

Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems

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API RECOMMENDED PRACTICE FOR DESIGN AND INSTALLATION OF OFFSHORE PRODUCTION PLATFORM PIPING SYSTEMS

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FOREWORD

- a. This recommended practice (RP) is under the jurisdiction of the American Petroleum Institute (API) Committee on Standardization of Offshore Safety and Anti-Pollution Equipment. It has been prepared with the overall advisory guidance of the API, Offshore Operators Committee (OOC), and the Western Oil and Gas Association (WOGA). Corrosion related sections were prepared with the assistance of the National Association of Corrosion Engineers (NACE).
- b. This RP contains information for use primarily by design engineers with a working knowledge of production platform operations. Some of the information may be useful to experienced operating personnel. Nothing in this RP is to be construed as a fixed rule without regard to sound engineering judgement nor is it intended to supercede or override any federal, state, or local regulation where applicable.
- c. Conversion of English units to International System (SI) metric units has been omitted to add clarity to graphs and empirical formulas. Factors that may be used for conversion of English units to SI units were taken from API Publication 2564, and are listed below:

LENGTH

1 inch (in.) = 25.4 millimetres (mm) exactly

PRESSURE

1 pound per square inch (psi) = 0.06894757 Bar

NOTE: 1 Bar = 100 kilopascals (kPa)

STRENGTH OR STRESS

1 pound per square inch (psi) = 0.006894757 Megapascals (MPa)

IMPACT ENERGY

1 foot-pound (ft-lb) = 1.355818 Joules (J)

TORQUE

1 foot-pound (ft-lb) = 1.355818 newton-metres (N·m)

TEMPERATURE

The following formula was used to convert degrees Fahrenheit (F) to degrees Celsius (C):

$C = 5/9 (F - 32)$

VOLUME

1 Cubic Foot (cu ft) = 0.02831685 Cubic Metre (m³)
 1 Gallon (gal) = 0.003785412 Cubic Metre (m³)
 1 Barrel (bbl) = 0.1589873 Cubic Metre (m³)

WEIGHT

1 pound (lb) = 0.4535924 Kilograms (kg)

FORCE

1 pound (lb) = 4.448222 Newtons (N)

FLOW RATE

1 Barrel per day (BPD) = 0.1589873 Cubic Metres per day (m³/d)
 1 Cubic foot per min (CFM) = 40.77626 Cubic Metres per day (m³/d)

DEFINITIONS

The following definitions apply specifically to the equipment and systems described in this RP.

CHLORIDE STRESS CRACKING SERVICE —Process streams which contain water and chlorides under conditions of concentration and temperature high enough to induce stress cracking of ferrous base alloy materials. Other constituents present, such as oxygen (O₂), may contribute to such chloride stress cracking.

CHOKE —A device specifically intended to restrict the flow rate of fluids.

CORROSION-EROSION —The phenomenon of a protective film of corrosion product being eroded away by the erosive action of the process stream, exposing fresh metal which then corrodes. Extremely high metal weight loss may occur under these conditions.

CORROSIVE GAS —A gas which when dissolved in water or other liquid causes metal attack. Usually included are hydrogen sulfide (H₂S), carbon dioxide (CO₂) and oxygen (O₂).

CORROSIVE HYDROCARBON SERVICE

—Process streams which contain water or brine and carbon dioxide (CO₂), hydrogen sulfide (H₂S), oxygen (O₂) or other corrosive agents under conditions which cause metal weight loss.

DESIGN PRESSURE —Maximum allowable working pressure at the design temperature.

EXPANSION BELLOWS —A corrugated piping device designed for absorbing expansion and contraction.

EXPANSION BEND —A piping configuration designed to absorb expansion and contraction.

FIRE WATCH —One or more trained persons with operable fire fighting equipment standing on alert during welding or burning operations.

FLOWLINE —Piping which carries well fluid from wellhead to manifold or first process vessel.

FLOW REGIME —The flow condition of a multiphase process stream such as slug, mist, or stratified flow.

FLUID —A generic term meaning a gas, vapor, liquid or combinations thereof.

HEADER	—That part of a manifold which directs fluid to a specific process system. (See Figure 6.1A)	PRESSURE SENSOR	—A device designed to detect a predetermined pressure.
HYDROCARBON WETABILITY	—The ability of the process stream to form a protective hydrocarbon film on metal surfaces.	PROCESS COMPONENT	—A single functional piece of production equipment and associated piping such as a pressure vessel, heater, pump, etc.
MANIFOLD	—An assembly of pipe, valves, and fittings by which fluid from one or more sources is selectively directed to various process systems.	RISER	—The vertical portion of a pipeline (including the bottom bend) arriving on or departing from a platform.
NIPPLE	—A section of threaded or socket welded pipe used as an appurtenance that is less than 12 inches in length.	SHUTDOWN VALVE	—An automatically operated valve used for isolating a process component or process system.
NON-CORROSIVE HYDROCARBON SERVICE	—Process streams under conditions which do not cause significant metal weight loss, selective attack, or stress corrosion cracking.	SULFIDE STRESS CRACKING SERVICE	—Process streams which contain water or brine and hydrogen sulfide (H_2S) in concentrations high enough to induce stress corrosion cracking of susceptible materials.
PLATFORM PIPING	—A general term referring to any piping, on a platform, intended to contain or transport fluid.	WELLHEAD PRESSURE	—The maximum shut-in surface pressure that may exist in a well.

SYMBOLS

The following symbols apply specifically to the equations contained in this RP.

A	= minimum pipe cross-sectional flow area required, inches ² /1000 barrels fluid/day	ΔP	= pressure drop, psi/100 ft
B	= mean coefficient of thermal expansion at operating temperatures normally encountered, inches/inch/°F	Q_g	= gas flow rate, million cubic feet/day (14.7 psia and 60°F)
C	= empirical pump constant	Q_l	= liquid flow rate, barrels/day
c	= empirical constant	$q'h$	= gas flow rate, cubic feet/hour (14.7 psia and 60°F)
C_v	= valve coefficient (GPM water flow at 60°F across valve with a pressure drop of 1 psi)	R	= gas/liquid ratio, standard cubic feet/barrel
d_i	= pipe inside diameter, feet	R_e	= Reynolds number, dimensionless
d_i	= pipe inside diameter, inches	R_p	= pump speed, revolutions/minute
D	= nominal pipe diameter, inches	ρ_g	= gas density at operating pressure and temperature, lbs/ft ³
D_o	= pipe outside diameter, inches	ρ_l	= liquid density at operating temperature, lbs/ft ³
E	= longitudinal weld joint factor, dimensionless	ρ_m	= gas/liquid mixture density at operating pressure and temperature, lbs/ft ³
E_m	= modulus of elasticity of piping material in the cold condition, psi	S	= allowable stress, psi
f	= Moody friction factor, dimensionless	S_g	= gas specific gravity (air = 1)
g	= gravitational constant, feet/second ²	S_l	= liquid specific gravity (water = 1)
GPM	= liquid flow rate, gallons/minute	T	= operating temperature, °R (See Note (2))
h_a	= acceleration head, feet of liquid	t	= pressure design thickness, inches
h_f	= friction head, feet of liquid	ΔT	= temperature change, °F
h_p	= absolute pressure head, feet of liquid	U	= anchor distance, feet (straight line distance between anchors)
h_{st}	= static head, feet of liquid	μ_g	= gas viscosity at flowing pressure and temperature, centipoise
h_{vb}	= velocity head, feet of liquid	μ_l	= liquid viscosity, lbs/ft-sec
h_{vpa}	= absolute vapor pressure, feet of liquid	V_e	= fluid erosional velocity, feet/second
Δh_w	= differential static pressure head, inches of water	V_g	= average gas velocity, feet/second (See Note (3))
K	= acceleration factor, dimensionless	V_l	= average liquid velocity, feet/second
L	= pipe length, feet	W	= total liquid plus vapor rate, lbs/hr
Δ_1	= expansion to be absorbed by pipe, inches	Y	= temperature factor, dimensionless
NPSH_a	= available net positive suction head, feet of liquid	Z	= gas compressibility factor, dimensionless
P	= operating pressure, psia (See Note (1))	NOTES: (1) Also denoted in text as "flowing pressure, psia." (2) Also denoted in text as "flowing temperature, °R." (3) Also denoted in text as "gas velocity, feet/second."	
P_i	= internal design pressure, psig		
Δp	= pressure drop, psi		

SECTION 1

GENERAL

1.1 Scope. This document recommends minimum requirements and guidelines for the design and installation of new piping systems on production platforms located offshore. The maximum design pressure within the scope of this document is 10,000 psig and the temperature range is -20°F to 650°F. For applications outside these pressures and temperatures, special consideration should be given to material properties (ductility, carbon migration, etc.). The recommended practices presented are based on years of experience in developing oil and gas leases. Practically all of the offshore experience has been in hydrocarbon service free of hydrogen sulfide. However, recommendations based on extensive experience onshore are included for some aspects of hydrocarbon service containing hydrogen sulfide.

- a. This document contains both general and specific information on surface facility piping systems not specified in API Specification 6A. Sections 2, 3 and 4 contain general information concerning the design and application of pipe, valves, and fittings for typical processes. Sections 6 and 7 contain general information concerning installation, quality control, and items related to piping systems, e.g., insulation, etc. for typical processes. Section 5 contains specific information concerning the design of particular piping systems including any deviations from the recommendations covered in the general sections.
- b. Carbon steel materials are suitable for the majority of the piping systems on production platforms. At least one carbon steel material recommendation is included for most applications. Other materials that may be suitable for platform piping systems have not been included because they are not generally used. The following should be considered when selecting materials other than those detailed in this RP.
 - (1) Type of service.
 - (2) Compatibility with other materials.
 - (3) Ductility.
 - (4) Need for special welding procedures.
 - (5) Need for special inspection, tests, or quality control.
 - (6) Possible misapplication in the field.
 - (7) Corrosion/erosion caused by internal fluids and/or marine environments.

1.2 Code for Pressure Piping. The design and installation of platform piping should conform to ANSI B31.3, as modified herein. Risers for which B31.3 is not applicable, should be designed and installed in accordance with the following practices:

- a. Design, construction, inspection and testing should be in accordance with ANSI B31.4, ANSI B31.8, CFR Title 49, Part 192, and/or CFR Title 49, Part 195, as appropriate to the application, using a design stress no greater than 0.6 times SMYS (Specified Minimum Yield Strength).
- b. One hundred percent radiography should be required for welding in accordance with API Std 1104.
- c. Impact tests should be required at the lowest expected operating temperatures for pipe grades higher than X-52.
- d. Valves, fittings and flanges may be manufactured in conformance with MSS (Manufacturers Standardization Society of the Valve and Fit-

tings Industry) standards. Pressure/temperature ratings and material compatibility should be verified.

- e. In determining the transition between risers and platform piping to which these practices apply, the first incoming and last outgoing valve which blocks pipeline flow shall be the limit of this document's application. Recommended Practices included in this document may be utilized for riser design when factors such as water depth, batter of platform legs, potential bubbling area, etc., are considered.

1.3 Policy. American Petroleum Institute (API) Recommended Practices are published to facilitate the broad availability of proven, sound, engineering and operating practices. These Recommended Practices are not intended to obviate the need for applying sound judgment as to when and where these Recommended Practices should be utilized.

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1.4 Industry Codes, Guides and Standards. Various organizations have developed numerous codes, guides and standards which have substantial acceptance by industry and governmental bodies. Listed below are the codes, guides and standards referenced herein.

Included-by-reference standards shall be the latest published edition unless otherwise stated.

- a. American Iron and Steel Institute.
AISI Steel Products Manual, *Stainless and Heat Resisting Steels*.
- b. American National Standards Institute (Formerly "ASA" and "USAS").
 - (1) ANSI B2.1, *Pipe Threads*.
 - (2) ANSI B16.5, *Steel Pipe Flanges, Flanged Valves, and Fittings*.
 - (3) ANSI B16.9, *Factory-Made Wrought Steel Butt Welding Fittings*.
 - (4) ANSI B16.10, *Face-to-Face and End-to-End Dimensions of Ferrous Valves*.
 - (5) ANSI B16.11, *Forged Steel Fittings, Socket-Welding and Threaded*.
 - (6) ANSI B16.28, *Wrought Steel Butt Welding Short Radius Elbows and Returns*.
 - (7) ANSI B31.3, *Petroleum Refinery Piping*.
 - (8) ANSI B31.4, *Oil Transportation Piping*.

- (9) ANSI B31.8, *Gas Transmission and Distribution Piping Systems*.
- (10) ANSI B36.10, *Wrought-Steel and Wrought Iron Pipe*.

c. American Petroleum Institute.

- (1) API RP 2G, *Recommended Practice for Production Facilities on Offshore Structures*.
- (2) API Bul 5A2, *Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe*.
- (3) API Spec 5B, *Specification for Threading, Gaging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads*.
- (4) API Spec 5L, *Specification for Line Pipe*.
- (5) API Spec 6A, *Specification for Wellhead Equipment*.
- (6) API Spec 6D, *Specification for Pipeline Valves*.
- (7) API RP 14C, *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*.
- (8) API RP 510, *Pressure Vessel Inspection Code*.
- (9) API RP 520, *Recommended Practice for Design and Installation of Pressure-Relieving Systems in Refineries, Parts I and II*.
- (10) API RP 521, *Guide for Pressure Relief and Depressuring Systems*.
- (11) API Std 526, *Flanged Steel Safety Relief Valves*.
- (12) API RP 550, *Manual on Installation of Refinery Instruments and Control Systems, Parts I and II*.
- (13) API Std 600, *Steel Gate Valves (Flanged or Butt-Welding Ends)*.
- (14) API Std 602, *Carbon Steel Gate Valves for Refinery Use (Compact Design)*.
- (15) API Std 1104, *Standard for Welding Pipelines and Related Facilities*.
- (16) API Medical Research Report EA 7301, *Guidelines on Noise*.

d. American Society for Testing and Materials.

- (1) ASTM A53, *Specification for Welded and Seamless Steel Pipe*.
- (2) ASTM A105, *Specification for Forgings, Carbon Steel, for Piping Components*.
- (3) ASTM A106, *Specification for Seamless Carbon Steel Pipe for High-Temperature Service*.
- (4) ASTM A153, *Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware*.
- (5) ASTM A193, *Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service*.

- (6) ASTM A194, *Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service*.
- (7) ASTM A234, *Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures*.
- (8) ASTM A333, *Specification for Seamless and Welded Steel Pipe for Low-Temperature Service*.
- (9) ASTM A354, *Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners*.

e. American Society of Mechanical Engineers.

- (1) ASME Boiler and Pressure Vessel Code, Section IV, *Heating*.
- (2) ASME Boiler and Pressure Vessel Code, Section VIII, *Pressure Vessels, Division 1*.
- (3) ASME Boiler and Pressure Vessel Code, Section IX, *Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators*.

f. National Association of Corrosion Engineers

- (1) NACE Std MR-01-75, *Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment*.
- (2) NACE Std. RP-01-76, *Corrosion Control on Steel, Fixed Offshore Platforms Associated with Petroleum Production*.

g. National Fire Protection Association.

- (1) National Fire Code Volume 6, *Sprinklers, Fire Pumps and Water Tanks*.
- (2) National Fire Code Volume 8, *Portable and Manual Fire Control Equipment*.

h. Gas Processors Suppliers Association (formerly Natural Gas Processors Suppliers Association). Engineering Data Books.

i. Hydraulics Institute.

- (1) *Standards for Centrifugal, Rotary and Reciprocating Pumps*.
- (2) *Pipe Friction Manual*.

1.5 Governmental Rules and Regulations. Regulatory agencies have established certain rules and regulations which may influence the nature and manner in which platform piping is installed and operated. Listed below are references to significant rules and regulations which should be considered in the design and installation of platform piping, where applicable.

a. Code of Federal Regulations.

- (1) Title 29, Part 1910, *Occupational Safety and Health Standards*.
- (2) Title 30, Part 250, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf*.
- (3) Title 33, Subchapter C, *Aids to Navigation*, Part 67, *Aids to Navigation on Artificial Islands and Fixed Structures*.

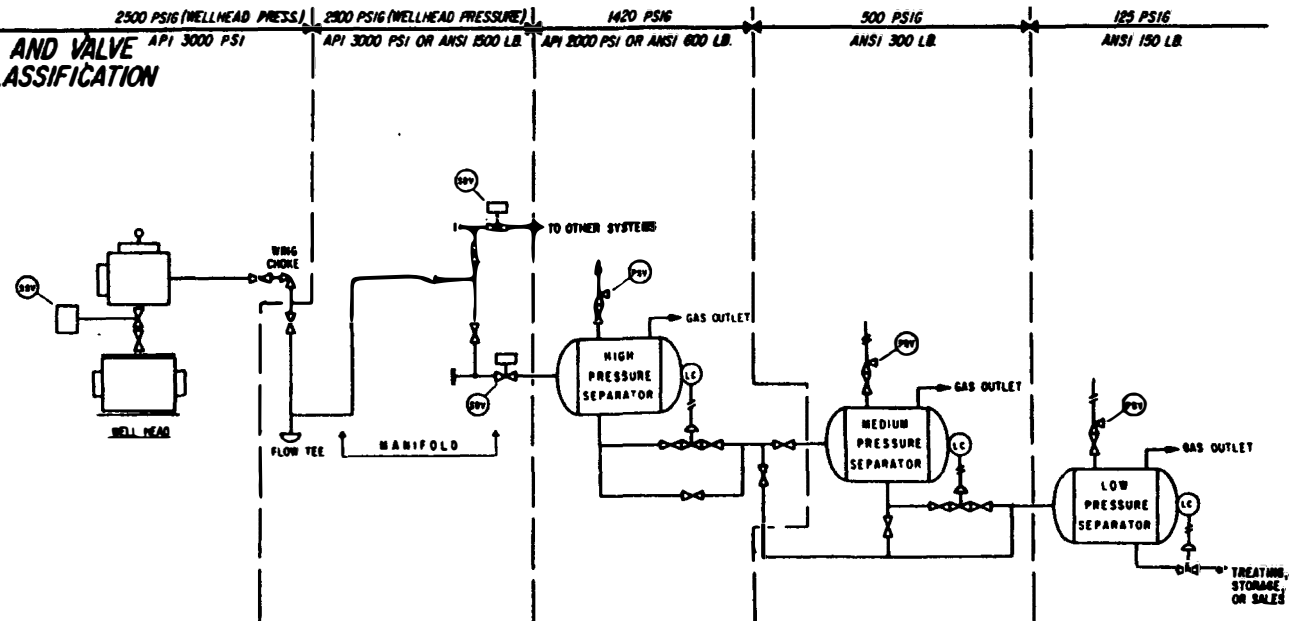
- (4) Title 33, Subchapter N, *Artificial Islands and Fixed Structures on the Outer Continental Shelf*, Parts 140 through 146.
 - (5) Title 33, Part 153, *Control of Pollution by Oil and Hazardous Substances, Discharge Removal*.
 - (6) Title 40, Part 110, *Discharge of Oil*.
 - (7) Title 40, Part 112, *Oil Pollution Prevention*.
 - (8) Title 49, Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards*.
 - (9) Title 49, Part 195, *Transportation of Liquids by Pipeline*.
 - b. **Environmental Protection Agency.** Document AP-26, *Workbook of Atmospheric Dispersion Estimates*.
 - c. Regional Outer Continental Shelf Orders Promulgated Under the Code of Federal Regulations, Title 30, Part 250, *Oil and Gas Sulphur Operations in the Outer Continental Shelf*.
 - d. State, municipal and other local regulatory agencies, as applicable.
- 1.6 Demarcation Between Systems with Different Pressure Ratings.** Normally after the wellstream leaves the wellhead, the pressure is reduced in stages.

After the pressure is reduced, process components of lower pressure rating may be used. A typical example is shown in Figure 1.1

- a. One rule can be used for pressure design: a pressure containing process component should either be designed to withstand the maximum internal pressure which can be exerted on it under any conditions, or be protected by a pressure relieving device. In this case, a pressure relieving device means a safety relief valve or a rupture disc. In general, when determining if pressure relieving devices are needed, high pressure shutdown valves, check valves, control valves or other such devices should not be considered as preventing overpressure of process components. See API RP 14C for recommended practices concerning required safety devices for process components.
- b. One good way to analyze required system design pressure ratings for process components is to show pressure rating boundaries on mechanical flow sheets. Each component (vessels, flanges, pipe or accessories) may then be checked to determine that it is either designed to withstand the highest pressure to which it could be subjected, or is protected by a pressure relieving device.

SYSTEM DESIGN PRESSURE

APPLICABLE FLANGE AND VALVE PRESSURE RATING CLASSIFICATION



NOTES

1. Design temperature is 150°F throughout.
2. Required shutdown sensors are not shown.
3. Flowline and manifold are designed for wellhead pressure.
4. System design pressures may be limited by factors other than the flange and valve pressure classifications (i.e. pipe wall thickness, separator design pressure, etc.).
5. Relief valves must be set no higher than system design pressure.
6. Valves under relief valves must be locked open.

FIGURE 1.1
EXAMPLE PROCESS SYSTEM
DENOTING FLANGE AND VALVE PRESSURE RATING CHANGES

1.7 Corrosion Considerations.

- a. General. Detailed corrosion control practices for platform piping systems are outside the scope of this recommended practice. Such practices should, in general, be developed by corrosion control specialists. Platform piping systems should, however, be designed to accommodate and to be compatible with the corrosion control practices described below. Suggestions for corrosion resistant materials and mitigation practices are given in the appropriate sections of this RP.

NOTE: *The corrosivity of process streams may change with time. The possibility of changing conditions should be considered at the design stage.*

- b. Weight Loss Corrosion. Carbon steel which is generally utilized for platform piping systems may corrode under some process conditions. Production process streams containing water, brine, carbon dioxide (CO₂), hydrogen sulfide (H₂S), or oxygen (O₂), or combinations of these, may be corrosive to metals used in system components. The type of attack (uniform metal loss, pitting, corrosion/erosion, etc.) as well as the specific corrosion rate may vary in the same system, and may vary with time. The corrosivity of a process stream is a complex function of many variables including (1) hydrocarbon, water, salt, and corrosive gas content, (2) hydrocarbon wettability, (3) flow velocity, flow regime, and piping configuration, (4) temperature, pressure, and pH, and (5) solids content (sand, mud, bacterial slime and microorganisms, corrosion products, and scale). Corrosivity predictions are very qualitative and may be unique for each system. Some corrosivity information for corrosive gases found in production streams is shown in Table 1.1.

Table 1.1 is intended only as a general guide for corrosion mitigation considerations and not for specific corrosivity predictions. Corrosion inhibition is an effective mitigation procedure when corrosive conditions are predicted or anticipated (See Paragraph 2.1.b).

- c. Sulfide Stress Cracking. Process streams containing water and hydrogen sulfide may cause sulfide stress cracking of susceptible materials. This phenomenon is affected by a complex interaction of parameters including metal chemical composition and hardness, heat treatment, and microstructure, as well as factors such as pH,

TABLE 1.1
QUALITATIVE GUIDELINE FOR WEIGHT LOSS CORROSION OF STEEL

Corrosive gas	Solubility* PPM	Limiting Values in Brine	
		Non-corrosive PPM	Corrosive PPM
Oxygen (O ₂)	8	<0.005	>0.025
Carbon Dioxide (CO ₂)	1700	<600	>1200
Hydrogen Sulfide (H ₂ S)	3900	**	**

*Solubility at 68°F in distilled water at 1 atmosphere partial pressure. Oxygen (O₂) is for 1 atmosphere air pressure. Source: Handbook of Chemistry and Physics, Chemical Rubber Company, 36th Edition.

**No limiting values for weight loss corrosion by hydrogen sulfide (H₂S) are shown in this table because the amount of carbon dioxide (CO₂) and/or oxygen (O₂) greatly influences the metal loss corrosion rate. Hydrogen sulfide alone is usually less corrosive than carbon dioxide due to the formation of an insoluble iron sulfide film which tends to reduce metal weight loss corrosion.

hydrogen sulfide concentration, stress and temperature. Materials used to contain process streams containing hydrogen sulfide should be selected to accommodate these parameters.

- d. Chloride Stress Cracking. Careful consideration should be given to the effect of stress and chlorides if alloy and stainless steels are selected to prevent corrosion by hydrogen sulfide and/or carbon dioxide. Process streams which contain water with chlorides may cause cracking in susceptible materials, especially if oxygen is present and the temperature is over 140°F. High alloy and stainless steels, such as the AISI 300 series austenitic stainless steels, precipitation hardening stainless steels, and "A-286" (ASTM A453, Grade 660), should not be used unless their suitability in the proposed environment has been adequately demonstrated. Consideration should also be given to the possibility that chlorides may be concentrated in localized areas in the system.
- e. Application of NACE MR-01-75. MR-01-75 lists materials which exhibit resistance to sulfide stress cracking. Corrosion resistant alloys not listed in MR-01-75 may exhibit such resistance and may be used if it can be demonstrated that they are resistant in the proposed environment of use (or in an equivalent laboratory environment). Caution should be exercised in the use of materials listed in MR-01-75. The materials listed in the document may be resistant to sulfide stress corrosion environments, but may not be suitable for use in chloride stress cracking environments.

SECTION 2

PIPING DESIGN

2.1 Pipe Grades.

- a. **Non-Corrosive Hydrocarbon Service.** The two most commonly used types of pipe are ASTM A106, Grade B, and API 5L, Grade B. Seamless pipe is generally preferred due to its consistent quality. ASTM A106 is only manufactured in seamless while API 5L is available in seamless, electric resistance welded (ERW) and submerged arc welded (SAW). When use of Grade B requires excessive wall thickness, higher strength pipe such as API 5L, Grade X52, may be required; however, special welding procedures and close supervision are necessary when using API 5L, Grade X46, or higher.

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

- (1) All grades of ASTM A120.
- (2) Furnace lap weld and furnace butt weld.
- (3) Fusion weld per ASTM A134 and A139.
- (4) Spiral weld, except API 5L spiral weld.

- b. **Corrosive Hydrocarbon Service.** Design for corrosive hydrocarbon service should provide for one or more of the following corrosion mitigating practices: (1) chemical treatment; (2) corrosion resistant alloys; (3) protective coatings (See Paragraph 6.5.b). Of these, chemical treatment of the fluid in contact with carbon steels is by far the most common practice and is generally recommended. Corrosion resistant alloys which have proven successful in similar applications (or by suitable laboratory tests) may be used. If such alloys are used, careful consideration should be given to welding procedures. Consideration should also be given to the possibility of sulfide and chloride stress cracking (See Paragraphs 1.7.c and 1.7.d). Adequate provisions should be made for corrosion monitoring (coupons, probes, spools, etc.) and chemical treating.

- c. **Sulfide Stress Cracking Service.** The following guidelines should be used when selecting pipe if sulfide stress corrosion cracking is anticipated:

- (1) Only seamless pipe should be used unless quality control applicable to this service has been exercised in manufacturing ERW or SAW pipe.
- (2) Cold expanded pipe should not be used unless followed by normalizing, quenching and tempering, or heat treatment as described in 2.1.c(4).
- (3) Carbon and alloy steels and other materials which meet the property, hardness, heat treatment and other requirements of NACE MR-01-75 are acceptable for use in sulfide stress cracking service.
- (4) Materials not meeting the metallurgical requirements of NACE MR-01-75 may be used; however, usage should be limited to appli-

cations or systems in which the external environment and the process stream can be continuously maintained to assure freedom from sulfide stress cracking, or limited to those materials for which adequate data exists to demonstrate resistance to sulfide or chloride stress cracking in the application or system environments to which the materials are exposed. (See MR-01-75).

The most commonly used pipe grades which will meet the above guidelines are: ASTM A106, Grade B; ASTM A333, Grade 1; and API 5L, Grade B, seamless. API 5L X grades are also acceptable; however, welding presents special problems. To enhance toughness and reduce brittle fracture tendencies, API 5L pipe should be normalized for service temperatures below 30° F. ASTM A333, Grade 1, is a cold service piping material and should have adequate notch toughness in the temperature range covered by this RP (-20° to 650°F).

- d. **Utilities Service.** Materials other than carbon steel are commonly used in utilities service. If, however, steel pipe is used that is of a type or grade not acceptable for hydrocarbon service in accordance with Paragraph 2.1.a, some definite marking system should be established to prevent such pipe from accidentally being used in hydrocarbon service. One way to accomplish this would be to have all such pipe galvanized.
- e. **Tubing.** AISI 316 or AISI 316L stainless steel, seamless or electric resistance welded tubing is preferred for all hydrocarbon service, and air service exposed to sunlight. Tubing used for air service not exposed to sunlight, or instrument tubing used for gas service contained in an enclosure, may be made of other materials. If used, synthetic tubing should be selected to withstand degradation caused by the contained fluids and the temperature to which it may be subjected.

2.2 Sizing Criteria — General. In determining the diameter of pipe to be used in platform piping systems, both the flow velocity and pressure drop should be considered. Sections 2.3, 2.4 and 2.5 present equations for calculating pipe diameters (and graphs for rapid approximation of pipe diameters) for liquid lines, single-phase gas lines, and gas/liquid two-phase lines, respectively. Many companies also use computer programs to facilitate piping design.

- a. When determining line sizes, the maximum flow rate expected during the life of the facility should be considered rather than the initial flow rate. It is also usually advisable to add a surge factor of 20 to 50 percent to the anticipated normal flow rate, unless surge expectations have been more precisely determined by pulse pressure measurements in similar systems or by specific fluid hammer calculation. Table 2.1 presents some typical surge factors that may be used if more definite information is not available.

In large diameter flow lines producing liquid-vapor phase fluids between platforms through riser systems, surge factors have been known to exceed 200% due to slug flow. Refer to liquid-vapor slug flow programs generally available to Industry for evaluation of slug flow.

TABLE 2.1
TYPICAL SURGE FACTORS

Service	Factor
Facility handling primary production from its own platform	20%
Facility handling primary production from another platform or remote well in less than 150 feet of water	30%
Facility handling primary production from another platform or remote well in greater than 150 feet of water	40%
Facility handling gas lifted production from its own platform	40%
Facility handling gas lifted production from another platform or remote well	50%

b. Determination of pressure drop in a line should include the effect of valves and fittings. Manufacturer's data or an equivalent length given in Table 2.2 may be used.

c. Calculated line sizes may need to be adjusted in accordance with good engineering judgment.

2.3 Sizing Criteria For Liquid Lines.

a. **General.** Single-phase liquid lines should be sized primarily on the basis of flow velocity. For lines transporting liquids in single-phase from one pressure vessel to another by pressure differential, the flow velocity should not exceed 15 feet/second at maximum flow rates, to minimize flashing ahead of the control valve. If practical, flow velocity should not be less than 3 feet/second to minimize deposition of sand and other solids. At these flow velocities, the overall pressure drop in the piping will usually be small. Most of the pressure drop in liquid lines between two pressure vessels will occur in the liquid dump valve and/or choke.

(1) Flow velocities in liquid lines may be read from Figure 2.1 or may be calculated using the following derived equation:

$$V_1 = \frac{.012 Q_1}{d_i^2} \quad \text{Eq. 2.1}$$

where:

V_1 = average liquid flow velocity, feet/second.

Q_1 = liquid flow rate, barrels/day.

d_i = pipe inside diameter, inches.

(2) Pressure drop (psi per 100 feet of flow length) for single phase liquid lines may be read from Figure 2.2 or may be calculated using the following (Fanning) equation:

$$\Delta P = \frac{0.00115f Q_1^2 S_1}{d_i^5} \quad \text{Eq. 2.2}$$

where:

ΔP = pressure drop, psi/100 feet.

f = Moody friction factor, dimensionless.

Q_1 = liquid flow rate, barrels/day.

S_1 = liquid specific gravity (water = 1).

d_i = pipe inside diameter, inches.

(3) The Moody friction factor, f , is a function of the Reynolds number and the surface roughness of the pipe. The modified Moody diagram, Figure 2.3, may be used to determine the friction factor once the Reynolds number is known. The Reynolds number may be determined by the following equation:

$$Re = \frac{\rho_1 d_i V_1}{\mu_1} \quad \text{Eq. 2.3}$$

where:

Re = Reynolds number, dimensionless.

ρ_1 = liquid density, lb/ft³.

d_i = pipe inside diameter, ft.

V_1 = liquid flow velocity, ft/sec.

μ_1 = liquid viscosity, lb/ft-sec, or

= centipoise divided by 1488, or

= (centistokes times specific gravity) divided by 1488.

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

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

(2) The necessary available pressure differential over the pumped fluid vapor pressure may be defined as net positive suction head available (NPSH_a). It is the total head in feet absolute determined at the suction nozzle, less the vapor pressure of the liquid in feet absolute. Available NPSH should always equal or exceed the pump's required NPSH. Available NPSH for most pump applications may be calculated using Equation 2.4.

TABLE 2.2
EQUIVALENT LENGTH OF 100 PERCENT
OPENING VALVES AND FITTINGS IN FEET

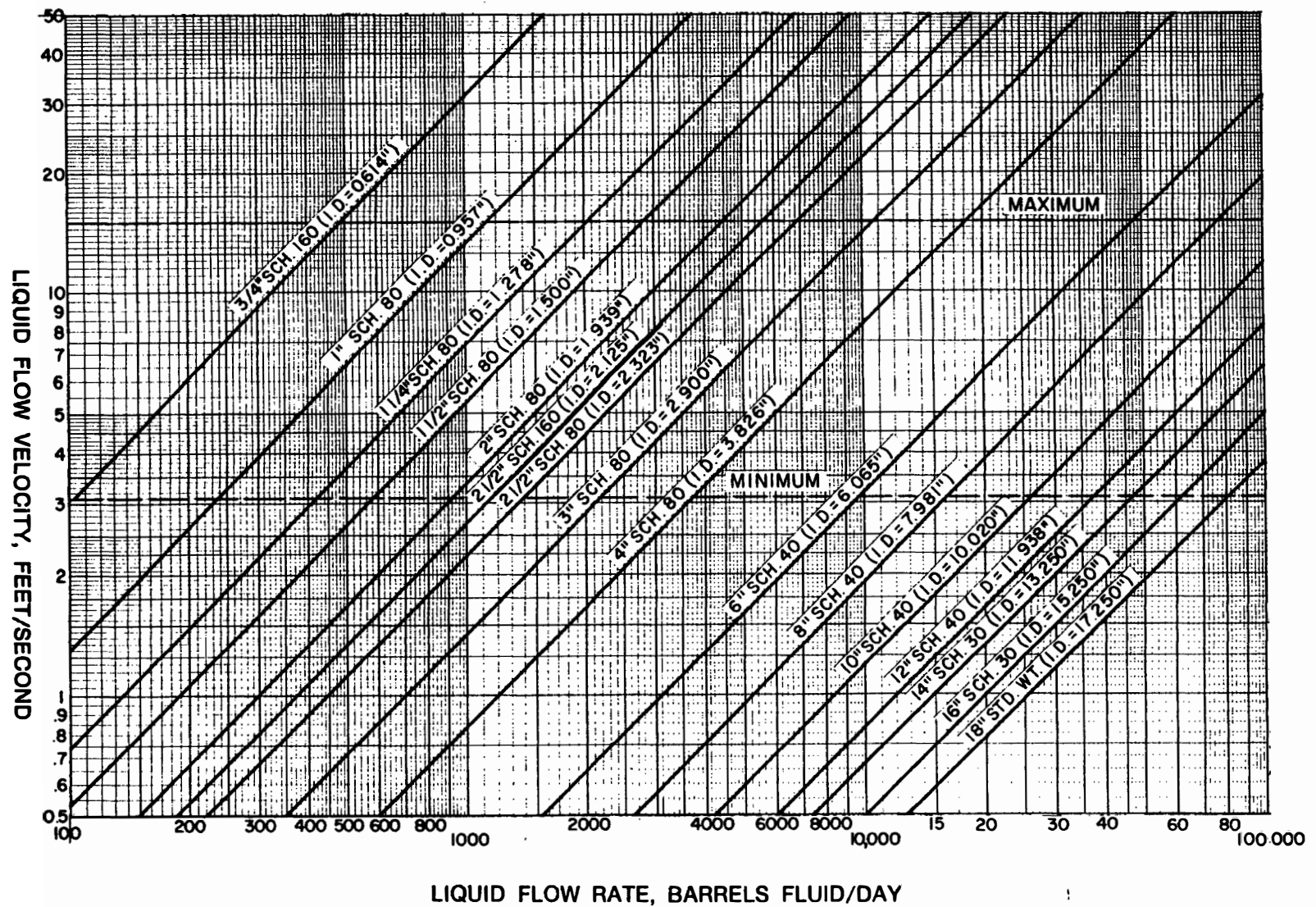
Nominal Pipe Size (Inches)	Globe Valve or Ball Check Valve	Angle Valve	Swing Check Valve	Plug Valve, Gate Valve or Ball Valve	45° Ell		Short Radius Ell		Long Radius Ell		Branch of Tee		Run of Tee		Enlargement					Contraction				
																	Sudden		Standard Reducer		Sudden		Standard Reducer	
					Equivalent length in terms of small diameter																			
					Weld	Thread	Weld	Thread	Weld	Thread	Weld	Thread	Weld	Thread	d/D=1/4	d/D=1/2	d/D=3/4	d/D=1/2	d/D=3/4	d/D=1/4	d/D=1/2	d/D=3/4	d/D=1/2	d/D=3/4
1 1/2	55	26	13	1	1	2	3	5	2	3	8	9	2	3	5	3	1	4	1	3	2	1	1	
2	70	33	17	2	2	3	4	5	3	4	10	11	3	4	7	4	1	5	1	3	3	1	1	
2 1/2	80	40	20	2	2		5		3		12		3		8	5	2	6	2	4	3	2	2	
3	100	50	25	2	2		6		4		14		4		10	6	2	8	2	5	4	2	2	
4	130	65	32	3	3		7		5		19		5		12	8	3	10	3	6	5	3	3	
6	200	100	48	4	4		11		8		28		8		18	12	4	14	4	9	7	4	4	1
8	260	125	64	6	6		15		9		37		9		25	16	5	19	5	12	9	5	5	2
10	330	160	80	7	7		18		12		47		12		31	20	7	24	7	15	12	6	6	2
12	400	190	95	9	9		22		14		55		14		37	24	8	28	8	18	14	7	7	2
14	450	210	105	10	10		26		16		62		16		42	26	9			20	16	8		
16	500	240	120	11	11		29		18		72		18		47	30	10			24	18	9		
18	550	280	140	12	12		33		20		82		20		53	35	11			26	20	10		
20	650	300	155	14	14		36		23		90		23		60	38	13			30	23	11		
22	688	335	170	15	15		40		25		100		25		65	42	14			32	25	12		
24	750	370	185	16	16		44		27		110		27		70	46	15			35	27	13		
30				21	21		55		40		140		40											
36				25	25		66		47		170		47											
42				30	30		77		55		200		55											
48				35	35		88		65		220		65											
54				40	40		99		70		250		70											
60				45	45		110		80		260		80											

NOTES:

- Source of data is GPSA Data Book, 1981 Revision.
- d is inside diameter of smaller outlet.
D is inside diameter of larger outlet.

NOTES:

- Source of data is GPSA Data Book, 1981 Revision.
- d is inside diameter of smaller outlet.
D is inside diameter of larger outlet.



LIQUID FLOW RATE, BARRELS FLUID/DAY
(NOTE: These curves were determined using Equation 2.1)

FIGURE 2.1
VELOCITY IN LIQUID LINES

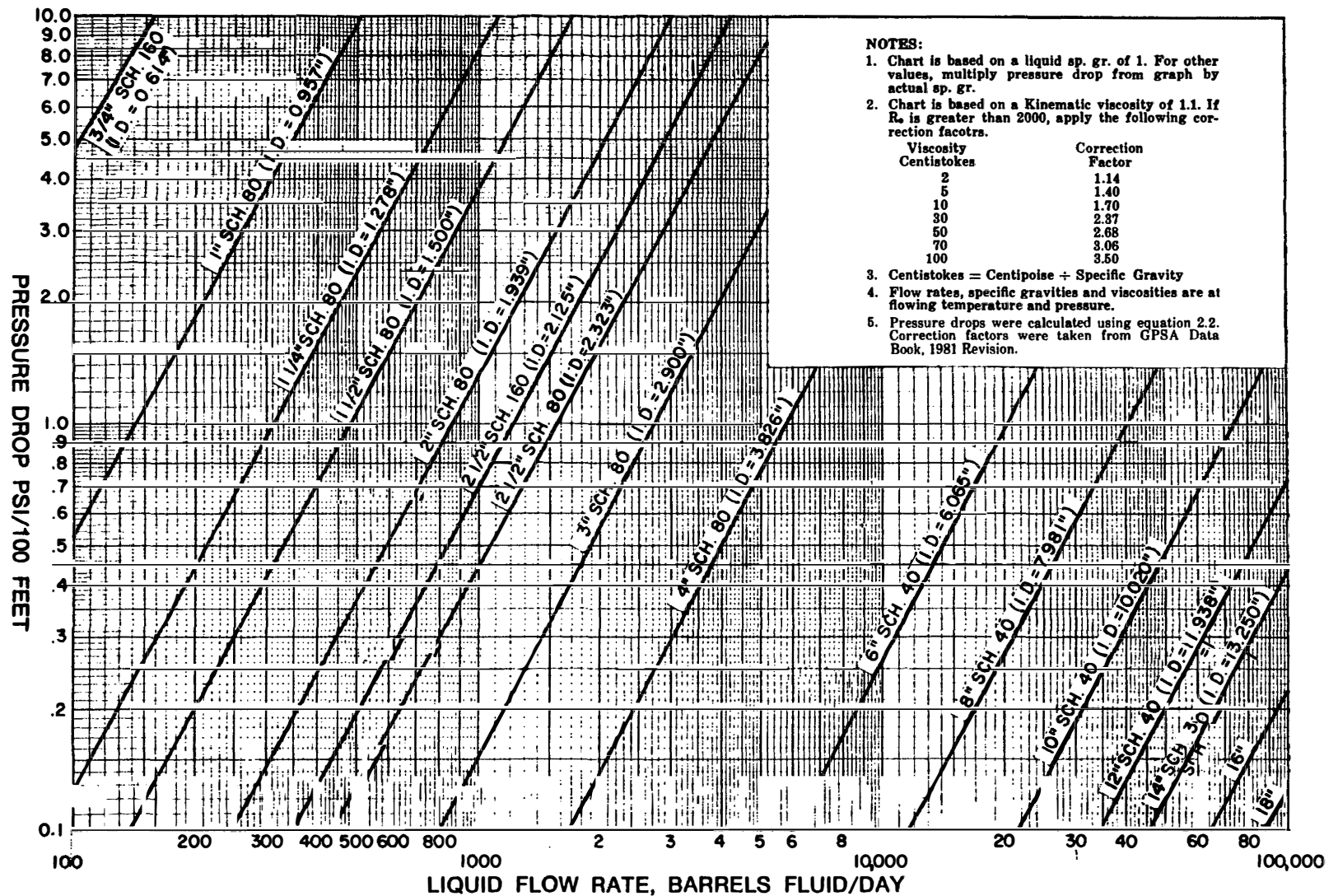


FIGURE 2.2
PRESSURE DROP IN LIQUID LINES