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

Section 13—Performance-Based Methodology for Non-Custody Gas Measurement

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API MPMS Ch. 14.13 supersedes API TR 2571, 1st Edition, March 2011 *Fuel Gas Measurement*, which is withdrawn.

Introduction

This document is not intended to be used for custody applications. Other API Standards contain more stringent requirements when employing any measurement device for custody measurement applications.

This document provides a simplified performance-based methodology for gas measurement and reporting. Specifically, considerations are provided for measurement device selection, installation, maintenance, calibration and documentation to achieve a targeted performance.

This document can be used for a single or multiple gas meter system. Techniques are described to assess the uncertainty contribution of individual components and the gas measurement uncertainty.

This document addresses the more common gas measurement devices. This document does not advocate the use of these devices or preclude the utilization of other types of devices, provided the targeted performance is achieved.

This document includes a brief description of the working principles of different types of gas meters and their influence parameters, installation recommendations, a uniform method to ascertain the measurement uncertainty, a recommended method to determine the frequency of maintenance, performance verification or calibration of the meter and secondary instruments, and other relevant and necessary information.

Gas can be measured by different types of flow meters. The selection of a meter typically depends on several factors such as:

— desired accuracy for the application;

— desired accuracy verification capability (i.e. calibration, inspection, replacement);

— life expectancy;

— operating conditions and their variability—flow rate, pressure, temperature, gas composition/density, etc.;

— cost of initial installation;

— operational requirements;

— regulatory requirements.

Listed below are different flow meters that are typically installed to measure the non-custody gas flows in the industry. The selection of the gas meter by the user may include other types of meters not included in this list:

— differential-pressure or head-type flow meters;

— displacement flow meters;

— turbine flow meters;

— thermal dispersion flow meters;

— Coriolis force flow meters;

— ultrasonic flow meters;

— vortex flow meter.

Gas Measurement

1 Scope

This recommended practice provides guidance in the following areas to allow the user to achieve a targeted uncertainty of measurement:

— selection of flow meter type; differential pressure (DP), displacement, ultrasonic, Coriolis, vortex, turbine, thermal, and others;

— associated instrumentation for measuring fluid properties and flowing conditions, such as pressure and temperature transmitters, densitometers, gas chromatographs;

— obtaining and use of gas composition or other analytical data;

— design and installation requirements of the measurement system;

— inspection, verification and calibration practices of flow meters and their associated accessory instrumentation; and

— simplified uncertainty calculations with examples to illustrate the methodology.

2 Terms and Definitions

For the purposes of this document, the following definitions apply.

2.1
Accuracy
The closeness of agreement between a measured quantity value and a true quantity value of a measurand.

2.2
Source of bias
Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the estimate of a systematic measurement error.

2.3
Calibration process
The process or procedure of adjusting an instrument so that its indication or registration is in satisfactorily close agreement, within acceptable tolerances, with a reference standard.

2.4
carbon content
The fraction of carbon in the fluid expressed as percent by weight.

2.5
Compensation to a reference condition
The adjustment of the measured value to reference conditions (e.g. pressure compensation).

2.6
flowing density
The density of the fluid at actual flowing temperature and pressure.

2.7
flowing compressibility
The compressibility of the fluid at actual flowing temperature and pressure.

2.8
influence parameter
Any factor that impacts the performance of the measuring device, hence the uncertainty and accuracy of the measurement. Examples are process temperature, pressure, fluid composition, upstream straight length, etc.

2.9
inspection
A visual assessment or mechanical activity (e.g. instrument lead line blow down or orifice plate cleanliness) that does not include comparison or adjustment to a reference standard.

2.10
metering or measurement system
A combination of primary, secondary and/or tertiary measurement components necessary to determine the flow rate.

2.11
meter condition factor
An estimate of additional uncertainty based on engineering judgment of the physical condition of the meter in lieu of the ability to inspect.

2.12
performance
The response of a measurement device to influence parameters such as operating conditions, installation effects, and fluid properties.

2.13
verification
The process or procedure of comparing an instrument to a reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

2.14
Uncertainty range
Describes the range of deviation between a measured value and the true value, expressed as a percentage. For example, a device with an accuracy of 2 % would have an uncertainty of ±2 %.

3 Performance Characteristics and Measurement by Meter Type

3.1 General

The primary purpose of a non-custody gas meter for any application is to measure the flow. The uncertainty of measurement depends on the measurement equipment selected for the application, proper installation of the equipment, the ability to inspect, verify, or calibrate the various measurement system components, and the frequency of those maintenance activities. The performance of the meter may also depend on the piping configuration and compensation for variability of operating pressure, temperature, and fluid composition. It is important to recognize individual influence parameters and their effect on the measurement. Since the principle of operation and differing influence parameters have varying degrees of influence by meter type, it is important to identify and define the significant influence factors for the meter to determine the total or combined measurement uncertainty. Gas measurement is based on single phase flow. At any point that multiphase flow exists, such as the inclusion of liquids from the gas source or a phase change inside the meter assembly, measurement accuracy will be compromised.

For “less than ideal installations” where the installation effects (e.g. insufficient straight lengths) are not defined in industry standards (e.g. API *MPMS* Ch. 14.3/AGA Report No. 3), the manufacturer should be consulted, or alternate means considered to quantify uncertainty. Table 1 summarizes the effects of major influence parameters for different meter types.

Table 1—Installation Effect Sensitivity and Secondary Instrument Requirements

Meter Type	Installation Sensitivity		Standard Volume		Mass	
	Point or Path Averaging	**Upstream Flow Disturbance Sensitivity**	**Pressure Temperature**	**Composition Required to Calculate**	**Pressure Temperature**	**Composition Required to Calculate**
Differential Pressure Meters						
Pitot Tube	Point or Multipoint Averaging	Yes	Yes	Base Density and Square Root of Flowing Density	Yes	Square Root of Flowing Density
Orifice, Venturi, Nozzle, Cone, Elbow, Wedge, Variable area	Path Averaging					
Linear Meters						
Ultrasonic, Vortex, Turbine	Path Averaging	Yes	Yes	Standard and Flowing Compressibility or Density	Yes	Flowing Compressibility or Density
Coriolis	NA	No	No	Standard Density	No	No
Displacement Meter (PD)	NA	No	Yes	Standard and Flowing Compressibility or Density	Yes	Flowing Compressibility or Density
Thermal Dispersion	Point or Multipoint Averaging	Yes	Yes	Thermal Conductivity, Viscosity, and Prandtl Number	Yes	Flowing Density, Thermal Conductivity, Viscosity, and Prandtl Number

NA — Not applicable.

NOTE For errors related to unknown or unmeasured composition changes, meters requiring the square root of the density for flow rate calculation have approximately $^1/_2$ the error of meters requiring direct density for flow rate calculation. To estimate the uncertainty of density and compressibility errors, see Section 5.

All parameters that significantly contribute to the measurement uncertainty should be identified and quantified. Any influence parameter that can change should be periodically checked or verified to ensure its contribution to measurement uncertainty remains within the allowable or desired limits. The verification frequency is typically established by historical data or established experience of the industry as detailed in Section 6. All inspections, verifications and calibrations should be appropriately documented.

A brief description of the operating principle, design features, and parameters that affect the measurement uncertainty of the non-custody gas flow meters commonly used by the industry are detailed in this section.

3.2 Differential Pressure Type Flow Meters

3.2.1 General

A differential pressure type flow meter is also referred to as a head type flow meter. The principle of operation of a differential pressure type flow meter is based on the physical law of conservation of energy. The primary element of a differential pressure device causes the fluid velocity to change. The differential pressure measured between two specific locations of the meter is a square root function of the flow rate.

Differential pressure producers are sensitive to the flowing density for mass measurements and to the flowing and base densities for volumetric measurements. Hence, the flow rate measurement by differential pressure flow meters is sensitive to variations in fluid composition, compressibility, and flowing temperature and pressure.

The square root relationship between velocity and measured differential pressure restricts the turndown of differential pressure producers. This limitation may be reduced but not eliminated through the use of multiple differential pressure transmitters or transmitters designed for the range of differential pressures to be measured. The primary element should be designed so that it will produce a differential pressure such that the overall measurement uncertainty is acceptable.

Some of the differential pressure devices used in the industry to measure non-custody gas are:

a) orifice flow meter;

b) nozzles;

c) venturi;

d) cone;

e) multiport averaging pitot;

f) wedge;

g) variable area meter;

h) pitot and pitot-static tube.

Table 2 lists the significant influence parameters applicable to all differential pressure meters, their relative importance, and the recommended inspection or performance verification activities associated with each parameter. Table 3 through Table 7 list additional influence parameters applicable to specific differential pressure meter types.

Table 2—Significant Common DP Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Flowing Pressure	Medium to High	The location of the line pressure measurement point relative to the orifice meter should be determined and recorded (upstream or downstream). Verify and record the pressure range of the transmitter. The pressure transmitter should be verified or calibrated as required to maintain desired uncertainty.	If the line pressure is not measured at one of the differential pressure taps of the flow meter, the difference between the measured line pressure and the pressure at the flow meter should be established as a function of flow rate and recorded. This will impact the decision regarding potential pressure error and its effect on overall uncertainty.
Fluid Composition	Medium to High	Fluid composition should be measured and utilized in flow compensation as required. Analyzers should be verified and or calibrated as required to maintain desired uncertainty.	Fluid composition may be established via an on-line analyzer such as a GC or by grab sampling and off-line analysis. If the gas supply source is stable (e.g. from a commercial non-custody gas supplier), a fixed value for composition can be used for calculating flow rate.
Density	Medium to High	Verify and record the range of the densitometer. The densitometer should be verified or calibrated as required to maintain desired uncertainty.	If a densitometer is not utilized, fluid composition should be used.
Differential Pressure	High	Verify and record the range of differential pressure transmitter. The differential pressure transmitter should be verified or calibrated as required to maintain desired uncertainty.	The calibrated range of the DP transducer should be reevaluated if the operating conditions change.
Flowing Temperature	Low to Medium	The location of the line temperature measurement point relative to the orifice meter should be recorded (e.g. 200 ft upstream of the meter). Verify and record the range of the temperature measurement device. The temperature measurement device should be verified or calibrated as required.	If the flowing gas temperature is not measured at the flow meter as per industry standards (e.g. API *MPMS* Ch. 14.3/AGA Report No. 3) or manufacturer's recommendations, or if the flowing gas temperature is not measured using a thermowell, the difference between the measured temperature and the temperature of the gas at the flow meter shall be established.

3.2.2 Orifice Flow Meter

The key component of an orifice flow meter is a plate with a hole and the differential pressure across the plate is measured to determine the flow rate. Typically, an orifice plate in non-custody gas service is installed between two flanges, so the flow is interrupted to remove the plate from the line. There are specially designed dual-chamber orifice fittings that allow removal of the orifice plate from the line without interrupting the service. Paddle plates with proper labeling provide the opportunity to confirm that the orifice bore dimension, plate type and direction of installation are correct. Orifice and paddle plates should be inspected for compliance with API MPMS Chapter 14.3.2 plate characteristics and eccentricity prior to placing the plate into service. In addition, any printed or stamped plate information such as orifice bore size and plate thickness should be verified.

Orifice flow meters are the one of the more commonly installed measurement systems, used in the industry, for non-custody gas.

Table 3 lists the additional parameters that affect the measurement uncertainty of the orifice meter, along with relative importance and recommended inspection or performance verification.

Table 3—Additional Orifice Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line internal diameter (ID), D	High	Shall be verified and recorded at the time of installation.	Periodic inspection or verification is not required.
Bore diameter, d	High	Shall be verified and recorded at the time of installation.	Periodic inspection or verification is required. Any time the plate is changed or replaced, the bore diameter shall be recorded.
Beta ratio, d/D	High	Calculated from line and bore diameters at the time of installation of the orifice plate.	Ensure the beta ratio selected is suitable for the application.
Plate flatness, cleanliness, edge sharpness, and eccentricity	High	Visual inspection at the time of installation.	Periodic inspection or verification is required. Any time the plate is changed or replaced, the plate flatness, edge sharpness, cleanliness, and eccentricity shall be verified.
Plate bevel direction	High	Ensure that the bevel is facing downstream every time an orifice plate is installed.	No periodic verification is required.
Differential pressure tap location and type	High	Shall be verified and recorded at the time of installation.	If verified and recorded, periodic verification is not required.
Pipe roughness and eccentricity	Low	Does not require verification for non-custody gas meters.	

Upstream pipe straight run – with or without flow conditioner	Low to High	Shall be measured and recorded at the time of installation. Where a flow conditioner is utilized, its type and location shall be documented.	— If straight run length conforms to the minimum requirement defined in API *MPMS* Ch. 14.3/AGA Report No. 3, no additional measurement uncertainty to that defined in API *MPMS* Ch. 14.3.2/AGA Report No. 3, Part 2. — If less than the minimum straight run of API but more than or equal to half of the minimum straight run, flow rate measured is expected to be within 1 % of the actual flow rate. — If the straight run is less than half but more than or equal to $^{1}/_{3}$ of the minimum length of API, the measured flow rate is expected to be within 2 % of actual flow rate. — If the straight run is less than $^{1}/_{3}$ of that defined by API, measurement uncertainty can be established, if required, by actual experimental data testing a meter run that duplicates the actual meter configuration or other techniques such as computational fluid dynamics.
Downstream pipe straight run	Low	Shall be measured and recorded at the time of installation.	If the downstream straight run is more than or equal to $2\,^{1}/_{2}\,D$, no additional uncertainty above that defined by API *MPMS* Ch. 14.3/AGA Report No. 3.

3.2.3 Venturi and Nozzles

The applicable standard for the Venturi and nozzles is ASME MFC 3M or ISO 5167. Many of the recommendations for installation and performance verifications are similar to that of the orifice meter. See Table 4.

Table 4—Additional Venturi and Nozzle Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Shall be verified and recorded at the time of installation.	Periodic inspection or verification is not required.
Throat diameter, d	High	Shall be verified and recorded at the time of installation.	Periodic inspection or verification is required. Any time the meter is changed or replaced, the throat diameter shall be recorded.
Beta ratio, d/D	High	Calculated from line and throat diameters at the time of installation of the primary element.	Ensure the beta ratio selected is suitable for the application.

Differential pressure tap location and type	High	Shall be verified and recorded at the time of installation.	If verified and recorded, further verification is not required.
Pipe roughness, and eccentricity	Low	Does not require verification for non-custody gas meters.	
Cleanliness	Low to Medium	Visual inspection is sufficient.	
Upstream pipe straight run – with or without flow conditioner	Low to High	Shall be measured and recorded at the time of installation. Where a flow conditioner is utilized, its type and location shall be documented.	— If straight run length conforms to the minimum requirement defined in ASME MFC 3M, no additional measurement uncertainty to that defined in the standard. — If less than the minimum straight run of but more than or equal to half of the minimum straight run (ASME MFC-3M), measured flow rate can be expected to have an additional deviation of 1 % beyond that defined in the standard (ISO 5167). — If the straight run is less than half of that defined by the standard (ASME MFC-3M) measurement uncertainty can be established, if required, by actual experimental data testing a meter run that duplicates the actual meter configuration or other techniques such as computational fluid dynamics.
Downstream pipe straight run	Low	Shall be measured and recorded at the time of installation.	If the downstream straight run is more than or equal to 1*D*, no additional uncertainty above that defined by ASME MFC-3M.

3.2.4 Cone, Multiport Averaging Pitot, and Wedge Meters

Multiport averaging Pitot meter requirements are detailed in ASME/MFC-12M. Recommendations for installation of cone and wedge meters are detailed in manufacturer's specifications and installation manuals. Influence parameter effects may also be found in independent test reports. See Table 5.

Table 5—Additional Multiport Averaging Pitot, and Wedge Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Shall be verified and recorded at the time of installation.	Once verified and recorded, need not be verified again.
Dimension or design details of the primary element	High	Shall be verified and recorded at the time of installation.	Once verified and recorded, need not be verified again.
Differential pressure tap location or placement	High	Shall be verified and recorded at the time of installation.	Once verified and recorded, further verification is not required.
Pipe roughness, and eccentricity	Low	Does not require verification for non-custody gas meters.	
Cleanliness	Low to Medium	Visual inspection is sufficient.	If necessary, clean the primary element.
Upstream pipe straight run – with or without flow conditioner as specified by the manufacturer	Medium to High	Shall be measured and recorded. Where a flow conditioner is utilized, its type and location shall be documented.	If the straight run does not meet the manufacturer’s recommendations, the additional measurement uncertainty can be established, if required, by actual performance testing of a meter run that duplicates the field meter installation or other techniques such as computational fluid dynamics.
Downstream pipe straight run	Low	Shall be measured and recorded at the time of installation.	Should conform to the manufacturer's specification or be established by actual flow calibration.

3.2.5 Variable Area Meter

The variable area meter has a float with a precise circular diameter in a vertical cylinder with a gradually increasing tapered internal diameter. Flow entering from the bottom of the meter forces the float to adjust to a height to open an area around the float in the tapered cylinder such that the forces of buoyancy, impact of the fluid velocity on the float, and the weight of the float are in exact balance. The height of the float in the tapered cylinder is indicated by the graduation on the cylinder or remotely monitored and recorded. Note that variable area meters are calibrated for a specific fluid density and viscosity at a defined pressure and temperature. Parameters listed in Table 2 do not apply to variable area meters. See Table 6.

Table 6—Variable Area Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Float dimension and weight	High	The tag on the meter with the float information should not be removed from the device.	Once verified and recorded, no further verification is required.
Pressure tap location	High	Shall be verified and recorded.	Once verified and recorded, further verification is not required.
Cleanliness	High	Cylinder internal condition as received shall be observed and recorded. Visual inspection is sufficient for non-custody gas meters.	
Vertical orientation	High	Shall be installed vertically and recorded.	Should be verified and recorded, if the meter is moved or re-installed.

3.2.6 Pitot and Pitot-Static Tube

See Table 7 for additional Pitot, Pitot-static tube meter influence parameters.

Table 7—Additional Pitot, Pitot-Static Tube Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Shall be verified and recorded at the time of installation.	Once verified and recorded, no further verification is required.
Static pressure tap location	High	Once verified and recorded, no further verification is required.	
Pitot radial location and Orientation	High	Shall be verified periodically.	

Upstream straight run with or without flow conditioner	High	Should meet the manufacturer's specifications for the installed piping configuration. Where a flow conditioner is utilized, its type and location shall be documented. Once verified and recorded, no further verification is required if the installation is not altered.	If the straight run does not meet the manufacturer's recommendations, the additional measurement uncertainty can be established, if required, by actual performance testing of a meter run that duplicates the field meter installation or other techniques like computational fluid dynamics.
Downstream straight run	Low	One diameter straight run is adequate for these meters.	No verification is required, unless the meter is moved or re-installed.

3.3 Linear Flow Meters

3.3.1 General

Table 8 lists the influence parameters, their relative importance, and recommended inspection or performance verification activities that affect the measurement uncertainty of volumetric linear flow meters such as positive displacement (PD), turbine, ultrasonic, and vortex. Table 9 through Table 13 list additional influence parameters applicable to specific volumetric linear meter types.

Table 8—Common Volumetric Linear Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Flowing pressure	Medium to High	The location of the line pressure measurement point relative to the meter shall be recorded (body, upstream or downstream). Verify and record the pressure range of the transmitter. The pressure transmitter should be verified or calibrated as required.	If the line pressure is not measured at the meter, the difference between the measured line pressure and the pressure at the flow meter shall be established as a function of flow rate and recorded.
Compressibility	Low to Medium	Fluid composition should be measured and utilized to compute compressibility for flow compensation as required. Analyzers should be verified and or calibrated as required.	Fluid composition can be established via an on-line analyzer such as a GC or by grab sampling and off-line analysis. If the gas supply source is stable (e.g. from a commercial non-custody gas supplier), a fixed value for compressibility can be used for calculating flow rate.
Density	Medium to High	Verify and record the range of the densitometer. The densitometer should be verified or calibrated as required.	If a densitometer is not utilized, fluid composition should be used to compute compressibility.

Flowing temperature	Low to Medium	The location of the line temperature measurement point relative to the meter shall be recorded. Verify and record the range of the temperature measurement device. The temperature measurement device should be verified or calibrated as required.	If the flowing gas temperature is not measured at the flow meter as per industry standards, or if the flowing gas temperature is not measured using a thermowell, the difference between the measured temperature and the temperature of the gas at the flow meter shall be established.

3.3.2 Positive Displacement Flow Meters

Positive displacement meters measure flow by separating the incoming stream by use of a vane, gear, piston, or diaphragm into known volumes which are totalized.

Positive displacement meters have internal moving parts but no straight run requirements and are removed from the line for repair. A mechanical failure of the positive displacement meter can block the flow path in the line. See Table 9.

Table 9—Additional Displacement Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Differential pressure across the meter	Low	Some manufacturers specify a maximum DP reading across the meter as a diagnostic tool for the meter.	Periodically record DP reading to ensure it is within limits.
Cleanliness	Medium to High	Cleanliness of the meter internals should be visually verified and recorded.	Clean and verify performance as necessary.

3.3.3 Turbine Flow Meters

Turbine flow meters consist of a multi-bladed rotor that is perpendicular to the flow path. The rotor is generally supported by bearings on its upstream and downstream axis. There are rotor designs that are installed on a cantilevered shaft. As flow passes through the meter body the momentum of the flowing fluid (function of density and velocity) causes the rotor to spin at a rate proportional to the velocity of the fluid. The rotation of the shaft may be monitored and displayed by a mechanical drive system or by a sensor that detects the rate of rotation of the blades and generates a frequency output which is proportional to the volumetric rate of flow. Turbine flow meters can be in-line or insertion type. See Table 10.

Table 10—Additional Turbine Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	Low to medium	Shall be verified and recorded at the time of installation.	No further verification required.
Upstream straight run with or without flow conditioner	High	Shall be verified and recorded at the time of installation of the meter. Where a flow conditioner is utilized, its type and location shall be documented. No further verification required.	If the straight run does not meet the manufacturer's recommendations or industry standards, the additional measurement uncertainty can be established, if required, by actual performance testing of a meter run that duplicates the field meter installation or other techniques such as computational fluid dynamics.
Cleanliness	Medium to High	Cleanliness of the meter internals should be visually verified and recorded.	Clean and verify performance as necessary.

3.3.4 Ultrasonic Flow Meters (UFM)

Ultrasonic flow meters are linear meters which measure flow velocity by measuring the difference in transit time of sound pulses travelling upstream and downstream relative to fluid flow between pairs of sensors. The flow volume at the base conditions is calculated from the flowing pressure, temperature, and composition of the gas. The ultrasonic flow meter can be a spool piece design, inserted transmitter type, or clamp on. Ultrasonic flow meters can be sensitive to the fouling of wetted components by contaminants in the process fluid. Some meters incorporate designs that are capable of identifying fouling effects prior to loss of signal. Insertion and clamp on meters are affected by improper determination of line ID. Clamp on meters can be affected by degradation of thermal contact with the pipe. A different type of ultrasonic flow meter operating on the principle of the physical law of Doppler shift, typically have a higher level of measurement uncertainty and may not provide measurement accuracy necessary for accurate non-custody gas measurement. See Table 11.

Table 11—Additional Ultrasonic Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Line and meter ID should be essentially the same. Meter ID is utilized in the flow rate calculation. The line/meter diameter shall be verified and recorded at the time of installation.	No further verification required.
Cleanliness	Low until meter becomes inoperable	Diagnostics such as signal strength can be used to determine need for sensor cleaning.	Clean as necessary.

Upstream straight run with or without flow conditioner	Medium to High	Shall be verified and recorded at the time of installation of the meter. Where a flow conditioner is utilized, its type and location shall be documented. No further verification required.	If the straight run does not meet the manufacturer's recommendations or industry standards, the additional measurement uncertainty can be established, if required, by actual performance testing of a meter run that duplicates the field meter installation or other techniques such as computational fluid dynamics.

3.3.5 Vortex Shedding Flow Meters

Vortex shedding flow meters operate on the principle that when fluid passes a bluff body, alternate vortices are shed on either side of the bluff body over a certain range of Reynolds number. The frequency of the shed vortices and the Reynolds number range are a function of the flow rate and the shape and size of the bluff body. The frequency of the shed vortices is sensed by different detection techniques. The measured frequency is proportional to the volumetric flow rate.

The sensitivity of the vortex meter is dependent on the sensor that detects the vortex shedding frequency. All vortex meters have a low and a high Reynolds number cut-off. So, changes to the fluid density can affect the operating flow rate range of the vortex meter. Vortex meter resolution is dependent on the meter size, which typically decreases with increasing meter size. The ID of the meter at the vortex shedder of the meter can be smaller than the pipe ID by design. See Table 12.

Table 12—Additional Vortex Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Shall be verified and recorded at the time of installation.	No further verification required.
Cleanliness	Low	Meter internals should be visually inspected and recorded at a frequency based on process conditions.	Clean as necessary
Upstream straight run with or without flow conditioner	Medium to High	Shall be verified and recorded at the time of installation of the meter. Where a flow conditioner is utilized, its type and location shall be documented. No further verification required.	If the straight run does not meet the manufacturer's recommendations or industry standards, the additional measurement uncertainty can be established, if required, by actual flow calibration of the meter that duplicates the field installation or by computational fluid dynamics.

3.3.6 Thermal Flow Meters

Thermal flow meters (often referred to as thermal mass meters) operate on the principle of thermal convection or dispersion. The major components of thermal flow meters are resistance temperature detectors (RTDs), a heater, and control electronics.

Thermal flow meters are typically available in insertion and in-line mounting types and may have either single or multiple sensing locations.

Two examples of thermal flow meters are constant differential temperature and constant power thermal flow meters.

Constant differential temperature thermal flow meters use a heated RTD which is compared and continually adjusted to maintain a constant temperature difference with respect to the process temperature measured by a second RTD. The power required to maintain the constant temperature difference is proportional to the rate of heat loss from the heated RTD.

Constant power thermal flow meters apply constant power to heat the active RTD and measure the temperature difference between the active RTD and the process temperature measured by a second RTD.

In both types, the rate of heat loss is proportional to the heat transfer coefficient of the assumed gas mixture and the flow rate at the sensor. Thermal flow meters have significant sensitivity to variations in gas composition and are affected by deposits or coatings on the sensor and variations in process pressure and temperature that affect the gas density. Thermal flow meters are not recommended for applications where liquid droplets or liquid mist are normally present, because this significantly impacts the heat transfer rate. The insertion depth and the orientation of the meter are specified by the manufacturer. See Table 13.

Table 13—Additional Thermal Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Line ID, D	High	Shall be verified and recorded at the time of installation.	Once verified and recorded, no further verification is required.
Pressure tap location	Medium	Shall be measured and recorded at the location where the meter is installed.	Once verified and recorded, no further verification is required.
Upstream straight run with or without flow conditioner	High	Shall be verified and recorded at the time of installation of the meter. Where a flow conditioner is utilized, its type and location shall be documented. No further verification required.	If the straight run does not meet the manufacturer's recommendations or industry standards, the additional measurement uncertainty can be established, if required, by actual performance testing of a meter run that duplicates the field meter installation or other techniques such as computational fluid dynamics.

Fluid composition	High	Fluid composition should be measured and utilized to compute heat transfer properties for flow compensation as required. Analyzers should be verified and or calibrated as required.	Fluid composition can be established via an on-line analyzer such as a GC or by grab sampling and off-line analysis. If the gas supply source is stable (e.g. from a commercial non-custody gas supplier), a fixed value for fluid properties can be used for calculating flow rate.
Cleanliness	High	Meter sensors should be periodically visually inspected and cleaned, if necessary.	Meter should be calibrated if it cannot be cleaned.

3.3.7 Coriolis Flow Meters

Coriolis flow meters utilize a law of physics known as Coriolis force that is exerted by the fluid mass passing the flow tubes when the flow tube(s) are oscillated perpendicular to the flow direction. Fluid passing through the oscillating tube causes the tube to deflect as the flowing mass exerts force against the movement of the tube. Coriolis meters are designed with a single tube or a pair of tubes. The phase difference between two locations on the oscillating tube(s) is detected by a pair of sensors and is proportional to the mass flow rate. Coriolis meters can also provide a density measurement of the fluid being measured. However, for non-custody gas applications the uncertainty of the measured density can be significant. Therefore, for non-custody gas applications Coriolis meters are generally configured to output in mass and converted to standard volume using a separately measured or determined standard density.

Coriolis meters are insensitive to the velocity profile. Since the Coriolis meter measures flow rate directly in mass, measurement is not influenced by the fluid pressure, temperature, composition, or density. However, the stiffness of the tubes determining the mass flow rate is weakly influenced by the temperature and pressure of the flowing fluid especially for non-custody gas applications. The influence of pressure and temperature on the tube stiffness is corrected by the electronics of the meter with input of the operating pressure and temperature. Almost all Coriolis meters have integral tube temperature monitoring capability.

Coriolis meters can be provided in either straight or curved tube designs. Depending on the meter design, pressure loss for a Coriolis flow meter can vary significantly. See Table 14.

Table 14—Additional Coriolis Meter Influence Parameters

Parameter	Significance	Inspection, Verification, and Calibration	Comment
Fluid composition – mass measurement	No effect	No verification required.	
Fluid composition – volumetric measurement	High	Fluid composition should be measured and utilized to compute standard density for volumetric flow compensation. Analyzers should be verified and or calibrated as required.	Fluid composition can be established via an on-line analyzer such as a GC or by grab sampling and off-line analysis. If the gas supply source is stable (e.g. from a commercial non-custody gas supplier), a fixed value for standard density can be used.

3.4 Selection Criteria and Documentation of Non-custody gas Meters

The non-custody gas meters described in this document are a list of meters typically used in the petrochemical industry. It is important to note that there are constant improvements in the fields of meter design, secondary instrumentation, and most importantly, in reducing the measurement uncertainty. These improvements allow users to extend the frequency of performance verifications of the installed meters. The emphasis of performance verification should be based on the total measurement uncertainty for the complete measurement system, and not on the performance of individual components of the metering system. Any gas meter can be installed to monitor or measure the non-custody gas usage provided it has a technically defensible and documented measurement uncertainty with the defined performance requirements that meet the user's specifications. This documentation is normally provided by the manufacturer and is readily available in the public domain.

4 Secondary and Tertiary Instrumentation

4.1 Introduction

Measurement of gas by volume meters requires knowledge of the gas composition, pressure, and temperature. The use of fixed values for gas composition, pressure, and temperature will lead to greater measurement uncertainty. This may be acceptable in steady-state systems or in applications such as low flow where increased uncertainty is tolerable. Consult Section 5 for guidance in the determination of the uncertainty associated with variances in influence parameters to determine if secondary measurements are required.

See Figure 1 for a representation of a gas measurement system and its components. This figure is designed to depict which instruments are primary, secondary, and tertiary.

The following apply:

— FE is the flow element.

— FC is a flow conditioner (optional).

— FT, PT, TT, and AT are flow, pressure, temperature, and analyzer transmitters, respectively.

— FI, PI, TI, and AI are flow, pressure, temperature, and analyzer indications, respectively, in the distributed control system (DCS) or other tertiary device.

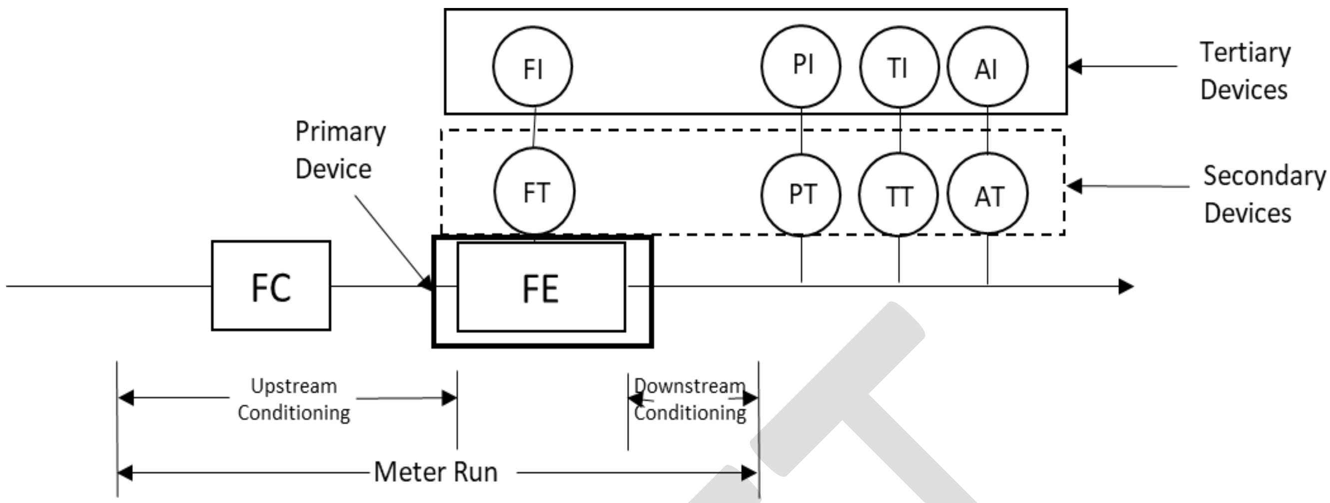

Figure 1—Schematic of a Non-Custody Gas Measurement System

Dependent upon process variability and targeted uncertainty, some applications may not require all secondary devices depicted.

Figure 2 illustrates various examples of flow measurement systems, ranging from close coupled pressure, temperature and composition measurements, to more distant measurements and bias factors applied where applicable.

*Figure **2** - Example of Non-Custody Gas Measurement System*

NOTES

1) The need for flow compensation is determined by the variability in influence parameters such as pressure, temperature, and composition.
2) FT-1 illustrates a case where close coupled pressure (PT) and temperature (TT) measurement and grab samples are utilized for compensation.
3) FT-2, FT-3, and FT-4 utilize the composition determined by AT-6 or via grab samples from sample point SP-6.
4) FT-2 illustrates a case where a control valve upstream of the meter can produce significant variability in the pressure and temperature at the meter.
5) FT-3 illustrates the use of a multi-variable transmitter with inherent differential pressure, static pressure, and temperature measurements.
6) FT-4 illustrates the use of the pressure header (PT6) and temperature (TT6) measurements for compensation.
7) FT-5 illustrates that purchased natural gas has a relatively constant composition so the supplier's composition may be utilized (i.e. AT not required).

4.2 Equipment Selection Considerations

Pressure, temperature, density and gas composition measurement instruments purchased for non-custody gas measurement applications are typically no different than those used in standard petrochemical applications. Manufacturers of such instruments generally have demonstrated acceptable tolerances with test data traceable to NIST or other national standards bodies.

Multi-variable transmitters measuring pressure, temperature and differential pressure are generally acceptable for non-custody gas measurement. Pipe skin temperature elements (properly insulated) add additional uncertainty compared to thermowell-based temperature measurements but can be utilized, provided the contribution to the overall uncertainty is acceptable.

For differential pressure type meters, the accuracy of the measured line pressure is more critical when the ratio of the differential pressure to the line pressure is more than 0.1.

For non-custody gas measurement applications, the tertiary device used to collect data and perform computations can be any of the following: DCS, programmable logic controller (PLC), multi-variable transmitter, or flow computer.

Gas composition and/or density can be determined by on-line analyzers, such as gas chromatographs, or by manual or automatic sampling with off-line analysis. Relative stream size, composition variability, and cost of on-line analyzers will influence the decision whether on-line analyzers or periodic manual sampling and off-line analysis are used. Compensation of natural gas meters for composition changes will often utilize the supplier's measurements (i.e. use the supplier's certificate of analysis or on-line chromatograph).

4.3 Equipment Location and Installation

Depending upon the flow meter technology selected, the ideal location of process connections for secondary devices (pressure, temperature and analytical sampling) may vary. In general, temperature and analytical connections (e.g. sample probes) should be downstream of all primary gas measurement system components, unless the upstream location does not cause significant disturbance of the flow profile or the device is insensitive to upstream profile disturbances (e.g. Coriolis, positive displacement). For example, ISO 5167-2:2003 states that thermowells should be located at distances $5D$ or greater upstream of an orifice plate provided the diameter of the thermowell is less than $0.03D$, and at distances $20D$ or greater for thermowells with a diameter between $0.03D$ and $0.13D$. Consult industry standards or with equipment manufacturers on recommendations for proper meter run piping configuration.

If the flowing gas temperature is not measured at the flow meter, as per industry standards or manufacturer's recommendations, or if the flowing gas temperature is not measured using a thermowell, the difference between the measured temperature and the temperature of the gas at the flow meter shall be established. If the line pressure is not measured at the meter, the difference between the measured line pressure and the pressure at the flow meter shall be established as a function of flow rate and recorded.

See Table 15 for the suggested upstream or downstream location of pressure devices relative to the gas flow meter.

Table 15—Static Pressure Tap Location

Meter Type	Recommended Location
Averaging Pitot Tube	Upstream or integral
Other Differential Pressure Type Meters	Upstream, Downstream, or at the location specified by the manufacturer
Venturi	Upstream or downstream

Orifice	Upstream or downstream
Vortex Shedding	Upstream, Downstream, or at the location specified by the manufacturer
Turbine	Integral
Ultrasonic	Integral, upstream or downstream
Positive Displacement	Integral, upstream or downstream
Thermal	Upstream or downstream
Coriolis	Not applicable

5 Uncertainty Calculations

5.1 Objective

The purpose of this section is to provide tools for the understanding and prediction of individual meter and overall facility non-custody gas measurement uncertainty. This provides a mechanism for the equipment owner to specifically identify and correct any significant deficiencies that are contributing to less than desired measurement certainty. Applications of uncertainty analysis include:

— determination of whether a non-custody gas meter and/or system will meet owner needs or regulatory requirements;

— comparison of non-custody gas metering technologies;

— determination of the effect of each metering station on a facility system's total non-custody gas measurement uncertainty;

— identification of the uncertainty contribution for individual non-custody gas metering components in order to improve uncertainty or make investment decisions.

The method described herein is intended to be applicable over a wide range of conditions and provides a consistent and simple approach appropriate for non-custody gas measurement. It is not intended to provide the rigorous uncertainty analysis typically associated with custody transfer measurement and does not follow the strict uncertainty analysis of the API MPMS Chapter 13.3 or ISO GUM/ISO 5168 due to the difficulty of translating the effects of fixed and estimated factors frequently used in non-custody gas measurement into the values required by these techniques. This is a consistent method to reasonably approximate the true uncertainty value but does not necessarily determine the true uncertainty value. For non-custody gas metering systems, several assumptions and simplifications are made. For individual meters, all uncertainties are assumed to be random, normally distributed, independent, and have infinite degrees of freedom. For overall facility uncertainty, a level of correlation between individual meters is assumed. It is often the case that several metering systems are used in a particular facility to measure total system throughput. System operators will often find that a lower uncertainty for metering systems on larger streams is desirable in order to achieve overall system uncertainty targets. A higher uncertainty for metering systems on smaller streams will not contribute significantly to the overall facility uncertainty.

Bias is a component of meter accuracy, but it is not a component of meter uncertainty. If a bias of a meter is known, that bias should be corrected, and is not included in the calculation of meter uncertainty. In order to minimize the effects of bias, it is recommended that all flow meters and associated instrumentation be installed according to manufacturer recommendation.

Examples of how to calculate the uncertainty of particular meters are included in Annex A, along with an example of a total facility uncertainty.

5.2 Uncertainty Analysis Procedure

The typical uncertainty analysis for an individual metering system consists of the steps listed below:

Step 1: Determine the measurement model.

The equation is dependent on the meter technology and should be supplied either by the vendor, applicable standards, or reference material. In this document, the uncertainties will focus on standard volume flow rate, energy flow rate, and carbon flow rate. For energy and carbon content uncertainty determination, additional influence parameters will be included.

Step 2: Set up a primary uncertainty table.

An uncertainty table serves to organize the numerical values that make up the analysis. A spreadsheet is a common tool. The table is constructed such that each uncertainty component or equation variable occupies a row.

For optimum performance and accuracy, industry standards and equipment manufacturers recommend a minimum length of pipe upstream and downstream for many meter types. These minimum length recommendations are frequently not achieved in non-custody meter applications. The uncertainty table includes a row item termed "Installation Effect Factor" that will enable the owner to estimate the possible uncertainty contribution for non-optimum meter run lengths (or other piping effects).

In many non-custody gas applications, inspection of meter internals or primary elements at recommended intervals for fiscal measurement is not practical. In these cases, it is necessary to introduce a component of uncertainty to account for the unknown condition of the meter or primary element. Thus, the "Meter Condition Factor" is included in the table. The value of the uncertainty associated with this term is determined by engineering judgment and is most often a function of:

— inspection interval and history of findings,

— cleanliness of the flowing gas and likelihood of fouling contributing to increased uncertainty,

— and the possibility of unknown damage or wear contributing to increased uncertainty.

For some meter types, it is advisable to consult the manufacturer for assistance in determination of the Meter Condition Factor.

The following column values are to be included in the table:

— flow equation variable or component,

— units of measure,

— nominal value,

— standard uncertainty in units of measurement,

— standard uncertainty in percent,

— sensitivity coefficient.

Step 3: Determine the sensitivity coefficients for each component in Step 1.

The sensitivity of flow, Q, to any of the inputs used to calculate flow, x_i, is given by:

$$S_{xi} = \left(\frac{\partial Q}{\partial x_i}\right) \tag{1}$$

where

S_{xi} is the sensitivity coefficient for input variable x_i ;

∂Q is the derivative of flow rate;

∂x_i is the derivative of input variable x_i .

From a practical standpoint, the sensitivity coefficient can be interpreted as the percent change in Q that results from a 1 % shift in x_i.

If the sensitivity is not apparent from the equation developed in Step 1, the sensitivity can be estimated from calculations using the normal expected operating conditions. This process is called dithering. First, calculate the flow at normal expected operating conditions. Second, recalculate the flow, leaving all other values constant, except the input variable for which the sensitivity constant is being determined. Change that value by 1 %. The percent change in flow divided by 1 % change in the input variable is the sensitivity of that variable. Repeat for each of the input variables to determine all of the sensitivity coefficients.

Sensitivity may change over the operating range. The uncertainty may be determined by analyzing: normal operating conditions; average conditions over a time period; minimum and maximum conditions; or another appropriate method.

Step 4: Obtain numerical values for the uncertainty of each component in Step 1.

Uncertainty of instrumentation may change over the operating range. The uncertainty may be determined by analyzing: normal operating conditions; average conditions over a time period; minimum and maximum conditions; conditions at an instant in time; or by another appropriate method. For installation effects, the values from the tables in Section 3 should be used to determine the possible error. Sources of numerical values are illustrated in Annex A.

Step 5: Combine the numerical values obtained in Step 4 to give a numerical value for the combined and expanded standard uncertainties.

Uncertainties can be estimated by summing the square of the sensitivity times the uncertainty. The estimated uncertainty is the square root of this sum. Systematic and random uncertainties in this instance are treated equally.

As sensitivity and uncertainty may change over the operating range, the combined uncertainty may be analyzed at: normal operating conditions; average conditions over a time period; minimum and maximum conditions; an instant in time; or another appropriate method.

5.3 Combining the Uncertainty of Multiple Meters

In a typical facility, more than one meter determines the flow of non-custody gas through the facility. An example of this is shown in Figure 2. As with the uncertainty determination of an individual meter, the uncertainty determination of a facility with multiple meters can be simplified with several assumptions. At a facility, there will almost always be some degree of correlation between some or all of the measurements. Some examples of correlated parameters include:

— common instrumentation (pressure, temperature, gas chromatograph);

— common calibration standards (deadweight tester, calibration gas, etc.);

— common constants (e.g. barometric pressure, gravity, etc.);

— equations of state (API *MPMS* Ch. 14.2/AGA Report No. 8);

— reference standards (API, AGA, ASME, GPA, ISO, etc.).

To more accurately determine the degree of correlation, a rigorous uncertainty analysis of the facility non-custody gas system would be required, but for non-custody gas measurement this rigorous method is not necessary. Therefore, the methods in this document produce both an overestimate of the uncertainty and an underestimate. The average of those two values is used to determine the final facility uncertainty. Because the true uncertainty lies somewhere between the correlated and the uncorrelated, the average of the two presents a consistent, simplified method of uncertainty determination. To determine the uncertainty of the facility as a whole, the uncertainty of each meter is flow weighted with the flow through that meter.

Equation (2) presents an overestimate of the facility uncertainty. This equation assumes that the measurements are fully correlated.

$$U_{cor} = \frac{\sum U_i}{\sum Flow_i} \times 100\% \tag{2}$$

where

U_{cor} is the facility overall uncertainty assuming all measurements are correlated, expressed in percent;

U_i is the meter uncertainty, expressed in units of measurement;

$Flow_i$ is the meter flow rate, expressed in units of measurement.

Equation (3) presents an underestimate of the facility uncertainty. This equation assumes that the measurements are fully independent.

$$U_{ind} = \frac{\sqrt{\sum U_i^2}}{\sum Flow_i} \times 100\% \tag{3}$$

where

U_{ind} is the facility overall uncertainty assuming all measurements are independent, expressed in percent;

U_i is the meter uncertainty, expressed in units of measurement;

$Flow_i$ is the meter flow rate, expressed in units of measurement.

The average of the correlated and uncorrelated uncertainties is then taken.

$$U_{tot} = \frac{U_{cor} + U_{ind}}{2} \tag{4}$$

where

U_{tot} is the final facility overall uncertainty, expressed in percent;

U_{cor} is the facility overall uncertainty assuming all measurements are correlated, expressed in percent;

U_{ind} is the facility overall uncertainty assuming all measurements are independent, expressed in percent.

An example of calculating facility uncertainty is included in Annex A.

If the user requires, a more rigorous uncertainty determination may be performed in which the correlated components of measurement are identified, and the total uncertainty is then calculated using the guidelines presented in ISO GUM (ISO/IEC Guide 98-3)/ISO 5168.

5.4 Differential Producers

Differential producers such as orifice and Venturi meters are influenced by variations in temperature and pressure, compressibility and gas composition. Per API *MPMS* Ch. 14.3.1-2012 Equation 1-1, the relationship between mass flow and differential pressure for an orifice plate is given below in Equation (5). Equation (6) through Equation (10) can also be found in API *MPMS* Ch. 14.3.1-2012. A common unit of measure in U.S. manufacturing is SCFH (standard cubic feet per hour); therefore, Equation (11) was derived by substitution using Equation (6) to Equation (10).

$$q_m = C_d \times E_v \times Y \times (\pi / 4) \times d^2 \times \sqrt{2g_c \times \rho_{t,p} \times dP} \tag{5}$$

$$Q_{STD} = \frac{q_m}{\rho_B} \tag{6}$$

$$E_v = 1 / \sqrt{1 - \beta^4} \tag{7}$$

$$\beta = \frac{d}{D} \tag{8}$$

$$\rho_{t,p} = \frac{MW \times P_F}{Z_F \times R \times T_F} \tag{9}$$

$$\rho_B = \frac{MW \times P_B}{Z_B \times R \times T_B} \tag{10}$$

$$Q_{STD} = \frac{N_1 \times \pi \times C_d \times Y \times d^2 \times Z_B \times T_B}{P_B \times 4\sqrt{1 - \left(\frac{d}{D}\right)^4}} \sqrt{\frac{2 \times P_F \times R \times g_c \times dP}{MW \times Z_F \times T_F}} \tag{11}$$

where

q_m is the mass flow, expressed in pounds per hour;

C_d is the discharge co-efficient;

E_v is the velocity of approach factor;

Y is the expansion factor;

d is the bore diameter, expressed in inches;

g_c is the gravitational constant;

$\rho_{t,p}$ is the density of the fluid at flowing conditions;

dP is the differential pressure, expressed in inches of water column);

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

ρ_B is the density of the fluid at base conditions (60 °F, 14.73 psia);

β is the beta ratio;

D is the pipe diameter, expressed in inches;

MW is the molecular weight, expressed in pounds per mole (lb/mole);

P_F is the flowing pressure, expressed in pounds per square inch (psia);

Z_F is the compressibility at flowing conditions;

R is the universal gas constant;

T_F is the flowing temperature, expressed in degrees Rankine;

P_B is the base pressure, expressed in pounds per square inch (psia);

Z_B is the compressibility at base conditions (60 °F, 14.73 psia);

T_B is the base temperature, expressed in degrees Rankine;

N_1 is the engineering units conversion factor.

The possible uncertainty effects of variations in process pressure, process temperature, compressibility, and molecular weight can be demonstrated using Equation (11).

NOTE Other forms of the equation could be utilized if the user has better access to or prefers to use specific gravity or density rather than molecular weight.

The effect of a static pressure variance can be estimated using Equation (12) for a differential producer.

$$\Delta Q_{STD}\% = \left[1 - \sqrt{\frac{\Delta P_F + P_F}{P_F}}\right] \times 100 \tag{12}$$

where

ΔP_F is the estimated error in pressure measurement or assumed value, expressed in pounds per square inch gauge (psig);

P_F is the typical process pressure, expressed in pounds per square inch absolute (psia).

Table 16 illustrates the magnitude of the resulting volumetric errors due to errors in static pressure measurement.

Table 16—DP Meter Static Pressure Variance Effect

Pressure Variance		Static Pressure (psig)				
		25	50	100	200	500
		Resulting Volumetric Variance (%)				
0.25 %	of reading	0.08	0.10	0.11	0.12	0.12
1	psig	1.3	0.8	0.4	0.2	0.1
5	psig	6.1	3.8	2.2	1.2	0.5
10	psig	11.9	7.4	4.3	2.3	1.0

The effect of a temperature variance can be estimated using Equation (13) for a differential producer.

$$\Delta Q_{STD}\% = \left[1 - \sqrt{\frac{T_F}{\Delta T_F + T_F}}\right] \times 100 \tag{13}$$

where

ΔT_F is the estimated error in temperature measurement or assumed value, expressed in degrees Fahrenheit;

T_F is the typical process temperature, expressed in degrees Rankine.

Table 17 illustrates the magnitude of the resulting volumetric errors due to errors in temperature measurement for a DP meter.

Table 17—DP Meter Temperature Variance Effect

Temperature Variance		Temperature (°F)				
		–20	0	20	60	100
		Resulting Volumetric Variance (%)				
1	°F	0.11	0.11	0.10	0.10	0.09
2	°F	0.23	0.22	0.21	0.19	0.18
5	°F	0.56	0.54	0.52	0.48	0.44
10	°F	1.12	1.07	1.03	0.95	0.88

The effect of a compressibility variance can be estimated using Equation (14) for a differential producer.

$$\Delta Q_{STD}\% = \left[1 - \frac{Z_{B\_1}}{Z_{B\_2}} \times \sqrt{\frac{Z_{F\_2}}{Z_{F\_1}}}\right] \times 100 \tag{14}$$

where

Z_{B_1} is the case #1 compressibility at base conditions (60 °F, 14.73 psia);

Z_{B_2} is the case #2 compressibility at base conditions (60 °F, 14.73 psia);

Z_{F_1} is the case #1 compressibility at flowing conditions;

Z_{F_2} is the case #2 compressibility at flowing conditions.

The values in Table 18 represent the errors that would be observed in reported volumetric flow rates if the compressibility values were not updated to reflect the changes in compressibility associated with composition changes resulting from blending typical purchased natural gas with 20 % hydrogen as might occur in a gas drum. API *MPMS* Ch. 14.2/AGA Report No. 8 was used to determine Table 18 values. It should be noted the compressibility effects detailed in Table 18 are minor compared to the effects of changing composition on molecular weight. (Consider including a table illustrating MW impacts)

For differential producers, variances in the gas composition also affect the molecular weight/gas gravity and hence computed flow rates as per Equation (15). Using the same example of natural gas blended with 20 % hydrogen produces a change in molecular weight from 17.59 g/mole to 14.48 g/mole. This represents a 21 % change in molecular weight, producing a potential error in the calculated flow rate of approximately 10 %.

$$\Delta Q_{STD}\% = \left[1 - \sqrt{\frac{MW_{\_1}}{MW_{\_2}}}\right] \times 100 \tag{15}$$

where

$MW_{\_1}$ is the case #1 molecular weight, expressed in grams per mole;

$MW_{\_2}$ is the case #2 molecular weight, expressed in grams per mole.

Table 18—DP Meter Compressibility Effect
Typical Natural Gas vs Typical Natural Gas + 20 % H_2

Temperature °F	Pressure (psig)						
	0	25	50	100	110	200	500
	Resulting Volumetric Variance (%)						
0	0.03	0.08	0.2	0.4	0.5	0.9	2.6
20	0.03	0.06	0.2	0.4	0.4	0.8	2.2
60	0.05	0.03	0.1	0.3	0.3	0.6	1.7
70	0.05	0.03	0.1	0.3	0.3	0.6	1.6
100	0.05	0.01	0.1	0.2	0.2	0.5	1.3
120	0.06	0.00	0.1	0.2	0.2	0.4	1.1

5.5 Linear Meters (Vortex, Ultrasonic, Turbine, PD)

Linear meters such as vortex, ultrasonic, turbine and PD, measure gas at flowing conditions (i.e. ACFH). Equation (16) is used to convert the gas flow rate at flowing or process conditions to standard or reference conditions (i.e. SCFH). Equation (16) can also be used to assess the effect of variations in compressibility and process temperature and pressure on the computed flow rate as detailed below. The results of such an assessment can be used to determine the maximum acceptable uncertainty associated with each influence parameter.

$$Q_{STD} = Q_{ACT} \times \frac{P_F}{P_B} \times \frac{T_B}{T_F} \times \frac{Z_B}{Z_F} \qquad (16)$$

where

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

Q_{ACT} is the actual cubic feet per hour (T_F, P_F);

P_F is the flowing pressure, expressed in pounds per square inch absolute (psia);

P_B is 14.73 psia;

T_F is the flowing temperature, expressed in degrees Rankine;

T_B is 519.67 °R (60 °F);

Z_F is the flowing compressibility;

Z_B is the base compressibility (60 °F, 14.73 psia).

The effect of variances in process pressure can be assessed for PD, turbine, ultrasonic and vortex meters using Equation (17).

$$\Delta Q_{STD}\% = \left[1 - \frac{\Delta P_F + P_F}{P_F}\right] \times 100 \qquad (17)$$

where

ΔP_F is the estimated error in pressure measurement or assumed value, expressed in pounds per square inch gauge (psig);

P_F is the typical process pressure, expressed in pounds per square inch absolute (psia).

Table 19 illustrates the magnitude of the resulting volumetric errors due to errors in static pressure measurement.

Table 19—Linear Meter Static Pressure Variance Effect

Pressure Variance		Static Pressure (psig)				
		25	50	100	200	500
		Resulting Volumetric Variance (%)				
0.25 %	of reading	0.16	0.19	0.22	0.23	0.24
1	psig	2.5	1.5	0.9	0.5	0.2
5	psig	12.6	7.7	4.4	2.3	1.0
10	psig	25.2	15.4	8.7	4.7	1.9

The effect of variances in process temperature can be assessed for PD, turbine, ultrasonic and vortex meters using Equation (18).

$$\Delta Q_{STD}\% = \left[1 - \frac{T_F}{\Delta T_F + T_F}\right] \times 100 \tag{18}$$

where

ΔT_F is the estimated error in temperature measurement or assumed value, expressed in degrees Fahrenheit;

T_F is the typical process temperature, expressed in degrees Rankine.

Table 20 illustrates the magnitude of the resulting volumetric errors due to errors in temperature measurement.

Table 20—Linear Meter Temperature Variance Effect

Temperature Variance		Temperature (°F)				
		–20	0	20	60	100
		Resulting Volumetric Variance (%)				
1	°F	0.2	0.2	0.2	0.2	0.2
2	°F	0.5	0.4	0.4	0.4	0.4
5	°F	1.1	1.1	1.0	1.0	0.9
10	°F	2.3	2.2	2.1	1.9	1.8

Unlike differential producers, and with the exception of thermal dispersion and Coriolis meters, variances in the gas composition only affect the compressibility. The effect of variances in compressibility can be assessed using Equation (19).

$$\Delta Q_{STD}\% = \left[1 - \frac{Z_{F\_1} \times Z_{B\_2}}{Z_{B\_1} \times Z_{F\_2}}\right] \times 100 \tag{19}$$

where

Z_{B_1} is the case #1 compressibility at base conditions (60 °F, 14.73 psia);

Z_{B_2} is the case #2 compressibility at base conditions (60 °F, 14.73 psia);

Z_{F_1} is the case #1 compressibility at flowing conditions;

Z_{F_2} is the case #2 compressibility at flowing conditions.

Table 21 illustrates the variance in compressibility with temperature and pressure for typical purchased natural gas. Z_B will not change unless the composition changes, so for a constant gas composition one only has to address the change in Z_F with changes in pressure and temperature.

Table 21—Compressibility–Typical Natural Gas

Temperature °F	Pressure (psig)						
	0	25	50	100	110	200	500
	API *MPMS* Ch. 14.2/AGA Report No. 8 Compressibility						
0	0.9966	0.9909	0.9851	0.9735	0.9712	0.9501	0.8781
20	0.9971	0.9921	0.9871	0.9771	0.9751	0.9569	0.8959
60	0.9978	0.9940	0.9902	0.9826	0.9811	0.9676	0.9229
70	0.9979	0.9944	0.9908	0.9838	0.9824	0.9697	0.9283
100	0.9983	0.9954	0.9925	0.9868	0.9856	0.9754	0.9422
120	0.9985	0.9960	0.9935	0.9884	0.9874	0.9785	0.9499

The values in Table 22 represent the errors that would be observed in the reported flow rates if the compressibility values were not updated to reflect the composition change from 100 % typical purchased natural gas to a mixture containing 80 % typical purchased natural gas and 20 % hydrogen as might occur in a refinery gas drum.

Table 22—Linear Meter Compressibility Effect
Typical Natural Gas vs Typical Natural Gas + 20 % H_2

Temperature °F	Pressure (psig)						
	0	25	50	100	110	200	500
	Resulting Volumetric Variance (%)						
0	0.04	0.26	0.48	0.94	1.03	1.91	5.31
20	0.02	0.22	0.41	0.82	0.90	1.66	4.53
60	0.00	0.15	0.31	0.63	0.69	1.29	3.40
70	0.00	0.14	0.29	0.59	0.65	1.21	3.19
100	–0.02	0.11	0.23	0.49	0.54	1.01	2.64
120	–0.02	0.09	0.20	0.43	0.48	0.90	2.34

5.6 Linear Meter (Coriolis)

Coriolis meters can be configured to output mass or volume. For gas applications the uncertainty associated with the measured density is so significant to the extent that the measured density cannot be utilized. Therefore, for gas applications Coriolis meters are configured to output mass and the conversion to standard volumetric units using the standard density is made as per Equation (6).

$$Q_{STD} = \frac{q_m}{\rho_B} \tag{6}$$

where

Q_{STD} is the standard cubic feet per hour (60 °F, 14.73 psia);

q_m is the mass flow, expressed in pounds per hour;

ρ_B is the density at reference conditions (60 °F, 14.73 psia), expressed in pounds per cubic feet (lb/ft^3).

The base density may be computed from the molecular weight as follows:

$$\rho_B = \frac{MW \times P_B}{Z_B \times R \times T_B} \tag{10}$$

where

Z_B is the compressibility at base conditions (60 °F, 14.73 psia);

P_B is the base pressure, 14.73 psia;

T_B is the base temperature, 519.67 °R (60 °F);

MW is the molecular weight, expressed in pounds per mole (lb/mole);

R is 10.73151: the universal gas constant (1545.33 ft-lbf/lb mol °R) divided by 12^2 for proper unit conversion.

From Equation (10) one can see that the base density is only influenced by the gas composition, which can be assessed by on-line sampling and analysis (e.g. GC) or by grab sampling and analysis. Errors in volumetric flow rate for Coriolis meters are proportional to uncorrected errors in molecular weight.

6 Inspection, Verification, and Calibration

6.1 General

There are numerous factors that influence a meter's measurement uncertainty and overall accuracy. Periodic instrument inspection, verification, and as needed calibration, will lessen the contribution of possible instrument error to the flow measurement uncertainty determination.

Equipment owners are responsible for determining the frequency and method of instrument inspection, verification, and calibration. The equipment manufacturer should be consulted as needed to offer specific guidance regarding equipment performance verification.

6.2 System Overview for Selection of Maintenance Activity, Frequency, and Tolerance

The determination of instrument calibration or verification frequency is not an exact science, but the following offers some guidance.

The typical steps involved are as follows.

1) Define the individual streams' relative significance within the plant's gas system.

2) For each stream, define the specific instruments or devices associated with the flow measurement that have to be inspected, verified, or calibrated at some frequency.

3) Determine the initial frequency of maintenance activity for each device or flow element based on:

   a) regulatory requirements;

   b) the stream's relative significance within the system;

   c) the contribution to measurement uncertainty by the components (e.g. pressure transmitter, orifice plate, etc.) of the measurement system;

   d) performance history of similar devices in similar or same service.

4) Determine the method and/or reference device with which the instrument or device will be inspected, verified, or calibrated.

5) Determine the acceptable tolerances for equipment inspection, verification, and calibration.

6) Utilize the documented findings to optimize (increase or decrease) the selected frequencies and/or activities.

Where available and appropriate, mass balance data and statistical meter performance evaluation methods can be used to adjust verification requirements.

6.3 Relative Stream Significance

Manufacturing plants or processing facilities often have numerous meters that are summed for energy management and reporting purposes. For a typical facility, some meters will measure large streams, while others will measure smaller streams. As mentioned, frequency of maintenance activity is an owner-defined variable rather than a default time interval. However, as a starting point, large volume meters (in relative terms) will likely demand more frequent attention at first than lower volume meters in order to confidently achieve the desired overall system uncertainty target. Plants with multiple gas meters/streams will also need to consider whether a large, medium, small categorization will be based on flow and heat content (energy and mass balance), or carbon content (regulatory).

Table 23 offers a conceptual guide of this discussion. The percentages of 15 % and 5 % are arbitrary and chosen for illustration only. System owners will need to define their own break points. Table 23 illustrates that while F100 measures a larger stream by volume, F101 measures the more significant stream from an energy and carbon content perspective.

Table 23—Plant Determination of Relative Stream Significance

Based on	Flow (volume)		Heat Content		Carbon Content	
	Meter Tag	% of Total	Meter Tag	% of Total	Meter Tag	% of Total
Large						
(>15 % of Total)	F100	30	F101	35	F101	32
	F101	20	F102	25	F102	27
	F102	15				
Medium						
(>5 %, <15 %)	F200	13	F100	14	F100	15
	F201	8	F200	9	F200	10
	F202	7	F201	6	F201	5
			F202	5	F202	5
Small						
(<5 % of Total)	F300	4	F300	3	F300	3
	F301	2	F301	2	F301	2
	F302	1	F302	1	F302	1
Total		**100**		**100**		**100**

6.4 Identify Devices to be Inspected, Verified, or Calibrated

6.4.1 General

Equipment owners should make a simple listing of all measurement system devices or components that are required to perform the measurement and deliver final results (e.g. standard flow volume, mass total, carbon content). This list should only include those system components that require periodic inspection, verification, or calibration as assessed by the owner or required by any applicable regulations.

6.4.2 Primary Devices

Common primary devices in use today are the flow elements associated with differential head type meters: orifice plate, Venturi, Pitot, cone.

Other common primary device meter types are vortex, Coriolis, positive displacement, ultrasonic, thermal dispersion, and turbine.

6.4.3 Secondary Devices

The most common secondary devices are the differential pressure flow transmitters, pressure transmitters, and temperature transmitters. The transmitters associated with Coriolis, vortex, ultrasonic, thermal dispersion, turbine, and PD are also considered secondary devices. Any composition analyzer, such as a gas chromatograph or densitometer, used to compensate the flow, is a secondary device.

6.4.4 Tertiary Devices

Common tertiary devices in a plant or facility environment are the basic process control system (BPCS), DCS, field mounted flow computer, PLC, or multi-variable transmitter.

6.4.5 Device Summary

Table 24 offers a summary of inspection, verification, and calibration guidance for common devices utilized in non-fiscal transfer service. Equipment owners shall make the final determination of the applicability and need for each maintenance activity for their devices based on measurement uncertainty targets, accessibility, cost effectiveness, and history of findings.

Table 24—Inspection, Verification, and Calibration Summary

	Inspection	Verification	Calibration
Primary			
DP			
Orifice	Required	Required	NA
Venturi	Required	Required	NA
Pitot	Required	NA	NA
Cone	Required	NA	NA
Turbine	Required	Spin test	NA**

Vortex	NA*	Manufacturer's recommendations including self-check diagnostics, if available	NA**
Coriolis	NA*		NA**
Ultrasonic	NA*		NA**
Thermal	Required	Normally not practical	NA**
PD	Required	Differential pressure	NA**
Secondary			
Pressure transmitter	NA*	Required	User defined
Temperature transmitter	NA*	Required	User defined
Analyzer	NA*	Required	User defined
Flow transmitter	NA*	Required	User defined
Tertiary			
BPCS/DCS	NA	Required	NA*
Flow computer	NA	Required	NA*
PLC	NA	Required	NA*
Multi-variable transmitter	NA	Required	NA*

NA – Not applicable.

NA* – Not applicable, unless a problem is suspected.

NA** – Normally not applicable in facility gas service, unless required to achieve desired uncertainty or verification test or self-diagnostics indicates a need.

User defined – Equipment owners often calibrate these devices only if found out of tolerance during verification.

6.5 Influence of Meter Type on Frequency Selection

Another variable used in the determination of equipment inspection, verification, and calibration frequency is the meter type. In general, meter types such as Coriolis, ultrasonic, vortex, positive displacement and turbine, require different frequencies of maintenance than that for thermal dispersion and differential/head type meters (orifice, Venturi, Pitot, averaging Pitot tube).

Flow elements are often installed so as to allow for inspection only at system shutdown. Therefore, primary elements should be inspected during system shutdown. Meters with diagnostics capable of detecting performance problems may not require periodic inspection or calibration of the primary element unless a problem is indicated or suspected.

Users of various meter types should make their own determinations of frequency based on inspection, verification, and calibration results, user experience, targeted uncertainty, and/or requirements of applicable regulations.

Frequency selection example:

Following is an example where F101 is an orifice meter. From the previous uncertainty discussion, we understand that differential pressure, static pressure, temperature, and composition, are of relative equal weight in the flow equation. For this example, the uncertainty associated with temperature measurements is significantly less than that of static pressure and differential pressure measurements. The orifice plate is installed between two flanges and can only be inspected at turnaround. Table 25 illustrates a typical operating plant's record of decision for an initial program. Steps 2 through 5 have been completed on the form.

Table 25—Meter Station F101: Initial Calibration Program

Step 2	**Flow Device**	**Description**		
	FT101	differential pressure (DP) instrument		
	PT101	static pressure instrument		
	TT101	temperature instrument (includes RTD and transmitter)		
	AT101	gas chromatograph		
	FE101	orifice plate		
Step 3	**Frequency**	**Inspection**	**Verification**	**Calibration**
	FT101	NA	Quarterly	If found out of tolerance
	PT101	NA	Quarterly	
	TT101	NA	Annual	
	AT101	NA	Quarterly	
	FE101	At system shutdown	At system shutdown	Not applicable
Step 4	**Site Procedure**[a]			
	FT101		REF-632-12V	REF-632-12C
	PT101		REF-632-10V	REF-632-10C
	TT101		REF-632-11V	REF-632-11C
	AT101		REF-121-15A	REF-121-15A
	FE101	REF-632-13[b]	REF-632-13	
Step 5	**Selected Tolerance**			
	FT101		0.10 mA at zero	0.25 % of span

	PT101		0.10 mA at zero	0.25 % of span
	TT101		5 °F	0.25 % of span
	AT101		certified gas standard	As required
	FE101	REPLACE plate as warranted	REPLACE plate as warranted	

a Plant or company practice specifying details of instrument calibration procedure.

b Complete and retain plate inspection form, as well as digital photo of “as-found” plate condition. Note on the form if the meter run was “steamed out” before pulling the orifice.

6.6 Calibration Results Influence on Frequency Selection

It is recommended that owner/operators of meters and accessory equipment maintain adequately detailed records of equipment inspection, verification, and calibration findings. This is necessary to perform a periodic reevaluation (Step 6) of the required calibration activities, frequencies, and tolerances necessary to achieve the desired uncertainty targets for the measurement.

Following the example in 6.5, Table 26 illustrates a plant’s revision to the calibration program after a year or more of documented, acceptable calibration results. Note the only change is to the **Verification Frequency** for **FT101** and **PT101.**

Table 26—Meter Station F101: Revised Calibration Program

Step 2	Flow Device	Description		
	FT101	differential pressure (DP) instrument		
	PT101	static pressure instrument		
	TT101	temperature instrument (includes RTD and transmitter)		
	AT101	gas chromatograph		
	FE101	orifice plate		
Step 3	**Frequency**	**Inspection**	**Verification**	**Calibration**
	FT101	NA	Bi-annual	If found out of tolerance
	PT101	NA	Bi-annual	
	TT101	NA	Annual	

	AT101	NA	Quarterly	
	FE101	At system shutdown	At system shutdown	NA
Step 4	**Site Procedure[a]**			
	FT101		REF-632-12V	REF-632-12C
	PT101		REF-632-10V	REF-632-10C
	TT101		REF-632-11V	REF-632-11C
	AT101		REF-121-15A	REF-121-15A
	FE101	REF-632-13[b]	REF-632-13	
Step 5	**Selected Tolerance**			
	FT101		0.10 mA at zero	0.25 % of span
	PT101		0.10 mA at zero	0.25 % of span
	TT101		5 °F	0.25 % of span
	AT101		certified gas standard	As Required
	FE101	REPLACE plate as warranted	REPLACE plate as warranted	

a Plant or company practice specifying details of instrument calibration procedure.

b Complete and retain plate inspection form, as well as digital photo of “as-found” plate condition. Note on the form if the meter run was “steamed out” before pulling the orifice.

Annex A
(informative)

Uncertainty Examples

The following examples are merely for illustration purposes only. Each company should develop its own approach. They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

The examples given in this section are based on the equations and processes set forth in Section 5 of this document. These examples will look at the uncertainty of measurement using average values for all variables. These examples will analyze the system illustrated in Figure A.1. The intermediate calculations are performed in floating mode. Flow uncertainty percentages are rounded to one decimal place.

The examples will assume the instrumentation on the meters shown in Table A.1.

Table A.1—Instrumentation on Meter Types

FE	Meter Type	Meter Output	Temp	Pressure	Gas Analysis
1	4 in. Line 1.3 in. Orifice Plate	FT-1 250 in. DP Transmitter	TT-1 RTD	PT-1 200 psia Transmitter	SP-1 Grab Samples
2	1 in. Coriolis	FT-2 Frequency	NONE	NONE	AT-6 On-Line GC at Gas Drum
3	2 in. Line 0.5 in. Orifice Plate	FT-3 MVT with 100 in. DP Transmitter	TT-3 MVT	FT-3 MVT with 150 psia Transmitter	AT-6 On-Line GC at Gas Drum
4	4 in. Ultrasonic Meter	FT-4 ACF Reading	TT-6 RTD	PT-6 300 psia Transmitter	AT-6 On-Line GC at Gas Drum
5	1 in. Displacement	FT-5 ACF Reading	TT-5 RTD	PT-5 200 psia Transmitter	Gas Supplier

NOTE Multi-Variable Transmitter (MVT).

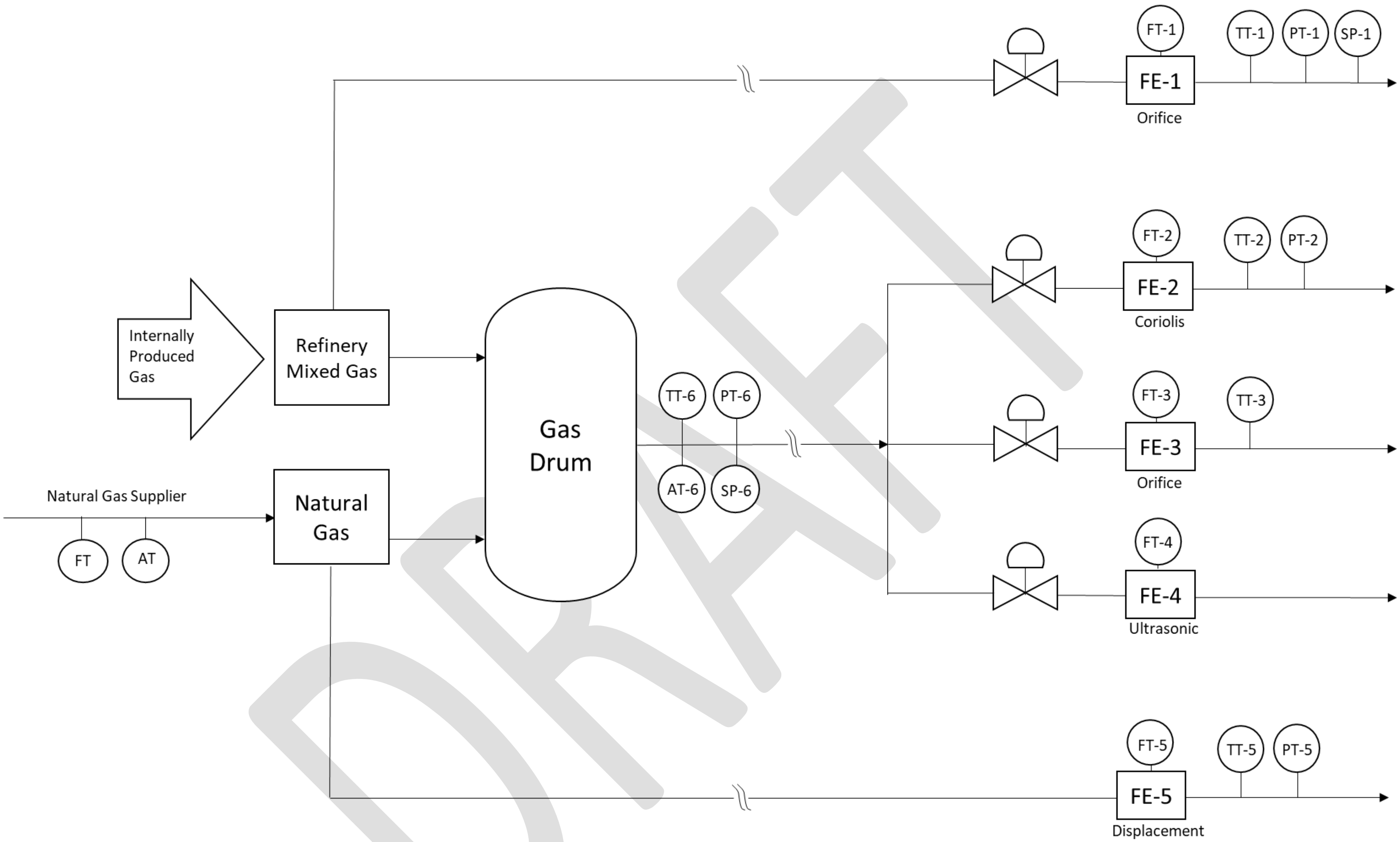

Figure A- 1 - Example of Non-Custody Gas Measurement System (For Illustration Purposes Only)

NOTES

1) FT-1 illustrates a case where close coupled pressure (PT) and temperature (TT) measurement and grab samples are utilized for compensation. The meter run is less than optimum, but is more than 1/2 of the minimum recommended by API.
2) FT-2, FT-3, and FT-4 utilize the composition determined by AT-6 or via grab samples from sample point SP-6.
3) FT-2 illustrates a case where a control valve upstream of the meter can produce significant variability in the pressure and temperature at the meter.
4) FT-3 illustrates the use of a multi-variable transmitter with inherent differential pressure, static pressure, and temperature measurements. The meter run is less than optimum, but is more than 1/3 of the minimum recommended by API.
5) FT-4 illustrates the use of the pressure header (PT6) and temperature (TT6) measurements for compensation. The meter run length is less than optimum length.
6) When the purchased natural gas has a relatively constant composition or the supplier's analyzer reading can be obtained, utilize that information to compensate FT-5.

EXAMPLE 1 FE-1

Step A.1.1 Determine the Uncertainty Model. FE-1 is a 4 in. orifice run with a 1.3 in. plate. The flow rate is determined from Equation (A.1):

$$Q_{STD} = \frac{N_1 \times \pi \times C_d \times Y \times d^2 \times Z_B \times T_B}{P_B \times 4 \sqrt{1 - \left(\frac{d}{D}\right)^4}} \sqrt{\frac{2 \times P_F \times R \times g_c \times dP}{MW \times Z_F \times T_F}} \tag{A.1}$$

where

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

N_1 is the engineering units conversion factor;

C_d is the discharge co-efficient;

Y is the expansion factor;

d is the bore diameter, expressed in inches;

D is the pipe diameter, expressed in inches;

Z_B is the compressibility at base conditions (60 °F, 14.73 psia);

T_B is the base temperature, expressed in degrees Rankine;

P_F is the flowing pressure, expressed in pounds per square inch absolute (psia);

R is the universal gas constant;

g_c is the gravitational constant;

dP is the differential pressure, expressed in inches water column;

MW is the molecular weight, expressed in pounds per mole (lb/mole);

Z_F is the compressibility at flowing conditions;

T_F is the flowing temperature, expressed in degrees Rankine;

P_B is the base pressure, expressed in pounds per square inch absolute (psia).

Step A.1.2 Set up a primary uncertainty table. Each component listed in the above equation is listed in a table, along with the average values for each variable. It is important to note that the values input could be instantaneous values, or the daily or monthly average from the meter. It is important when calculating the facility uncertainty that the timeframe for each meter included in the analysis is consistent. An installation effect parameter (see 3.1 and 5.2) is included to handle non-standard installations. A meter condition factor (see 5.2) is included to address primary element inspection frequency. To convert the volume flow rate to energy and carbon content, those fluid properties are also listed. The remaining values will be filled into the table in the following steps of the process.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Unit Conversion Factor	N_1	NA	1.899				
Discharge Coefficient	C_d	Dimensionless	0.5998				
Expansion Factor	Y	Dimensionless	0.99904				
Bore Diameter	d	Inches	1.3	inches			
Pipe Diameter	D	Inches	4.026	inches			
Base Compressibility	Z_B	Dimensionless	0.9978				
Base Temperature	T_B	°Fahrenheit	60	°Rankine			
		°Rankine	519.67				
Flowing Pressure	P_F	psia	120	psia			
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	ft-lbf/lbmol-°R			
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	lbm-ft/lbf-s^2			
Differential Pressure	dP	in. H_2O	10	in. H_2O			
Base Pressure	P_B	psia	14.73	psia			
Molecular Weight	MW	lbm/lbmol	17.5955	lbm/lbmol			
Flowing Compressibility	Z_F	Dimensionless	0.9819				
Flowing Temperature	T_F	°Fahrenheit	65	°Rankine			
		°Rankine	524.67				
Installation Effect Factor		Dimensionless	1				
Meter Condition Factor		Dimensionless	1				
Energy Content		BTU/ft^3	1025	BTU/ft^3			
Carbon Content		lbm/ft^3	0.037	lbm/ft^3			

Volume Flow Rate	6134	SCFH
Energy Flow Rate	6,287,065	BTU per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	

Carbon Flow Rate	0.113	Tons per Hour

Total Carbon Uncertainty	

Step A.1.3 Determine the sensitivity coefficients for each component in Step A.1.1. The sensitivities for most of the components are easily determined by looking at the equation. In general, the sensitivity of a term is equal to the exponent of the term. For example, discharge coefficient is raised to the first power, so the sensitivity is equal to one. Likewise, the items under the square root have a sensitivity of 0.5. Some components are more difficult (d and D) and require dithering to determine the sensitivity. The sensitivities are listed below.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Unit Conversion Factor	N_1	NA	1.899			**1.00**	
Discharge Coefficient	C_d	Dimensionless	0.5998			**1.00**	
Expansion Factor	Y	Dimensionless	0.99904			**1.00**	
Bore Diameter	d	Inches	1.3	inches		**2.04**	
Pipe Diameter	D	Inches	4.026	inches		**0.04**	
Base Compressibility	Z_B	Dimensionless	0.9978			**1.00**	
Base Temperature	T_B	°Fahrenheit	60	°Rankine		**1.00**	
		°Rankine	519.67				
Flowing Pressure	P_F	psia	120	psia		**0.50**	
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	ft-lbf/lbmol-°R		**0.50**	
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	lbm-ft/lbf-s^2		**1.00**	
Differential Pressure	dP	in. H_2O	10	in. H_2O		**0.50**	
Base Pressure	P_B	psia	14.73	psia		**1.00**	
Molecular Weight	MW	lbm/lbmol	17.5955	lbm/lbmol		**0.50**	
Flowing Compressibility	Z_F	Dimensionless	0.9819			**0.50**	
Flowing Temperature	T_F	°Fahrenheit	65	°Rankine		**0.50**	
		°Rankine	524.67				
Installation Effect Factor		Dimensionless	1			**1.00**	
Meter Condition Factor		Dimensionless	1			**1.00**	
Energy Content		BTU/ft^3	1025	BTU/ft^3		**1.00**	
Carbon Content		lbm/ft^3	0.037	lbm/ft^3		**1.00**	

Volume Flow Rate	6134	SCFH
Energy Flow Rate	6,287,065	BTU per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	

Carbon Flow Rate	0.113	Tons per Hour

Total Carbon Uncertainty	

Step A.1.4 Obtain numerical values for the uncertainty of each component in Step A.1.1. If this is a measured value (dP, P, T), manufacturer's specifications may be used. For calculated values such as discharge coefficient and expansion factor, the applicable calibration or standard may be applied. API *MPMS* Chapter14.3/AGA Report No. 3 is used to determine the values for this example. Uncertainties in diameters may be acquired from the manufacturer of the pipe and differential producer. Uncertainties in fluid properties (compressibility, energy content, carbon content) are determined by the analysis method. Typically, compressibility is determined from API *MPMS* Chapter14.2/AGA Report No. 8. In this case, there is an on-site gas chromatograph, so the uncertainties come from the analysis of that device. The installation effect factor has an uncertainty of 1 % from the information in Table 3. The orifice is able to be inspected on a periodic basis, so the uncertainty associated with the orifice condition is determined to be 0.5 %. The uncertainties can be determined as either a value or a percent, and the remaining value calculated. There are several components with zero uncertainty. These components may have a very small uncertainty associated with them, but the effect is not considered significant. If the uncertainty is determined in percent, it is not necessary to convert it to the units of measure, but if the uncertainty is given in the unit of measure, it can be converted to a percent.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Unit Conversion Factor	N_1	NA	1.899	**0**		**0.0000**	1.00	
Discharge Coefficient	C_d	Dimensionless	0.5998	**0.00323**		**0.5387**	1.00	
Expansion Factor	Y	Dimensionless	0.99904	**0.00012**		**0.0120**	1.00	
Bore Diameter	d	Inches	1.3	**0.0010**	inches	**0.0750**	2.04	
Pipe Diameter	D	Inches	4.026	**0.0500**	inches	**1.2425**	0.04	
Base Compressibility	Z_B	Dimensionless	0.9978	**0.0010**		**0.1000**	1.00	
Base Temperature	T_B	°Fahrenheit	60	**0**	°Rankine	**0.0000**	1.00	
		°Rankine	519.67					
Flowing Pressure	P_F	psia	120	**1.78**	psia	**1.4831**	0.50	
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	**0**	ft-lbf/lbmol-°R	**0.0000**	0.50	
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	**0**	lbm-ft/lbf-s^2	**0.0000**	1.00	
Differential Pressure	dP	in. H_2O	10	**0.3431**	in. H_2O	**3.4305**	0.50	
Base Pressure	P_B	psia	14.73	**0**	psia	**0.0000**	1.00	
Molecular Weight	MW	lbm/lbmol	17.5955	**0.2111**	lbm/lbmol	**1.2000**	0.50	
Flowing Compressibility	Z_F	Dimensionless	0.9819	**0.005**		**0.5000**	0.50	
Flowing Temperature	T_F	°Fahrenheit	65	**2.623**	°Rankine	**0.5000**	0.50	
		°Rankine	524.67					
Installation Effect Factor		Dimensionless	1	**0.01**		**1.0000**	1.00	
Meter Condition Factor		Dimensionless	1	**0.01**		**0.5000**	1.00	
Energy Content		BTU/ft^3	1025	**12.30**	BTU/ft^3	**1.2000**	1.00	
Carbon Content		lbm/ft^3	0.037	**0.000444**	lbm/ft^3	**1.2000**	1.00	

Volume Flow Rate	6134	SCFH

Total Volume Uncertainty	

Energy Flow Rate	6,287,065	BTU per Hour
Carbon Flow Rate	0.113	Tons per Hour

Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.1.5 Combine the numerical values obtained in Step A.1.4 to give numerical values for the combined and expanded standard uncertainties.

.	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Unit Conversion Factor	N_1	NA	1.899	0		0.0000	1.00	**0.000**
Discharge Coefficient	C_d	Dimensionless	0.5998	0.00323		0.5387	1.00	**0.290**
Expansion Factor	Y	Dimensionless	0.99904	0.00012		0.0120	1.00	**0.000**
Bore Diameter	d	Inches	1.3	0.0010	inches	0.0750	2.04	**0.023**
Pipe Diameter	D	Inches	4.026	0.0500	inches	1.2425	0.04	**0.002**
Base Compressibility	Z_B	Dimensionless	0.9978	0.0010		0.1000	1.00	**0.010**
Base Temperature	T_B	°Fahrenheit	60	0	°Rankine	0.0000	1.00	**0.000**
		°Rankine	519.67					
Flowing Pressure	P_F	psia	120	1.78	psia	1.4831	0.50	**0.550**
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	0	ft-lbf/lbmol-°R	0.0000	0.50	**0.000**
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	0	lbm-ft/lbf-s^2	0.0000	1.00	**0.000**
Differential Pressure	dP	in. H_2O	10	0.3431	in. H_2O	3.4305	0.50	**2.942**
Base Pressure	P_B	psia	14.73	0	psia	0.0000	1.00	**0.000**
Molecular Weight	MW	lbm/lbmol	17.5955	0.2111	lbm/lbmol	1.2000	0.50	**0.360**
Flowing Compressibility	Z_F	Dimensionless	0.9819	0.005		0.5000	0.50	**0.063**
Flowing Temperature	T_F	°Fahrenheit	65	2.623	°Rankine	0.5000	0.50	**0.063**
		°Rankine	524.67					
Installation Effect Factor		Dimensionless	1	0.01		1.0000	1.00	**1.000**
Meter Condition Factor		Dimensionless	1	0.01		0.5000	1.00	**0.250**
Energy Content		BTU/ft^3	1025	12.30	BTU/ft^3	1.2000	1.00	**1.440**
Carbon Content		lbm/ft^3	0.037	0.000444	lbm/ft^3	1.2000	1.00	**1.440**

Volume Flow Rate	6134	SCFH
Energy Flow Rate	6,287,065	BTU per Hour
Carbon Flow Rate	0.113	Tons per Hour

Total Volume Uncertainty	**2.36**
Total Energy Uncertainty	**2.64**
Total Carbon Uncertainty	**2.64**

The total uncertainty is determined by summing the individual combined uncertainties $(U_x \times S_x)^2$ and taking the square root of that sum. Because this example looks at three different uncertainties (volume, energy, and carbon), the calculation is performed three different ways. To calculate the volume uncertainty, all components are included with the exception of energy content and carbon content. To calculate the energy uncertainty, all components are included with the exception of the carbon content. To calculate the carbon uncertainty, all components are included with the exception of the energy content. Note that in this case, the Energy Uncertainty and the Carbon Uncertainty are equivalent, because the uncertainty in Energy and Carbon Content is the same.

EXAMPLE 2 FE-2

Step A.2.1 Determine the uncertainty model. FE-2 is a 1 in. Coriolis run. The flow rate is determined from Equation (A.2):

$$Q_{STD} = \frac{q_m}{\rho_B} \tag{A.2}$$

where

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

q_m is pounds per hour;

ρ_B is density at reference conditions (60 °F, 14.73 psia), expressed in pounds per cubic feet (lb/ft^3).

The base density may be computed from the molecular weight as follows:

$$\rho_B = \frac{MW \times P_B}{T_B \times Z_B \times 10.73151} \tag{A.3}$$

where

Z_B is the base compressibility (60 °F, 14.73 psia);

P_B is 14.73 psia;

T_B is 519.67 °R (60 °F);

MW is the molecular weight, expressed in pounds per mole (lb/mole).

Step A.2.2 Set up a primary uncertainty table. Each component listed in the above equation is listed in a table. To convert the volume flow rate to energy and carbon content, those fluid properties are also listed.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Mass Flow Rate	q_m	lbm/hr	500		lbm/hr			
Molecular Weight	MW	lbm/lbmol	17.5955		lbm/lbmol			
Base Pressure	P_B	psia	14.73		psia			
Base Temperature	T_B	°Fahrenheit	60		°Rankine			
		°Rankine	519.67					
Base Compressibility	Z_B	Dimensionless	0.9979					
Installation Effect Factor		Dimensionless	1					
Meter Condition Factor		Dimensionless	1					
Energy Content		BTU/ft^3	1050		BTU/ft^3			
Carbon Content		lbm/ft^3	0.035		lbm/ft^3			

Volume Flow Rate	**10,736**	SCFH
Energy Flow Rate	**11,272,765**	BTU per Hour
Carbon Flow Rate	**0.188**	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.2.3 Determine the sensitivity coefficients for each component in Step A.2.1. The sensitivities for all of the components are easily determined by looking at the equation. The sensitivity of each component is equal to 1 as is the case with most linear meter applications. The sensitivities are listed below.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Mass Flow Rate	q_m	lbm/hr	500		lbm/hr		**1.00**	
Molecular Weight	MW	lbm/lbmol	17.5955		lbm/lbmol		**1.00**	
Base Pressure	P_B	psia	14.73		psia		**1.00**	
Base Temperature	T_B	°Fahrenheit	60		°Rankine		**1.00**	
		°Rankine	519.67					
Base Compressibility	Z_B	Dimensionless	0.9979				**1.00**	
Installation Effect Factor		Dimensionless	1				**1.00**	
Meter Condition Factor		Dimensionless	1				**1.00**	
Energy Content		BTU/ft^3	1050		BTU/ft^3		**1.00**	
Carbon Content		lbm/ft^3	0.035		lbm/ft^3		**1.00**	

Volume Flow Rate	**10,736**	SCFH
Energy Flow Rate	**11,272,765**	BTU per Hour
Carbon Flow Rate	**0.188**	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.2.4 Obtain numerical values for the uncertainty of each component in Step A.2.1. If this is a measured value (q, mass flow), manufacturer's specifications may be used. Uncertainties in fluid properties (molecular weight, energy content, carbon content) are determined by the analysis method. In this case, the gas chromatograph is located at the gas drum, so the uncertainty determined for that common analyzer is utilized and have to include any additional uncertainties for the possible change in composition between the gas drum and the meter. The installation effect factor for a Coriolis meter will be zero because a Coriolis meter does not require upstream/downstream run lengths. In this example, it is not feasible for the user to inspect the meter periodically, so the only quality check on the meter is the periodic zero of the meter. From this, it was determined that the meter condition uncertainty is 1 %. The uncertainties can be determined as either a value or a percent, and the remaining value calculated.

Component	**Symbol**	**Units**	**Nominal Value**	**Standard Uncertainty**		**Standard Uncertainty (U_x)%**	**Sensitivity Coefficient (S_x)**	$(U_x \times S_x)^2$
Mass Flow Rate	q_B	lbm/hr	500	**5.00**	lbm/hr	**1.0000**	1.00	
Molecular Weight	MW	lbm/lbmol	17.5955	**0.1320**	lbm/lbmol	**0.7500**	1.00	
Base Pressure	P_B	psia	14.73	**0**	psia	**0.0000**	1.00	
Base Temperature	T_B	°Fahrenheit	60	**0**	°Rankine	**0.0000**	1.00	
		°Rankine	519.67					
Base Compressibility	Z_B	Dimensionless	0.9979	**0**		**0.0000**	1.00	
Installation Effect Factor		Dimensionless	1	**0**		**0.0000**	1.00	
Meter Condition Factor		Dimensionless	1	**0.01**		**1.0000**	1.00	
Energy Content		BTU/ft^3	1050	**7.875**	BTU/ft^3	**0.7500**	1.00	
Carbon Content		lbm/ft^3	0.035	**0.0002625**	lbm/ft^3	**0.7500**	1.00	

Volume Flow Rate	**10,736**	SCFH
Energy Flow Rate	**11,272,765**	BTU per Hour
Carbon Flow Rate	**0.188**	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.2.5 Combine the numerical values obtained in Step A.2.4 to give numerical values for the combined and expanded standard uncertainties.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Mass Flow Rate	q_B	lbm/hr	500	5.00	lbm/hr	1.0000	1.00	**1.000**
Molecular Weight	MW	lbm/lbmol	17.5955	0.1320	lbm/lbmol	0.7500	1.00	**0.563**
Base Pressure	P_B	psia	14.73	0	psia	0.0000	1.00	**0.000**
Base Temperature	T_B	°Fahrenheit	60	0	°Rankine	0.0000	1.00	**0.000**
		°Rankine	519.67					
Base Compressibility	Z_B	Dimensionless	0.9979	0		0.0000	1.00	**0.000**
Installation Effect Factor		Dimensionless	1	0		0.0000	1.00	**0.000**
Meter Condition Factor		Dimensionless	1	0.01		1.0000	1.00	**1.000**
Energy Content		BTU/ft^3	1050	7.875	BTU/ft^3	0.7500	1.00	**0.563**
Carbon Content		lbm/ft^3	0.035	0.0002625	lbm/ft^3	0.7500	1.00	**0.563**

Volume Flow Rate	**10,736**	SCFH
Energy Flow Rate	**11,272,765**	BTU per Hour
Carbon Flow Rate	**0.188**	Tons per Hour

Total Volume Uncertainty	**1.60**
Total Energy Uncertainty	**1.77**
Total Carbon Uncertainty	**1.77**

The total uncertainty is determined by summing the individual combined uncertainties $(U_x \times S_x)^2$ and taking the square root of that sum. Because this example looks at three different uncertainties (volume, energy, and carbon), the calculation is done three different ways.

EXAMPLE 3 FE-3

Step A.3.1 Determine the Uncertainty Model. FE-3 is a 2 in. orifice run with a 0.85 in. Plate. The flow rate is determined from Equation (A.4):

$$Q_{STD} = \frac{N_1 \times \pi \times C_d \times Y \times d^2 \times Z_B \times T_B}{P_B \times 4\sqrt{1-\left(\frac{d}{D}\right)^4}} \sqrt{\frac{2 \times P_F \times R \times g_c \times dP}{MW \times Z_F \times T_F}} \tag{A.4}$$

where

- Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);
- N_1 is the engineering units conversion factor;
- C_d is the discharge co-efficient;
- Y is the expansion factor;
- d is the bore diameter, expressed in inches;
- D is the pipe diameter, expressed in inches;
- Z_B is the compressibility at base conditions (60 °F, 14.73 psia);
- T_B is the base temperature, expressed in degrees Rankine;
- P_F is the flowing pressure, expressed in pounds per square inch (psia);
- R is the universal gas constant;
- g_c is the gravitational constant;
- dP is the differential pressure, expressed in inches water column at 68°F;
- MW is the molecular weight, expressed in pounds per mole (lb/mole);
- Z_F is the compressibility at flowing conditions;
- T_F is the flowing temperature, expressed in degrees Rankine;
- P_B is the base pressure, expressed in pounds per square inch (psia).

The main differences between Example 1 and Example 3 are:

1) Meter sizes.

2) Example 1 measured dP, P, and T using three different devices. Example 3 uses a multi-variable transmitter.

3) In Example 1, the DP transmitter was ranged to 250 in. and being used at 10 in. In Example 3, the DP transmitter was ranged to 100 in. and being used at 10 in. This results in decreased uncertainty in the DP measurement.

4) In Example 3, the composition is measured at the gas drum by an on-line analyzer. Hence, a lower molecular weight uncertainty is used in the numerical example than the uncertainty value used in Example 1.

Step A.3.2 Set up a primary uncertainty table. Each component listed in the above equation is listed in a table. An installation effect parameter explained in Section 3 is included to handle non-standard installations. To convert the volume flow rate to energy and carbon content, those fluid properties are also listed.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Unit Conversion Factor	N_1	NA	**1.899**				
Discharge Coefficient	C_d	Dimensionless	**0.6008**				
Expansion Factor	Y	Dimensionless	**0.9989**				
Bore Diameter	d	Inches	**0.5**	inches			
Pipe Diameter	D	Inches	**2.067**	inches			
Base Compressibility	Z_B	Dimensionless	**0.9979**				
Base Temperature	T_B	°Fahrenheit	**60**	°Rankine			
		°Rankine	**519.67**				
Flowing Pressure	P_F	psia	**100**	psia			
Universal Gas Constant	R	ft-lbf/lbmol-°R	**1545.33**	ft-lbf/lbmol-°R			
Gravitational Constant	g_c	lbm-ft/lbf-s^2	**32.174**	lbm-ft/lbf-s^2			
Differential Pressure	dP	in. H_2O	**10**	in. H_2O			
Base Pressure	P_B	psia	**14.73**	psia			
Molecular Weight	MW	lbm/lbmol	**16.799**	lbm/lbmol			
Flowing Compressibility	Z_F	Dimensionless	**0.98664**				
Flowing Temperature	T_F	°Fahrenheit	**60**	°Rankine			
		°Rankine	**519.67**				
Installation Effect Factor		Dimensionless	**1**				
Meter Condition Factor		Dimensionless	**1**				
Energy Content		BTU/ft^3	**1050**	BTU/ft^3			
Carbon Content		lbm/ft^3	**0.035**	lbm/ft^3			

Volume Flow Rate	848	SCFH
Energy Flow Rate	890,320	BTU per Hour
Carbon Flow Rate	0.015	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.3.3 Determine the sensitivity coefficients for each component in Step A.3.1. The sensitivities for most of the components are easily determined by looking at the equation. Some components are more difficult (d and D) and require dithering to determine the sensitivity. The sensitivities are listed below.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Unit Conversion Factor	N_1	NA	1.899			**1.00**	
Discharge Coefficient	C_d	Dimensionless	0.6008			**1.00**	
Expansion Factor	Y	Dimensionless	0.9989			**1.00**	
Bore Diameter	d	Inches	0.5	inches		**2.04**	
Pipe Diameter	D	Inches	2.067	inches		**0.04**	
Base Compressibility	Z_B	Dimensionless	0.9979			**1.00**	
Base Temperature	T_B	°Fahrenheit	60	°Rankine		**1.00**	
		°Rankine	519.67				
Flowing Pressure	P_F	psia	100	psia		**0.50**	
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	ft-lbf/lbmol-°R		**0.50**	
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	lbm-ft/lbf-s^2		**1.00**	
Differential Pressure	dP	in. H_2O	10	in. H_2O		**0.50**	
Base Pressure	P_B	psia	14.73	psia		**1.00**	
Molecular Weight	MW	lbm/lbmol	16.799	lbm/lbmol		**0.50**	
Flowing Compressibility	Z_F	Dimensionless	0.98664			**0.50**	
Flowing Temperature	T_F	°Fahrenheit	60	°Rankine		**0.50**	
		°Rankine	519.67				
Installation Effect Factor		Dimensionless	1			**1.00**	
Meter Condition Factor		Dimensionless	1			**1.00**	
Energy Content		BTU/ft^3	1050	BTU/ft^3		**1.00**	
Carbon Content		lbm/ft^3	0.035	lbm/ft^3		**1.00**	

Volume Flow Rate	848	SCFH
Energy Flow Rate	890,320	BTU per Hour
Carbon Flow Rate	0.015	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.3.4 Obtain numerical values for the uncertainty of each component in Step A.3.1. If this is a measured value (dP, P, T), manufacturer's specifications may be used. For calculated values such as discharge coefficient and expansion factor, the applicable calibration or standard may be applied (API *MPMS* Chapter 14.3/AGA Report No. 3). Uncertainties in diameters may be acquired from the manufacturer of the piece. Uncertainties in fluid properties (compressibility, energy content, carbon content) are determined by the analysis method. In this case, the composition is being recorded at the drum. The installation effect factor has an uncertainty of 2 % from the information in Table 3. The meter is not able to be inspected at regular intervals, so the uncertainty associated with the meter condition is determined to be 2 %. The uncertainties can be determined as either a value or a percent, and the remaining value calculated.

Component	**Symbol**	**Units**	**Nominal Value**	**Standard Uncertainty**		**Standard Uncertainty (U_x)%**	**Sensitivity Coefficient (S_x)**	**$(U_x \times S_x)^2$**
Unit Conversion Factor	N_1	NA	1.899	**0**		**0.0000**	1.00	
Discharge Coefficient	C_d	Dimensionless	0.6008	**0.00411**		**0.6834**	1.00	
Expansion Factor	Y	Dimensionless	0.9989	**0.00014**		**0.0144**	1.00	
Bore Diameter	d	Inches	0.5	**0.0004**	inches	**0.0750**	2.04	
Pipe Diameter	D	Inches	2.067	**0.0257**	inches	**1.2425**	0.04	
Base Compressibility	Z_B	Dimensionless	0.9979	**0.0010**		**0.1000**	1.00	
Base Temperature	T_B	°Fahrenheit	60	**0**	°Rankine	**0.0000**	1.00	
		°Rankine	519.67					
Flowing Pressure	P_F	psia	100	**0.46**	psia	**0.4575**	0.50	
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	**0**	ft-lbf/lbmol-°R	**0.0000**	0.50	
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	**0**	lbm-ft/lbf-s^2	**0.0000**	1.00	
Differential Pressure	dP	in. H_2O	10	**0.1120**	in. H_2O	**1.1204**	0.50	
Base Pressure	P_B	psia	14.73	**0**	psia	**0.0000**	1.00	
Molecular Weight	MW	lbm/lbmol	16.799	**0.1260**	lbm/lbmol	**0.7500**	0.50	
Flowing Compressibility	Z_F	Dimensionless	0.98664	**0.007**		**0.7500**	0.50	
Flowing Temperature	T_F	°Fahrenheit	60	**2.598**	°Rankine	**0.5000**	0.50	
		°Rankine	519.67					
Installation Effect Factor		Dimensionless	1	**0.02**		**2.0000**	1.00	
Meter Condition Factor		Dimensionless	1	**0.02**		**2.0000**	1.00	
Energy Content		BTU/ft^3	1050	**7.88**	BTU/ft^3	**0.7500**	1.00	
Carbon Content		lbm/ft^3	0.035	**0.0002625**	lbm/ft^3	**0.7500**	1.00	

Volume Flow Rate	848	SCFH
Energy Flow Rate	890,320	BTU per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	

Carbon Flow Rate	0.015	Tons per Hour

Total Carbon Uncertainty	

Step A.3.5 Combine the numerical values obtained in Step A.3.4 to give numerical values for the combined and expanded standard uncertainties.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Unit Conversion Factor	N_1	NA	1.899	0		0.0000	1.00	**0.000**
Discharge Coefficient	C_d	Dimensionless	0.6008	0.00411		0.6834	1.00	**0.467**
Expansion Factor	Y	Dimensionless	0.9989	0.00014		0.0144	1.00	**0.000**
Bore Diameter	d	Inches	0.5	0.0004	inches	0.0750	2.04	**0.023**
Pipe Diameter	D	Inches	2.067	0.0257	inches	1.2425	0.04	**0.002**
Base Compressibility	Z_B	Dimensionless	0.9979	0.0010		0.1000	1.00	**0.010**
Base Temperature	T_B	°Fahrenheit	60	0	°Rankine	0.0000	1.00	**0.000**
		°Rankine	519.67					
Flowing Pressure	P_F	psia	100	0.46	psia	0.4575	0.50	**0.052**
Universal Gas Constant	R	ft-lbf/lbmol-°R	1545.33	0	ft-lbf/lbmol-°R	0.0000	0.50	**0.000**
Gravitational Constant	g_c	lbm-ft/lbf-s^2	32.174	0	lbm-ft/lbf-s^2	0.0000	1.00	**0.000**
Differential Pressure	dP	in. H_2O	10	0.1120	in. H_2O	1.1204	0.50	**0.314**
Base Pressure	P_B	psia	14.73	0	psia	0.0000	1.00	**0.000**
Molecular Weight	MW	lbm/lbmol	16.799	0.1260	lbm/lbmol	0.7500	0.50	**0.141**
Flowing Compressibility	Z_F	Dimensionless	0.98664	0.007		0.7500	0.50	**0.141**
Flowing Temperature	T_F	°Fahrenheit	60	2.598	°Rankine	0.5000	0.50	**0.063**
		°Rankine	519.67					
Installation Effect Factor		Dimensionless	1	0.02		2.0000	1.00	**4.000**
Meter Condition Factor		Dimensionless	1	0.02		2.0000	1.00	**4.000**
Energy Content		BTU/ft^3	1050	7.88	BTU/ft^3	0.7500	1.00	**0.563**
Carbon Content		lbm/ft^3	0.035	0.0002625	lbm/ft^3	0.7500	1.00	**0.563**

Volume Flow Rate	848	SCFH
Energy Flow Rate	890,320	BTU per Hour
Carbon Flow Rate	0.015	Tons per Hour

Total Volume Uncertainty	**3.04**
Total Energy Uncertainty	**3.13**
Total Carbon Uncertainty	**3.13**

The total uncertainty is determined by summing the individual combined uncertainties $(U_x \times S_x)^2$ and taking the square root of that sum. Because this example looks at three different uncertainties (volume, energy, and carbon), the calculation is done three different ways. To calculate the volume uncertainty, all components are included with the exception of energy content and carbon content. To calculate the energy uncertainty all components are included with the exception of the carbon content. To calculate the carbon uncertainty all components are included with the exception of the energy content.

EXAMPLE 4 FE-4

Step A.4.1 Determine the Uncertainty Model. FE-4 is a 4 in. ultrasonic meter run. The flow rate is determined from Equation (A.5):

$$Q_{STD} = Q_{ACT} \times \frac{P_F}{P_B} \times \frac{T_B}{T_F} \times \frac{Z_B}{Z_F} \tag{A.5}$$

where

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

Q_{ACT} is the actual cubic feet per hour (T_F, P_F);

P_F is the flowing pressure, expressed in pounds per square inch (psia);

P_B is 14.73 psia;

T_F is the flowing temperature, expressed in degrees Rankine;

T_B is 519.67 °R (60 °F);

Z_F is the flowing compressibility;

Z_B is the base compressibility (60 °F, 14.73 psia).

The actual volumetric flow rate is read straight from the ultrasonic meter, and the uncertainty associated with that value is determined by the calibration of that device.

Step A.4.2 Set up a primary uncertainty table. Each component listed in the above equation is listed in a table. An installation effect parameter was determined using the process explained in Section 3. To convert the volume flow rate to energy and carbon content, those fluid properties are also listed.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Volumetric Flow Rate	Q_{ACT}	ACFH	**1199.75**	ACFH			
Base Compressibility	Z_B	Dimensionless	**0.9979**				
Base Temperature	T_B	°Fahrenheit	**60**	°Rankine			
		°Rankine	**519.67**				
Flowing Pressure	P_F	psia	**100**	psia			
Flowing Compressibility	Z_F	Dimensionless	**0.9332**				
Flowing Temperature	T_F	°Fahrenheit	**55**	°Rankine			
		°Rankine	**514.67**				
Base Pressure	P_B	psia	**14.73**	psia			
Installation Effect Factor		Dimensionless	**1**				
Meter Condition Factor		Dimensionless	**1**				
Energy Content		BTU/ft^3	**1050**	BTU/ft^3			
Carbon Content		lbm/ft^3	**0.035**	lbm/ft^3			

Volume Flow Rate	**8794**	SCFH
Energy Flow Rate	**9,233,969**	BTU per Hour
Carbon Flow Rate	**0.154**	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.4.3 Determine the sensitivity coefficients for each component in Step A.4.1. The sensitivities for all of the components are easily determined by looking at the equation. The sensitivity of each component is equal to 1 as is the case with most linear meter applications. The sensitivities are listed below.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	1199.75	ACFH		**1.00**	
Base Compressibility	Z_B	Dimensionless	0.9979			**1.00**	
Base Temperature	T_B	°Fahrenheit	60	°Rankine		**1.00**	
		°Rankine	519.67				
Flowing Pressure	P_F	psia	100	psia		**1.00**	
Flowing Compressibility	Z_F	Dimensionless	0.9332			**1.00**	
Flowing Temperature	T_F	°Fahrenheit	55	°Rankine		**1.00**	
		°Rankine	514.67				
Base Pressure	P_B	psia	14.73	psia		**1.00**	
Installation Effect Factor		Dimensionless	1			**1.00**	
Meter Condition Factor		Dimensionless	1			**1.00**	
Energy Content		BTU/ft^3	1050	BTU/ft^3		**1.00**	
Carbon Content		lbm/ft^3	0.035	lbm/ft^3		**1.00**	

Volume Flow Rate	8794	SCFH
Energy Flow Rate	9,233,969	BTU per Hour
Carbon Flow Rate	0.154	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.4.4 Obtain numerical values for the uncertainty of each component in Step A.4.1. If this is a measured value (P, T), manufacturer's specifications may be used. For the flow rate value, the applicable calibration has to be applied. Uncertainties in fluid properties (compressibility, energy content, carbon content) are determined by the analysis method. In this case, the gas chromatograph is located at the gas drum. The meter run length is less than manufacturer recommendations and after consultation with the manufacturer, an installation effect uncertainty of 1 % was chosen. The meter is not routinely removed and inspected, so the meter condition factor is determined to be 2 %.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	1199.75	**9.00** ACFH	**0.7500**	1.00	
Base Compressibility	Z_B	Dimensionless	0.9979	**0.001**	**0.1000**	1.00	
Base Temperature	T_B	°Fahrenheit	60	**0** °Rankine	**0.0000**	1.00	
		°Rankine	519.67				
Flowing Pressure	P_F	psia	100	**0.46** psia	**0.4575**	1.00	
Flowing Compressibility	Z_F	Dimensionless	0.9332	**0.007**	**0.7500**	1.00	
Flowing Temperature	T_F	°Fahrenheit	55	**2.573** °Rankine	**0.5000**	1.00	
		°Rankine	514.67				
Base Pressure	P_B	psia	14.73	**0** psia	**0.0000**	1.00	
Installation Effect Factor		Dimensionless	1	**0.01**	**1.0000**	1.00	
Meter Condition Factor		Dimensionless	1	**0.02**	**2.0000**	1.00	
Energy Content		BTU/ft^3	1050	**7.875** BTU/ft^3	**0.7500**	1.00	
Carbon Content		lbm/ft^3	0.035	**0.0002625** lbm/ft^3	**0.7500**	1.00	

Volume Flow Rate	8,794	SCFH
Energy Flow Rate	9,233,969	BTU per Hour
Carbon Flow Rate	0.154	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.4.5 Combine the numerical values obtained to give numerical values for the combined and expanded standard uncertainties.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	1199.75	9.00 ACFH	0.7500	1.00	**0.563**
Base Compressibility	Z_B	Dimensionless	0.9979	0.001	0.1000	1.00	**0.010**
Base Temperature	T_B	°Fahrenheit	60	0 °Rankine	0.0000	1.00	**0.000**
		°Rankine	519.67				
Flowing Pressure	P_F	psia	100	0.46 psia	0.4575	1.00	**0.209**
Flowing Compressibility	Z_F	Dimensionless	0.9332	0.007	0.7500	1.00	**0.563**
Flowing Temperature	T_F	°Fahrenheit	55	2.573 °Rankine	0.5000	1.00	**0.250**
		°Rankine	514.67				
Base Pressure	P_B	psia	14.73	0 psia	0.0000	1.00	**0.000**
Installation Effect Factor		Dimensionless	1	0.01	1.0000	1.00	**1.000**
Meter Condition Factor		Dimensionless	1	0.02	2.0000	1.00	**4.000**
Energy Content		BTU/ft^3	1050	7.875 BTU/ft^3	0.7500	1.00	**0.563**
Carbon Content		lbm/ft^3	0.035	0.0002625 lbm/ft^3	0.7500	1.00	**0.563**

Volume Flow Rate	8794	SCFH
Energy Flow Rate	9,233,969	BTU per Hour
Carbon Flow Rate	0.154	Tons per Hour

Total Volume Uncertainty	**2.57**
Total Energy Uncertainty	**2.68**
Total Carbon Uncertainty	**2.68**

The total uncertainty is determined by summing the individual combined uncertainties $(U_x \times S_x)^2$ and taking the square root of that sum. Because this example looks at three different uncertainties (volume, energy, and carbon), the calculation is done three different ways.

EXAMPLE 5 FE-5

Step A.5.1 Determine the Uncertainty Model. FE-5 is a 1 in. displacement meter run. The flow rate is determined from Equation (A.6):

$$Q_{STD} = Q_{ACT} \times \frac{P_F}{P_B} \times \frac{T_B}{T_F} \times \frac{Z_B}{Z_F} \tag{A.6}$$

where

Q_{STD} is standard cubic feet per hour (60 °F, 14.73 psia);

Q_{ACT} is the actual cubic feet per hour (T_F, P_F);

P_F is the flowing pressure, expressed in pounds per square inch (psia);

P_B is 14.73 psia;

T_F is the flowing temperature, expressed in degrees Rankine;

T_B is 519.67 °R (60 °F);

Z_F is the flowing compressibility;

Z_B is the base compressibility (60 °F, 14.73 psia).

In this example, the actual volumetric flow rate is read straight from the displacement meter and the uncertainty associated with that value is determined from the calibration data of that device. The actual volumetric flow rate is equal to the difference between the current and previous readings divided by the elapsed time between readings.

Step A.5.2 Set up a primary uncertainty table. Each component listed in the above equation is listed in a table. A positive displacement meter does not have an installation effect. To convert the volume flow rate to energy and carbon content, those fluid properties are also listed.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	**160.8**		ACFH			
Base Compressibility	Z_B	Dimensionless	**0.9979**					
Base Temperature	T_B	°Fahrenheit	**60**		°Rankine			
		°Rankine	**519.67**					
Flowing Pressure	P_F	psia	**25**		psia			
Flowing Compressibility	Z_F	Dimensionless	**0.9332**					
Flowing Temperature	T_F	°Fahrenheit	**55**		°Rankine			
		°Rankine	**514.67**					
Base Pressure	P_B	psia	**14.73**		psia			
Installation Effect Factor		Dimensionless	**1**					
Meter Condition Factor		Dimensionless	**1**					
Energy Content		BTU/ft^3	**1000**		BTU/ft^3			
Carbon Content		lbm/ft^3	**0.035**		lbm/ft^3			

Volume Flow Rate	**295**	SCFH
Energy Flow Rate	**294,669**	BTU per Hour
Carbon Flow Rate	**0.005**	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.5.3 Determine the sensitivity coefficients for each component in Step A.5.1. The sensitivities for all of the components are easily determined by looking at the equation. The sensitivity of each component is equal to 1 as is the case with most linear meter applications. The sensitivities are listed below.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	160.8	ACFH		**1.00**	
Base Compressibility	Z_B	Dimensionless	0.9979			**1.00**	
Base Temperature	T_B	°Fahrenheit	60	°Rankine		**1.00**	
		°Rankine	519.67				
Flowing Pressure	P_F	psia	25	psia		**1.00**	
Flowing Compressibility	Z_F	Dimensionless	0.9332			**1.00**	
Flowing Temperature	T_F	°Fahrenheit	55	°Rankine		**1.00**	
		°Rankine	514.67				
Base Pressure	P_B	psia	14.73	psia		**1.00**	
Installation Effect Factor		Dimensionless	1			**1.00**	
Meter Condition Factor		Dimensionless	1			**1.00**	
Energy Content		BTU/ft^3	1000	BTU/ft^3		**1.00**	
Carbon Content		lbm/ft^3	0.035	lbm/ft^3		**1.00**	

Volume Flow Rate	295	SCFH
Energy Flow Rate	294,669	BTU per Hour
Carbon Flow Rate	0.005	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.5.4 Obtain numerical values for the uncertainty of each component in Step A.5.1. For the flow rate value, the applicable calibration has to be applied. In this case, the gas composition is required by contract with the local distribution company (LDC), and the uncertainty in fluid properties is equal to the variance allowed. The installation effect factor has an uncertainty of 0 % as a displacement meter does not require any upstream/downstream run lengths, and the meter condition uncertainty is determined to be 1 % through annual inspection. The uncertainties can be determined as either a value or a percent, and the remaining value calculated.

Component	Symbol	Units	Nominal Value	Standard Uncertainty		Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	$(U_x \times S_x)^2$
Volumetric Flow Rate	Q_{ACT}	ACFH	160.8	**2.41**	ACFH	**1.5000**	1.00	
Base Compressibility	Z_B	Dimensionless	0.9979	**0.0010**		**0.1000**	1.00	
Base Temperature	T_B	°Fahrenheit	60	**0**	°Rankine	**0.0000**	1.00	
		°Rankine	519.67					
Flowing Pressure	P_F	psia	25	**0.19**	psia	**0.7622**	1.00	
Flowing Compressibility	Z_F	Dimensionless	0.9332	**0.001**		**0.1000**	1.00	
Flowing Temperature	T_F	°Fahrenheit	55	**1.135**	°Rankine	**0.2205**	1.00	
		°Rankine	514.67					
Base Pressure	P_B	psia	14.73	**0**	psia	**0.0000**	1.00	
Installation Effect Factor		Dimensionless	1	**0**		**0.0000**	1.00	
Meter Condition Factor		Dimensionless	1	**0.01**		**1.0000**	1.00	
Energy Content		BTU/ft^3	1000	**40**	BTU/ft^3	**4.0000**	1.00	
Carbon Content		lbm/ft^3	0.035	**0.00175**	lbm/ft^3	**5.0000**	1.00	

Volume Flow Rate	295	SCFH
Energy Flow Rate	294,669	BTU per Hour
Carbon Flow Rate	0.005	Tons per Hour

Total Volume Uncertainty	
Total Energy Uncertainty	
Total Carbon Uncertainty	

Step A.5.5 Combine the numerical values obtained to give numerical values for the combined and expanded standard uncertainties.

Component	Symbol	Units	Nominal Value	Standard Uncertainty	Standard Uncertainty (U_x)%	Sensitivity Coefficient (S_x)	(U_x x S_x)^2
Volumetric Flow Rate	Q_{ACT}	ACFH	160.8	2.41 ACFH	1.5000	1.00	**2.250**
Base Compressibility	Z_B	Dimensionless	0.9979	0.0010	0.1000	1.00	**0.010**
Base Temperature	T_B	°Fahrenheit	60	0 °Rankine	0.0000	1.00	**0.000**
		°Rankine	519.67				
Flowing Pressure	P_F	psia	25	0.19 psia	0.7622	1.00	**0.581**
Flowing Compressibility	Z_F	Dimensionless	0.9332	0.001	0.1000	1.00	**0.010**
Flowing Temperature	T_F	°Fahrenheit	55	1.135 °Rankine	0.2205	1.00	**0.049**
		°Rankine	514.67				
Base Pressure	P_B	psia	14.73	0 psia	0.0000	1.00	**0.000**
Installation Effect Factor		Dimensionless	1	0	0.0000	1.00	**0.000**
Meter Condition Factor		Dimensionless	1	0.01	1.0000	1.00	**1.000**
Energy Content		BTU/ft^3	1000	40 BTU/ft^3	4.0000	1.00	**16.000**
Carbon Content		lbm/ft^3	0.035	0.00175 lbm/ft^3	5.0000	1.00	**25.000**

Volume Flow Rate	295	SCFH
Energy Flow Rate	294,669	BTU per Hour
Carbon Flow Rate	0.005	Tons per Hour

Total Volume Uncertainty	**1.97**
Total Energy Uncertainty	**4.46**
Total Carbon Uncertainty	**5.38**

The total uncertainty is determined by summing the individual combined uncertainties (U_x x S_x)^2 and taking the square root of that sum. Because this example looks at three different uncertainties (volume, energy, and carbon), the calculation is done three different ways.

EXAMPLE 6 TOTAL FACILITY UNCERTAINTY

To determine the total facility uncertainty, all meters that are being reported in the facility have to be listed. Also list the flow rate of each meter, and the uncertainty associated with that flow rate. This example uses the numerical values of volume, energy, and carbon content, as well as the uncertainties determined in the previous five examples, and is based on Figure A.1.

Step A.6.1 To determine the uncertainty in standard volume flow rate, a table is created listing each meter. The values for the uncertainty of each meter are input into the table:

Meter	SCFH	Uncertainty %	Uncertainty (SCFH)	Uncertainty^2
FE-1	**6134**	**2.36**		
FE-2	**10,736**	**1.60**		
FE-3	**848**	**3.04**		
FE-4	**8794**	**2.57**		
FE-5	**295**	**1.97**		

Sum				
U_{cor}				
SQRT(SUM(Uncertainty^2))				
U_{ind}				
U_{tot}				

Step A.6.2

The uncertainty in percent is converted to an uncertainty in flow rate units by multiplying the flow rate by the uncertainty and dividing by 100. This value is then squared.

Meter	SCFH	Uncertainty %	Uncertainty (SCFH)	Uncertainty^2
FE-1	6134	2.36	**145**	**20,893**
FE-2	10,736	1.60	**172**	**29,536**
FE-3	848	3.04	**26**	**662**
FE-4	8794	2.57	**226**	**51,000**
FE-5	295	1.97	**6**	**34**

Sum				
U_{cor}				
SQRT(SUM(Uncertainty^2))				
U_{ind}				
U_{tot}				

Step A.6.3 The following sums are calculated.

Meter	SCFH	Uncertainty %	Uncertainty (SCFH)	Uncertainty^2
FE-1	6134	2.36	145	20,893
FE-2	10,736	1.60	172	29,536
FE-3	848	3.04	26	662
FE-4	8794	2.57	226	51,000
FE-5	295	1.97	6	34

Sum	**26,807**		**574**	**102,124**
U_{cor}				
SQRT(SUM(Uncertainty^2))				
U_{ind}				
U_{tot}				

Step A.6.4 The square root of the sum of the squares is then determined.

Meter	SCFH	Uncertainty %	Uncertainty (SCFH)	Uncertainty^2
FE-1	6134	2.36	145	20,893
FE-2	10,736	1.60	172	29,536
FE-3	848	3.04	26	662
FE-4	8794	2.57	226	51,000
FE-5	295	1.97	6	34

Sum	26,807		574	102,124
U_{cor}				
SQRT(SUM(Uncertainty^2))				**320**
U_{ind}				
U_{tot}				

Step A.6.5 The facility uncertainties are calculated using the below equations:

$$U_{cor} = \frac{\sum U_i}{\sum Flow_i} \times 100\%$$

$$U_{ind} = \frac{\sqrt{\sum U_i^2}}{\sum Flow_i} \times 100\%$$

$$U_{tot} = \frac{U_{cor} + U_{ind}}{2}$$

Meter	SCFH	Uncertainty %	Uncertainty (SCFH)	Uncertainty^2
FE-1	6134	2.36	145	20,893
FE-2	10,736	1.60	172	29,536
FE-3	848	3.04	26	662
FE-4	8794	2.57	226	51,000
FE-5	295	1.97	6	34

Sum	26,807		574	102,124
U_{cor}			**2.14**	
	SQRT(SUM(Uncertainty^2))			320
U_{ind}				**1.19**
U_{tot}				**1.67**

Step A.6.6 The same calculations can be performed on the energy flow rate and the carbon flow rate.

Energy Flow Rate				
Meter	**BTU/Hour**	**Uncertainty %**	**Uncertainty (BTU/Hour)**	**Uncertainty^2**
FE-1	6,287,065	2.64	166,259	27,642,155,083
FE-2	11,272,765	1.77	199,276	39,711,008,524
FE-3	890,320	3.13	27,837	774,875,795
FE-4	9,233,969	2.68	247,029	61,023,350,785
FE-5	294,669	4.46	13,145	172,787,553

Sum	27,978,788		653,546	129,324,177,739
U_{cor}			2.34	
	SQRT(SUM(Uncertainty^2))			359,617
U_{ind}				1.29
U_{tot}				**1.81**

Carbon Flow Rate				
Meter	**Tons/Hour**	**Uncertainty %**	**Uncertainty (Tons/Hour)**	**Uncertainty^2**
FE-1	0.113	2.64	0.003	0.00001
FE-2	0.188	1.77	0.003	0.00001
FE-3	0.015	3.13	0.000	0.00000
FE-4	0.154	2.68	0.004	0.00002
FE-5	0.005	5.38	0.000	0.00000
Sum	0.475		0.011	0.00004
U_{cor}			2.35	
SQRT(SUM(Uncertainty^2))				0.00611
U_{ind}				1.28
U_{tot}				1.82

Step A.6.7 The final reported uncertainties for this facility are then summarized:

	Flow Rate		
	Volumetric	**Energy**	**Carbon**
Facility Uncertainty	1.67	1.81	1.82

Bibliography

Numerous publications, symposium proceedings, trade journals, textbooks, and society papers were consulted for the preparation of this document.

The standards listed below contain provisions of installation requirements, determination of flow rate, and measurement uncertainties. This is a reduced list only. Those standards included are those directly applicable and primarily referenced in developing this document. At the time of publication of this document, the provisions in the latest edition of each of the standards were valid. All standards are subject to revision and parties utilizing this document are encouraged to investigate the possibility of applying the most recent edition of the standards for applicable requirements and best practice in the industry to achieve the desired measurement uncertainty.

American Petroleum Institute

Manual of Petroleum Measurement (MPMS)

Chapter 1 *Vocabulary*

Chapter 4.5 *Master-meter Provers*

Chapter 7 *Temperature Determination*

Chapter 13 *Statistical Aspects of Measuring and Sampling*

Chapter 14 *Natural Gas Fluids Measurement*

Chapter 14.3.1 *Concentric, Square-Edged Orifice Meters, Part 1—General Equations and Uncertainty Guidelines*

Chapter 14.12 *Vortex Shedding Flowmeter for Measurement of Hydrocarbon Fluids*

Chapter 16 *Measurement of Hydrocarbon Fluids by Weight or Mass*

Chapter 21.1 *Electronic Gas Measurement*

Chapter 22.2 *Testing Protocol-Differential Pressure Flow Measurement Devices*

Archival Data

API/GPA Orifice Meter Data Project Archival Data Tapes

American Gas Association

AGA Report No. 3 4 parts - *Measurement of Natural Gas by Orifice Meter*

AGA Report No. 4A *Natural Gas Contract, Measurement and Quality Clauses*

AGA Report No. 5 *Fuel Gas Energy Metering*

AGA Report No. 6 *Field Proving of Gas Meters Using Transfer Methods*

AGA Report No. 7 *Measurement of Natural Gas by Turbine Meters*

AGA Report No. 8 *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*

AGA Report No. 9 *Measurement of Gas by Multipath Ultrasonic Meters*

AGA Report No. 11 *Measurement of Natural Gas by Coriolis Meter*

AGA XQ0503 *Fluidic Oscillation Measurement for Natural Gas Applications*

American Society of Mechanical Engineers

Measurement of Fluid Flow in Close Conduit

ASME MFC-1M *Glossary of Terms Used in the Measurement of Fluid Flow in Pipes*

ASME MFC-2M *Uncertainty for Fluid Flow in Closed Conduits*

ASME MFC-3M *Measurement of Fluid Flow in Pipes Using Orifice, Nozzle and Venturi*

ASME MFC-4M *Measurement of Gas Flow by Turbine Meters*

ASME MFC-6M *Measurement of Fluid Flow in Pipes Using Vortex Flow Meters*

ASME MFC-7M *Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles*

ASME MFC-8M *Fluid Flow in Closed Conduits—Connections for Pressure Signal Transmissions between Primary and Secondary Devices*

ASME MFC-10M *Method for Establishing Installation Effects on Flow meters*

ASME MFC-11M *Measurement of Fluid Flow by Means of Coriolis Mass Flow meters*

ASME MFC-12M *Measurement of Fluid Flow in Closed Conduits Using Multiport Averaging Pitot Primary Elements*

ASME MFC-13M *Measurement of Fluid Flow in Closed Conduits—Tracer Methods*

ASME MFC-14M *Measurement of Fluid Flow Using Small Bore Precision Orifice Meters*

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ASME MFC-21-2 *Thermal Mass Meters—Dispersion Flow meters*

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ASME -PTC 19.2 *Pressure Measurement*

ASME -PTC 19.3 *Temperature Measurement*

ASME -PTC 19.5 *Flow Measurement*

Gas Processors Association

GPA 2166 *Obtaining Natural Gas Samples for Analysis by Gas Chromatography*

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GPA 2286 *Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography*

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