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Flow Measurement

User Manual

Flow Computer Division

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This manual is periodically altered to incorporate new or updated information. The date revision level of each page is indicated at the bottom of the page opposite the page number. A major change in the content of the manual also changes the date of the manual, which appears on the front cover. Listed below is the date revision level of each page.

Page	Revision
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SECTION 1 – INTRODUCTION

1.1 Overview

This manual discusses gas flow measurement based on philosophies expressed in AGA (American Gas Association) and API (American Petroleum Institute) guidelines.

❖ **NOTE**: AGA and API do not certify manufacturers' equipment for flow measurement. Products of The Flow Computer Division of Emerson Process Management are in compliance with AGA and API guidelines.

The American Gas Association (AGA) has published various reports describing how to measure the flow of natural gas, starting with AGA Report No. 1, issued in 1930, describing the measurement of natural gas through an orifice meter. This report was revised in 1935 with the publication of AGA Report No. 2 and again in 1955 with the publication of AGA Report No. 3. The report was revised again in 1969, 1978, 1985, and 1992, but has remained AGA Report No. 3 -- Orifice Metering of Natural Gas and Other Related Hydrocarbons. Thus, AGA3 has become synonymous with orifice metering.

In 1975, the American Petroleum Institute (API) adopted AGA Report No. 3 and approved it as API Standard 2530 and also published it as Chapter 14.3 of the API Manual of Petroleum Measurement Standards. In 1977, the American National Standards Institute (ANSI) also approved AGA Report No. 3 and referred to it as ANSI/API 2530. Thus references to API 2530, Chapter 14.3 and ANSI/API 2530 are identical to AGA Report No. 3. In 1980 (revised in 1984 and in 1996), AGA Report No. 7--Measurement of Fuel Gas by Turbine Meters--was published, detailing the measurement of natural gas through a turbine meter.

While AGA No. 3 and AGA No. 7 detail methods of calculating gas flow, separate documents have been created to explain the calculation of the compressibility factor, used in both AGA No. 3 and AGA No. 7. The older method, called NX-19, was last published in 1963. A more comprehensive method was published in 1985 as AGA Report No. 8. This report was revised in 1992.

In 1992, the API released Chapter 21, Section 1, which addressed the application of electronic flow meters in gas measurement systems. It addresses the calculation frequency and the method of executing the AGA calculations.

SECTION 2 – NATURAL GAS MEASUREMENT

2.1 AGA Report No. 7 - Measurement of Gas by Turbine Meters

2.1.1 General Description

AGA No. 7 covers the measurement of gas by turbine meters and is limited to axial-flow turbine meters. Although the report covers meter construction, installation, and other aspects of metering, this Flow Manual summarizes only the equations used in calculating flow.

The meter construction and installation sections are specific to axial-flow turbine meters, but the flow equations are applicable to any linear meter, including ultrasonic and vortex meters.

2.1.2 Introduction

The turbine meter is a velocity measuring device. It consists of three basic components:

- The body
- The measuring mechanism
- The output and readout device

It relies upon the flow of gas to cause the meter rotor to turn at a speed proportional to the flow rate. Ideally, the rotational speed is proportional to the flow rate. In actuality, the speed is a function of passage-way size, shape, rotor design, internal mechanical friction, fluid drag, external loading, and gas density.

Several characteristics that affect the performance of a turbine meter are presented in Section 5 of AGA No. 7. Here is a summary of these characteristics:

Swirl Effect - Turbine meters are designed and calibrated under conditions approaching axial flow. If the flowing gas has substantial swirl near the rotor inlet, depending on the direction, the rotor can either increase or decrease in velocity. Buyer or seller can lose.

Velocity Profile Effect - If poor installation practices result in a non-uniform velocity profile across the meter inlet, the rotor speed for a given flow rate will be affected. Typically, this results in higher rotor velocities. Thus, less gas passes through the meter than the calculated value represents. Buyer loses.

Fluid Drag Effect - Fluid drag on the rotor blades, blade tips and rotor hub can cause the rotor to slip from its ideal speed. This rotor slip is known to be a function of a dimensionless ratio of inertia to viscous forces. This ratio is the well known Reynolds number and the fluid drag effect has become known as the “Reynolds number effect.” Basically, it slows the rotor down, thus the Buyer wins.

Non-Fluid Drag Effect - Also decreasing rotor speed from its ideal speed are forces created from non-fluid related forces, such as bearing friction and mechanical or electrical readout drag. The amount of slip is a function of flow rate and density. Also know as "the density effect." It also benefits the buyer.

Accuracy - Accuracy statements are typically provided within ± 1% for a designated range.

Linearity - Turbine meters are usually linear over some designated flow range. Linear means that the output frequency is proportional to flow.

Pressure Loss - Pressure loss is attributed to the energy required to drive the meter.

Minimum and Maximum Flow Rates - Turbine meters will have designated minimum flow rates for specific conditions.

Pulsation - Error due to pulsation generally creates an error causing the rotor to spin faster, thus resulting in errors that favor the seller. A peak-to-peak flow variation of 10% of the average flow generally will result in a pulsation error of less than 0.25% and can be considered as the pulsation threshold.

2.1.3 Basic Gas Law Relationship

The basic gas law relationships are presented similarly in the 1985 and 1996 versions of AGA No. 7. The equation numbers shown here are from the 1996 version. The relationships are:

$$(P_f)(V_f) = (Z_f)(N)(R)(T_f) \text{ For Flowing Conditions} \quad \text{[AGA Equation 12]}$$

and

$$(P_b)(V_b) = (Z_b)(N)(R)(T_b) \text{ For Base Conditions} \quad \text{[AGA Equation 13]}$$

where: P = Absolute pressure

V = Volume

Z = Compressibility

N = Number of moles of gas

T = Absolute temperature

R = Universal gas constant

subscript $_f$ = Flowing conditions (use with P, V, and Z)

subscript $_b$ = Base-conditions (use with P, V, and Z)

Since R is a constant for the gas regardless of pressure and temperature, and for the same number of moles of gas N, the two equations can be combined to yield:

$$V_b = V_f \left(\frac{P_f}{P_b}\right)\left(\frac{T_b}{T_f}\right)\left(\frac{Z_b}{Z_f}\right) \quad \text{[AGA Equation 14]}$$

2.1.4 Difference Between the 1985 and 1996 Versions

The difference between the versions as it applies to the flow calculations, is that the 1985 flow equations included factors, such as F_{pm} , the measured pressure factor, and F_{Pb}, the base pressure factor. In the 1996 version, the correction factors have been combined into multipliers. For example, the pressure factors, F_{pm} and F_b have been combined into the pressure multiplier, P_f / P_b

$$1985: \quad P_m = \frac{P_f}{P_s} \text{ and } P_b = \frac{P_s}{P_b}$$

$$1996: \quad \text{Pressure Multiplier} = P_m \bullet P_b = \frac{P_f}{P_b}$$

2.1.5 AGA No. 7 – 1985 Version

2.1.5.1 The Flow Equation

Rotor revolutions are counted mechanically or electrically and converted to a continuously totalized volumetric registration. Because the registered volume is at flowing pressure and temperature conditions, it must be corrected to the specified base conditions for billing purposes.

2.1.5.2 General Form of the Flow Equation and a Term-by-Term Explanation

Q_b Flow rate at base conditions (cubic feet per hour)

$$Q_b = (Q_f)(F_{pm})(F_{pb})(F_{tm})(F_{tb})(s) \qquad \text{[AGA Equation 15]}$$

where: Q_b = Volumetric flow rate at base conditions

Q_f = Volumetric flow rate at flowing conditions

F_{pm} = Pressure factor

F_{pb} = Pressure base factor

F_{tm} = Flowing temperature factor

F_{tb} = Temperature base factor

s = Compressibility ratio factor

Q_f Flow Rate at Flowing Conditions (Cubic Feet per Hour)

$$Q_f = \frac{V_f}{t} \qquad \text{[AGA Equation 14]}$$

where Q_f = Flow rate at flowing conditions

V_f = Volume timed at flowing conditions

= Counter differences on mechanical output

$= \text{Total pulses} \times \frac{1}{K}$ on electrical output

t = Time

K = Pulses per cubic foot

F_{pm} Pressure Factor

$$F_{pm} = \frac{p_f}{14.73} \qquad \text{[AGA Equation 16]}$$

where p_f = $P_f + p_a$

P_f = Static gauge pressure, psig

p_a = Atmospheric pressure, psia

F_{pb} Pressure Base Factor

$$F_{pb} = \frac{14.73}{p_b} \qquad \text{[AGA Equation 18]}$$

Where p_b is the contract base pressure in psia.

This factor is applied to change the base pressure from 14.73 psia to another contract pressure base.

F_{tm} Flowing Temperature Factor

$$F_{tm} = \frac{520}{T_f} \qquad \text{[AGA Equation 19]}$$

Where T_f = actual flowing temperature of the gas in degrees Rankine. °R = ° F + 459.76°

F_{tb} Temperature Base Factor

$$F_{tb} = \frac{T_b}{520} \qquad \text{[AGA Equation 20]}$$

Where T_b = the contract base temperature in degrees Rankine.

This factor is applied to change the assumed temperature base of 60 deg F to the actual contract base temperature.

s Compressibility Factor Ratio

$$s = \frac{Z_b}{Z_f} \qquad \text{[AGA Equation 21]}$$

where Z_b = Compressibility factor at base conditions

Z_f = Compressibility factor at flowing conditions

The compressibility ratio "s" can be evaluated from the supercompressibility factor "F_{pv}", which is defined as:

$$s = (F_{pv})^2$$

where $F_{pv} = \sqrt{Z_b / Z_f}$

The calculation of the supercompressibility factor F_{pv} is given in AGA Report NX-19 or AGA No. 8. For more information, refer to Section 3.

2.1.6 AGA No. 7 – 1996 Version

2.1.6.1 The Flow Equation

Rotor revolutions are counted mechanically or electrically and converted to a continuously totalized volumetric registration. Since the registered volume is at flowing pressure and temperature conditions, it must be corrected to the specified base conditions for billing purposes.

2.1.6.2 General Form of the Volumetric Flow Equation

Q_b Flow rate at flowing conditions

$$Q_f = \frac{V_f}{t} \qquad \text{[AGA Equation 15]}$$

where Q_f = Flow rate at flowing conditions

V_f = Volume timed at flowing conditions

= Counter differences on mechanical output

= Total pulses $\times \dfrac{1}{K} \times$ *METER FACTOR* on electrical pulse output

t = Time

K = K-Factor, pulses per cubic foot

METER FACTOR is a dimensionless term obtained by dividing the actual volume of gas passed through the meter (as measured by a prover during proving) by the corresponding meter indicated volume. For subsequent metering operations, actual measured volume is determined by multiplying the indicated volume registered by the meter times the METER FACTOR.

Q_b Flow rate at base conditions (cubic feet per hour)

$$Q_b = (Q_f)\left(\frac{P_f}{P_b}\right)\left(\frac{T_b}{T_f}\right)\left(\frac{Z_b}{Z_f}\right) \qquad \text{[AGA Equation 16]}$$

where: Q_b = Volumetric flow rate at base conditions

Q_f = Volumetric flow rate at flowing conditions

The *P, T,* and *Z* quotients in the above equation are the pressure multiplier, temperature multiplier, and the compressibility multipliers, respectively. They are defined below.

Pressure Multiplier

$$pressure\ \ Multiplier = \frac{P_f}{P_b} \qquad \text{[AGA Equation 17]}$$

where: P_f = $p_f + p_a$, in psia

p_f = Static gauge pressure, in psig

P_a = Atmospheric pressure, in psia

P_b = Base pressure, in psia

Temperature Multiplier

$$Temperature\ \ Multiplier = \frac{T_b}{T_f} \qquad \text{[AGA Equation 18]}$$

where: T_b = Base temperature, °R

T_f = Flowing temperature, °R

Absolute Flowing Temperature, °R = ° F + 459.76°

Compressibility Multiplier

$$Compressibility\ \ Multiplier = \frac{Z_b}{Z_f} \qquad \text{[AGA Equation 19]}$$

where: Z_b = Compressibility at base conditions

Z_f = Compressibility at flowing conditions

The compressibility multiplier can be evaluated from the supercompressibility factor, F_{pv} as follows:

$$\frac{Z_b}{Z_f} = (F_{pv})^2 \qquad \text{[AGA Equation 20]}$$

Where natural gas mixtures are being measured, compressibility values may be determined from the latest edition of AGA Transmission Measurement Committee Report No. 8 “Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases” or as specified in contracts or tariffs or as mutually agreed to by both parties. For more information, refer to Section 3.

2.2 AGA Report No. 3 – Orifice Metering of Natural Gas

2.2.1 General Description

AGA Report No. 3 is an application guide for orifice metering of natural gas and other related hydrocarbon fluids. This Flow Manual summarizes some of the equations used in calculating flow and is based on part 3 of the report.

2.2.2 Differences Between 1985 and 1992 Versions of AGA No. 3

AGA No. 3 – 1992 version was developed for flange-tap orifice meters only. The pipe tap methodology of the 1985 version is included as an appendix in the 1992 standard. This appendix is identical to the 1985 version with the exception of F_{pb}, F_{tb}, F_{tf}, F_{gr}, and F_{pr}. These factors are to be implemented per the body of the 1992 standard. For F_{pr}, this indicates using the most recent version of AGA No. 8 to calculate compressibility. The new version is based on the calculation of a discharge coefficient. The Reynolds number is a function of flow. It must be determined iteratively. In addition, the orifice diameter and pipe diameter are both corrected for temperature variations from the temperature at which they were measured. This requires additional parameters for the measured temperature of the pipe and the orifice material.

The empirical coefficient of discharge has received much emphasis in the creation of the 1992 report. It is a function of the Reynolds Number, sensing tap location, pipe diameter and the beta ratio. An expanded Regression data base consisting of data taken from 4 fluids (oil, water, natural gas, air) from different sources, 11 different laboratories, on 12 different meter tubes of differing origins and more than 100 orifice plates of different origins. This data provided a pipe Reynolds Number range of accepted turbulent flow from 4,000 to 36,000,000 on which to best select the mathematical model. Flange, corner, and radius taps; 2, 3, 4, 6, and 10 inch pipe diameters; and beta ratios of 0.1, 0.2, 0.375, 0.5, 0.575, 0.660, and 0.750 were all tested.

Technical experts from the US, Europe, Canada, Norway and Japan worked together to develop an equation using the Stolz linkage form that fits this expanded Regression Data Base more accurately than any previously published equations. The empirical data associated with this data base is the highest quality and largest quantity available today. This is perhaps the greatest improvement over the 1985 equations. This mathematical model for the Coefficient of Discharge is applicable and most accurately follows the Regression data base for nominal pipe sizes of 2 inches and larger, beta ratios of 0.1 to 0.75 (provided that the orifice plate bore diameter is greater than 0.45 inch), and pipe Reynolds number greater than or equal to 4000.

Concentricity tolerances have been tightened from the 1985 statement of 3%. The 1992 uses an equation to calculate the maximum allowed eccentricity. Eccentricity has a major effect on the accuracy of the coefficient of discharge calculations.

AGA No. 3 – 1992 version calls for the use of AGA No. 8 for the calculation of the supercompressibility factor. As no specific version is specified, this implies using the most recently released version, NX-19 or AGA No. 8 - 1985 version should not be used with the new version.

Unlike the 1985 report, the AGA No. 3 - 1992 report was divided into four parts:

- Part 1 - General Equations and Uncertainty Guidelines

- Part 2 - Specifications and Installation Requirements
- Part 3 - Natural Gas Applications
- Part 4 - Background, Development, Implementation Procedure, and Subroutine Documentation for Empirical Flange Tapped Discharge Coefficient Equation

Part 3 provides an application guide along with practical guidelines for applying AGA Report No. 3, Parts 1 and 2, to the measurement of natural gas. Mass flow rate and base (or standard) volumetric rate methods are presented in conformance with North American industry practices.

2.2.3 AGA No. 3 – 1985 Version

The orifice meter is essentially a mass flow meter. It is based on the concepts of conservation of mass and energy. The orifice mass flow equation is the basis for volumetric flow rate calculations under actual conditions as well as at standard conditions. Once mass flow rate is calculated, it can be converted into volumetric flow rate at base (standard) conditions if the fluid density at base conditions can be determined or is specified.

AGA Report No. 3 defined measurement for orifice meters with circular orifices located concentrically in the meter tube having upstream and downstream pressure taps. Pressure taps must be either flange taps or pipe taps and must conform to guidelines found in the AGA 3 report.

This standard applies to natural gas, natural gas liquids, and associated hydrocarbon gases and liquids. It was not intended for non-hydrocarbon gas or liquid streams.

2.2.3.1 Topics Worthy of Mention

Concentricity - When centering the orifice plates, the orifice must be concentric with the inside of the meter tube to within 3% of the inside diameters. This is more critical in small tubes, tubes with large beta ratios, and when the orifice is offset towards the taps.

Beta Ratio Limitations - Beta ratio, the ratio of the orifice to meter tube for flange taps, is limited to the range of 0.15 to 0.7. For pipe taps, it should be limited to 0.2 to 0.67.

Pulsation Flow - Reliable measurements of gas flow cannot be obtained with an orifice meter when appreciable pulsations are present at the place of measurement. No satisfactory adjustment for flow pulsation has ever been found. Sources of pulsation include:

1. Reciprocating compressors, engines or impeller type boosters
2. Pumping or improperly sized regulators
3. Irregular movement of water or condensates in the line
4. Intermitters on wells and automatic drips
5. Dead-ended piping tee junctions and similar cavities.

2.2.3.2 General Form of the Flow Equation

$$Q_v = C'[h_w P_f]^{0.5}$$ [AGA Equation 59]

where: Q_v = Volume flow rate (cubic feet per hour) at base conditions

h_w = Differential pressure (inches of water at 60 Deg F)

P_f = Absolute static pressure in pounds per square inch absolute, use subscript 1 when the absolute static pressure is measured at the upstream orifice tap or subscript 2 when the absolute static pressure is measured at the downstream orifice tap.

and:

$$C' = F_b F_r Y F_{pb} F_{tb} F_{tf} F_{gr} F_{pv}$$ [AGA Equation 60]

where: C' = Orifice flow constant

F_b = Basic orifice factor

F_r = Reynolds Number factor

Y = Expansion factor

F_{pb} = Pressure base factor

F_{tb} = Temperature base factor

F_{tf} = Flowing temperature factor

F_{gr} = Real gas relative density factor

F_{pv} = Supercompressibility (F_{pv} is called the "supercompressibility factor" in the 1985 standard. Z is referred to as "compressibility.")

<u>Terms</u>

F_b = The basic orifice factor is a function of the orifice diameter and the flow coefficient, K.

F_r = Reynolds Number factor accounts for changes in the Reynolds number based on meter tube size and orifice diameter.

Y = The expansion factor is used to adjust the basic orifice factor for the change in the fluids velocity and static pressure which is accompanied by a change in the density. It is a function of the beta ratio and the ratio of specific heats of the gas at specific pressure and volume.

F_{pb} = Pressure base factor is used to account for contracts where the contract pressure is other than 14.73 PSIA.

$$F_{pb} = \frac{14.73}{p_b}$$

Where p_b is the contract base pressure in psia.

This factor is applied to change the base pressure from 14.73 psia to another contract pressure base.

F_{tb} = Temperature base factor is used to account for contracts where the contract temperature is other than 60 degrees F.

$$F_{tb} = \frac{T_b}{519.67}$$

Where T_b = the contract base temperature in degrees Rankine. °R = ° F + 459.76°

This factor is applied to change the assumed temperature base of 60 deg F to the actual contract base temperature.

F_{tf} = Flowing temperature factor is used to change the assumed flowing temperature of 60 degrees to the actual flowing temperature.

$$F_{tf} = [\ \frac{519.67}{T_f}\ ]^{0.5}$$

Where T_f = actual flowing temperature of the gas in degrees Rankine. °R = ° F + 459.76°

F_{gr} = Real gas relative density is used to change the gas density from a real gas relative density of 1.0 to the real gas relative density during flowing conditions.

$$F_{gr} = [\ \frac{1}{G_r}\ ]^{0.5}$$

Where G_r = is the real relative gas density and is calculated from the ideal gas relative density and a ratio of the compressibility of air to the compressibility of the gas.

F_{pv} = Supercompressibility

$$F_{pv} = [\ \frac{Z_b}{Z_{f1}}\ ]^{0.5}$$

Where Z_b is the compressibility of the gas at base conditions (P_b,T_b) and Z_{f1} is the compressibility of the gas at upstream flowing conditions (P_{f1},T_{f1}).

2.2.4 AGA No. 3 – 1992 Version

The term "Natural Gas" is defined as fluids that for all practical purposes are considered to include both pipeline- and production-quality gas with single-phase flow and mole percentage ranges of components as given in AGA Report No. 8, Compressibility and Supercompressibility for Natural Gas and other Hydrocarbon Gases.

This standard applies to fluids that, for all practical purposes, are considered to be clean, single phase, homogeneous, and Newtonian, measured using concentric, square-edged, flange tapped orifice meters. Pulsating flow, as in 1985, should be avoided. General flow conditions to be followed:

1. Flow shall approach steady-state mass flow conditions on fluids that are considered clean, single phase, homogeneous and Newtonian.

2. The fluid shall not undergo any change of state as it passes through the orifice.
3. The flow shall be subsonic through the orifice and meter tube.
4. The Reynolds number shall be within the specified limitations of the empirical coefficients.
5. No bypass of flow around the orifice shall occur at any time.

Temperature is assumed to be constant between the two different pressure tap locations and the temperature well. Standard conditions are defined as a designated set of base conditions. These conditions are Ps = 14.73 PSIA, Ts = 60 Degrees F, and the fluid compressibility, Zs, for a stated relative density, G. Once they are calculated for assumed conditions, they are adjusted for non-base conditions.

Bi-directional flow through an orifice meter requires a specially configured meter tube and the use of an unbeveled orifice plate. Use of an unbeveled orifice plate must meet the limits specified in AGA No. 3 – 1992 version, Table 2-4.

The fluid should enter the orifice plate with a fully developed flow profile, free from swirl or vortices. To do this, flow conditioners or adequate upstream and downstream straight pipe length should exist. Any serious distortion of the flow profile will produce flow measurement errors. Several installation guidelines are provided in Part 2 of the report dealing with proper installation layouts.

2.2.5 General Form of the Flow Equation

$$Q_m = E_v Y C_d d^2 \frac{\pi}{4} \sqrt{2 g_c \rho_{tP} \Delta P}$$ [AGA Equation 1-1]

2.2.6 Volume Flow Rate Equation at Standard Conditions

[AGA Equation 3-6b]

$$Q_v = 7709.61 E_v Y_1 C_d d^2 \sqrt{\frac{Z_s P_{f1} h_w}{G_r Z_{f1} T_f}}$$

where: Q_v = Standard volume flow rate (cubic feet per hour)

C_d = Orifice Plate discharge coefficient (dimensionless)

E_v = Velocity of approach factor (dimensionless)

Y_1 = Gas expansion factor (upstream) (dimensionless)

d = Orifice bore (inches)

G_r = Real gas relative density (dimensionless)

Z_s = Compressibility factor of gas at standard conditions (dimensionless)

Z_{f1} = Compressibility factor of gas at flowing conditions (upstream) (dimensionless)

P_{f1} = Upstream absolute pressure of gas at flowing conditions (psia)

T_f = Absolute temperature of gas at flowing conditions (Deg Rankine)

h_w = Differential pressure (inches of water at 60 Deg F)

❖ **NOTES:** AGA 3, Part 4 imposes a calculation accuracy requirement of 0.005%. This is not related to the flow accuracy, which is affected by sensor errors and other measurement-related errors. To achieve the 0.005% calculation accuracy, the flow computer must implement the full AGA equations and IEEE 32-bit floating-point arithmetic for a given set process variables.

2.2.6.1 Term by Term Explanation

Q_v Standard volume flow rate in SCFH (Standard Cubic Feet per Hour)

Note: The word “standard” is frequently dropped and the “volumes” are spoken of.

C_d Orifice discharge coefficient

1. This is an empirical term that relates to the geometry of the meter and relates the true flow rate to the theoretical flow rate. An approximate value is 0.6 (i.e., a square edged orifice passes about 60% of the flow one would expect through a hole the size of the orifice bore).
2. The AGA discharge coefficient equation is defined in AGA Report No. 3, Part 1 - Section 1.7.2. It is a complex, iterative calculation that gives C_d as a function of beta ratio, Reynolds number, and meter tube bore size.

E_v Velocity of approach factor

1. This term relates to the geometry of the meter run. It relates the velocity of the flowing fluid in the upstream pipe to the velocity in the orifice bore.
2. Defined as $E_v = \frac{1}{\sqrt{1-\beta^4}}$; where $\beta = \frac{orifice \quad bore \quad size}{meter \quad tube \quad bore \quad size}$

Since both the meter tube and orifice bore are functions of temperature, the beta ratio is also a function of temperature.

Y_1 Gas expansion factor

1. This term relates to the geometry of the meter run, the fluid properties and the pressure drop. It is an empirical term used to adjust the coefficient of discharge to account for the change in the density from the fluid’s velocity change and static pressure change as it moves through the orifice.
2. Defined as $Y_1 = 1 - (.41 + .35\beta^4)\frac{h_w}{27.707\kappa P_{f1}}$

   It is a function of beta, static and differential pressure ratios, and κ, the isentropic exponent of the gas. The isentropic exponent of the gas is equal to the ratio of the specific heat at a constant pressure and a constant volume. Generally, the flow equation is not sensitive to variations in the isentropic exponent; thus AGA allows for the simplification of the calculations by fixing the value to 1.3.

3. The upstream expansion factor is recommended by AGA because of its simplicity. It requires the determination of the upstream static pressure, diameter ratio, and the isentropic exponent. The downstream expansion factor requires downstream and upstream pressure, the downstream and upstream compressibility factor, the diameter ratio, and the isentropic exponent.

❖ **NOTE:** The value of the isentropic exponent for natural gas is 1.3 as recommended in AGA No. 3. The user has the option of entering a different value via the User Interface. It is a constant. No provisions are made for continuous calculation of the isentropic exponent.

d Orifice bore diameter, inches

1. The reference temperature for the orifice bore diameter is configurable.
2. The bore diameter calculation is done using the following equation:

$$d = d_r[1 + \alpha(T_f - T_r)]$$

❖ **NOTE:** The user must provide the bore diameter of the orifice plate (dr) at reference temperature (Tr), the meter tube internal diameter (Dr) at the reference temperature (Tr), the reference temperature (Tr) at which diameters were measured, and orifice and pipe materials. The α will vary for different materials.

G_r Real gas relative density

1. The real gas relative density (specific gravity) is a property of the fluid and is defined as:

$$G_r = \left(\frac{Mr_{gas}}{Mr_{air}}\right)\left(\frac{Z_{b-air}}{Z_{b-gas}}\right)$$

where M_r is the molecular weight and Z_b is the compressibility factors at base conditions.

2. The equation can be written in terms of the ideal gas or the real gas relative density. The Flow Computer Division of Emerson Process Management implements the real gas relative density.

❖ **NOTE:** The specific gravity can either be entered or calculated when a full analysis is available.

Z_b Compressibility factor at base conditions

Z_{f1} Upstream Compressibility factor at flowing conditions

1. These are empirical terms that are functions of the gas composition, the absolute pressure, and the absolute temperature.
2. AGA No. 3 – 1992 version specifies that only AGA No. 8 – 1992 version is to be used to calculate the compressibility factor of natural gas mixtures. It has two methods: the Detail Characterization Method (DCM) and the Gross Characterization Method (GCM). For more information, refer to Section 3.

P_{f1} Absolute pressure at flowing conditions referenced to the upstream tap location, psia

1. The flow equation requires the absolute pressure defined by:

$$P_{absolute} = P_{gage} + P_{atmospheric}$$

2. If downstream pressure is selected, add the pressure drop to downstream pressure to get upstream pressure.
3. The flow equation requires that the conversion between psi and inches of water be referenced to 60°F.

❖ **NOTES**: Most customers are currently measuring gage pressure and converting it to an absolute pressure by adding a constant or calculated value of atmospheric pressure to the measurement. The main reason for using gage pressure measurements has been the lack of availability of absolute pressure sensors and transmitters. However, the API and AGA standards recognize the use of absolute pressure sensors as acceptable.

T_f Flowing temperature of the gas, °R

1. The temperature of the gas is typically measured down-stream of the orifice plate. This is done to avoid disturbing the velocity profile of the gas coming into the orifice meter. Such disturbances could result in incorrect pressure measurements, leading to erroneous flow calculations.
2. The flow equation requires the absolute temperature of the gas. The absolute temperature unit in the English system of units is degrees Rankine:

$$°R = °F + 459.67$$

h_w Differential pressure, inches of water referenced to 60°F.

1. The flow equation requires that the conversion between psi and inches of water be referenced to 60°F.

2.2.6.2 Adjustments for Instrumentation Calibration and Use

Other multiplying factors may be applied to the orifice constant, C', as a function of the type of instrumentation applied, the method of calibration, the meter environment, or any combination of these. These factors are calculated and applied independently of tap type. With these factors, the orifice flow rate is calculated using the following equation:

$$Q_v = C' \, F_{am} F_{wl} F_{wt} F_{pwl} F_{hgm} F_{hgt} \sqrt{h_w P_f}$$

where:

F_{am} = Correction for air over water in a water manometer during differential instrumentation calibration

F_{wl} = Local gravitational correction for water column calibration

F_{wt} = Water density correction (temperature or composition) for water column calibration

F_{pwl} = Local gravitational correction for deadweight tester static pressure calibration

F_{hgm} = Correction for gas column in a mercury manometer

F_{hgt} = Mercury manometer span correction for instrument temperature change after calibration

2.3 Calculations for Ultrasonic Meters

AGA Report No. 9, "Measurement of Gas by Multipath Ultrasonic Meters," Section 7.3, refers the reader to AGA No. 7 for calculations. Using AGA 7 calculations will allow a flow computer to be AGA 9 compliant.

AGA No. 9 also outlines the method for calculating uncorrected volume for the ultrasonic meter.

ROC800 Series products provide speed of sound calculation per AGA Report 10 "Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases" for diagnostic purposes.

SECTION 3 – COMPRESSIBILITY

3.1 Introduction

What is compressibility? In developing gas equations, the first assumption usually made is that the gas will behave as an ideal gas. This would be a gas that follows the ideal gas law (PV = nRT). However, not all gases are ideal, and in fact, most are not. It is for these reasons that factors are developed to account for the varying characteristics that they exhibit under different conditions. One such characteristic is called compressibility.

In ideal gases, the distance between molecules is great enough that the influences of attraction from other molecules are negligible. As pressure increases or temperature decreases, molecules get closer and closer resulting in a smaller volume that was predicted by the ideal gas law. To compare these deviations we look at the following two characteristics:

1. The finite size of the molecules present within some volume
2. The interactive forces between these molecules.

To account for this change in predicted volume, the ideal gas law is modified. In order to account for the inter-attractive molecular forces, the pressure P is modified. Since gas is more compressible, it will occupy more volume at standard pressure and temperature (STP). Thus, we enter the factor know as compressibility Z. The ideal gas law takes the form PV = ZnRT. The square root of the ratio of the compressibility at base conditions to the compressibility at flowing conditions is known as the supercompressibility factor, F_{pv}.

$$F_{pv} = \sqrt{\frac{Z_b}{Z_{f_1}}}$$

3.2 NX-19

In 1956, the Pipeline Research Committee set forth on a project to extend the range of the AGA Supercompressibility factor table published in 1955 and 1956. This document, officially know as the PAR Research Project NX-19, was completed in April 1961. Initially, it provided basic data for extending the range of the AGA supercompressibility factor from previous know data sets. It also resulted in the development of a mathematical expression suitable for industry-wide electronic computer computation.

Basic Limitations on Ranges and Applicability for NX-19:

Pressure, psig	0 to 5000
Temperature, F°	-40 to 240
Specific Gravity	0.554 to 1.00
CO_2, mole %	0 to 15%
N_2, mole %	0 to 15%

As mentioned above, the technique for determining a supercompressibility factor for natural gas involves the evaluation of its critical pressure and temperature points and its relation to the specific gravity. This is the most common technique and was presented as NX-19's standard method. This is the standard method that has been implemented in the ROC300 Series and FloBoss 407. ROC800-Series, FloBoss™ 500 Series, and FloBoss™ 100 Series products do not support NX-19.

The Standard Method of NX-19 Limitations and Ranges:

Pressure, psig	0 to 5000
Temperature, F°	-40 to 240
Specific Gravity	0.554 to 0.75
CO_2, mole %	0 to 15%
N_2, mole %	0 to 15%

The standard method is applicable to natural gas that does not have "large concentrations of heavier hydrocarbons."

The NX-19 supercompressibility equation is a function of pressure, temperature, specific gravity, and the mole percents of CO_2 and N_2.

The following graph (Figure 1) shows the regions in which different equations are used to calculate the E factor. This factor is used to adjust the supercompressibility factor F_{pv} under different operating conditions. Note the large number of equations referenced on the E factor chart. This is due to the fact that the best data set available at the time still required several different equations to adequately model the empirical data. The second graph (Figure 2) shows the relationship of supercompressibility over an increasing pressure range for a pure hydrocarbon gas with a 0.600 specific gravity.

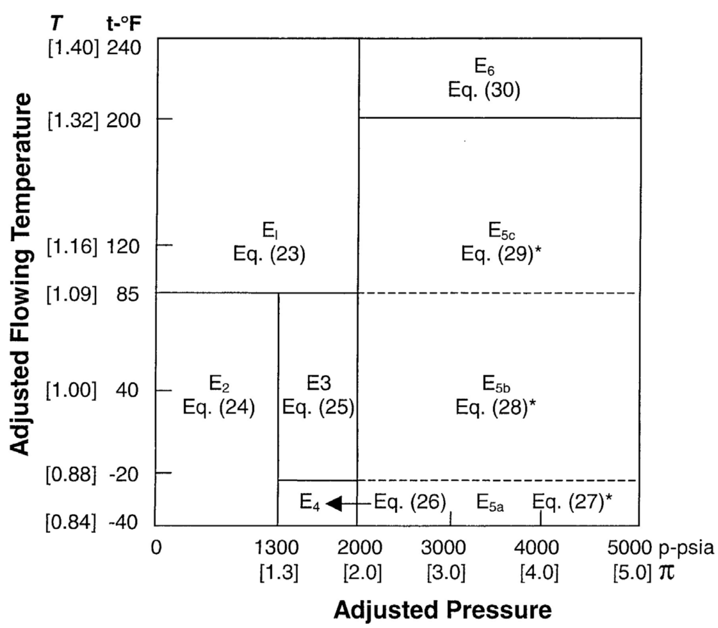

Figure 1. Range of Applicability of the E Factor

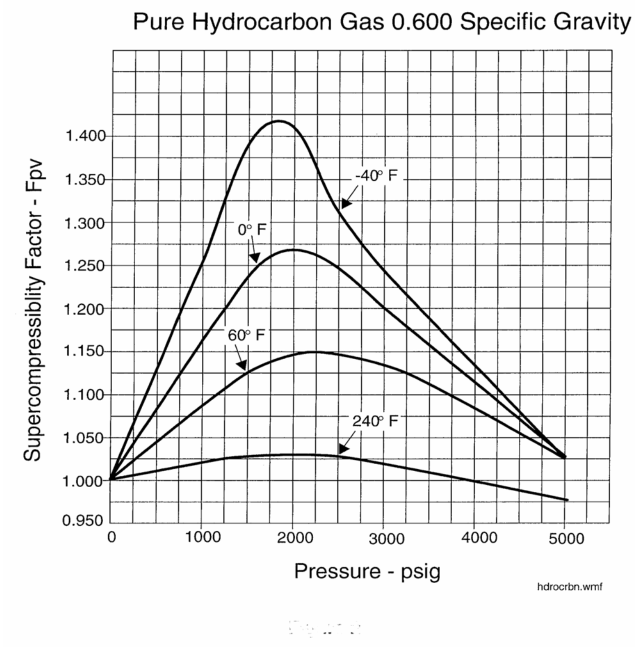

Figure 2. Supercompressibility versus Pressure for a 0.600 Specific Gravity Hydrocarbon Gas

3.3 AGA No. 8 – 1985 Version

The AGA Report No. 8 – 1985 version allows for certain variations in gas compositions. When the gas analysis falls into the range of values given in Table 1. Figure 3A can be used to determine the expected uncertainty for various operating conditions. If the composition falls outside the range given in Table 1, uncertainties can become substantially greater. This is especially true as you move away from Region 1 (see Figure 3A).

This report is only valid for the gas phase in these ranges:

Pressure, psia	0	to	20,000
Temperature, F°	-200	to	460

Table 1. Ranges for Gas Mixture Characteristics for Use by AGA No. 8 – 1985 Version

Quantity	Normal
Mole % Methane	50 to 100%
Mole % Nitrogen	0 to 50%
Mole % Carbon Dioxide	0 to 50%
Mole % Ethane	0 to 20%
Mole % Propane	0 to 5%
Mole % Butanes	0 to 3%
Mole % Pentanes	0 to 2%
Mole % Hexanes Plus	0 to 1%
Mole % Water Vapor, Hydrogen Sulfide, Hydrogen, Carbon Monoxide, Oxygen, Helium, and Argon Combined	0 to 1%

AGA No. 8 – 1985 version provides for an "alternate" method that utilizes a partial composition; however, the ROC300-Series and FloBoss 407 products support only the full analysis. ROC800-Series, FloBoss 500 Series, and FloBoss 100 Series products do not support 1985 calculations.

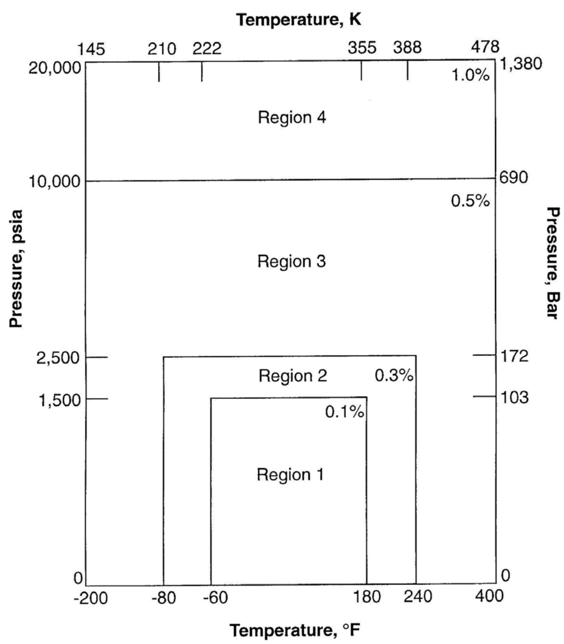

Figure 3A. Targeted Uncertainty Limits for Computation of Natural Gas Supercompressibility Factor

Reprinted from *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases*, AGA Catalog No. XQ 1285, December 15, 1985, Page 2.

3.4 AGA No. 8 – 1992 Version

The AGA Report No. 8 – 1992 version allows for wide variations in gas compositions. When the gas analysis falls into the Normal range of values given in Table 2. Figure 3B can be used to determine the expected uncertainty for various operating conditions. If the composition falls into the Expanded range of the table below, uncertainties can become substantially greater. This is especially true as you move away from Region 1 (see Figure 3B). The AGA No. 8 -1992 version calculation will have greater uncertainty than shown on Figure 3B if the composition falls outside the analysis contained in the table below. However, in these cases, the 1992 method will still provide more accurate data than the NX-19 and AGA No. 8 – 1985 version methods. The 1992 version is provided by all ROC and FloBoss porducts.

This report is only valid for the gas phase in these ranges:

Pressure, psig	0	to	40,000
Temperature, F°	-200	to	760

Table 2. Ranges for Gas Mixture Characteristics for Use by AGA No. 8—1992 Version

Quantity	Normal	Expanded
Relative Density *	0.554 to 0.87	0.07 to 1.52
Heating Value **	477 to 1150 Btu/SCF	0 to 1800 Btu/SCF
Mole % Methane	45 to 100%	0 to 100%
Mole % Nitrogen	0 to 50%	0 to 100%
Mole % Carbon Dioxide	0 to 30%	0 to 100%
Mole % Ethane	0 to 30%	0 to 100
Mole % Propane	0 to 4%	0 to 12%
Mole % Total Butanes	0 to 1%	0 to 6%
Mole % Total Pentanes	0 to 3%	0 to 4%
Mole % Hexanes Plus	0 to 0.2%	0 to Dew Point
Mole % Helium	0 to 2%	0 to 3%
Mole % Hydrogen	0 to 10%	0 to 100%
Mole % Carbon Monoxide	0 to 3%	0 to 3%
Mole % Argon	--	0 to 1%
Mole % Oxygen	--	0 to 21%
Mole % Water	0 to 0.05%	0 to Dew Point
Mole % Hydrogen Sulfide	0 to 0.02%	0 to 100%

* Reference conditions: Relative density at 60° F, 14.73 PSIA

** Reference conditions: Combustion and density at 60° F, 14.73 PSIA

The report allows for two different methods of compressibility calculation. They are the Detail Characterization Method (DCM) and the Gross Characterization Method (GCM). The GCM was not designed for and should not be used in applications outside the Normal range given in the table above nor outside Region 1 of Figure 3B.

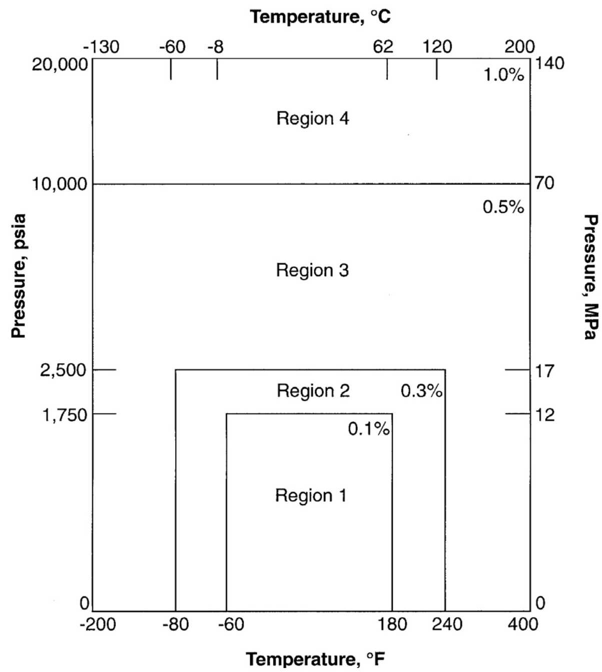

Figure 3B. Targeted Uncertainty Limits for Computation of Natural Gas Compressibility Factors using the Detail Characterization Method

Reprinted from *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*, AGA Catalog No. XQ9212, November 1992, Page 4.

3.4.1.1 AGA No. 8 Recommends the Following:

- Use the **Gross Characterization Method** (GCM) for applications with flowing conditions meeting the following parameters.
    1. Temperature: 32 to 130 º F
    2. Pressure: 0 to 1200 PSIA
    3. Gas composition is within the normal range of Table 2.
- For all other applications, use the **Detailed Characterization Method** (DCM).

When properly applied, the AGA No. 8 - 1992 version calculation can compute the compressibility factor to within 0.1% of the experimental data. The AGA No. 8 clearly tells the user to review the gas composition at flowing conditions to determine which method to use. It is likely that some users will note that the NX-19 inputs are the same as required for the **GCM** equations and will assume that they can use **GCM** freely in place of NX-19. However, this is not a valid assumption. Users should ensure they adhere to the application ranges set forth in AGA No. 8 before selecting one of the **GCM** equations.

3.4.1.2 Detailed Characterization Method (DCM)

The DCM requires the natural gas composition in mole percent to be entered.

3.4.1.3 Gross Characterization Method (GCM)

The GCM requires the density of the natural gas as well as the quantity of non-hydrocarbon components. There are two GCMs available (Method I and Method II); each method uses three of the four following quantities:

1. Specific Gravity
2. Real gas gross heating value per unit volume
3. The mole % of CO_2
3. The mole % of N_2

The GCM approximates a natural gas mixture by treating it as a mixture of three components:

1. A hydrocarbon component
2. A nitrogen component
3. A carbon dioxide component

The hydrocarbon component represents all hydrocarbons. N_2 and CO_2 represent the diluent components.

3.4.1.4 Gross Characterization Method I Uses:

1. Specific Gravity
2. Real gas gross heating value per unit volume
3. The mole % of CO_2

3.4.1.5 Gross Characterization Method II Uses:

1. Specific Gravity
2. The mole % of CO_2
3. The mole % of N_2

SECTION 4 – INDUSTRY APPLICATION OF THE STANDARDS

4.1 Introduction

In addition to the industry-wide acceptance of the AGA No. 3, AGA No. 7, and AGA No. 8 equations used to calculate gas flow, other documents have received quite a bit of attention from the gas measurement industry.

One such document is a standard published by the American Petroleum Institute. It is the API Manual of Petroleum Standards, Chapter 21, Flow Measurement Using Electronic Metering Systems, Section 1, Electronic Gas Measurement (referred to as API Chapter 21). Another document is the Bureau of Land Management's Onshore Order No. 5. Another federal document worth mentioning is the Federal Energy Regulation Committee's Order No. 636 (FERC 636). This document, which facilitated the deregulation of the pipeline industry, is not discussed here.

4.2 API Chapter 21, Section 1

The AGA equations provide a means to calculate an instantaneous flow rate under steady-state conditions. This is only the beginning of the story. Once the flow rate is calculated, it must be integrated to provide a quantity of gas that is passed through the meter for some given time period. Decisions must be made concerning dynamic variable scan rates, AGA calculation rates, integration methods, averaging techniques, and much more. API Chapter 21 addresses these issues and others as well. Basically, the AGA equations dictate how to calculate the flow rate, and the API standard provides recommendations on how often to calculate it and what to do with it once it has been calculated.

API Chapter 21 describes the minimum specifications for electronic gas measurement (EGM) systems. It provides recommendations on sampling rates, calculation methodologies, and averaging techniques. In determining sampling frequencies and calculation rates, computer modeling was used to assure adequate performance under fluctuating flow rates. Both differential and linear meters are addressed in this standard. For differential meters, studies show that dynamic inputs should be sampled at a minimum of one second. For linear meters, sampling should be at 5 seconds. These inputs could be sampled at slower rates, provided it could be demonstrated by the Rans Methodology (found in Appendix A of API Chapter 21, Section 1) that a slower integral would not increase the uncertainty more than 0.05% compared to 1 second samples.

4.2.1 Differential Meter Measurement

In differential metering applications, a total quantity is determined by the integration of a flow rate equation over its defined time interval.

The flowing variables that define flow rate are typically not static; therefore, a true total quantity is the integrated flow rate over that interval for the continuously changing conditions.

API defines several critical algorithms that are required to integrate a differential flow rate into a quantity. They are listed in the following sections. These operations allow the flow rate computation to be factored into an integral multiplier value (IMV) and an integral value (IV). Each of these factors can be computed using independent variable input time intervals. A common time unit must be defined for total quantity calculations such that:

$$Q_{imp} = (IMV_{imp})(IV_{imp})$$

where: imp= A unit of time defined by the integral multiplier period.

Q_{imp}	= The quantity accumulated for the integral multiplier period (imp).
IMV_{imp}	= The integral multiplier value for the integral multiplier period (imp). It is calculated at regular intervals as set by the integral multiplier period (imp).
IV_{imp}	= The integral value accumulated over the integral multiplier period (imp).

Flow computers of The Flow Computer Division of Emerson Process Management use the equivalent of the integral value (IV). The period at which the integral multiplier value is calculated can vary and is set by the user.

For FloBoss™ 103 and FloBoss 503 Series products, it can be set to 1 to 60 minutes. It is not configurable for ROC809, ROC300, or FloBoss 407 Series products. For ROC809 Series products, it is 1 second. For ROC300 and FloBoss 407 Series, it is 5 minutes or change in pressure greater than 5 psia or change in temperature greater than 2°F.

The expression "Average Flow Extension" is the same as integral value (IV).

4.2.1.1 Sampling Flow Variables—Differential Meter Measurement

API states that the minimum sampling frequency for a dynamic input variable shall be once every second. Multiple samples taken within the one-second time interval may be averaged using any of the techniques defined in section 4.2.3 of this Flow Manual.

4.2.1.2 Low-Flow Detection

A low-flow cutoff point for differential meters should be determined by the contractually concerned parties based up a realistic assessment of site conditions.

Factors that influence the selection of a low-flow cutoff for an application include: anticipated minimum flow conditions of the application, accuracy and span of the sensor, and expected variability of the flow.

The low-flow cutoff is set in the software by the user. For AGA calculations, it is expressed in inches of water column or kPa. There is no absolute value of low-flow cutoff that can be used for all applications. The flow rate is set to zero when the differential pressure reading drops below the low-flow cutoff value.

4.2.1.3 Integral Value Calculation

API defines the integral value (IV) as the value resulting from the integration of the factored portion of the flow rate equation that best defines the conditions of continuously changing flow over a specified time period. For ROC and FloBoss products, the IV is equal to $\sqrt{Pf * hw}$.

4.2.1.4 Integral Multiplier Value Calculation

An integral multiplier value (IMV) is the value resulting from the calculation of all other factors of the flow rate equation not included in the integral value (IV). Dynamic input values required in the IMV calculation are averaged over the imp (integral multiplier period) using one of the techniques in section 4.2.3.

At the end of each integral multiplier period (imp), an integral multiplier value (IMV) is calculated using the flow variable inputs as determined using the techniques given in section 4.2.3 of this Flow Manual. The integral multiplier period (imp) shall not exceed one hour. An integral multiplier period (imp) of less than one hour shall be such that an integral (whole) number of multiplier periods occurs during one hour (that is 1, 2, 3, 4, 5, 6, 10, 12, 15, 20, 30, 60 minutes).

4.2.1.5 Quantity Calculation—Differential Meter Measurement

Once the integral multiplier value (IMV) is calculated, it is multiplied by the accumulated integral value (IV) to compute a volume quantity for the integral multiplier period (imp).

4.2.2 Linear Meter Measurement

In linear metering applications, a total quantity is determined by the summation of flow over its defined time interval.

The flowing variables that define flow rate are typically not static; therefore, a true total quantity is the integrated flow rate over that interval for the continuously changing conditions.

In linear metering applications, the primary device provides measurement in actual volumetric units at flowing conditions.

To calculate equal-base volumetric, energy, or mass quantities, API defines several algorithms that are required as defined in the following sections.

These operations allow the quantity calculation to be factored into an actual volumetric quantity (AVQ) and base multiplier value (BMV). Each of these factors as defined can be computed using independent variable input intervals. A common time unit must be defined for total quantity calculations such that:

$$Q_{bmp} = (AVQ_{bmp})(BMV_{bmp})$$

where: bmp = a unit of time defined by the base multiplier period.

Q_{bmp} = base quantity accumulated for the base multiplier period (bmp).

AVQ_{bmp} = actual volumetric quantity accumulated for the base multiplier period (bmp).

BMV_{bmp} = base multiplier value for base multiplier period (bmp).

The base multiplier period (bmp) is the amount of time between calculations of the combined correctional factors, which are called the base multiplier value (BMV) in the API Measurement Standard Chapter 21, Section 1. The BMV is multiplied by the accumulated actual (uncorrected) volume to arrive at the quantity accumulated for the period.

The base multiplier value (BMV) is the value resulting from the calculation of all other factors of the base quantity calculation not included in the actual volumetric quantity.

At the end of each base multiplier period (bmp), the base multiplier value (BMV) is calculated using the flow variable inputs averaged over the bmp using one of the techniques described in Section 4.2.3. The base multiplier period (bmp) shall not exceed one hour. A base multiplier period (bmp) of less than one hour shall be such that an integral (whole) number of multiplier periods occurs during one hour (that is 1, 2, 3, 4, 5, 6, 10, 12, 15, 20, 30, 60 minutes).

For FloBoss 104 and FloBoss 504 Series products, it can be set to 1 to 60 minutes. It is not configurable for ROC809, ROC300, or FloBoss 407 Series products. For ROC809 Series products, it is 1 second. For ROC300 and FloBoss 407 Series, it is 5 minutes or change in pressure greater than 5 psia or change in temperature greater than 2°F.

To determine if flow was occurring over the Base Multiplier Period, the number of counts (pulses) from the linear meter over the period is viewed. If there is an absence of counts during a period, the following occurs:

- Meter run is set in a No Flow condition.
- Accumulated flow is stored as zero for historical data over that time period.

If there are counts, then the accumulated flow and energy are calculated and accumulated for historical data over that time period. To ensure history data can provide a proper recalculation, the Base Multiplier Period should be greater than the normal time it takes to get a pulse. For example: If a pulse only occurs once every 5 minutes, set the base multiplier period to 5 minutes or greater. The Base Multiplier Period should always be equal to or greater than the Scan Period of the Pulse Input receiving pulses from the linear meter to eliminate a No Flow condition.

Once the base multiplier value is calculated, it is multiplied by the accumulated actual volumetric quantity to compute a volume quantity for the base multiplier period.

4.2.2.1 Sampling Flow Variables—Linear Meter Measurement

API states that the minimum sampling frequency for a dynamic input variable shall be once every five seconds. Multiple samples taken within the five-second time interval may be averaged using one of the techniques is section 4.2.3 of this Flow Manual.

4.2.2.2 Actual Volumetric Quantity Calculation

An actual volumetric quantity (AVQ) is the value resulting from the calculation of accumulated counts from a primary device divided by the meter constant (pulse/volume).

4.2.2.3 No-Flow Detection

API defines no-flow is defined as an absence of counts over any base multiplier period (bmp). During no-flow conditions, sampled input variables shall be discarded from the averages.

4.2.2.4 Base Multiplier Value Calculation

The base multiplier value (BMV) is the value resulting from the calculation of all other factors of the base quantity calculation not included in the actual volumetric quantity (AVQ) calculation.

At the end of each base multiplier period (bmp), the base multiplier value (BMV) is calculated using the flow variable inputs. Dynamic input values required in the BMV calculation are averaged over the bmp using one of the techniques in Section 4.2.3 of this manual.

4.2.2.5 Quantity Calculation—Linear Meter Measurement

Once the base multiplier value (BMV) is computed, it is multiplied by the accumulated actual volumetric quantity (AVQ) to compute a volumetric quantity for the base multiplier period (bmp).

4.2.3 Averaging Techniques

There are four averaging techniques defined by API (in Appendix B of Report 21) that can be used to average dynamic input values. These techniques are based on a combination of flow-weighted, flow-dependent, linear, and formulaic averages. The techniques are:

Flow Dependent Linear. This is the simplest, most easily understood method. This method discards samples for periods when there is no measurable flow, and performs a straight-forward (linear) average of the remaining samples to compute the average values.

Flow Dependent Formulaic. This method discards samples for periods when there is no flow. However, in calculating the average, this method typically takes the square root of each sample before averaging the samples together, and then squares the result at the end of the hour. This formulaic method produces a slightly lower value than the linear method.

Flow Weighted Linear. This method does not discard any samples; instead, it “weights” each sample by multiplying it by a flow value (square root of the current differential pressure or actual volumetric flow rate for linear applications). A linear average is calculated by dividing the sum of the flow-weighted samples by the sum of the flow values. The result includes average values that are more reflective of short periods of high flow.

Flow Weighted Formulaic. This method combines the flow-weighting action with the formulaic averaging technique, both of which were described previously.

The ability to recalculate a quantity precisely based on the averages stored for that quantity period varies with the flow and with the averaging technique used. Here are examples showing linear and formulaic methods:

Linear:

$$\frac{(14+15+16+17+18)}{5}=16$$

Formulaic:

$$\left[\frac{\left(\sqrt{14}+\sqrt{15}+\sqrt{16}+\sqrt{17}+\sqrt{18}\right)}{5}\right]^2=15.97$$

❖ **NOTE:** API does not provide guidelines as to which averaging technique should be used for an installation. It should be determined by the buyer and seller.

The result of averaging calculated flow rates will be different than averaging input variables and then attempting to re-calculate the flow rate from those averages.

For example, in the simple mathematical example below, note that averaging the numbers results in an average of 9.3, but attempting to average and then calculating a total would result in an average of 10. Note the difference as shown in the table.

Sample	Variable A	Variable B	Total
A	2	3	2 x 3 = 6
B	2	5	2 x 5 = 10
C	3	4	3 x 4 = 12
Totals	7	12	28
Averages	7/3 = 2.5	12/3 = 4	28/3 = 9.3
Calculated Total	2.5 x 4 = 10		9.3

4.2.4 Hourly and Daily Quantity Calculation

For compliance with the Audit and Reporting Requirements of API, the quantity accumulated for a given period, Q_{period}, is the summation of the quantities occurring during the integral multiplier period, Q_{imp}, from the time 0 at the beginning of the period to the time at the end of the period. Or, it is the summation of the quantities for the base multiplier period, Q_{bmp}, from the time 0 at the beginning of the period to the time at the end of the period. All ROC and FloBoss products keep separate quantity sums are kept for hourly and daily periods.

4.2.5 Data Availability, Audit, and Other Topics

API Report 21, Section 1, also covers guidelines for data collection and retention, audit, reporting, equipment installation and calibration, and security.

4.3 BLM Onshore Order No. 5

There is a document issued by the Bureau of Land Management that can influence a company's electronic gas measurement philosophy. It is Onshore Order No. 5, a federal document that originally addressed circular charts. Changes to this order were proposed in 1994 to address electronic flow measurement. Since the government takes a long time to ratify changes, local BLM offices often send out a Notice To Lessee (NTL), which speaks of the proposed changes to the Onshore Order No. 5.

To view a copy of the proposed changes to Onshore Order No. 5, refer to a printed copy of the manual, or contact the Federal Register and ask for the following:

Federal Register
Volume 59, No. 4, Thursday, January 4, 1994
Proposed Rules
Department of the Interior
Bureau of Land Management
43 CRF Part 3160
[WO-610-4111-02-24 1A]
RIN 1004-AB22
Onshore Oil and gas Operations, Federal and Indian Oil and Gas Leases;

Onshore Oil and Gas Order No. 5, Measurement of Gas.
Pages 718 through 725

SECTION 5 – CONTRACTS AND ELECTRONIC FLOW COMPUTERS

5.1 Introduction

In the end, when all is said and done, the terms set forth in the legal contract between the buyer and seller is all that matters.

Many times, the individuals that are actually configuring the flow computer will never see the contract governing the configuration of the flow computer.

Prior to the advent of electronic flow computers, circular chart recorders were the mainstay of flow measurement. A paper chart recorded differential gas pressure across an orifice plate. These charts were gathered and sent in to the company's gas accounting group either on a weekly or monthly basis for integration. The integration process was slow and "off-chart" gas flow could not be accounted for. Records were kept in the field office showing verification and calibration information. Gas samples were taken quarterly and analyzed, and the analysis information was forwarded to the gas accounting department for use in chart integration. The gas accounting group did the rest. The field never was exposed to the level of configuration choices that they are today. In the world of charts it is easy to see why the field staff had never been exposed to the actual gas contract.

With flow computers, the responsibility to enter and maintain information used by the flow computer's flow calculations and the maintenance of the subsequent audit trail information is shifted from the office to the field. Other responsibilities being moved to the field are data editing and recalculation. The office still handles the data processing, accounting, and archiving.

Issues pertaining to the physical installation, calculation options, and the choice of data averaging techniques must be understood and addressed before choosing a flow computer. This is to ensure compatibility with internal requirements and existing systems, as well as to reduce the installation time. While no two wells are alike, runs within a gas field may be identical with respect to physical installation but can vary in gas composition, control and monitoring needs, and contractual obligations. Between gas fields these variances are even greater.

It is becoming ever more important that the field staff has a minimum understanding of as many factors influencing gas measurement as possible. This is especially true when you consider the level of responsibility that electronic gas measurement shifts from the gas accounting group to the field. For this reason, we have included excerpts dealing with gas measurement from two "typical" gas contracts. These excerpts are from actual, working, legal contracts that were written between 1980 and 1995. They are not complete and are presented for example only. It should be enlightening to read them and to relate them to your field experiences.

5.2 Example Contract 1

Article V

MEASUREMENT

5.1 The unit of measurement for Gas shall be one (1) MCF adjusted to a dry basis from a saturated condition at the individual Receipt Point pressure and temperature; provided Producer has not dehydrated the Gas to meet the specifications set forth in Section 4.1, in which case no adjustment will be made. The measured volumes of Gas shall then be multiplied by their Gross Dry Heating Value to determine the Dkts received by Gatherer. The unit of measure of payment for Services shall be dollars per individual Dkt, or fraction thereof, as determined at the Receipt Point(s).

5.2 The volumes of gas measured under this agreement shall be measured and computed as prescribed by ANSI/API 2530, Third Edition, AGA Report #3, “Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids,” as amended, supplemented or revised from time to time. The volumes of Gas measured under this Agreement shall be measured and computed as prescribed by AGA Report #8 at such time as all third parties receiving Gas at the Delivery Points downstream of the “Plant”, as identified in Exhibit “D”, convert to AGA Report #8, or one year from the date of this Agreement, whichever is sooner. Electronic Flow Measurement may be installed at any existing locations, at Producer’s election and expense, except as provided in Article VII, at any Receipt Point. Installation of EFM at new locations shall be governed by the Terms of Article VII.

5.3 The atmospheric pressure shall be the average atmospheric pressure as determined by elevation at the points of Delivery and Receipt. For the System, this pressure shall be assumed to be 12.2 p.s.i.a.

5.4 Component analysis of Gas received from a given Receipt Point shall initially be made within thirty (30) days after commencement of Services from the Receipt Point, and within thirty (30) days after notification by Producer that any additional well has been connected to any Receipt Point. Gatherer shall conduct a component analysis at its expense at least once every six (6) months to determine the Gross Dry Heating Value, relative density, and compressibility factor of the Gas received at each Receipt Point. For Delivery Points operated by Gatherer, such determinations will be made on a quarterly basis. Producer may request that Gatherer conduct more frequent Gas sampling and analysis at Producer’s own expense. Producer shall have the right to audit all procedures of the lab providing the component analysis.

5.5 (a) The volume of Gas delivered through each Delivery Point and Receipt Point shall be corrected to a base temperature of sixty (60) degrees Fahrenheit by using the arithmetic average of the hourly temperatures recorded by a properly installed continuously operated recording thermometer. The relative density (specific gravity) of the Gas delivered hereunder shall be determined by approved methods as determined by Section 5.2, and the specific gravity so obtained shall be used in computing volumes of gas delivered hereunder. The Gross Dry Heating Value, relative density, and compressibility values determined from a Gas analysis shall be made effective the first Day of the Month following the Month during which the sample was taken and for each Month thereafter until a new analysis is performed. The relative density shall be calculated in accordance with the Gas Processors Association Standard 2172 “Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.”

(b) More modern measurement equipment, techniques and computation methods may be utilized by Gatherer to satisfy measurement requirements hereunder after authorization from Producer, provided that any such new equipment, techniques or methods shall be recognized as generally acceptable for the intended purpose by recognized industry authorities and shall have been deemed as acceptable by the appropriate regulator agency.

(c) Gatherer shall allow Producer access to meter taps for the connection of automation equipment to the extent that such access does not interfere with Gatherer’s operations or measurement accuracy.

5.6 Gatherer agrees to install, operate and maintain on its pipeline at or near each point of connection of the facilities of Gatherer and Producer (or other party which is transporting the gas on behalf of Producer), a meter or meters of standard type and design to measure all of the gas to be delivered hereunder. Gatherer also agrees to install, operate and maintain at or near each Point of Delivery such pressure and volume regulating equipment as may be necessary. Both Gatherer and Producer shall have the right to be represented at any installing, reading, cleaning, changing, repairing, inspecting, calibrating or adjusting done in connection with the other’s measuring equipment installed hereunder. The records from such measuring equipment shall remain the property of the owner but the owner upon request of the other will submit records and charts, together with calculations therefrom, for its inspection and verification, subject to return within sixty (60) days after receipt. Gatherer shall preserve all test and measurement data, charts, or similar records for a period of three (3) years or such longer periods as may be required by law or regulation.

.1 Gatherer, or its agent, shall verify the accuracy of measurement equipment based upon the following schedule:

Type of Receipt Point	Frequency of Testing
delivering > 100 MCFD	once every 6 months
delivering < 100 MCFD	once every 12 months

Such verification shall include the removal and physical inspection of the meter orifice plate.

Gatherer shall give five (5) business days advance notice to Producer of the time and location of all tests at Receipt Points of any equipment used in measuring or for conducting sampling to determine the nature or quality of the Gas, so that Producer may have its representative present. If Producer is not satisfied with a test, it may request Gatherer to retest. The expense of a retest shall be paid by Producer unless the retest reflects Gas measurement error greater than one percent (1%) by volume, in which event, Gatherer shall pay the cost of the retest.

5.8 If, upon any test, any measuring equipment shall be found to be inaccurate by an amount exceeding one percent (1%) by volume or 150 MCF, whichever is greater, then any previous readings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such adjustment shall be for a period extending over one-half of the time elapsed since the date of last test.

5.9 Gatherer shall provide to Producer the following items, within thirty (30) days after the data becomes available to Gatherer: (a) Meter test reports; and (b) copies of Gas analyses from samples. Gatherer shall provide corrections to Producer necessary to past production and billings as a result of meter test reports within sixty (60) days after the data becomes available to Gatherer.

5.10 If for any reason Gatherer's meters are out of service or out of repair so that the quantity of Gas delivered is not correctly indicated by the reading thereof, the Gas delivered during the period such meters are out of service or out of repair shall be estimated and agreed upon the basis of the best data available, using the first of the following methods which shall be feasible:

(a) By using the registration of any check meter or meters if installed and accurately registering;

(b) By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculation; or

(c) By estimating the quantity of delivery based on deliveries during the preceding period under similar conditions when the meter was registering accurately.

5.3 Example Contract 2

V. MEASUREMENT

5.1 The casinghead gas delivered hereunder shall be measured by a meter or meters of standard make to be furnished, installed and kept in repair by Buyer on the land herein described and all volumes of such gas shall be computed to a standard cubic foot at a pressure base of 14.65 pounds per square inch absolute and at a temperature base of 60° Fahrenheit. No correction shall be made for any variation of the flowing temperature from the base temperature. For purposes of measurement, the gas shall be assumed to obey Boyle's Law and the absolute atmospheric pressure shall be assumed to be 12.7 pounds per square inch. Buyer shall test its meters at least semi-annually for accuracy of measurement. The specific gravity shall be determined semi-annually by the Balance Method or such other method as shall be agreed upon by the parties hereto. The tests for specific gravity and for accuracy of measurement shall be made at the same time. Buyer shall notify Seller in writing of the date of such semi-annual tests at least ten (10) days prior thereto. Seller may witness the tests or make joint tests with its own appliances. Said meter shall be open to inspection by Seller in the presence of Buyer. In case any question arises as to the accuracy of the meter measurement, said meter shall be tested upon demand of either party, and if any error found, the meter shall be corrected. If any total measurement error is found to be two percent (2%) or less, prior measurements shall be deemed correct. The volume delivered for any period of inoperation of the meter or of inaccurate measurement shall be determined by using an arithmetic average daily volume based upon total measured volume for thirty (30) days prior to and thirty (30) days following the period of inoperation or inaccurate methods.

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If you have comments or questions regarding this manual, please direct them to your local sales representative or contact:

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