

Fuel Gas Measurement

API TECHNICAL REPORT 2571
FIRST EDITION, MARCH 2011



AMERICAN PETROLEUM INSTITUTE

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Measurement Coordination

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Contents

	Page
1 Scope	1
2 Terms and Definitions	1
3 Performance Characteristics and Measurement by Meter Type	3
3.1 General	3
3.2 Differential Pressure Type Flow Meters	4
3.3 Linear Flow Meters	10
3.4 Selection Criteria and Documentation of Fuel Gas Meters	14
4 Secondary and Tertiary Instrumentation	15
4.1 Introduction	15
4.2 Equipment Selection Considerations	15
4.3 Equipment Location and Installation	17
5 Uncertainty Calculations	18
5.1 Objective	18
5.2 Uncertainty Analysis Procedure	18
5.3 Combining the Uncertainty of Multiple Meters	20
5.4 Differential Producers	21
5.5 Linear Meters (Vortex, Ultrasonic, Turbine, PD)	25
5.6 Linear Meter (Coriolis)	28
6 Inspection, Verification, and Calibration	28
6.1 General	28
6.2 System Overview for Selection of Maintenance Activity, Frequency, and Tolerance	29
6.3 Relative Stream Significance	29
6.4 Identify Devices to be Inspected, Verified, or Calibrated	30
6.5 Influence of Meter Type on Frequency Selection	31
6.6 Calibration Results Influence on Frequency Selection	33
Annex A (informative) Uncertainty Examples	34
Bibliography	65
Figures	
1 Schematic of a Fuel Gas Measurement System	15
2 Example of Fuel Gas Measurement System	16
A.1 Example of Fuel Gas Measurement System (for Illustration Purposes Only)	35
Tables	
1 Installation Effect Sensitivity and Secondary Instrument Requirements	3
2 Significant Common DP Meter Influence Parameters	5
3 Additional Orifice Meter Influence Parameters	6
4 Additional Venturi and Nozzle Meter Influence Parameters	7
5 Additional Multiport Averaging Pitot, and Wedge Meter Influence Parameters	8
6 Variable Area Meter Influence Parameters	9
7 Additional Pitot, Pitot-Static Tube Meter Influence Parameters	9
8 Common Volumetric Linear Meter Influence Parameters	10
9 Additional Displacement Meter Influence Parameters	11
10 Additional Turbine Meter Influence Parameters	11
11 Additional Ultrasonic Meter Influence Parameters	12

Contents

	Page
12 Additional Vortex Meter Influence Parameters	12
13 Additional Thermal Meter Influence Parameters	13
14 Additional Coriolis Meter Influence Parameters	14
15 Static Pressure Tap Location	17
16 DP Meter Static Pressure Variance Effect.	23
17 DP Meter Temperature Variance Effect.	24
18 DP Meter Compressibility Effect Typical Natural Gas vs Typical Natural Gas + 20 % H ₂	25
19 Linear Meter Static Pressure Variance Effect.	26
20 Linear Meter Temperature Variance Effect.	26
21 Compressibility–Typical Natural Gas	27
22 Linear Meter Compressibility Effect Typical Natural Gas vs Typical Natural Gas + 20 % H ₂	27
23 Plant Determination of Relative Stream Significance	30
24 Inspection, Verification, and Calibration Summary.	31
25 Meter Station F101: Initial Calibration Program	32
26 Meter Station F101: Revised Calibration Program	33
A.1 Instrumentation on Meter Types	34

Introduction

This document provides a performance-based methodology for the measurement and reporting of fuel gas consumption. Specifically, considerations are provided for measurement device selection, installation, maintenance, calibration and documentation to achieve the targeted performance in terms of availability and uncertainty. If the performance of any installed measurement device is determined not to be in compliance with an acceptable level of uncertainty, the measurement device, its installation, or maintenance practices, etc. can be upgraded. Techniques are described to assess the uncertainty contribution of individual components of fuel gas measurement systems and the overall facility fuel gas measurement uncertainty. By following the guidance and calculation procedures of this document, cost effective fuel gas measurements of appropriate quality can be achieved. In most cases the rigorous requirements of industry standards intended for custody transfer quality measurements can be reduced and still achieve the desired measurement uncertainty. For this document, a fuel gas system in a facility could be comprised of multiple fuel gas meters or a single meter.

This document addresses the most common fuel gas measurement devices in use at the time of its development. This does not advocate the use of these devices or preclude the utilization of other types of devices, provided the targeted performance is achieved.

This Technical Report (TR) includes a brief description of the working principles of different types of fuel 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.

Fuel 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 fuel gas flows in the industry. The selection of the fuel 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.

Fuel Gas Measurement

1 Scope

This Technical Report (TR) 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 ability of a measurement instrument to indicate values closely approximating the true value of the quantity measured.

2.2

bias

Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

2.3

calibration

The process or procedure of adjusting an instrument so that its indication or registration is in satisfactorily close agreement with a reference standard.

2.4

carbon content

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

2.5

compensation

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

2.6

fuel gas

Typically a mixture of light hydrocarbon and other molecules (e.g. H₂, N₂) in a gaseous state that are consumed in fired heaters. Fuel gas is often a mixture of recovered gaseous molecules from plant operations and purchased natural gas.

2.7**flowing density**

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

2.8**flowing compressibility**

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

2.9**higher heating value**

The high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.

2.10**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.

2.11**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.

2.12**metering or measurement system**

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

2.13**meter condition factor**

An estimate of additional uncertainty based on a technical judgment of the physical condition of the meter in lieu of the ability to inspect.

2.14**performance**

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

2.15**range of uncertainty**

The range or interval within which the true value is expected to lie with a stated degree of confidence.

2.16**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.

2.17**uncertainty**

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 fuel 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.

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 fuel 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 with performance suitable for the range of differential pressures to be measured. The primary element should be designed so that it will produce a differential pressure of sufficient magnitude such that the overall measurement uncertainty is acceptable.

Some of the differential pressure devices used in the industry to measure fuel 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 shall 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.	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 shall be established as a function of flow rate and recorded.
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.	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 fuel 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.	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.	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 shall 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 primary element 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 fuel gas service is installed between two flanges, so the flow has to be 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 flow. Paddle plates with proper labeling provide the opportunity to confirm that the orifice bore dimension, plate type and direction of installation are correct.

At the time of writing of this document, the most commonly installed fuel gas meter in the industry is the orifice flow meter.

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

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 and edge sharpness	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 and edge sharpness and cleanliness 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 fuel 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 <i>MPMS</i> Ch. 14.3/AGA Report No. 3, no additional measurement uncertainty to that defined in API <i>MPMS</i> 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 $\frac{1}{3}$ 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 $\frac{1}{3}$ 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 $2\frac{1}{2} D$, no additional uncertainty above that defined by API <i>MPMS</i> 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 fuel gas meters.	
Cleanliness	Low to Medium	Visual inspection at plant shutdown 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 $1D$, 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, which lack Industry standards, 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 fuel gas meters.	
Cleanliness	Low to Medium	Visual inspection and documentation at plant shutdown.	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 (e.g. Rotameter^{® 1}) 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.

¹ This term is used as an example only, and does not constitute an endorsement of this product by API.

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 at plant shutdowns is sufficient for fuel 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 fuel 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 have to be 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 at shutdowns 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 at shutdowns 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 fuel 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 at shutdown and recorded.	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, <i>D</i>	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 fuel 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 fuel gas applications the uncertainty of the measured density can be significant. Therefore, for fuel 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 fuel 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 fuel gas supplier), a fixed value for standard density can be used.

3.4 Selection Criteria and Documentation of Fuel Gas Meters

At the time of development of this document, fuel gas meters installed in the petrochemical industries were typically the meters listed above in this section. 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.

The fuel gas meters described in this section represent a reasonably comprehensive list covering an estimated >95 % of petroleum manufacturing installations in the USA. Any gas meter with a technically defensible and documented measurement uncertainty within acceptable performance requirements can be installed to monitor or measure the fuel gas usage by the industry.

4 Secondary and Tertiary Instrumentation

4.1 Introduction

Measurement of fuel 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 fuel 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 (possible, but not normal in fuel gas service).
- 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.

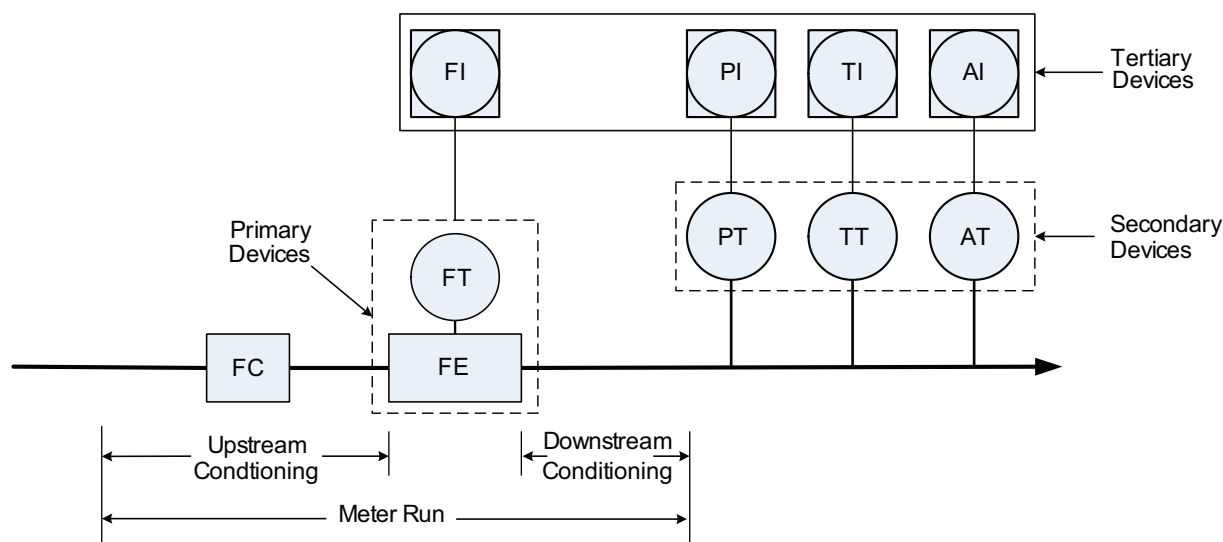


Figure 1—Schematic of a Fuel Gas Measurement System

Dependent upon process variability and targeted uncertainty, some application 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.

4.2 Equipment Selection Considerations

Pressure, temperature, density and gas composition measurement instruments purchased for fuel gas 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.