# Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement

## Section 8—Liquefied Petroleum Gas Measurement

SECOND EDITION, JULY 1997

REAFFIRMED, OCTOBER 2011

AMERICAN PETROLEUM INSTITUTE

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**Measurement Coordination**

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# Chapter 14—Natural Gas Fluids Measurement

## SECTION 8—LIQUEFIED PETROLEUM GAS MEASUREMENT

### 1 Scope and Purpose

This publication describes dynamic and static measurement systems used to measure liquefied petroleum gas (LPG) in the relative density range of 0.350 to 0.637 (see Chapter 11.2.2). The physical properties of the components to be measured and the mixture composition of liquefied petroleum gas should be reviewed to determine the measurement system to be used. Various systems and methods can be used in measuring the quantity of product, and mutual agreement on the system and method between the contracting parties is required.

This publication does not endorse or advocate the preferential use of any specific type of meter or metering system. Further, this publication is not intended to restrict the future development of meters or measuring devices, nor to in any way affect metering equipment already installed and in operation.

This publication serves as a guide in the selection, installation, operation, and maintenance of measuring systems applicable to liquefied petroleum gases and includes functional descriptions for individual systems.

### 2 Referenced Publications

To the extent specified in the text, the latest edition or revision of the following standards and publications form a part of this publication.

API

*Manual of Petroleum Measurement Standards* (MPMS)

| | |
|---|---|
| Chapter 2 | *Tank Calibration* |
| Chapter 3 | *Tank Gauging* |
| Chapter 4 | *Proving Systems* |
| Chapter 5.2 | *Measurement of Liquid Hydrocarbons by Displacement Meters* |
| Chapter 5.3 | *Measurement of Liquid Hydrocarbons by Turbine Meters* |
| Chapter 5.4 | *Accessory Equipment for Liquid Meters* |
| Chapter 6.6 | *Pipeline Metering Systems* |
| Chapter 7.2 | *Dynamic Temperature Determination* |
| Chapter 8 | *Sampling* |
| Chapter 9 | *Density Determination* |
| Chapter 9.2 | *Pressure Hydrometer Test Method for Density or Relative Density* |
| Chapter 11.2.2 | *Compressibility Factors for Hydrocarbons: 0.350-0.637 Relative Density (60/60°F) and 50°F to 140°F Metering Temperature* |
| Chapter 12.2 | *Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters* |
| Chapter 14.3 | *Concentric Square-Edged Orifice Meters (A.G.A. Report No. 3) (GPA 8185-90)* |
| Chapter 14.4 | *Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes* |
| Chapter 14.6 | *Continuous Density Measurement* |
| Chapter 14.7 | *Mass Measurement of Natural Gas Liquids* |

ASM Int'l[1]

*Metals Handbook*

ASME[2]

*Performance Test Code 19.5 (current edition)*

ASTM[3]

| | |
|---|---|
| D 1250-80 | *Volume XII, Table 34—Reduction of Volume to 60°F Against Specific Gravity 60/60°F for Liquefied Petroleum Gases* |
| D 2713-91 | *Test Method for Dryness of Propane (Valve Freeze Method)* |

GPA[4]

| | |
|---|---|
| 2140 | *Liquefied Petroleum Gas Specifications and Test Methods (ASTM D 1835; ANSI Z11.91)* |
| 2142 | *Standard Factors for Volume Correction and Specific Gravity Conversion of Liquefied Petroleum Gases* |
| 2145 | *Physical Constants for Paraffin Hydrocarbons and Other Components of Natural Gas* |
| 2165 | *Standard for Analysis of Natural Gas Liquid Mixtures by Gas Chromatography* |
| 2166 | *Obtaining Natural Gas Samples for Analysis by Gas Chromatography* |
| 2174 | *Method for Obtaining Liquid Hydrocarbon Samples Using a Floating Piston Cylinder* |
| 2177 | *Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography* |
| 2186 | *Tentative Method for the Extended Analysis of Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Diox-* |

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[1] ASM International, 9639 Kinsman Road, Materials Park, Ohio 44073-0002.

[2] American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017-2392.

[3] ASTM, 100 Bar Harbor Drive, West Conshohocken, Pennsylvania 19428.

[4] Gas Processors Association, 6526 E. 60th Street, Tulsa, Oklahoma 74145.

| | |
|---|---|
| | *ide by Temperature Programmed Gas Chromatography* |
| 2261 | *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography* |
| 2286 | *Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography* |
| 8173 | *Method for Converting Mass Natural Gas Liquids and Vapors to Equivalent Liquid Volumes* |
| 8182-95 | *Standard for the Mass Measurement of National Gas Liquids* |
| GPSA[5] | *Engineering Data Book* |

## 3 Application

This publication does not set tolerances or accuracy limits. The application of the information here should be adequate to achieve acceptable measurement performance using good measurement practices, while also considering user requirements and applicable codes and regulations.

Systems for measuring liquefied petroleum gases use either volumetric or mass determination methods, and both methods apply to either static or dynamic conditions.

Mass determination methods of measurement are most commonly used where conditions in addition to temperature and pressure will affect the measurement. Such conditions include compositional changes, intermolecular adhesion, and volumetric changes caused by solution mixing. Mass measurement is applicable to liquefied petroleum gas mixtures where accurate physical correction factors have not been determined, and to some manufacturing processes for mass balance determination.

Volumetric methods of measurement are generally used where physical property changes in temperature and pressure are known and correction factors can be applied to correct the measurement to standard conditions.[6,7] Volumetric measurement is applicable to most pure components and many commercial product grades.

Many of the measurement procedures pertaining to the measurement of other products are applicable to the measurement of liquefied petroleum gases. However, certain characteristics of liquefied petroleum gas require extra precautions to improve measurement accuracy.

Liquefied petroleum gas will remain in the liquid state only if a pressure sufficiently greater than the equilibrium vapor pressure is maintained (see Chapters 5.3 and 6.6). In liquid meter systems, adequate pressure must be maintained to prevent vaporization caused by pressure drops attributed to piping, valves, and meter tubes. When liquefied petroleum gas is stored in tanks or containers, a portion of the liquid will vaporize and fill the space above the liquid. The amount vaporized will be related to the temperature and the equilibrium constant for the mixture of components.

Liquefied petroleum gas is more compressible and has a greater coefficient of thermal expansion than the heavier hydrocarbons. The application of appropriate compressibility and temperature correction factors is required to correct measurements to standard conditions, except when measurement for mass determination is from density and volume at metering temperatures and pressures.

Meters should be proven on each product at or near the normal operating temperature, pressure, and flow rate. If the product or operating conditions change so that a significant change in the meter factor occurs, the meter should be proven again according to Chapters 4 and 5.

## 4 Requirements For All Measurement Methods

The following general requirements apply to dynamic measurement systems using either volumetric or mass determination methods of measuring liquefied petroleum gases.

### 4.1 PROVISIONS TO ENSURE THAT FLUIDS ARE IN THE LIQUID PHASE

Provisions shall be made to ensure liquefied petroleum gas measurement conditions of temperature and pressure will be adequate to keep the fluid totally in the liquid phase. For measurement in the liquid phase, the pressure at the meter inlet must be at least 1.25 times the equilibrium vapor pressure at measurement temperature, plus twice the pressure drop across the meter at maximum operating flow rate, or at a pressure 125 pounds per square inch higher than the vapor pressure at a maximum operating temperature, whichever is lower (see Chapters 5.3 and 6.6).

### 4.2 ELIMINATION OF SWIRL

When using turbine or orifice meters, the installation shall comply with the requirements specified in chapters 5.3 or 14.3, respectively.

### 4.3 TEMPERATURE MEASUREMENT

Use of a fixed temperature may be acceptable, in some cases, when it varies by only a small amount; however, a continuously measured temperature is recommended for maximum accuracy.

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[5] Gas Processors Suppliers Association; Order from Gas Processors Association, 6526 E. 60th Street, Tulsa, Oklahoma 74145.

[6] USA System—Standard temperature is 60°F and standard pressure is the vapor pressure at 60°F or 14.696 pounds per square inch absolute, whichever is higher. This is not the same pressure base standard as that used for gas.

[7] International System of Units (SI)—Standard temperature is 15°C and standard pressure is the vapor pressure at 15°C or 101.325 kilopascals, whichever is higher.

Temperature measurements, where required, should be made at a point that indicates flowing conditions in the measuring device. The accuracy of instruments and the type of measurement used are specified in Chapters 4, 5.2, 5.3, 5.4, 7.2, and 14.6.

### 4.4 PRESSURE MEASUREMENT

Use of a fixed pressure may be acceptable in some cases, where it varies by only a small amount; however, a continuously measured pressure is recommended for maximum accuracy.

Pressure measurements, where required, should be made at a point that will be responsive to varying pressure conditions in the measuring device. The accuracy of instruments and the type of measurement used should be as described in Chapters 4, 5.2, 5.3, 5.4, and 14.6.

### 4.5 DENSITY OR RELATIVE DENSITY MEASUREMENT

The sample point for measurement of density or relative density (specific gravity) of the liquid should reflect the varying conditions that exist at the meter. Densities to be used to determine mass measurement must be obtained at the same flowing conditions that exist at the meter. The accuracy of instruments and the type of measurement used should be as described in Chapters 9.2 and 14.6.

### 4.6 LOCATION OF MEASURING AND SAMPLING EQUIPMENT

Measuring and sampling equipment shall be located as required in Chapter 8 and must be located to minimize or eliminate the influence of pulsation or mechanical vibration caused by pump or control valve generated noise. Special precautions should be taken to minimize or eliminate the effects of electrical interference that may be induced in the flow meter pick-up coil circuit. Use of a preamplifier is recommended.

Representative samples shall be obtained as required in GPA 2166 and GPA 2174. When automatic sampling systems are used, care must be taken to ensure that the sample is taken from the center one-third of cross-sectional area of the stream, the stream is well mixed at that point, the sample point is not in a dead leg, and the sample system does not permit bypassing the meter.

## 5 Volumetric Determination in Dynamic Systems

Dynamic measurement of liquefied petroleum gas (liquid phase), for custody transfer, can be performed using several different measurement devices. The choice of the specific type selected is dependent upon mutual agreement between the contracting parties.

### 5.1 MEASUREMENT BY ORIFICE METER

### 5.1.1 GENERAL ORIFICE METERING EQUATIONS

Measurement of liquefied petroleum gases by orifice meter shall conform to Chapter 14.3, Part 1 using orifice and line internal diameter ratios and appropriate coefficients for flow as agreed upon between the parties. The equations and factors development given in this standard are limited in scope. For a complete explanation and development refer to Chapter 14.3, Part 1. A complete listing of all the unit conversion factors ($N_1$) can be found in Chapter 14.3, Part 1, Section 1.11.4.

The orifice meter is inherently a mass measurement device with the following fundamental flow equation:

$$q_m = C_d E_v Y(\pi / 4) d^2 \sqrt{2 g_c \rho_{t,p} \Delta P}$$

The practical orifice meter flow equation used in this standard is a simplified form that combines the numerical constants and unit conversion constants in a unit conversion factor ($N_1$):

$$q_m = N_1 C_d E_v Y d^2 \sqrt{\rho_{t,p} \Delta P}$$

*Where:*

$C_d$ = orifice plate coefficient of discharge.
$d$ = orifice plate bore diameter calculated at flowing temperature ($T_f$).
$\Delta P$ = orifice differential pressure.
$E_v$ = velocity of approach factor.
$N_1$ = unit conversion factor.
$q_m$ = mass flow rate.
$\rho_{t,p}$ = density of the fluid at flowing conditions ($P_f$,$T_f$).
$P_f$ = flowing pressure (psia)
$Y$ = expansion factor.

The expansion factor, *Y*, is included in the above equations because it is applicable to all single-phase, homogeneous Newtonian fluids. For incompressible fluids, such as water at 60°F and atmospheric pressure, the empirical expansion factor is defined as 1.0000.

The following equations can be used to determine flow rate:

1. Flow rate in cubic feet per hour at flowing conditions:

$$Q_f = 359.072 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{\rho_{t,p}}}$$

$$Q_f = 359.072 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{\rho_{w,b} G_f}}$$

$$Q_f = 45.4683 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{G_f}}$$

2. Flow rate in pounds mass per hour:

$$Q_f = 359.072 C_d E_v Y d^2 \sqrt{\Delta P \rho_{t,p}}$$

$$Q_f = 2835.6681 C_d E_v Y d^2 \sqrt{\Delta P G_f}$$

Measurement of liquefied petroleum gas having a high vapor pressure is sometimes simplified, where deliveries are obtained in mass units, by multiplying the volume at flowing conditions times the density (measured within prescribed limits at the same flowing temperature and pressure that exists at the meter) times the meter and density adjustment factors as shown in 6.2. Calculation of the volume at standard conditions can then be made using 6.5 or GPA 8173.

3. Flow rate in cubic feet per hour at base conditions:

$$Q_f = \frac{359.072}{\rho_b} C_d E_v Y d^2 \sqrt{\Delta P \rho_{t,p}}$$

$$Q_f = \frac{45.4683}{G_b} C_d E_v Y d^2 \sqrt{\Delta P G_f}$$

4. Flow rate in cubic feet per hour at base conditions using volume and compressibility correction tables. (This method should only be used when measuring a pure product or mixture with well defined fluid properties.)

$$Q_f = 359.072 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{\rho_{t,p}}} (C_{tl} C_{pl})$$

$$Q_f = 45.4683 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{G_f}} (C_{tl} C_{pl})$$

*Where:*

$d$ = orifice plate bore diameter in inches.
$\Delta P$ = orifice differential pressure in inches of $H_2O$ at 60°F.
$E_v$ = velocity of approach factor.
$N_1$ = 359.072 (US units conversion factor 9.97424 E-02 $\times$ 3600)
$q_m$ = mass flow rate in pound-mole/hour.
$\rho_{t,p}$ = density of the fluid at flowing conditions ($P_f$,$T_f$) in pound-mole/foot$^3$.
$\rho_b$ = density of the fluid at base conditions ($P_b$,$T_b$) in pound-mole/foot$^3$.
$\rho_{w,b}$ = 62.3663 pound-mole/foot$^3$—density of air-free pure water at 60°F and an atmospheric pressure of 14.696 pounds per square inch.
$G_f$ = relative density at flowing conditions. Ratio of the density of the liquid at flowing conditions to the density of water at 60°F.
$G_b$ = relative density at base conditions.
$C_{tl}$ = correction factor for temperature to correct the volume at flowing temperature to standard temperature. See ASTM D 1250-80, Volume XII, Table 34, GPA 2142-57 or other agreed-upon tables.
$C_{pl}$ = correction factor for pressure to correct the volume at flowing pressure to standard conditions. See Chapter 11.2.2 or other agreed-upon tables.

$Y$ = 1.0000, per 4.1, provisions are made toensure that the liquefied petroleum gas fluids are always measured in a liquid state. Normally 1.0000 should be used unless the liquefied petroleum gas is being measured at temperatures and pressures that may alter the fluid properties.

### 5.1.2 Velocity of Approach Factor ($E_v$)

The velocity of approach factor, $E_v$, is calculated as follows:

$$E_v = \frac{1}{\sqrt{1-\beta^4}}$$

and,

$$\beta = d/D.$$

*Where:*

$d$ = orifice plate bore diameter calculated at flowing temperature ($T_f$).
$D$ = meter tube internal diameter calculated at flowing temperature ($T_f$).

### 5.1.3 Orifice Plate Bore Diameter ($d$)

The orifice plate bore diameter, $d$, is defined as the diameter at flowing conditions and can be calculated using the following equation:

$$d = d_r\,[1 + \alpha_1(T_f - T_r)]$$

*Where:*

$\alpha_1$ = linear coefficient of thermal expansion for the orifice plate material (see Table 1).
$d$ = orifice plate bore diameter calculated at flowing temperature ($T_f$).
$d_r$ = reference orifice plate bore diameter at $T_r$.
$T_f$ = temperature of the fluid at flowing conditions.
$T_r$ = reference temperature of the orifice plate bore diameter.

Note: $\alpha$, $T_f$, and $T_r$ must be in consistent units. For the purpose of this standard $T_r$ is assumed to be at 68°F (20°C).

The orifice plate bore diameter, $d_r$, calculated at $T_r$ is the diameter determined in accordance with the requirements Chapter 14.3, Part 2.

### 5.1.4 Meter Tube Internal Diameter ($D$)

The meter tube internal diameter, $D$, is defined as the diameter at flowing conditions and can be calculated using the following equation:

$$D = D_r[1 + \alpha_2(T_f - T_r)]$$

*Where:*

$\alpha_2$ = linear coefficient of thermal expansion for the meter tube material (see Table 1).
$D$ = meter tube internal diameter calculated at flowing temperature ($T_f$).

### Table 1—Linear Coefficient of Thermal Expansion

| | Linear Coefficient of Thermal Expansion ($\alpha$) | |
|---|---|---|
| Material | U.S. Units (in/in/°F) | Metric Units (mm/mm/°C) |
| Type 304 and 316 stainless steel[a] | 0.00000925 | 0.0000167 |
| Monel[a] | 0.00000795 | 0.0000143 |
| Carbon steel[b] | 0.00000620 | 0.0000112 |

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Note: For flowing temperature conditions outside those stated above and for other materials, refer to the American Society for Metals *Metals Handbook*.

[a] For flowing conditions between –100°F and +300°F, refer to ASME PTC 19.5.

[b] For flowing conditions between –7°F and +154°F, refer to Chapter 12, Section 2.

### 5.1.5 Empirical Coefficient of Discharge Equation for Flange-Tapped Orifice Meters.

The concentric, square-edged flange-tapped orifice meter coefficient of discharge, $C_d$, (FT) equation, developed by Reader-Harris/Gallagher (RG), is structured into distinct linkage terms and is considered to best represent the current regression database. The equation is applicable to nominal pipe sizes of 2 inches (50 millimeters) and larger; diameter ratios ($\beta$) of 0.1 to 0.75, provided the orifice plate bore diameter, $d_r$, is greater than 0.45 inch (11.4 millimeters); and pipe Reynolds numbers ($Re_D$) greater than or equal to 4000. For diameter ratios and pipe Reynolds numbers below the limit stated, refer to Chapter 14.3.1.12.4.1. The RG coefficient of discharge equation for an orifice meter equipped with flange taps is defined as follows:

$$C_d = C_i(\mathrm{FT}) + 0.000511\left[\frac{10^6\beta}{\mathrm{Re}_D}\right]^{0.7} + (0.0210 + 0.0049A)\beta^4 C.$$

$$C_i(\mathrm{FT}) = C_i(\mathrm{CT}) + TapTerm.$$

$$C_i(\mathrm{CT}) = 0.5961 + 0.029\beta^2 - 0.2290\beta^8 + 0.003(1-\beta)M_1.$$

$$TapTerm = Upstrm + Dnstrm.$$

$$Upstrm = [0.0433 + 0.0712e^{-8.5\mathrm{L}_1} - 0.1145e^{-6.\mathrm{OL}_1}](1 - 0.23\mathrm{A})B.$$

$$Dnstrm = -0.0116[M_2 - 0.52M_2^{1.3}]\beta^{1.1}(1 - 0.14A)$$

Also,

$$B = \frac{\beta^4}{1-\beta^4}$$

$$M_1 = max\left(2.8 - \frac{D}{N_4}, 0.0\right)$$

$$M_2 = \frac{2\mathrm{L}_2}{1-\beta}$$

$$A = \left(\frac{19,000\beta}{Re_D}\right)^{0.8}$$

$$C = \left(\frac{10^6\beta}{Re_D}\right)^{0.35}$$

*Where*:

$\beta$ = diameter ratio.
= $d/D$.
$C_d(\mathrm{FT})$ = coefficient of discharge at a specified pipe Reynolds number for flange-tapped orifice meter.
$C_i(\mathrm{FT})$ = coefficient of discharge at infinite pipe Reynolds number for flange-tapped orifice meter.
$C_i(\mathrm{CT})$ = coefficient of discharge at infinite pipe Reynolds number for corner-tapped orifice meter.
$d$ = orifice plate bore diameter calculated at $T_f$.
$D$ = meter tube internal diameter calculated at $T_f$.
$e$ = Napierian constant.
= 2.71828.
$\mathrm{L}_1$ = dimensionless correction for the tap location.
= $\mathrm{L}_2$.
= $N_4/D$ for flange taps.
$N_4$ = 1.0 when $D$ is in inches.
= 25.4 when $D$ is in millimeters.
$Re_D$ = pipe Reynolds number.

### 5.1.6 Reynolds Number (*Re*$_D$)

The RG equation uses pipe Reynolds number as the correlating parameter to represent the change in the orifice plate coefficient of discharge, $C_d$, with reference to the fluid's mass flow rate (its velocity through the orifice), the fluid density, and the fluid's viscosity.

The pipe Reynolds number can be calculated using the following equation:

$$Re_D = \frac{4q_m}{\pi\mu D}$$

The pipe Reynolds number equation used in this standard is in a simplified form that combines the numerical constants and unit conversion constants:

$$Re_D = \frac{N_2 q_m}{\mu D}$$

For the Reynolds number equations presented above, the symbols are described as follows:

$D$ = meter tube internal diameter calculated at flowing temperature ($T_f$).
$\mu$ = absolute viscosity of fluid.
$N_2$ = unit conversion factor.
$\pi$ = universal constant.
= 3.14159.
$q_m$ = mass flow rate.
$Re_D$ = pipe Reynolds number.

## 5.2 MEASUREMENT BY POSITIVE DISPLACEMENT METER

The manufacturer's recommendations should be carefully considered in sizing positive displacement meters (see Chapter 5.2).

Air eliminators should be used with caution, particularly where the line in which they are installed could be shut-in occasionally, and where complete vaporization could occur.

Vapor formation resulting from the effects of ambient temperature or heat tracing on the line ahead of the meter could cause inaccuracies and damage, which are most likely to be encountered during startup. Caution must be exercised.

### 5.2.1 Volume at Standard or Base Conditions

Liquid measurement by positive displacement meters should conform to the procedures in Chapter 5.2. Appropriate correction factors should be used to adjust the measured volume to standard conditions by correcting for temperature, pressure, and meter factor. Factors to be applied will be found in Chapters 11 and 12.

The positive displacement measurement equation is:

$$V_b = V_f \times \text{M.F.} \times C_{tl} \times C_{pl}$$

*Where:*

$V_b$ = volume at base or standard conditions.
$V_f$ = volume at flowing conditions, indicated by a measuring device.
M.F. = meter factor, obtained by proving the meter according to Chapters 4 and 12.2.
$C_{tl}$ = correction factor for temperature to correct the volume at flowing temperature to standard temperature. See ASTM D 1250-80, Volume XII, Table 34, GPA Standard 2142-57 or other agreed-upon tables.
$C_{pl}$ = correction factor for pressure to correct the volume at flowing pressure to standard conditions. See Chapter 11.2.2 or other agreed-upon tables.

### 5.2.2 Volume at Flowing Conditions for Mass Determination

The volume measured at flowing conditions ($V_m$) times the meter factor equals the volume at flowing conditions. Displacement meters used for volumetric measurement in deriving total mass shall conform to the standards described in Chapter 5.2 for the service intended. Temperature or pressure compensation devices are not to be used on these meters, and the accessories used shall conform to Chapter 5.4.

## 5.3 MEASUREMENT BY TURBINE METER

The manufacturer's recommendations should be carefully considered in sizing turbine meters (see Chapter 5.3).

Air eliminators should be used with caution, particularly where the line in which they are installed could be shut-in occasionally and where complete vaporization could occur. In this case, thermal relief valves may be required to prevent physical damage to the equipment.

Vapor formation resulting from the effects of ambient temperature or heat tracing on the line ahead of the meter could cause inaccuracies and damage, which are most likely to be encountered during startup. Caution must be exercised.

Liquid measurement by turbine meter should conform to the procedures described in Chapter 5.3. If volumetric measurement is being performed, appropriate correction factors should be used that will adjust the measured volume to standard conditions by correcting for temperature, pressure, and meter factor. Factors to be applied will be found in Chapters 4, 11, and 12.

The following equation is used when performing volumetric measurement by turbine meter:

$$V_b = V_f \times \text{M.F.} \times C_{tl} \times C_{pl}$$

*Where:*

$V_b$ = volume at base or standard conditions.
$V_f$ = volume at flowing conditions, indicated by a measuring device.
M.F. = meter factor, obtained by proving the meter according to Chapters 4 and 12.2.
$C_{tl}$ = correction factor for temperature to correct the volume at flowing temperature to standard temperature. See ASTM D 1250-80, Volume XII, Table 34, GPA Standard 2142-57 or other agreed-upon tables.
$C_{pl}$ = correction factor for pressure to correct the volume at flowing pressure to standard conditions. See Chapter 11.2.2 or other agreed-upon tables.

Turbine meters used for volumetric measurement at flowing conditions, in deriving total mass shall conform to Chapter 5.3 for the service intended. Temperature or pressure compensating devices shall not be used on these meters, and accessories shall conform to Chapter 5.4. The measured mass, converted to equivalent component volumes at standard conditions, may be determined according to GPA 8173.

## 5.4 MEASUREMENT BY OTHER DEVICES

Dynamic measurement of liquefied petroleum gas can be accomplished using other types of equipment by mutual agreement of the contracting parties. Application of this standard requires use of industry recognized custody transfer devices.

## 5.5 METER PROVING

The primary measuring device must be compared to a known standard. Comparison to a standard is accomplished by proving positive displacement and turbine meters using a conventional pipe prover or a small volume prover calibrated in accordance with Chapter 4. Tank-type provers are not recommended because liquefied petroleum gas may vaporize in the tank, making accountability for these vapors difficult. When a meter is used to measure more than one product, the meter shall be proved at the operating rates of flow, pressure, and temperature and at the specification of the liquid that it will measure in routine operation. Several meter factors may be required where normal operations change significantly. The proving device should be installed so that the temperature and pressure within the prover and meter coincide as closely as possible. Meter and prover volumes shall be corrected to base conditions according to Chapters 4, 11, and 12. Factors shall be adjusted, as required, between proving dates as a result of significant changes in metering pressure, temperature, product, or flow rate since the last proving.

## 5.6 SAMPLING

Sampling shall be accomplished to yield a sample that is proportional to, and representative of, the flowing stream during the measuring interval. Proportional samplers take small samples of the flowing stream proportional to the flow rate. Time incremental sampling may be used only when the flow rate is constant. Time proportional sampling systems must stop sampling when the flow stops.

The sample collecting system shall be designed to contain the collected sample in the liquid state. This may be done using a piston cylinder or a bladder cylinder. Both the piston cylinder and bladder cylinder normally use inert gas vapor not normally found in the sample stream (for example, helium), hydraulic oil, or pipeline fluid to oppose the liquid injection and maintain a pressure level above the vapor pressure of the sample.

Precautions shall be taken to avoid vaporization in sample loop lines when operating near the product vapor pressure. In some cases when sampling volatile materials, it may be necessary to either insulate sample lines and sample containers, or to control the pressure or temperature of sample containers.

Sample loops should be short and in small diameter. Sampling should be from the center one-third of the cross-sectional area of the stream using a sample probe. Adequate sample loop flow rates should be maintained to keep fresh product at the sample valve and to minimize the time lag between the meter and the sampler. Sample loops must not bypass the primary measurement element.

When sample collection cylinders are emptied, all sample lines, pumps, and related equipment should be purged or bled down to avoid contamination or distortion of the flowing sample. Sampler systems should be designed to minimize dead product areas, which could distort samples.

Obtaining a representative sample shall be in accordance with GPA 2166 and GPA 2174. Sample containers must be adequately sized. If samples are to be shipped by common carrier, containers must comply with the latest hazardous materials regulations of the United States Department of Transportation, manufacturer's recommendations, or similar appropriate authority.

Products or mixtures that have equilibrium vapor pressures above atmospheric pressure shall be maintained at a pressure where vaporization cannot occur within the on-line sample system or transfer containers. For single cavity sample containers, care must be taken to ensure at least a 20 percent outage in transfer containers. All systems must allow for thermal expansion without overpressuring the system. (See GPA 2174 on sampling.)

Use of sample collection and transportation containers equipped with floating pistons or bladders (and equipped to maintain sample storage pressures above vapor pressure) is one effective way to avoid liquid-vapor separation. When using this type of equipment, adequate precautions must be observed to allow for thermal expansion of the product so that excessive pressure or release of product does not occur.

Sample handling procedures outlined in GPA 2174, using immiscible fluid outage cylinders, may also be used. Water used with this method may result in removal of carbon dioxide or other water-soluble components from the sample.

A sampling system, for taking proportional samples over a period of time, must provide a workable mixing system that thoroughly mixes the sample. Proportional samples, to be truly representative, must be mixed before being transferred to the portable sample container. Product mixing should not be attempted until the sampler has been isolated from the source. Procedures for thorough mixing of samples shall be provided to ensure that samples transferred to transportation cylinders and the analysis obtained are representative of the flowing stream during the measured interval.

After mixing, the sampled product is transferred to a portable piston cylinder or a double-valved sample cylinder, using the immiscible fluid displacement method. Transfer the sample to the portable cylinder using the same procedure used to take spot samples. When the required number of portable cylinders has been filled, the remaining product in the sampler must be vented back into the pipeline or disposed of before the sampler is returned to service.

Obtaining a representative sample of the liquid stream for transport to the laboratory shall be in accordance with GPA 2174. Provisions shall be made for thermal expansion. Department of Transportation-approved containers shall be used.

## 5.7 SAMPLE ANALYSIS

Depending upon the composition of the stream, the liquid sample analysis shall follow the chromatographic procedures described in GPA Publications 2165, 2177, 2186, and 2261.

Where applicable, such as with liquefied petroleum gas mixtures, special efforts shall be made to accurately determine the molecular weight and the density of the heaviest final combined peak eluted—for example, heptanes plus fraction (or of the last significant fraction determined by agreement).

## 6 Mass Determination in Dynamic Systems (Relative Density Range 0.350 to 0.637)

Mass measurement is applicable to liquefied petroleum gas mixtures and to components that are affected by compositional changes, intermolecular adhesions, solution mixing, or extreme pressure and temperature conditions where accurate physical correction factors have not been determined.

Mass measurement in a dynamic state normally utilizes (a) a volumetric measuring device at flowing conditions, (b) a density or relative density (specific gravity) measuring device for determining density or relative density at the same flowing conditions as the measuring device, and (c) a representative sample of the fluid flowing through the measuring system, collected proportional to flow, as presented in GPA 8182.

Mass measurement is obtained by multiplying the measured volume at flowing conditions times flowing density measured at the same conditions, using consistent units. The equivalent volume at standard conditions of each component in the mixture may be obtained by using a compositional analysis of the representative sample and the density of each component at 60°F and the equilibrium pressure at 60°F (see GPA 8173).

Liquids with relative densities below 0.350 and above 0.637 and cryogenic fluids are excluded from the scope of this document. However, the principles can apply to these fluids with modified application techniques.

Equipment exists that uses diverse principles for measuring volume, sampling the product, and determining the composition and density of the product. This publication does not advocate the preferential use of any particular type of equipment. It is not the intention of this publication to restrict future development or improvement of equipment.

### 6.1 BASE CONDITIONS

Density is defined as mass per unit volume:

$$\text{Density} = \frac{\text{Mass}}{\text{Volume}}$$

Mass is an absolute measure of the quantity of matter. Weight is the force resulting from an acceleration due to gravity acting upon a mass. Changes of gravity acceleration from one locality to another will affect the resulting weight force observed. Quantities determined in accordance with GPA 8182 shall be mass rather than weight. This may be accomplished through procedures in Chapter 14.6 by referral to weighing devices used to calibrate density meters to test weights of known mass. This referral or calibration is done at or near the densitometer location, eliminating the need for further correction for local gravitational force variances.

Weight observations to determine fluid density shall be corrected for air buoyancy (commonly called weighed in vacuum) and for local gravity, as necessary. Such observations can be used in conjunction with the calibration of density meters or for checking the performance of equation of state correlations. Procedures are outlined in Chapter 14.6.

Volumes and densities for mass measurement shall be determined at operating temperature and pressure to eliminate temperature and compressibility corrections. However, equivalent volumes of components are often computed for the determined mass flow. These volumes shall be calculated at a temperature of 60°F (15.56°C) and a pressure of either 14.696 psia (101.325 kPa) or equilibrium pressure of the product at 60°F (15.56°C) whichever is greater.

### 6.2 MASS MEASUREMENT USING DISPLACEMENT TYPE OR TURBINE METERS

The equation for determining mass using displacement-type or turbine meters is:

$$\text{Mass} = \begin{bmatrix}\text{Metered volume}\\ \text{at meter}\\ \text{operating}\\ \text{conditions}\end{bmatrix} \times \begin{bmatrix}\text{Meter factor}\\ \text{at meter}\\ \text{operating}\\ \text{conditions}\end{bmatrix}$$

$$\times \begin{bmatrix}\text{Density at}\\ \text{meter operating}\\ \text{conditions}\end{bmatrix} \times \begin{bmatrix}\text{Densitomer}\\ \text{correction}\\ \text{factor (if}\\ \text{applicable)}\end{bmatrix}$$

### 6.3 ORIFICE METERS FOR MASS MEASUREMENT

The following is a sample calculation of the mass flow rate using an orifice meter to measure delivery of a liquefied petroleum gas (raw mix) from a gas processing plant.

A. Given

1. Orifice meter station designed, installed, and operated in compliance with specifications in the API MPMS, Chapter 14, Section 3, Parts 1 and 2.
2. Product being delivered is de-methanized liquid (raw mix) from a gas processing plant having the following analysis:

a. Metering temperature - - - 80°F.
b. Viscosity - - - 0.095 centipoise.
c. Meter tube internal diameter (I.D.) 4.026" at 68°F.
d. Orifice plate 316 ss - - - 2.005" at 68°F.
e. Operating differential pressure ΔP - - - 50" $H_2O$ at 60°F.
f. Operating density of 29.47 pounds/feet.$^3$

B. Problem

Calculate the mass flow rate in pounds mass per 24 hours and convert to volume at 60°F and equilibrium vapor pressure in gallons of each component.

C. Solution

$$q_m = N_1 C_d E_v Y \, d^2 \sqrt{\rho_{t_1, p_1} \Delta P}$$

*Where:*

$q_m$ = pounds mass per second.
$C_d$ = orifice plate coefficient of discharge.
$d$ = orifice plate bore diameter calculated at flowing temperature.
$\Delta P$ = differential pressure across orifice plate. Static pressure measured at upstream flange tap.
$E_v$ = velocity of approach factor.
$N_1$ = unit conversion factor.
$t_1$, $\rho_1$ = indicates temperature and pressure at flowing conditions.

a. Calculate the I.D. of the meter tube at 80°F.

$D = D_r [1 + \alpha_2 (T_f - T_r)]$ $T_f$ = Flowing temperature, $T_r$ = Reference temperature, $D_r$ (reference temperature) = 4.026 at 68°F. Carbon steel.
$D = 4.026 [1 + 0.00000620(80-68)] = 4.02630$".
$\alpha_2$ = Coefficient of thermal expansion in carbon steel (inch/inch/°F).

b. Calculate orifice bore diameter at flowing temperature of 80°F.

$d = d_r [1 + 0.00000925(80–68)] = 2.00522$".

c. Calculate, $\beta$, ratio of $d/D = 2.00522/4.0630 = 0.498031$.

d. Calculate $E_v$—velocity of approach factor.

$E_v = 1/(1–\beta^4)^{0.5} = 1/(1–0.061531)^{.5} = 1.032256$.

e. Expansion factor $Y = 1.0$.

f. Calculated, $C_d$ (FT), coefficient of discharge for flange taps.

Calculation of the mass flow rate provides an easy way to obtain the volumetric flow rate at flowing conditions and the volumetric flow rate at base conditions. Calculation of flow involves an iteration process on a digital computer. For the given set of conditions the rate of flow is:

$Q_m$ per day (24 hours) = 828,600 pounds mass

## 6.4 DENSITY DETERMINATION

Density may be determined by empirical correlation, based on an analysis of the fluid or on a direct measurement of the flowing density.

### 6.4.1 Empirical Density

Liquid density may be calculated as a function of composition, temperature, and pressure. It is preferred that the calculated or measured density be applied in real time to the flowmeter. This provides for the maximum mass measurement precision, that is, the incremental volume of measured liquid is always in direct time relation to the density measured or calculated. However, it is common practice to use the composition of a sample taken continuously during the delivery period proportional to the volume delivered, and to use the average temperature and pressure for the delivery period.

Calculations may be made by means of empirical correlations or by generalized equations of state. The empirical correlations are derived from fitting experimental data covering specific ranges of compositions, temperatures, and pressures and can be inaccurate outside these ranges. The GPA procedure TP-1 for ethane/propane mix and TP-2 for high ethane raw make streams are examples. TP-3 is a more theoretical procedure for application to liquefied natural gas.

Generalized equations of state do not have strict limitations on ranges of compositions and conditions and can be applied to a wide variety of systems; however, empirical correlations are much more accurate when applied to the specific systems for which they were derived. The Rackett equation, the Han-Starling modification of the BWR equation of state, and several modified Redlich-Kwong equations of state (Soave, Mark V, Peng-Robinson) are examples.

It is the responsibility of the contracting parties to verify the validity and limits of the accuracy of methods considered for empirical density determination on the particular fluids to be measured.

Significant errors can occur from inaccuracies in temperature and pressure measurement, recording, or integration. Products with a relative density less than 0.6 are particularly susceptible to errors and require a higher level of precision. See Chapter 14.6 for recommended precision levels of temperature and pressure.

### 6.4.2 Measured Density

Measured density of products having a relative density between 0.350 and 0.637 shall be determined using density meters installed and calibrated in accordance with Chapter 14.6.

Density instruments or probes shall be installed as follows:

a. No interaction that would adversely affect the flow or density measurements shall exist between the flowmeter and the density transducer or probe.
b. Temperature and pressure differences among the fluid in the flowmeter, the density measuring device, and the calibrating devices must be minimized and must be within specified limits for the fluid being measured and the mass measurement accuracy expected or required.
c. Density meters may be installed either upstream or downstream of primary flow devices in accordance with Chapter 14.6, but should not be located between flow straightening devices and meters and must not bypass the primary flow measurement device.

Densitometer accuracy will be seriously affected by the accumulation of foreign material from the flowing stream. The possibility of accumulation should be considered in selecting density measurement equipment and in determining the frequency of density equipment calibration and maintenance. Accuracy of the data recording, transmission, and computation equipment and methods should also be considered in system selection. See Chapter 14.6 for further comments.

### 6.5 CONVERSION OF MEASURED MASS TO VOLUME

Conversion from mass determined into equivalent volumes of components shall be in accordance with the latest revision of GPA 8173, as described below. In this procedure, a chromatographic analysis representative of the delivered product is used to determine the mass of each individual component that comprised the total mass. The individual component masses are then converted to their respective equivalent liquid volumes at 60°F (or 15.56°C) and equilibrium vapor pressure at 60°F (or 15.56°C), using component density values from GPA 2145. The method and frequency of determining physical properties for combined component fractions (such as C7+) must be established and agreed to by the affected parties.

The calculation of total mass flowing must be performed continuously on-line by a suitable device or by off-line integration of charts on which metered volume and density are continuously recorded, so that at all times the density corresponds to the volume measured.

Conversion of the determined mass into an equivalent volume of each component at base or standard conditions at equilibrium vapor pressure at 60°F (15.56°C) or 14.696 pounds per square inch absolute (101.325 kilopascals), whichever is higher, shall be in accordance with Chapter 14.4. In this procedure a chromatographic analysis, representative of the delivered product, is used to determine the mass of each individual component comprising the total mass. The individual component masses are then converted to their respective equivalent liquid volumes at 60°F (or 15.56°C) and the equilibrium vapor pressure at 60°F (or 15.56°C), using component density values in vacuum from Chapter 11 or GPA 2145. Example calculations, repeated from Chapter 14.4, are provided in the appendix.

## 7 Volumetric Measurement in Static Systems

The total fluid volume is the sum of the volume of the fluid currently in the liquid state plus the volume of the fluid in the vapor state converted to equivalent liquid volume.

Volumetric measurement is obtained by using calibrated vessels or tanks with gauging devices that can be read at the vessel operating pressures to determine the liquid level. The volume of vapor above the liquid is determined by using the ideal gas law ($PV = NRT$) corrected by the gas compressibility factor. The liquid and vapor are corrected for temperature and pressure to standard or base conditions of temperature and the vapor pressure of the product at standard or base temperature. The vapor volume can be converted to equivalent liquid volume by using the appropriate factors. A pressure vessel or container must be able to safely withstand the vapor pressures of the contained product at the maximum operating temperature.

### 7.1 TANK CALIBRATION

Procedures for calibrating tanks and vessels are presented in Chapter 2.

### 7.2 TANK GAUGING OF LIQUEFIED PETROLEUM GAS

Procedures for gauging liquefied petroleum gas in storage tanks are presented in Chapter 3. Special precautions are necessary to accurately account for the vapors above the liquid. The composition and volume of the vapors are dependent upon the temperature and pressure conditions of the liquid.

### 7.3 TEMPERATURE MEASUREMENT

Chapter 5.4 contains general requirements for temperature measurement. Procedures for measuring the temperature of liquefied petroleum gas in storage vessels under static conditions are presented in Chapter 7.

### 7.4 RELATIVE DENSITY MEASUREMENT

Procedures for determining relative density of liquefied petroleum gas are presented in Chapters 9, 11, 12, 14.6, and 14.7. Observed relative densities (specific gravities) are corrected to standard or base conditions by using tables in Chapter 11.1.

## 7.5 WATER AND FOREIGN MATERIAL

Water and sediment content is not as serious a problem with liquefied petroleum gases as with crude oil. Product specifications in contracts for custody transfer should contain a section on product quality to provide for testing propane by the freeze valve method (ANSI/ASTM D 2713-91), the cobal bromide method, or the Bureau of Mines method. Other mutually acceptable methods for determining dryness may be used for other liquefied petroleum gases having a high vapor pressure, including on stream moisture monitors.

## 7.6 SAMPLING

The scope of Chapter 8 does not include sampling of liquefied petroleum gases; however, GPA 2140 contains a section on sampling this type of product. GPA 2140 is also designated as ASTM D 1835. Its scope covers the procedure for obtaining representative samples of liquefied petroleum gases, such as propane, butane, or mixtures thereof, in containers other than those used in laboratory testing apparatus. A liquid sample is transferred from the source into a sample container by purging the container and filling it with liquid to 80 percent of capacity.

Considerable effort may be required to obtain a representative sample, especially if the material being sampled is a mixture of liquefied petroleum gases. The following factors must be considered:

a. Samples must be obtained in the liquid phase.
b. When it is definitely known that the material being sampled is composed predominantly of only one liquefied petroleum gas, a liquid sample may be taken from any part of the vessel.
c. When the material being sampled has been mixed until uniformity is ensured, a liquid sample may be taken from any part of the vessel.
d. Because of wide variations in the construction details of containers for liquefied petroleum gases, it is difficult to specify a uniform method for obtaining representative samples of heterogeneous mixtures. If it is not practical to agitate a mixture for homogeneity, obtain liquid samples by a procedure that has been agreed upon by the contracting parties.

Directions for sampling cannot be explicit enough to cover all cases. Directions must be supplemented by judgment, skill, and sampling experience. Extreme care and good judgment are necessary to ensure that samples represent the general character and average condition of the material. Because of the hazards involved, liquefied petroleum gases should be sampled by, or under the supervision of, persons familiar with the necessary safety precautions. Care should be taken to transfer and handle the sample a minimum number of times. Care must be taken to allow for the thermal expansion of the liquid.

## 7.7 VOLUMETRIC CALCULATION

When product is removed from or added to a tank, the beginning and ending liquid levels are obtained along with corresponding temperatures and pressures. The volumes of liquid and vapor are calculated for the beginning and ending conditions, and the difference between the beginning and ending calculations of the total volume of the vapor and liquid is the volume change in the vessel.

$$\begin{bmatrix}\text{Total volume}\\ \text{at standard}\\ \text{conditions}\end{bmatrix} = \begin{bmatrix}\text{Volume of liquid}\\ \text{at standard}\\ \text{conditions}\end{bmatrix} + \begin{bmatrix}\text{Volume of}\\ \text{vapor above}\\ \text{the liquid}\\ \text{in equivalent}\\ \text{liquid units}\\ \text{at standard}\\ \text{conditions}\end{bmatrix}$$

$$\begin{bmatrix}\text{Volume of liquid}\\ \text{at standard}\\ \text{conditions}\end{bmatrix} = \begin{bmatrix}\text{Liquid volume}\\ \text{at tank}\\ \text{conditions}\end{bmatrix} \times \begin{bmatrix}\text{Volume}\\ \text{correction}\\ \text{factor for}\\ \text{temperature}\\ \text{and gravity}\end{bmatrix}$$

$$\begin{bmatrix}\text{Volume of}\\ \text{vapor above}\\ \text{liquid in}\\ \text{equivalent}\\ \text{liquid}\\ \text{units at base}\\ \text{conditions}\end{bmatrix} = \begin{bmatrix}\text{Volume}\\ \text{of vapor}\\ \text{above the}\\ \text{liquid}\end{bmatrix} \times \frac{P_o}{P_a} \times \frac{T_a}{T_o} \times \begin{bmatrix}\text{Factor}\\ \text{for liquid}\\ \text{volume}\\ \text{per vapor}\\ \text{volume}\end{bmatrix}$$

*Where:*

Total volume = (volume of product in the vessel as a liquid) + (vapor above the liquid converted to its liquid volume equivalent). Volume measured at standard conditions.

Volume of liquid at standard conditions = volume measured at standard temperature and vapor pressure of the liquid at standard temperature.

Volume of liquid at tank conditions = volume of vessel at liquid level determined by tank calibration and gauging device.

Volume of vapor above the liquid = volume of vessel above the liquid level determined by tank calibration and gauging device.

Volume correction factor = factor used to correct the liquid volume to standard temperature. Refer to tables in ASTM D 1250-80, Volume XII, Table 34 and Chapter 12.2.

$P_o$ = observed pressure, in absolute units.
$P_a$ = standard pressure, in absolute units.
$T_o$ = observed temperature, in kelvins (K) or degrees Rankine (°R).
$T_a$ = standard temperature in kelvins (K) or degrees Rankine (°R).

Factor for liquid volume per vapor volume = standard conversion unit for product being measured.

### 7.8 MIXTURE CALCULATION

When mixtures are measured, the composition of the liquid and vapor will be different for varying conditions of temperature and pressure. The composition of each phase can be determined by sampling and analysis of each. Refer to GPA 8182 for the procedure for calculating liquid equivalent of the vapor volume above stored natural gas liquid mixtures.

## 8 Mass Measurement in Static Systems

Mass is determined by weighing the container or vessel before and after product movement. The difference in weight provides the basis for total mass of the product transferred.

To calculate the volume using mass units:

$$V_b = \frac{\text{Mass}}{\text{Density}}$$

*Where:*

$V_b$ = volume at standard temperature and vapor pressure of the product at standard temperature.
Mass = difference in mass measured before and after product movement.
Density = density of liquid product at standard conditions in same units as mass.

Refer to ASTM D 1250-80, Volume XII, Table 34 to determine relative density at standard conditions.

# APPENDIX A—COMPONENT SAMPLE CALCULATIONS

Step 1—Calculate the weight (mass) fraction of each component. Given: 828.000 = Total pounds mass.

| Component | Mole Percent | Mole Weight | Mole percent × Mole Weight | Weight Fraction of Component |
|---|---|---|---|---|
| C02 | 0.11 | 44.01 | 4.8411 | 0.001099 |
| C1 | 2.14 | 16.043 | 34.3320 | 0.007796 |
| C2 | 38.97 | 30.07 | 1171.8279 | 0.266084 |
| C3 | 36.48 | 44.097 | 1608.6586 | 0.365273 |
| IC4 | 2.94 | 58.123 | 170.8816 | 0.038802 |
| NC4 | 8.77 | 58.123 | 509.7387 | 0.115745 |
| IC5 | 1.71 | 72.15 | 123.3765 | 0.028015 |
| NC5 | 1.82 | 72.15 | 131.313 | 0.029817 |
| C6+ | 7.06 | 91.928[a] | 649.0117 | 0.147369 |
| | 100.00 | | 4403.9811 | 1.000000 |

Step 2—Calculate the mass of each component as follows: Weight fraction times total pounds mass equals pounds mass each component:

| Component | Weight Fraction of Component | Total Pounds Mass | Pounds Mass of Component |
|---|---|---|---|
| CO2 | 0.001099 | 828,600 | 910.6 |
| C1 | 0.007796 | 828,600 | 6,459.8 |
| C2 | 0.266084 | 828,600 | 220,477.2 |
| C3 | 0.365273 | 828,600 | 302,665.2 |
| IC4 | 0.038802 | 828,600 | 32,151.3 |
| NC4 | 0.115745 | 828,600 | 95,906.3 |
| IC5 | 0.028015 | 828,600 | 23,213.2 |
| NC5 | 0.029817 | 828,600 | 24,706.4 |
| C6+ | 0.147369 | 828,600 | 122,110.0 |
| | | | 828,600.0 |

Step 3—Calculate the volume of each component at equilibrium pressure and 60°F as follows:

| Component | Component Pounds Mass | Density Pounds/Gallon (in vacuum) | U.S. Gallons |
|---|---|---|---|
| CO2 | 910.6 | 6.8199 | 133.5 |
| C1 | 6,459.8 | 2.50 | 2,583.9 |
| C2 | 220,477.2 | 2.9696 | 74,244.7 |
| C3 | 302,665.2 | 4.2268 | 71,606.2 |
| IC4 | 32,151.3 | 4.6927 | 6,851.3 |
| NC4 | 95,906.3 | 4.8691 | 19,696.9 |
| IC5 | 23,213.2 | 5.2058 | 4,459.1 |
| NC5 | 24,706.4 | 5.2614 | 4,695.8 |
| C6+ | 122,110.0 | 5.6230[a] | 21,716.2 |
| | | | 205,987.6 |

[a] From analysis.

Note: For this example, the C6+ mole % is: C6, 74%; C7, 18%; C8, 3%; C9, 3%; C10, 2%.

Figure 1—Calculations for Liquid Vapor Conversion

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