

SECTION 3

Measurement

The information presented in this section provides sufficient information for determining flow quantities with a reasonable degree of accuracy, but not necessarily to the accuracy desired for custody transfer. Agreement of acceptable accuracy for cus-

tody transfer should be between the parties involved, and supplemental information and procedures may be required, such as the API Manual of Petroleum Measurement Standards or corresponding ISO standards.

FIG. 3-1

Nomenclature

C = Pitot tube flow coefficient	F_{pb} = pressure base factor applied to change the base pressure from 101.55 kPa (abs)
C' = the product of multiplying all orifice correction factors	F_{pm} = pressure factor applied to meter volumes to correct to standard pressure. See API Manual of Petroleum Measurement Standards, Chapter 12, Section 2
C_{pl} = liquid pressure correction factor. Correction for the change in volume resulting from application of pressure. Proportional to the liquid compressibility factor, which depends upon both relative density and temperature.	F_{pv} = supercompressibility factor required to correct for deviation from the ideal gas laws = $\sqrt{1/Z}$
C_{ps} = correction factor for effect of pressure on steel. See API Manual of Petroleum Measurement Standards, Chapter 12, Section 2	F_s = steam factor
C_g = gravity correction factor for orifice well tester to change from a gas relative density of 0.6	F_{sl} = orifice slope factor
C_{tl} = liquid temperature correction factor. Proportional to the thermal coefficient which varies with density and temperature	F_{tb} = temperature base factor. To change the temperature base from 15°C to another desired base
C_{ts} = correction factor for effect of temperature on steel	F_{tf} = flowing temperature factor to change from the assumed flowing temperature of 15°C to the actual flowing temperature
C_u = velocity of sound in the gas non-flowing condition.	F_{tm} = temperature correction factor applied to displacement meter volumes to correct to standard temperature. See API Manual of Petroleum Measurement Standards, Chapter 12, Section 2
d = orifice diameter, mm	G, G_l = relative density (specific gravity) at 15°C
D = internal pipe diameter of orifice meter run or prover section, mm	G_f = relative density (specific gravity) at flowing temperature
DL = Minimum downstream meter tube length, mm	H = pressure, mm of mercury
D_p = the difference between the flowing pressure and the equilibrium vapor pressure of the liquid.	h_m = differential pressure measured across the orifice plate in mm of mercury at 15°C
D_u = diameter of the meter bore	h_w = differential pressure measured across the orifice plate in mm of water at 15°C
ρ = flowing fluid density, kg/m ³	$\sqrt{h_w P_f}$ = pressure extension. The square root of the differential pressure times the square root of the absolute static pressure
e = orifice edge thickness, mm	IM = indicated mass, mass measured at flowing conditions without correction for meter performance, counts / K. Also the difference between opening and closing meter readings.
E = orifice plate thickness, mm	IV = indicated volume, volume measured at flowing conditions without correction for meter performance, counts / K. Also the difference between opening and closing meter readings.
E_m = modulus of elasticity for steel [(206.8)(10 ⁶)] kPa	k = ratio of the specific heat at constant pressure to the specific heat at constant volume
F = liquid compressibility factor	K = a numerical constant. Pulses generated per unit volume or mass through a turbine, positive displacement, Coriolis or ultrasonic meter
F_a = orifice thermal expansion factor. Corrects for the metallic expansion or contraction of the orifice plate. Generally ignored between -20°C and 50°C	
F_c = orifice calculation factor	
F_g = relative density (specific gravity) factor applied to change from a relative density of 1.0 (air) to the relative density of the flowing gas	
F_{gt} = gravity-temperature factor for liquids	
F_n = numeric conversion factor	
F_{na} = units conversion factor for pitot tubes	

FIG. 3-1 (Cont'd)
Nomenclature

Key = $F_n (F_c + F_{sl})$ = orifice factor	SPU = Signal Processing Unit, the electronic microprocessor system of the multi-path ultrasonic meter.
L = distance between upstream and downstream transducer.	t1 = transit time from upstream transducer to downstream transducer.
LTB = Length of tube bundle, in flow conditioner, mm (See Fig. 3-3)	t2 = transit time from downstream transducer to upstream transducer.
MF = meter factor, a number obtained by dividing the actual quantity of liquid passed through the meter during proving by the quantity indicated or registered by the meter	T_b = base temperature, °C
N = number of whole meter pulses per single proving run	T_f = flowing temperature, °C
N_{avg} = average number of pulses or interpolated pulses for proving runs that satisfy the repeatability requirements	T_{meas} = reference temperature of the orifice plate bore, °C
P = pressure, kPa (abs)	UL = Minimum upstream meter tube length, m (See Fig. 3-9)
P_b = base pressure, kPa (abs)	UL1 = See Fig. 3-9
P_{f1}, P_{f2} = static pressure at either the upstream(1) or downstream(2) pressure tap, kPa (abs)	UL2 = See Fig. 3-9
P_p = operating or observed pressure, kPa (ga)	UM = ultrasonic meter for measuring gas flow rates
P_s = pressure at which the base volume of a meter prover was determined, usually 0 kPa (ga)	V = velocity of flowing gas.
P_1/P_2 = pressure ratio	VOS = velocity of sound
Q = gas flow rate, m ³ /day	X = axial distance separating transducers
Q_h = rate of flow, usually in m ³ /h	Y = expansion factor to compensate for the change in density as the fluid passes through an orifice
R_h = maximum differential range, mm of water	Y_{CR} = critical flow constant
R_p = maximum pressure range of pressure spring, kPa	Z = compressibility factor
S = square of supercompressibility	β = ratio of the orifice or throat diameter to the internal diameter of the meter run, dimensionless
SEP = Separation distance between elbows, m (See Fig. 3-9)	ρ = density, kg/m ³

The American Petroleum Institute Manual of Petroleum Measurement Standards is the source of a large portion of the information presented in this Section. Copies of the complete API Manual of Petroleum Measurement Standards or specific chapters and sections can be ordered from:

American Petroleum Institute
Publications and Distribution Section
1220 L Street Northwest
Washington, D.C. 20005

CHAPTER	API Manual of Petroleum Measurement Standards
1	Vocabulary
2	Tank Calibration
3	Tank Gauging
4	Proving Systems
5	Metering
6	Metering Assemblies
7	Temperature Determination
8	Sampling
9	Density Determination
10	Sediment and Water
11	Physical Properties Data
12	Calculation of Petroleum Quantities
13	Statistical Aspects of Measuring and Sampling
14	Natural Gas Fluids Measurement
15	Guidelines for use of the International System of Units (SI) in the Petroleum and Allied Industries
16	Measurement of Hydrocarbon Fluids by Weight or Mass
17	Marine Measurement
18	Custody Transfer
19	Evaporation Loss Measurement
20	Allocation Measurement
21	Flow Measurement Using Electronic Metering Systems
22	Testing Protocols

Chapter 14 is of particular interest to Gas Processors because it applies specifically to the measurement of gas and liquefied gas products. Chapter 14 is further divided as follows:

SECTION	API Manual of Petroleum Measurement Standards
14.1	Collecting and Handling of Natural Gas Samples for Custody Transfer
14.2	Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases (AGA Report No. 8)
14.3	Concentric, Square-Edged Orifice Meters (AGA Report No. 3), 4 parts
14.4	Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes (GPA 8173)
14.5	Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures from Compositional Analysis (GPA 2172)
14.6	Continuous Density Measurement
14.7	Mass Measurement of Natural Gas Liquids (GPA-8182)
14.8	Liquefied Petroleum Gas Measurement
14.9	Measurement of Natural Gas by Coriolis Meter (AGA 11)
14.10	Measurement of Flow to Flares

The American Gas Association also produces measurement guidance applicable to this section and co-sponsors standards published by API and others. AGA measurement documents include:

Report No.	AGA Title
3	Orifice Metering of Natural Gas, (API MPMS Ch. 14.3), 4 parts
5	Natural Gas Energy Measurement (similar to GPA 2172 and ISO 6976)
7	Measurement of Natural Gas by Turbine Meter
8	Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (API MPMS Ch. 14.2)
9	Measurement of Gas by Multipath Ultrasonic Meters
10	Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases
11	Measurement of Natural Gas by Coriolis Meter (API MPMS Ch. 14.9)

The International Organization for Standardization (ISO) also produces measurement standards that may provide additional information. The typical North American custody transfer measurement installation follows API, AGA and/or GPA guidance. Where ISO standards are required, refer to the catalog at their website.

FLOW CALCULATION GUIDE

The Flow Calculation Guide (Fig. 3-2) is the suggested starting point for any fluid measuring determination. This chart identifies the necessary data to determine flows of gas, liquid, and steam using mechanical meters or differential pressure devices. The equations to determine either volumetric or mass quantities are shown in Fig. 3-4.

GAS MEASUREMENT

Orifice-Meter Measurement

The most commonly used differential measurement device, the orifice meter, is widely accepted for use in measuring volumes of liquids or vapors.

The procedures presented in this chapter for calculating flow by use of an orifice meter are designed to provide *approximate* solutions using a hand calculator or equivalent, and do not include the rigorous, iterative solution procedures required when using the Reader-Harris/Gallagher flow equation recommended for accurate, custody transfer calculations with computing equipment. The procedures for applying the Reader-Harris/Gallagher equation can be found in Chapter 14.3 of the API Manual of Petroleum Measurement Standards.

The orifice meter consists of static pressure and differential-pressure sensing points connected to an orifice flange or orifice fitting. The orifice meter tube (meter run) consists of upstream and downstream sections of pipe for which size and tolerance have been determined through calculation and which conform to specifications set forth in API Chapter 14.3 (AGA Report No. 3).

The orifice plate is held perpendicular to flow by flanges or a fitting. Bore, circumference, edge sharpness, and other tolerances must meet specifications as set forth in API Chapter 14.3 (AGA Report No. 3).

Orifice Flanges (Fig. 3-5a) — Orifice flanges require that the line be shut down and depressured to inspect or change the orifice plate. The flange bolts are loosened and removed. The flanges are spread by use of “jack” bolts, and the plate is removed.

When orifice flanges are used, the pressure tap hole placement may be determined by measuring from the face of the flange to the pressure tap hole center. Allowable variations are shown in Fig. 3-7.

Single Chamber Orifice Fitting (Fig. 3-5b) — This fitting also requires that the line be shut down and depressured to inspect or change the orifice plate. However, this fitting does not require breaking apart the flanges. Instead, the bolts are loosened on the cover plate and the cover plate removed. The orifice plate holder and orifice plate are then removed from the fitting. Single and dual-chamber orifice fittings are designed to provide precise alignment of the orifice plate.

Dual-Chamber Orifice Fitting (Fig. 3-5c) — This fitting allows the removal and inspection of an orifice plate while the line remains in service. It allows the orifice plate holder and orifice plate to be raised into the upper cavity of the fitting by the use of a crank handle. A valve is then closed to separate the upper cavity from the lower cavity of the fitting. The upper cavity is then depressured, the top cover plate removed, and the orifice plate cranked out.

FIG. 3-2
Flow Calculation Guide

	Gas						Steam		Liquid							
	Turbine, Displacement or Ultrasonic		Orifice		Coriolis		Orifice	Vortex	Turbine, Displacement or Ultrasonic		Orifice		Coriolis			
Factors	Unit of Measurement	Mass	Vol	Mass	Vol	Mass	Vol	Mass	Vol	Mass	Vol	Mass	Vol	Mass	Vol	Fig. #
	Square Root of Differential	kg/h	m³/h	kg/h	m³/h	kg/h	m³/h	kg/h	kg/h	kg/h	m³/h	kg/h	m³/h	kg/h	m³/h	
	Square Root of Static Pressure	—	—	•	•	—	—	•	—	—	—	•	•	—	—	—
	Square Root of Static Pressure	—	—	—	•	—	—	—	—	—	—	—	—	—	—	—
	Orifice Factor (KEY)	—	—	•	•	—	—	•	—	—	—	•	•	—	—	3-13
	Pressure Base Factor	—	•	—	—	—	—	—	—	—	—	—	—	—	—	3-4
	Flowing Temperature Factor	—	—	—	•	—	—	—	—	—	—	—	—	—	—	3-4
	Temperature Factor	—	•	—	—	—	—	—	—	—	—	—	—	—	—	3-1
	Temperature Correction Factor (Liquids)	—	—	—	—	—	—	—	—	—	•	—	—	—	•	3-1
	Pressure Correction Factor (Liquids)	—	—	—	—	—	—	—	—	—	—	—	—	—	•	3-4
	Pressure Factor	—	•	—	—	—	—	—	—	—	—	—	—	—	—	3-1
	Supercompressibility Factor	—	—	—	•	—	—	—	—	—	—	—	—	—	—	23-4
	Square of Supercompressibility Factor	—	•	—	—	—	—	—	—	—	—	—	—	—	—	3-1
	Density	•	—	—	—	—	—	—	•	—	—	—	—	—	—	3-1
	Square Root of Density	—	—	—	—	•	—	—	•	—	—	•	—	—	—	—
	Relative Density (specific gravity) Factor	—	—	—	—	—	•	—	—	—	—	—	—	—	—	3-4
	Gravity-Temperature Factor Liquid	—	—	—	—	—	—	—	—	—	—	—	•	—	—	3-4
	Meter Factor	•	•	—	—	—	•	—	—	•	•	—	—	•	•	3-1
	Indicated Volume	•	•	—	—	—	—	—	•	•	•	—	—	—	•	3-1
	Indicated Mass	—	—	—	—	—	•	—	—	—	—	—	—	•	—	3-1
	Constant	—	—	—	—	1.0618	—	—	—	—	—	1.0618	—	—	—	—
	Steam Factor	—	—	—	—	—	—	—	•	—	—	—	—	—	—	3-27/28
	Expansion Factor	—	—	—	—	•	•	—	•	—	—	—	—	—	—	3-1
	Temperature Base Factor	—	•	—	—	—	•	—	—	—	—	—	—	—	—	3-4
	Orifice Thermal Expansion Factor	—	—	—	—	•	•	—	•	—	—	•	•	—	—	3-4

Notes:

1. This guide is intended for use in obtaining approximate flows when used in conjunction with data contained in this section as referenced in the far right-hand column
2. To obtain flow, substitute areas containing dots with known numbers and multiply top to bottom.
3. The number of factors used may vary depending on method of calculation in specific application, content of flowing stream and individual contractual agreements
4. Factors appearing in shaded areas are not generally necessary for calculating approximate flows.
5. The factors Fpv, S, Ctl, Cpl, Y and Fa must be obtained for the specific substance being measured.



Orifice Plates — The minimum, maximum, and recommended thicknesses of orifice plates for various pipe sizes are given in Fig. 3-6. Also shown in this figure are maximum allowable differential pressures for stainless steel plates of the recommended thickness at a maximum temperature of 65.6°C.

The thickness of the orifice plate at the orifice edge (e) shall meet the following:

The minimum thickness is defined by $e \geq 0.01d$ or $e > 0.005$ in. whichever is greater.

The maximum thickness is defined by $e \geq 0.02d$ or $\leq 0.125d$ whichever is smaller.

If the thickness of the orifice plate must be greater than permitted by these limitations, the downstream edge shall be cut away (beveled or recessed) at an angle of $45^\circ \pm 15^\circ$ or less to the face of the plate, leaving the thickness of the orifice edge within these requirements. All orifice plates which are beveled should have the square-edge side (i.e., the side opposite the beveling) stamped “inlet” or the beveled side stamped “outlet.”

The upstream face of the orifice plate shall be flat and perpendicular to the axis of the meter tube, when in position between the orifice flanges or in the orifice fitting. Any plate that does not depart from flatness along any diameter by more than 0.010 mm per mm of the dam height, $(D-d)/2$, shall be considered flat. See Fig. 3-8.

The upstream edge of the orifice shall be square and sharp so that it will not show a beam of light when checked with an orifice edge gauge, or alternately will not reflect a beam of light when viewed without magnification. The orifice shall not have a burred or feathered edge. It shall be maintained in this condition at all times. Moreover, the orifice plate shall be kept clean at all times and free from accumulation of dirt, ice, and other extraneous material. Orifice plates with small nicks in the edge can be expected to increase the flow measurement uncertainty.

Meter Tubes — The term “meter tube” shall mean the straight upstream pipe ahead of the orifice fitting of the same internal diameter as the orifice fitting (length UL on Fig. 3-9) and the similar downstream pipe (length DL on Fig. 3-9) following the orifice.

The sections of pipe to which the orifice flanges are attached or the sections adjacent to the orifice flange or fitting shall comply with API Chapter 14.3 (AGA Report No. 3).

See Figs. 3-10, 3-11, and 3-12 for proper meter tube lengths.

Flow Conditioners (Fig. 3-3) — The purpose of flow conditioners is to eliminate swirls and cross currents set up by the pipe, fittings and valves upstream of the meter tube. There are two categories of flow conditioners: isolating flow conditioners and flow straighteners such as the 19-tube uniform concentric tube bundle flow straightener and flow straighteners such as the 19-tube uniform concentric tube bundle. Please refer to API Chapter 14.3 (AGA Report No. 3) for detailed specifications for flow conditioners.

FIG. 3-3
Flow Conditioners

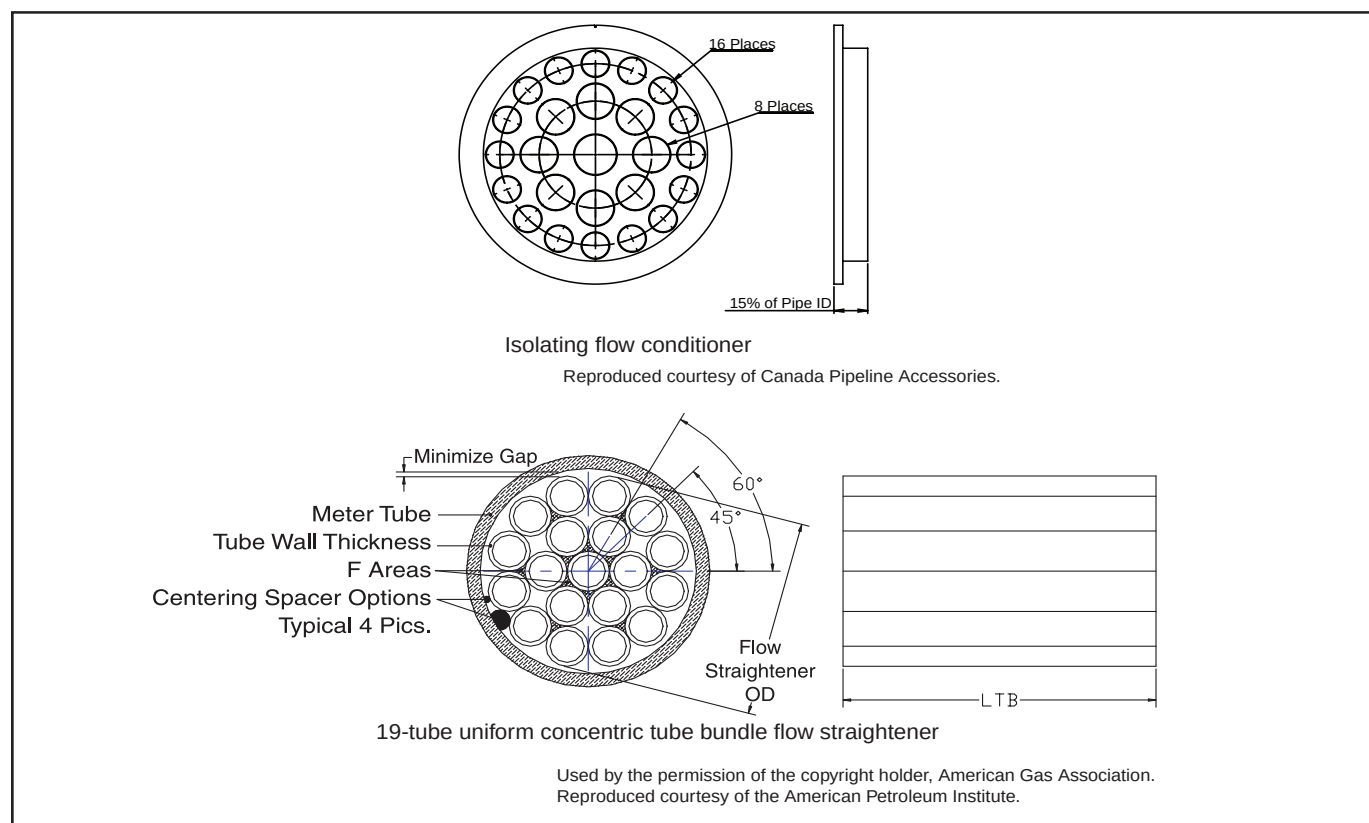
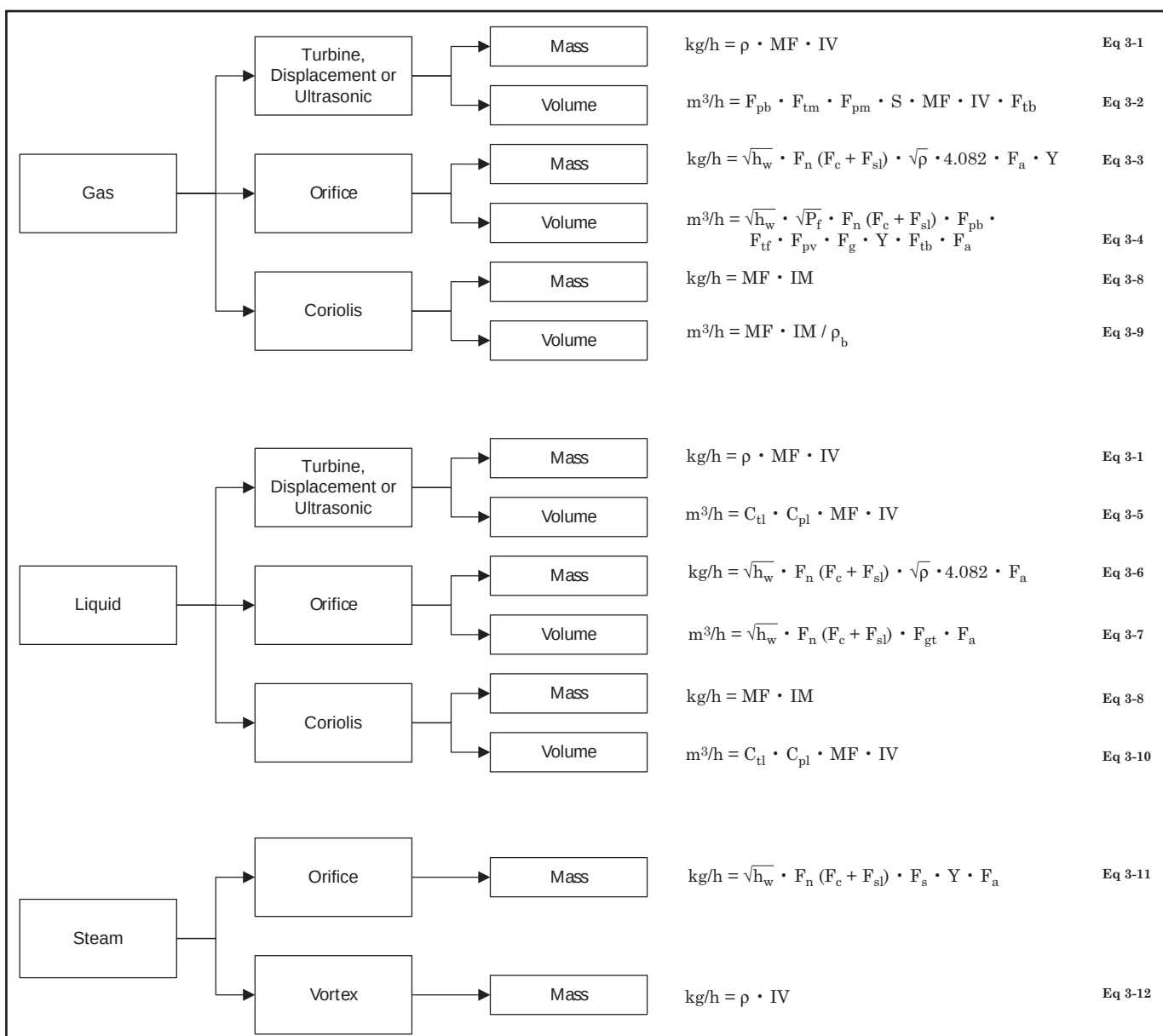


FIG. 3-4
Flow Calculation Guide Equations



Other Equations

$$F_{pb} = \frac{101.325}{P_b}$$

$$F_{tb} = \frac{273 + T_b}{288}$$

$$F_{tf} = \sqrt{\frac{288}{273 + T_f}}$$

$$F_g = \sqrt{\frac{1.0000}{G}} \quad F_{gt} = \frac{0.3528}{\sqrt{G_l}} \sqrt{\frac{G_f}{G_l}}$$

(See Fig. 23-10 and 23-11 for G_f/G_l conversions)

$$Q = C' \sqrt{h_w \cdot P_f}$$

$$C' = F_n (F_c + F_{sl}) \cdot F_{pb} \cdot F_{tf} \cdot F_{pv} \cdot F_g \cdot Y \cdot F_{tb} \cdot F_a$$

$$F_a = 1 + [0.0000333 (T_f - T_{meas})] \text{ for 304/316 Stainless Steel}$$

$$C_{pl} = \frac{1}{1 - (F \cdot D_p)}$$

$$F_n (F_c + F_{sl}) = \text{Key} = \text{orifice factor (Fig. 3-13)}$$



FIG. 3-5
Orifice Plate Holders

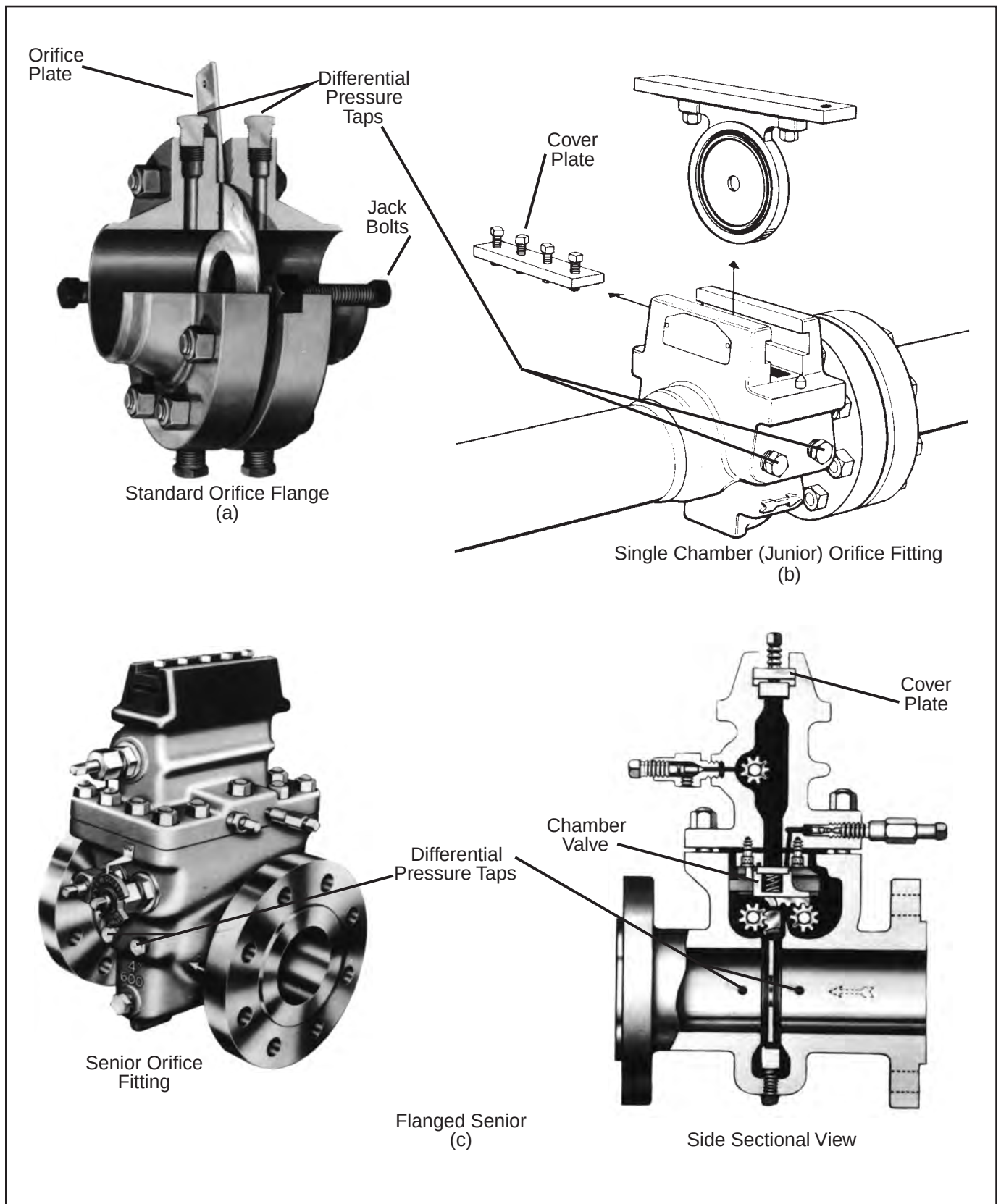
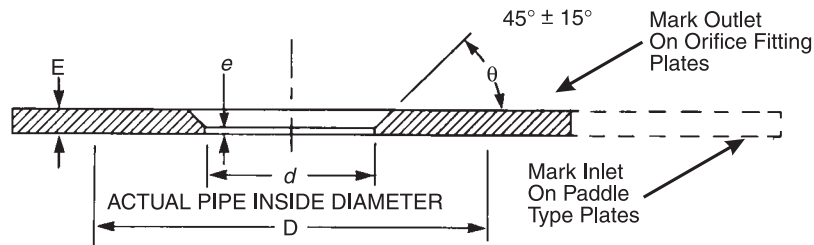


FIG. 3-6

Orifice Plate Thickness and Maximum Allowable Differential Pressure Based on the Structural Limit



Nominal Pipe Size (DN) (mm)	Published Inside Pipe Diameter (mm)	Orifice Plate Thickness E (mm)			Maximum Allowable ΔP (mm H ₂ O) Orifice Fitting	Maximum Allowable ΔP (mm H ₂ O) Orifice Flanges
		Minimum	Maximum	Recommended		
50	42.85	2.921	3.302	3.175	25 400	25 400
	49.25	2.921	3.302	3.175	25 400	25 400
	52.50	2.921	3.302	3.175	25 400	25 400
75	58.42	2.921	3.302	3.175	25 400	25 400
	66.65	2.921	3.302	3.175	25 400	25 400
	73.66	2.921	3.302	3.175	25 400	25 400
	77.93	2.921	3.302	3.175	25 400	25 400
100	80.06	2.921	3.302	3.175	25 400	25 400
	87.33	2.921	3.302	3.175	25 400	25 400
	97.18	2.921	3.302	3.175	25 400	25 400
	102.26	2.921	3.302	3.175	25 400	25 400
150	124.38	2.921	4.140	3.175	8763	25 400
	131.75	2.921	4.140	3.175	8763	25 400
	146.33	2.921	4.877	3.175	8763	25 400
	154.05	2.921	4.877	3.175	8763	25 400
200	193.68	2.921	6.452	6.350	25 400	25 400
	202.72	2.921	8.102	6.350	25 400	25 400
	205.00	2.921	8.102	6.350	25 400	25 400
250	242.87	2.921	8.102	6.350	14 478	25 400
	254.51	2.921	8.102	6.350	14 478	25 400
	257.45	2.921	8.102	6.350	14 478	25 400
300	288.90	4.445	9.627	6.350	7239	25 400
	303.23	4.445	10.109	6.350	7239	25 400
	307.09	4.445	10.109	6.350	7239	25 400
400	373.08	4.445	12.446	9.525	11 811	25 400
	381.00	4.445	12.700	9.525	11 811	25 400
	381.64	4.445	12.700	9.525	11 811	25 400

FIG. 3-6 (Cont'd.)

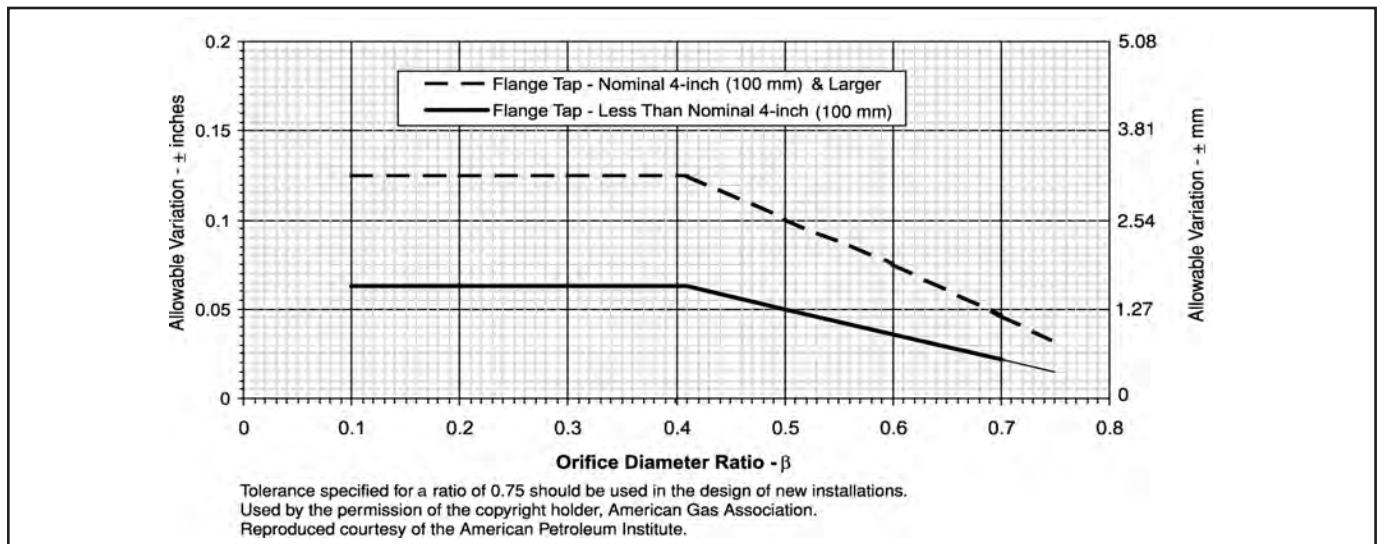
Orifice Plate Thickness and Maximum Allowable Differential Pressure Based on the Structural Limit

Nominal Pipe Size (DN) (mm)	Published Inside Pipe Diameter (mm)	Orifice Plate Thickness E (mm)			Maximum Allowable ΔP (mm H ₂ O) Orifice Fitting	Maximum Allowable ΔP (mm H ₂ O) Orifice Flanges
		Minimum	Maximum	Recommended		
500	477.82	6.096	12.827	9.525	5969	25 400
	482.60	6.096	12.827	9.525	5969	25 400
	488.95	6.096	12.827	9.525	5969	25 400
600	574.65	6.096	12.827	12.700	9144	25 400
	584.20	6.096	14.274	12.700	9144	25 400
	590.55	6.096	14.274	12.700	9144	25 400
750	730.25	9.398	14.274	12.700	4572	25 400
	736.60	9.398	14.681	12.700	4572	25 400
	742.95	9.398	14.681	12.700	4572	25 400

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FIG. 3-7

Allowable Variations in Pressure Tap Hole Location



Gas Orifice Calculations

Orifice Sizing — A simple calculation is often needed to properly size an orifice plate for new or changing flow rates through existing meter tubes. The procedure uses an existing or assumed flow quantity, a desired differential pressure at a specific static pressure, an estimated flowing temperature, and a determined or assumed relative density (specific gravity). The Key orifice coefficient is calculated from the gas flow equation. This calculated value is then compared to Fig. 3-13, and the next larger size is usually selected.

Example 3-1 — Size an orifice plate in gas service.

Given Data:

Line Size, D = 100 mm
Flange Taps

Relative Density = 0.700
Flowing Temperature = 38°C
Flowing Pressure = 517 kPa (abs)
Flow Rate = 402.1 m³/h
101.56 kPa (abs), 15.6°C
Desired Differential = 1270 mm of water

To determine the approximate orifice size required, the corresponding Key_g (natural gas) is calculated using appropriate terms of Equation 3-4;

$$Q_h = \text{Key}_g \cdot F_{tf} \cdot F_g \cdot \sqrt{h_w \cdot P_f} \quad \text{from Equation 3-4}$$

Rearranging,

$$\text{Key}_g = \frac{Q_h}{F_{tf} \cdot F_g \cdot \sqrt{h_w \cdot P_f}} \quad \text{Eq 3-13}$$

$$Key_g = \frac{402.1}{0.9623 (1.1952) \sqrt{1270 \cdot 517}}$$

$$F_{tf} = [288 / (273 + T_f)]^{1/2} = 0.9623 \quad \text{Fig. 3-4}$$

$$F_g = [1.000/G]^{1/2} = 1.1952 \quad \text{Fig. 3-4}$$

$$Key_g = 0.4315$$

Referring to Key_g (Fig. 3-13) for a 100 mm line with flange taps, access the Key_g value which approximates the calculated number. A 25 mm orifice size would be selected which has a Key_g value of 0.418. More precise calculations would include other corrections. For more precise custody transfer calculations, please refer to API Chapter 14.3 (AGA Report No. 3).

Orifice Flow Rate — The following example illustrates a calculation of flow rate through an orifice.

Example 3-2 — Calculate an approximate flow rate for the orifice using appropriate terms from Equation 3-4.

Given Data:

Line Size, D	=	150 mm
Orifice Size, d	=	85 mm
Flange Taps		
Flowing Temperature	=	21°C
Flowing Pressure	=	620.5 kPa (abs)
Differential	=	1524 mm of water
Relative Density	=	0.750

From Fig. 3-4,

$$Q_h = Key_g \cdot F_{tf} \cdot F_g \cdot \sqrt{h_w \cdot P_f} \quad \text{from Equation 3-4}$$

$$F_{tf} = [288 / (273 + T_f)]^{1/2} = 0.9897 \quad \text{Fig. 3-4}$$

$$F_g = [1.000/G]^{1/2} = 1.1547 \quad \text{Fig. 3-4}$$

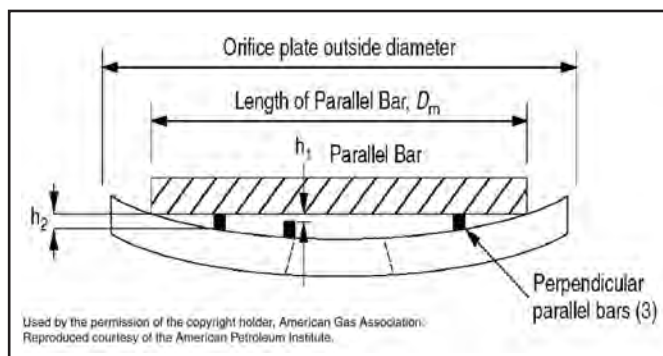
$$Q_h = 5.143 (0.9897) (1.1547) \sqrt{1524 \cdot 620.5}$$

$$Q_h = 5715.5 \text{ m}^3/\text{h}$$

More precise calculations would include other corrections such as F_{pv} , F_{gt} , Y , F_{tb} and F_a .

FIG. 3-8

Alternative Method for Determination of Orifice Plate Departure from Flatness
(Departure from Flatness = $h_2 - h_1$)



For more precise custody transfer calculations, please refer to API Chapter 14.3 (AGA Report No. 3).

Orifice Well Test

Often it is necessary to determine an approximate flow quantity from a well head or field separator vent to the atmosphere for test purposes. The use of a "well head tester" has been a common practice since the early days of the oil and gas industry. See Fig. 3-14. An orifice is installed between a pair of flanges, at the outlet of a pipe nipple which is at least eight pipe diameters long. The square edge of the orifice faces the flow. The diameter of the pipe nipple should not be greater than the preceding fittings. The pressure connection may be made in the upstream flange or at any point in the pipe nipple within three diameters from the orifice. The pressure differential across the orifice is the difference between the upstream pressure and atmospheric pressure.

For conditions other than 15.6°C (flowing) and G of 0.6, correction factors must be applied.

Example 3-3 — Calculate the daily gas flow through a 25.4 mm orifice in a nominal 75 mm pipe. The gas relative density is 0.60, the flowing temperature is 15.6°C, and the pressure upstream of the orifice is 127 mm Hg. The published ID of a 75 mm pipe is 77.93 mm.

$$Q = 0.0283 (1 + \beta^4) (d^2) \sqrt{H (744.2 + 0.3H)} \cdot F_{tf} \cdot C_g \quad \text{Eq 3-14}$$

$$F_{tf} = \sqrt{\frac{288}{273 + T_f}} \quad \text{Eq 3-15}$$

$$C_g = \sqrt{\frac{0.60}{G}} \quad \text{Eq 3-16}$$

$$Q = 0.0283 \left[1 + \left(\frac{25.4}{77.93} \right)^4 \right] (25.4)^2 \sqrt{127 [744.2 + (0.3) (127)]} \cdot 0.9990 \cdot 1.0000 = 5814 \text{ m}^3/\text{day}$$

FIG. 3-9

Orifice Meter Tube Layout for Flanged or Welded Limit

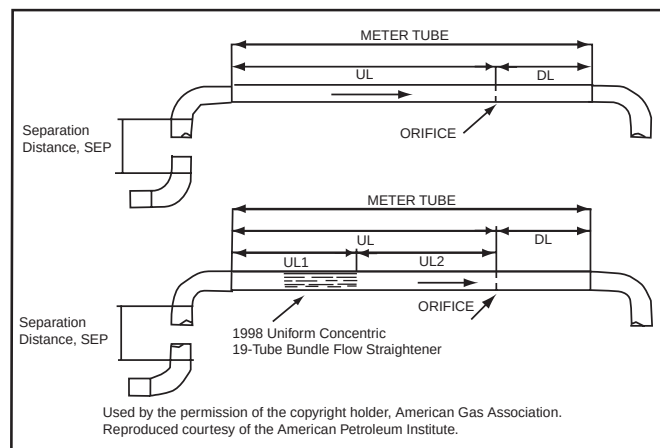


FIG. 3-10

Orifice Meter Installation Requirements Without a Flow Conditioner

Minimum straight unobstructed meter tube length from the upstream and downstream side of the orifice plate (in multiples of published internal pipe diameter, D_1)

Minimum straight unobstructed meter tube length from the upstream and downstream side of the orifice plate (in multiples of published internal pipe diameter, D_1)

Diameter ratio β	a. Single 90° elbow. b. Two 90° elbows in the same plane with SEP > 30D ₁ . c. Two 90° elbows in perpendicular planes with SEP > 15D ₁ .	Two 90° elbows in the same plane "SEP" configuration SEP ≤ 10D ₁ .	Two 90° elbows in perpendicular planes, SEP < 5D ₁ .*	Two 90° elbows in perpendicular planes, 5D ₁ ≤ SEP ≤ 15D ₁ .	Single 90° Tee used as an elbow but not as a header element	a. Single 45° elbow. b. Two 45° elbows in the same "SEP" configuration SEP ≥ 22D ₁ .	Gate valve at least 50% open	Concentric reducer	Any other configuration (catch all category)*	Downstream meter tube length
	UL	UL	UL	UL	UL	UL	UL	UL	UL	DL
	6	10	10	50	19	9	30	17	70	2.8
0.30	11	10	12	50	32	9	30	19	108	3.0
0.40	16	10	13	50	44	9	30	21	145	3.2
0.50	30	30	18	95	44	19	30	25	145	3.5
0.60	44	44	30	95	44	29	30	30	145	3.9
0.67	44	44	44	95	44	36	44	35	145	4.2
0.75	44	44	44	95	44	44	44	44	145	4.5
Recommended length for maximum range $\beta \leq 0.75$	44	44	44	95	44	44	44	44	145	4.5

UL – Minimum meter tube length upstream of the orifice plate in internal pipe diameter, D_1 (See Figure 3-9). Straight length shall be measured from the downstream end of the curved portion of the nearest (or only) elbow or of the tee or the downstream end of the conical portion of reducer or expander.

DL – Minimum downstream meter tube length in internal pipe diameters, D_1 (See Figure 3-9).

SEP – Separation distance between piping elements in internal pipe diameter, D_1 , measured from the downstream end of the curved portion of the upstream elbow to the upstream end of the curved portion of the downstream elbow.

Note: The tolerance on specified lengths for UL and DL is $\pm 0.25D_1$.

* – This installation exhibits strong effect of Reynolds number and pipe roughness on the recommended length due to rate of decay of swirl. The present recommendations have been developed for high Reynolds numbers and smooth pipes to capture the worst case.

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