall also be placed in the main air line on the immediate outlet side of the air tank or tanks. It is recommended that equipment for cooling the air and removing the moisture and entrained oil be installed between the starting air compressor and the air storage tanks.

(d) Suitable provision shall be made to prevent starting air from entering the power cylinders of an engine and actuating moving parts while work is in progress on the engine or on equipment driven by the engines. Acceptable means of accomplishing this are installing a blind flange, removing a portion of the air supply piping, or locking closed a stop valve and locking open a vent downstream from it.

(e) Air receivers or air storage bottles for use in compressor stations shall be constructed and equipped in accordance with Section VIII of the BPV Code.

843.4.4 Lubricating Oil Piping. All lubricating oil piping within gas compressing stations shall be constructed in accordance with ASME B31.3.

843.4.5 Water Piping. All water piping within gas compressing stations shall be constructed in accordance with ASME B31.1.

843.4.6 Steam Piping. All steam piping within gas compressing stations shall be constructed in accordance with ASME B31.1 or ASME B31.3. **(16)**

843.4.7 Hydraulic Piping. All hydraulic power piping within gas compressing stations shall be constructed in accordance with ASME B31.3.

844 PIPE-TYPE AND BOTTLE-TYPE HOLDERS

844.1 Pipe-Type Holders in Rights-of-Way Not Under Exclusive Use and Control of the Operating Company

A pipe-type holder that is to be installed in streets, highways, or in private rights-of-way not under the exclusive control and use of the operating company shall be designed, installed, and tested in accordance with the provisions of this Code applicable to a pipeline installed in the same location and operated at the same maximum pressure.

844.2 Bottle-Type Holders

Bottle-type holders shall be located on land owned or under the exclusive control and use of the operating company.

844.3 Pipe-Type and Bottle-Type Holders on Property Under the Exclusive Use and Control of the Operating Company

(a) The storage site shall be entirely surrounded with fencing to prevent access by unauthorized persons.

(b) A pipe-type or bottle-type holder that is to be installed on property under the exclusive control and use of the operating company shall be designed in accordance with construction design factors. The selection of these factors depends on the Location Class in which the site is situated, the clearance between the pipe containers or bottles and the fence, and the maximum operating pressure, as shown in Table 844.3-1.

(c) The minimum clearance between containers and the fenced boundaries of the site is fixed by the maximum operating pressure of the holder as shown in Table 844.3-2.

Table 844.3-1 Design Factors, *F*

Holder Size Location Class	Design Factors, *F*: For Minimum Clearance Between Containers and Fenced Boundaries of Site of 25 ft (7.6 m) to 100 ft (30 m)	Design Factors, *F*: For Minimum Clearance Between Containers and Fenced Boundaries of Site of 100 ft (30 m) and Over
1	0.72	0.72
2	0.60	0.72
3	0.60	0.60
4	0.40	0.40

Table 844.3-2 Minimum Clearance Between Containers and Fenced Boundaries

Maximum Operating Pressure, psig (kPa)	Minimum Clearance, ft (m)
Less than 1,000 (6 900)	25 (7.6)
1,000 (6 900) or more	100 (30)

(d) The minimum clearance in inches (millimeters) between pipe containers or bottles shall be determined by the following formula:

(U.S. Customary Units)

$$C = \frac{3DPF}{1{,}000}$$

(SI Units)

$$\left(C = \frac{3DPF}{6\,895}\right)$$

where

C = minimum clearance between pipe containers or bottles, in. (mm)
D = outside diameter of pipe container or bottle, in. (mm)
F = design factor [see (b) above]
P = maximum allowable operating pressure, psig (kPa)

(e) Pipe containers shall be buried with the top of each container not less than 24 in. (610 mm) below the ground surface.

(f) Bottles shall be buried with the top of each container below the normal frost line but in no case closer than 24 in. (610 mm) to the surface.

(g) Pipe-type holders shall be tested in accordance with the provisions of para. 841.3.2 for a pipeline located in the same Location Class as the holder site, provided, however, that in any case where the test pressure will produce a hoop stress of 80% or more of the specified minimum yield strength of the pipe, water shall be used as the test medium.

844.4 Special Provisions Applicable to Bottle-Type Holders Only

A bottle-type holder may be manufactured from steel that is not weldable under field conditions, subject to all of the following limitations:

(a) Bottle-type holders made from alloy steel shall meet the chemical and tensile requirements for the various grades of steel in ASTM A372.

(b) In no case shall the ratio of actual yield strength to actual tensile strength exceed 0.85.

(c) Welding shall not be performed on such bottles after they have been heat treated and/or stress relieved, except that it shall be permissible to attach small copper wires to the small diameter portion of the bottle end closure for cathodic protection purposes using a localized thermit welding process (charge not to exceed 15 g).

(d) Such bottles shall be given a hydrostatic test in the mill and need not be retested hydrostatically at the time of installation. The mill test pressure shall not be less than that required to produce a hoop stress equal to 85% of the specified minimum yield strength of the steel. Careful inspection of the bottles at the time of installation shall be made, and no damaged bottle shall be used.

(e) Such bottles and connecting piping shall be tested for tightness after installation using air or gas at a pressure of 50 psi (340 kPa) above the maximum operating pressure.

844.5 General Provisions Applicable to Both Pipe-Type and Bottle-Type Holders

(a) No gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet (2.8 m^3) shall be stored when free water is present or anticipated without employing suitable means to identify, mitigate, or prevent detrimental internal corrosion. (See section 864.)

(b) Provision shall be made to prevent the formation or accumulation of liquids in the holder, connecting piping, and auxiliary equipment that might cause corrosion or interfere with the safe operation of the storage equipment.

Relief valves shall be installed in accordance with provisions of this Code that will have relieving capacity adequate to limit the pressure imposed on the filling line and thereby on the storage holder to 100% of the design pressure of the holder or to the pressure that produces a hoop stress of 75% of the specified minimum yield strength of the steel, whichever is the lesser.

845 CONTROL AND LIMITING OF GAS PRESSURE

845.1 Basic Requirement for Protection Against Accidental Overpressuring

Every pipeline, main, distribution system, customer's meter and connected facilities, compressor station, pipe-type holder, bottle-type holder, containers fabricated from pipe and fittings, and all special equipment, if connected to a compressor or to a gas source where the failure of pressure control or other causes might result in a pressure that would exceed the maximum allowable operating pressure of the facility (refer to para. 805.2.1), shall be equipped with suitable pressure-relieving or pressure-limiting devices. Special provisions for service regulators are set forth in para. 845.2.7.

845.2 Control and Limiting of Gas Pressure

845.2.1 Control and Limiting of Gas Pressure in Holders, Pipelines, and All Facilities That Might at Times Be Bottle Tight. Suitable types of protective devices to prevent overpressuring of such facilities include

(a) spring-loaded relief valves of types meeting the provisions of BPV Code, Section VIII

(b) pilot-loaded back-pressure regulators used as relief valves, so designed that failure of the pilot system or control lines will cause the regulator to open

(c) rupture disks of the type meeting the provisions of BPV Code, Section VIII, Division 1

845.2.2 Maximum Allowable Operating Pressure for Steel or Plastic Pipelines or Mains. This pressure is by definition the maximum operating pressure to which the pipeline or main may be subjected in accordance with the requirements of this Code. For a pipeline or main, the maximum allowable operating pressure shall not exceed the lesser of the following four items:

(a) The design pressure (defined in para. 805.2.1) of the weakest element of the pipeline or main. Assuming that all fittings, valves, and other accessories in the line have an adequate pressure rating, the maximum allowable operating pressure of a pipeline or main shall be the design pressure determined in accordance with para. 841.1.1 for steel or para. 842.2 for plastic.

(b) The pressure obtained by dividing the pressure to which the pipeline or main is tested after construction by the appropriate factor for the Location Class involved, as shown in Table 845.2.2-1.

(c) The maximum safe pressure to which the pipeline or main should be subjected based on its operating and maintenance history (for pipelines, see para. 851.1).

(d) When service lines are connected to the pipeline or main, the limitations set forth in paras. 845.2.4(c)(2) and (c)(5).

845.2.3 Qualification of a Steel Pipeline or Main to Establish the MAOP

(a) Pipeline Operating at 100 psig (690 kPa) or More. This paragraph applies to existing natural gas pipelines or to existing pipelines being converted to natural gas service where one or more factors of the steel pipe design formula (see para. 841.1.1) is unknown, and the pipeline is to be operated at 100 psig (690 kPa) or more. The maximum allowable operating pressure shall be determined by hydrostatic testing of the pipeline.

Table 845.2.2-1 Maximum Allowable Operating Pressure for Steel or Plastic Pipelines or Mains

Location Class	Pressure for Steel [Note (1)]	Pressure for Plastic
1, Division 1	$\frac{\text{Test pressure}}{1.25}$	N.A.
1, Division 2	$\frac{\text{Test pressure}}{1.25}$	$\frac{\text{Test pressure}}{1.50}$
2	$\frac{\text{Test pressure}}{1.25}$	$\frac{\text{Test pressure}}{1.50}$
3	$\frac{\text{Test pressure [Note (2)]}}{1.50}$	$\frac{\text{Test pressure}}{1.50}$
4	$\frac{\text{Test pressure [Note (2)]}}{1.50}$	$\frac{\text{Test pressure}}{1.50}$

NOTES:
(1) See para. 845.2.3 for test factors applicable to conversion of pipelines with unknown factors.
(2) Other factors should be used if the line was tested under the special conditions described in paras. 841.3.2(d) and (i), and 841.3.3. In such cases, use factors that are consistent with the applicable requirements of these sections.

Table 845.2.3-1 Maximum Allowable Operating Pressure for Pipelines Operating at 100 psig (690 kPa) or More

Location Class	Maximum Allowable Operating Pressure
1, Division 1	$\frac{\text{Test pressure}}{1.25}$
1, Division 2	$\frac{\text{Test pressure}}{1.39}$
2	$\frac{\text{Test pressure}}{1.67}$
3	$\frac{\text{Test pressure}}{2.0}$
4	$\frac{\text{Test pressure}}{2.5}$

(1) The maximum allowable operating pressure shall be limited to the pressure obtained by dividing the pressure to which the pipeline or main is tested by the appropriate factor for the Location Class involved as shown in Table 845.2.3-1.

(2) The test pressure to be used in the maximum allowable operating pressure calculation shall be the test pressure obtained at the high elevation point of the minimum strength test section and shall not be higher than the pressure required to produce a hoop stress equal

Table 845.2.3-2 Maximum Allowable Operating Pressure for Pipelines Operating at Less Than 100 psig (690 kPa)

Location Class	Maximum Allowable Operating Pressure
1	$\frac{\text{Test pressure}}{1.25}$
2	$\frac{\text{Test pressure}}{1.25}$
3	$\frac{\text{Test pressure}}{1.5}$
4	$\frac{\text{Test pressure}}{1.5}$

to the yield strength as determined by testing. Only the first test to yield can be used to determine maximum allowable operating pressure.

(3) Records of hydrostatic pressure tests and line repairs shall be preserved as long as the facilities involved remain in service.

(4) Determine that all valves, flanges, and other pressure rated components have adequate ratings.

(5) While the maximum pressure of a test used to establish the maximum allowable working pressure is not limited by this paragraph except by (a)(2) above, due caution should be exercised in selecting the maximum test pressure.

(b) Pipelines Operating at Less Than 100 psig (690 kPa). This paragraph applies to existing natural gas pipelines or to existing pipelines being converted to natural gas service where one or more factors of the steel pipe design formula (see para. 841.1.1) is unknown, and the pipeline is to be operated at less than 100 psig (690 kPa). The maximum allowable operating pressure shall be determined by pressure testing the pipeline.

(1) The maximum allowable operating pressure shall be limited to the pressure obtained by dividing the pressure to which the pipeline or main is tested by the appropriate factor for the Location Class involved as shown in Table 845.2.3-2.

(2) The test pressure to be used in the maximum allowable operating pressure calculation shall be the test pressure obtained at the high elevation point of the minimum strength test section and shall not be higher than the pressure required to produce a hoop stress equal to the yield strength as determined by testing. Only the first test to yield can be used to determine maximum allowable operating pressure.

(3) Records of pressure tests and line repairs shall be preserved as long as the facilities involved remain in service.

(4) Determine that all valves, flanges, and other pressure rated components have adequate ratings.

(5) Although the maximum pressure of a test utilized to establish the maximum allowable working pressure is not limited by this paragraph except by (b)(2) above, due caution should be exercised in selecting the maximum test pressure.

845.2.4 Control and Limiting of Gas Pressure in High-Pressure Steel, Ductile Iron, Cast Iron, or Plastic Distribution Systems

(a) Each high-pressure distribution system or main, supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system, shall be equipped with pressure-regulating devices of adequate capacity and designed to meet the pressure, load, and other service conditions under which they will operate or to which they may be subjected.

(b) In addition to the pressure-regulating devices prescribed in (a), a suitable method shall be provided to prevent accidental overpressuring of a high-pressure distribution system.

Suitable types of protective devices to prevent overpressuring of high-pressure distribution systems include

(1) relief valves as prescribed in paras. 845.2.1(a) and (b).

(2) weight-loaded relief valves.

(3) a monitoring regulator installed in series with the primary pressure regulator.

(4) a series regulator installed upstream from the primary regulator and set to limit the pressure on the inlet of the primary regulator continuously to the maximum allowable operating pressure of the distribution system or less.

(5) an automatic shutoff device installed in series with the primary pressure regulator and set to shut off when the pressure on the distribution system reaches the maximum allowable operating pressure or less. This device must remain closed until manually reset. It should not be used where it might cause an interruption in service to a large number of customers.

(6) spring-loaded, diaphragm-type relief valves.

(c) Maximum Allowable Operating Pressure for High-Pressure Distribution Systems. This pressure shall be the maximum pressure to which the system can be subjected in accordance with the requirements of this Code. It shall not exceed

(1) the design pressure of the weakest element of the system as defined in para. 805.2.1

(2) 60 psig (410 kPa) if the service lines in the system are not equipped with series regulators or other pressure-limiting devices as prescribed in para. 845.2.7(c)

(3) 25 psig (170 kPa) in cast iron systems having caulked bell and spigot joints, which have not been

equipped with bell joint clamps or other effective leak sealing methods

(4) the pressure limits to which any joint could be subjected without possibility of parting

(5) 2 psig (14 kPa) in high-pressure distribution systems equipped with service regulators not meeting the requirements of para. 845.2.7(a) and that do not have an overpressure protective device as required in para. 845.2.7(b)

(6) the maximum safe pressure to which the system should be subjected based on its operation and maintenance history

845.2.5 Control and Limiting of Gas Pressure in Low-Pressure Distribution Systems

(a) Each low-pressure distribution system or low-pressure main supplied from a gas source that is at a higher pressure than the maximum allowable operating pressure for the low-pressure system shall be equipped with pressure-regulating devices of adequate capacity. These devices must be designed to meet the pressure, load, and other service conditions under which they will have to operate.

(b) In addition to the pressure-regulating devices prescribed in (a), a suitable device shall be provided to prevent accidental overpressuring. Suitable types of protective devices to prevent overpressuring of low-pressure distribution systems include

(1) a liquid seal relief device that can be set to open accurately and consistently at the desired pressure

(2) weight-loaded relief valves

(3) an automatic shutoff device as described in para. 845.2.4(b)(5)

(4) a pilot-loaded, back-pressure regulator as described in para. 845.2.1(b)

(5) a monitoring regulator as described in para. 845.2.4(b)(3)

(6) a series regulator as described in para. 845.2.4(b)(4)

(c) Maximum Allowable Operating Pressure for Low-Pressure Distribution Systems. The maximum allowable operating pressure for a low-pressure distribution system shall not exceed either of the following:

(1) a pressure that would cause the unsafe operation of any connected and properly adjusted low-pressure gas burning equipment

(2) a pressure of 2 psig (14 kPa)

845.2.6 Conversion of Low-Pressure Distribution Systems to High-Pressure Distribution Systems

(a) Before converting a low-pressure distribution system to a high-pressure distribution system, it is required that the following factors be considered:

(1) the design of the system, including kinds of material and equipment used

(2) past maintenance records, including results of any previous leakage surveys

(b) Before increasing the pressure, the following steps (not necessarily in sequence shown) shall be taken:

(1) Make a leakage survey and repair leaks found.

(2) Reinforce or replace parts of the system found to be inadequate for the higher operating pressures.

(3) Install a service regulator on each service line, and test each regulator to determine that it is functioning. In some cases it may be necessary to raise the pressure slightly to permit proper operation of the service regulators.

(4) Isolate the system from adjacent low-pressure systems.

(5) At bends or offsets in coupled or bell and spigot pipe, reinforce or replace anchorages determined to be inadequate for the higher pressures.

(c) The pressure in the system being converted shall be increased by steps, with a period to check the effect of the previous increase before making the next increase. The desirable magnitude of each increase and the length of the check period will vary depending on conditions. The objective of this procedure is to afford an opportunity to discover any unknown open and unregulated connections to adjacent low-pressure systems or to individual customers before excessive pressures are reached.

845.2.7 Control and Limiting of the Pressure of Gas Delivered to Domestic, Small Commercial, and Small Industrial Customers From High-Pressure Distribution Systems

(a) If the maximum allowable operating pressure of the distribution system is 60 psig (410 kPa) or less, and a service regulator having the following characteristics is used, no other pressure-limiting device is required:

(1) a pressure regulator capable of reducing distribution line pressure, psig (kPa), to pressures recommended for household appliances, inches (millimeters) of water column

(2) a single port valve with orifice diameter no greater than that recommended by the manufacturer for the maximum gas pressure at the regulator inlet

(3) a valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, and cutting by the valve, and designed to resist permanent deformation when it is pressed against the valve port

(4) pipe connections to the regulator not exceeding NPS 2 (DN 50)

(5) the capability under normal operating conditions of regulating the downstream pressure within the necessary limits of accuracy and of limiting the buildup of pressure under no-flow conditions to no more than 50% over the normal discharge pressure maintained under flow conditions

(6) a self-contained service regulator with no external static or control lines

(b) If the maximum allowable operating pressure of the distribution system is 60 psig (410 kPa) or less, and a service regulator not having all of the characteristics

listed in (a) is used, or if the gas contains materials that seriously interfere with the operation of service regulators, suitable protective devices shall be installed to prevent unsafe overpressuring of the customer's appliances, should the service regulator fail. Some of the suitable types of protective devices to prevent overpressuring of the customers' appliances are

(1) a monitoring regulator

(2) a relief valve

(3) an automatic shutoff device

These devices may be installed as an integral part of the service regulator or as a separate unit.

(c) If the maximum allowable operating pressure of the distribution system exceeds 60 psig (410 kPa), suitable methods shall be used to regulate and limit the pressure of the gas delivered to the customer to the maximum safe value. Such methods may include

(1) a service regulator having the characteristics listed in (a) and a secondary regulator located upstream from the service regulator. In no case shall the secondary regulator be set to maintain a pressure higher than 60 psig (410 kPa). A device shall be installed between the secondary regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 psig (410 kPa) or less in case the secondary regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts if the pressure on the inlet of the service regulator exceeds the set pressure [60 psig (410 kPa) or less] and remains closed until manually reset.

(2) a service regulator and a monitoring regulator set to limit to a maximum safe value the pressure of the gas delivered to the customer.

(3) a service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer shall not exceed a maximum safe value. The relief valve may be either built into the service regulator or may be a separate unit installed downstream from the service regulator. This combination may be used alone only in cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and it is not recommended for use where the inlet pressure on the service regulator exceeds 125 psig (860 kPa). For higher inlet pressures, the method in (c)(1) or (c)(2) should be used.

(d) When the pressure of the gas and the demand by the customer are greater than those applicable under the provisions of (a), (b), and (c), the requirements for control and limiting of the pressure of gas delivered are included in para. 845.1.

845.3 Requirements for Design of Pressure Relief and Pressure-Limiting Installations

(a) Pressure relief or pressure-limiting devices except rupture disks shall

(1) be constructed of materials such that the operation of the device will not normally be impaired by corrosion of external parts by the atmosphere or internal parts by gas

(2) have valves and valve seats that are designed not to stick in a position that will make the device inoperative and result in failure of the device to perform in the manner for which it was intended

(3) be designed and installed so that they can be readily operated to determine if the valve is free, can be tested to determine the pressure at which they will operate, and can be tested for leakage when in the closed position

(4) be designed and installed such that operation is not impaired at the minimum design temperature

(b) Rupture discs shall meet the requirements for design as set out in BPV Code, Section VIII, Division 1.

(c) The discharge stacks, vents, or outlet ports of all pressure relief devices shall be located where gas can be discharged into the atmosphere without undue hazard. Consideration should be given to all exposures in the immediate vicinity, including where gas pipelines parallel overhead electric transmission lines on the same right-of-way to ensure that the blowdown connections will direct the gas away from the electric conductors. Where required to protect devices, the discharge stacks or vents shall be protected with rain caps to preclude the entry of water.

(d) The size of the openings, pipe, and fittings located between the system to be protected and the pressure-relieving device and the vent line shall be of adequate size to prevent hammering of the valve and to prevent impairment of relief capacity.

(e) Precautions shall be taken to prevent unauthorized operation of any stop valve that will make a pressure relief valve inoperative. This provision shall not apply to valves that will isolate the system under protection from its source of pressure. Acceptable methods for complying with this provision are as follows:

(1) Lock the stop valve in the open position. Instruct authorized personnel of the importance of not inadvertently leaving the stop valve closed and of being present during the entire period that the stop valve is closed so that they can lock it in the open position before they leave the location.

(2) Install duplicate relief valves, each having adequate capacity by itself to protect the system, and arrange the isolating valves or three-way valve so that mechanically it is possible to render only one safety device inoperative at a time.

(f) Precautions shall be taken to prevent unauthorized operation of any valve that will make pressure-limiting devices inoperative. This provision applies to isolating valves, bypass valves, and valves on control or float lines that are located between the pressure-limiting device and the system that the device protects. A method similar to that described in (e)(1) shall be considered acceptable in complying with this provision.

(g) When a monitoring regulator, series regulator, system relief, or system shutoff is installed at a district regulator station to protect a piping system from overpressuring, the installation shall be designed and installed to prevent any single incident, such as an explosion in a vault or damage by a vehicle or icing (both internal and external), from affecting the operation of both the overpressure protective device and the district regulator. (See sections 846 and 847.)

(h) Special attention shall be given to control lines. All control lines shall be protected from falling objects, excavations by others, or other foreseeable causes of damage and shall be designed and installed to prevent damage to any one control line from making both the district regulator and the overpressure protective device inoperative.

845.4 Capacity of Pressure-Relieving and Pressure-Limiting Station and Devices

(16) **845.4.1 Required Capacity of Pressure-Relieving and Pressure-Limiting Stations**

(a) Each pressure relief station, pressure-limiting station, or group of such stations installed to protect a piping system or pressure vessel shall have sufficient capacity and shall be set to operate to prevent the pressure from exceeding the following levels:

(1) Systems With Pipe or Pipeline Components Operating at Hoop Stress Levels Over 72% of the SMYS. The required capacity shall not be less than the capacity required to prevent the pressure from exceeding the maximum allowable operating pressure plus 4%.

(2) Systems With Pipe or Pipeline Components Operating at Hoop Stress Levels at or Below 72% of the SMYS Other Than in Low-Pressure Distribution Systems. The required capacity shall not be less than the capacity required to prevent the pressure from exceeding the lesser of the following two items:

(-a) the maximum allowable operating pressure plus 10%

(-b) the pressure that produces a hoop stress of 75% of the specified minimum yield strength

(3) Low-Pressure Distribution Systems. The required capacity shall not be less than the capacity required to prevent the pressure from exceeding a pressure that would cause the unsafe operation of any connected and properly adjusted gas burning equipment.

(4) Pressure Vessels. Pressure vessels shall be protected against overpressure in accordance with the BPV Code, Section VIII, Division 1.

(b) When more than one pressure-regulating or compressor station feeds into the pipeline or distribution system and pressure relief devices are installed at such stations, the relieving capacity at the remote station may be taken into account in sizing the relief devices at each station. In doing this, however, the assumed remote relieving capacity must be limited to the capacity of the piping system to transmit gas to the remote location or to the capacity of the remote relief device, whichever is less.

845.4.2 Proof of Adequate Capacity and Satisfactory Performance of Pressure-Limiting and Pressure Relief Devices. Where the safety device consists of an additional regulator that is associated with or functions in combination with one or more regulators in a series arrangement to control or limit the pressure in a piping system, suitable checks shall be made. These checks shall be conducted to determine that the equipment will operate in a satisfactory manner to prevent any pressure in excess of the established maximum allowable operating pressure of the system, should any one of the associated regulators malfunction or remain in the wide-open position.

845.5 Instrument, Control, and Sample Piping

845.5.1 Scope

(a) The requirements given in this section apply to the design of instrument, control, and sampling piping for safe and proper operation of the piping itself and do not cover design of piping to secure proper functioning of instruments for which the piping is installed.

(b) This section does not apply to permanently closed piping systems, such as fluid-filled, temperature-responsive devices.

845.5.2 Materials and Design

(a) The materials employed for valves, fittings, tubing, and piping shall be designed to meet the particular conditions of service.

(b) Takeoff connections and attaching bosses, fittings, or adapters shall be made of suitable material and shall be capable of withstanding the maximum and minimum operating pressures and temperatures of the piping or equipment to which they are attached. They shall be designed to satisfactorily withstand all stresses without failure by fatigue.

(c) A shutoff valve shall be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves shall be installed where necessary for the safe operation of piping, instruments, and equipment.

(d) Brass pipe or copper pipe or tubing shall not be used for metal temperatures greater than 400°F (204°C).

(e) Piping subject to clogging from solids or deposits shall be provided with suitable connections for cleaning.

(f) Pipe or tubing required under this section may be specified by the manufacturers of the instrument, control apparatus, or sampling device, provided that the safety of the pipe or tubing as installed is at least equal to that otherwise required under the Code.

(g) Piping that may contain liquids shall be protected by heating or other suitable means from damage due to freezing.

(h) Piping in which liquids may accumulate shall be provided with drains or drips.

(i) The arrangement of piping and supports shall be designed to provide not only for safety under operating stresses, but also to provide protection for the piping against detrimental sagging, external mechanical injury, abuse, and damage due to unusual service conditions other than those connected with pressure, temperature, and service vibration.

(j) Suitable precautions shall be taken to protect against corrosion. (See section 864.)

(k) Joints between sections of tubing and/or pipe, between tubing and/or pipe and valves or fittings shall be made in a manner suitable for the pressure and temperature conditions, such as by means of flared, flareless, and compression-type fittings, or equal, or they may be of the brazed, screwed, or socket-welded type. If screwed-end valves are to be used with flared, flareless, or compression-type fittings, adapters are required.

Slip-type expansion joints shall not be used; expansion shall be compensated for by providing flexibility within the piping or tubing system itself.

(l) Plastic shall not be used where operating temperatures exceed limitations shown in paras. 842.2.2(b) and 842.2.3(b).

(m) Plastic piping shall not be painted. If identification other than that already provided by the manufacturer's marking is required, it shall be accomplished by other means.

846 VALVES[4]

846.1 Required Spacing of Valves

846.1.1 Transmission Lines. Onshore block valves shall be installed in new transmission pipelines at the time of construction for the purpose of isolating the pipeline for maintenance and for response to operating emergencies. When determining the placement of such valves for sectionalizing the pipeline, primary consideration shall be given to locations that provide continuous accessibility to the valves.

(a) In determining the number and spacing of valves to be installed, the operator shall perform an assessment that gives consideration to factors such as

(1) the amount of gas released due to repair and maintenance blowdowns, leaks, or ruptures

(2) the time to blow down an isolated section

(3) the impact in the area of gas release (e.g., nuisance and any hazard resulting from prolonged blowdowns)

(4) continuity of service

(5) operating and maintenance flexibility of the system

(6) future development in the vicinity of the pipeline

(7) significant conditions that may adversely affect the operation and security of the line

(b) In lieu of (a) above, the following maximum spacing between valves shall be used:

(1) 20 mi (32 km) in areas of predominantly Location Class 1

(2) 15 mi (24 km) in areas of predominantly Location Class 2

(3) 10 mi (16 km) in areas of predominantly Location Class 3

(4) 5 mi (8 km) in areas of predominantly Location Class 4

The spacing defined above may be adjusted to permit a valve to be installed in a location that is more accessible.

846.1.2 Distribution Mains. Valves on distribution mains, whether for operating or emergency purposes, shall be spaced as follows:

(a) High-Pressure Distribution Systems. Valves shall be installed in high-pressure distribution systems in accessible locations to reduce the time to shut down a section of main in an emergency. In determining the spacing of the valves, consideration should be given to the operating pressure and size of the mains and local physical conditions as well as the number and type of consumers that might be affected by a shutdown.

(b) Low-Pressure Distribution Systems. Valves may be used on low-pressure distribution systems but are not required except as specified in para. 846.2.2(a).

846.2 Location of Valves

846.2.1 Transmission Valves

(a) Sectionalizing block valves shall be accessible and protected from damage and tampering. If a blowdown valve is involved, it shall be located where the gas can be blown to the atmosphere without undue hazard.

(b) Sectionalizing valves may be installed above ground, in a vault, or buried. In all installations an operating device to open or close the valve shall be readily accessible to authorized persons. All valves shall be suitably supported to prevent settlement or movement of the attached piping.

(c) Blowdown valves shall be provided so that each section of pipeline between main line valves can be blown down. The sizes and capacity of the connections for blowing down the line shall be such that under emergency conditions the section of line can be blown down as rapidly as is practicable.

(d) This Code does not require the use of automatic valves nor does the Code imply that the use of automatic valves presently developed will provide full protection to a piping system. Their use and installation shall be at the discretion of the operating company.

[4] See paras. 849.1.2 and 849.1.3 for provisions covering valves in service lines.

846.2.2 Distribution System Valves

(a) A valve shall be installed on the inlet piping of each regulator station controlling the flow or pressure of gas in a distribution system. The distance between the valve and the regulator or regulators shall be sufficient to permit the operation of the valve during an emergency, such as a large gas leak or a fire in the station.

(b) Valves on distribution mains, whether for operating or emergency purposes, shall be located in a manner that will provide ready access and facilitate their operation during an emergency. Where a valve is installed in a buried box or enclosure, only ready access to the operating stem or mechanism is implied. The box or enclosure shall be installed in a manner to avoid transmitting external loads to the main.

847 VAULTS

847.1 Structural Design Requirements

Underground vaults or pits for valves and pressure-relieving, pressure-limiting, or pressure-regulating stations, etc., shall be designed and constructed in accordance with the following provisions:

(a) Vaults and pits shall be designed and constructed in accordance with good structural engineering practice to meet the loads that may be imposed on them.

(b) Sufficient working space shall be provided so that all of the equipment required in the vault can be properly installed, operated, and maintained.

(c) In the design of vaults and pits for pressure-limiting, pressure-relieving, and pressure-regulating equipment, consideration shall be given to the protection of the installed equipment from damage, such as that resulting from an explosion within the vault or pit that may cause portions of the roof or cover to fall into the vault.

(d) Pipe entering and within regulator vaults or pits shall be steel for NPS 10 (DN 250) and smaller sizes, except that control and gage piping may be copper. Where piping extends through the vault or pit structure, provision shall be made to prevent the passage of gases or liquids through the opening and to avert strains in the piping. Equipment and piping shall be suitably sustained by metal, masonry, or concrete supports. The control piping shall be placed and supported in the vault or pit so that its exposure to injury or damage is reduced to a minimum.

(e) Vault or pit openings shall be located so as to minimize the hazards of tools or other objects falling on the regulator, piping, or other equipment. The control piping and the operating parts of the equipment installed shall not be located under a vault or pit opening where workmen can step on them when entering or leaving the vault or pit, unless such parts are suitably protected.

(f) Whenever a vault or pit opening is to be located above equipment that could be damaged by a falling cover, a circular cover should be installed, or other suitable precautions should be taken.

847.2 Accessibility

Accessibility shall be considered in selecting a site for a vault. Some of the important factors to consider in selecting the location of a vault are as follows:

(a) Exposure to Traffic. The location of vaults in street intersections or at points where traffic is heavy or dense should be avoided.

(b) Exposure to Flooding. Vaults should not be located at points of minimum elevation, near catch basins, or where the access cover will be in the course of surface waters.

(c) Exposure to Adjacent Subsurface Hazards. Vaults should be located as far as is practical from water, electric, steam, or other facilities.

847.3 Vault Sealing, Venting, and Ventilation

Underground vaults and closed top pits containing either a pressure-regulating or reduction station, or a pressure-limiting or relieving station shall be sealed, vented, or ventilated as follows:

(a) When the internal volume exceeds 200 ft^3 (5.7 m^3), such vaults or pits shall be ventilated with two ducts each having at least the ventilating effect of an NPS 4 (DN 100) pipe.

(b) The ventilation provided shall be sufficient to minimize the possible formation of a combustible atmosphere in the vault or pit. Vents associated with the pressure-regulating or pressure-relieving equipment must not be connected to the vault or pit ventilation.

(c) The ducts shall extend to a height above grade adequate to disperse any gas–air mixtures that might be discharged. The outside end of the ducts shall be equipped with a suitable weatherproof fitting or vent head designed to prevent foreign matter from entering or obstructing the duct. The effective area of the opening in such fittings or vent heads shall be at least equal to the cross-sectional area of an NPS 4 (DN 100) duct. The horizontal section of the ducts shall be as short as practical and shall be pitched to prevent the accumulation of liquids in the line. The number of bends and offsets shall be reduced to a minimum, and provisions shall be incorporated to facilitate the periodic cleaning of the ducts.

(d) Such vaults or pits having an internal volume between 75 ft^3 and 200 ft^3 (2.1 m^3 and 5.7 m^3) may be either sealed, vented, or ventilated. If sealed, all openings shall be equipped with tight-fitting covers without open holes through which an explosive mixture might be ignited. Means shall be provided for testing the internal atmosphere before removing the cover. If vented, the proper provision to prevent external sources of ignition

from reaching the vault atmosphere must be provided. If ventilated, the provisions of either (a), (b), and (c) above or (e) below shall apply.

(e) If vaults or pits referred to in (d) above are ventilated by means of openings in the covers or gratings, and the ratio of the internal volume in cubic feet (m^3) to the effective ventilating area of the cover or grating in square feet (m^2) is less than 20 to 1, no additional ventilation is required.

(f) Vaults or pits having an internal volume less than 75 ft^3 (2.1 m^3) have no specific requirements.

847.4 Drainage and Waterproofing

(a) Provisions shall be made to minimize the entrance of water into vaults. Nevertheless, vault equipment shall always be designed to operate safely, if submerged.

(b) No vault containing gas piping shall be connected by means of a drain connection to any other substructure, such as a sewer.

(c) Electrical equipment in vaults shall conform to the requirements of Class 1, Group D of NFPA 70.

848 CUSTOMERS' METERS AND REGULATORS

848.1 Location for Customers' Meter and Regulator Installations

(a) Customers' meters and regulators may be located either inside or outside of buildings, depending on local conditions, except that on service lines requiring series regulation, in accordance with para. 845.2.7(c), the upstream regulator shall be located outside of the building.

(b) When installed within a building, the service regulator shall be in a readily accessible location near the point of gas service line entrance, and whenever practical, the meters shall be installed at the same location. Neither meters nor regulators shall be installed in bedrooms, closets, or bathrooms; under combustible stairways; in unventilated or inaccessible places; or closer than 3 ft (0.9 m) to sources of ignition, including furnaces and water heaters. On service lines supplying large industrial customers or installations where gas is used at higher than standard service pressure, the regulators may be installed at other readily accessible locations.

(c) When located outside of buildings, meters and service regulators shall be installed in readily accessible locations where they will be reasonably protected from damage.

(d) Regulators requiring vents for their proper and effective operation shall be vented to the outside atmosphere in accordance with the provisions of para. 848.3.3. Individual vents shall be provided for each regulator.

848.2 Operating Pressures for Customers' Meter Installations

Iron or aluminum case meters shall not be used at a maximum operating pressure higher than the manufacturer's rating for the meter. New tinned steel case meters shall not be used at a pressure in excess of 50% of the manufacturer's test pressure; rebuilt tinned steel case meters shall not be used at a pressure in excess of 50% of the pressure used to test the meter after rebuilding.

848.3 Protection of Customers' Meter and Regulator Installations From Damage

848.3.1 Corrosive Area. Meters and service regulators shall not be installed where rapid deterioration from corrosion or other causes is likely to occur, unless proven measures are taken to protect against such deterioration.

848.3.2 Protective Device. A suitable protective device, such as a back-pressure regulator or a check valve, shall be installed downstream of the meter if and as required under the following conditions:

(a) If the nature of the utilization equipment is such that it may induce a vacuum at the meter, install a back-pressure regulator downstream from the meter.

(b) Install a check valve or equivalent if

(1) the utilization equipment may induce a back-pressure.

(2) the gas utilization equipment is connected to a source of oxygen or compressed air.

(3) liquefied petroleum gas or other supplementary gas is used as standby and may flow back into the meter. A three-way valve, installed to admit the standby supply and at the same time shut off the regular supply, can be substituted for a check valve if desired.

848.3.3 Termination of Vents. All service regulator vents and relief vents, where required, shall terminate in the outside air in rain- and insect-resistant fittings. The open end of the vent shall be located where the gas can escape freely into the atmosphere and away from any openings into the buildings if a regulator failure resulting in the release of gas occurs. At locations where service regulators may be submerged during floods, either a special antiflood type breather vent fitting shall be installed or the vent line shall be extended above the height of the expected flood waters.

848.3.4 Pit and Vault Design. Pits and vaults housing customers' meters and regulators shall be designed to support vehicular traffic when installed in the following locations:

(a) traveled portions of alleys, streets, and highways
(b) driveways

848.4 Installation of Meters and Regulators

All meters and regulators shall be installed in such a manner as to prevent undue stresses on the connecting piping and/or the meter. Lead (Pb) connections or other connections made of material that can be easily damaged shall not be used. The use of standard weight close (all thread) nipples is prohibited.

849 GAS SERVICE LINES

849.1 General Provisions Applicable to Steel, Copper, and Plastic Service Lines

849.1.1 Installation of Service Lines

(a) Service lines shall be installed at a depth that will protect them from excessive external loading and local activities, such as gardening. It is required that a minimum of 12 in. (300 mm) of cover be provided in private property and a minimum of 18 in. (460 mm) of cover be provided in streets and roads. Where these cover requirements cannot be met due to existing substructures, less cover is permitted provided such portions of these service lines that are subject to excessive superimposed loads are cased or bridged or the pipe is appropriately strengthened.

(b) Service lines shall be properly supported at all points on undisturbed or well-compacted soil so that the pipe will not be subject to excessive external loading by the backfill. The material used for the backfill shall be free of rocks, building materials, etc., that may cause damage to the pipe or the protective coating.

(c) Where there is evidence of condensate in the gas in sufficient quantities to cause interruptions in the gas supply to the customer, the service line shall be graded so as to drain into the main or to drips at the low points in the service line.

849.1.2 Types of Valves Suitable for Service Line Valves

(a) Valves used as service line valves shall meet the applicable requirements of section 810 and para. 831.1.

(b) The use of soft seat service line valves is not recommended when the design of the valves is such that exposure to excessive heat could adversely affect the ability of the valve to prevent the flow of gas.

(c) A valve incorporated in a meter bar that permits the meter to be bypassed does not qualify under this Code as a service line valve.

(d) Service line valves on high-pressure service lines, installed either inside buildings or in confined locations outside buildings where the blowing of gas would be hazardous, shall be designed and constructed to minimize the possibility of the removal of the core of the valve accidentally or willfully with ordinary household tools.

(e) The operating company shall make certain that the service line valves installed on high-pressure service lines are suitable for this use either by making their own tests or by reviewing the tests made by the manufacturers.

(f) On service lines designed to operate at pressures in excess of 60 psig (410 kPa), the service line valves shall be the equivalent of a pressure-lubricated valve or a needle-type valve. Other types of valves may be used where tests by the manufacturer or by the user indicate that they are suitable for this kind of service.

849.1.3 Location of Service Line Valves

(a) Service line valves shall be installed on all new service lines (including replacements) in a location readily accessible from the outside.

(b) Valves shall be located upstream of the meter if there is no regulator, or upstream of the regulator, if there is one.

(c) All service lines operating at a pressure greater than 10 psig (69 kPa) and all service lines NPS 2 (DN 50) or larger shall be equipped with a valve located on the service line outside of the building, except that whenever gas is supplied to a theater, church, school, factory, or other building where large numbers of persons assemble, an outside valve will be required, regardless of the size of the service line or the service line pressure.

(d) Underground valves shall be located in a covered durable curb box or standpipe designed to permit ready operation of the valve. The curb box or standpipe shall be supported independently of the service line.

849.1.4 Location of Service Line Connections to Main Piping. It is recommended that service lines be connected to either the top or the side of the main. The connection to the top of the main is preferred to minimize the possibility of dust and moisture being carried from the main into the service line.

849.1.5 Testing of Service Lines After Construction

(a) General Provisions. Each service line shall be tested after construction and before being placed in service to demonstrate that it does not leak. The service line connection to the main need not be included in this test if it is not feasible to do so.

(b) Test Requirements

(1) Service lines to operate at a pressure less than 1 psig (7 kPa) that do not have a protective coating capable of temporarily sealing a leak shall be given a standup air or gas pressure test at not less than 10 psig (69 kPa) for at least 5 min.

(2) Service lines to operate at a pressure less than 1 psig (7 kPa) that have a protective coating that might temporarily seal a leak, and all service lines to operate at a pressure of 1 psig (7 kPa) or more, shall be given a standup air or gas pressure test for at least 5 min at the proposed maximum operating pressure or 90 psig (620 kPa), whichever is greater. Service lines of steel, however, that are operating at hoop stress levels of 20% or more of the specified minimum yield strength shall be tested in accordance with the requirements for testing mains. (See para. 841.3.)

(3) The requirements of (a) and (b) above shall apply to plastic service lines, except that plastic service lines shall be tested to at least 1.5 times the maximum

operating pressure, and the limitations on maximum test pressure, temperature, and duration set forth in para. 842.4.2 shall be observed.

849.2 Steel Service Lines

849.2.1 Design of Steel Service Lines

(a) Steel pipe, when used for service lines, shall conform to the applicable requirements of Chapter I.

(b) Steel service pipe shall be designed in accordance with the requirements of paras. 841.1.1 and 841.1.9(a). Where the pressure is less than 100 psig (690 kPa), the steel service pipe shall be designed for at least 100 psig (690 kPa) pressure.

(c) Steel pipe used for service lines shall be installed in such a manner that the piping strain or external loading shall not be excessive.

(d) All underground steel service lines shall be joined by threaded and coupled joints, compression-type fittings, or by qualified welding or brazing methods, procedures, and operators.

849.2.2 Installation of Steel Service Lines

(a) Installation of Steel Service Lines in Bores

(1) When coated steel pipe is to be installed as a service line in a bore, care shall be exercised to prevent damage to the coating during installation.

(2) When a service line is to be installed by boring or driving, and coated steel pipe is to be used, it shall not be used as the bore pipe or drive pipe and left in the ground as part of the service line unless it has been demonstrated that the coating is sufficiently durable to withstand the boring or driving operation in the type of soil involved without significant damage to the coating. Where significant damage to the coating may result from boring or driving, the coated service line should be installed in an oversized bore or casing pipe of sufficient diameter to accommodate the service pipe.

(3) In exceptionally rocky soil, coated pipe shall not be inserted through an open bore if significant damage to the coating is likely.

(b) Installation of Service Lines Into or Under Buildings

(1) Underground steel service lines, when installed below grade through the outer foundation wall of a building, shall be either encased in a sleeve or otherwise protected against corrosion. The service line and/or sleeve shall be sealed at the foundation wall to prevent entry of gas or water into the building.

(2) Steel service lines, where installed underground under buildings, shall be encased in a gas-tight conduit. When such a service line supplies the building it subtends, the conduit shall extend into a normally usable and accessible portion of the building. At the point where the conduit terminates, the space between the conduit and the service line shall be sealed to prevent the possible entrance of any gas leakage. The casing shall be vented at a safe location.

849.3 Ductile Iron Service Lines

When used for service lines, ductile iron pipe shall meet the applicable requirements of section 842. Ductile iron pipe may be used for service lines except for the portion of the service line that extends through the building wall. Ductile iron service lines shall not be installed in unstable soils or under buildings.

849.4 Plastic Service Lines

849.4.1 Design of Plastic Service Lines

(a) Plastic pipe and tubing shall be used for service lines only where the piping strain or external loading will not be excessive.

(b) Plastic pipe, tubing, cements, and fittings used for service lines shall conform to the applicable requirements of Chapter I.

(c) Plastic service lines shall be designed in accordance with the applicable requirements of para. 842.2.

(d) Plastic service lines shall be joined in accordance with the applicable requirements of para. 842.2.9.

849.4.2 Installation of Plastic Service Lines

(a) Plastic service lines shall be installed in accordance with the applicable requirements of paras. 842.3 and 849.1.1. Particular care must be taken to prevent damage to plastic service line piping at the connection to the main or other facility. Precautions shall be taken to prevent crushing or shearing of plastic piping due to external loading or settling of backfill and to prevent damage or pullout from the connection resulting from thermal expansion or contraction. [See paras. 842.3.3(d) and (e).]

(b) Notwithstanding the limitations imposed in para. 842.3.3, a plastic service line may terminate above ground and outside the building, provided that

(1) the aboveground portion of the plastic service line is completely enclosed in a conduit or casing of sufficient strength to provide protection from external damage and deterioration. Where a flexible conduit is used, the top of the riser must be attached to a solid support. The conduit or casing shall extend a minimum of 6 in. (150 mm) below grade.

(2) the plastic service line is not subjected to external loading stresses by the customer's meter or its connecting piping.

(c) Installation of Plastic Service Lines Into or Under Buildings

(1) An underground plastic service line installed through the outer foundation or wall of a building shall be encased in a rigid sleeve with suitable protection from shearing action or backfill settlement. The sleeve shall extend past the outside face of the foundation a sufficient distance to reach undisturbed soil or thoroughly compacted backfill. At the point where the sleeve terminates inside the foundation or wall, the space between the sleeve and the service line shall be sealed to prevent leakage into the building. The plastic service line shall not be exposed inside the building.

(2) A plastic service line installed underground under a building shall be encased in a gas-tight conduit.

When such a service line supplies the building it subtends, the conduit shall extend into a normally usable and accessible portion of the building. At the point where the conduit terminates, the space between the conduit and the service line shall be sealed to prevent leakage into the building. The plastic service line shall not be exposed inside the building. The casing shall be vented at a safe location.

849.5 Copper Service Lines

849.5.1 Design of Copper Service Lines

(a) Use of Copper Service Lines. Copper pipe or tubing, when used for service lines, shall conform to the following requirements:

(1) Copper pipe or tubing shall not be used for service lines where the pressure exceeds 100 psig (690 kPa).

(2) Copper pipe or tubing shall not be used for service lines where the gas carried contains more than an average of 0.3 grains of hydrogen sulfide per 100 standard cubic feet (2.8 m^3) of gas. This is equivalent to a trace as determined by a lead-acetate test.

(3) The minimum wall thickness for copper pipe or tubing used for service lines shall be not less than type "L" as specified in ASTM B88.

(4) Copper pipe or tubing shall not be used for service lines where strain or external loading may damage the piping.

(b) Valves in Copper Piping. Valves installed in copper service lines may be made of any suitable material permitted by this Code.

(c) Fittings in Copper Piping. It is recommended that fittings in copper piping and exposed to the soil, such as service line tees, pressure control fittings, etc., be made of bronze, copper, or brass.

(d) Joints in Copper Pipe and Tubing. Copper pipe shall be joined by using either a compression-type coupling or a brazed or soldered lap joint. The filler material used for brazing shall be a copper–phosphorus alloy or silver base alloy. Butt welds are not permissible for joining copper pipe or tubing. Copper tubing shall not be threaded, but copper pipe with a wall thickness equivalent to the comparable size of Schedule 40 steel pipe, i.e., ranging from 0.068 in. (1.73 mm) for NPS $\frac{1}{8}$ (DN 6) to 0.406 in. (10.31 mm) for NPS 12 (DN 300), may be threaded and used for connecting screwed fittings or valves.

(e) Protection Against Galvanic Action Caused by Copper. Provisions shall be made to prevent harmful galvanic action where copper is connected underground to steel. [See para. 861.1.3(a).]

849.5.2 Installation of Copper Service Lines. The following requirements shall apply to copper service lines within buildings:

(a) Copper service lines may be installed within buildings, provided that the service line is not concealed and is suitably protected against external damage.

(b) An underground copper service line installed through the outer foundation wall of a building shall be either encased in a sleeve or otherwise protected against corrosion. The annular space between the service line and sleeve shall be sealed at the foundation wall to prevent entry of gas or water.

(c) A copper service line installed underground under buildings shall be encased in a conduit designed to prevent gas leaking from the service line from getting into the building. When joints are used, they shall be of brazed or soldered type in accordance with para. 849.5.1(d).

849.6 Service Line Connections to Mains

849.6.1 Service Line Connections to Steel Mains. Service lines may be connected to steel mains by

(a) welding a service line tee or similar device to the main.

(b) using a service line clamp or saddle.

(c) using compression fittings with rubber or rubber-like gaskets or welded connections to connect the service line to the main connection fitting. Gaskets used in a manufactured gas system shall be of a type that effectively resists that type of gas.

(d) welding a steel service line directly to the main (see para. 831.4.2 and Table 831.4.2-1).

849.6.2 Service Line Connection to Cast Iron and Ductile Iron Mains

(a) Service lines may be connected to cast iron and ductile iron mains by

(1) drilling and tapping the main, provided the diameter of the tapped hole shall not exceed the limitations imposed by para. 831.3.3(b), or

(2) using a reinforcing sleeve

(b) Service line connections shall not be brazed directly to cast iron or ductile iron mains.

(c) Compression fittings using rubber or rubber-like gaskets or welded connections may be used to connect the service line to the main connection fitting.

(d) Gaskets used in a manufactured gas system shall be of a type that effectively resists that type of gas.

849.6.3 Service Line Connections to Plastic Mains

(a) Plastic or metal service lines shall be connected to plastic mains with suitable fittings.

(b) A compression-type service line to main connection shall be designed and installed to effectively sustain the longitudinal pullout forces caused by contraction of the piping or external loading.

849.6.4 Service Line Connections to Copper Mains

(a) Connections using a copper or cast bronze service line tee or extension fitting sweat-brazed to the copper main are recommended for copper mains.

(b) Butt welds are not permitted.

(c) Fillet-brazed joints are not recommended.

(d) The requirements of para. 849.5.1(d) shall apply to

(1) joints not specifically mentioned in (a) through (c)

(2) all brazing material

849.6.5 Plastic Service Line Connections to Metal Mains

(a) Plastic service lines shall be connected to metal mains with a suitable metallic or plastic main fitting as provided in para. 849.6.1, 849.6.2, or 849.6.4 having a compression end or other suitable transition fitting.

(b) A compression-type service line to main connection shall be designed and installed to effectively sustain the longitudinal pullout forces caused by contraction of the piping or external loading.

Chapter V
Operating and Maintenance Procedures

850 OPERATING AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF GAS TRANSMISSION AND DISTRIBUTION FACILITIES

850.1 General

(a) Because of many variables, it is not possible to prescribe in a code a detailed set of operating and maintenance procedures that will encompass all cases. It is possible, however, for each operating company to develop operating and maintenance procedures based on the provisions of this Code, its experience, and its knowledge of its facilities and conditions under which they are operated that will be adequate from the standpoint of public safety. For operating and maintenance procedures relating to corrosion control, see Chapter VI.

(b) Upon initiating gas service in a pipeline designed and constructed or converted to gas service in accordance with this Code, the operating company shall determine the Location Class in accordance with Table 854.1-1.

850.2 Basic Requirements

Each operating company having facilities within the scope of this Code shall

(a) have a written plan covering operating and maintenance procedures in accordance with the scope and intent of this Code.

(b) have a written emergency plan covering facility failure or other emergencies.

(c) operate and maintain its facilities in conformance with these plans.

(d) modify the plans periodically as experience dictates and as exposure of the public to the facilities and changes in operating conditions require.

(e) provide training for employees in procedures established for their operating and maintenance functions that is comprehensive and designed to prepare employees for service in their area of responsibility. See section 807 for guidance on the training and qualification of personnel performing tasks that could impact the safety or integrity of a pipeline.

(f) keep records to administer the plans and training properly.

850.3 Essential Features of the Operating and Maintenance Plan

The plan prescribed in para. 850.2(a) shall include

(a) detailed plans and instructions for employees covering operating and maintenance procedures for gas facilities during normal operations and repairs.

(b) items recommended for inclusion in the plan for specific classes of facilities that are given in paras. 851.2, 851.3, 851.4, 851.5, 851.6, and 860.1(d).

(c) plans to give particular attention to those portions of the facilities presenting the greatest hazard to the public in the event of an emergency or because of construction or extraordinary maintenance requirements.

(d) provisions for periodic inspections along the route of existing steel pipelines or mains, operating at a hoop stress in excess of 40% of the specified minimum yield strength of the pipe material to consider the possibility of Location Class changes. It is not intended that these inspections include surveys of the number of buildings intended for human occupancy. (See section 854.)

850.4 Essential Features of the Emergency Plan

850.4.1 Written Emergency Procedures. Each operating company shall establish written procedures that will provide the basis for instructions to appropriate operating and maintenance personnel that will minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures shall provide for the following:

(a) a system for receiving, identifying, and classifying emergencies that require immediate response by the operating company

(b) indicating clearly the responsibility for instructing employees in the procedures listed in the emergency plans and for training employees in the execution of those procedures

(c) indicating clearly those responsible for updating the plan

(d) establishing a plan for prompt and adequate handling of all calls that concern emergencies whether they are from customers, the public, company employees, or other sources

(e) establishing a plan for the prompt and effective response to a notice of each type of emergency

(f) controlling emergency situations, including the action to be taken by the first employee arriving at the scene

(g) the dissemination of information to the public

(h) the safe restoration of service to all facilities affected by the emergency after proper corrective measures have been taken

(i) reporting and documenting the emergency

850.4.2 Training Program. Each operating company shall have a program for informing, instructing, and training employees responsible for executing emergency procedures. The program shall acquaint the employee with the emergency procedures and how to promptly and effectively handle emergency situations. The program may be implemented by oral instruction, written instruction, and, in some instances, group instruction, followed by practice sessions. The program shall be established and maintained on a continuing basis with provision for updating as necessitated by revision of the written emergency procedures. Program records shall be maintained to establish what training each employee has received and the date of such training.

850.4.3 Liaison

(a) Each operating company shall establish and maintain liaison with appropriate fire, police, and other public officials, entities in or near the pipeline right-of-way (e.g., electrical and other utilities, highway authorities, and railroads), and news media.

(b) Each operating company must have a means of communication with appropriate public officials during an emergency.

(c) Emergency procedures, including the contingency plan under para. B854.5(e), must be prepared in coordination with appropriate public officials.

850.4.4 Educational Program. An educational program shall be established to enable customers and the general public to recognize a gas emergency and report it to the appropriate officials. The educational program shall be tailored to the type of pipeline operation and the environment traversed by the pipeline and shall be conducted in each language that is significant in the community served. Operators of distribution systems shall communicate their programs to consumers and the general public in their distribution area. Operators of transmission systems shall communicate their programs to residents along their pipeline rights-of-way. Operators of sour gas pipelines subject to Chapter IX shall notify residents affected by the contingency plan under para. B854.5(e) of the hazards of sour gas, the potential source of the gas, and protective measures to take in an emergency. The programs of operators in the same area shall be coordinated to properly direct reports of emergencies and to avoid inconsistencies.

850.5 Pipeline Failure Investigation

Each operating company shall establish procedures to analyze all failures and accidents for determining the cause and to minimize the possibility of a recurrence. This plan shall include a procedure to select samples of the failed facility or equipment for laboratory examination when necessary.

850.6 Prevention of Accidental Ignition

Smoking and all open flames shall be prohibited in and around structures, or areas under the control of the operating company containing gas facilities (such as compressor stations, meter and regulator stations, and other gas handling equipment), where possible leakage of gas constitutes a hazard of fire or explosion. Each operating company shall take steps to minimize the danger of accidental ignition of gas.

(a) When a hazardous amount of gas is to be vented into open air, each potential source of ignition shall first be removed from the area and adequate fire extinguishers shall be provided. All flashlights, lighting fixtures, extension cords, and tools shall be of a type approved for hazardous atmospheres. Blowdown connections that will direct the gas away from any electrical transmission lines must be installed or used.

(b) Suitable signs and flagmen or guards, if necessary, shall be posted to warn others approaching or entering the area of the hazard.

(c) To prevent accidental ignition by electric arcing, an adequate bonding cable should be connected to each side of any pipe that is to be parted, tapped, squeezed-off, or joined, and any cathodic protection rectifiers in the area shall be turned off. Where gas pipelines parallel overhead electric transmission lines on the same right-of-way, the company operating the pipeline shall ensure that the current carrying capacity of the bonding conductor should be at least one-half of the current carrying capacity of the overhead line conductors. [See also para. 861.1.3(b).] The bonding connection is to be maintained while the pipeline is separated. When plastic pipe is being parted, tapped, or joined, attention must be given to the static electrical charges that may be present on both the inside and outside diameters of the pipe. These charges can be dissipated by using antistatic fluids or a water-and-detergent solution in combination with a moisture retaining material that must be in contact with the exposed pipe and the earth. Cutting tools and squeeze-off and tapping equipment used on plastic pipe where static charges may be present shall be grounded to drain these charges from the pipe.

(d) When cutting by torch or welding is to be performed, a thorough check shall first be made for the presence of a combustible gas mixture in the area outside of the pipeline. If found, the mixture shall be eliminated before starting welding or cutting. Monitoring of the air mixture should continue throughout the progress of the work.

(e) Should welding be anticipated on a pipeline filled with gas and the safety check under (d) above has been completed satisfactorily, the gas pressure must be controlled by a suitable means to keep a slight positive pressure in the pipeline at the welding area before starting work. Precautions should be taken to prevent a backdraft from occurring at the welding area.

(f) Before cutting by torch or welding on a line that may contain a mixture of gas and air, it shall be made safe by displacing the mixture with gas, air, or an inert gas. Caution must be taken when using an inert gas to provide adequate ventilation for all workers in the area.

850.7 Blasting Effects

Each operating company shall establish procedures for protection of facilities in the vicinity of blasting activities. The operating company shall

(a) locate and mark its pipeline when explosives are to be detonated within distances as specified in company plans. Consideration should be given to the marking of minimum blasting distances from the pipelines depending upon the type of blasting operation.

(b) determine the necessity and extent of observing or monitoring blasting activities based upon the proximity of the blast with respect to the pipelines, the size of charge, and soil conditions.

(c) conduct a leak survey following each blasting operation near its pipelines.

850.8 Damage Prevention Program

Each operating company shall have a program to reduce the risk associated with damage to gas facilities resulting from excavation activities. Operators should consider the following elements within the program:

(a) participation in excavation notification systems, in places where such a system exists. Excavation notification systems allow excavators to provide notification to a single point of contact, which in turn forwards the excavation details to participating facility owners/operators.

(b) identification of persons who normally perform excavations in the area in which the operator has facilities, including the public, and providing for periodic communication with these parties. The communication could include such items as: how to determine the location of facilities, how to get the facilities field marked prior to excavating, and who to contact in the event of damage to the operator's facility.

(c) a process for receiving notifications of planned excavations, providing the excavators with locations of the operator's facilities through temporary field markings, establishing lines of communication with the excavator to ensure the immediate protection and future operation of the facility, and consideration of monitoring excavation activities.

(d) performing inspections of pipelines where there are indications that the pipe could have been damaged as a result of excavation. If damage occurs that affects the integrity of the pipeline, the damage shall be remediated in accordance with established procedures.

(e) maintaining maps indicating the location of facilities. The maps should be updated to reflect new and replacement facilities.

(f) a process to ensure the effectiveness of the program. This process may include: trending of excavation damages and location, investigation of excavation damages and identification of root cause, and identification of preventive measures targeting excavators or locations with high damage rates.

A useful reference for identifying elements of an effective damage prevention program is the *Best Practices Guide*, maintained and published by the Common Ground Alliance.

851 PIPELINE MAINTENANCE

851.1 Periodic Surveillance of Pipelines

As a means of maintaining the integrity of its pipeline system, each operating company shall establish and implement procedures for periodic surveillance of its facilities. Studies shall be initiated and appropriate action shall be taken where unusual operating and maintenance conditions occur, such as failures, leakage history, drop in flow efficiency due to internal corrosion, or substantial changes in cathodic protection requirements.

When such studies indicate the facility is in unsatisfactory condition, a planned program shall be initiated to abandon, replace, or recondition and proof test. If such a facility cannot be reconditioned or phased out, the maximum allowable operating pressure shall be reduced commensurate with the requirements described in para. 845.2.2(c).

851.2 Pipeline Patrolling

Each operating company shall maintain a periodic pipeline patrol program to observe surface conditions on and adjacent to each pipeline right-of-way, indications of leaks, construction activity other than that performed by the company, natural hazards, and any other factors affecting the safety and operation of the pipeline. Patrols shall be performed at least once every year in Location Classes 1 and 2, at least once every 6 months in Location Class 3, and at least once every 3 months in Location Class 4. Weather, terrain, size of line, operating pressures, and other conditions will be factors in determining the need for more frequent patrol. Main highways and railroad crossings shall be inspected with greater frequency and more closely than pipelines in open country.

851.2.1 Maintenance of Cover at Road Crossings and Drainage Ditches. The operating company shall determine by periodic surveys if the cover over the pipeline at road crossings and drainage ditches has been reduced below the requirements of the original design. If the operating company determines that the normal cover provided at the time of pipeline construction has become unacceptably reduced due to earth removal or line movement, the operating company shall provide additional protection by providing barriers, culverts, concrete pads, casing, lowering of the line, or other suitable means.

851.2.2 Maintenance of Cover in Cross-Country Terrain. If the operating company learns, as a result of patrolling, that the cover over the pipeline in cross-country terrain does not meet the original design, it shall determine whether the cover has been reduced to an unacceptable level. If the level is unacceptable, the operating company shall provide additional protection by replacing cover, lowering the line, or other suitable means.

851.3 Leakage Surveys

Each operating company of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan. The types of surveys selected shall be effective for determining if potentially hazardous leakage exists. The extent and frequency of the leakage surveys shall be determined by the operating pressure, piping age, Location Class, and whether the transmission line transports gas without an odorant.

851.4 Repair Procedures for Steel Pipelines

Evaluation of pipeline defects and associated repair methods are discussed in paras. 851.4.1 through 851.4.5. Additional guidance may be found in Parts 2 and 3 of ASME PCC-2, Repair of Pressure Equipment and Piping, and in the following PRCI documents: Pipeline Repair Manual (original or updated version), and Pipeline Defect Assessment — A Review and Comparison of Commonly Used Methods. Information on these documents is found in Mandatory Appendix A.

If at any time a defect mentioned in the following subsections of para. 851.4 is evident on a pipeline, temporary measures shall be employed immediately to protect the property and the public. If it is not feasible to make repairs at the time of discovery, permanent repairs shall be made as soon as described herein. The use of a welded patch as a repair method is prohibited, except as provided in para. 851.4.4(e). Whenever a pipeline remains pressurized while being exposed to investigate or repair a likely defect, the operating pressure shall be at a level that provides safety during excavation, investigation and/or repair operations.

(a) If there is sufficient information about the defect to determine through engineering analysis the pressure at which excavation, investigation, and/or repair operations may be conducted safely, the pipeline shall be operated at or below this pressure during these activities.

(b) If there is insufficient information about the defect to determine the pressure at which excavation, investigation, and/or repair operations may be conducted safely, the pipeline shall be operated at a pressure no greater than 80% of the operating pressure at the time of discovery. The operating pressure shall remain at or below this reduced pressure during these activities unless sufficient information becomes available to determine a different pressure.

Nonleaking corroded areas that must be repaired or replaced are defined in para. 860.2(a). Longitudinal weld seams are commonly identified by visual inspection, etchants, or ultrasonic testing.

A full encirclement welded split sleeve with welded ends shall have a design pressure at least equal to that required for the maximum allowable operating pressure of the pipe being repaired [see para. 841.1.1(a)]. If conditions require that the sleeve carry the full longitudinal stresses, the sleeve shall be at least equal to the design strength of the pipe being repaired. Full encirclement sleeves shall not be less than 4 in. (100 mm) in width.

If the defect is not a leak, the circumferential fillet welds are optional in certain cases as described in the following sections of para. 851.4. If circumferential fillet welds are made, the sleeve's longitudinal welds shall be butt welds. The welding procedures for the circumferential fillet welds shall be suitable for the materials and shall consider the potential for underbead cracking. Backup strips are not required. If the circumferential fillet welds are not made, the longitudinal welds may be butt welds, or fillets to a side bar. The circumferential edges, which would have been sealed had the fillet weld been made, should be sealed with a coating material such as enamel or mastic, so that the soil environment will be kept out of the area under the sleeve.

Prior to the installation of a sleeve, the pipe body shall be inspected by ultrasonic methods for laminations where sleeve fillet welds will be deposited onto the pipe body.

Consideration shall be given to the toughness characteristics and quality of all seam welds when depositing welds across the seam in the course of repairs.

851.4.1 Definition of Injurious Dents and Mechanical Damage

(a) Dents are indentations of the pipe or distortions of the pipe's circular cross section caused by external forces.

(b) Plain dents are dents that vary smoothly and do not contain creases, mechanical damage [such as described in (c)], corrosion, arc burns, girth, or seam welds.

(c) Mechanical damage is damage to the pipe surface caused by external forces. Mechanical damage includes features such as creasing of the pipe wall, gouges, scrapes, smeared metal, and metal loss not due to corrosion. Cracking may or may not be present in conjunction with mechanical damage. Denting of the pipe may or may not be apparent in conjunction with mechanical damage.

(d) Plain dents are defined as injurious if they exceed a depth of 6% of the nominal pipe diameter. Plain dents of any depth are acceptable provided strain levels associated with the deformation do not exceed 6% strain. Strain levels may be calculated in accordance with Nonmandatory Appendix R or other engineering methodology. In evaluating the depth of plain dents, the need for the segment to be able to safely pass an internal inspection or cleaning device shall also be considered. Any dents that are not acceptable for this purpose should be removed prior to passing these devices through the segment, even if the dent is not injurious.

(e) All external mechanical damage with or without concurrent visible indentation of the pipe is considered injurious.

(f) Dents that contain corrosion are injurious if the corrosion is in excess of what is allowed by para. 860.2(a), or if they exceed a depth of 6% of the nominal pipe diameter.

(g) Dents that contain stress corrosion cracks or other cracks are injurious.

(h) Dents that affect ductile girth or seam welds are injurious if they exceed a depth of 2% of the nominal pipe diameter, except those evaluated and determined to be safe by an engineering analysis that considers weld quality, nondestructive examinations, and operation of the pipeline are acceptable provided strain levels associated with the deformation do not exceed 4%. It is the operator's responsibility to establish the quality level of the weld.

(i) Dents of any depth that affect nonductile welds, such as acetylene girth welds or seam welds that are prone to brittle fracture, are injurious.

(j) The allowable height of mild ripples in carbon steel pipe formed during the cold bending process can be determined from Fig. 851.4.1-1, where d is the maximum depth or crest-to-trough dimension of the ripple and D is the specified outside diameter of the pipe. Ripples in carbon steel pipe are acceptable if their height is below the line shown. Ripples with heights above the line may be demonstrated to be acceptable using a more rigorous analysis.

851.4.2 Permanent Field Repairs of Injurious Dents and Mechanical Damage

(a) Injurious dents and mechanical damage shall be removed or repaired by one of the methods below, or the operating pressure shall be reduced. The reduced pressure shall not exceed 80% of the operating pressure experienced by the injurious feature at the time of discovery. Pressure reduction does not constitute a permanent repair.

(b) Removal of injurious dents or mechanical damage shall be performed by taking the pipeline out of service and cutting out a cylindrical piece of pipe and replacing same with pipe of equal or greater design pressure, or by removing the defect by hot tapping, provided the entire defect is removed.

(c) Repairs of injurious dents or mechanical damage shall be performed as described below.

(1) Plain dents, dents containing corrosion, dents containing stress corrosion cracking, and dents affecting ductile girth welds or seams may be repaired with either a full encirclement steel sleeve with open ends or with ends welded to the pipe.

(2) External mechanical damage, and all dents affecting acetylene girth welds or seam welds that are known to exhibit brittle fracture characteristics may be repaired with a full encirclement steel sleeve with ends welded to the pipe.

(3) External mechanical damage, including cracks, may be repaired by grinding out the damage, provided any associated indentation of the pipe does not exceed a depth of 4% of the nominal pipe diameter. Grinding is permitted to a depth of 10% of the nominal pipe wall with no limit on length. Grinding is permitted to a depth greater than 10% up to a maximum of 40% of the pipe wall, with metal removal confined to a length given by the following equation:

(U.S. Customary Units)

$$L = 1.12\left[(Dt)\left(\left(\frac{a/t}{1.1a/t - 0.11}\right)^2 - 1\right)\right]^{1/2}$$

(SI Units)

$$\left[L = 28.45\left[(Dt)\left(\left(\frac{a/t}{1.1a/t - 0.11}\right)^2 - 1\right)\right]^{1/2}\right]$$

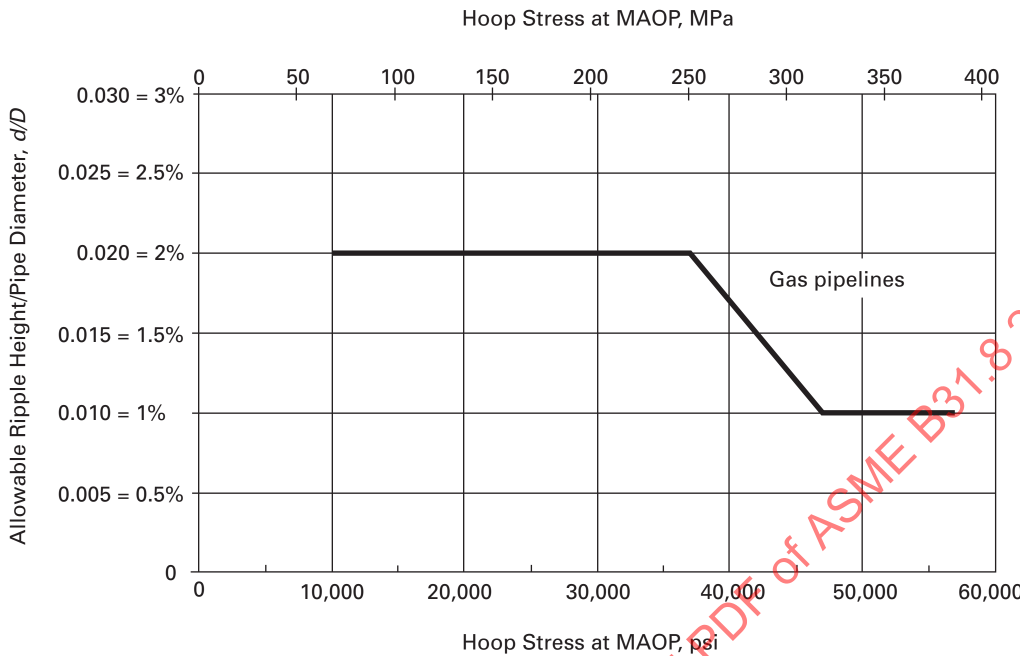
where

a = measured maximum depth of ground area, in. (mm)
D = nominal outside diameter of the pipe, in. (mm)
L = maximum allowable longitudinal extent of the ground area, in. (mm)
t = nominal wall thickness of pipe, in. (mm)

Grinding shall produce a smooth contour in the pipe wall. The remaining wall thickness shall be verified using ultrasonic testing. After grinding, the surface shall be inspected for cracks using a nondestructive surface examination method capable of detecting cracks and the surface shall be inspected with a suitable etchant per para. 841.2.4(e). If grinding within the depth and length limitations fails to completely remove the damage, the damage shall be removed or repaired in accordance with (c)(2).

(4) Dents containing stress corrosion cracking may be repaired by grinding out the cracks to a length and depth permitted in para. 860.2(a) for corrosion in plain

Fig. 851.4.1-1 Allowable Ripple Heights



GENERAL NOTE: Source: "Development of Acceptance Criteria for Mild Ripples in Pipeline Field Bends" paper IPC02-27124 from the International Pipeline Conference 2002. Copyright © 2002 by The American Society of Mechanical Engineers.

pipe. The wall thickness shall be checked using ultrasonic testing. After grinding, the surface shall be inspected for cracks using a nondestructive surface examination method capable of detecting cracks and the surface shall be inspected with a suitable etchant as per para. 841.2.4(e). If grinding within the depth and length limitations fails to completely remove the damage, the damage shall be removed or repaired in accordance with (c)(1).

(d) If a dent or mechanical damage is repaired with a sleeve not designed to carry maximum allowable operating line pressure, the dent shall first be filled with an incompressible filler. If the sleeve is designed to carry maximum allowable operating pressure, the incompressible filler is recommended but not required.

(e) Nonmetallic composite wrap repairs are not acceptable for repair of injurious dents or mechanical damage, unless proven through reliable engineering tests and analysis.

(f) All repairs under para. 851.4.2 shall pass nondestructive inspections and tests as provided in para. 851.5.

851.4.3 Permanent Field Repair of Welds Having Injurious Defects

(a) All circumferential butt welds found to have unacceptable defects (according to API 1104) shall be repaired in accordance with the requirements of section 827, provided the pipeline can be taken out of service. Repairs on welds may be made while the pipeline is in service, provided the weld is not leaking, the pressure in the pipeline has been reduced to a pressure that will not produce a hoop stress in excess of 20% of the specified minimum yield of the pipe, and grinding of the defective area can be limited so that there will remain at least $\frac{1}{8}$ in. (3.2 mm) thickness in the pipe weld.

(b) Defective welds mentioned in (a) above, which cannot be repaired under (a) above and where it is not feasible to remove the defect from the pipeline by replacement, may be repaired by the installation of a full encirclement welded split sleeve using circumferential fillet welds.

(c) If a manufacturing defect is found in a double submerged-arc-welded seam or high frequency ERW seam, a full encirclement welded split sleeve shall be installed.

(d) If a manufacturing defect is discovered in a low frequency ERW weld seam or any seam having a factor *E* less than 1.0 in Table 841.1.7-1, or if hydrogen stress cracking is found in any weld zone, a full encirclement welded split sleeve designed to carry maximum allowable operating pressure shall be installed.

(e) All repairs performed under (a) through (d) above shall be tested and inspected as provided in para. 851.5.

(f) Corroded areas may be repaired by filling them with deposited weld metal using a low-hydrogen welding process. Repairs shall be accomplished in accordance with a written maintenance procedure, which when followed will permanently restore the required wall thickness and mechanical properties of the pipeline. The

Table 851.4.4-1 Wall Thickness for Unlikely Occurrence of Burn-Through

	Gas Velocity, ft/sec (m/s)			
psia (kPa)	0	5 (1.5)	10 (3.0)	20 (6.1)
15 (100)	0.320 in. (8.13 mm)	. . .	. . .	. . .
500 (3,450)	0.300 in. (7.62 mm)	0.270 in. (6.86 mm)	0.240 in. (6.10 mm)	0.205 in. (5.21 mm)
900 (6,200)	0.280 in. (7.11 mm)	0.235 in. (5.97 mm)	0.190 in. (4.83 mm)	0.150 in. (3.81 mm)

welding procedures and welders shall be qualified under para. 823.2.1. The procedures shall provide sufficient direction for avoiding burn-through and minimizing the risk of hydrogen cracking on in-service pipelines. For background information on developing a weld deposition repair procedure, refer to "Guidelines for Weld Deposition Repair on Pipelines" (PRCI Catalog L51782) in Mandatory Appendix A. This method of repair shall not be attempted on pipe that is thought to be susceptible to brittle failure.

851.4.4 Permanent Field Repair of Leaks and Nonleaking Corroded Areas

(a) If feasible, the pipeline shall be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing with pipe of equal or greater design strength.

(b) If it is not feasible to take the pipeline out of service, repairs shall be made by the installation of a full encirclement welded split sleeve unless a patch is chosen in accordance with (e) below, or unless corrosion is repaired with deposited weld metal in accordance with (f) below. If nonleaking corrosion is repaired with a full encirclement welded split sleeve, the circumferential fillet welds are optional.

(c) If the leak is due to a corrosion pit, the repair may be made by the installation of a properly designed bolt-on leak clamp.

(d) A small leak may be repaired by welding a nipple over it to vent the gas while welding and then installing an appropriate fitting on the nipple.

(e) Leaking or nonleaking corroded areas on pipe of not more than 40,000 psi (276 MPa) specified minimum yield strength may be repaired by using a steel plate patch with rounded corners and with dimensions not in excess of one-half the circumference of the pipe fillet welded over the pitted area. The design strength of the plate shall be the same or greater than the pipe.

(f) Small corroded areas may be repaired by filling them with deposited weld metal from low-hydrogen electrodes. The higher the pressure and the greater the flow rate, the lesser the chance of burn-through. At 20 V and 100 A, burn-through is unlikely to occur when the actual wall thicknesses exist, as shown in Table 851.4.4-1.

This method of repair should not be attempted on pipe that is thought to be susceptible to brittle fracture.

(g) All repairs performed under (a), (b), and (d) above shall be tested and inspected as provided in para. 851.5.

851.4.5 Permanent Field Repair of Hydrogen Stress Cracking in Hard Spots and Stress Corrosion Cracking

(a) If feasible, the pipeline shall be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing with pipe of equal or greater design strength.

(b) If it is not feasible to take the pipeline out of service, repairs shall be made by the installation of a full encirclement welded split sleeve. In the case of stress corrosion cracking, the fillet welds are optional. If the fillet welds are made, pressurization of the sleeve is optional. The same applies to hydrogen stress cracking in hard spots, except that a flat hard spot shall be protected with a hardenable filler or by pressurization of a fillet welded sleeve. Stress corrosion cracking may also be repaired per para. 851.4.2(c)(4), which describes repairs for stress corrosion cracking in dents.

(c) All repairs performed under (a) and (b) shall be tested and inspected as provided in para. 851.5.

851.5 Testing Repairs to Steel Pipelines or Mains

851.5.1 Testing of Replacement Pipe Sections. When a scheduled repair to a pipeline or main is made by cutting out the damaged portion of the pipe as a cylinder and replacing it with another section of pipe, the replacement section of pipe shall be subjected to a pressure test. The replacement section of pipe shall be tested to the pressure required for a new pipeline or main installed in the same location. The tests may be made on the pipe prior to installation, provided nondestructive tests meeting the requirements of section 826 are made on all field girth butt welds after installation. If the replacement is made under controlled fire conditions (gas in the pipeline), full encirclement welded split sleeves may be used to join the pipe sections instead of butt welds. All sleeve welds should be radiographed. (See para. 851.5.2.)

851.5.2 Nondestructive Testing of Repairs, Gouges, Grooves, Dents, and Welds. If the defects are repaired by welding in accordance with the provisions of para. 851.4 and any of its subsections, the welding shall be examined in accordance with section 826.

851.6 Pipeline Leak Records

Records shall be made covering all leaks discovered and repairs made. All pipeline breaks shall be reported in detail. These records along with leakage survey records, line patrol records, and other records relating to routine or unusual inspections shall be kept in the file of the operating company, as long as the section of line remains in service.

851.7 Pipeline Markers

(a) Signs or markers shall be installed where it is considered necessary to indicate the presence of a pipeline at road, highway, railroad, and stream crossings. Additional signs and markers shall be installed along the remainder of the pipeline at locations where there is a probability of damage or interference.

(b) Signs or markers and the surrounding right-of-way shall be maintained so markers can be easily read and are not obscured.

(c) The signs or markers shall include the words "Gas (or name of gas transported) Pipeline," the name of the operating company, and the telephone number (including area code) where the operating company can be contacted.

851.8 Abandoning of Transmission Facilities

Each operating company shall have a plan in its operating and maintenance procedures for abandoning transmission facilities. The plan shall include the following provisions:

(a) Facilities to be abandoned shall be disconnected from all sources and supplies of gas such as other pipelines, mains, crossover piping, meter stations, control lines, and other appurtenances.

(b) Facilities to be abandoned in place shall be purged of gas with an inert material and the ends shall be sealed, except that

(c) After precautions are taken to determine that no liquid hydrocarbons remain in the facilities to be abandoned, then such facilities may be purged with air. If the facilities are purged with air, then precautions must be taken to determine that a combustible mixture is not present after purging. [See para. 841.2.7(e).]

851.9 Decommissioning of Transmission Facilities

Operators planning the decommissioning (temporary disconnect) of transmission facilities shall develop procedures for the decommissioning of facilities from service. The procedures shall include the following:

(a) Facilities to be decommissioned shall be isolated and sealed from all sources and supplies of gas, such as other pipelines, mains, crossover piping, meter stations, control lines, and other appurtenances.

(b) Purge facilities to be commissioned with an inert material and effectively seal the ends. For facilities where purging is not necessary and where a need to restore to service exists, a small amount of gas can remain in the facility provided the gas amount poses no potential hazard, and contains no corrosive contaminants exceeding pipeline quality standards such as water, carbon dioxide, and sulfides.

(c) After the facilities have been decommissioned, the maintenance procedures shall continue to be applied as if the facility were still in service.

(d) The cathodic protection shall be maintained with the periodic inspections and record keeping to continue as if the facility were still in service.

(e) For stations where blanket gas remains, the Emergency Shut Down (ESD) system shall remain in service. Some modification to the ESD system may be required to allow for a low pressure ESD. The hazardous gas and fire detectors should remain in service to blow the units and piping down, if necessary.

851.10 Recommissioning of Transmission Facilities

Operators planning to recommission (reactivate) transmission facilities temporarily removed from service shall develop written procedures for recommissioning facilities to service. The procedures shall include the following:

(a) Before a facility is recommissioned, all maintenance and cathodic protection records shall be reviewed to ensure that the condition and integrity of the facility has been maintained during the decommissioned period.

(b) Facilities to be recommissioned that have been decommissioned for an extended period of time shall be repressured incrementally.

(c) A leak survey shall be performed after the facility has been recommissioned. Any defects or leaks discovered shall be repaired before the facility is back in full operation.

851.11 Repositioning a Pipeline in Service

When repositioning a pipeline in service, the following are some of the factors that shall be considered:

(a) deflection
(b) diameter, wall thickness, and grade of pipe
(c) pipeline pressure
(d) type of girth welds
(e) test and operating history
(f) presence of defects
(g) existing curvature
(h) bends
(i) valves and fittings
(j) terrain and soil conditions
(k) personnel safety considerations
(l) additional stresses caused by repositioning of the pipeline

851.12 Pressure Testing for Integrity Assessment of In-Service Pipelines

The integrity of an in-service pipeline may be determined by pressure testing for strength and leaks. Comparison of new test pressures with previous test pressures will demonstrate that the integrity of the pipeline has not been reduced if new test pressures are equal to or greater than previous test pressures. If there was no previous strength test with which to compare the current test, a minimum specified margin of safety can be established. A strength test, however, will not indicate ongoing deterioration of the pipeline that has not progressed to the point where defects fail during the strength test. Refer to Nonmandatory Appendix N for hydrostatic testing guidelines.

851.12.1 Pressure Test Levels. When establishing test pressures for a test section, the maximum test pressure shall be determined by the operator to prevent damage to the pipeline and its components. Consideration must be given to the effect of test section elevation differences on the test pressure. Whenever test pressure will cause a hoop stress in excess of 100% of the SMYS, refer to Nonmandatory Appendix N, section N-5 for guidance on yield monitoring. The minimum test pressure shall be as required by (a) through (c).

(a) To determine the integrity of an in-service pipeline by strength testing, the pipeline shall be strength tested at a pressure that will cause a hoop stress of at least 90% of the SMYS in the segment with the lowest design or rated pressure in the section tested except as provided in (b) or (c).

(b) For pipelines in which SCC (Stress Corrosion Cracking) has been identified, defects may be mitigated by pressure testing to a pressure that will create a hoop stress of at least 100% of the SMYS at the high point elevation.

(c) For those in-service pipelines for which the hoop stress percent of the SMYS cannot be accurately determined or those pipelines that operate at hoop stress levels lower than maximum design pressure, the minimum strength test pressure shall be 1.10 times the MAOP.

(d) Following the strength test period, a leak test should be performed. The leak test pressure should be at least 1.10 times the MAOP of the pipeline.

851.12.2 Pressure Hold Period

(a) The strength test pressure shall be held for a minimum time period of $\frac{1}{2}$ hr, except for those lines with known SCC, which are to be pressure tested in accordance with (b).

(b) The pressure test for SCC shall be held long enough for the test pressure to stabilize, in most cases $\frac{1}{2}$ hr or less.

(c) The leak test pressure should be maintained for as long as necessary to detect and locate or evaluate any leakage of test media. Additional leak test methods may be employed if detection of leakage of the test media is not practical due to very small leaks such as may be experienced after testing for SCC.

851.12.3 Time Interval Between Tests. The time interval between pressure tests, or performing the initial pressure test if the pipeline was not post-construction tested, should be based upon an engineering critical assessment to prevent defects from growing to critical sizes. That engineering critical assessment should include consideration of the following factors:

(a) Risk to the Public. The first consideration in a test or retest should be the exposure that the public could have to a failure of a given pipeline.

(b) Stress Level of Previous Test. Testing shows that the higher the stress level of the strength test, the smaller the remaining flaw will be. Smaller remaining flaws will result in a longer time before the flaw could be expected to grow to a critical size, if not mitigated. This means that increasing the ratio of the test pressure to the operating pressure may potentially increase the retest interval.

(c) Corrosion Growth Rate. The corrosion growth rate on a given pipeline depends upon the aggressiveness of the corrosive environment and the effectiveness of corrosion control measures.

(d) Maintenance. Deterioration of the pipeline is also a function of the timing and effectiveness of actions to correct such conditions as corrosion control deficiencies, external force damage, and operating conditions that increase the potential for corrosion. The effectiveness of programs to prevent damage by excavation affects pipeline maintenance.

(e) Other Inspection Methods. In-line inspection, external electrical surveys of coating condition and cathodic protection levels, direct inspection of the pipe, monitoring of internal corrosion, monitoring of gas quality, and monitoring to detect encroachment are methods that can be used to predict or confirm the presence of defects that may reduce the integrity of the pipeline.

852 DISTRIBUTION PIPING MAINTENANCE

852.1 Patrolling

Distribution mains shall be patrolled in areas where necessary to observe factors that may affect safe operation. The patrolling shall be considered in areas of construction activity, physical deterioration of exposed piping and supports, or any natural causes, which could result in damage to the pipe. The frequency of the patrolling shall be determined by the severity of the conditions that could cause failure or leakage and the subsequent hazards to public safety.

852.2 Leakage Surveys

Each operating company having a gas distribution system shall set up in its operating and maintenance plan a provision for making periodic leakage surveys on the system.

852.2.1 Types of Surveys. The types of surveys selected shall be effective for determining if potentially hazardous leakage exists. The following are some procedures that may be employed:

(a) surface gas detection surveys

(b) subsurface gas detector survey (including bar hole surveys)

(c) vegetation surveys

(d) pressure drop tests

(e) bubble leakage tests

(f) ultrasonic leakage tests

A detailed description of the various surveys and leakage detection procedures is shown in Nonmandatory Appendix M.

852.2.2 Frequency of Surveys. The extent and frequency of leakage surveys shall be determined by the character of the general service area, building concentrations, piping age, system condition, operating pressure, and any other known condition (such as surface faulting, subsidence, flooding, or an increase in operating pressure) that has significant potential to either initiate a leak or to cause leaking gas to migrate to an area where it could result in a hazardous condition. Special one-time surveys should be considered following exposure of the gas distribution system to unusual stresses (such as those resulting from earthquakes or blasting). The leakage survey frequencies shall be based on operating experience, sound judgment, and a knowledge of the system. Once established, frequencies shall be reviewed periodically to affirm that they are still appropriate. The frequencies of the leakage survey shall at least meet the following:

(a) Distribution systems in a principal business district should be surveyed at least annually. Such surveys shall be conducted using a gas detector and shall include tests of the atmosphere that will indicate the presence of gas in utility manholes, at cracks in the pavement and sidewalks, and at other locations that provide opportunities for finding gas leaks.

(b) The underground distribution system outside the areas covered by (a) above should be surveyed as frequently as experience indicates necessary, but not less than once every 5 yr.

852.3 Leakage Investigation and Action

852.3.1 Leakage Classification and Repair. Leaks located by surveys and/or investigation should be evaluated, classified, and controlled in accordance with the criteria set forth in section M-5 of Nonmandatory Appendix M.

Prior to taking any repair action, leaks should be pinpointed but only after it has been established that an immediate hazard does not exist or has been controlled by such emergency actions as evacuation, blocking an area off, rerouting traffic, eliminating sources of ignition, ventilating, or stopping the flow of gas. The pinpointing guidelines provided in section M-6 of Nonmandatory Appendix M should be followed.

852.3.2 Investigation of Reports From Outside Sources. Any notification from an outside source (such as police or fire department, other utility, contractor, customer, or general public) reporting a leak, explosion, or fire, which may involve gas pipelines or other gas facilities, shall be investigated promptly. If the investigation reveals a leak, the leak should be classified and action should be taken in accordance with the criteria in section M-5 of Nonmandatory Appendix M.

852.3.3 Odor or Indications From Foreign Sources. When potentially hazardous leak indications (such as natural, sewer, or marsh gas or gasoline vapors) are found to originate from a foreign source or facility or customer-owned piping, they shall be reported to the operator of the facility and, where appropriate, to the police department, fire department, or other governmental agency. When the company's pipeline is connected to a foreign facility (such as the customer's piping), necessary action, such as disconnecting or shutting off the flow of gas to the facility, shall be taken to eliminate the potential hazard.

852.3.4 Follow-Up Inspections. While the excavation is open, the adequacy of leak repairs shall be checked by using acceptable methods. The perimeter of the leak area shall be checked with a gas detector. In the case of a Grade 1 leak repair as defined in Nonmandatory Appendix M, where there is residual gas in the ground, a followup inspection should be made as soon as practicable after allowing the soil to vent to the atmosphere and stabilize, but in no case later than 1 month following the repair. In the case of other leak repairs, the need for a followup inspection should be determined by qualified personnel.

852.4 Requirements for Abandoning, Disconnecting, and Reinstating Distribution Facilities

852.4.1 Abandoning of Distribution Facilities. Each operating company shall have a plan for abandoning inactive facilities, such as service lines, mains, control lines, equipment, and appurtenances for which there is no planned use.

The plan shall also include the following provisions:

(a) If the facilities are abandoned in place, they shall be physically disconnected from the piping system. The open ends of all abandoned facilities shall be capped, plugged, or otherwise effectively sealed. The need for purging the abandoned facility to prevent the development of a potential combustion hazard shall be considered and appropriate measures shall be taken. Abandonment shall not be completed until it has been determined that the volume of gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. Air or inert gas may be used for purging, or the facility may be filled with water or other inert material. [See para. 841.2.7(e).] If air is used for purging, the operating company shall determine that a combustible mixture is not present after purging. Consideration shall be given to any effects the abandonment may have on an active cathodic protection system, and appropriate action shall be taken.

(b) In cases where a main and the service lines connected to it are abandoned, insofar as service lines are concerned, only the customer's end of such service lines needs to be sealed as stipulated above.

(c) Service lines abandoned from the active mains should be disconnected as close to the main as practicable.

(d) All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

(e) All above-grade valves, risers, and vault and valve box covers shall be removed. Vault and valve box voids shall be filled with suitable compacted backfill material.

852.4.2 Temporarily Disconnected Service. Whenever service to a customer is temporarily discontinued, one of the following shall be complied with:

(a) The valve that is closed to prevent the flow of gas to the customer shall be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operating company.

(b) A mechanical device or fitting that will prevent the flow of gas shall be installed in the service line or in the meter assembly.

(c) The customer's piping shall be physically disconnected from the gas supply and the open pipe ends shall be sealed.

852.4.3 Test Requirements for Reinstating Abandoned Facilities and Temporarily Disconnected Service Lines. Facilities previously abandoned shall be tested in the same manner as new facilities before being reinstated.

Service lines previously abandoned shall be tested in the same manner as new service lines before being reinstated.

Service lines temporarily disconnected because of main renewals or other planned work shall be tested from the point of disconnection to the service line valve in the same manner as new service lines before reconnecting, except

(a) when provisions to maintain continuous service are made, such as by installation of a bypass, any portion of the original service line used to maintain continuous service need not be tested; or

(b) when the service line has been designed, installed, tested, and maintained in accordance with the requirements of this Code

852.5 Plastic Pipe Maintenance

852.5.1 Squeezing-Off and Reopening of Thermoplastic Pipe or Tubing for Pressure Control

(a) Before thermoplastic pipe or tubing is squeezed-off and reopened, it is required that investigations and tests be made to determine that the particular type, grade, size, and wall thickness of pipe or tubing of the same manufacture can be squeezed-off and reopened without causing failure under the conditions that will prevail at the time of the squeezing-off and reopening.

(b) After compliance with (a), whenever thermoplastic pipe or tubing is squeezed-off and reopened, it is required that

(1) the work be done with equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively

(2) the squeezed-off and reopened area of the pipe or tubing be reinforced in accordance with the appropriate provisions of para. 852.5.2, unless it has been determined by investigation and test that squeeze-off and reopening do not affect the long-term properties of the pipe or tubing

(c) Squeeze-off and reopening shall be done in accordance with ASTM F1041, Standard Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing, and ASTM F1563, Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing.

(d) Refer to Nonmandatory Appendix C for a list of other pertinent ASTM standards and industry literature.

852.5.2 Repair of Plastic Pipe or Tubing. If at any time an injurious defect, groove, gouge, or dent is found in plastic pipe or tubing, the damaged or defective section shall be replaced unless satisfactory repairs are made.

The damaged section can be cut out and replaced in accordance with applicable provisions of para. 842.3, Installation of Plastic Piping. The replacement pipe or tubing shall be 100% visually inspected inside and out. There shall be no visible defects on the inside or outside of the replacement pipe or tubing. The replacement pipe or tubing shall be leak tested at available system pressure.

Repairs shall be made in accordance with qualified procedures that have been established and proven by test and in accordance with the following (special consideration shall be given to ensure that the repair procedure is applicable at the ambient temperature during the repair):

(a) The recommendations of the plastic manufacturer shall be taken into consideration when determining the type of repair to be made. Special consideration shall be given to the extent of fiber damage in the case of thermosetting plastic pipe.

(b) If a patch or full encirclement sleeve is used, it shall extend at least ½ in. (13 mm) beyond the damaged area.

(c) If a full encirclement split sleeve is used, the joining line between the halves of the sleeve shall be as far as possible from the defect, but in no case closer than ½ in. (13 mm). Suitable precautions shall be taken to ensure a proper fit at the longitudinal seam.

(d) The patch or sleeve material shall be the same type and grade as the pipe or tubing being repaired. Wall thickness of the patch or sleeve shall be at least equal to that of the pipe or tubing.

(e) The method of attachment of the patch or sleeve shall be compatible with the material and shall conform to the applicable provisions of para. 842.2.9(b). Precautions shall be taken to ensure a proper fit and a complete bond between the patch or sleeve and the pipe being repaired. The patch or sleeve shall be clamped or held in place by other suitable means during the setting or curing of the bonding material or during the hardening of a heat-fusion bond. Excess solvent cement shall be removed from the edges of the patch or sleeve.

852.6 Piping Maintenance Records

852.6.1 Inspection of Underground Piping. Whenever any portion or section of an existing underground distribution piping system is uncovered for operating or maintenance purposes or for the installation of new facilities, the following information shall be recorded:

(a) the condition of the surface of bare pipe, if pitted or generally corroded

(b) the condition of the pipe surface and of the protective coating where the coating has deteriorated to the extent that the pipe is corroding underneath

(c) any damaged protective coating

(d) any repairs made

852.6.2 Cause of Cast Iron Breakage. Whenever broken cast iron facilities are uncovered, the cause of breakage, such as thermal effect, backfill, or construction by others, shall be recorded if it can be determined.

852.6.3 Analysis of Condition Records. Distribution piping condition records shall be analyzed periodically. Any indicated remedial action on the piping system shall be taken and recorded.

852.7 Cast Iron Pipe Maintenance

852.7.1 Sealing Joints of 25 psig (170 kPa) or More. Each cast iron caulked bell and spigot joint operating at pressures of 25 psig (170 kPa) or more that is exposed for any reason must be sealed with a mechanical leak clamp or a material or device that does not reduce the flexibility of the joint and permanently seals and bonds.

852.7.2 Sealing Joints Under 25 psig (170 kPa). Each cast iron caulked bell and spigot joint operating at pressures of less than 25 psig (170 kPa) that is exposed for any reason must be sealed by a means other than caulking.

852.7.3 Inspection for Graphitization. When a section of cast iron pipe is exposed for any reason, an inspection shall be made to determine if graphitization exists. If detrimental graphitization is found, the affected segment must be replaced.

852.7.4 Disturbed Pipeline Support. When an operating company has knowledge that the support for a segment of a buried cast iron pipeline is disturbed

(a) that segment of the pipeline must be protected as necessary against damage during the disturbance

(b) as soon as possible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads

853 MISCELLANEOUS FACILITIES MAINTENANCE

853.1 Compressor Station Maintenance

853.1.1 Compressors and Prime Movers. The starting, operating, and shutdown procedures for all gas compressor units shall be established by the operating company. The operating company shall take appropriate steps to see that the approved practices are followed.

853.1.2 Inspection and Testing of Relief Valves. All pressure-relieving devices in compressor stations shall be inspected and/or tested in accordance with para. 853.3, and all devices except rupture disks shall be operated periodically to determine that they open at the correct set pressure. Any defective or inadequate equipment found shall be promptly repaired or replaced. All remote control shutdown devices shall be inspected and tested at least annually to determine that they function properly.

853.1.3 Repairs to Compressor Station Piping. All scheduled repairs to compressor station piping operating at hoop stress levels at or above 40% of the specified minimum yield strength shall be done in accordance with para. 851.3, except that the use of a welded patch is prohibited. Testing of repairs shall be done in accordance with para. 851.4.

853.1.4 Isolation of Equipment for Maintenance or Alterations. The operating company shall establish procedures for isolation of units or sections of piping for maintenance, and for purging prior to returning units to service, and shall follow these established procedures in all cases.

853.1.5 Storage of Combustible Materials. All flammable or combustible materials in quantities beyond those required for everyday use or other than those normally used in compressor buildings shall be stored in a separate structure built of noncombustible material located a suitable distance from the compressor building. All aboveground oil or gasoline storage tanks shall be protected in accordance with NFPA 30.

853.1.6 Maintenance and Testing of Gas Detection and Alarm Systems. Each gas detection and alarm system required by this Code shall be maintained to function reliably. The operator shall develop maintenance and calibration procedures to periodically verify the operational integrity of the gas detectors and alarm systems installed.

853.1.7 Monitoring Effects of Pulsation and Vibration. Facilities exposed to the effets of vibration and pulsation induced by reciprocating compression as well as vibration induced by gas flow or discharge, may be susceptible to fatigue crack growth in fabrication and attachment welds. Susceptible facilities include

(a) compressor station piping having an observed history of vibration

(b) blowdown piping

(c) pulsation bottles and manifolds

(d) piping not meeting the requirements of para. 833.7(a)

Such facilities may warrant engineering assessment and/or nondestructive examination for fatigue cracking in fabrication and attachment welds.

853.2 Procedures for Maintaining Pipe-Type and Bottle-Type Holders in Safe Operating Condition

(a) Each operating company having a pipe-type or bottle-type holder shall prepare and place in its files a plan for the systematic, routine inspection and testing of the facilities that has the following provisions:

(1) Procedures shall be followed to enable the detection of external corrosion before the strength of the container has been impaired.

(2) Periodic sampling and testing of gas in storage shall be made to determine the dew point of vapors contained in the stored gas that might cause internal corrosion or interfere with the safe operations of the storage plant.

(3) The pressure control and pressure-limiting equipment shall be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

(b) Each operating company, having prepared such a plan as prescribed in (a), shall follow the plan and keep records that detail the inspection and testing work done and the conditions found.

(c) All unsatisfactory conditions found shall be promptly corrected.

853.3 Maintenance of Pressure-Limiting and Pressure-Regulating Stations

853.3.1 Condition and Adequacy. All pressure-limiting stations, relief devices, and other pressure-regulating stations and equipment shall be subject to systematic, periodic inspections and suitable tests, or reviewed to determine that they are

(a) in good mechanical condition. Visual inspections shall be made to determine that equipment is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. The following shall be included in the inspection where appropriate:

(1) station piping supports, pits, and vaults for general condition and indications of ground settlement. See para. 853.5 for vault maintenance.

(2) station doors and gates and pit vault covers to determine that they are functioning properly and that access is adequate and free from obstructions.

(3) ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions.

(4) control, sensing, and supply lines for conditions that could result in a failure.

(5) all locking devices for proper operation.

(6) station schematics for correctness.

(b) adequate from the standpoint of capacity and reliability of operation for the service in which they are employed and set to function at the correct pressure

(1) If acceptable operation is not obtained during the operational check, the cause of the malfunction shall be determined, and the appropriate components shall be adjusted, repaired, or replaced as required. After repair, the component shall again be checked for proper operation.

(2) At least once each calendar year, a review shall be made to ensure that the combined capacity of the relief devices on a piping system or facility is adequate to limit the pressure at all times to values prescribed by this Code. This review should be based on the operating conditions that create the maximum probable requirement for relief capacity in each case, even though such operating conditions actually occur infrequently and/or for only short periods of time. If it is determined that the relieving equipment is of insufficient capacity, steps shall be taken to install new or additional equipment to provide adequate capacity.

853.3.2 Abnormal Conditions. Whenever abnormal conditions are imposed on pressure or flow control devices, the incident shall be investigated and a determination shall be made as to the need for inspection and/or repairs. Abnormal conditions may include regulator bodies that are subjected to erosive service conditions or contaminants from upstream construction and hydrostatic testing.

853.3.3 Stop Valves

(a) An inspection and/or test of stop valves shall be made to determine that the valves will operate and are correctly positioned. (Caution shall be used to avoid any undesirable effect on pressure during operational

checks.) The following shall be included in the inspection and/or test:

(1) station inlet, outlet, and bypass valves

(2) relief device isolating valves

(3) control, sensing, and supply line valves

(b) The final inspection procedure shall include the following:

(1) a check for proper position of all valves. Special attention shall be given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines.

(2) restoration of all locking and security devices to proper position.

853.3.4 Pressure-Regulating Stations

(a) Every distribution system supplied by more than one pressure-regulating station shall be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single pressure-regulating station, the operating company shall determine the necessity of installing such gages in the district. In making this determination, the operating company shall take into consideration the operating conditions such as the number of customers supplied, the operating pressures, the capacity of the installation, etc.

(c) If there are indications of abnormal high or low pressures, the regulator and the auxiliary equipment shall be inspected and the necessary measures shall be employed to rectify any unsatisfactory operating conditions. Suitable periodic inspections of single pressure regulation stations not equipped with telemetering or recording gages shall be made to determine that the pressure-regulating equipment is functioning properly.

853.4 Valve Maintenance

853.4.1 Pipeline Valves. Pipeline valves that would be required to be operated during an emergency shall be inspected periodically and partially operated at least once a year to provide safe and proper operating conditions.

(a) Routine valve maintenance procedures shall include, but not be limited to, the following:

(1) servicing in accordance with written procedures by adequately trained personnel

(2) accurate system maps for use during routine or emergency conditions

(3) valve security to prevent service interruptions, tampering, etc., as required

(4) employee training programs to familiarize personnel with the correct valve maintenance procedures

(b) Emergency valve maintenance procedures include

(1) written contingency plans to be followed during any type of emergency

(2) training personnel to anticipate all potential hazards

(3) furnishing tools and equipment as required, including auxiliary breathing equipment, to meet anticipated emergency valve servicing and/or maintenance requirements

853.4.2 Distribution System Valves. Valves, the use of which may be necessary for the safe operation of a gas distribution system, shall be checked and serviced, including lubrication where necessary, at sufficiently frequent intervals to ensure their satisfactory operation. Inspection shall include checking of alignment to permit use of a key or wrench and clearing from the valve box or vault any debris that would interfere with or delay the operation of the valve. System maps showing valve locations should be available.

853.4.3 Service Line Valves. Outside shutoff valves installed in service lines supplying places of public assembly, such as theaters, churches, schools, and hospitals, shall be inspected and lubricated where required at sufficiently frequent intervals to ensure their satisfactory operation. The inspection shall determine if the valve is accessible, if the alignment is satisfactory, and if the valve box or vault, if used, contains debris that would interfere with or delay the operation of the valve. Unsatisfactory conditions encountered shall be corrected.

853.4.4 Valve Records. A record shall be maintained for locating valves covered by paras. 853.4.1 and 853.4.2. These records may be maintained on operating maps, separate files, or summary sheets, and the information on these records shall be readily accessible to personnel required to respond to emergencies.

853.4.5 Prevention of Accidental Operation. Precautions shall be taken to prevent accidental operation of any valve covered by paras. 853.4.1 and 853.4.2. Accidental valve operation by operating company personnel and the general public should be considered in taking these precautions. Some recommended actions to be taken, where applicable, are as follows:

(a) Lock valves in aboveground settings readily accessible to the general public that are not enclosed by a building or fence.

(b) Lock valves located in vaults, if accessible to the general public.

(c) Identify the valve by tagging, color coding, or any other suitable means of identification.

853.5 Vault Maintenance

Each vault housing a pressure-limiting, pressure-relief, or pressure-regulating station shall be inspected to determine its condition each time the equipment is inspected and tested in accordance with para. 853.3. For any vault that personnel enter, the atmosphere shall be tested for combustible gas. If the atmosphere is hazardous, the cause shall be determined. The vault shall be inspected for adequate ventilation. The condition of the vault covers shall be carefully examined for hazards.

Table 854.1-1 Location Class

Original [Note (1)] Location Class	Original [Note (1)] Number of Buildings	Current Location Class	Current Number of Buildings	Maximum Allowable Operating Pressure (MAOP)
1, Division 1	0–10	1	11–25	Previous MAOP but not greater than 80% SMYS
1, Division 2	0–10	1	11–25	Previous MAOP but not greater than 72% SMYS
1	0–10	2	26–45	0.800 × test pressure but not greater than 72% SMYS
1	0–10	2	46–65	0.667 × test pressure but not greater than 60% SMYS
1	0–10	3	66+	0.667 × test pressure but not greater than 60% SMYS
1	0–10	4	[Note (2)]	0.555 × test pressure but not greater than 50% SMYS
2	11–45	2	46–65	Previous MAOP but not greater than 60% SMYS
2	11–45	3	66+	0.667 × test pressure but not greater than 60% SMYS
2	11–45	4	[Note (2)]	0.555 × test pressure but not greater than 50% SMYS
3	46+	4	[Note (2)]	0.555 × test pressure but not greater than 50% SMYS

NOTES:
(1) At time of design and construction.
(2) Multistory buildings become prevalent.

Unsatisfactory conditions disclosed shall be corrected. The applicable provisions of para. 821.6 shall be met before any welding is performed in the vault. Maintenance work performed in the vault shall be in accordance with procedures developed per para. 850.2(a), giving particular consideration to the monitoring of the atmosphere and safety protection for personnel in the vault.

854 LOCATION CLASS AND CHANGES IN NUMBER OF BUILDINGS INTENDED FOR HUMAN OCCUPANCY

854.1 Monitoring

(a) Existing steel pipelines or mains operating at hoop stress levels in excess of 40% of specified minimum yield strength shall be monitored to determine if additional buildings intended for human occupancy have been constructed. The total number of buildings intended for human occupancy shall be counted to determine the current Location Class in accordance with the procedures specified in paras. 840.2.2(a) and (b).

(b) In accordance with the principles stated in para. 840.1(c), and with the knowledge that the number of buildings intended for human occupancy is not an exact or absolute means of determining damage-causing activities, judgment must be used to determine the changes that should be made to items, such as operating stress levels, frequency of patrolling and cathodic protection requirements, as additional buildings intended for human occupancy are constructed.

(c) When there is an increase in the number of buildings intended for human occupancy to or near the upper limit of the Location Class listed in Table 854.1-1 to the extent that a change in Location Class is likely, a study shall be completed within 6 months of perception of the increase to determine the following:

(1) the design, construction, and testing procedures followed in the original construction and a comparison of such procedures with the applicable provisions of this Code.

(2) the physical conditions of the pipeline or main to the extent that this can be ascertained from current tests and evaluation records.

(3) operating and maintenance history of the pipeline or main.

(4) the maximum operating pressure and the corresponding operating hoop stress. The pressure gradient may be taken into account in the section of the pipeline or main directly affected by the increasing number of buildings intended for human occupancy.

(5) the actual area affected by the increase in the number of buildings intended for human occupancy and physical barriers or other factors that may limit the further expansion of the more densely populated area.

(d) Following this study, if a change of Location Class is indicated, the patrols and leakage surveys shall immediately be adjusted to the intervals established by the operating company for the new Location Class.

854.2 Confirmation or Revision of MAOP

If the study described in para. 854.1 indicates that the established maximum allowable operating pressure of a section of pipeline or main is not commensurate with existing Location Class 2, 3, or 4, and such section is in satisfactory physical condition, the maximum allowable operating pressure of that section shall be confirmed or revised within 18 months following completion of the study as follows:

(a) If the section involved has been previously tested in place for not less than 2 hr, the maximum allowable operating pressure shall be confirmed or reduced so that it does not exceed that allowed in Table 854.1-1.

(b) If the previous test pressure was not high enough to allow the pipeline to retain its MAOP or to achieve an acceptable lower MAOP in the Location Class according to (a) above, the pipeline may either retain its MAOP or become qualified for an acceptable lower MAOP if it is retested at a higher test pressure for not less than 2 hr in compliance with the applicable provisions of this Code. If the new strength test is not performed during the 18-month period following the Location Class change, the MAOP must be reduced so as not to exceed the design pressure commensurate with the requirements of Chapter IV at the end of the 18-month period. If the test is performed any time after the 18-month period has expired, however, the MAOP may be increased to the level it would have achieved if the test had been performed during that 18-month period.

(c) An MAOP that has been confirmed or revised according to (a) or (b) above shall not exceed that established by this Code or previously established by applicable editions of the B31.8 Code. Confirmation or revision according to para. 854.2 shall not preclude the application of section 857.

(d) Where operating conditions require that the existing maximum allowable operating pressure be maintained, and the pipeline cannot be brought into compliance as provided in (a), (b), or (c) above, the pipe within the area of the Location Class change shall be replaced with pipe commensurate with the requirements of Chapter IV, using the design factor obtained from Table 841.1.6-1 for the appropriate Location Class.

854.3 Pressure-Relieving or Pressure-Limiting Devices

Where the MAOP of a section of pipeline or main is revised in accordance with para. 854.2 and becomes less than the maximum allowable operating pressure of the pipeline or main of which it is a part, a suitable pressure-relieving or pressure-limiting device shall be installed in accordance with provisions of paras. 845.1, 845.2, and 845.2.1.

854.4 Review of Valve Spacing

Where the study required in para. 854.1 indicates that the established maximum allowable operating pressure of a transmission pipeline is not commensurate with that permitted by this Code for the new Location Class, the sectionalizing valve spacing shall be reviewed and revised as follows:

(a) If the section of pipe is qualified for continued service because of a prior test [para. 854.2(a)], or can be brought into compliance by lowering the maximum allowable operating pressure [para. 854.2(a)], or testing [para. 854.2(b)], no additional valves will normally be required.

(b) Where a segment of pipeline must be replaced to maintain the established maximum allowable operating pressure as provided in para. 854.2(d), consideration should be given to valve spacing as follows:

(1) Where a short section of line is replaced, additional valves will normally not be required.

(2) Where the replacement section involves 1 mi (1.6 km) or more of transmission line, additional valve installation shall be considered to conform to the spacing requirements in para. 846.1.1.

854.5 Concentrations of People in Location Classes 1 and 2

(a) Where a facility meeting the criteria of para. 840.3 is built near an existing steel pipeline in Location Classes 1 or 2, consideration shall be given to the possible consequence of a failure, even though the probability of such an occurrence is very unlikely if the line is designed, constructed, and operated in accordance with this Code.

(1) Where such a facility described in (a) above results in frequent concentrations of people, the requirements of (b) below shall apply.

(2) However, (b) below need not be applied if the facility is used infrequently. The lesser usage combined with the very remote possibility of a failure at that particular point on the pipeline virtually eliminates the possibility of an occurrence.

(b) Pipelines near places of public assembly as outlined in (a) above shall have a maximum allowable hoop stress not exceeding 50% of SMYS. Alternatively, the operating company may make the study described in para. 854.1(c) and determine that compliance with the following will result in an adequate level of safety:

(1) The segment is hydrostatically retested for at least 2 hr to a minimum hoop stress level of one of the following:

(-a) 100% of SMYS if the pipeline is operating at a hoop stress level over 60% and up to 72% of SMYS

(-b) 90% of SMYS if the pipeline is operating at a hoop stress level over 50% and up to 60% of SMYS, unless the segment was tested previously to a pressure of at least 1.5 times the MAOP

If the segment contains pipe of various operating stress levels, the minimum test hoop stress levels stated above should be based on the SMYS of the pipe with the highest operating stress level.

(2) Patrols and leakage surveys are conducted at intervals consistent with those established by the operating company for Location Class 3.

(3) When the maximum allowable hoop stress exceeds 60% of SMYS, adequate periodic visual inspections are conducted by an appropriate sampling technique, or instrumented inspections capable of detecting

gouges and corrosion damage are made to confirm the continuing satisfactory physical condition of the pipe.

(4) If the nearby facility is likely to encourage additional construction activity, provide appropriate pipeline markers.

855 PIPELINE SERVICE CONVERSIONS

855.1 General

The intent of this section is to provide requirements to allow an operator of a steel pipeline previously used for service not covered by this Code to qualify that pipeline for service under this Code. For a dual service pipeline used alternately to transport liquids in conformance with an appropriate Code, such as ASME B31.4, and gas under this Code, only the initial conversion to gas service requires qualification testing.

855.2 Historical Records Study

Review the following historical data and make an evaluation of the pipeline's condition:

(a) Study all available information on the original pipeline design, inspection, and testing. Particular attention should be paid to welding procedures used and other joining methods, internal and external coating, pipe, and other material descriptions.

(b) Study available operating and maintenance data including leak records, inspections, failures, cathodic protection, and internal corrosion control practices.

(c) Consider the age of the pipeline and the length of time it may have been out of service in preparing a final evaluation to convert the pipeline to gas service.

855.3 Requirements for Conversion to Gas Service

A steel pipeline previously used for service not subject to this Code may be qualified for service under this Code as follows:

(a) Review historical records of the pipeline as indicated in para. 855.2.

(b) Inspect all aboveground segments of the pipeline for physical condition. During the inspection, identify the material where possible for comparison with available records.

(c) Operating Stress Level Study

(1) Establish the number of buildings near the pipeline or main intended for human occupancy, and determine the design factor for each segment in accordance with para. 840.2 and Table 841.1.6-1.

(2) Conduct a study to compare the proposed operating stress levels with those allowed for the Location Class.

(3) Replace facilities necessary to make sure the operating stress level is commensurate with the Location Class.

(d) If necessary, make inspections of appropriate sections of underground piping to determine the condition of the pipeline.

(e) Make replacements, repairs, or alterations that in the operating company's judgment are advisable.

(f) Perform a strength test in accordance with this Code to establish the maximum allowable operating pressure of the pipeline, unless the pipeline has been so tested previously.

(g) Perform a leak test in conformance with this Code.

(h) Within 1 yr of the date that the converted pipeline is placed in gas service, provide cathodic protection as set out in para. 860.2(a), except that wherever feasible, replacement sections and other new piping shall be cathodically protected as required for new pipelines.

855.4 Conversion Procedure

Prepare a written procedure outlining the steps to be followed during the study and conversion of the pipeline system. Note any unusual conditions relating to this conversion.

855.5 Records of the Conversion

Maintain for the life of the pipeline a record of the studies, inspections, tests, repairs, replacements, and alterations made in connection with conversion of the existing steel pipeline to gas service under this Code.

856 ODORIZATION

856.1 General

Any gas distributed to customers through gas mains or service lines or used for domestic purposes in compressor plants, which does not naturally possess a distinctive odor to the extent that its presence in the atmosphere is readily detectable at all gas concentrations of one-fifth of the lower explosive limit and above, shall have an odorant added to it to make it so detectable. Liquefied petroleum gases are usually nontoxic, but when distributed for consumer use or used as fuel in a place of employment, they shall also be odorized for safety.[1]

Odorization is not required for

(a) gas in underground or other storage

(b) gas used for further processing or use where the odorant would serve no useful purpose as a warning agent or would be a detriment to the process

(c) gas used in lease or field operations

If gas is delivered for use primarily in one of the above exempted activities or facilities and is also used in one of those activities for space heating, refrigeration, water heating, cooking, and other domestic uses, or if such gas is used for furnishing heat or air conditioning for office or living quarters, the gas shall be odorized.

[1] Refer to NFPA 58 and NFPA 59.

856.2 Odorization Equipment

Each operating company shall use odorization equipment designed for the type and injection rate of odorant being used.

856.3 Odorant Requirements

Each operating company shall use an odorant in accordance with the following requirements:

(a) The odorant, when blended with gas in the specified amount, shall not be deleterious to humans or to the materials present in the gas system and shall not be soluble in water to a greater extent than 2½ parts of odorant to 100 parts of water by weight.

(b) The products of combustion from the odorant shall be nontoxic to humans breathing air containing the products of combustion and shall not be corrosive or harmful to the materials with which such products of combustion would ordinarily come in contact.

(c) The combination of the odorant and the natural odor of the gas shall provide a distinctive odor so that when gas is present in air at the concentration of as little as 1% by volume, the odor is readily detectable by a person with a normal sense of smell.

856.4 Records

For all odorizers, except small wick-type or bypass-type, or similar odorizers serving individual customers or small distribution systems, each operating company shall maintain records containing the following items:

(a) the type of odorant introduced into the gas

(b) the amount of odorant injected per million cubic feet (m^3)

856.5 Odorant Concentration Tests

Each operating company shall conduct odorant concentration tests on gas supplied through its facilities that requires odorization. Test points shall be remotely located from the odorizing equipment to provide data representative of gas at all points of the system.

857 UPRATING

This section of the Code prescribes minimum requirements for uprating pipelines or mains to higher maximum allowable operating pressures.

857.1 General

(a) A higher maximum allowable operating pressure established under this section may not exceed the design pressure of the weakest element in the segment to be uprated. It is not intended that the requirements of this Code be applied retroactively to such items as road crossings, fabricated assemblies, minimum cover, and valve spacings. Instead, the requirements for these items shall meet the criteria of the operating company before the uprating is performed.

(b) A plan shall be prepared for uprating that shall include a written procedure that will ensure compliance with each applicable requirement of this section.

(c) Before increasing the maximum allowable operating pressure of a segment that has been operating at a pressure less than that determined by para. 845.2.2, the following investigative and corrective measures shall be taken:

(1) The design, initial installation, method, and date of previous testing, Location Classes, materials, and equipment shall be reviewed to determine that the proposed increase is safe and consistent with the requirements of this Code.

(2) The condition of the line shall be determined by leakage surveys, other field inspections, and examination of maintenance records.

(3) Repairs, replacements, or alterations disclosed to be necessary by (c)(1) and (c)(2) above shall be made prior to the uprating.

(d) A new test according to the requirements of this Code should be considered if satisfactory evidence is not available to ensure safe operation at the proposed maximum allowable operating pressure.

(e) When gas upratings are permitted under paras. 857.2, 857.3, 857.4, and 857.5, the gas pressure shall be increased in increments, with a leak survey performed after each incremental increase. The number of increments shall be determined by the operator after considering the total amount of the pressure increase, the stress level at the final maximum allowable operating pressure, the known condition of the line, and the proximity of the line to other structures. The number of increments shall be sufficient to ensure that any leaks are detected before they can create a potential hazard. Potentially hazardous leaks discovered shall be repaired before further increasing the pressure. A final leak survey shall be conducted at the higher maximum allowable operating pressure.

(f) Records for uprating, including each investigation required by this section, corrective action taken, and pressure test conducted, shall be retained as long as the facilities involved remain in service.

857.2 Uprating Steel Pipelines or Mains to a Pressure That Will Produce a Hoop Stress of 30% or More of SMYS

The maximum allowable operating pressure may be increased after compliance with para. 857.1(c) and one of the following provisions:

(a) If the physical condition of the line as determined by para. 857.1(c) indicates the line is capable of withstanding the desired higher operating pressure, is in general agreement with the design requirements of this Code, and has previously been tested to a pressure equal to or greater than that required by this Code for a new line for the proposed maximum allowable operating

pressure, the line may be operated at the higher maximum allowable operating pressure.

(b) If the physical condition of the line as determined by para. 857.1(c) indicates that the ability of the line to withstand the higher maximum operating pressure has not been satisfactorily verified or that the line has not been previously tested to the levels required by this Code for a new line for the proposed higher maximum allowable operating pressure, the line may be operated at the higher maximum allowable operating pressure if it shall successfully withstand the test required by this Code for a new line to operate under the same conditions.

(c) If the physical condition of the line as determined by para. 857.1(c) verifies its capability of operating at a higher pressure, a higher maximum allowable operating pressure may be established according to para. 845.2.2 using as a test pressure the highest pressure to which the line has been subjected, either in a strength test or in actual operation.

(d) If it is necessary to test a pipeline or main before it can be uprated to a higher maximum allowable operating pressure, and if it is not practical to test the line either because of the expense or difficulties created by taking it out of service or because of other operating conditions, a higher maximum allowable operating pressure may be established in Location Class 1 as follows:

(1) Perform the requirements of para. 857.1(c).

(2) Select a new maximum allowable operating pressure consistent with the condition of the line and the design requirements of this Code, provided

(-a) the new maximum allowable operating pressure does not exceed 80% of that permitted for a new line to operate under the same conditions

(-b) the pressure is increased in increments as provided in para. 857.1(e)

857.3 Uprating Steel or Plastic Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30% of SMYS

(a) This applies to high-pressure steel mains and pipelines where the higher maximum allowable operating pressure is less than that required to produce a hoop stress of 30% of the specified minimum yield strength of the pipe and to all high-pressure plastic distribution systems. If the higher maximum allowable operating pressure of a steel pipeline or main is producing a hoop stress level more than 30% of the specified minimum yield strength of the pipe, the provisions of para. 857.2 shall apply.

(b) Before increasing the maximum allowable operating pressure of a system that has been operating at less than the applicable maximum pressure to a higher maximum allowable operating pressure, the following factors shall be considered:

(1) the physical condition of the line as determined by para. 857.1(c)

(2) information from the manufacturer or supplier determining that each component of a plastic system is capable of performing satisfactorily at the higher pressure

(c) Before increasing the pressure, the following steps shall be taken:

(1) Install suitable devices on the service lines to regulate and limit the pressure of the gas in accordance with para. 845.2.7(c) if the new maximum allowable operating pressure is to be over 60 psi (410 kPa).

(2) Adequately reinforce or anchor offsets, bends, and dead ends in coupled pipe to avoid movement of the pipe should the offset, bend, or dead end be exposed in an excavation.

(3) Increase pressure in increments as provided in para. 857.1(e).

857.4 Uprating a Ductile Iron High-Pressure Main or System to a New and Higher Maximum Allowable Operating Pressure

(a) The maximum allowable operating pressure of a ductile iron main or system shall not be increased to a pressure in excess of that permitted in para. 842.1.1(a). Where records are not complete enough to permit the direct application of para. 842.1.1(a), the following procedures shall be used:

(1) *Laying Condition.* Where the original laying conditions cannot be ascertained, it shall be assumed that Condition D (pipe supported on blocks, tamped backfill) exists for cast iron pipe and Condition B (pipe laid without blocks, tamped backfill) exists for ductile iron pipe.

(2) *Cover.* Unless the actual maximum cover depth is known with certainty, it shall be determined by exposing the main or system at three or more points and making actual measurements. The main or system shall be exposed in areas where the cover depth is most likely to be greatest. The greatest measured cover depth shall be used for computations.

(3) *Nominal Wall Thickness.* Unless the nominal thickness is known with certainty, it shall be determined with ultrasonic measuring devices. The average of all measurements taken shall be increased by the allowance indicated in Table 857.4-1.

The nominal wall thickness of cast iron shall be the standard thickness listed in Table 10 or Table 11, whichever is applicable, of AWWA C101 that is nearest the value obtained. The nominal wall thickness of ductile iron shall be the standard thickness listed in Table 6 of ANSI/AWWA C150/A21.50 nearest the value obtained.

(4) *Manufacturing Process.* Unless the cast iron pipe manufacturing process is known with certainty, it shall be assumed to be pit cast pipe having a bursting tensile

Table 857.4-1 Wall Thickness Allowance for Uprating a Ductile Iron High-Pressure Main or System

Nominal Pipe Size, in. (DN)	Allowance, in. (mm)		
	Cast Iron Pipe		
	Pit Cast Pipe	Centrifugally Cast Pipe	Ductile Iron Pipe
3–8 (75–200)	0.075 (1.9)	0.065 (1.7)	0.065 (1.7)
10–12 (250–300)	0.08 (2.0)	0.07 (1.8)	0.07 (1.8)
14–24 (350–600)	0.08 (2.0)	0.08 (2.0)	0.075 (1.9)
30–42 (750–1050)	0.09 (2.3)	0.09 (2.3)	0.075 (1.9)
48 (1200)	0.09 (2.3)	0.09 (2.3)	0.08 (2.0)
54–60 (1350–1500)	0.09 (2.3)	. . .	. . .

strength, *S*, of 11,000 psi (76 MPa) and a modulus of rupture, *R*, of 31,000 psi (214 MPa).

(b) Before increasing the maximum allowable operating pressure, the following measures shall be taken:

(1) Review the physical condition as required by para. 857.1(c).

(2) Adequately reinforce or anchor offsets, bends, and dead ends in coupled or bell and spigot pipe to avoid movement of the pipe, should the offset, bend, or dead end be exposed by excavation.

(3) Install suitable devices on the service lines to regulate and limit the pressure of the gas in accordance with para. 845.2.7(c) if the new and higher maximum allowable operating pressure is to be over 60 psig (410 kPa).

(c) If after compliance with (a) and (b) it is established that the main system is capable of safely withstanding the proposed new and higher maximum allowable operating pressure, the pressure shall be increased as provided in para. 857.1(e).

857.5 Uprating a Distribution System That Has Been Operating at Inches (Millimeters) of Water (Low Pressure) to a Higher Pressure

(a) In addition to the precautions outlined in para. 857.1(c) and the applicable requirements contained in paras. 857.3 and 857.4, the following steps must be taken:

(1) Install pressure-regulating devices at each customer's meter.

(2) Verify that the segment being uprated is physically disconnected from all segments of line that will continue to operate at inches (millimeters) of water.

(b) After performing the steps outlined in (a) above, the pressure shall be increased in increments as outlined in para. 857.1(e). After the first incremental increase, however, steps shall be taken to verify that the customer's regulators are performing satisfactorily.

Chapter VI
Corrosion Control

860 CORROSION CONTROL — GENERAL

860.1 Scope

(a) This Chapter contains the minimum requirements and procedures for corrosion control of exposed, buried, and submerged metallic piping and components. (See Chapter VIII for special offshore requirements.) This Chapter contains minimum requirements and procedures for controlling external (including atmospheric) and internal corrosion. This Chapter is applicable to the design and installation of new piping systems and to the operation and maintenance of existing piping systems.

(b) The provisions of this Chapter should be applied under the direction of competent corrosion personnel. Every specific situation cannot be anticipated; therefore, the application and evaluation of corrosion control practices requires a significant amount of competent judgment to be effective in mitigating corrosion.

(c) Deviations from the provisions of this Chapter are permissible in specific situations, provided the operating company can demonstrate that the objectives expressed herein have been achieved.

(d) Corrosion control requirements and procedures may, in many instances, require measures in addition to those shown in this Chapter. Each operating company shall establish procedures to implement its corrosion control program, including the requirements of this Chapter, to achieve the desired objectives. Procedures, including those for design, installation, and maintenance of cathodic protection systems, shall be prepared and implemented by, or under the direction of, persons qualified by training and/or experience in corrosion control methods.

(e) Records indicating cathodically protected piping, cathodic protection facilities, and other structures affected by or affecting the cathodic protection system shall be maintained by the operating company.

(f) Records of tests, surveys, inspection results, leaks, etc., necessary for evaluating the effectiveness of corrosion control measures shall be maintained and retained for as long as the piping remains in service.

860.2 Evaluation of Existing Installations

(a) Procedures shall be established for evaluating the need for and effectiveness of a corrosion control program. Appropriate corrective action shall be taken commensurate with the conditions found. If the extent of corrosion has reduced the strength of a facility below its maximum allowable operating pressure, that portion shall be repaired, reconditioned, or replaced, or the operating pressure shall be reduced, commensurate with the remaining strength of the corroded pipe. For steel pipelines, the remaining strength of corroded pipe may be determined in accordance with ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines.

(b) The records available as a result of leakage surveys and normal maintenance work in accordance with paras. 852.2 and 852.6 shall be continuously reviewed for evidence of continuing corrosion.

(c) Electrical survey methods may be used as an indication of suspected corrosive areas where surface conditions permit sufficiently accurate measurements. Such surveys are most effective in nonurban environments. Common methods of electrical survey include

(1) pipe-to-soil potentials

(2) surface potentials (cell-to-cell)

(3) soil resistivity measurements

(d) The continued effectiveness of a cathodic protection system shall be monitored in accordance with section 863.

(e) Whenever a buried facility is exposed during normal maintenance or construction activities, a visual inspection shall be made of the coating condition, the metal surface, or both, if exposed. The extent of any corrosion shall be evaluated in accordance with para. 860.2.

(f) When any part of a pipeline is removed and the internal surface is accessible for inspection, it shall be visually examined and evaluated for internal corrosion.

(1) If evidence of internal corrosion is discovered, the gas shall be analyzed to determine the types and concentrations of any corrosive agents.

(2) Liquids or solids removed from the pipeline by pigging, draining, or cleanup shall be analyzed as necessary for determining the presence of corrosive materials and evidence of corrosion products.

860.3 Corrective Measures

(a) If continuing external corrosion that, unless controlled, could result in a condition that is detrimental to public or employee safety is found by the evaluation made under para. 860.2(a) or section 863, appropriate corrective measures shall be taken to mitigate further corrosion on the piping system or segment. Corrective measures shall be continued in effect as long as required

to maintain a safe operating system. Appropriate corrective measures may include the following:

(1) provisions for proper and continuous operation of cathodic protection facilities

(2) application of protective coating

(3) installation of galvanic anode(s)

(4) application of impressed current

(5) electrical isolation

(6) stray current control

(7) other effective measures

(8) any combination of the above

(b) Where it is determined that internal corrosion taking place could affect public or employee safety, one or more of the following protective or corrective measures shall be used to control detrimental internal corrosion:

(1) An effective corrosion inhibitor shall be applied in a manner and quantity to protect all affected portions of the piping systems.

(2) Corrosive agents shall be removed by recognized methods, such as acid gas or dehydration treating plants.

(3) Fittings shall be added for removal of water from low spots, or piping shall be positioned to reduce sump capacities.

(4) Under some circumstances, application of a suitable internal coating may be effective.

(c) When experience or testing indicates the above mitigation methods will not control continuing corrosion to an acceptable level, the segment shall be reconditioned or replaced and suitably protected.

861 EXTERNAL CORROSION CONTROL FOR STEEL PIPELINES

861.1 Buried/Submerged Installations

All new transmission pipelines, compressor station piping, distribution mains, service lines, and pipe-type and bottle-type holders installed under this Code shall, except as permitted under para. 862.1.2, be externally coated and cathodically protected unless it can be demonstrated by test or experience that the materials are resistant to corrosion in the environment in which they are installed. Consideration shall be given to the handling, shipping, storing, installation conditions, and the service environment and cathodic protection requirements when selecting the coating materials. *The Corrosion Data Survey*, published by NACE International, is a source of information on materials performance in corrosive environments.

861.1.1 Coatings

(a) The surface preparation should be compatible with the coating to be applied. The pipe surface shall be free of deleterious materials, such as rust, scale, moisture, dirt, oils, lacquers, and varnish. The surface shall be inspected for irregularities that could protrude through the coating. Any such irregularities shall be removed. Further information can be obtained from NACE SP0169.

(b) Suitable coatings, including compatible field joint and patch coatings, shall be selected, giving consideration to handling, shipping, storing, installation condition, moisture adsorption, operating temperatures of the pipeline, environmental factors (including the nature of the soil in contact with the coating), adhesion characteristics, and dielectric strength.

(c) Coating shall be applied in a manner that ensures effective adhesion to the pipe. Voids, wrinkles, holidays, and gas entrapment should be avoided.

(d) The coating shall be visually inspected for defects before the pipe is lowered into the ditch. Insulating type coatings on mains and transmission lines shall be inspected for holidays by the most appropriate method. Coating defects or damage that may impair effective corrosion control shall be repaired before the pipe is installed in the ditch.

(e) In addition to the provisions of paras. 841.2.2(b), 841.2.5(b), and 841.2.5(c), care shall be exercised in handling, storage, and installation to prevent damage to the coating, including measures noted as follows:

(1) Minimize handling of coated pipe. Use equipment least likely to damage the coating, e.g., belts or cradles instead of cables.

(2) Use padded skids where appropriate.

(3) Stack or store pipe in a manner that minimizes damage to coating.

861.1.2 Cathodic Protection Requirements. Unless it can be demonstrated by tests or experience that cathodic protection is not needed, all buried or submerged facilities with insulating type coatings, except facilities installed for a limited service life, shall be cathodically protected as soon as feasible following installation. Minor replacements or extensions, however, shall be protected as covered by para. 860.3.

Facilities installed for a limited service life need not be cathodically protected if it can be demonstrated that the facility will not experience corrosion that will cause it to be harmful to the public or environment. Cathodic protection systems shall be designed to protect the buried or submerged system in its entirety. A facility is considered to be cathodically protected when it meets one or more of the criteria established in Mandatory Appendix K.

861.1.3 Electrical Isolation

(a) All coated transmission and distribution systems shall be electrically isolated at all interconnections with foreign systems including customer's fuel lines, except where underground metallic structures are electrically interconnected and cathodically protected as a unit. Steel pipelines shall be electrically isolated from cast iron, ductile iron, or nonferrous metal pipelines and

components. Electrical tests shall be made of transmission and distribution systems to locate unintentional contacts with other metallic structures. If such contacts exist, they shall be corrected. See para. 841.1.11(c) for clearance requirements.

(b) Where a gas pipeline parallels overhead electric transmission lines, consideration shall be given to

(1) investigating the necessity of protecting insulating joints in the pipeline against induced voltages resulting from ground faults and lightning. Such protection can be obtained by connecting buried galvanic anodes to the pipe near the insulating joints and/or by bridging the pipeline insulator with a spark gap, or by other effective means.

(2) making a study in collaboration with the electric company, taking the following factors into consideration and applying remedial measures as appropriate:

(-a) the need to mitigate induced AC voltages or their effects on personnel safety during construction and operation of the pipeline by means of suitable design for bonding, shielding, or grounding techniques

(-b) the possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings or pipe

(-c) possible adverse effects on cathodic protection, communications, or other electronic facilities

(-d) the corrosive effects of high voltage direct current (HVDC) power systems

(3) obtaining further information from NACE SP0177 and EPRI EL-3106.

861.1.4 Electrical Connections and Monitoring Points

(a) Except for offshore pipelines, sufficient test points should be installed to demonstrate the effectiveness of corrosion control or the need for cathodic protection. (See Chapter VIII for special considerations for offshore pipelines.)

(b) Special attention shall be given to the manner of installation of electrical leads used for corrosion control or testing to avoid harmful stress concentration at the point of attachment to the pipe. Acceptable methods include, but are not limited to

(1) electrical leads attached directly on the pipe or by the thermit welding process, using copper oxide and aluminum powder. The size of the thermit welding charge shall not exceed a 15-g cartridge.

(2) attachment of electrical leads directly to the pipe by the use of soft solders or other materials that do not involve temperatures exceeding those for soft solders.

(c) All pipe that is barred for electrical lead connections and all bared electrical lead wires shall be protected by electrical insulating material compatible with existing coating.

861.1.5 Electrical Interference

(a) Impressed current cathodic protection systems shall be designed, installed, and operated so as to minimize adverse effects on existing metallic structures.

(b) Field tests shall be conducted to determine the adverse electrical interference from foreign structures, including DC electrical facilities. The effects shall be mitigated by such means as control bonds, supplementary cathodic protection, protective coatings, and insulating devices.

861.1.6 Isolation From Casings. The use of metallic casings should be avoided as much as as possible from a corrosion control standpoint. It is recognized, however, that installation of metallic casings is frequently required or desirable to facilitate construction, as an economical method of protecting existing pipelines, to provide structural protection from heavy and/or impact loads to facilitate replacement as required by a governmental agency and as required by the landowner or permit grantor, and for other reasons. Where metallic casing is used, care should be exercised to ensure that coating on the carrier pipe is not damaged during installation. The carrier pipe should be insulated from metallic casings, and the casing ends should be sealed with a durable material to minimize the accumulation of solids and liquids in the annular space. Special attention should be given to the casing ends to prevent electrical shorting due to backfilling movement or settling. Where electrical isolation is not achieved, action shall be taken to correct the condition or mitigate corrosion inside of the casing by supplemental or localized cathodic protection, installation of a high-resistivity inhibited material in the annular space, or other effective means.

861.1.7 Electrical Interference

(a) Adverse electrical interference from or to foreign structures as determined by field tests shall be mitigated.

(b) Facilities for mitigating electrical interference shall be periodically monitored.

861.2 Aboveground Piping Atmospheric Protection

861.2.1 Coatings. Facilities exposed to the atmosphere shall be protected from external corrosion by a suitable coating or jacket.

861.2.2 Surface Preparation. The surface to be coated shall be free of deleterious materials, such as rust, scale, moisture, dirt, oil, lacquer, and varnish. The surface preparation shall be compatible with the coating or jacket to be applied.

861.2.3 Coating Characteristics. The coating or jacket selected shall possess characteristics that will provide adequate protection from the environment. Coatings and jackets shall completely cover the exposed structure and shall be applied in accordance with established specifications or manufacturer's recommendations.

861.2.4 Air/Electrolyte Interface. Special consideration shall be given to surfaces near the ground line or in a splash zone.

861.3 Harsh Environments

Where investigation or experience indicates that the environment in which the pipe or component is to be installed is substantially corrosive, the following shall be considered:

(a) materials and/or component geometry shall be designed to resist detrimental corrosion
(b) a suitable coating
(c) cathodic protection

862 CATHODIC PROTECTION CRITERIA

862.1 Standard Criteria

A facility is considered to be cathodically protected when it meets one or more of the criteria established in Mandatory Appendix K.

862.2 Alternative Criteria

It is not intended that cathodic protection be limited to these criteria if it can be demonstrated by other means that adequate control of corrosion has been achieved.

863 OPERATION AND MAINTENANCE OF CATHODIC PROTECTION SYSTEMS

863.1 Inspection of Equipment

Inspections shall be made as required to maintain continuous and effective operation of the cathodic protection system.

863.2 Measurement of Cathodic Protection

Electrical tests shall be made periodically to determine that the piping system is protected in accordance with the applicable criteria.

863.3 Frequency of Testing

The type, frequency, and location of inspections and tests shall be adequate to establish with reasonable accuracy the degree of protection provided on the piping system. Frequency should be determined by consideration of items including, but not limited to, the following:

(a) condition of pipe
(b) method of cathodic protection
(c) corrosiveness of the environment
(d) probability of loss or interruption of protection
(e) operating experience, including inspections and leak investigations
(f) design life of the cathodic protection installation
(g) public or employee safety

863.4 Appropriate Correction Measure

Where the tests or surveys indicate that adequate protection does not exist, appropriate corrective measure shall be taken.

864 INTERNAL CORROSION CONTROL

864.1 General

When corrosive gas is transported, provisions shall be taken to protect the piping system from detrimental corrosion. Gas containing free water under the conditions at which it will be transported shall be assumed to be corrosive, unless proven to be noncorrosive by recognized tests or experience.

Internal corrosion control measures shall be evaluated by an inspection and monitoring program, including but not limited to, the following:

(a) The inhibitor and the inhibitor injection system should be periodically checked.

(b) Corrosion coupons and test spools shall be removed and evaluated at periodic intervals.

(c) Corrosion probes should be checked manually at intervals, or continuously or intermittently monitored, recorded, or both, to evaluate control of pipeline internal corrosion.

(d) A record of the internal condition of the pipe, of leaks and repairs from corrosion, and of gas, liquids, or solids quantities and corrosivity should be kept and used as a basis for changes in the pigging schedule, inhibitor program, or gas treatment facility.

(e) When pipe is uncovered or on exposed piping where internal corrosion may be anticipated, pipe wall thickness measurement or monitoring will help evaluate internal corrosion.

(f) Where inspections, observation, or record analysis indicates internal corrosion is taking place to an extent that may be detrimental to public or employee safety, that portion of the system shall be repaired or reconditioned, and appropriate steps taken to mitigate the internal corrosion.

864.2 Design of New Installations

When designing a new or replacement pipeline system, or additions or modifications to existing systems, measures shall be considered to prevent and/or inhibit internal corrosion. To preserve the integrity and efficiency of a pipeline in which it is known or anticipated that corrosive gas will be transported, the following factors should be included in the design and construction, either separately or in combination.

864.2.1 Use of Internal Protective Coating. When internal coating is to be used to protect a piping system

(a) the coating shall meet the quality specifications, and the minimum dry film thickness shall be established to protect the facility from the corrosive media involved, based on the type of coating and methods of application

(b) applied coatings shall be inspected in accordance with established specifications or accepted practice

(c) provision shall be made to prevent joint corrosion, such as cleaning and recoating or the continuing use of a suitable inhibitor when coated pipe or other components are joined by welding or other methods that leave the parent metal exposed

(d) the types of coating and pigging tools used should be evaluated and chosen to prevent damage to the internal coating if pigs or spheres are to be used

864.2.2 Use of Corrosion Inhibitor. When a corrosion inhibitor is to be used as an additive to the gas streams

(a) the equipment for the holding, transfer, and injection of the inhibitor into the stream shall be included in the design

(b) the operation of the injection program should be a part of the planning

(c) sufficient test coupon holders or other monitoring equipment shall be provided to allow for continued program evaluations

(d) the corrosion inhibitor selected shall be of a type that will not cause deterioration of any components of the piping system

864.2.3 Use of Pigging Equipment. When a pipeline pigging system is planned

(a) scraper traps for the insertion and removal of pigs, spheres, or both, shall be provided

(b) sections of pipeline to be traversed by pigs or spheres shall be designed to prevent damage to pigs, spheres, pipes, or fittings during operations

(c) piping for pigs or spheres shall be designed to guide the tool and the materials they propel effectively and safely

(d) provisions shall be made for effective accumulation and handling of liquid and solid materials removed from the pipeline by pigs or spheres

864.2.4 Use of Corrosion Coupons. When corrosion coupons, corrosion probes, and/or test spools are to be used

(a) corrosion coupons, probes, or test spools shall be installed where practical at locations where the greatest potential for internal corrosion exists

(b) corrosion coupons, probes, and test spools must be designed to permit passage of pigs or spheres when installed in sections traversed thereby

864.2.5 Sweetening or Refining of Gas. When gas is to be treated to reduce its corrosivity

(a) separators and/or dehydration equipment may be installed

(b) equipment for the removal of other deleterious material from the gas should be considered

864.2.6 Use of Corrosion-Resistant Materials. The material of the pipe and other equipment exposed to the gas stream must resist internal corrosion; therefore

(a) materials selected for pipe and fittings shall be compatible with the components of the gas, the liquids carried by the gas, and with each other. A source of information on materials performance in corrosive environments is *The Corrosion Data Survey*, published by NACE International.

(b) where plastic, nonferrous, or alloy steel pipe and components are used to prevent or control internal corrosion, such materials shall have been determined to be effective under the conditions encountered. [See paras. 842.5.1(a)(2) and 849.5.1(a)(2) for limitations on copper.]

(c) erosion–corrosion effects from high-velocity particles at probable points of turbulence and impingement should be minimized by use of erosion-resistant materials, added wall thickness, design or flow configuration, and size or dimensions of the pipe and fittings.

864.2.7 High-Temperature Considerations. When gas or a mixture of gas and liquids or solids known or anticipated to be corrosive is transported at elevated temperatures, special consideration shall be given to the identification and mitigation of possible internal corrosion. Such measures are necessary because corrosion reaction rates increase with elevated temperatures and are not stable. Appropriate mitigation and monitoring measures are given in section 864.

864.2.8 Low-Temperature Considerations. Where the gas stream is chilled to prevent melting of frozen soil surrounding the pipeline, there will not normally be enough free water in the gas to result in internal corrosion in the presence of contaminants, such as sulfur compounds or CO_2. If it is anticipated, however, that free water or water/alcohol solutions will be present in the pipeline along with potentially corrosive contaminants, suitable corrective measures shall be taken as prescribed in section 864.

865 STEEL PIPELINES IN ARCTIC ENVIRONMENTS

865.1 Special Considerations for Arctic Environments

Special consideration must be given to the corrosion control requirements of buried pipelines and other facilities installed in arctic environments, particularly in permafrost regions. For pipelines in contact with frozen earth, the corrosion rate is reduced because of the extremely high resistivity of the soil and low ion mobility, but it does not reach zero. Significant corrosion can occur, however, in unfrozen inclusions, discontinuous permafrost, or thaw areas such as those that may occur in the vicinity of rivers, lakes, springs, or pipeline sections where the pipe surface temperature is above the freezing point of the environment. Cathodic protection in localized thaw areas may be more difficult due to the shielding of cathodic protection currents by the surrounding frozen soil. Other detrimental effects can be caused by seasonal thaws that increase biological and bacteriologic activity in the nonpermafrost areas or in the "active layer" above underlying permafrost.

Pipeline facilities installed in arctic environments shall be coated and cathodically protected in the same manner as pipelines in temperate locations, and the same consideration shall be given to the need for protection from internal and atmospheric corrosion, except as specifically provided in this section.

865.1.1 External Coating Requirements. Coatings for pipelines in low-temperature environments shall be selected according to the particular requirements of that environment. These include adhesion, resistance to cracking or damage during handling and installation in subfreezing temperatures, applicability of field joint coatings or coating repairs, compatibility with any applied cathodic protection, and resistance to soil stresses due to frost heave, thaw settlement, seasonal temperature changes, or other reasons.

865.1.2 Impressed Current Considerations. Criteria for cathodic protection shall be the same as those for pipelines in temperate environments. Because higher driving voltages are normally required in frozen soils, the voltage impressed across the coating should be limited so that the coating is not subject to damage due to cathodic overvoltage or excessive current density.

(a) Impressed current facilities shall be used on pipelines in permanently frozen soil, especially where the gas is chilled to prevent thawing of the earth. Such facilities are capable of providing the higher driving voltage needed to overcome the high resistivity of frozen soil. They can be installed at compressor stations or other facilities where power is available and access for adjustment and maintenance is ensured. The effects of seasonal variations in soil resistivity should be compensated for by using constant potential rectifiers or manual adjustments.

(b) Impressed current anode beds shall be installed whenever feasible at a sufficient distance from the pipeline or other underground structures to achieve maximum spread along the pipeline and to reduce the peak potential at the pipeline.

(c) Anode beds shall be installed, where practical, below the permafrost level or in other unfrozen locations, such as a stream or lake, to achieve better cathodic current distribution. Where anodes must be installed in permanently frozen ground, the volume of the anode backfill material should be increased to reduce the effective resistance between the anode and the surrounding earth.

(d) Impressed current facilities using distributed or deep anode ground beds should be used to protect buried station facilities and pilings where used to support aboveground plant facilities. The pilings and any other adjacent underground metallic facilities must be electrically interconnected to prevent detrimental interference.

865.1.3 Galvanic Anode Considerations. Galvanic anodes (packaged or ribbon) may be needed on pipelines in permafrost areas to supplement impressed current facilities in localized thawed areas. This provides localized cathodic protection to those sections of pipe that might be shielded by the extremely high resistivity of the surrounding soil.

865.1.4 Monitoring Considerations. Installation of calibrated current measurement spans should be considered in addition to the normal test points. These should be installed at sufficient intervals to evaluate current distribution along the protected pipeline and the effects of telluric currents prevalent in polar regions. These spans also provide contact points for measuring indications of possible coating damage due to stresses induced by a frozen environment.

866 STEEL PIPELINES IN HIGH-TEMPERATURE SERVICE

866.1 Special Considerations for High-Temperature Service

Special consideration must be given to the corrosion control requirements of pipelines and other facilities in high-temperature service [above 150°F (66°C)]. Elevated temperatures tend to decrease the resistivity of buried or submerged pipeline environments and to increase the electrochemical corrosion reaction as a result of accelerated ionic or molecular activity. Elevated temperatures typically occur downstream of compressor stations or in gathering systems.

866.1.1 External Coating Considerations. Coatings shall be selected based on the particular requirements for pipeline facilities in high-temperature service. These include resistance to damage from soil or secondary stresses, compatibility with any applied cathodic protection, and particularly, resistance to thermal degradation. In rocky environments, the use of a protective outer wrap, select backfill, or other suitable measures shall be considered to minimize physical damage.

866.1.2 Impressed Current Considerations. Criteria for cathodic protection shall be the same as those for normal temperature service, except that recognition should be given to the effects of decreased resistivity and increased cathodic protection current requirements in elevated temperature service on any IR component of the pipe-to-soil potential measurement. Possible depolarization effects due to high-temperature operation shall also be considered.

866.1.3 Galvanic Anode Considerations. Consideration shall be given to the impact on the performance of close galvanic anodes (especially bracelet or ribbon type) subject to elevated temperatures due to their proximity to a hot pipeline. Higher temperatures tend to increase the current output and rate of degradation of most anode materials. Some anode materials may become more noble than steel at temperatures above 140°F (60°C) in certain electrolytes. Zinc anodes containing aluminum are also susceptible to intergranular corrosion above 120°F (49°C).

867 STRESS CORROSION AND OTHER PHENOMENA

Environmentally induced and other corrosion-related phenomena, including stress corrosion cracking, corrosion fatigue, hydrogen stress cracking, and hydrogen embrittlement have been identified as causes of pipeline failure. Considerable knowledge and data have been acquired and assembled on these phenomena, and research is continuing as to their causes and prevention. Operating companies should be alert for evidence of such phenomena during all pipe inspections and at other such opportunities. Where evidence of such a condition is found, an investigative program shall be initiated, and remedial measures shall be taken as necessary. Any such evidence should be given consideration in all pipeline failure investigations. Operating companies should avail themselves of current technology on the subject and/or consult with knowledgeable experts.

This paragraph must be limited to general statements rather than specific limits in regard to stress corrosion. Stress corrosion is currently the subject of investigative research programs, and more specific data will certainly be available to the pipeline designer and operating company in the future. In the interim, this Code suggests that the user refer to the current state of the art. Cathodic protection current levels, quality of pipe surface preparation and coating, operating temperatures, stress levels, and soil conditions shall be considered in pipeline design and operations.

868 CAST IRON, WROUGHT IRON, DUCTILE IRON, AND OTHER METALLIC PIPELINES

868.1 Requirements for Cast Iron and Ductile Iron Piping Facilities Exposed to Atmosphere

Aboveground cast iron and ductile iron pipe shall be suitably protected in areas where severe atmospheric corrosion may occur.

868.2 Other Metallic Materials

When a nonferrous metal or ferrous alloy component is found to have corroded to the point where public or employee safety may be affected, it shall be reconditioned in accordance with para. 861.3 or replaced. The replacement shall meet one of the following criteria:

(a) It shall be constructed with other materials, geometry, or both, designed for the remaining life of the parent facility.

(b) It shall be cathodically or otherwise protected.

868.3 Installation of Electrical Connections

(a) Electrical connections may be attached directly onto the cast or ductile iron pipe by the thermit welding process using copper oxide and aluminum powder. The size of the thermit welding charge shall not exceed a 32-g cartridge.

(b) All pipe that is bared for test lead connections and all bared test lead wires shall be protected by electrical insulating material compatible with existing coating.

Chapter VII
Intentionally Left Blank

The material previously shown in this Chapter has been moved to other Chapters in this Code.

This Chapter has been intentionally left blank and is reserved for future use.

Chapter VIII
Offshore Gas Transmission

A800 OFFSHORE GAS TRANSMISSION

(16) A801 GENERAL

Chapter VIII pertains only to offshore gas transmission systems as defined in para. A802.1. With the exception of sections A840 through A842, A844, and A847, this Chapter is organized to parallel the numbering and the content of the first six chapters of the Code. All applicable provisions of Chapters I through VI of this Code are also requirements of this Chapter unless specifically modified herein. With the exceptions noted above, paragraph designations follow those in the first six chapters with the prefix "A."

A802 SCOPE AND INTENT

A802.1 Scope

This Chapter of the Code covers the design, material requirements, fabrication, installation, inspection, testing, and safety aspects of operation and maintenance of offshore gas transmission systems. For this Chapter, offshore gas transmission systems include offshore gas pipelines, pipeline risers, offshore gas compressor stations, pipeline appurtenances, pipe supports, connectors, and other components as addressed specifically in this Code.

A802.2 Intent

The intent of this Chapter is to provide adequate requirements for the safe and reliable design, installation, and operation of offshore gas transmission systems. Requirements of this Chapter supplement the requirements of the remainder of this Code. It is therefore not the intent of this Chapter to be all inclusive, and provisions must be made for any special considerations that are not specifically addressed.

It is not the intent of this Chapter to prevent the development and application of new equipment and technologies. Such activity is encouraged as long as the safety and reliability requirements of this Code are satisfied.

(16) A803 OFFSHORE GAS TRANSMISSION TERMS AND DEFINITIONS

accidental loads: any unplanned load or combination of unplanned loads caused by human intervention or natural phenomena.

biofouling: an accumulation of deposits. This includes accumulation and growth of marine organisms on a submerged metal surface and the accumulation of deposits (usually inorganic) on heat exchanger tubing.

breakaway coupling: a component installed in the pipeline to allow the pipeline to separate when a predetermined axial load is applied to the coupling.

buckle: a condition in which the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling in the pipe wall or excessive cross-sectional deformation caused by bending, axial, impact, and/or torsional loads acting alone or in combination with hydrostatic pressure.

cathodic disbondment: the loss of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

column buckling: buckling of a beam or pipe under compressive axial load in which loads cause unstable lateral deflection, also referred to as *upheaval buckling*.

connectors: any component, except flanges, used for mechanically joining two sections of pipe.

disbondment: the loss of adhesion between a coating and the substrate.

documented: the condition of being in written form.

external hydrostatic pressure: pressure acting on any external surface resulting from its submergence in water.

flexible pipe: pipe that is

(a) manufactured as a composite from both metal and nonmetal components

(b) capable of allowing large deflections without adversely affecting the pipe's integrity

(c) intended to be an integral part of the permanent product transportation system

Flexible pipe does not include solid metallic steel pipe, plastic pipe, fiber-reinforced plastic pipe, rubber hose, or metallic pipes lined with nonmetallic linings or coatings.

fracture mechanics: a quantitative analysis for evaluating structural reliability in terms of applied stress, crack length, specimen geometry, and material properties.

hyperbaric weld: a weld performed at ambient hydrostatic pressure in a submerged chamber from which the water has been removed from the surfaces to be welded.

minimum wall thickness, t_{min}: the nominal wall thickness, t (see para. 804.5), minus the manufacturing tolerance in accordance with the applicable pipe specification, and minus all corrosion and erosion allowances. The minimum wall thickness is used in the design equations in para. A842.2.2(d).

near white blast cleaned: a surface that, when viewed without magnification, is free of all visible oil, grease, dust, dirt, mill scale, rust, coating, oxides, corrosion products, and other foreign matter. Random staining is limited to not more than 5% of each unit area of surface [approximately 9.0 in.^{2} (58 cm^2)], and may consist of light shadows, slight streaks, or minor discolorations caused by stains of rust, stains of mill scale, or stains of previously applied coating (see NACE No. 2/SSPC-SP 10).

offshore: the area beyond the line of ordinary high water along the portion of the coast that is in direct contact with the open seas and beyond the line marking the seaward limit of inland coastal waters.

offshore pipeline riser: the vertical or near vertical portion of an offshore pipeline between the platform piping and the pipeline at or below the seabed, including a length of pipe of at least five pipe diameters beyond the bottom elbow, bend, or fitting. Due to the wide variety of configurations, the exact location of transition between pipeline, pipeline riser, and platform piping must be selected on a case-by-case basis.

offshore pipeline system: all components of a pipeline installed offshore for transporting gas other than production facility piping. Tanker or barge loading hoses are not considered part of the offshore pipeline system.

offshore platform: any man-made fixed or permanently anchored structure or artificial island located offshore.

pipe collapse: flattening deformation of the pipe resulting in loss of cross-sectional strength and circular shape, which is caused by excessive external hydrostatic pressure acting alone.

plastic deformation: a permanent deformation caused by stressing beyond the elastic limit.

platform piping:

(a) On offshore platforms producing hydrocarbons, platform piping is all the gas transmission piping, appurtenances, and components between the production facility and the offshore pipeline riser(s). This includes any gas compressors and piping that are not a part of the production facility.

(b) On offshore platforms not producing hydrocarbons, platform piping is all the gas transmission piping, compressors, appurtenances, and components between the offshore pipeline risers.

(c) Because of a wide variety of configurations, the exact location of the transition between the offshore pipeline riser(s), the platform piping, and the production facility must be selected on a case-by-case basis.

prefabricated piping: a section of riser, platform piping, or subsea pipeline that contains fittings and butt welds, flanges, and/or mechanical connectors and is typically fabricated onshore and connected to the pipeline system during installation. Some examples of prefabricated piping include a riser offset, jumper, expansion loop, tie-in spool, and prefabricated riser.

propagating buckle: a buckle that progresses rapidly along a pipeline caused by the effect of external hydrostatic pressure on a previously formed buckle, local collapse, or other cross-sectional deformation.

pull tube: a conduit attached to an offshore platform through which a riser can be installed.

pull-tube riser: riser pipe or pipes installed through a pull tube (e.g., J-tube or I-tube).

return interval: statistically determined time interval between successive events of design environmental conditions being equaled or exceeded, typically calculated as the reciprocal of the annual probability of occurence of the event.

riser: see *offshore pipeline riser.*

sea floor bathymetry: refers to water depths along the pipeline route.

soil liquefaction: a soil condition, typically caused by dynamic cyclic loading (e.g., earthquake, waves), where the effective shear strength in the soil is reduced such that the soil exhibits the properties of a liquid.

special assembly: a subsea pipeline section that contains pipeline components such as a buckle or fracture arrestor, in-line sled, subsea tie-in assembly, pipeline end manifold, pipeline end termination, in-line valve assembly, side valve assembly, or subsea manifold and is typically fabricated onshore and connected to the pipeline system during installation.

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

steel catenary riser (SCR): a catenary-shaped extension of a subsea pipeline that is attached to a floating or fixed offshore platform.

trawl board: a structure that is attached to the bottom of commercial fishing nets and is dragged along the sea floor.

vortex shedding: the periodic shedding of fluid vortices and resulting unsteady flow patterns downstream of a pipeline span that may introduce dynamic forces on the pipeline.

weight coating: any coating applied to the pipeline for increasing the pipeline specific gravity.

A811 QUALIFICATION OF MATERIALS AND EQUIPMENT

Plastic pipe, plastic pipe with nonmetallic reinforcement, cast iron pipe, and ductile iron pipe shall not be used for transporting natural gas.

A814 MATERIAL SPECIFICATIONS

A814.1 Pipe Conforming to Referenced Standards and Specifications

A814.1.1 Steel Pipe. Steel line pipe with a longitudinal joint factor of 1.00 in Table 841.1.7-1 shall be used.

A814.3 Weight Coating

Concrete weight coating materials (cement, aggregate, reinforcing steel) shall meet or exceed the requirements of applicable ASTM standards.

A814.4 Flexible Pipe

Flexible pipe shall be manufactured from materials meeting the requirements of applicable ASTM or ASME standards.

A814.5 Other Requirements

In addition to the requirements contained in referenced standards, certain other requirements may be considered for pipe and other components used offshore, depending on water depth, water temperature, internal pressure, product composition, product temperature, installation method and/or other loading conditions. Thus, consideration may include one or more of the following:

(a) wall thickness tolerance

(b) outside diameter tolerance

(c) out-of-roundness

(d) maximum and minimum yield and tensile strengths

(e) maximum carbon equivalent

(f) fracture toughness

(g) hardness

(h) pipe mill hydrostatic testing and other mechanical testing

A817 CONDITIONS FOR THE REUSE AND REQUALIFICATION OF PIPE

A817.1 Reuse of Steel Pipe

Used pipe may be reused, subject to the following conditions:

(a) The pipe meets the design considerations in sections A841, A842, and A843.

(b) The pipe meets the testing requirements in section A847.

(c) The pipe shall be inspected per para. 817.1.3 to identify any defects that impair the serviceability of the pipe. If such defects are identified, they shall be removed or repaired.

Unidentified line pipe shall not be used for subsea pipelines.

A817.4 Requalification of Pipeline Systems

A pipeline system that has previously been used for gas transmission service may be requalified, subject to the following conditions:

(a) The pipeline system meets the design considerations in sections A841, A842, and A843.

(b) The pipeline system meets the hydrotesting requirements in paras. A847.1 through A847.6. In addition, if the pipeline system is moved, it shall also meet the testing for buckles requirement in para. A847.7.

A820 WELDING OFFSHORE PIPELINES

A821 GENERAL

A821.1 General Requirements

This section concerns the welding of carbon steel materials that are used in a pipeline in the offshore environment. The welding covered may be performed under atmospheric or hyperbaric conditions.

A821.2 Welding Processes

The welding may be done by any process or combination of processes that produce welds that meet the procedure qualification requirements of this Code and can be inspected by conventional means.

A821.3 Welding Procedure

(a) Prior to atmospheric welding of any pipe, piping components, or related equipment, Welding Procedure Specifications shall be written and the procedure shall be qualified. The approved procedure shall include all of the applicable details listed in API 1104.

(b) Prior to hyperbaric welding of any pipe, piping components, or related equipment, Welding Procedure Specifications shall be written and the procedure shall be qualified. The approved procedure shall include all of the applicable details listed in API 1104 and AWS D3.6.

(c) Each welder or welding operator shall be qualified for the established procedure before performing any welding on any pipe, piping component, or related equipment installed in accordance with this Code.

(d) Welding procedure qualifications, as well as welder or welding operator qualifications, are valid only within the specified limits of the welding procedure. If changes are made in certain details, called "essential variables" or "essential changes," additional qualification is required. API 1104 essential variables shall take precedence in matters not affected by the underwater environment, and AWS D3.6 shall govern those essential changes related to the underwater welding environment and working conditions.

A823 QUALIFICATION OF PROCEDURES AND WELDERS

Qualification of procedures and welders shall be in accordance with the requirements of para. 823, except paras. 823.1 and 823.2 do not apply offshore.

(a) Welding procedures and welders performing atmospheric welding under this section shall be

qualified under API 1104, except that for applications in which design, materials, fabrication, inspection, and testing are in accordance with BPV Code, Section VIII, welding procedures and welders shall be qualified under BPV Code, Section IX.

(b) Welding procedures and welders performing hyperbaric welding under this section shall be qualified in accordance with the testing provisions of API 1104 as supplemented by AWS D3.6, Specification for Underwater Welding for Type "O" Welds.

A825 STRESS RELIEVING

Stress relieving requirements may be waived, regardless of wall thickness, provided that it can be demonstrated that a satisfactory welding procedure without the use of postweld heat treatment has been developed. Such a demonstration shall be conducted on materials and under conditions that simulate, as closely as practical, the actual production welding. Measurements shall be taken of the tensile, toughness, and hardness properties of the weld and heat-affected zone. No stress relieving will be required if

(a) the measurements indicate that the metallurgical and mechanical properties are within the limits specified for the materials and intended service.

(b) an engineering analysis is conducted to ensure that the mechanical properties of the weldment and the residual stresses without postweld heat treatment are satisfactory for the intended service. In some cases, measurement of residual stresses may be required.

A826 INSPECTION OF WELDS

A826.2 Inspection and Tests for Quality Control of Welds on Piping Systems

A826.2.1 Extent of Examination. One-hundred percent of the total number of field welds on offshore pipelines and pipeline components that are subjected to loading by pipeline internal pressure shall be nondestructively inspected, if practical, but in no case shall less than 90% of such welds be inspected. The inspection shall cover 100% of the length of such inspected welds.

A826.2.2 Standard of Acceptability. All welds that are inspected must meet the standards of acceptability of API 1104 or BPV Code, Section VIII, as appropriate for the service of the weld, or be appropriately repaired and reinspected or removed.

A826.2.3 Alternative Flaw Acceptance Limits. For girth welds on a pipeline, alternative flaw acceptance limits may be established based on fracture mechanics analyses and fitness-for-purpose criteria as described in API 1104. Such alternative acceptance standards shall be supported by appropriate stress analyses, supplementary welding procedure test requirements, and nondestructive examinations beyond the minimum requirements specified herein. The accuracy of the nondestructive techniques for flaw depth measurement shall be verified by sufficient data to establish probabilities for the proposed inspection error allowance.

A830 PIPING SYSTEM COMPONENTS AND FABRICATION DETAILS

A830.1 General

The purpose of paras. A831 through A835 is to provide a set of criteria for system components to be used in an offshore application.

A831 PIPING SYSTEM COMPONENTS

Cast iron or ductile iron shall not be used in flanges, fittings, or valve shell components.

All system components for offshore applications shall be capable of safely resisting the same loads as the pipe in the run in which they are included, except "weak links" (e.g., breakaway couplings) designed into a system to fail under specific loads. Consideration should be given to minimizing stress concentrations.

System components that are not specifically covered in para. 831 shall be validated for fitness by either

(a) documented full scale prototype testing of the components or special assemblies, or

(b) a history of successful usage of these components or special assemblies produced by the same design method. Care should be exercised in any new application of existing designs to ensure suitability for the intended service.

A831.1 Valves and Pressure-Reducing Devices

A831.1.1 Valves. In addition to the valve standards listed in para. 831.1.1(a), the following specifications may be used:

API Spec 6DSS/ISO 14723	Specification for Subsea Pipeline Valves
API Spec 17D	Design and Operation of Subsea Production Systems — Subsea Wellhead and Tree Equipment

A832 EXPANSION AND FLEXIBILITY

Thermal expansion and contraction calculations shall consider the temperature differential between material temperature during operations and material temperature during installation.

A834 SUPPORTS AND ANCHORAGE FOR EXPOSED PIPING

No attachment other than an encircling member shall be welded directly to the pipeline (see para. A842.2.7).

A835 ANCHORAGE FOR BURIED PIPING

Thermal expansion and contraction calculations shall consider the effects of fully saturated backfill material on soil restraint.

When a submerged pipeline is to be laid across a known fault zone, or in an earthquake-prone area where new faults are a possibility, consideration shall be given to the need for flexibility in the pipeline system and its components to minimize the possibility of damage due to seismic activity.

The requirements of para. 835.5(c) for header and branch connections are not applicable to offshore submerged piping systems. An appropriate means of preventing undue stresses at offshore submerged piping connections is to provide adequate flexibility at branch connections on the seabed.

A840 DESIGN, INSTALLATION, AND TESTING

A840.1 General Provisions

The design, installation, and testing of offshore gas transmission systems shall be in accordance with Chapter IV as specifically modified by the provisions of Chapter VIII. Also, all provisions of Chapter IV that depend on Location Class do not apply to offshore gas transmission systems, except that offshore pipelines approaching shoreline areas shall be additionally designed and tested consistently with Location Class provisions as determined in para. A840.2.

A840.2 Shoreline Approaches

Offshore pipelines approaching shoreline areas shall be additionally designed and tested consistently with Location Class provisions as determined in section 840, except that

(a) offshore pipelines in Location Classes 3 and 4 may alternatively be hydrostatically tested to a pressure not less than 1.25 times the maximum operating pressure so long as the provisions of section A826 are met

(b) for offshore pipelines, the provisions of section A847 supersede para. 841.3.2

A841 DESIGN CONSIDERATIONS

A841.1 Design Conditions

A number of physical parameters, henceforth referred to as design conditions, govern design of the offshore pipeline system so that it meets installation, operation, and other postinstallation requirements. Some of the factors that may influence the safety and reliability of an offshore pipeline and riser include

(a) waves
(b) current
(c) marine soils
(d) wind
(e) ice
(f) seismic activity
(g) platform motion
(h) temperature
(i) pressure
(j) water depth
(k) support settlement
(l) accidental loads
(m) commercial shipping
(n) fishing/shrimping activities

The design of offshore pipelines is often controlled by installation considerations rather than by operating load conditions.

Additional information for design conditions can be found in API RP 1111, para. 4.1.

A841.2 Installation Design Considerations

The design of an offshore pipeline system suitable for safe installation and the development of offshore pipeline construction procedures shall be based on consideration of the parameters listed in paras. A841.2.1 through A841.2.5. These parameters shall be considered to the extent that they are significant to the proposed system and applicable to the method of installation being considered.

A841.2.1 Weight. The effect of pipe or pipeline assembly weights (in air and submerged) on installation stresses and strains shall be considered. Variability due to weight coating manufacturing tolerances and water absorption shall also be considered.

A841.2.2 Profile. Variations in water depth along the pipeline route shall be considered. The effect of tides shall be included for locations where such variations are a significant fraction of the water depth. Bottom slope, obstructions, or irregularities that affect installation stresses shall be considered.

A841.2.3 Environmental Loads. Local environmental forces including those induced by wind, wave, currents, ice, seismic activity, and other natural phenomenon are subject to radical change in offshore areas. These potential changes should be considered during installation design and contingency planning.

A841.2.4 Loads Imposed by Construction Equipment and Vessel Motions. Limitations and behavioral characteristics of installation equipment shall be considered in the installation design.

Vessel motions shall be considered if they are expected to result in pipe stresses or pipe/coating damage sufficient to impair the serviceability of the pipeline.

A841.2.5 Bottom Soils. Soil characteristics shall be considered when installation procedures are developed for the following:

(a) riser installation in pull tubes
(b) laying horizontal curves in the pipeline routing
(c) pipeline bottom tows
(d) trenching and backfilling

A841.3 Operational Design Considerations

A841.3.1 Loading Classifications. All parts of the offshore pipeline and riser system shall be designed for the most critical combinations of operational and design environmental loads, acting concurrently, to which the system may be subjected. Wind, wave, and current design loads should be based on a design return interval no less than five times the design life of the pipeline or 100 yr, whichever is smaller.

If the pipeline operating philosophy is such that operations with full operational loads will be maintained during design storms, then the system shall be designed for concurrent action of operational and design environmental loads.

If the operating philosophy is such that operations will be reduced or discontinued during design storm conditions, then the system shall be designed for

(a) full operational loads plus maximum coincidental environmental loads
(b) design environmental loads plus appropriate reduced operational loads

Directionality of waves, winds, and currents shall be considered to determine the most critical expected combination of above loadings.

A841.3.2 Operational Loads. Operational loads that shall be considered are those forces imposed on the pipeline system under static environmental conditions (i.e., excluding wind, waves, current, and other dynamic loadings).

Loads that should be considered as operational loads include

(a) weight of unsupported span of pipe, including (as appropriate) the weight of
  (1) pipe
  (2) coatings and their absorbed water
  (3) attachments to the pipe
  (4) transported contents
(b) internal and external pressure
(c) thermal expansion and contraction
(d) buoyancy
(e) prestressing (exclusive of structurally restrained pipe configurations, such as in a pull-tube riser bend)
(f) static soil-induced loadings (e.g., overburden)

The effects of prestressing, such as permanent curvatures induced by installation, should be considered when they affect the serviceability of the pipeline.

Additional information for operational loads can be found in API RP 1111, para. 4.1.4.

A841.3.3 Design Environmental Loads. Loadings that should be considered under this category include, as appropriate, those arising due to

(a) waves
(b) current
(c) wind
(d) seismic events
(e) accidental loadings (e.g., trawl boards and anchors)
(f) dynamic soil-induced loadings (e.g., mudslides and liquefaction)
(g) ice loads (e.g., weight, floating impacts, and scouring)

A842 STRENGTH CONSIDERATIONS

Design and installation analyses shall be based on accepted engineering methods, material strength, and applicable design conditions.

A842.1 Strength Consideration During Installation

The following subsections define the minimum safety requirements against failure due to yielding or buckling during all phases of pipeline system installation (i.e., handling, laying, trenching, etc., through testing).

A842.1.1 Buckling. The pipeline should be designed and installed in a manner to prevent buckling during installation. Design and procedures for installation should account for the effect of external hydrostatic pressure, bending moment, axial, and torsional loads and pipe out-of-roundness. Consideration should also be given to the buckle propagation phenomenon.

Additional information for calculating buckling stresses due to bending and external pressure can be found in API RP 1111, para. 4.3.2.2.

A842.1.2 Collapse. The pipe wall thickness shall be designed to resist collapse due to external hydrostatic pressure. Considerations shall include the effects of mill tolerances in the wall thickness, out-of-roundness, and any other applicable factors.

Additional information for designing to prevent collapse can be found in API RP 1111, para. 4.3.2.1.

A842.1.3 Allowable Longitudinal Stress. The maximum longitudinal stress due to axial and bending loads during installation shall be limited to a value that prevents pipe buckling and will not impair the serviceability of the installed pipeline.

Additional information for longitudinal load design can be found in API RP 1111, para. 4.3.1.1.

A842.1.4 Allowable Strains. Instead of the stress criteria of para. A842.1.3, an allowable installation strain limit may be used. The maximum longitudinal strain due to axial and bending loads during installation shall be limited to a value that prevents pipe buckling and will not impair the serviceability of the installed pipeline.

A842.1.5 Installation Fatigue. Anticipated stress fluctuations of sufficient magnitude and frequency to induce significant fatigue shall be considered in design.

(16) **A842.1.6 Special Assemblies.** Installation of pipelines with special assemblies are subject to the same requirements stated in paras. A842.1.1 through A842.1.5.

A842.1.7 Residual Stresses. The pipeline system shall normally be installed in a manner so as to minimize residual stresses. The exception shall be when the designer purposefully plans for residual stresses (e.g., cold-springing of risers and pull-tube risers). When residual stresses are significant, they should be considered in the operating design of the pipeline system (see para. A842.2).

A842.1.8 Flexible Pipe. The manufacturers recommended maximum loadings and minimum bending radius shall be adhered to during installation. Flexible pipe shall be designed or selected to prevent collapse due to the combined effects of external pressure, axial forces, and bending. Installation procedures shall be designed to prevent buckling (see API RP 17B).

A842.2 Strength Considerations During Operations

A842.2.1 Operational and Design Criteria

(a) Failure Modes. Pipelines and risers shall be designed against the following possible modes of failure, as appropriate:

(1) excessive yielding
(2) buckling
(3) fatigue failure
(4) ductile fracture
(5) brittle fracture
(6) loss of in-place stability
(7) propagating fracture
(8) corrosion
(9) collapse

(b) Other Considerations. Furthermore, consideration shall be given to impacts due to

(1) foreign objects
(2) anchors
(3) trawlboards
(4) vessels, ice keels, etc.

(16) **A842.2.2 Design Against Yielding.** Pipelines and risers shall be designed against yielding in accordance with this paragraph. The combined stress calculations and allowables of paras. 833.2 through 833.6 are superseded by the provisions of (b), (c), and (d) below (see also Table A842.2.2-1):

(a) Hoop Stress. For pipelines, risers, and platform piping, the tensile hoop stress due to the difference between internal and external pressures shall not exceed the value given below. S_h may be calculated by either of the following:

NOTE: Sign convention is such that tension is positive and compression is negative.

$$S_h \leq F_1 S T \tag{1}$$

Table A842.2.2-1 Design Factors for Offshore Pipelines, Platform Piping, and Pipeline Risers (16)

Location	Hoop Stress, F_1	Longitudinal Stress, F_2	Combined Stress, F_3
Pipeline	0.72	0.80	0.90
Platform piping and risers	0.50	0.80	0.90 [Note (1)]

NOTE:
(1) The wall thickness used in the calculation of combined stress for platform piping and risers shall be based upon minimum wall thickness, t_{min}.

(U.S. Customary Units)

$$S_h = (P_i - P_e)\frac{D}{2t} \tag{2}$$

(SI Units)

$$\left[S_h = (P_i - P_e)\frac{D}{2\,000t}\right] \tag{3}$$

or

(U.S. Customary Units)

$$S_h = (P_i - P_e)\frac{D - t}{2t} \tag{4}$$

(SI Units)

$$\left[S_h = (P_i - P_e)\frac{D - t}{2\,000t}\right] \tag{5}$$

where
D = nominal outside diameter of pipe, in. (mm)
F_1 = hoop stress design factor from Table A842.2.2-1
P_e = external pressure, psig (kPa)
P_i = internal design pressure, psig (kPa)
S = specified minimum yield strength, psi (MPa)
S_h = hoop stress, psi (MPa)
T = temperature derating factor from Table 841.1.8-1
t = nominal wall thickness, in. (mm)

NOTE: It is recommended that eq. (2) or (3) be used for D/t greater than or equal to 30 and that eq. (4) or (5) be used for D/t less than 30.

Additional information for pressure design can be found in API RP 1111, paras. 4.3.1 and 4.3.2.

(b) Longitudinal Stress. For pipelines, risers, and platform piping, the longitudinal stress shall not exceed values found from

$$|S_L| \leq F_2 S$$

where
A = cross-sectional area of pipe material using t, in.^{2} (mm^2)

F_2 = longitudinal stress design factor from Table A842.2.2-1
F_a = axial force, lb (N)
i_i = in-plane stress intensification factor from Mandatory Appendix E
i_o = out-plane stress intensification factor from Mandatory Appendix E
M_i = in-plane bending moment, in.-lb (N·m)
M_o = out-plane bending moment, in.-lb (N·m)
S = specified minimum yield strength, psi (MPa)
S_a = axial stress, psi (positive tensile or negative compressive) (MPa)
= F_a / A
S_b = resultant bending stress, psi (MPa)
= $[(i_i M_i)^2 + (i_o M_o)^2]^{1/2}/z$
$S_{L\max}$ = maximum longitudinal stress, psi (positive tensile or negative compressive) (MPa)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger stress value
t = nominal wall thickness, in. (mm)
z = section modulus of pipe using t, in.^{3} (cm^3)
$|\ |$ = absolute value

Additional information for longitudinal load design can be found in API RP 1111, para. 4.3.1.1.

(c) Combined Stress for Pipelines. The combined stress shall not exceed the value given by the maximum shear stress equation (Tresca combined stress):

$$2\left[\left(\frac{S_L - S_h}{2}\right)^2 + S_t^2\right]^{1/2} \le F_3 S$$

where

A = cross-sectional area of pipe material using t, in.^{2} (mm^2)
F_3 = combined stress design factor from Table A842.2.2-1
F_a = axial force, lb (N)
i_i = in-plane stress intensification factor from Mandatory Appendix E
i_o = out-plane stress intensification factor from Mandatory Appendix E
M_i = in-plane bending moment, in.-lb (N·m)
M_o = out-plane bending moment, in.-lb (N·m)
M_t = torsional moment, in.-lb (N·m)
S = specified minimum yield strength, psi (MPa)
S_a = axial stress, psi (positive tensile or negative compressive) (MPa)
= F_a / A
S_b = resultant bending stress, psi (MPa)
= $[(i_i M_i)^2 + (i_o M_o)^2]^{1/2}/z$
S_h = hoop stress using t, psi (MPa)
S_L = longitudinal stress, psi (positive tensile or negative compressive) (MPa)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger combined stress value
S_t = torsional stress, psi (MPa)
= $M_t/2z$
t = nominal wall thickness, in. (mm)
z = section modulus of pipe using t, in.^{3} (cm^3)

Alternatively, the Maximum Distortional Energy Theory (Von Mises combined stress) may be used for limiting combined stress values. Accordingly, the combined stress should not exceed values given by

$$(S_h^2 - S_L S_h + S_L^2 + 3S_t^2)^{1/2} \le F_3 S$$

(d) Combined Stress for Risers and Platform Piping. The combined stress shall not exceed the value given by the maximum shear stress equation (Tresca combined stress):

$$2\left[\left(\frac{S_{L\,(mwt)} - S_{h\,(mwt)}}{2}\right)^2 + S_{t\,(mwt)}^2\right]^{1/2} \le F_3 S$$

where

$A_{(mwt)}$ = cross-sectional area of pipe material using $t_{\min}$, in.^{2} (mm^2)
F_3 = combined stress design factor from Table A842.2.2-1
F_a = axial force, lb (N)
i_i = in-plane stress intensification factor from Mandatory Appendix E
i_o = out-plane stress intensification factor from Mandatory Appendix E
M_i = in-plane bending moment, in.-lb (N·m)
M_o = out-plane bending moment, in.-lb (N·m)
M_t = torsional moment, in.-lb (N·m)
S = specified minimum yield strength, psi (MPa)
$S_{a\,(mwt)}$ = axial stress, psi (positive tensile or negative compressive) (MPa)
= $F_a / A_{(mwt)}$
$S_{b\,(mwt)}$ = resultant bending stress, psi (MPa)
= $[(i_i M_i)^2 + (i_o M_o)^2]^{1/2}/z_{(mwt)}$
$S_{h\,(mwt)}$ = hoop stress using $t_{\min}$, psi (MPa)
$S_{L\,(mwt)}$ = longitudinal stress, psi (positive tensile or negative compressive) (MPa)
= $S_{a\,(mwt)} + S_{b\,(mwt)}$ or $S_{a\,(mwt)} - S_{b\,(mwt)}$, whichever results in the larger combined stress value
$S_{t\,(mwt)}$ = torsional stress, psi (MPa)
= $M_t/2_{z\,(mwt)}$
$t_{\min}$ = minimum wall thickness, in. (mm)
$z_{(mwt)}$ = section modulus of pipe using $t_{\min}$, in.^{3} (cm^3)

Alternatively, the Maximum Distortional Energy Theory (Von Mises combined stress) may be used for limiting combined stress values. Accordingly, the combined stress should not exceed values given by

$$\left(S_{h\,(mwt)}{}^2 - S_{L\,(mwt)}S_{h\,(mwt)} + S_{L\,(mwt)}{}^2 + 3S_{t\,(mwt)}{}^2\right)^{1/2} \leq F_3S$$

A842.2.3 Alternate Design for Strain. In situations where the pipeline experiences a predictable noncyclic displacement of its support (e.g., fault movement along the pipeline route or differential subsidence along the line) or pipe sag before support contact, the longitudinal and combined stress limits need not be used as criteria for safety against excessive yielding, so long as the consequences of yielding are not detrimental to the integrity of the pipeline. The permissible maximum longitudinal strain depends on the ductility of the material, any previously experienced plastic strain, and the buckling behavior of the pipe. Where plastic strains are anticipated, the pipe eccentricity, pipe out-of-roundness, and the ability of the weld to undergo such strains without detrimental effect should be considered. Similarly, the same criteria may be applied to the pipe during construction (e.g., pull-tube or bending shoe risers).

A842.2.4 Design Against Buckling and Ovalization. Avoidance of buckling of the pipeline and riser during operation shall be considered in design. Modes of buckling that may be possible include

(a) local buckling of the pipe wall

(b) propagation buckling following local buckling

(c) column buckling

Additional information for determining buckling tendencies can be found in API RP 1111, paras. 4.3.2.2 and 4.3.2.3, and Annex D.

A842.2.5 Design Against Fatigue. Stress fluctuations of sufficient magnitude and frequency to induce significant fatigue should be considered in design.

Loadings that may affect fatigue include

(a) pipe vibration, such as that induced by vortex shedding

(b) wave action

Pipe and riser spans shall be designed so that vortex induced resonant vibrations are prevented, whenever practical. When doing so is impractical, the total resultant stresses shall be less than the allowable limits in para. A842.2.2, and such that fatigue failure should not result during the design life of the pipeline.

Additional information for fatigue analysis can be found in API RP 1111, para. 4.5.

A842.2.6 Design Against Fracture. Materials used for pipelines transporting gas or gas-liquid mixtures under high pressure should have reasonably high resistance to propagating fractures at the design conditions, or other methods shall be used to limit the extent of a fracture.

A842.2.7 Design of Clamps and Supports. Clamps and supports shall be designed such that a smooth transfer of loads is made from the pipeline or riser to the supporting structure without highly localized stresses due to stress concentrations. When members are to be welded to the pipe they shall fully encircle the pipe and be welded to the pipe by a full encirclement weld. The support shall be attached to the encircling member and not the pipe.

All welds to the pipe shall be nondestructively tested. Clamps and supports shall be designed in accordance with the requirements of API RP 2A-WSD, Section 3.

Clamp and support design shall consider the corrosive effects of moisture retaining gaps and crevices and galvanically dissimilar metals.

A842.2.8 Design of Connectors and Flanges. Connectors and flanges shall be such that smooth transfer of loads is made without high localized stresses or excessive deformation of the attached pipe.

Connectors and flanges shall have a level of safety against failure by yielding and failure by fatigue that is comparable to that of the attached pipeline or riser.

A842.2.9 Design of Structural Pipeline Riser Protectors. Where pipeline risers are installed in locations subject to impact from marine traffic, protective devices shall be installed in the zone subject to damage to protect the pipe and coating.

A842.2.10 Design and Protection of Special Assemblies. Design of connections and special assemblies shall consider the additional forces and effects imposed by a subsea environment. Such additional considerations include design storm currents and potential for seabed movement in soft sediments, soil liquefaction, increased potential corrosion, thermal expansion and contraction, and stress due to installation procedures. In areas of active fishing, protective measures may be appropriate for connections and special assemblies. (16)

A842.2.11 Design of Flexible Pipe. Due to its composite makeup, the mechanical behavior of flexible pipe is significantly different from steel pipe. Flexible pipe may be used for offshore pipelines if calculations and/or test results verify that the pipe can safely withstand loadings considered in paras. A841.3.2 and A841.3.3. In the selection of flexible pipe, consideration should be given to its permeable nature. The possibility of implosion under the combined conditions of high pressure, high temperature, and very rapid depressurization should be investigated where such conditions may be expected. Selection of flexible pipe shall be in accordance with API RP 17B and API Spec 17J.

A843 COMPRESSOR STATIONS

A843.1 Compressor Station Design

The requirements of this paragraph recognize the unique design conditions and space limitations imposed when designing offshore compression facilities and therefore relate only to offshore compression facilities.

It is the further intent of this section to make the designer aware of personnel safety during the design and operation of offshore compression facilities.

A843.1.1 Location of Compressor Facilities. The compressor facilities located on platforms should be designed to facilitate free movement of fire fighting or other emergency equipment.

A843.1.2 Enclosures. All enclosures located on an offshore platform shall be constructed of noncombustible or limited combustible material as defined in NFPA 220, Chapter 2. Design of enclosures on offshore platforms shall consider the loading conditions defined in para. A841.3.

A843.1.3 Exits. A minimum of two exits shall be provided for each operating level of a compressor building. Any elevated walkway, including engine catwalks more than 10 ft (3 m) above the deck, shall also be provided with two exits. The maximum distance from any point within the compressor building to an exit shall not exceed 75 ft (23 m). Enclosure exits shall be unobstructed and located so as to provide a convenient route of escape and shall provide continuous unobstructed passage to a place of safety. Exit doors located on exterior walls shall swing outward and shall be equipped with latches that can be readily opened from the inside without a key.

A843.1.5 Hazard Analysis for Offshore Compressor Stations. A hazard analysis for offshore compressor stations shall be conducted in accordance with API RP 14J to meet the requirements of API RP 14C.

A843.2 Electrical Facilities

All electrical equipment and wiring installed on offshore compression platforms shall conform to the requirements of NFPA 70, if commercially available equipment permits.

Electrical installations in offshore hazardous locations as defined in NFPA 70, Chapter 5, Article 500 and that are to remain in operation during compressor station emergency shutdown as provided in para. A843.3.3(a) shall be designed to conform to NFPA 70, for Class I, Division I requirements.

The guidelines of API RP 14F should be considered in electrical facility design.

A843.3 Compressor Station Equipment

A843.3.3 Safety Devices

(a) Emergency Shutdown Facilities. All gas compression equipment shall be provided with an emergency shutdown system that will block out the gas going to and from the compressor station. Operation of the emergency shutdown system shall cause the shutdown of all gas compression equipment and all gas-fired equipment and shall de-energize the electrical facilities in the compressor building, except for those that provide emergency lighting for personnel protection and those that are necessary for protection of equipment. The emergency shutdown system shall be operable from a minimum of two locations on each deck level; that is, should an offshore platform facility have more than one clearly defined deck, each deck shall have a minimum of two shutdown locations. Blowdown piping shall extend to a location where the discharge of gas is not likely to create a hazard to the platform facilities. Consideration should be given to potential entrained liquids, prevailing winds, and location of crew quarters if part of the platform facility. Under conditions of heavy liquid entrainment and poor prevailing wind conditions, a separate structure for a blowdown facility shall be considered.

A843.3.4 Pressure-Limiting Requirements for Offshore Compression Facilities

(c) Venting. Pressure relief valves shall be vented to atmosphere such that no hazard is created. Vent lines, common headers, and platform blowdown lines shall have sufficient capacity so that they will not interfere with the performance of the relief device.

A844 ON-BOTTOM STABILITY

Pipeline design for lateral and vertical stability is governed by sea floor bathymetry, soil characteristics, and by hydrodynamic, seismic, and soil behavior events having a significant probability of occurrence during the life of the system. Design conditions to consider are provided in the following subsections.

The pipeline system shall be designed to prevent horizontal and vertical movements, or shall be designed so that any movements will be limited to values not causing design strength to be exceeded (see section A842).

Typical factors to be considered in the stability design include

(a) wave and current forces
(b) scour and resultant spanning
(c) liquefaction
(d) slope failure

Stability may be obtained by such means including, but not limited to, pipe submerged weight, trenching of pipe below grade, and anchoring.

When calculating hydrodynamic forces, the spatial variance of wave forces along the length of the pipeline may be taken into account.

Additional information on hydrostatic stability can be found in API RP 1111, para. 4.4.2.

A844.1 Design Storm Conditions

Design wave and current conditions for portions of a pipeline that will not be trenched shall be based on a storm having a minimum return interval of no less than five times the design life or 100 yr, whichever is smaller. Portions of the pipeline system to be trenched shall be designed for wave and current conditions based on prudent assessment of the period of pipe exposure. The most unfavorable expected combination of wave and current conditions shall be used. Maximum wave and maximum current conditions do not necessarily occur simultaneously. The most unfavorable condition selection shall account for the timing of occurrence of the wave and current direction and magnitude.

A844.2 Stability Against Waves and Currents

A844.2.1 Submerged Weight. The submerged weight of the pipe may be designed (such as by weight coating) to resist or limit movement to acceptable values. Hydrodynamic forces shall be based on the wave and current values for the design storm condition for the specific location.

Wave and current directionality and concurrency shall be considered.

A844.2.2 Bottom Soils. The pipe-soil interaction factors that are used shall be representative of the bottom conditions at the site.

A844.2.3 Trenching. The pipeline and its appurtenances may be trenched below bottom grade to provide stability. The pipeline must be designed for wave and current stability prior to trenching. Such stability, however, need only be based on environmental conditions expected during the period of pipe exposure.

A844.2.4 Backfilling. Backfilling or other protective coverings, when necessary, shall be accomplished by using such materials and procedures to preclude damage to the pipeline and coatings.

A844.2.5 Anchoring. Anchoring may be used instead of or in conjunction with submerged weight to maintain stability. The anchors shall be designed to withstand lateral and vertical loads expected from the design storm condition. Anchors shall be spaced to prevent excessive stresses in the pipe sections between anchors. The anchoring system and adjacent pipe shall be designed to prevent scour and resultant spanning from overstressing the pipe. The effect of anchors on the cathodic protection system shall be considered.

A844.3 Shore Approaches

Pipe in the shore approach zone shall be trenched or bored to the depth necessary to prevent scouring, spanning, or stability problems that affect integrity and safe operation of the pipeline during its anticipated service life. Seasonal variation in the near shore thickness of sea floor sediments and shoreline erosion over the pipeline service life shall be considered.

A844.4 Slope Failure

The pipeline shall be designed for slope failure in zones of known or anticipated occurrence, such as mudslide zones and areas of seismic slumping. The design exposure period shall be no less than the expected life of the pipline. If it is not practical to design the pipeline system to survive the event, the pipeline shall be designed for controlled breakaway with check valving to prevent blowdown of the pipeline.

A844.5 Soil Liquefaction

Design for the effects of liquefaction shall be performed for areas of known or expected occurrence. Soil liquefaction normally results from cyclic wave overpressures or seismic loading of susceptible soils. The bulk specific gravity of the pipeline shall be designed, or alternative methods shall be selected to ensure both horizontal and vertical stability.

Seismic design conditions used to predict the occurrence of bottom liquefaction or slope failure shall have the same recurrence interval as used for the operating design strength calculations for the pipeline. Occurrence of soil liquefaction due to wave overpressures shall be based on a storm return interval of no less than five times the design life or 100 yr, whichever is smaller.

A846 VALVES

Offshore transmission lines shall be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

Block valves shall be accessible and protected from damage and tampering. If a blowdown valve is involved, it shall be located where the gas can be blown to the atmosphere without undue hazard.

Blowdown valves shall be provided so that each section of pipeline between main line valves can be blown down. The sizes and capacity of the connections for blowing down the line shall be such that under emergency conditions the section of line can be blown down as rapidly as is practicable.

A847 TESTING

A847.1 General Provisions

All offshore pipelines shall be tested after installation and prior to operation within the provisions of this section.

A847.2 Test Pressure

The installed pipeline system (including any SCR up to its hang-off point) shall be hydrostatically tested to at least 1.25 times the maximum allowable operating pressure. Offshore platform piping and offshore pipeline risers other than SCRs must be tested to at least 1.5 times the maximum allowable operating pressure either before or after installation. Prefabricated portions of platform piping that have been pretested to 1.5 times the maximum allowable operating pressure need not be tested after installation if all items are tied in by connectors, flanges, or welds that have been radiographically inspected.

CAUTION: When an external pressure, P_e, greater than zero is used in the hoop stress formula in para. A842.2.2(a), there is a possible combination of conditions where the yield strength of the pipe could be exceeded during the hydrostatic test. Therefore, the hoop stress and combined stress shall be checked to confirm that they are within allowable limits to prevent pipe yielding, considering both the internal and external pressures when determining the maximum hydrostatic test pressure.

A847.3 Test Medium

The test medium for all offshore pipelines will be water. Additives to mitigate the effects of corrosion, biofouling, and freezing should be considered. Such additives should be suitable for the methods of disposal of the test medium.

In arctic areas where freezing of water is a hazard, the use of air, inert gas, or glycol is allowable. Platform gas and compression piping may be tested with inert gas.

A847.4 Test Procedure

The hydrostatic pressure test shall be conducted in accordance with a specified procedure that shall, at a minimum, provide for

(a) performance of the test after installation and before initial operation of the pipeline system except as provided in para. A847.2.

(b) the inclusion of prefabricated, pretested portions of offshore pipeline risers in the pipeline system hydrostatic test, whenever practical.

(c) maintenance of the test and recording of results on pipeline and assemblies for a minimum of eight continuous hours at or above the specified pressure. All variations in test pressure shall be accounted for. Test duration of prefabricated piping may be 2 hr.

(d) a retest if, during the hold time, a rupture or hazardous leak occurs that renders the test invalid. Retesting shall commence after repairs have been made.

A847.5 Records

The operating company shall maintain in its file, for the useful life of each pipeline, records showing the type of test fluid, the test procedure, the test pressure, and the duration of the test.

A847.6 Tie-Ins

It is recognized that it may not be possible to hydrostatically test the tie-in between two test sections. Pressure testing of tie-in welds may be exempted if the tie-in weld is inspected by radiographic and/or other applicable NDT methods.

A847.7 Testing for Buckles

Testing for buckles, dents, and other diameter restrictions shall be performed after installation. Testing shall be accomplished by passing a deformation detection device through the pipeline section, or by other methods capable of detecting a change in pipe diameter. Pipe having excessive deformation that affects the serviceability of the pipeline facilities shall be repaired or replaced. Consideration should also be given to repairing excessive ovality that may interfere with pigging operation or internal inspection.

A850 OPERATING AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF GAS TRANSMISSION FACILITIES

A850.1 General

All provisions of Chapter V, which depend on Location Class, do not apply to offshore gas transmission systems, except that offshore pipelines approaching shoreline areas shall additionally be operated and maintained consistently with Location Class provisions as determined in section 840.

A850.3 Essential Features of the Operating and Maintenance Plan

The plan prescribed in para. 850.2(a) shall include

(a) detailed plans and instructions for employees covering operating and maintenance procedures for gas facilities during normal operations and repairs

(b) items recommended for inclusion in the plan for specific classes of facilities, which are given in paras. A851.2 and A851.4, and section A860

(c) plans to give particular attention to those portions of the facilities presenting the greatest hazard to the public and environment in the event of an emergency or because of construction or extraordinary maintenance requirements

(d) provisions for periodic inspections along the route of existing pipelines

A850.4 Essential Features of the Emergency Plan

A850.4.3 Liaison. Each operating company shall establish and maintain liaison with available offshore firefighting entities (public and or privately owned) that may be designated for any particular offshore area.

A850.4.4 Educational Program. An educational program shall be established to enable producers and the general public operating in the offshore area to recognize and report a gas emergency to the appropriate officials. The educational program called for under this section should be tailored to the type of pipeline operation and the environment traversed by the pipeline and should be conducted in each language that is significant in the community served. Operators of transmission systems should communicate their programs to people, contractors, or others that usually work in the offshore area of concern. The programs of operators in the same area should be coordinated to properly direct reports of emergencies and to avoid inconsistencies.

A850.7 Blasting Effects

Each operating company shall establish procedures for protection of facilities in the vicinity of blasting activities. The operating company shall

(a) locate and mark its pipeline when explosives are to be detonated within distances as specified in company plans. Consideration should be given to the marking of minimum blasting distances from the pipelines depending on the type of blasting operation.

(b) determine the necessity and extent of observing or monitoring blasting activities based on the proximity of the blast considering the pipe materials, the operating conditions, the size of charge, and soil conditions. Consideration should be given to

(1) the effect of shock waves on the pipeline from blasting

(2) conducting a leak survey following completion of the blasting program

A851 PIPELINE MAINTENANCE

A851.2 Pipeline Patrolling

Each operating company shall maintain a periodic pipeline patrolling program to observe conditions on and adjacent to the pipeline right-of-way, indication of leaks, construction activity other than that performed by the company, and any other factors affecting the safety and operation of the pipeline. These inspections should be made as often as necessary to maintain the integrity of the pipeline. Records of these inspections shall be maintained for the life of the facility. Provisions of paras. 851.2, 851.2.1, and 851.2.2 do not apply to this Chapter.

A851.4 Above-Water and Hyperbaric Repair Procedures for Steel Pipelines

All above-water and hyperbaric repair procedures for steel pipelines shall conform to the requirements of para. 851.4.

A851.4.5 Offshore Below-Water Repair Procedures for Steel Pipelines. Submerged offshore pipelines may be repaired by replacement of the damaged section or by the use of a full encirclement split sleeve of appropriate design installed over the damage. Replacement sections and split sleeves shall be secured by atmospheric dry or hyperbaric welding or mechanical devices. Repairs shall be visually inspected for leaks after being returned to service.

Any offshore below-water repair procedures shall conform to para. 851.4 provisions.

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 public safety and environment.

Evacuation and repair operations should not result in imposed loads or deformations that would impair the integrity of the pipe materials, weight, or protective coating.

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

When lifting or supporting pipe during repairs, the curvature of a pipe sag bend and overbend should be controlled and maintained within limits to minimize pipe coating damage, overstressing, denting or buckling during the repair operation, and lifting equipment should be selected accordingly.

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

Personnel working on pipeline repairs should understand the need for careful job planning, be briefed on procedures to be followed in accomplishing repairs, and follow necessary precautionary measures and procedures.

When pipe is repaired, damaged coating should also be repaired. Replacement pipe and components shall be protected from corrosion.

A851.4.6 Offshore Repair of Flexible Pipe. If the operability of the flexible pipe is impaired (i.e., major structural damage), the pipe shall be repaired by replacement of the damaged section. In the event of surface cuts and abrasions in the protective coating that do not expose the load carrying members to potential corrosion, the repair shall be performed in a manner recommended by the manufacturer.

A851.7 Pipeline Markers and Signs

Permanent markers are not required for offshore pipelines; however, suitable signs should be posted on platforms to serve as a hazard area warning. Where appropriate, signs should display the operating company identification and emergency communication procedures.

A854 LOCATION CLASS

There are no operating Location Classes offshore.

A860 CORROSION CONTROL OF OFFSHORE PIPELINES

A860.1 Scope

Since offshore pipelines cannot be readily inspected after installation and there is the possibility of damage to the coating system, special consideration should be given to the selection, design, and application of corrosion control coatings, the cathodic protection system, and other corrosion design elements.

A860.2 Evaluation of Existing Installations

(a) Monitoring. The operating company must rely on monitoring, investigation, inspections, and corrective action to control corrosion. Such activities shall be performed at periodic intervals sufficient to ensure that adequate corrosion control is maintained. Where it is determined that corrosion that is taking place may be detrimental to public or employee safety, the facility shall be repaired or replaced, and corrosion control measures applied or augmented.

(e) Examination When Exposed

(1) When a pipeline is lifted above water for maintenance or repair, the operating company shall visually inspect for evidence of coating deterioration, external corrosion, and where possible, the condition of any exposed anode. If excessive corrosion is present, remedial action shall be taken as necessary.

(2) If repairs are made below water, inspection for evidence of external corrosion or coating deterioration shall be made, and necessary corrective action shall be taken to maintain the corrosion protection of the pipeline.

A861 EXTERNAL CORROSION CONTROL

A861.1 Submerged Installations

All submerged steel pipe, valves, and related fittings shall be externally coated and cathodically protected. All above-water piping and components shall be protected from the particularly corrosive conditions of the salt water atmosphere and cyclic wetting and drying.

A861.1.1 Coatings

(a) Coating Design. The design of coating systems for offshore installation should reflect the type of environment in which the facility is to be installed. Selection of the protective coating should be based on

(1) low water absorption

(2) compatibility with the type of cathodic protection to be applied to the system

(3) compatibility with the system operating temperature

(4) sufficient ductility to minimize detrimental cracking

(5) sufficient toughness to withstand damage during installation

(6) resistance to future deterioration in a submerged environment

(7) ease of repair

(b) Cleaning and Surface Preparation. There may be additional cleaning and surface preparation requirements, such as a near white metal finish and an anchor pattern to promote a good bond for all epoxy-based thin film coatings. Welds should be inspected for irregularities that could protrude through the pipe coating, and any such irregularities should be removed.

(c) Application and Inspection. The coating should be applied under controlled conditions and have a high resistance to disbondment. Further information can be obtained from NACE SP0169. A holiday detector, suitable for the type of coating applied, shall be used to detect flaws. Flaws noted shall be repaired and retested. Weights or weight coating shall not damage the protective coating during application or installation.

(d) Coating for Weld Joints, Appurtenances, and Patching. Weld joints and appurtenances shall be coated with material that is compatible with the basic coating. A holiday detector, designed for the type of field joint material applied, may be used to detect flaws, and flaws shall be repaired and retested.

(e) Field Inspection. The pipe shall be visually inspected prior to installation to ensure that unacceptable damage has not occurred during loading, welding, or other laying activities prior to submergence of the pipe. Any significant damage to the coating shall be repaired with material compatible with the pipeline coating. Care should be exercised to minimize damage to the coating system, particularly during laying and trenching of the pipe.

A861.1.2 Cathodic Protection Requirements

(a) Design Criteria. An offshore facility is considered to be cathodically protected when it meets the criteria established in Section 6.2 of NACE SP0607/ISO 15589-2.

(b) Impressed Currents. Where impressed current systems are used, the system shall be designed to minimize outages, and the output shall be such that the design criterion is met. Also, consideration should be given to minimize the interference effect on other pipelines or structures.

(c) Galvanic Anodes. Where galvanic anodes are used for protection, consideration shall be given to the quality of the coating (i.e., the percent of exposed pipe). Also, the design formula for the system should include the output of the anodes, the desired life of the system, anode material, and utilization efficiency. Anodes used should be compatible with the operating temperature of the pipeline and the marine environment.

(d) Other. Consideration should be given to the effects on cathodic protection of variations in oxygen content, temperature, and water/soil resistivity of the particular offshore environment in which the pipeline is installed.

A861.1.3 Electrical Isolation. Underwater pipeline systems shall be electrically isolated from other metallic structures so that cathodic protection can be effective.

An exception can be made when both the foreign structure and the pipeline are designed to be protected as a unit. Other general considerations include the following:

(a) Tie-Ins. Isolation from foreign pipelines at tie-ins may be made by installing insulation flanges, unions, or other insulating devices. When making a tie-in of a coated line to a bare line, the two lines shall be electrically isolated.

(b) Foreign Pipeline Crossings. When crossing a foreign pipeline, care shall be exercised to ensure adequate separation between the two lines so that the possibility for electrical interference is minimized.

(c) Pipeline Riser Support and Secondary Piping. When installing riser piping at platforms, supporting devices such as clamps and pipe supports shall isolate the piping from the structure. Insulating devices shall be installed where electrical isolation of a portion of the piping system from production piping, tanks, and other facilities is necessary to facilitate application of cathodic protection. Electrical interference between electrically isolated structures shall be minimized. Wiring and piping connections to an isolated pipeline shall also have insulation between the pipeline and the platform. Tests shall be made to ensure adequate isolation, and appropriate action shall be taken to ensure such isolation when necessary.

A861.1.4 Electrical Connections and Monitoring Points. Test leads shall be installed so that they are mechanically secure, electrically conductive, and accessible for testing. It is considered impractical to locate test leads in deep or open water. Test leads installations are usually limited to platforms and the pipeline entrance to the shore.

A861.1.7 Electrical Interference. Periodic tests shall be made to ensure that electrical isolation from foreign pipelines or other structures remains complete. Some indications of electrical interference are changes in pipe-to-electrolyte potential, changes in current magnitude or direction, localized pitting, and coating breakdown. When new foreign pipelines are laid in the vicinity of existing lines, inspections shall be made to ensure electrical isolation in accordance with para. 861.1.3(a). If electrical isolation cannot be attained, measures shall be taken to minimize electrical interference. Electrical isolation from the platform should be checked and maintained unless the system was specifically designed to be jointly protected.

A861.2 Above-Water Atmospheric Protection

A861.2.1 Coatings. The splash zone area, where the pipeline is intermittently wet and dry, shall be designed with additional protection against corrosion. This shall be accomplished by one or more of the following:

(a) special coating

(b) special protective systems and techniques

(c) other suitable measures, including selection of pipe material

A861.2.2 Surface Preparation. Coatings and other protective systems shall be installed on a properly prepared surface and in accordance with established specifications or manufacturer's recommendations. The coating should resist water action, atmospheric deterioration, mechanical damage, and cathodic disbondment.

A861.4 Atmospheric Corrosion Inspection

Detailed inspections shall be made periodically of all piping for atmospheric corrosion. This inspection shall include those areas most susceptible to corrosion such as flanges, flange bolts, areas under pipe straps, areas where pipe is in contact with supports, and other places where moisture collects. Where atmospheric corrosion is found, prompt corrective action shall be taken. Corrective action shall consist of painting, replacement of components as necessary, or other action deemed appropriate by the operating company.

A862 CATHODIC PROTECTION CRITERIA

A862.1 Criteria

The criteria for cathodic protection are specified in Section 6.2 of NACE SP0607/ISO 15589-2.

A862.3 Electrical Checks

The operating company shall take electrical readings periodically at each test location available to ensure that the cathodic protection level meets the criteria in Section 6.2 of NACE SP0607/ISO 15589-2.

Before each electrical test is performed, an inspection shall be made to ensure electrical continuity and that a good contact to the pipelines is made by the test connection.

A864 INTERNAL CORROSION CONTROL

A864.1 General

The design and maintenance of offshore pipeline facilities that may carry natural gas containing carbon dioxide, chlorides, hydrogen sulfide, organic acids, solids or precipitates, sulfur-bearing compounds, oxygen, or free water require special consideration for the control of internal corrosion.

Chapter IX
Sour Gas Service

B800 SOUR GAS SERVICE

B801 GENERAL

Chapter IX pertains only to gas pipeline service that contains hydrogen sulfide levels defined as "sour gas" in this Chapter. This Chapter is organized to parallel the numbering and content of the first six chapters of the Code. All provisions of the first six chapters of the Code are also requirements of this Chapter unless specifically modified herein. Paragraph headings follow those in the first six chapters with the prefix "B."

If a paragraph appearing in Chapters I through VI does not have a corresponding paragraph in this Chapter, the provisions apply to sour gas service without modification. If a paragraph in this Chapter has no corresponding paragraph in Chapters I through VI, the provisions apply to sour gas only.

B802 SCOPE AND INTENT

B802.1 Scope

This Chapter of the Code covers the design, material requirements, fabrication, installation, inspection, testing, and safety aspects of operation and maintenance of sour gas systems.

B802.2 Intent

The intent of this Chapter is to provide adequate requirements for the safe and reliable design, installation, operation, and maintenance of sour gas service pipeline systems. Requirements of this Chapter supplement the requirements of the remainder of this Code. It is not the intent of this Chapter to be all inclusive. Provisions must be made for special considerations that are not specifically addressed. This Chapter is not intended to prevent the development and application of new equipment and technology. Such activity is encouraged as long as the safety and reliability requirements of this Code are satisfied.

B803 SOUR GAS TERMS AND DEFINITIONS

chloride stress corrosion cracking: cracking of a metal under the combined action of tensile stress and corrosion in the presence of chlorides and an electrolyte (usually water).

diffusion: the flow of the gas through a substance in which the gas actually migrates through the crystal lattice of the substance rather than through a geometrical leak (molecular diameters versus hole dimension).

hardness: resistance of metal to plastic deformation usually by indentation. For carbon steels, hardness can be related to the ultimate tensile strength.

Brinell Hardness Number (BHN): a value to express the hardness of metals obtained by forcing a hard steel ball of specified diameter into the metal under a specified load. For the standard 3 000-kg load, numbers range from 81 to 945.

Microhardness: any hardness measurement using an indentor load less than 10 kg.

Rockwell Hardness: a series of hardness scales for metals.

(a) The Rockwell "C" (HRC) scale uses a cone diamond indentor and a load of 150 kg. The scale starts at 20 for soft steels and reaches a maximum of about 67 for very hard alloys.

(b) The Rockwell "B" (HRB) scale uses a hard metal ball indentor and starts at 0 for extremely soft metals and reaches a maximum of 100 for soft steels and alloys. HRB 100 = HRC 20.

Vickers Hardness HV 10: a value achieved by use of a diamond pyramid indentor with a load of 10 kg.

heat-affected zone (HAZ): the portion of the base metal that was not melted during brazing, cutting, or welding, but whose microstructure and properties were affected by the heat of these processes.

hydrogen blistering: the formation of subsurface planar cavities, called hydrogen blisters, in a metal resulting from excessive internal hydrogen pressure. Growth of near-surface blisters in low-strength metals usually results in surface bulges.

hydrogen-induced cracking (HIC): a cracking mechanism of susceptible materials caused by atomic hydrogen diffusion in the metal. The atomic hydrogen usually is created by the corrosive reaction of hydrogen sulfide on steel in the presence of water.

hydrogen sulfide (H_2S): a toxic gaseous impurity found in some well gas streams. It also can be generated in situ as a result of microbiologic activity.

microbiologically influenced corrosion (MIC): corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be either initiated or accelerated, or both, by microbial activity.

microstructure: the grain size and morphology of metals and alloys as revealed after polishing and etching; characterized by grains or regions that exhibit distinct phases of solid solutions of constituent elements.

partial pressure: the contribution of a single component, such as hydrogen sulfide, in a mixture of gases to the total pressure of the mixture, determined by multiplying the mol fraction (mol percent divided by 100) of hydrogen sulfide in the gas by the total system pressure.

radius of exposure (ROE): when dealing with sour gas, the distance from a point of release at which the hydrogen sulfide concentrations reached a specified level (frequently 100 ppm or 500 ppm) determined by dispersion calculations.

sour gas: gas containing hydrogen sulfide (H_2S) at 65 psia (450 kPa) or greater at a partial pressure of 0.05 psia (350 Pa) or greater. See NACE MR0175/ISO 15156, titled *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production.*

sulfide stress cracking (SSC): a corrosion-related cracking mechanism caused by exposure of susceptible materials to sulfide ions in the presence of free water.

B813 MARKING

Valves meeting NACE MR0175/ISO 15156 shall be so identified with a permanent tag or marking.

B814 MATERIAL SPECIFICATIONS

B814.1 Pipe Conforming to Referenced Standards and Specifications

Materials must meet the requirements of NACE MR0175/ISO 15156.

B820 WELDING SOUR GAS PIPELINES

B821 GENERAL

B821.1 General Requirements

This paragraph concerns the welding of pipe in sour gas service in both wrought and cast steel materials and covers butt and fillet welded joints in pipe, valves, flanges, fittings, and fillet welded joints in pipe, slip-on flanges, socket welds, fittings, etc., as applied in pipelines, components, and connections to apparatus or equipment.

B821.2 Welding Processes

This paragraph does not apply to the welding of the seam in the manufacture of pipe, but the user is cautioned to ensure that such seams are suitable for sour gas service in their installed condition.

B821.4 Weld Acceptance

The standards of acceptability for welds of piping systems as established in API 1104 or BPV Code, Section IX, Division 1 shall be used; however, additional requirements for hardness and residual stress should be considered.

B822 PREPARATION FOR WELDING

B822.3 Seal Welds

Seal welds shall have a separate qualified procedure.

B822.4 Cleaning

Pipe that has been in sour gas service shall be thoroughly cleaned to bright metal on the inside surfaces back 1 in. (25 mm) from the weld bevel.

B823 QUALIFICATION OF PROCEDURES AND WELDERS

The requirements of para. 823.1 shall not apply to this section.

B823.2 Requirements for Qualification of Procedures and Welders on Sour Gas Piping Systems

B823.2.1 Qualifying Standard. All procedure and performance qualifications shall be based on destructive mechanical test requirements.

B823.2.4 Hardness Control. The hardness of all weld zones including weld metal and heat-affected zones on welding qualification test specimens shall meet the hardness requirements for the alloys welded as specified in NACE MR0175/ISO 15156. For most common pipe alloys, the maximum allowable hardness is HRC 22. It is the user's responsibility to ensure the welding qualification specimen is metallurgically representative of full-scale pipeline welds.

NOTE: Both macrohardness and microhardness surveys of properly prepared qualification specimens are frequently used to determine the presence of thin HAZ hard zones. A commonly accepted maximum macrohardness limit near the inside surface is 250 HV10.

B824 PREHEATING

B824.5 Hydrogen Bake Out of Used Pipe

Pipe that has been used in sour gas service shall be heated for at least 20 min at 400°F (204°C) or higher to drive off any hydrogen in the metal. Heating shall be done just prior to welding. This heating should be in addition to and immediately preceding any preheating specified in the welding procedure for new pipe.

B825 STRESS RELIEVING

B825.1 Carbon Steels

The chemistry of the steel and welding procedure shall be controlled to limit the hardness of the weldment as required by para. B823.2.4. When the effectiveness of such controls is questionable, consideration shall be given to stress relieving welds in sour gas service. In general, temper bead welding, peening procedures, or low-temperature postweld heat treatment does not provide the equivalent protection from service cracking as does a full thermal stress relief.

B825.6 Stress Relieving Temperature

(a) Stress relieving is normally performed at a temperature of 1,100°F (593°C) for carbon steels and 1,200°F (649°C) for ferritic alloy steels. Other stress relieving procedures may be substituted when properly supported with metallurgical evidence. The exact temperature range shall be stated in the procedure specification.

(b) When stress relieving a joint between dissimilar metals having different stress relieving requirements, the material requiring the higher stress relieving temperature shall govern. Special considerations may be required for austenitic and other high alloys.

(c) The parts heated shall be brought slowly to the required temperature and held at that temperature for a period of time proportioned on the basis of at least 1 hr/in. (1 h/25 mm) of pipe wall thickness, but in no case less than ½ hr, and shall be allowed to cool slowly and uniformly.

(d) Records. A suitable record of the stress relief cycles shall be provided for each weld stress relieved.

(e) Temperature Control. A group of closely spaced welds, such as three welds on a tee, can be controlled and recorded by a single thermocouple.

B826 WELDING AND INSPECTION TESTS

B826.2 Inspection and Tests for Quality Control of Welds on Sour Gas Piping Systems

In addition to paras. 826.2(a) through (f), for sour gas lines in Class 3 or 4 Locations, compressor stations, major or navigable river crossings, railroad crossings, and road crossings, 100% of all field welds shall be checked by nondestructive inspection. Nondestructive inspection may be conducted before or after stress relieving.

B830 PIPING SYSTEM COMPONENTS AND FABRICATION DETAILS

In addition to para. 830, all components shall meet the requirements of NACE MR0175/ISO 15156 as appropriate.

B831 PIPING SYSTEM COMPONENTS

B831.1 Valves and Pressure-Reducing Devices

B831.1.3 Pressure-Reducing Devices

(a) Instruments, instrument tubing, controllers, gages, and other components that become a part of the pressure containment system shall meet NACE MR0175/ISO 15156 requirements.

(b) Most copper-based alloys suffer severe corrosion in sour service. Use of such alloys in any components shall be investigated for suitability.

B831.2 Flanges

B831.2.2 Bolting

(h) Bolting exposed to sour gas and denied access to air due to thermal insulation, flange protectors, or certain design features shall meet the requirements of NACE MR0175/ISO 15156 as appropriate. Designers should note that bolting meeting NACE MR0175/ISO 15156 requirements, such as type ASTM A193 grade B7M, have derated tensile properties, and the joint design shall be appropriate for such deration. Bolting opened to atmosphere may be conventional ASTM A193 grade B7 bolting.

B840 DESIGN, INSTALLATION, AND TESTING

B841 STEEL PIPE

B841.1 Steel Piping Systems Design Requirements

B841.1.2 Fracture Control and Arrest

(c) Fracture Control. Fracture control should be considered for sour gas service.

B841.1.6 Design Factors, *F*, and Location Classes. When using Table 841.1.6-1, design factor F of 0.80 shall not be used for sour gas service.

B841.2 Installation of Steel Pipelines and Mains

B841.2.3 Bends, Miters, and Elbows in Steel Pipelines

(a) Bends. Bends used in sour gas pipe shall meet the requirements of NACE MR0175/ISO 15156 in the as-bent condition. Hot bends may be needed to meet NACE MR0175/ISO 15156 requirements. The first prototype bend may be needed for testing to ensure hardness requirements of NACE MR0175/ISO 15156 and that both toughness and tensile properties are still acceptable. Neither wrinkle bends nor miter bends are permitted for sour gas lines.

B841.2.4 Pipe Surfaces Requirements Applicable to Pipelines and Mains to Operate at a Hoop Stress of 20% or More of the Specified Minimum Yield Strength

(e) Arc Burns. Additionally, arc burns have been found to cause serious stress concentration in pipelines and in sour gas lines, and shall be prevented or eliminated in all lines.

Arc burns may be removed by grinding, chipping, or machining. The resulting cavity shall be thoroughly cleaned and checked for complete removal of damaged material by etching with a 10% solution of ammonium persulfate or a 5% solution of nitric acid in alcohol (nital). If removal of damaged material is complete, the cavity may be merged smoothly into the original contour of the pipe by grinding, provided the remaining wall thickness is within specified limits.

B841.2.6 Hot Taps. In addition to para. 841.2.6 of Chapter IV, it should be noted that hot tapping of sour gas lines presents special health and metallurgical concerns and shall be done only to written operating company approved plans.

B841.2.7 Precautions to Avoid Explosions of Gas–Air Mixtures or Uncontrolled Fires During Construction Operations

(a) In addition to the precautions outlined in para. 841.2.7(a) of Chapter IV, it should be noted that welding and cutting on sour gas lines presents special health and metallurgical concerns and shall be done only to written operating company approved plans.

B841.3 Testing After Construction

B841.3.1 General Provisions. In addition to para. 841.3.1 of Chapter IV, it should be noted that testing with sour gas presents special health and metallurgical concerns and shall be done only to written operating company approved plans.

B842 OTHER MATERIALS

Materials shall meet the requirements of NACE MR0175/ISO 15156 as applicable.

B842.2 Design of Plastic Piping

(16) #### B842.2.2 Thermoplastic Design Limitations

(f) The designer should consider extra protection from third party damage in all class locations and at all road crossings.

(g) New construction for sour gas applications shall utilize only ASTM D2513 polyethylene, ASTM F2945 polyamide, or ASTM F2817 PVC (maintenance or repair only) thermoplastic pipe.

(16) #### B842.2.9 Plastic Pipe and Tubing Joints and Connections

(b) Joint Requirements. All joining procedures shall be qualified using destructive test specimens of full scalle plastic pipe joints. Polyethylene and polyamide pipe for sour gas service may be joined by butt fusion, socket fusion, and electrofusion methods, or mechanical fittings when recommended by the manufacturer as suitable for sour gas service.

(f) Mechanical Joints

(4) Steel to Plastic Transition Fittings. Steel to plastic transition fittings for sour gas service shall be factory made. Joints made from field-fabricated fittings are prohibited.

B842.4 Testing Plastic Piping After Construction

B842.4.2 Testing Requirements

(f) All plastic pipe installed for sour gas service shall be leak tested with air for 12 hr minimum at a pressure not less than 1.5 times the maximum allowable operating pressure or 50 psig (340 kPa), whichever is greater.

B843 COMPRESSOR STATIONS

B843.3 Compressor Station Equipment

B843.3.1 Gas Treating Facilities

(c) Metallic Materials. All metallic materials in contact with pressurized sour gas shall meet the requirements of NACE MR0175/ISO 15156 as applicable.

Personal safety equipment should be considered for use at sour gas facilities. Use of appropriate hydrogen sulfide sensors capable of actuating station emergency shutdown systems should be considered.

B844 PIPE-TYPE AND BOTTLE-TYPE HOLDERS

Pipe- and bottle-type holders shall not be used for sour gas. Storage of sour gas is outside the scope of this Code.

B850 ADDITIONAL OPERATING AND MAINTENANCE CONSIDERATIONS AFFECTING THE SAFETY OF SOUR GAS PIPELINES

B850.1 General

(c) Radius of exposure (ROE) to H_2S calculations shall be made using a suitable air dispersion equation such as the Pasquel–Gifford equation given as follows:

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the system. Suitable standards are GPA Plant Operations Test Manual, Section C, and GPA Standard 2265.

(2) Radius of Exposure Equations

(-a) Radius of exposure equation to the 100-ppm level of H_2S after dispersal:

$$X = [(1.589)\, M\, Q]^{0.6258}$$

(-b) Radius of exposure equation to the 500-ppm level of H_2S after dispersal:

$$X = [(0.4546)\, M\, Q]^{0.6258}$$

where

M = mol fraction of hydrogen sulfide in the gaseous mixture

Q = maximum volume determined to be available for escape in cubic feet per day corrected to 14.65 psia and 60°F
X = radius of exposure (ROE) in feet

(3) *Metric Equations for Radius of Exposure*

(-a) 100-ppm level of H_2S after dispersal:

$$X_m = [(8.404)\, M\, Q_m]^{0.6258}$$

(-b) 500-ppm level of H_2S after dispersal:

$$X_m = [(2.404)\, M\, Q_m]^{0.6258}$$

where
M = mol fraction of hydrogen sulfide in the gaseous mixture
Q_m = maximum volume determined to be available for escape in cubic meters per day corrected to 101 kPa and 15.6°C
X_m = radius of exposure (ROE) in meters

NOTE: The equations assume a 24-hr release. When a pipeline segment can be isolated in less than 24 hr, appropriate reductions in Q may be used.

(4) Examples of 100-ppm and 500-ppm ROE for various 24-hr releases and H_2S mol fractions are shown in Tables B850.1-1 and B850.1-2. Metric examples of 100-ppm and 500-ppm ROE for various 24-hr releases and H_2S mol fractions are shown in Tables B850.1-3 and B850.1-4.

B850.4 Essential Features of the Emergency Plan

B850.4.2 Training Program. In addition to conventional training, all sour gas operation and maintenance line personnel shall be trained in

(a) hazards and characteristics of H_2S
(b) effect on metal components of the lines and equipment
(c) safety precautions
(d) operation of safety equipment and life support systems
(e) corrective action and shutdown procedures

B851 PIPELINE MAINTENANCE

B851.7 Pipeline Markers

(d) In addition to each sign required in para. 851.7(c) of Chapter V, for operations where the 100-ppm radius of exposure is greater than 50 ft (15 m), a "POISON GAS" sign shall be installed.

All surface facilities shall also be marked with "POISON GAS" signs.

B851.10 Sour Gas Pipeline Blowdown

When blowing down sour gas lines, consideration shall be given to the use of suitable permanent or temporary flare systems.

B854 LOCATION CLASS AND CHANGES IN NUMBER OF BUILDINGS INTENDED FOR HUMAN OCCUPANCY

B854.5 Concentrations of People in Location Classes 1 and 2

(c) *Security.* Unattended fixed surface facilities should be protected from public access when located within ¼ mile (400 m) of a residential, commercial, or other inhabited or occupied structure; bus stop; public park; or similarly populated area.

(1) The protection should be provided by fencing and locking or removal of valves and instrumentation and plugging of ports, or other similar means.

(2) Surface pipeline is not considered a fixed surface facility.

(d) Additional control and safety procedures or safety devices should be installed and maintained to prevent the undetected continuing release of hydrogen sulfide if any of the following conditions exist:

(1) The 100-ppm radius of exposure is in excess of 50 ft (15 m) and includes any part of a public area except a public road.

(2) The 500-ppm radius of exposure is greater than 50 ft (15 m) and includes any part of a public road.

(3) The 100-ppm radius of exposure is greater than 3,000 ft (915 m).

(e) *Contingency Plan.* Operations subject to (d) above shall have a written contingency plan prepared and given to state and local emergency response authorities. Plans shall include maps, location of block valves, valve keys, and keys for locks.

B860 CORROSION CONTROL OF SOUR GAS PIPELINES

B860.1 Scope

This section contains the minimum additive or substitutive requirements for corrosion control of external and internal corrosion of sour gas piping and components. Where specific provisions are not set forth herein, the provisions of section 860 of Chapter VI shall apply.

B860.4 Special Considerations

Due to the corrosivity of hydrogen sulfide and the frequent presence of carbon dioxide and salt water, which also are corrosive, special emphasis shall be given to internal corrosion mitigation and monitoring.

Also, due to the corrosive and hazardous nature of the sour gas, special consideration shall be given to the selection of the corrosion allowance.

Table B850.1-1 100-ppm ROE

ROE, *X*, ft	Release, *Q*, MMSCFD (1,000,000)	H_2S Mol Fraction
1,165	1	0.05
3,191	5	0.05
4,924	10	0.05
7,597	20	0.05
9,792	30	0.05
1,798	1	0.1
4,924	5	0.1
7,597	10	0.1
11,723	20	0.1
15,109	30	0.1
2,775	1	0.2
7,597	5	0.2
11,723	10	0.2
18,090	20	0.2
23,315	30	0.2

Table B850.1-2 500-ppm ROE

ROE, *X*, ft	Release, *Q*, MMSCFD (1,000,000)	H_2S Mol Fraction
533	1	0.05
1,458	5	0.05
2,250	10	0.05
3,472	20	0.05
4,474	30	0.05
822	1	0.1
2,250	5	0.1
3,472	10	0.1
5,357	20	0.1
6,904	30	0.1
1,268	1	0.2
3,472	5	0.2
5,357	10	0.2
8,266	20	0.2
10,654	30	0.2

Table B850.1-3 Metric Example for 100-ppm ROE

ROE, X_m, m	Release, Q_m, m^3/day (1,000,000)	H_2S Mol Fraction
782	0.1	0.05
2,142	0.5	0.05
3,305	1	0.05
9,048	5	0.05
13,962	10	0.05
1,207	0.1	0.1
3,305	0.5	0.1
5,100	1	0.1
13,962	5	0.1
21,544	10	0.1
1,863	0.1	0.2
5,100	0.5	0.2
7,869	1	0.2
21,544	5	0.2
33,244	10	0.2

Table B850.1-4 Metric Example for 500-ppm ROE

ROE, X_m, m	Release, Q_m, m^3/day (1,000,000)	H_2S Mol Fraction
357	0.1	0.05
979	0.5	0.05
1,510	1	0.05
4,135	5	0.05
6,380	10	0.05
552	0.1	0.1
1,510	0.5	0.1
2,330	1	0.1
6,380	5	0.1
9,845	10	0.1
851	0.1	0.2
2,330	0.5	0.2
3,596	1	0.2
9,845	5	0.2
15,191	10	0.2

B861 EXTERNAL CORROSION CONTROL FOR STEEL PIPELINES

B861.1 Buried/Submerged Installations

B861.1.2 Cathodic Protection Requirements. Unless it can be demonstrated by tests or experience that cathodic protection is not needed, all buried or submerged facilities with insulating type coatings, except facilities installed for a limited service life, shall be cathodically protected as soon as feasible following installation, except that minor replacements or extensions shall be protected as covered by para. 860.3.

Facilities installed for a limited service life need not be cathodically protected if it can be demonstrated that the facility will not experience corrosion that will cause it to be harmful to the public or environment. Cathodic protection systems shall be designed to protect the buried or submerged system in its entirety.

A facility is considered to be cathodically protected when it meets one or more of the criteria established in Mandatory Appendix K.

Use of cathodic protection is encouraged to protect buried sour gas facilities.

B864 INTERNAL CORROSION CONTROL

B864.1 General

Sour gas facilities shall be assumed to be internally corrosive unless proven by experience to be otherwise. Water dewpoint control frequently is used as a corrosion control method. Upset conditions or operational changes may make this control method ineffective. The use of inhibitors is also common.

B864.2 Design of New Installations

New installations should be designed with

(a) suitable dedicated fittings for corrosion inhibitor injection

(b) suitable dedicated fittings and valves to insert and retrieve corrosion measuring devices such as probes and coupons

B867 STRESS CORROSION AND OTHER PHENOMENA

Sour gas lines, particularly when combined with carbon dioxide and produced salt water, can suffer from several corrosion-related phenomena.

(a) Hydrogen-Related Problems. The corrosion reaction in the presence of the sulfide ion permits a high amount of liberated hydrogen atoms to enter the steel. The hydrogen causes many problems that have been given different names:

(1) Sulfide stress cracking (SSC) occurs when the alloys are too hard and/or too highly stressed in the presence of corrosion with sour gas. NACE MR0175/ISO 15156 outlines all of the acceptable materials combinations to resist this type of cracking.

(2) Hydrogen-induced cracking (HIC) occurs when hydrogen causes inclusions in the steel to delaminate. Multiple shear cracks then develop to link the delaminations creating a stair step crack system. Use of HIC resistant materials should be considered for sour gas service.

(3) Stress-oriented hydrogen-induced cracking (SOHIC) is another variant of HIC. SOHIC is HIC enhanced by high-tensile stress.

(4) Hydrogen blistering consists of hydrogen atoms diffusing inside the steel to delaminated areas and recombining to form molecules of hydrogen gas. The resulting pressure can create large blisters on either the inside or outside surfaces of the steel.

(b) Chloride stress corrosion cracking is caused by chlorides in the produced water. Austenitic stainless steels are particularly prone to this type of cracking. The sulfide ion has a synergistic effect with the chloride ion. The net result is the occurrence of cracking at lower temperatures and at lower chloride concentrations than normally expected. Except for small low-stressed parts such as thermowells, use of alloys not resistant to chloride stress cracking above 140°F (60°C) is discouraged in wet sour gas systems.

(c) Microbiologically Induced Corrosion (MIC). Microbiologic activity can create severe pitting-type corrosion and hydrogen-related cracking in sour gas lines. Use of appropriate biocides and monitoring may be needed.

MANDATORY APPENDIX A REFERENCES

(16)

These references may be immediately applied to materials purchased for use under this Code and shall be applied to all materials purchased at least 12 months after the date of issuance of the reference's latest edition, including addenda, if applicable. A component or pipe conforming to an earlier approved material specification edition purchased by the user before the date of issuance of a new edition or addenda may be used, provided the component or pipe is inspected and determined to be satisfactory for the service intended by the user.

Standards are incorporated in this Code by reference, and the names and addresses of the sponsoring organizations are shown in this Mandatory Appendix. It is not practical to refer to a specific edition of each publication throughout the Code text; instead, the specific edition reference dates are shown herein. Reference shall be limited to the specific edition cited below, except the user may use the latest published edition of ANSI approved standards unless specifically prohibited by this Code, and provided the user has reviewed the latest edition of the standard to ensure that the integrity of the pipeline system is not compromised. If a newer or amended edition of a standard is not ANSI approved, then the user shall use the specific edition reference date shown herein.

An asterisk (*) indicates that the specific edition of the standard has been accepted as an American National Standard by the American National Standards Institute (ANSI).

A-1 AGA

AGA Catalog No. XR0603 (October 2006), Plastic Pipe Manual for Gas Service

*ANSI Z223.1/NFPA 54 (2012), National Fuel Gas Code

*ANSI/GPTC Z380.1 (2012, including Addenda 1 through 3), GPTC Guide for Gas Transmission and Distribution Piping Systems

Gas Piping Technology Committee's Guide Material Appendix G-192-15, Design of Uncased Pipeline Crossings of Highways and Railroads (2009)

Publisher: American Gas Association (AGA), 400 North Capitol Street, NW, Washington, DC 20001 (www.aga.org)

A-2 API

*API Spec 5L (45th edition, December 2012), Specification for Line Pipe[1]

*API Manual of Petroleum Measurement Standards (second edition, February 1, 2013), Chapter 21 — Flow Measurement Using Electronic Metering Systems, Section 1 — Electronic Gas Measurement

API RP 2A-WSD (21st edition, December 2000, including Errata and Supplements through October 2007; reaffirmed 2010), Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms — Working Stress Design

API RP 5L1 (seventh edition, September 2009), Recommended Practice for Railroad Transportation of Line Pipe

*API RP 5LW (third edition, September 2009), Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels

API RP 14C (seventh edition, March 2001, reaffirmed March 2007), Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms

*API RP 14E (fifth edition, October 1991, reaffirmed March 2007), Recommended Practice for the Design and Installation of Offshore Production Platform Piping Systems

*API RP 14F (fifth edition, July 2008), Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations

API RP 14J (second edition, May 2001, reaffirmed March 2007), Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities

*API RP 17B/ISO 13628-11:2007 (fourth edition, July 2008, including Technical Corrigendum 1), Recommended Practice for Flexible Pipe

API RP 80 (first edition, April 2000), Guidelines for the Definition of Onshore Gas Gathering Lines

API RP 1102 (seventh edition, December 2007, including Errata through September 2012), Steel Pipelines Crossing Railroads and Highways

*API RP 1110 (sixth edition, February 2013), Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas,

[1] See Note in para. 814.1.1 regarding the use of the 45th edition of API 5L.

Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide
API RP 1111 (fourth edition, December 2009, including Errata through May 2011), Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)
*API Spec 6A/ISO 10423:2009 (Modified) (20th edition, October 2010, including Errata and Addenda through March 2013), Specification for Wellhead and Christmas Tree Equipment
*API Spec 6D/ISO 14313:2007 (23rd edition, April 2008, including Errata and Addenda through October 2012), Specification for Pipeline Valves
*API Spec 6DSS/ISO 14723:2009 (second edition, December 2009), Specification for Subsea Pipeline Valves
*API Spec 17D/ISO 13628-4 (second edition, May 2011, including Errata through June 2013), Design and Operation of Subsea Production Systems — Subsea Wellhead and Tree Equipment
*API Spec 17J/ISO 13628-2:2006 (third edition, July 2008, including Errata through August 2010), Specification for Unbonded Flexible Pipe
API Std 1104 (21st edition, September 2013), Welding of Pipelines and Related Facilities

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005 (www.api.org)

A-3 ASME

*ASME B1.1-2003 (R2008), Unified Inch Screw Threads (UN and UNR Thread Form)
*ASME B1.20.1-1983 (R2006), Pipe Threads, General Purpose (Inch)
*ASME B16.1-2010, Gray Iron Pipe Flanges and Flanged Fittings: Classes 25, 125, and 250
*ASME B16.5-2013, Pipe Flanges and Flanged Fittings: NPS ½ Through NPS 24 Metric/Inch Standard
*ASME B16.9-2012, Factory-Made Wrought Buttwelding Fittings
*ASME B16.11-2011, Forged Fittings, Socket-Welding and Threaded
*ASME B16.20-2012, Metallic Gaskets for Pipe Flanges: Ring-Joint, Spiral-Wound, and Jacketed
*ASME B16.24-2011, Cast Copper Alloy Pipe Flanges and Flanged Fittings: Classes 150, 300, 600, 900, 1500, and 2500
*ASME B16.33-2012, Manually Operated Metallic Gas Valves for Use in Gas Piping Systems up to 175 psi (Sizes NPS ½ Through NPS 2)
*ASME B16.34-2013, Valves — Flanged, Threaded, and Welding End
*ASME B16.38-2012, Large Metallic Valves for Gas Distribution: Manually Operated, NPS 2½ (DN 65) to NPS 12 (DN 300), 125 psig (8.6 bar) Maximum
*ASME B16.40-2013, Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems
*ASME B16.42-2011, Ductile Iron Pipe Flanges and Flanged Fittings: Classes 150 and 300
*ASME B16.47-2011, Large Diameter Steel Flanges: NPS 26 Through NPS 60 Metric/Inch Standard
*ASME B16.49-2012, Factory-Made, Wrought Steel, Buttwelding Induction Bends for Transportation and Distribution Systems
*ASME B18.2.1-2012, Square, Hex, Heavy Hex, and Askew Head Bolts and Hex, Heavy Hex, Hex Flange, Lobed Head, and Lag Screws (Inch Series)
*ASME B18.2.2-2010, Nuts for General Applications: Machine Screw Nuts, Hex, Square, Hex Flange, and Coupling Nuts (Inch Series)
*ASME B31G-2012, Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping
*ASME B31Q-2010, Pipeline Personnel Qualification
*ASME B31.1-2012, Power Piping
*ASME B31.3-2012, Process Piping
*ASME B31.4-2012, Pipeline Transportation Systems for Liquids and Slurries
*ASME B31.8S-2012, Managing System Integrity of Gas Pipelines
*ASME B36.10M-2004 (R2010), Welded and Seamless Wrought Steel Pipe
*ASME BPV Code: Section II, Materials; Section VIII, Rules for Construction of Pressure Vessels; and Section IX, Qualification Standard for Welding, Brazing, and Fusing Procedures; Welders; Brazers; and Welding, Brazing, and Fusing Operators (2013)
ASME SI-1-1982, ASME Orientation and Guide for Use of SI (Metric) Units
ASME PCC-2-2011, Repair of Pressure Equipment and Piping
IPC2002-27124, "Development of Acceptance Criteria for Mild Ripples in Pipeline Field Bends," Proceedings of IPC 2002, Fourth International Pipeline Conference, September 2002

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

A-4 ASTM

ASTM A53/A53M-12, Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless
ASTM A105/A105M-12, Standard Specification for Carbon Steel Forgings for Piping Applications
ASTM A106/A106M-11, Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service
ASTM A134-96(R2012), Standard Specification for Pipe, Steel, Electric-Fusion (Arc)-Welded (Sizes NPS 16 and Over)

ASTM A135/A135M-09, Standard Specification for Electric-Resistance-Welded Steel Pipe
ASTM A139/A139M-04(R2010), Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes NPS 4 and Over)
ASTM A193/A193M-12b, Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High Temperature or High-Pressure Service and Other Special Purpose Applications
ASTM A194/A194M-12a, Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both
ASTM A307-12, Standard Specification for Carbon Steel Bolts, Studs, and Threaded Rod 60 000 PSI Tensile Strength
ASTM A320/A320M-11a, Standard Specification for Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service
ASTM A333/A333M-11, Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service
ASTM A354-11, Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners
ASTM A372/A372M-12, Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels
ASTM A381-96(R2012), Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems
ASTM A395/A395M-99(R2009), Standard Specification for Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures
ASTM A449-10, Standard Specification for Hex Cap Screws, Bolts and Studs, Steel, Heat Treated, 120/105/90 ksi Minimum Tensile Strength, General Use
ASTM A671/A671M-10, Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures
ASTM A672/A672M-09, Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures
ASTM A691/A691M-09, Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures
ASTM A984/A984M-03(R2009), Standard Specification for Steel Line Pipe, Black, Plain-End, Electric-Resistance-Welded
ASTM A1005/A1005M-00(R2010), Standard Specification for Steel Line Pipe, Black, Plain-End, Longitudinal and Helical Seam, Double Submerged-Arc Welded
ASTM A1006/A1006M-00(R2010), Standard Specification for Steel Line Pipe, Black, Plain-End, Laser Beam Welded
ASTM B88-09, Standard Specification for Seamless Copper Water Tube
ASTM D696-08$^{\epsilon1}$, Standard Test Method for Coefficient of Linear Thermal Expansion of Plastics Between −30°C and 30°C With a Vitreous Silica Dilatometer
ASTM D1598-02(R2009), Standard Test Method for Time-to-Failure of Plastic Pipe Under Constant Internal Pressure
*ASTM D2513-13, Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings
*ASTM D2517-06(R2011), Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings
*ASTM D2837-11, Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products
*ASME F1041-02(R2008), Standard Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing
*ASTM F1563-01(R2011), Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing
ASTM F2817-13, Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair
ASTM F2945-15, Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings
Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

A-5 AWS

*AWS A3.0M/A3.0:2010, Standard Welding Terms and Definitions, Including Terms for Adhesive Bonding, Brazing, Soldering, Thermal Cutting, and Thermal Spraying
*AWS D3.6M:2010, Underwater Welding Code
Publisher: American Welding Society (AWS), 8669 NW 36th Street, No. 130, Miami, FL 33166 (www.aws.org)

A-6 AWWA

ANSI A21.14-1979, Ductile-Iron Fittings 3-Inch Through 24-Inch for Gas[2]
ANSI A21.52-1991, Ductile-Iron Pipe, Centrifugally Cast, for Gas[2]
*ANSI/AWWA C111/A21.11-12, Rubber-Gasket Joints for Ductile-Iron Pressure Pipe and Fittings
*ANSI/AWWA C150/A21.50-08, Thickness Design of Ductile-Iron Pipe
AWWA C101-1976(R1977), Thickness Design of Cast Iron Pipe[2]

[2] This publication has been superseded, withdrawn, or is no longer in print.

Publisher: American Water Works Association (AWWA), 6666 West Quincy Avenue, Denver, CO 80235 (www.awwa.org)

A-7 CGA

Best Practices Guide (version 10.0, 2013)

Publisher: Common Ground Alliance (CGA), 2200 Wilson Boulevard, Suite 102-172, Arlington, VA 22201 (www.commongroundalliance.com)

A-8 EPRI

EPRI EL-3106 (1983) (also published as PRCI-AGA-L51418), Power Line-Induced AC Potential on Natural Gas Pipelines for Complex Rights-of-Way Configurations

Publisher: Electric Power Research Institute (EPRI), 3420 Hillview Avenue, Palo Alto, CA 94304 (www.epri.com)

A-9 GPA

GPA Plant Operations Test Manual, Section C, Test for Hydrogen Sulfide in LPG and Gases (Tutweiler Method)

GPA Standard 2265-68, Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas (Cadmium Sulfate-Iodometric Titration Method)

Publisher: Gas Processors Association (GPA), Sixty Sixty American Plaza, Suite 700, Tulsa, OK 74135 (www.gpaglobal.org)

A-10 GTI

GRI-00/0154 (2000), Design Guide for Polyethylene Gas Pipes Across Bridges

GRI-91/0284 (1991), Guidelines for Pipelines Crossing Highways[2]

Publisher: Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018 (www.gastechnology.org)

A-11 IEEE

*IEEE/ASTM SI 10-2010, American National Standard for Metric Practice

Publisher: Institute of Electrical and Electronics Engineers, Inc. (IEEE), 445 Hoes Lane, Piscataway, NJ 08854 (www.ieee.org)

A-12 MSS

MSS SP-6-2012, Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings

MSS SP-25-2008, Standard Marking System for Valves, Fittings, Flanges, and Unions

MSS SP-44-2010 (including May 2011 errata), Steel Pipeline Flanges

MSS SP-70-2011, Gray Iron Gate Valves, Flanged and Threaded Ends

MSS SP-71-2011, Gray Iron Swing Check Valves, Flanged and Threaded Ends

MSS SP-75-2008, Specification for High-Test Wrought Butt Welding Fittings

MSS SP-78-2011, Gray Iron Plug Valves, Flanged and Threaded Ends

Publisher: Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE, Vienna, VA 22180 (www.msshq.org)

A-13 NACE

*ANSI/NACE MR0175/ISO 15156:2009, Petroleum and Natural Gas Industries — Materials for Use in H_2S-Containing Environments in Oil and Gas Production, Parts 1, 2, and 3 (including all Technical Circulars through 2011)

NACE Corrosion Data Survey (1985)[2]

NACE SP0169-2007, Control of External Corrosion on Underground or Submerged Metallic Piping Systems

NACE SP0177-2007, Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

*NACE SP0607-2007/ISO 15589-2:2004 (Modified), Petroleum and Natural Gas Industries — Cathodic Protection of Pipeline Transportation Systems — Offshore Pipelines

Publisher: National Association of Corrosion Engineers (NACE International), 15835 Park Ten Place, Houston, TX 77084-4906 (www.nace.org)

A-14 NFPA

*NFPA 10-2013, Standard for Portable Fire Extinguishers

*NFPA 30-2012, Flammable and Combustible Liquids Code

*NFPA 58-2013, Liquefied Petroleum Gas Code

*NFPA 59-2012, Utility LP-Gas Plant Code

*NFPA 59A-2013, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)

*NFPA 70-2013, National Electrical Code (including Amendment 1)

*NFPA 220-2012, Standard on Types of Building Construction

Publisher: National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02169 (www.nfpa.org)

A-15 PPI

Handbook of Polyethylene Pipe, second edition, November 2007 (including Errata Sheet, June 6, 2012)
TR-3/2004, Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe
TR-4/2013, Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Ratings For Thermoplastic Piping Materials or Pipe
TR-33/2006, Generic Butt Fusion Joining Procedure for Polyethylene Gas Pipe
TR-41/2002, Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping
TR-45/2008, Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe
Publisher: Plastics Pipe Institute (PPI), 105 Decker Court, Suite 825, Irving, TX 75062 (www.plasticpipe.org)

A-16 PRCI

PRCI PR-185-9734 (PRCI Catalog L51782), Guidelines for Weld Deposition Repair on Pipelines (1998)
PRCI PR-186-0324 (PRCI Catalog L52047), Updated Pipeline Repair Manual (2006)
PRCI PR-218-05404 (PRCI Catalog L52314), Pipeline Defect Assessment — A Review and Comparison of Commonly Used Methods (2010)
PRCI PR-218-9307 (PRCI Catalog L51716), Pipeline Repair Manual (1994)
Publisher: Pipeline Research Council International (PRCI), 3141 Fairview Park Drive, Suite 525, Falls Church, VA 22042 (www.prci.org)

MANDATORY APPENDIX B NUMBERS AND SUBJECTS OF STANDARDS AND SPECIFICATIONS THAT APPEAR IN MANDATORY APPENDIX A

The information in this Appendix has been incorporated into Mandatory Appendix A.

NONMANDATORY APPENDIX C PUBLICATIONS THAT DO NOT APPEAR IN THE CODE OR MANDATORY APPENDIX A

(16)

NOTE: An asterisk (*) indicates standards that have been accepted as American National Standards by the American National Standards Institute (ANSI).

C-1 AGA

AGA Catalog XL1001 (December 2010, including Errata 1 and 2), Classification of Locations for Electrical Installations in Gas Utility Areas

Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry (December 2004)

Publisher: American Gas Association (AGA), 400 North Capitol Street, NW, Washington, DC 20001 (www.aga.org)

C-2 API

API RP 2A-LRFD (first edition, July 1993, including Errata and Supplements through February 1997; reaffirmed May 2003), Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms — Load and Resistance Factor Design[1]

*API RP 500 (third edition, December 2012), Recommended Practices for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2

API Spec 5B (15th edition, April 2008), Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005 (www.api.org)

C-3 ASCE

ASCE Manuals and Reports on Engineering Practices No. 89 — Pipeline Crossings Handbook (June 1996)

Publisher: American Society of Civil Engineers (ASCE), 1801 Alexander Bell Drive, Reston, VA 20191 (www.asce.org)

[1] This publication has been superseded, withdrawn, or is no longer in print.

C-4 ASME

*ASME B1.20.3-1976 (R2013), Dryseal Pipe Threads (Inch)

*ASME B16.3-2011, Malleable Iron Threaded Fittings: Classes 150 and 300

*ASME B16.4-2011, Gray Iron Threaded Fittings: Classes 125 and 250

*ASME B16.14-2010, Ferrous Pipe Plugs, Bushings, and Locknuts With Pipe Threads

*ASME B16.15-2011, Cast Copper Alloy Threaded Fittings: Classes 125 and 250

*ASME B16.18-2012, Cast Copper Alloy Solder Joint Pressure Fittings

*ASME B16.22-2012, Wrought Copper and Copper Alloy Solder-Joint Pressure Fittings

*ASME B16.25-2012, Buttwelding Ends

*ASME B31.12-2011, Hydrogen Piping and Pipelines

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

C-5 ASTM

ASTM A6/A6M-13, Standard Specification for General Requirements for Rolled Structural Steel Bars, Plates, Shapes, and Sheet Piling

ASTM A20/A20M-11, Standard Specification for General Requirements for Steel Plates for Pressure Vessels

ASTM A29/A29M-12, Standard Specification for General Requirements for Steel Bars, Carbon and Alloy, Hot-Wrought

ASTM A36/A36M-12, Standard Specification for Carbon Structural Steel

ASTM A47/A47M-99(R2009), Standard Specification for Ferritic Malleable Iron Castings

ASTM A48/A48M-03(R2012), Standard Specification for Gray Iron Castings

ASTM A125-96(R2007), Standard Specification for Steel Springs, Helical, Heat-Treated

ASTM A126-04(R2009), Standard Specification for Gray Iron Castings for Valves, Flanges, and Pipe Fittings

ASTM A181/A181M-12, Standard Specification for Carbon Steel Forgings, for General-Purpose Piping

*ASTM A182/A182M-13, Standard Specification for Forged or Rolled Alloy and Stainless-Steel Pipe

Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service

ASTM A197/A197M-00(R2011), Standard Specification for Cupola Malleable Iron

ASTM A216/A216M-12, Standard Specification for Steel Castings, Carbon, Suitable for Fusion Welding, for High-Temperature Service

ASTM A217/A217M-12, Standard Specification for Steel Castings, Martensitic Stainless and Alloy, for Pressure-Containing Parts, Suitable for High-Temperature Service

ASTM A225/A225M-12, Standard Specification for Pressure Vessel Plates, Alloy Steel, Manganese-Vanadium-Nickel

ASTM A234/A234M-11a, Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High-Temperature Service

ASTM A242/A242M-13, Standard Specification for High-Strength Low-Alloy Structural Steel

ASTM A283/A283M-12a, Standard Specification for Low and Intermediate Tensile Strength Carbon Steel Plates

ASTM A285/A285M-12, Standard Specification for Pressure Vessel Plates, Carbon Steel, Low- and Intermediate-Tensile Strength

ASTM A350/A350M-12, Standard Specification for Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components

ASTM A377-03(R2008)$^{\epsilon 1}$, Standard Index of Specifications for Ductile-Iron Pressure Pipe

ASTM A420/A420M-10a, Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service

ASTM A487/A487M-93(R2012), Standard Specification for Steel Castings Suitable for Pressure Service

ASTM A502-03(R2009), Standard Specification for Rivets, Steel, Structural

ASTM A515/A515M-10, Standard Specification for Pressure Vessel Plates, Carbon Steel, for Intermediate- and Higher-Temperature Service

ASTM A516/A516M-10, Standard Specification for Pressure Vessel Plates, Carbon Steel, for Moderate- and Lower-Temperature Service

ASTM A575-96(R2013)$^{\epsilon 1}$, Standard Specification for Steel Bars, Carbon, Merchant Quality, M-Grades

ASTM A576-90b(R2012), Standard Specification for Steel Bars, Carbon, Hot-Wrought, Special Quality

ASTM A694/A694M-08, Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service

ASTM B21/B21M-12, Standard Specification for Naval Brass Rod, Bar, and Shapes

ASTM B42-10, Standard Specification for Seamless Copper Pipe, Standard Sizes

ASTM B43-09, Standard Specification for Seamless Red Brass Pipe, Standard Sizes

ASTM B61-08, Standard Specification for Steam or Valve Bronze Castings

ASTM B62-09, Standard Specification for Composition Bronze or Ounce Metal Castings

ASTM B68/B68M-11, Standard Specification for Seamless Copper Tube, Bright Annealed

ASTM B75/B75M-11, Standard Specification for Seamless Copper Tube

ASTM B249/B249M-12, Standard Specification for General Requirements for Wrought Copper and Copper-Alloy Rod, Bar, Shapes, and Forgings

ASTM B251-10, Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube

ASTM B584-13, Standard Specification for Copper Alloy Sand Castings for General Applications

Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959 (www.astm.org)

C-6 AWWA

*AWWA C207-13, Steel Pipe Flanges for Waterworks Service — Sizes 4 in. Through 144 in. (100 mm Through 3,600 mm)

Publisher: American Water Works Association (AWWA), 6666 West Quincy Avenue, Denver, CO 80235 (www.awwa.org)

C-7 GTI

GRI-00/0154 (2001), Design Guide for Pipes Across Bridges

GRI-00/0192.01 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 1: Fracture Propagation and Arrest

GRI-00/0192.02 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 2: Defect Assessment

GRI-00/0192.03 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 3: Identifying Types of Defects and Causes of Pipeline Failures

GRI-00/0192.04 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 4: Hydrostatic Testing

GRI-00/0192.05 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 5: Line Pipe

GRI-00/0192.06 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 6: Welding

GRI-00/0192.07 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 7: Fittings and Components

GRI-00/0192.08 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 8: Pipeline Repair Methods
GRI-00/0192.09 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 9: Mechanical Damage
GRI-00/0192.10 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 10: Corrosion
GRI-00/0192.11 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 11: Stress Corrosion Cracking
GRI-00/0192.12 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 12: Industry Statistics
GRI-00/0192.13 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 13: Offshore Pipelines
GRI-00/0192.14 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 14: In-Line Inspection
GRI-00/0192.15 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 15: Special Situations
GRI-00/0192.16 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 16: Risk Assessment
GRI-00/0192.17 (2001), GRI Guide for Locating and Using Pipeline Industry Research. Section 17: Geographical Information Systems
GRI-96/0368 (1996), Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe
Publisher: Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018 (www.gastechnology.org)

C-8 MSS

*MSS SP-55-2011, Quality Standard for Steel Castings for Valves, Flanges, Fittings, and Other Piping Components — Visual Method for Evaluation of Surface Irregularities
MSS SP-61-2013, Pressure Testing of Valves

Publisher: Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE, Vienna, VA 22180 (www.msshq.org)

C-9 OTHER PUBLICATIONS

ANSI Z17.1-1973, American National Standard for Preferred Numbers[1]

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036 (www.ansi.org)

Horizonal Directional Drilling — Good Practices Guidelines (third edition, 2008)

Publisher: HDD Consortium, available through North American Society for Trenchless Technology (NASTT), 14500 Lorain Avenue #110063, Cleveland, OH 44111 (www.nastt.org)

PRCI PR-227-03110 (PRCI Catalog L52290), Installation of Pipelines Using Horizontal Directional Drilling — An Engineering Design Guide (2008)

Publisher: Pipeline Research Council International (PRCI), 3141 Fairview Park Drive, Suite 525, Falls Church, VA 22042 (www.prci.org)

MANDATORY APPENDIX D SPECIFIED MINIMUM YIELD STRENGTH FOR STEEL PIPE COMMONLY USED IN PIPING SYSTEMS[1]

Table D-1 Specified Minimum Yield Strength for Steel Pipe Commonly Used in Piping Systems

Spec. No.	Grade	Type [Note (1)]	SMYS, psi (MPa)
API 5L [Note (2)]	A25	BW, ERW, S	25,000 (172)
API 5L [Note (2)]	A	ERW, S, DSA	30,000 (207)
API 5L [Note (2)]	B	ERW, S, DSA	35,000 (241)
API 5L [Note (2)]	×42	ERW, S, DSA	42,000 (290)
API 5L [Note (2)]	×46	ERW, S, DSA	46,000 (317)
API 5L [Note (2)]	×52	ERW, S, DSA	52,000 (359)
API 5L [Note (2)]	×56	ERW, S, DSA	56,000 (386)
API 5L [Note (2)]	×60	ERW, S, DSA	60,000 (414)
API 5L [Note (2)]	×65	ERW, S, DSA	65,000 (448)
API 5L [Note (2)]	×70	ERW, S, DSA	70,000 (483)
API 5L [Note (2)]	×80	ERW, S, DSA	80,000 (552)
ASTM A53	Type F	BW	25,000 (172)
ASTM A53	A	ERW, S	30,000 (207)
ASTM A53	B	ERW, S	35,000 (241)
ASTM A106	A	S	30,000 (207)
ASTM A106	B	S	35,000 (241)
ASTM A106	C	S	40,000 (276)
ASTM A134	. . .	EFW	[Note (3)]
ASTM A135	A	ERW	30,000 (207)
ASTM A135	B	ERW	35,000 (241)
ASTM A139	A	EFW	30,000 (207)
ASTM A139	B	EFW	35,000 (241)
ASTM A139	C	EFW	42,000 (290)
ASTM A139	D	EFW	46,000 (317)
ASTM A139	E	EFW	52,000 (359)
ASTM A333	1	S, ERW	30,000 (207)
ASTM A333	3	S, ERW	35,000 (241)
ASTM A333	4	S	35,000 (241)
ASTM A333	6	S, ERW	35,000 (241)
ASTM A333	7	S, ERW	35,000 (241)
ASTM A333	8	S, ERW	75,000 (517)
ASTM A333	9	S, ERW	46,000 (317)
ASTM A381	Class Y-35	DSA	35,000 (241)
ASTM A381	Class Y-42	DSA	42,000 (291)
ASTM A381	Class Y-46	DSA	46,000 (317)
ASTM A381	Class Y-48	DSA	48,000 (331)
ASTM A381	Class Y-50	DSA	50,000 (345)

[1] See para. 841.1.

Table D-1 Specified Minimum Yield Strength for Steel Pipe Commonly Used in Piping Systems (Cont'd)

Spec. No.	Grade	Type [Note (1)]	SMYS, psi (MPa)
ASTM A381	Class Y-52	DSA	52,000 (359)
ASTM A381	Class Y-56	DSA	56,000 (386)
ASTM A381	Class Y-60	DSA	60,000 (414)
ASTM A381	Class Y-65	DSA	65,000 (448)
ASTM A984	35	ERW	35,000 (241)
ASTM A984	50	ERW	50,000 (345)
ASTM A984	60	ERW	60,000 (414)
ASTM A984	70	ERW	70,000 (483)
ASTM A984	80	ERW	80,000 (552)
ASTM A1005	35	DSA	35,000 (241)
ASTM A1005	50	DSA	50,000 (345)
ASTM A1005	60	DSA	60,000 (414)
ASTM A1005	70	DSA	70,000 (483)
ASTM A1005	80	DSA	80,000 (552)
ASTM A1006	35	LW	35,000 (241)
ASTM A1006	50	LW	50,000 (345)
ASTM A1006	60	LW	60,000 (414)
ASTM A1006	70	LW	70,000 (483)
ASTM A1006	80	LW	80,000 (552)

GENERAL NOTE: This Table is not complete. For the minimum specified yield strength of other grades and grades in other approved specifications, refer to the particular specification.

NOTES:

(1) Abbreviations: BW = furnace buttwelded; DSA = double submerged-arc welded; EFW = electric fusion welded; ERW = electric resistance welded; LW = laser welded; S = seamless.

(2) Intermediate grades are available in API 5L.

(3) See applicable plate specification for SMYS.

(16)

Table D-2 HDB Values for Thermoplastic Materials

Plastic Pipe Material Designation (D2513 for PE and F2945 for PA-11)	HDB at 73°F, psi
PA 32312 (PA-11)	2,500
PA 32316 (PA-11)	3,150
PB 2110	2,000
PE 2406	1,250
PE 3408	1,600
PE 2606	1.250
PE 2706	1.250
PE 2708	1,250
PE 3608	1,600
PE 3708	1,600
PE 3710	1,600
PE 4708	1,600
PE 4710	1.600
PVC 1120	4,000
PVC 1220	4,000
PVC 2110	2,000
PVC 2116	3,150

GENERAL NOTES:

(a) *Long-Term Hydrostatic Strength Values for Thermoplastic Pipes Covered by ASTM D2513.* The values apply only to materials and pipes meeting all the requirements of the basic materials and ASTM D2513. They are based on engineering test data obtained in accordance with ASTM D1598 and analyzed in accordance with ASTM D2837. A list of commercial compounds meeting these requirements is published yearly by the Plastics Pipe Institute.

(b) *HDB Values for Reinforced Thermosetting Pipes Covered by ASTM D2517.* The value is established in accordance with ASTM D2517. In the absence of an established HDB, the value is 11,000 psi (75.8 MPa).

MANDATORY APPENDIX E
FLEXIBILITY AND STRESS INTENSIFICATION FACTORS

Table E-1 begins on the following page.

(16)

Table E-1 Flexibility Factor, k, and Stress Intensification Factor, i

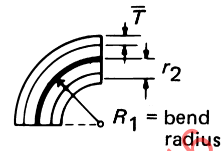
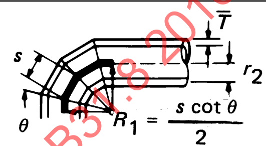
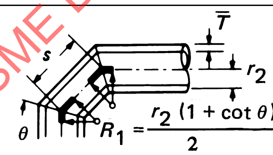
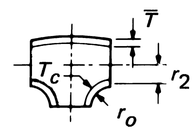
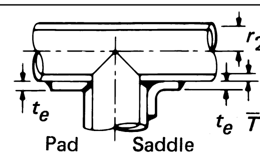
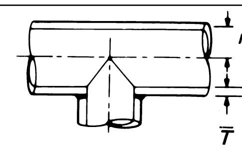
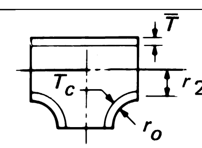
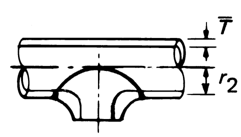
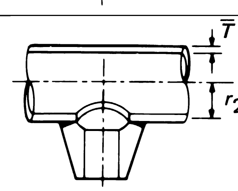
Description	Flexibility Factor, k	Stress Intensification Factor, i [Notes (1) and (2)] Out-Plane, i_o	In-Plane, i_i	Flexibility Characteristic, h	Sketch
Welding elbow or pipe bend [Notes (1)–(5)]	$\frac{1.65}{h}$	$\frac{0.75}{h^{2/3}}$	$\frac{0.9}{h^{2/3}}$	$\frac{\bar{T} R_1}{r_2^2}$	
Closely spaced miter bend [Notes (1), (2), (3), and (5)] $s < r_2 (1 + \tan \theta)$	$\frac{1.52}{h^{5/6}}$	$\frac{0.9}{h^{2/3}}$	$\frac{0.9}{h^{2/3}}$	$\frac{\cot \theta}{2} \frac{\bar{T}s}{r_2^2}$	
Single miter bend or widely spaced miter bend $s \geq r_2 (1 + \tan \theta)$ [Notes (1), (2), and (5)]	$\frac{1.52}{h^{5/6}}$	$\frac{0.9}{h^{2/3}}$	$\frac{0.9}{h^{2/3}}$	$\frac{1 + \cot \theta}{2} \frac{\bar{T}}{r_2}$	
Welding tee per ASME B16.9 with $r_o \geq d/8$ $T_c \geq 1.5\,\bar{T}$ [Notes (1), (2), and (6)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{3}{4} i_o + \frac{1}{4}$	$4.4 \frac{\bar{T}}{r_2}$	
Reinforced fabricated tee with pad or saddle [Notes (1), (2), (7)–(9)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{3}{4} i_o + \frac{1}{4}$	$\frac{(\bar{T} + \frac{1}{2} t_e)^{5/2}}{\bar{T}^{3/2} r_2}$	
Unreinforced fabricated tee [Notes (1), (2), and (9)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{3}{4} i_o + \frac{1}{4}$	$\frac{\bar{T}}{r_2}$	
Extruded outlet $r_o \geq 0.05d$ $T_c < 1.5\,\bar{T}$ [Notes (1), (2), and (6)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{3}{4} i_o + \frac{1}{4}$	$\left(1 + \frac{r_o}{r_2}\right) \frac{\bar{T}}{r_2}$	
Welded-in contour insert $r_o \geq d/8$ $T_c \geq 1.5\,\bar{T}$ [Notes (1), (2), and (10)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{3}{4} i_o + \frac{1}{4}$	$4.4 \frac{\bar{T}}{r_2}$	
Branch welded-on fitting (integrally reinforced) [Notes (1), (2), (9), and (11)]	1	$\frac{0.9}{h^{2/3}}$	$\frac{0.9}{h^{2/3}}$	$3.3 \frac{\bar{T}}{r_2}$	

Table E-1 Flexibility Factor, *k*, and Stress Intensification Factor, *i* (Cont'd)

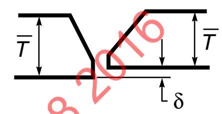
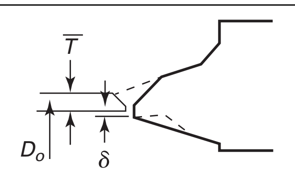
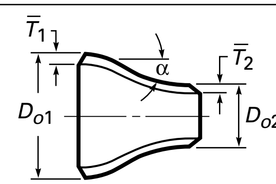
Description	Flexibility Factor, k	Stress Intensification Factor, i	Sketch
Butt weld [Notes (1) and (12)] $\bar{T} \geq 0.237$ in. (6.02 mm), $\delta_{max} \leq 1/16$ in. (1.59 mm), and $\delta_{avg}/\bar{T} \leq 0.13$	1	1.0	
Butt weld [Notes (1) and (12)] $\bar{T} \geq 0.237$ in. (6.02 mm), $\delta_{max} \leq 1/8$ in. (3.18 mm), and $\delta_{avg}/\bar{T}$ = any value	1	1.9 max. or $[0.9 + 2.7(\delta_{avg}/\bar{T})]$, but not less than 1.0	
Butt weld [Notes (1) and (12)] $\bar{T} \leq 0.237$ in. (6.02 mm), $\delta_{max} \leq 1/16$ in. (1.59 mm), and $\delta_{avg}/\bar{T} \leq 0.33$			
Tapered transition per ASME B16.25 [Note (1)]	1	1.9 max. or $1.3 + 0.0036\frac{D_o}{\bar{T}} + 3.6\frac{\delta}{\bar{T}}$	
Concentric reducer per ASME B16.9 [Notes (1) and (13)]	1	2.0 max. or $0.5 + 0.01\alpha\left(\frac{D_{o2}}{\bar{T}_2}\right)^{1/2}$	
Double-welded slip-on flange [Note (14)]	1	1.2	
Socket welding flange or fitting [Notes (14) and (15)]	1	2.1 max. or $2.1\ \bar{T}/C_x$ but not less than 1.3	
Lap joint flange (with ASME B16.9 lap joint stub) [Note (14)]	1	1.6	
Threaded pipe joint or threaded flange [Note (14)]	1	2.3	
Corrugated straight pipe, or corrugated or creased bend [Note (16)]	5	2.5	

Table E-1 Flexibility Factor, k, and Stress Intensification Factor, i (Cont'd)

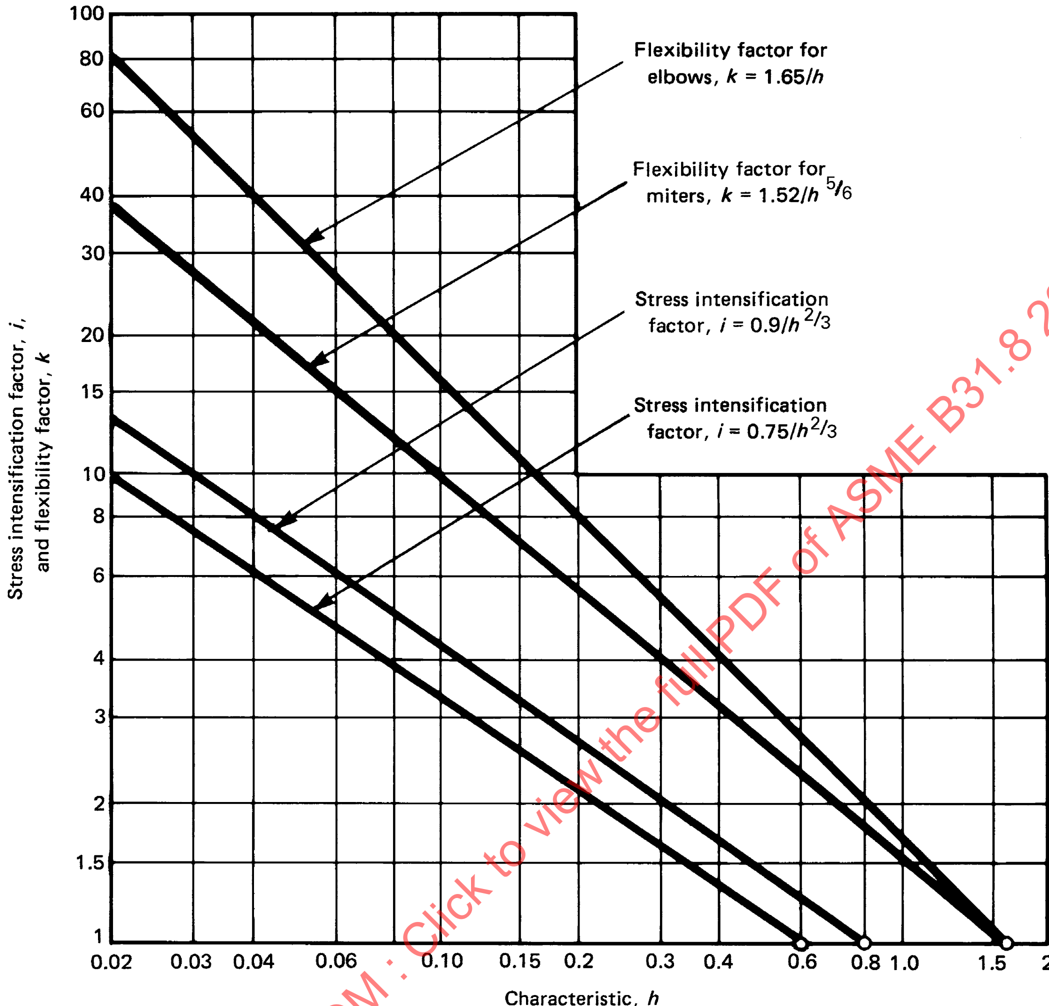


Chart A

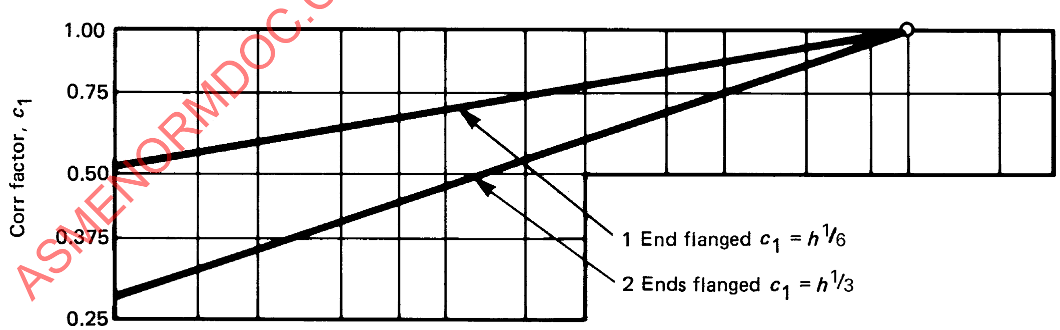


Chart B

Table E-1 Flexibility Factor, k, and Stress Intensification Factor, i (Cont'd)

NOTES:

(1) The nomenclature is as follows:

D_o = outside diameter, in. (mm)
d = outside diameter of branch, in. (mm)
R_1 = bend radius of welding elbow or pipe bend, in. (mm)
r_o = radius of curvature of external contoured portion of outlet, measured in the plane containing the axes of the header and branch, in. (mm)
r_2 = mean radius of matching pipe, in. (mm)
s = miter spacing at centerline, in. (mm)
$\bar{T}$ = nominal wall thickness of piping component, in. (mm)
= for elbows and miter bends, the nominal wall thickness of the fitting, in. (mm)
= for welding tees, the nominal wall thickness of the matching pipe, in. (mm)
= for fabricated tees, the nominal wall thickness of the run or header (provided that if thickness is greater than that of matching pipe, increased thickness must be maintained for at least one run outside diameter to each side of the branch outside diameter), in. (mm)
T_c = the crotch thickness of tees, in. (mm)
t_e = pad or saddle thickness, in. (mm)
α = reducer cone angle, deg
δ = mismatch, in. (mm)
θ = one-half angle between adjacent miter axes, deg

(2) The flexibility factor, k, applies to bending in any plane. The flexibility factors, k, and stress intensification factors, i, shall not be less than unity; factors for torsion equal unity. Both factors apply over the effective arc length (shown by heavy centerlines in the sketches) for curved and miter bends and to the intersection point for tees.

The values of k and i can be read directly from Chart A by entering with the characteristic, h, computed from the formulas given.

(3) Where flanges are attached to one or both ends, the values of k and i shall be corrected by the factors, C_u, which can be read directly from Chart B, entering with the computed h.

(4) The designer is cautioned that cast buttwelded fittings may have considerably heavier walls than that of the pipe with which they are used. Large errors may be introduced unless the effect of these greater thicknesses is considered.

(5) In large diameter thin-wall elbows and bends, pressure can significantly affect the magnitudes of k and i. To correct values from the table, divide k by

$$\left[1 + 6\left(\frac{P}{E_e}\right)\left(\frac{r_2}{\bar{T}}\right)^{7/3}\left(\frac{R_1}{r_2}\right)^{1/3}\right]$$

divide i by

$$\left[1 + 3.25\left(\frac{P}{E_e}\right)\left(\frac{r_2}{\bar{T}}\right)^{5/2}\left(\frac{R_1}{r_2}\right)^{2/3}\right]$$

where
E_e = cold modulus of elasticity, psi (MPa)
P = gage pressure, psi (MPa)

(6) If the number of displacement cycles is less than 200, the radius and thickness limits specified need not be met. When the radius and thickness limits are not met and the number of design cycles exceeds 200, the out-plane and in-plane stress intensification factors shall be calculated as $1.12/h^{2/3}$ and $(0.67/h^{2/3}) + \frac{1}{4}$, respectively.

(7) When $t_e > 1\frac{1}{2}\bar{T}$, use $h = 4.05\bar{T}/r_2$.

(8) The minimum value of the stress intensification factor shall be 1.2.

(9) When the branch-to-run diameter ratio exceeds 0.5, but is less than 1.0, and the number of design displacement cycles exceeds 200, the out-plane and in-plane stress intensification factors shall be calculated as $1.8/h^{2/3}$ and $(0.67/h^{2/3}) + \frac{1}{4}$, respectively, unless the transition weld between the branch and run is blended to a smooth concave contour. If the transition weld is blended to a smooth concave contour, the stress intensification factors in the table still apply.

(10) If the number of displacement cycles is less than 200, the radius and thickness limits specified need not be met. When the radius and thickness limits are not met and the number of design displacement cycles exceeds 200, the out-plane and in-plane stress intensification factors shall be calculated as $1.8/h^{2/3}$ and $(0.67/h^{2/3}) + \frac{1}{4}$, respectively.

(11) The designer must be satisfied that this fabrication has a pressure rating equivalent to straight pipe.

(12) The stress intensification factors apply to girth butt welds between two items for which the wall thicknesses are between $0.875\bar{T}$ and $1.10\bar{T}$ for an axial distance of $\sqrt{D_o\bar{T}}$. D_o and $\bar{T}$ are nominal outside diameter and nominal wall thickness, respectively. δ_{avg} is the average mismatch or offset.

Table E-1 Flexibility Factor, *k*, and Stress Intensification Factor, *i* (Cont'd)

NOTES (Cont'd):

(13) The equation applies only if the following conditions are met.

(a) Cone angle α does not exceed 60 deg, and the reducer is concentric.

(b) The larger of $D_{o1}/\overline{T}$ and $D_{o2}/\overline{T}$ does not exceed 100.

(c) The wall thickness is not less than $\overline{T}_1$ throughout the body of the reducer, except in and immediately adjacent to the cylindrical portion on the small end, where the thickness shall not be less than $\overline{T}_2$.

(14) For some flanged joints, leakage may occur at expansion stresses otherwise permitted herein. The moment to produce leakage of a flanged joint with a gasket having no self-sealing characteristics can be estimated by the following equation:

$$M_L = (C/4)\ (S_b\, A_b - PA_p)$$

A_b = total area of flange bolts, in.^{2} (mm^3)
A_p = area to outside of gasket contact, in.^{2} (mm^2)
C = bolt circle, in. (mm)
M_L = moment to produce flange leakage, in.-lb (mm·N)
P = internal pressure, psi (MPa)
S_b = bolt stress, psi (MPa)

(15) C_x is the fillet weld length. For unequal lengths, use the smaller leg for C_x.

(16) Factors shown apply to bending. Flexibility factor for torsion equals 0.9.

MANDATORY APPENDIX F
EXTRUDED HEADERS AND WELDED BRANCH CONNECTIONS[1]

F-1 EXTRUDED HEADERS

Definitions and limitations applicable to Figs. F-1 through F-4 are as follows:

D = outside diameter of run, in. (mm)

D_c = corroded internal diameter of run, in. (mm)

D_o = corroded internal diameter of extruded outlet measured at the level of the outside surface of run, in. (mm)

d = outside diameter of branch pipe, in. (mm)

d_c = corroded internal diameter of branch pipe, in. (mm)

h_o = height of the extruded lip. This must be equal to or greater than r_o, except as shown in limitation (b) of r_o below, in. (mm).

L = height of the reinforcement zone, in. (mm)
$= 0.7\sqrt{dT_0}$

r_1 = half width of reinforcement zone (equal to D_o), in. (mm)

r_o = radius of curvature of external contoured portion of outlet measured in the plane containing the axes of the run and branch, in. (mm). This is subject to the following limitations:

(a) Minimum Radius. This dimension shall not be less than 0.05d, except that on branch diameters larger than 30 in. (762 mm), it need not exceed 1.50 in. (38.1 mm).

(b) Maximum Radius. For outlet pipe sizes NPS 8 (DN 200) and larger, this dimension shall not exceed 0.10d + 0.50 in. (0.10d + 12.7 mm). For outlet pipe sizes smaller than NPS 8 (DN 200), this dimension shall not be greater than 1.25 in. (31.75 mm).

(c) When the external contour contains more than one radius, the radius on any arc sector of approximately 45 deg shall meet the requirements of (a) and (b) above.

(d) Machining shall not be employed to meet the above requirements.

T_b = actual thickness of branch wall, not including corrosion allowance, in. (mm)

T_o = corroded finished thickness of extruded outlet measured at a height equal to r_o above the outside surface of the run, in. (mm)

T_r = actual thickness of the run wall, not including the corrosion allowance, in. (mm)

t_b = required thickness of branch pipe according to the steel pipe design formula of para. 841.1.1, but not including any thickness for corrosion, in. (mm)

t_r = required thickness of the run according to the steel pipe design formula para. 841.1.1, but not including any allowance for corrosion or under-thickness tolerance, in. (mm)

F-2 EXAMPLES ILLUSTRATING THE APPLICATION OF THE RULES FOR REINFORCEMENT OF WELDED BRANCH CONNECTIONS

F-2.1 Example 1 (16)

An NPS 8 outlet is welded to an NPS 24 header. The header material is API 5LX 46 with a 0.312-in. wall. The outlet is API 5L Grade B (Seamless) Schedule 40 with a 0.322-in. wall. The working pressure is 650 psig. The fabrication is in Location Class 1. Using para. 841.1, the joint efficiency is 1.00. The temperature is 100°F. Design

Fig. F-1

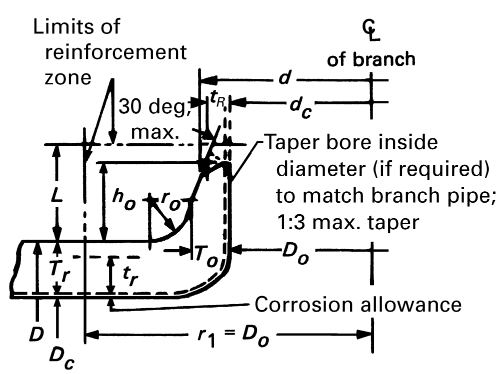
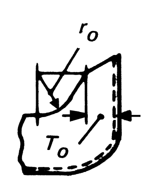


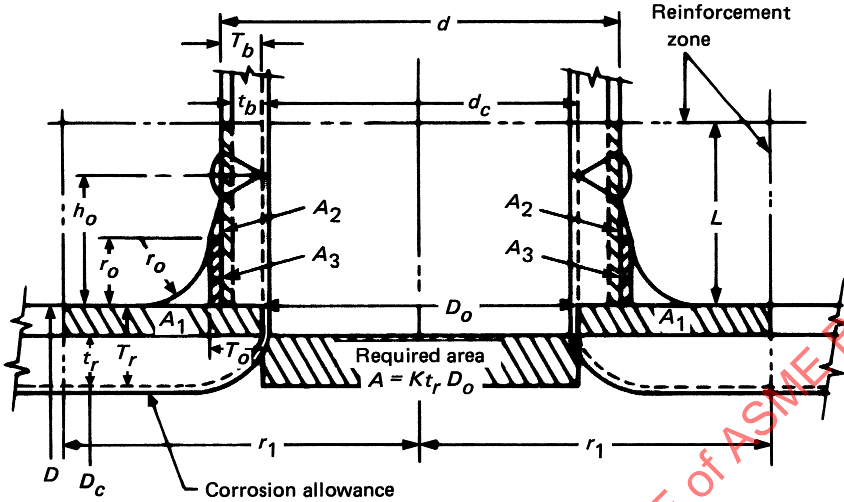
Fig. F-2



GENERAL NOTE: Sketch to show method of establishing T_o when the taper encroaches on the crotch radius.

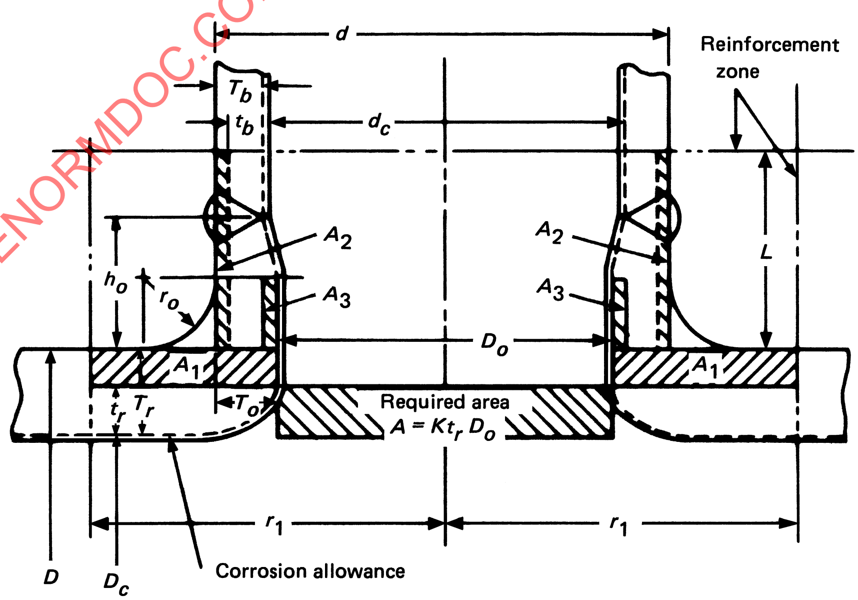
[1] See para. 831.6.

Fig. F-3



GENERAL NOTE: Sketch is drawn for condition where $K = 1.00$.

Fig. F-4



GENERAL NOTE: Sketch is drawn for condition where $K = 1.00$.

factors $F = 0.60$, $E = 1.00$, and $T = 1.00$. For dimensions, see Fig. F-6.

F-2.1.1 Header. Nominal wall thickness required:

$$t = \frac{PD}{2\,SFET} = \frac{650 \times 24}{2 \times 46{,}000 \times 0.60 \times 1.00 \times 1.00} = 0.283 \text{ in.}$$

Excess thickness in header wall:

$$H - t = 0.312 - 0.283 = 0.029 \text{ in.}$$

F-2.1.2 Outlet. Nominal wall thickness required:

$$t_b = \frac{650 \times 8.625}{2 \times 35{,}000 \times 0.60 \times 1.00 \times 1.00} = 0.133 \text{ in.}$$

Excess thickness in outlet wall:

$$B - t_b = 0.322 - 0.133 = 0.189 \text{ in.}$$

$$d = \text{inside diameter of opening} = 8.625 - 2 \times 0.322 = 7.981 \text{ in.}$$

F-2.1.3 Reinforcement Required

$$A_R = dt = 7.981 \times 0.283 = 2.259 \text{ in.}^2$$

F-2.1.4 Reinforcement Provided by Header

$$A_1 = (H - t)\,d = 0.029 \times 7.981 = 0.231 \text{ in.}^2$$

(16) **F-2.1.5 Effective Area in Outlet**

$$\text{Height } L = 2^1/_2\,B + M \text{ (assume } ^1/_4\text{-in. pad)} = (2^1/_2 \times 0.322) + 0.25 = 1.055 \text{ in.}$$

or $L = 2^1/_2 H = 2.5 \times 0.312 = 0.780$ in. Use $L = 0.780$ in.

$$A_2 = 2\,(B - t_b)\,L = 2 \times 0.189 \times 0.780 = 0.295 \text{ in.}^2$$

This must be multiplied by 35,000/46,000 [see para. 831.4.1(f)].

$$\text{Effective } A'_2 = 0.295 \times \frac{35{,}000}{46{,}000} = 0.224 \text{ in.}^2$$

Required area:

$$A_3 = A_R - A_1 - A'_2 = 2.259 - 0.231 - 0.224 = 1.804 \text{ in.}^2$$

Use a reinforced plate that is 0.250 in. thick (minimum practicable) × 15.5 in. in diameter.

$$\text{Area} = (15.500 - 8.625) \times 0.250 = 1.719 \text{ in.}^2$$

Fillet welds (assuming two $^1/_4$-in. welds each side):

$$^1/_2\,(0.25 \times 0.25) \times 4 = 0.125 \text{ in.}^2$$

Total A_3 provided $= 1.844$ in.^{2}
See also Fig. F-5.

F-2.1M Example 1M (16)

A DN 200 outlet is welded to a DN 600 header. The header material is 317.2 MPa with a 7.92-mm wall. The outlet is 241.3 MPa (Seamless) with a 8.18 mm wall. The working pressure is 4.48 MPa. The fabrication is in Location Class 1. Using para. 841.1, the joint efficiency is 1.00. The temperature is 37.8°C. Design factors $F = 0.60$, $E = 1.00$, and $T = 1.00$. For dimensions, see Fig. F-6.

F-2.1.1M Header. Nominal wall thickness required:

$$t = \frac{PD}{2SFET} = \frac{4.48 \times 609.6}{2 \times 317.16 \times 0.60 \times 1.00 \times 1.00} = 7.178 \text{ mm}$$

Excess thickness in header wall:

$$H - t = 7.925 - 7.178 = 0.747 \text{ mm}$$

F-2.1.2M Outlet. Nominal wall thickness required:

$$t_b = \frac{4.48 \times 219.1}{2 \times 241.32 \times 0.60 \times 1.00 \times 1.00} = 3.390 \text{ mm}$$

Excess thickness in outlet wall:

$$B - t_b = 8.179 - 3.390 = 4.788 \text{ mm}$$

$$d = \text{inside diameter of opening} = 219.08 - 2 \times 8.179 = 202.72 \text{ mm}$$

F-2.1.3M Reinforcement Required

$$A_R = dt = 202.72 \times 7.178 = 1\,455.2 \text{ mm}^2$$

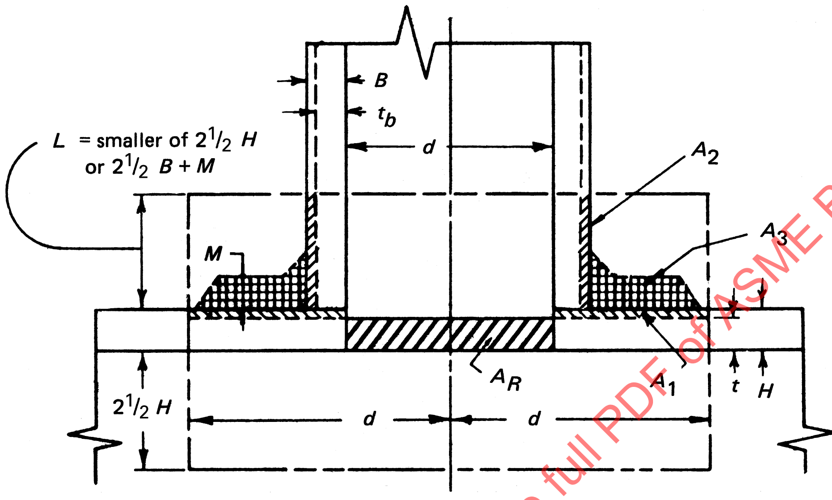
F-2.1.4M Reinforcement Provided by Header

$$A_1 = (H - t)\,d = 0.747 \times 202.72 = 151.34 \text{ mm}^2$$

F-2.1.5M Effective Area in Outlet (16)

$$\text{Height } L = 2^1/_2\,B + M \text{ (assume 6.35 mm pad)} = (2^1/_2 \times 8.179) + 6.35 = 26.797 \text{ mm}$$

Fig. F-5 Rules for Reinforcement of Welded Branch Connections

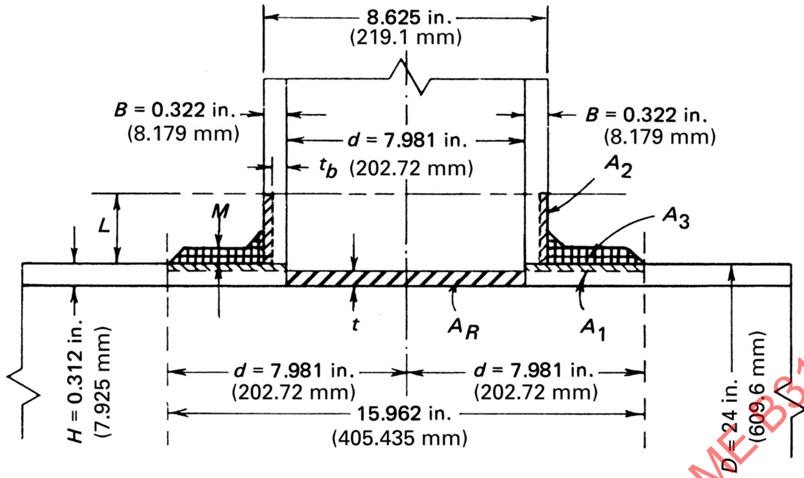


Area of reinforcement enclosed by ——— — — ——— lines.
Reinforcement area required $A_R = dt$
Area available as reinforcement = $A_1 + A_2 + A_3$

$A_1 = (H - t)\ (d)$ (If negative, use zero for value of A_1)
$A_2 = 2(B - t_b)L$
A_3 = summation of area of all added reinforcement, including weld areas that lie within the area of reinforcement
$A_1 + A_2 + A_3$ must be equal to or greater than A_R
where

B = nominal wall thickness of branch
d = the greater of the length of the finished opening in the header wall measured parallel to the axis of the run or the inside diameter of the branch connection
H = nominal wall thickness of header
M = actual (by measurement) or nominal thickness of added reinforcement
t = required nominal wall thickness of the header (under the appropriate section of this Code)
t_b = required nominal wall thickness of the branch (under the appropriate section of this Code)

Fig. F-6



or $L = 2^1/_2 H = 2.5 \times 7.92 = 19.812$ mm. Use $L = 19.812$ mm

$$A_2 = 2\,(B - t_b)\,L = 2 \times 4.788 \times 19.812 = 189.73 \text{ mm}^2$$

This must be multiplied by 241.3/317.2 [see para. 831.4.1(f)].

$$\text{Effective } A'_2 = 189.73 \times \frac{241.3}{317.2} = 144.36 \text{ mm}^2$$

Required area:

$$A_3 = A_R - A_1 - A'_2 = 1\,455.2 - 151.34 - 144.36 = 1\,159.5 \text{ mm}^2$$

Use a reinforced plate that is 6.35 mm thick (minimum practicable) × 393.7 mm in diameter.

$$\text{Area} = (393.7 - 219.1) \times 6.35 = 1\,108.9 \text{ mm}^2$$

Fillet welds (assuming two 6.35 mm welds each side):

$$^1/_2\,(6.35 \times 6.35) \times 4 = 80.65 \text{ mm}^2$$

Total A_3 provided $= 1\,189.5$ mm^2
See also Fig. F-5.

F-2.2 Example 2

An NPS 16 outlet is welded to an NPS 24 header. The header material is API 5LX 46 with a 0.312-in. wall. The outlet is API 5L Grade B (Seamless) Schedule 20 with a 0.312-in. wall. The working pressure is 650 psig. The fabrication is in Location Class 1. By para. 831.4.2, the reinforcement must be of the complete encirclement type. Using para. 841.1, the joint efficiency is 1.00. The temperature is 100°F. Design factors $F = 0.60$, $E = 1.00$, and $T = 1.00$. For dimensions, see Fig. F-7.

F-2.2.1 Header. Nominal wall thickness required:

$$t = \frac{PD}{2\,SFET} = \frac{650 \times 24}{2 \times 46{,}000 \times 0.60 \times 1.00 \times 1.00} = 0.283 \text{ in.}$$

Excess thickness in header wall:

$$H - t = 0.312 - 0.283 = 0.029 \text{ in.}$$

F-2.2.2 Outlet. Nominal wall thickness required:

$$t_b = \frac{650 \times 16}{2 \times 35{,}000 \times 0.60 \times 1.00 \times 1.00} = 0.248 \text{ in.}$$

Excess thickness in outlet wall:

$$B - t_b = 0.312 - 0.248 = 0.064 \text{ in.}$$

d = inside diameter of opening $= 16.000 - 2 \times 0.312 = 15.376$ in.

F-2.2.3 Reinforcement Required

$$A_R = dt = 15.376 \times 0.283 = 4.351 \text{ in.}^2$$

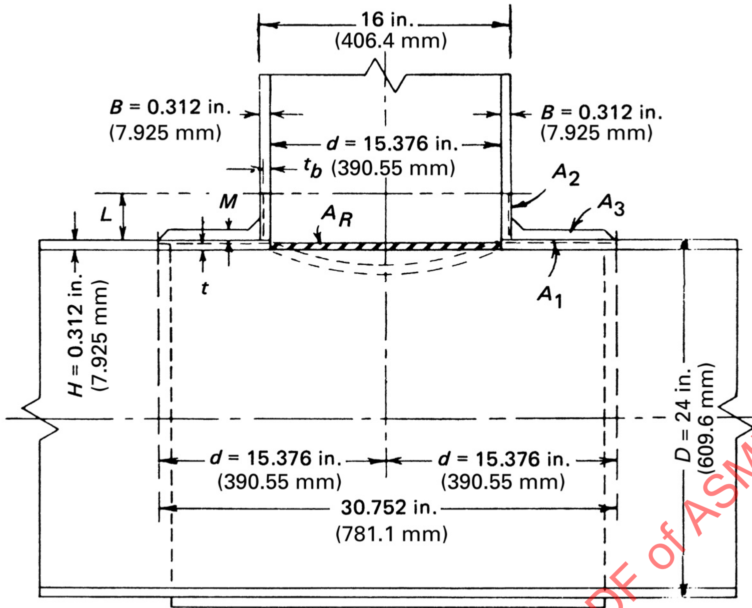
F-2.2.4 Reinforcement Provided

$$A_1 = (H - t)\,d = 0.029 \times 15.376 = 0.446 \text{ in.}^2$$

F-2.2.5 Effective Area in Outlet

$$\text{Height } L = 2^1/_2\,B + M \text{ (assume } ^5/_{16}\text{-in. plate)} = (2.5 \times 0.312) + 0.312 = 1.092 \text{ in.}$$

Fig. F-7



or

$L = 2^1/_2H = 2.5 \times 0.312 = 0.780$ in. Use $L = 0.780$ in.

$$A_2 = 2\ (B - t_b)\ L = 2 \times 0.064 \times 0.780 = 0.100 \text{ in.}^2$$

This must be multiplied by 35,000/46,000 [see para. 831.4.1(f)].

$$\text{Effective } A'_2 = 0.100 \times 35{,}000/46{,}000 = 0.076 \text{ in.}^2$$

Required area:

$$A_3 = A_R - A_1 - A'_2 = 4.351 - 0.446 - 0.076 = 3.829 \text{ in.}^2$$

Approximate required thickness of reinforcement:

$$3.829 \div (30 - 16) = 0.274 \text{ in.}$$

Use a 0.312-in. plate minimum required length (neglecting welds):

$$3.829 \div 0.312 = 12.272 \text{ in.}$$

$16 + 12.272 = 29$ in. (rounded to the next higher whole number)

Use a plate that is 29 in. long:

$$\text{Area} = 0.312 \times (29 - 16) = 4.056 \text{ in.}^2$$

Two ¼-in. welds to outlet:

$$^1/_2 \times (0.25 \times 0.25) \times 2 = 0.063 \text{ in.}^2$$

$$\text{Total } A_3 \text{ provided} = 4.119 \text{ in.}^2$$

The use of end welds is optional (see Fig. I-3).

F-2.2M Example 2M

A DN 400 outlet is welded to an DN 600 header. The header material is 317.2 MPa with a 7.92 mm wall. The outlet is 241.3 MPa (Seamless) with a 7.92 mm wall. The working pressure is 4.48 MPa. The fabrication is in Location Class 1. By para. 841.4.2, the reinforcement must be of the complete encirclement type. Using para. 841.1, the joint efficiency is 1.00. The temperature is 37.8°C. Design factors $F = 0.60$, $E = 1.00$, and $T = 1.00$. For dimensions, see Fig. F-7.

F-2.2.1M Header. Nominal wall thickness required:

$$t = \frac{PD}{2\ SFET} = \frac{4.48 \times 609.6}{2 \times 317.16 \times 0.60 \times 1.00 \times 1.00} = 7.178 \text{ mm}$$

Excess thickness in header wall:

$$H - t = 7.925 - 7.178 = 0.747 \text{ mm}$$

F-2.2.2M Outlet. Nominal wall thickness required:

$$t_b = \frac{4.48 \times 406.4}{2 \times 241.32 \times 0.60 \times 1.00 \times 1.00} = 6.290 \text{ mm}$$

Excess thickness in outlet wall:

$$B - t_b = 7.925 - 6.290 = 1.635 \text{ mm}$$

d = inside diameter of opening $= 406.4 - 2 \times 7.925 = 390.55$ mm

F-2.2.3M Reinforcement Required

$$A_R = dt = 390.55 \times 7.178 = 2\,803.5 \text{ mm}^2$$

F-2.2.4M Reinforcement Provided

$$A_1 = (H - t)\, d = 0.747 \times 390.55 = 291.56 \text{ mm}^2$$

F-2.2.5M Effective Area in Outlet

$$\begin{aligned} \text{Height } L &= 2^1/_2\, B + M \text{ (assume 7.94 mm plate)} \\ &= (2.5 \times 7.92) + 7.94 = 27.75 \text{ mm} \end{aligned}$$

or

$$L = 2^1/_2 H = 2.5 \times 7.92 = 19.812 \text{ mm. Use } L = 19.812 \text{ in.}$$

$$\begin{aligned} A_2 &= 2\,(B - t_b)\, L = 2 \times 1.635 \times 19.812 \\ &= 64.80 \text{ mm}^2 \end{aligned}$$

This must be multiplied by 241.3/317.2 [see para. 831.4.1(f)].

$$\text{Effective } A'_2 = 64.80 \times 241.3/317.2 = 49.30 \text{ mm}^2$$

Required area:

$$\begin{aligned} A_3 &= A_R - A_1 - A'_2 \\ &= 2\,803.5 - 291.56 - 49.30 = 2\,462.6 \text{ mm}^2 \end{aligned}$$

Approximate required thickness of reinforcement:

$$2\,462.6 \div (762 - 406.4) = 6.925 \text{ mm}$$

Use a 7.92 mm plate minimum required length (neglecting welds):

$$2\,462.6 \div 7.92 = 310.75 \text{ mm}$$

$$406.4 + 310.75 = 736.6 \text{ mm}$$ (rounded to the next higher whole number in customary units, i.e., equivalent to 29 in.)

Use a plate that is 736.6 mm long:

$$\text{Area} = 7.92 \times (736.6 - 406.4) = 2\,616.8 \text{ mm}^2$$

Two 6.35 mm welds to outlet:

$$^1/_2 \times (0.25 \times 0.25) \times 2 = 40.32 \text{ mm}^2$$

$$\text{Total } A_3 \text{ provided} = 2\,657.1 \text{ mm}^2$$

The use of end welds is optional (see Fig. I-3).

MANDATORY APPENDIX G
TESTING OF WELDERS LIMITED TO WORK ON LINES OPERATING AT HOOP STRESSES OF LESS THAN 20% OF THE SPECIFIED MINIMUM YIELD STRENGTH[1]

G-1 TEST PROCEDURES

(a) An initial test shall qualify a welder for work. Thereafter, the welder's work shall be checked either by requalification at 1-yr intervals or by cutting out and testing production work at least every 6 months.

(b) The test may be made on pipe of any diameter NPS 12 (DN 300) or smaller. The test weld shall be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding.

(c) The beveling, root opening, and other details must conform to the procedure specification under which the welder is qualified.

(d) The test weld shall be cut into four coupons and subjected to the root bend test. If as a result of this test, a crack develops in the weld material or between the weld and base metal more than $\frac{1}{8}$ in. (3.2 mm) long in any direction, this shall be cause for rejection. Cracks occurring on the corner of the specimen during testing shall not be considered. If not more than one coupon is rejected, the weld is to be considered acceptable.

(e) Welders who are to make welded service line connections to mains shall be required to pass the following tests satisfactorily:

(1) Weld a service line connection fitting to a pipe section having the same diameter as a typical main. This weld shall be made in the same position as this type of weld is made in the field.

(2) The weld shall be tested by attempting to break the fitting off the run pipe by any available means (knocking it off).

A sample shall be rejected if the broken weld at the junction of the fitting and run pipe shows incomplete fusion, overlap, or poor penetration.

(f) For the periodic checking of welders who work on small service lines only [NPS 2 (DN 50) or smaller in diameter], the following special field test may be employed. This test should not be used as a substitute for the original qualifying test.

Two sample welds made by the welder under test shall be taken from steel service line. Each sample shall be cut 8 in. (200 mm) long with the weld located approximately in the center. One sample shall have the ends flattened and the entire joint subjected to the tensile strength test. Failure must be in the parent metal and not adjacent to or in the weld metal to be acceptable. The second sample shall be centered in the guided bend testing machine and bent to the contour of the die for a distance of 2 in. (50 mm) on each side of the weld. The sample to be acceptable must show no breaks or cracks after removal from the bending machine.

When a tensile strength testing machine is not available, two bend test samples will be acceptable in lieu of one tension and one bending test.

(g) Tests for Copper Joints. Personnel who are to work on copper piping should pass the following test satisfactorily.

A brazed or soldered copper bell joint should be made on any size of copper pipe used, with the axis of the pipe stationary in the horizontal position. The joint so welded is to be sawed open longitudinally at the top of the pipe (the top being the uppermost point on the circumstance at time joint is brazed). The joint should be spread apart for examination. The bell end of the joint must be completely bonded. The spigot end of the joint must give evidence that the brazing alloy has reached at least 75% of the total area of the telescoped surfaces. At least 50% of the length at the top of the joint must be joined.

(h) Records shall be kept of the original tests and all subsequent tests conducted on the work of each welder.

[1] See para. 823.1.

MANDATORY APPENDIX H
FLATTENING TEST FOR PIPE[1]

H-1 TEST PROCEDURES

(a) The flattening test shall be made on standard weight and extra strong pipe over NPS 2 (DN 50). It shall not be required for double extra strong pipe.

(b) For a lap-welded and buttwelded pipe, the test section shall be 4 in. to 6 in. (100 mm to 150 mm) in length, and the weld shall be located 45 deg from the line of direction of the applied force.

(c) For electric-resistance welded pipe, both crop ends from each length of pipe shall be flattened between parallel plates with the weld at the point of maximum bending until the opposite walls of the pipe meet. No opening in the weld shall take place until the distance between the plates is less than two-thirds of the original outside diameter of the pipe. No cracks or breaks in the metal other than in the weld shall occur until the distance between the plates is less than one-third of the original outside diameter of the pipe, but in no case less than five times the thickness of the pipe wall. Evidence of lamination or burnt material shall not develop during the entire flattening process, and the weld shall not show injurious defects.

(d) For seamless pipe the test section shall be not less than 2½ in. (64 mm) in length.

(e) The test shall consist of flattening a section of pipe between parallel plates until the opposite walls meet. For welded pipe, no opening in the weld shall take place until the distance between the plates is less than three-fourths of the original outside diameter for buttwelded pipe, and two-thirds of the outside diameter for lap-welded and electric-resistance welded pipes. No cracks or breaks in the metal other than in the weld shall occur until the distance between the plates is less than three-fifths of the outside diameter for buttwelded pipe, and one-third of the outside diameter for lap-welded and electric-resistance welded (Grades A and B) pipes. For seamless (Grades A and B) pipe, no breaks or cracks in the metal shall occur until the distance between the plates is less than that shown below:

$$H = \frac{(1 + e)\,t}{e + t/D}$$

where

D = actual outside diameter of pipes, in. [2.375 in. (60.33 mm) nominal]

e = deformation per unit length (constant for a given grade of steel, 0.09 for Grade A and 0.07 for Grade B)

H = distance between flattening plates, in. (mm)

t = nominal wall thickness of pipe, in. (mm)

[1] See para. 817.1.3(b).

MANDATORY APPENDIX I
END PREPARATIONS FOR BUTTWELDING

I-1 EXPLANATORY NOTES

I-1.1 General

This Mandatory Appendix applies to end preparation for buttwelding sections having unequal thicknesses and unequal specified minimum yield strengths (see Figs. I-1 through I-4).

(a) The sketches in Fig. I-5 illustrate acceptable preparations for joining pipe ends by buttwelding for materials having unequal wall thicknesses and/or with unequal strengths (specified minimum yield strength).

(b) The thickness of the sections to be joined beyond the joint design area shall comply with the design requirements of this Code.

(c) When the specified minimum yield strengths of the sections to be joined are unequal, the deposited weld metal shall have mechanical properties at least equal to those of the section having the higher strength.

(d) The transition between ends of unequal thickness may be accomplished by taper or welding as illustrated or by means of a prefabricated transition ring.

(e) Sharp notches or grooves at the edge of the weld where it joins a slanted surface shall be avoided.

(f) For joining unequal thicknesses of equal specified minimum yield strengths, the rules given herein apply, except there is no minimum angle limit to the taper.

(g) The maximum thickness, t_D, for design purposes shall not be greater than 1.5t.

I-1.2 Unequal Internal Diameters

(a) For piping to operate at hoop stresses of less than 20% of specified minimum yield strength, if the nominal wall thicknesses of the adjoining ends do not vary more than $\frac{1}{8}$ in. (3.2 mm), no special treatment is necessary provided adequate penetration and bond is accomplished in welding. If the offset is greater than $\frac{1}{8}$ in. (3.2 mm), the following paragraphs will apply.

(b) For Hoop Stress Levels 20% or More of the Specified Minimum Yield Strength

(1) If the nominal wall thickness of the adjoining ends does not vary more than $\frac{3}{32}$ in. (2.38 mm), no special treatment is necessary, provided full penetration and bond is accomplished in welding. See sketch (a) of Fig. I-5.

(2) Where the nominal internal offset is greater than $\frac{3}{32}$ in. (2.38 mm) and there is no access to the inside of the pipe for welding, the transition must be made by a taper cut on the inside end of the thicker section. See sketch (b) of Fig. I-5. The taper angle shall be not greater than 30 deg nor less than 14 deg.

(3) Where the nominal internal offset is more than $\frac{3}{32}$ in. (2.38 mm) but does not exceed one-half the thinner section, and there is access to the inside of the pipe for welding, the transition may be made with a tapered weld as shown in sketch (c) of Fig. I-5. The land on the thicker section must be equal to the offset plus the land on abutting section.

(4) Where the nominal internal offset is more than one-half the thinner section and there is access to the inside of the pipe for welding, the transition may be made with a taper cut on the inside end of the thicker section as shown in sketch (b) of Fig. I-5, or by a combination taper weld to one-half the thinner section and a taper cut from that point as shown in sketch (d) of Fig. I-5.

I-1.3 Unequal External Diameters

(a) Where the external offset does not exceed one-half the thinner section, the transition may be made by welding as shown by sketch (e) of Fig. I-5, provided the angle of rise of the weld surface does not exceed 30 deg and both bevel edges are properly fused.

(b) Where there is an external offset exceeding one-half the thinner section, that portion of the offset over $\frac{1}{2}t$ shall be tapered as shown in sketch (f) of Fig. I-5.

I-1.4 Unequal Internal and External Diameters

Where there is both an internal and an external offset, the joint design shall be a combination of sketches (a) through (f) of Fig. I-5, i.e., sketch (g). Particular attention must be paid to proper alignment under these conditions. See also Fig. I-6 and Tables I-1 and I-1M.