

Manual of Petroleum Measurement Standards Chapter 5.6

Measurement of Liquid Hydrocarbons by Coriolis Meters

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Measurement of Liquid Hydrocarbons by Coriolis Meters

1 Scope

This standard is intended to be a guide for the specification, installation, verification, and operation of Coriolis meters used to dynamically measure liquid hydrocarbons. API *MPMS* Ch. 5.6 also includes information that will assist in troubleshooting and improving the performance of the meters.

Use of a Coriolis meter as a stand-alone density meter is not addressed by this standard.

1.1 Field of Application

This standard describes methods to achieve custody transfer measurement of liquid hydrocarbon quantities (mass or volume) using a Coriolis meter. Coriolis meters can provide outputs for mass flow rate, volumetric flow rate, and density. The choice of the quantity output (mass or volume) depends on commercial, contractual, regulatory, and performance requirements.

This document provides guidance for the application, installation, proving, mass calculations, auditing, reporting, and security requirements for Coriolis meters.

Some of the guidance provided within also applies to allocation measurement. API *MPMS* Ch. 20^[19] allows for different performance requirements.

Guidance for the measurement of density is found in API *MPMS* Ch. 9^[6].

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API *MPMS* Ch. 21 (all sections), *Flow Measurement Using Electronic Metering Systems*

API *MPMS* Ch. 21.2, *Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters*

API *MPMS* Ch. 21.2-A1, *Addendum 1 to Flow Measurement Using Electronic Metering Systems, Inferred Mass*

3 Terms, Definitions, And Symbols

3.1 Terms and Definitions

For the purpose of this document, the following definitions apply. Terms of more general use may be found in the API *MPMS* Chapter 1, Online Terms and Definitions Database.

3.1.1 calibration (Coriolis)

The process of using a reference standard to determine a coefficient that adjusts the output of the Coriolis transmitter to bring it to a value that is within the specified accuracy tolerance of the meter over a specified flow range. This process is normally conducted by the manufacturer.

3.1.2**cavitation**

A phenomenon related to and following flashing if the pressure recovers and the vapor bubbles collapse (implode).

3.1.3**Mass (Coriolis)****M**

The indicated mass of a transaction period with a mass meter factor and the pressure compensation factor applied.

NOTE The pressure compensation factor can be 1.0000 in certain applications.

3.1.4**Coriolis meter**

A meter composed of a transmitter (Coriolis) and a sensor (Coriolis).

3.1.5**meter factor (Coriolis), mass or volume****MF, MFm, MFv**

A dimensionless number obtained by dividing the actual quantity of fluid passed through the meter (as determined by proving) by the quantity registered by the meter. For subsequent metering operations, the actual quantity is determined by multiplying the indicated quantity by the meter factor.

3.1.6**transmitter (Coriolis)**

The electronics associated with a Coriolis meter that interpret the phase shift signal from the sensor, converts it to a meaningful mass flow rate (represented in engineering units), and generates an output signal representing mass flow rate. Manufacturers can also use it to drive the flow tube(s), determine fluid density, and calculate and output a volumetric flow rate.

3.1.7**sensor (Coriolis)**

A mechanical assembly consisting of:

- a) Housing: the means of providing environmental protection. This may or may not provide secondary containment.
- b) Measurement sensor(s): sensors to monitor oscillations and to detect the effect of Coriolis forces. These are also referred to as pickups or pickoffs.
- c) Support structure: a means for supporting the flow tube(s).
- d) Flow tube: oscillating flow tube(s) or channel through which the fluid to be measured flows.
- e) Vibrating drive system: the means for inducing the oscillation of the flow tube(s).

3.1.8**indicated mass (Coriolis)****IM**

The registered indicated mass quantity accumulated during the transaction period.

3.1.9**manufacturer density calibration factor**

A numerical factor(s) that can be used to compensate for the density sensitivity of each Coriolis sensor. It is unique to the sensor and derived during sensor calibration. When programmed into the transmitter, the

density calibration factor(s) causes the meter density measurement performance to meet its stated specifications.

NOTE The manufacturer density calibration factor should not be confused with density meter factor (DMF).

3.1.10

manufacturer flow calibration factor

A numerical factor that can be used to compensate for the flow sensitivity of each Coriolis sensor. It is unique to the sensor and derived during sensor calibration. When programmed into the transmitter, the flow calibration factor(s) causes the meter flow rate measurement performance to meet its stated specifications.

NOTE The manufacturer flow calibration factor should not be confused with K-factor or meter factor (MF).

3.1.11

net mass

NM

The mass (M) of the fluid without sediment and water (S&W).

3.1.12

pressure drop (pressure loss)

The difference between upstream and downstream pressures due to the frictional and inertial losses associated with fluid motion in the entrance, exit, and internal passages of the flow meter or other specified systems and equipment.

3.1.13

sediment and water mass

SWM

The mass of sediment and water during a measurement period.

3.1.14

zeroing

A procedure that sets the stored zero value.

NOTE The zeroing operation should not be confused with resetting the totalizer.

3.1.15

zero offset, observed

The difference between the current observed zero value and the previous observed zero value.

3.1.16

zero stability

The variability of the observed zero value during the process of determining the value.

3.1.17

zero value, observed

The average mass or volume flow rate observed reading under zero (no)-flow conditions, without inhibited flow indications (i.e., low-flow cutoff disabled, bidirectional flow enabled).

NOTE This is a systematic uncertainty that can be present over the working range of the meter.

3.1.18

zero error

The observed zero value expressed as a percentage of normal flow rate.

3.1.19

zero value, stored

The value within the transmitter representing a no-flow condition.

3.1.20**zero verification**

The process of determining if the observed zero value is within the operator's zero error limit (a tolerance).

3.1.21**zero value, as-found**

The observed zero value before a meter is zeroed.

3.1.22**zero value, as-left**

The observed zero value after a meter has been zeroed.

3.2 Acronyms and Symbols

$\%S \& W_M$ percent of sediment and water by mass

$\%S \& W_V$ volume percent of sediment and water determined by volume test method

ρ fluid density

Δp pressure drop through the flow meter at the maximum operating flow rate (psi)

BPM_a sum of the liquid and vapor inferred mass in the prove

BPV base prover volume

BPV_a adjusted tank prover volume, defined as the difference between the upper and lower scale readings during a proving run

$CFPS_{fwa}$ flow-weighted average flow pressure effect compensation factor

$CFPS_i$ flow pressure effect compensation factor over the i th sampling interval

$CFPS_{M_x}$ mass flow pressure effect compensation factor

$CFPS_{mm}$ master meter prover pressure effect compensation factor over a prove run

$CFPS_x$ flow pressure effect compensation factor

CPL correction for pressure effect

CPS_p correction factor for the effect of pressure on steel

CSW_M correction of sediment and water by mass

CTL correction for thermal expansion

$CTPL$ correction for temperature and pressure

CTS_p	correction factor for the effect of temperature on steel
DMF	density meter factor
EMI	electromagnetic Interference
Err_0	zero error (%)
f	flow tube frequency, resonant frequency of the sensor
FR	actual flow rate of the line meter
i	i th sampling interval
IM	indicated mass
IM_c	closing indicated mass
IM_i	indicated mass over the i th sampling interval
IM_m	indicated Coriolis meter mass
IM_{mm_c}	master meter prover closing indicated mass
IM_{mm_o}	master meter prover opening indicated mass
IM_o	opening indicated mass
IMF	intermediate meter factor
IMF_j	j th intermediate meter factor
KF_m	K-factor in units of pulses per unit mass
K_{units}	unit conversion
M	mass of fluid measured during the measurement period
MF_M	mass meter factor
$MF_{M_{fwa}}$	flow-weighted mass meter factor
MF_{M_i}	mass meter factor over the i th sampling interval
MF_v	meter factor when the Coriolis meter is configured to indicate volume

MMF_M	master meter prover mass meter factor
N	number of whole pulses: — between detector switches for unidirectional; — round trip for a bidirectional.
Ni	number of interpolated pulses: — between detector switches for unidirectional; — round trip for a bidirectional.
N_j	number of whole pulses for the j th pass or round trip: — between detector switches for unidirectional; — round trip for a bidirectional.
Ni_j	number of interpolated pulses for the j th pass or round trip: — between detector switches for unidirectional; — round trip for a bidirectional.
NM	net mass during the measurement period
N_{M_c}	closing mass pulse count
N_{M_o}	opening mass pulse count
ΔN_{M_i}	delta mass pulse count i th sampling interval
NKF_{M_m}	mass meter nominal K-factor (pulse counts per unit mass)
$NKF_{M_{mm}}$	master meter prover nominal K-factor (pulse counts per unit mass)
p_e	equilibrium vapor pressure of fluid at the operating temperature (psia)
P_b	minimum back pressure (psig)
P_{Cal}	calibration or average meter proving static gauge pressure (psig)
$P_{Cal_{fwa}}$	flow-weighted average calibration or meter proving average static pressure (psig)
P_{Cal_M}	mass calibration pressure when PECl equals 1 (Coriolis transmitter) or average meter proving static gauge pressure when PECl equals 2 (tertiary device) or 3 (off-site)



PECI pressure effect compensation indicator

PECI status:

- 1 (CT) = $CFPS_m$ is active/applied in the Coriolis transmitter.
- 2 (TD) = $CFPS_m$ is active/applied in tertiary device.
- 3 (OS) = $CFPS_m$ is active/applied within off-site measurement system.
- 4 (N/A) = $CFPS_m$ is defaulted to and applied as 1.0000.

P_m average pressure of the meter during prove

P_{max_op} maximum operating pressure

P_{min_op} minimum operating pressure

P_{wa} flow-weighted average pressure of transaction period

PE_D density pressure effect in density units per unit gauge pressure

PE_M mass flow pressure effect in percent (%) of mass flow rate per unit of gauge pressure (psig)

$P_{f_{wa}}$ flow-weighted average flowing pressure (psig)

Pf_i flowing static gauge pressure or flow-weighted average pressure at the meter over the i th sampling interval

Pf_x flowing gauge pressure when PECI equals 1 (Coriolis transmitter) or 2 (tertiary device), flow-weighted average gauge pressure when PECI equals 3 (off-site)

PIM_L inferred mass of the liquid in the prover

PIM_{VS} inferred mass of the vapor in the prover

q_0 observed Coriolis meter flow rate with no flow

q_i quantity per pulse = $\left(\frac{1}{NKF_{M_m}} \right)$ over the i th sampling interval

q_f typical flow rate during normal operation

RFI radio frequency interference

RHO_{tp_p}	prover liquid density at measured temperature and pressure
$RHO_{tp_{vap}}$	prover vapor space density at measured temperature and pressure
SWM	mass of sediment and water during the measurement period
t	time period
v	fluid velocity in a tube of a Coriolis meter
VSV_a	adjusted vapor space tank prover volume
ZV	recorded observed zero value at the meter factor determination (“as-found” recorded after the last proving)
ZV_{NEW}	current observed zero value

4 General

A Coriolis meter consists of a sensor and a transmitter. A sensor has one or more flow tubes through which the fluid flows. The flow tube or tubes are made to vibrate at their natural or harmonic frequencies by means of an electromagnetic driving mechanism. The fluid flowing through the tube(s) generates a Coriolis force that is directly proportional to the mass flow rate of the fluid. The magnitude of the Coriolis force is measured and used to determine a mass flow rate. The transmitter powers the sensor, processes the output from the sensor in response to mass flow, and generates signals for the tertiary device(s).

The frequency of the oscillating flow tube(s) can be measured and used to determine the density of the fluid. Density determination is independent of the mass flow rate determination.

A meter typically can determine a volumetric flow rate through calculation by dividing the mass flow rate with either the measured flowing density or a user programmed (fixed) base density.

5 Application

5.1 Sensor Considerations

Sensors should be selected to measure flow rate over the full operating flow range. Consider the effect of the following issues on the sensor to ensure it meets all requirements.

5.1.1 Flow Tube Design

Flow tube(s) restrict the cross-sectional flow area, resulting in higher fluid velocity and pressure drop than experienced in the associated piping. The pressure drop (pressure loss) depends on the sensor design along with the viscosity and density of the fluid at the desired flow rate. Select the sensor to provide required accuracy within the allowable system pressure drop constraints while avoiding erosion. Consult the manufacturer for sensor limitations and methods to calculate velocity and pressure drop.

Different flow tube geometry can be more or less likely to promote the accumulation of sediments or coatings within the tube(s). Besides restricting flow, the accumulation of material within the flow tube(s) can affect the observed zero, as well as the accuracy of the density and volume measurements.

Higher fluid velocities, when coupled with abrasive particles in the stream, can cause flow tube erosion and measurement error. The user should consult the manufacturer to ensure that the flow tube material is compatible with operating conditions and fluid properties, including corrosiveness or abrasiveness characteristics.

5.1.2 Accuracy

Sensors have different accuracy specifications and sensitivities with regard to changes in ambient and operating conditions. Consult the manufacturer for the performance envelope describing error limits throughout these conditions and consider the limits with respect to the system requirements.

To address the effects of process pressure and temperature on the accuracy of the measurement of mass, density, and the corresponding determination of volume:

- Temperature effect compensation for the flow tube(s) stiffness shall be integral to the meter and performed real time in the meter.

NOTE This temperature measurement is typically flow tube skin temperature and might not be sufficient for CTL calculations. See API *MPMS* Ch. 7^[4].

- Pressure effect compensation for flow tube stiffness is recommended for all applications, but is required when the effect is biasing quantity determination by more than 0.05 %. Generalized equations for evaluation of the effect are provided in Annex D.

NOTE This pressure effect compensation is not the correction for compressibility of liquid (CPL).

- Pressure effect on flow tube stiffness can also affect density determination and its use within volume calculations (e.g., CTL, CPL, CTPL). Refer to API *MPMS* Ch. 9^[6].

Real-time pressure compensation can be accomplished by:

- activating the pressure effect compensation mode in the transmitter (if available) and using a live pressure input (analog or digital communication) to continuously adjust for pressure change. Pressure values should be shared between the transmitter and tertiary device for audit purposes; or
- activating the pressure effect compensation mode in the transmitter and using a live pressure measurement integral to the sensor. Pressure values should be shared between the transmitter and tertiary device for audit purposes. This integral pressure value may not be suitable for other calculations requiring a pressure value; or
- calculating the pressure compensation in a tertiary device. See Annex D for details.

In lieu of real-time pressure compensation:

- prove the meter close enough to the average operating pressure to satisfy Equation (D.2) in Annex D; or
- correct the quantity external to the transmitter in an off-site measurement system (see Annex D and Annex E).

Any change in pressure compensation values or implementation of pressure compensation requires proving (see 7.2.7).

In both mass and volume measurement applications, this standard requires documentation of flow tube pressure effect compensation in accordance with PECO status in Annex D.

5.1.3 Flow Tube Pressure Rating

Flow tube(s) and end connections shall meet the pressure code requirement for the service. The external housing around the flow tube(s) is designed to protect the sensor electronics and typically not designed to meet the same pressure ratings as the flow tube(s).

5.1.4 Documentation

Meter manufacturers provide calibration certificates. Other documentation for the meter, such as electrical area classification certification, pressure ratings on the flow tube(s), pressure containment ability of the outer flow tube case, hydrostatic test report, and material test reports can be provided.

5.1.5 Bidirectional Flow

If bidirectional flow is required, ensure that the transmitter and the flow computer are both compatible with bidirectional flow. If the meter is used to measure bidirectional flow, a meter factor shall be developed for each flow direction.

5.1.6 Pressure Containment and Relief

Optional sensor features can be provided by the manufacturer to reduce the effect of flow tube failure. Items to consider:

- sensor housings constructed as a pressure-containing vessel, designed to contain fluid under pressure to a specified pressure limit;
- rupture disks, pressure relief valves and drains, or vents on the sensor housing, designed to relieve pressure or allow fluid release from inside the sensor housing.

5.1.7 Crosstalk

With multiple sensors in close proximity, either in parallel or series, the vibrations generated by each sensor could interfere (crosstalk) with each other, thereby causing measurement error. Vibration isolation or dampening can be achieved by altering piping or supports. Consult the manufacturer to reduce the possibility of crosstalk.

5.1.8 Cavitation and Flashing

Avoid cavitation or flashing in the meter and the prover. Cavitation will cause a measurement error and can damage the sensor. Equation (B.1) provides a guideline to maintain sufficient pressure downstream of the meter and the prover.

5.2 Transmitter Considerations

5.2.1 Environmental

The operator should evaluate the expected temperature, humidity, and corrosion extremes at the installation and select a transmitter that provides the appropriate protection. Alternatively, a transmitter could be installed in an environmentally controlled enclosure.

5.2.2 Electrical

Select the transmitter and sensor to meet the required electrical area classification. Consider the power requirements for the sensor and transmitter. Design the electrical signal system to provide appropriate fidelity and security. Refer to API MPMS Ch. 5.5^[2].

The sensor, transmitter, and their interconnecting cables are all susceptible to electromagnetic interference (EMI). Since the electrical signals of the meter are at relatively low power levels, care should be taken to avoid interference generated from nearby electrical equipment and wiring.

5.2.3 Operability Considerations

It is recommended that the transmitter is mounted such that it can be easily accessed to attach communications equipment, view displays, and use associated keypads. The meter pulse output signal is from the transmitter, not from the sensor. For applications using portable provers, it is recommended that the transmitter is mounted as close as practical to the proving computer location. This facilitates connecting the pulse signal to the prover.

Consideration should be given for access to and operation of the meter. Items to consider are:

- the programming or configuring method (keypad, hand-held tool, or laptop);
- local display, if required;
- ease of electrical connections.

5.2.4 Frequency Output to Tertiary Devices

Sensors do not, by the nature of their operation, have a pulse output representing either mass or volume. The transmitter performs internal calculations to determine a flow rate and generates a user-defined frequency to represent flow rate. The exact relationship between frequency and flow rate is typically configured by the user.

Alternately, some versions of these meters allow the user to enter a K-factor. When the K-factor is entered, the frequency value and flow rate value are typically calculated in the transmitter.

To estimate a K-factor from frequency and a flow rate (pulse scaling factor), use Equation (1).

$$\text{User-defined frequency} / \text{User-defined flow rate} = \text{K-factor} \quad (1)$$

Example:

$$1000 \text{ Hz} / 10 \text{ barrels/second} = 100 \text{ pulses/barrel}$$

$$1000 \text{ Hz} / 1000 \text{ pounds/second} = 1 \text{ pulse/pound}$$

$$1000 \text{ Hz} / 16.667 \text{ pounds/second} = 60 \text{ pulses/pound (approximately)}$$

Care should be taken when selecting the values to ensure that the following two conditions are satisfied:

- When fluid is flowing through the meter at maximum operational flow rate: The frequency output by the transmitter should neither exceed 90 % of its rated maximum nor 90 % of the maximum rated input frequency of the tertiary device(s) receiving the signal.
- When fluid is flowing through the meter at minimum operational flow rate: The frequency output by the transmitter should provide appropriate flow rate and quantity indications, especially for proving.

5.2.5 Low-flow Cutoff

Low-flow or no-flow cutoffs can be programmed in the transmitter or the tertiary device. These values inhibit flow totalization for very low-flow or true no-flow conditions that can occur.

5.3 System Design Considerations

Coriolis meter-based measurement system design considerations for custody transfer metering can be found in Annex B and API *MPMS* Ch. 6^[3].

6 Installation and Operation

6.1 Mounting

Follow the manufacturer recommendations for the proper mounting of the sensor. Consideration should be given to the support of the sensor, the alignment of the inlet and outlet flanges with the sensor, and the orientation of the sensor.

Piping should be supported or anchored to avoid transferring stresses from the piping to the sensor. Meter performance, specifically observed zero offset, can be adversely affected by axial bending and torsional stresses from pressure, weight, and thermal effects. These stresses and associated loads can be minimized by using properly aligned pipe and well-designed pipe supports. During the system construction phase, a pipe spool piece equal in length to the meter should be used in place of the meter to correctly align pipework.

Sensor orientation depends on the application and the geometry of the flow tube(s) and should be recommended by the manufacturer. For example, solids settlement, plugging, coating, or trapped gas can affect meter performance.

A provision for adequate draining, vapor elimination, and cleaning should be considered based upon the fluid characteristics and sensor design. Sensors should be installed to avoid trapping vapors, particulates, or liquids heavier than the process liquid.

6.2 Installation Conditions

There are several considerations for installing a Coriolis meter:

- Vibration: Meters are designed to withstand vibration in pipeline installations, but vibration near the resonant frequency of the sensor can affect the accuracy of the meter. The sensor should be installed as far as possible from vibration sources, such as pumps, compressors, and motors. The manufacturer can advise on vibration mitigation methods.
- Multiple sensor vibration interference (crosstalk): Sensors of the same size and model operate at similar frequencies and can transmit vibrational energy to adjacent meters. This can cause measurement errors (see 5.1.7).
- Pulsating flow: Hydraulic pulsation, especially near the operating frequency of the sensor (or one of its harmonics), can affect the measurement of the meter. If this condition exists, pulsation dampeners can be helpful.
- Mechanical stress: The sensor is susceptible to axial, radial, and torsional stresses caused by the piping installation (see 6.1).
- Non-uniform velocity profile or swirl: Flow conditioning is typically not required.
- Electromagnetic and radio frequency interference: Strong magnetic fields could affect the electromagnetic signals from the sensor. The meter sensor and electronics should not be installed near sources generating radio frequency, or electromagnetic interference sources, such as variable frequency motors, transformers, radio transmitters, large switchgear, or high voltage cables, without taking proper wiring precautions. Cables that connect the sensor and transmitter should not be installed near high voltage power cables or sources of EMI and RFI noise.

- Voltage regulation: An unstable power source can affect both the sensor and transmitter. Install power line conditioning if the power to the electronics does not meet manufacturer's specifications.

6.3 Meter Commissioning

6.3.1 Fill

To avoid damage to the sensor, a pipe spool should be installed in place of the meter each time new piping or fluids are introduced into the piping system that can contain materials from construction or maintenance activities.

Avoid cavitation, flashing, and fluid hammer when filling to prevent damage to the sensor. Avoid shock loading caused by rapid opening or closing of valves.

6.3.2 Initial Observed Zero Verification

As part of the commissioning and prior to performing the initial observed zero verification, flow should be established through the sensor until normal operating conditions are achieved. While maintaining normal operating conditions, verify and record the observed zero value. To verify the observed zero value, there shall be no flow through the sensor. See Annex A for a zero value verification and evaluation procedure.

The observed zero value in real time will not normally be a constant value. Small variations are expected, and a properly zeroed meter will fluctuate between positive and negative flow rate values within the specified zero stability of the meter.

An improperly zeroed meter or a shift in observed zero value can result in measurement bias. A zero shift is usually caused by variations in temperature, pressure, or density, or changes in the mounting conditions as a result of poor installation practices. The bias is a constant offset in flow rate. Thus, this constant offset will result in a percent error that increases as the flow rate decreases.

6.4 Conditions Affecting Meter Performance

Performance can be affected by conditions that change the flexibility of the oscillating flow tube(s), as well as fluid properties, operating conditions, and installation conditions. If there are changes in those properties or operating conditions, or if there is an alteration to the sensor installation, a change in meter factor can result.

- Flow rate: Fluid velocity can affect the density measurement. When the volumetric flow rate is determined from the meter's measured density, higher velocities can produce measurement errors, with the error increasing as the velocity increases. Manufacturers can compensate for this effect in the transmitter.

As the flow rate approaches no flow, meter factor variation increases due to the zero offset (a measurement bias primarily affecting the lower range of the meter) and zero stability. See Figure 1 and Figure 2.

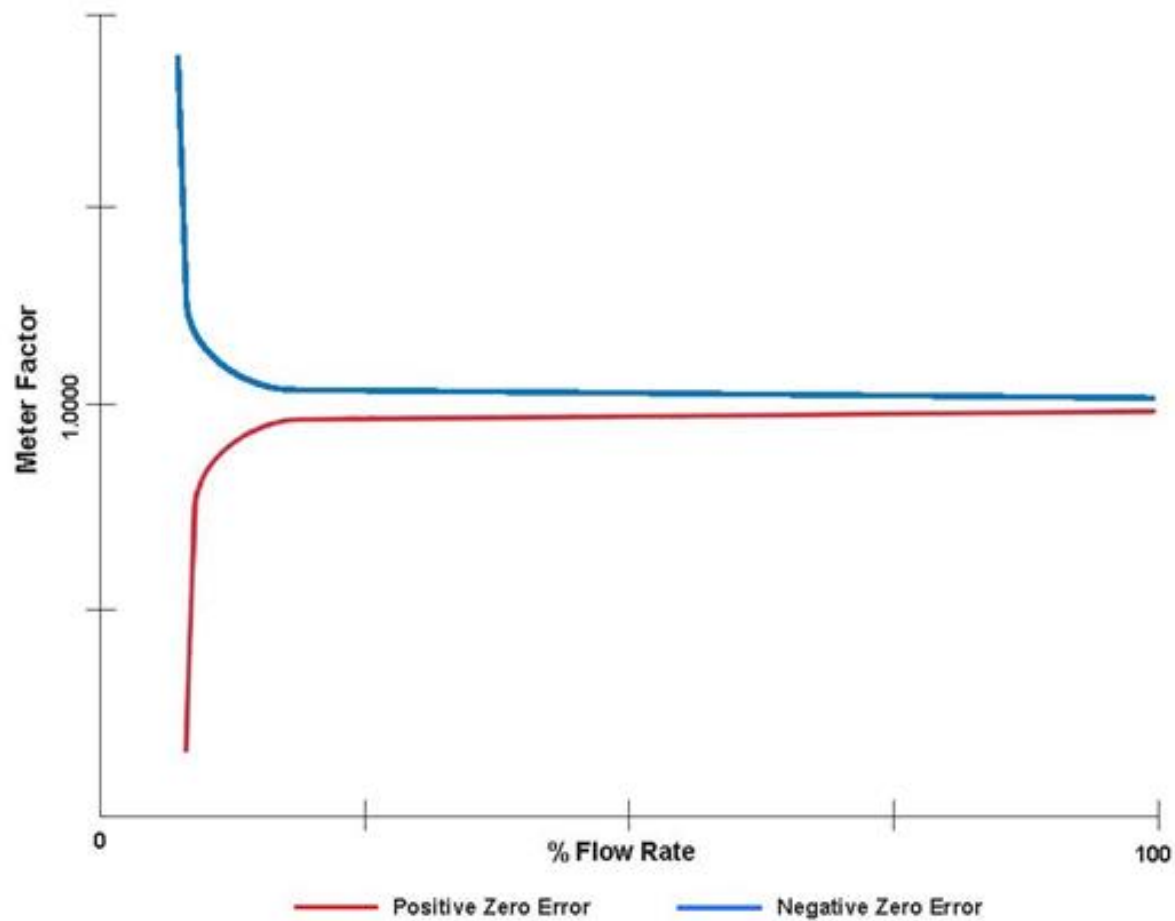


Figure 1—Illustrative Impact of Zero Error on Meter Factor

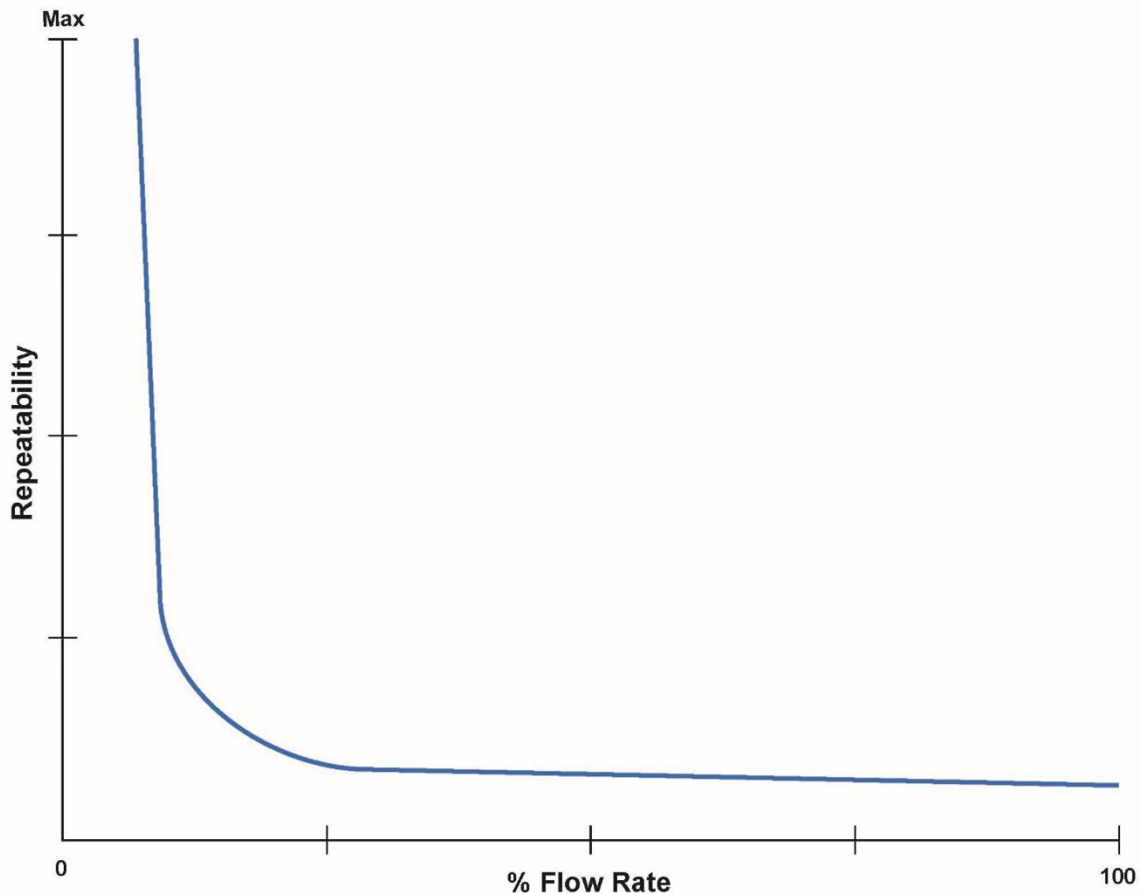


Figure 2—Illustrative Impact of Zero Stability on Repeatability versus Flow Rate

- Fluid temperature: Changes in fluid temperature affect the elasticity of the oscillating flow tube(s). The effect of temperature is systematic and is characterized and compensated for in the transmitter to minimize its influence on the performance of the meter. The magnitude of this effect depends on meter size, flow tube material, geometry, and amount of temperature change.

Fluid temperature changes within the sensor and connecting piping can create piping stresses that can change the observed zero value.

- Fluid pressure: Changes in pressure affect the vibrational characteristics of the flow tube(s). The effect of pressure is systematic, affecting both mass flow and density measurements. The effect can be characterized, and compensation implemented, to minimize its influence on the performance of the meter. The magnitude of this effect depends on meter size, design, and magnitude of the pressure variations. Pressure sensitivity tends to increase with sensor size. For installations not using live pressure compensation, any pressure effect bias will be minimized by operating within a narrow range of the proving pressure. Consult the manufacturer for the effects of pressure on their sensor and reference 5.1.2.
- Two-phase liquids: Gas, vapor, or air in a liquid stream is detrimental to accurate measurement. Two-phase liquids are unacceptable for custody transfer measurement applications.
- Flashing or cavitation within the sensor: Flow tube geometries and sensor designs can create a pressure area within the sensor that is lower than the outlet pressure. Sufficient backpressure shall be maintained on the sensor and prover to prevent flashing or cavitation in the sensor or prover (see Annex B).