Manual of Petroleum Measurement Standards Chapter 21—Flow Measurement Using Electronic Metering Systems

ADDENDUM TO SECTION 2—FLOW MEASUREMENT USING ELECTRONIC METERING SYSTEMS, INFERRED MASS

FIRST EDITION, AUGUST 2000

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Addendum to Section 2—Flow Measurement Using Electronic Metering Systems, Inferred Mass

Measurement Coordination

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Chapter 21—Flow Measurement Using Electronic Metering Systems

ADDENDUM TO SECTION 2, FLOW MEASUREMENT USING ELECTRONIC METERING SYSTEMS, INFERRED MASS

1 Scope

This Addendum specifically covers inferred mass measurement systems utilizing flow computers as the tertiary flow calculation device and either turbine or displacement type meters, working with on-line density meters, as the primary measurement devices. The Scope does not include systems using calculated flowing densities, i.e., Equations of State. The hardware is essentially identical to that referenced in *API MPMS* Chapter 21.2 and the methods and procedures are as described in *API MPMS* Chapters 14.4, 14.6, 14.7 and 14.8. Audit, record keeping, collection and calculation interval, security and most other requirements for systems covered in *API MPMS* Chapter 21.2 will apply to this Addendum. As in Chapter 21.2, the hydrocarbon liquid streams covered in the scope must be single phase liquids at measurement conditions.

1.1 APPLICATION

The procedures and techniques discussed in this document are recommended for use with new measurement applications. Liquid measurement using existing equipment and techniques not in compliance with this standard may have a higher uncertainty than liquid measurement based on the recommendations contained in this document.

1.2 ELECTRONIC LIQUID MEASUREMENT (ELM)

The term "electronic liquid measurement," or ELM, will be freely used throughout this document to denote liquid measurement using electronic metering systems. (Also see 3.20 in Chapter 21.2.)

2 Referenced Publications

If the wording of this document conflicts with a referenced standard, the referenced standard will govern.

API

Manual of Petroleum Measurement Standards

Chapter 1	"Vocabulary"
Chapter 4	Section 2, "Conventional Pipe Provers"
Chapter 4	Section 3, "Small Volume Provers"
Chapter 4	Section 6, "Pulse Interpolation"
Chapter 5	Section 2, "Measurement of Liquid Hydrocarbons by Displacement Meters"
Chapter 5	Section 3, "Measurement of Liquid Hydrocarbons by Turbine Meters"
Chapter 5	Section 4, "Accessory Equipment for Liquid Meters"
Chapter 5	Section 5, "Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"
Chapter 7	Section 2, "Dynamic Temperature Determination"
Chapter 9	"Density Determination"
Chapter 11	"Physical Properties Data"
Chapter 12	Section 2, "Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volume Correction Factors"
Chapter 13	"Statistical Aspects of Measuring and Sampling"
Chapter 14	Section 4, "Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes"
Chapter 14	Section 6, "Continuous Density Measurement"
Chapter 14	Section 7, "Mass Measurement of Natural Gas "Liquids"
Chapter 14	Section 8, "Liquefied Petroleum Gas Measurement"
Chapter 21	Section 1, "Electronic Gas Measurement"
Chapter 21	Section 2, "Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters"
RP 500	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2*

ASTM[1]

D5002	*Test Methods for Density and Relative Density of Crude Oil by Digital Density Analyzer*

3 Definitions and Symbols

3.1 INTRODUCTION

The purpose of these definitions is to clarify the terminology used in the discussion of this standard only. The definitions are not intended to be an all-inclusive directory of terms used within the measurement industry, nor are they intended to conflict with any standards currently in use.

[1]American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

3.2 WORDS AND TERMS—IN ADDITION TO THOSE IN CHAPTER 21.2

3.2.1 base conditions: Defined pressure and temperature conditions used in the custody transfer measurement of fluid volume and other calculations. Base conditions may be defined by regulation or contract. In some cases, base conditions are equal to standard conditions, which within the U.S. are 14.696 psia and 60 degrees Fahrenheit.

3.2.2 base density: The density of the fluid at base conditions. Base density is derived by correcting flowing density for the effect of temperature and compressibility, expressed by the symbol RHO_b.

3.2.3 flowing density: The density of the fluid at actual flowing temperature and pressure. In inferred mass application, flowing density is the indicated or observed density from an online density device, expressed by the symbol RHO_{obs}.

3.2.4 inferred mass measurement: Electronic measurement system using a turbine or displacement type meter and an online density meter to determine the flowing mass of a hydrocarbon fluid stream in accordance with the requirements of *API MPMS* Chapters 14.4, 14.6, 14.7 and 14.8.

4 Field of Application

Inferred mass measurement was excluded from the scope of *API Manual of Petroleum Measurement Standards,* Chapter 21.2. This addendum to the basic API MPMS Chapter 21.2 standard will specifically address inferred mass measurement using turbine and displacement type meters, as described and allowed in *API MPMS* Chapters 14.4, 14.6, 14.7 and 14.8. API 14.4 was derived from GPA 8173 and API 14.7 was derived from GPA 8182.

Direct mass measurement using gravimetric methods or Coriolis mass meters, inferred mass measurement using orifice meters, and other forms of mass measurement are not covered in this addendum.

Only exceptions to Chapter 21.2 are detailed in this addendum. If a section of Chapter 21.2 is not referenced in the following section, that means it is to be used in the Addendum without modification.

5 Description of an Electronic Liquid Measurement System

5.1 PRIMARY DEVICES

As inferred mass is the mathematical product of flow and density, errors in either device, flow meter or density meter, will produce a proportional error in the resultant mass. The devices are therefore considered primary devices. In determining ELM system uncertainty, this addendum does not address the uncertainty of the primary devices themselves. See Figure 1 for an example of a typical ELM inferred mass system and Figure 2 for an ELM System Uncertainty.

5.2 SECONDARY DEVICES

Chapter 21.2, paragraph 5.1.2 listed density as a secondary measurement because it was used as an input to CTL and CPL calculations. In inferred mass, density measurement becomes a primary measurement.

6 System Uncertainty

Chapter 21.2, Section 6 shall govern with the exception that "inferred mass" is to replace "gross standard volume" in paragraph 6.1.1.

7 Guidelines for Design, Selection and use of ELM System Components

7.1 PRIMARY DEVICES—SELECTION AND INSTALLATION

The following applies to inferred mass in addition to those found in Chapter 21.2, Section 7.1.

7.1.1 The density meter in an ELM system produces an electrical signal representing the flowing density of the fluid passing through it. Methods for producing this electrical signal depend on the density meter type. The signals may be analog or digital pulse.

7.2 SECONDARY DEVICES—SELECTION AND INSTALLATION

7.2.1 Chapter 21.2, paragraph 7.3.1 shall govern with the exception that "inferred mass" is to replace "volume."

7.3 ELECTRONIC LIQUID MEASUREMENT ALGORITHMS FOR INFERRED MASS

This section defines algorithms for inferred mass liquid measurement and replaces Chapter 21.2, Sections 9.1 through 9.2.12.2. Averaging techniques are contained in Chapter 21.2, Section 9.2.13.

When applying these methods to turbine and displacement measurement, the appropriate algorithms, equations and rounding methods are found in, or referenced in, the latest revision of *API MPMS* Chapter 12.2, including Chapter 12.2, Part 1, Appendix B. All supporting algorithms and equations referenced shall be applied consistent with the latest revision of the appropriate standard.

In inferred mass liquid metering applications, a total mass quantity is determined by the summation of discrete mass quantities measured for a defined flow interval. In equation form, the calculation of total mass quantity is expressed as the following:

$$Qmtot = \sum_{p=t_o}^{t} Q_p \times D_p \quad (1)$$

where

Σ = summation operation for p time intervals,

$Qmtot$ = mass quantity accrued between time t_o and time t,

Q_p = Volume measured at flowing conditions[2] for each sample period p,

D_p = Density measured at flowing conditions[2] for each sample period p,

t_o = time at beginning of operation,

t = time at end of operation.

The process variables that influence a mass flow rate normally vary during a metered transfer. Therefore, obtaining the total quantity requires the summation of flow over the transfer period with allowance made for the continuously changing conditions.

In inferred mass liquid metering applications, two primary devices are used[3]; a flowmeter primary device providing measurement in actual volumetric units at flowing conditions[2], and a density meter device providing measurement of liquid density at flowing conditions[2].

The volumetric units for an interval of time are provided as counts or pulses that are linearly proportional to a unit volume such that:

$$Q_p = \frac{counts}{KF} \quad (2)$$

where

$counts$ = accumulated counts from primary device for time period p seconds,

KF = K-factor in counts per unit volume.

The inferred mass units for this same interval of time are provided by multiplying the result of Equation (2) by the flowing density value obtained during the same time period.

$$Qm_p = Q_p \times D_p \quad (3)$$

Instantaneous mass flow per unit time, for example; flow rate per hour or flow rate per day can be calculated as follows:

$$Qm_p = \frac{Qm_p}{p} \times k \quad (4)$$

where

Qm_p = instantaneous mass flow rate based on time period p,

p = sample period (seconds),

k = conversion factor.

for example

k = 60 for minute based flow rates,

k = 3,600 for hourly based flow rates,

k = 86,400 for 24-hour based flow rates.

Note: The discrimination of mass flow rate Qm_p in Equation (4) is proportional to the number of flowmeter counts accumulated during the sample period.

7.3.1 Calculation Intervals

Frequent samples of the pulse accumulator and density meter[4] must be taken to allow an accurate incremental volume to be calculated using Equation (2), and an accurate inferred mass to be calculated using Equation (1). This sample period may be a fixed or variable time interval not to exceed 5 seconds. In all cases, every pulse from the primary device shall be counted.

7.3.2 Applying Performance Correction Factors

The primary devices, flowmeter and density meter, require that correction factors be applied to compensate for reproducible variations in performance caused by the environment and the operating conditions of the devices. These factors are:

a. ***Meter Factor (MF)***: Determined by flowmeter proving performed in accordance with *API MPMS* Chapter 12.2.

b. ***Density Meter Factor (DMF)***: Determined by density meter proving performed in accordance with *API MPMS* Chapter 14.6.

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[2] Inferred mass measurement requires flowing density and pressure conditions at the flowmeter and density meter device which are in accordance with *API MPMS* Chapter 14.6.7.2.2.

[3] As inferred mass is the product of flow and density, errors in either device, flowmeter or densitomer, will produce a proportional error in the resultant mass. The devices are therefore considered primary devices.

[4] For the purposes of this document which deals with "real time" inferred mass measurement, it is necessary to sample and calculate the volume and density on the same sample period.

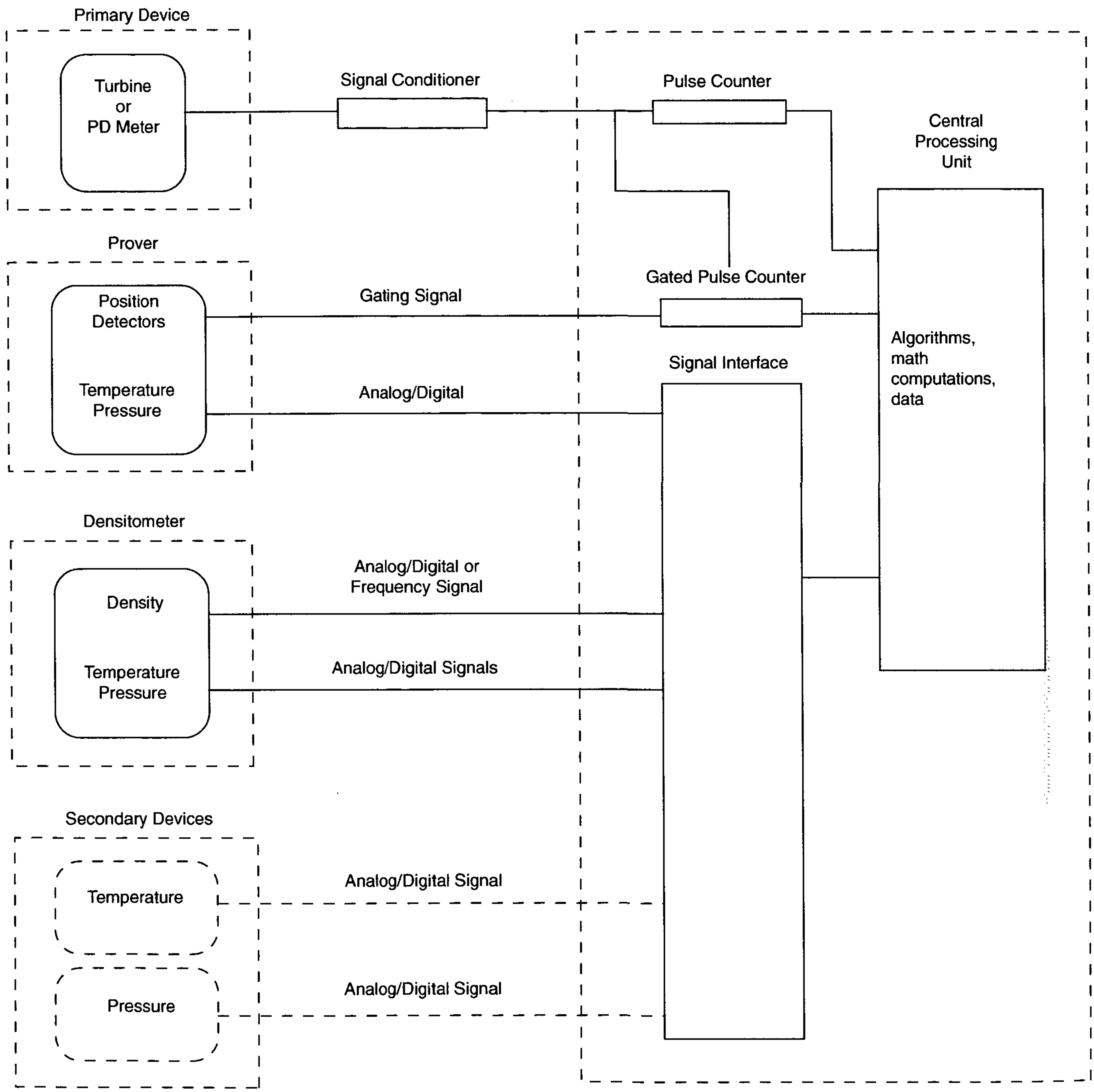
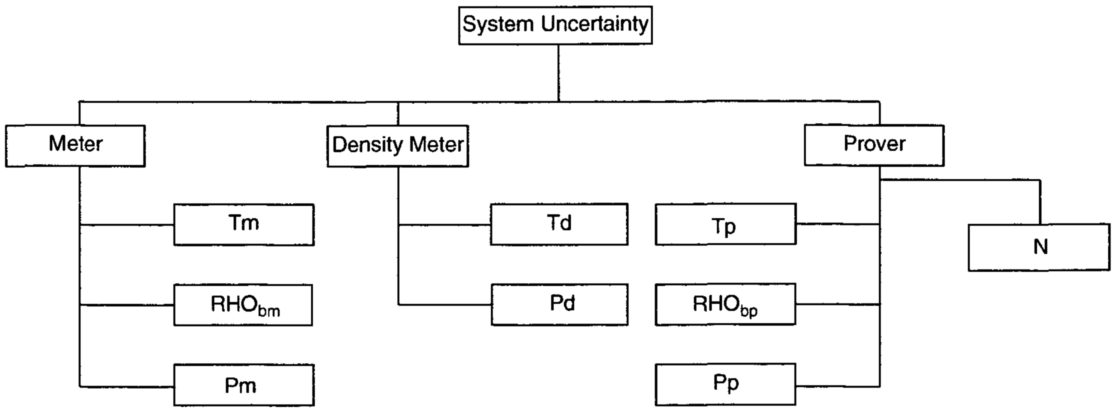


Figure 1—Typical ELM Inferred Mass System



Measure	Description	Allowable Deviation	Source
Td	Temperature at the density meter	0.5°F (0.25°C)	No source, assume to be same as Tm
Pd	Pressure at the density meter	3 psig (20 kPag)	No source, assume to be same as Pm
Tm	Temperature of the liquid at the meter	0.5°F (0.25°C)	Chapter 7.2
RHObm	Base density at the meter	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pm	Pressure of the liquid at the meter	3 psig (20 kPag)	Chapter 21.2
Tp	Temperature of the liquid at the prover	0.2°F (0.1°C)	Chapter 7.2
RHObp	Base density at the prover	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pp	Pressure of the liquid at the prover	3 psig (20 kPag)	Chapter 21.2
N	Least discernable increment	1 part in 10000	Chapter 4.8

Figure 2—Example of System Uncertainty Calculation

These factors can be applied continuously in real time, to data obtained for each sample period p as shown in Equation (5) below, or applied once at the end of the custody transfer transaction (see Equation (8)).

Applying performance factors continuously in real time

$$Qmc_p = Q(IV)_p \times D(UF)_p \times MF_p \times DMF_p \qquad (5)$$

where

Qmc_p = Mass quantity measured during sample period p, corrected for performance variations in the flowmeter device and density meter device,

$Q(IV)_p$ = Indicated volume measured during sample period p, uncorrected for flowmeter performance variations,

$D(UF)_p$ = Unfactored density measured during sample period p, uncorrected for meter performance variations,

MF_p = Flowmeter performance correction factor *(MF)* used during sample period p,

DMF_p = Density Meter performance correction factor *(DMF)* used during sample period p.

If the *MF* and *DMF* are applied continuously as in Equation (5) above they must be individually averaged[5] during the custody transfer transaction, in accordance with *API MPMS* Chapter 21.2 and recorded in the quantity transaction record *(QTR)*.

7.3.3 Determining the Transaction Mass Quantity

Inferred Mass *(IM)* is determined for a custody transfer transaction using the following equation:

$$IM = \sum_{p=1}^{n} QT_p \times DT_p \qquad (6)$$

where

Σ = Summation operation for all sample periods p during transaction T,

IM = Inferred Mass accrued during transaction T,

QT_p = actual volume measured at flowing conditions for each sample period p during the transaction T,

DT_p = actual density measured at flowing conditions for each sample period p during the transaction T,

n = Last sample taken at the end of the transaction.

[5] Averages should be flow-weighted based on gross volume.

When the flow meter *(MF)* and density meter *(DMF)* performance factors have been applied continuously using Equation (5), Equation (6) is modified to:

$$IM_C = \sum_{p=1}^{n} Q(IV)_p \times D(UF)_p \times MF_p \times DMF_p \quad (7)$$

where

Σ = Summation operation for all sample periods p during transaction T,

IM_C = Inferred Mass accrued during transaction T corrected for flowmeter and density meter performance,

$Q(IV)_p$ = Indicated volume measured during sample periods p, uncorrected for flowmeter performance variations,

$D(IV)_p$ = Unfactored density measured during sample periods p, uncorrected for density meter performance variations,

MF_p = Flowmeter performance correction factor *(MF)* used during sample periods p,

DMF_p = Density Meter performance correction factor *(DMF)* used during sample periods p,

n = Last sample taken at the end of the transaction.

If the flowmeter *(MF)* and density meter *(DMF)* performance factors are constant throughout the transaction, they may be applied one time at the end of the custody transfer transaction to the uncorrected inferred mass *(IM)* as follows:

$$IM_C = MF_T \times DMF_T \times \sum_{p=1}^{n} Q(IV)_p \times D(UF)_p \quad (8)$$

where

Σ = Summation operation for all sample periods p during transaction T,

IM_C = Inferred Mass accrued during transaction T corrected for flowmeter and density meter performance,

$Q(IV)_p$ = Indicated volume measured during sample time period p, uncorrected for flowmeter performance variations,

$D(UF)_p$ = Unfactored density measured during sample time period p, uncorrected for density meter performance variations,

MF_T = Flowmeter performance correction factor *(MF)* used for transaction T,

DMF_T = Density Meter performance correction factor *(DMF)* used for transaction T,

n = Last sample taken at the end of the transaction.

7.3.3.1 Liquid Volume Correction Factors

In volumetric measurement, liquid volume correction factors are employed to account for changes in density and volume due to the effects of temperature and pressure upon the liquid. These correction factors are:

a. *CTL*—correction for effect of temperature on liquid at normal operating conditions.
b. *CPL*—correction for compressibility of liquid at normal operating conditions.

Refer to *API MPMS* Chapter 21.2 for further explanation of factors *CTL* and *CPL*.

When measuring inferred mass, these correction factors are not required for continuous mass integration, but may be required during a meter proving operation to compensate for differences in liquid flowing conditions at the flowmeter and prover.

7.3.4 Application of CTL and CPL for Inferred Mass ELM Proving Systems

Systematic errors will be introduced into the inferred mass measurement during flowmeter proving operations if temperature and pressure conditions at the flowmeter and the prover are outside the limits defined in *API MPMS* Chapter 14.6.7.2.2. If the density of the liquid at base conditions *(RHO_b)* can be accurately determined, it is permissible to calculate and apply the correction factors *CTLm, CPLm, CTLp* and *CPLp* during proving of the flowmeter when calculating a meter factor *(MF)*. These factors must be applied in accordance with *API MPMS* Chapter 12.2

Appendix B of *API MPMS* Chapter 12.2 contains a list of recommended correlations between liquid density, temperature and pressure for different liquids. Where an API correlation does not currently exist, an appropriate ASTM or GPA standard, technical paper, or report has been provided to assist the user community.

The method selected for determining the liquid density at base conditions *(RHO_b)* shall be mutually agreed upon by all parties involved in the measurement.

7.3.5 Rounding Rules to be Used by Tertiary Devices

Differences between results of mathematical calculations can occur in different equipment or programming languages because of variations in multiplication sequence and rounding procedures. To ensure consistency, individual correction factors are multiplied serially and rounded once to the required number of decimal places. *API MPMS* Chapter 12.2 details the correct sequence, rounding, and truncating procedures to be used in *CCF* calculations that determine meter factors during flowmeter proving.

The rounding rules and discrimination levels to be used when calculating and integrating incremental volumes and mass quantities should be in accordance with *API MPMS* Chapter 21.2. The method of rounding or truncation of volumes, such as Indicated Gross Volume *(IV)* etc., at the end of the Quantity Transaction Record period should be per *API MPMS* Chapter 21.2, unless otherwise agreed upon by the parties involved. Maximum discrimination levels of totalized mass quantities shall be to the nearest whole pound mass unit or nearest whole kilogram mass unit. Lower discrimination levels of totalized mass quantities are permitted depending upon the specific mass flowrate and mass quantity transaction size. Because the density meter is a primary device, the flowing density value obtained from this device should not be rounded or truncated when used in mass quantity calculations.

7.3.6 Flowing Liquid Density

All calculations and algorithms involving the determination of online density shall be in accordance with *API MPMS* Chapter 14.6.

8 Auditing and Report Requirements

8.1 GENERAL

Chapter 21.2 Section 10 shall apply, with the exception of paragraph 10.1.2. For inferred mass, audit trail requirements apply only to data that affect inferred mass and volumetric calculations and the custody transfer quantity. Off-site systems often perform diverse functions other than those described within the standard. These other functions are not a part of this standard. Only data associated with measurement is to be included under auditing and reporting requirements.

8.2 CONFIGURATION LOG

In addition to the items listed in Chapter 21.2, paragraph 10.2.1, the following will become part of the configuration log when measuring inferred mass:

8.2.1 Density Meter

a. Density meter factor *(DMF)*.
b. Density meter calibration factors.
c. Engineering units.
d. High and low alarm limits.
e. Default values in case of failure.
f. Density meter identifier or tag name.

8.3 QUANTITY TRANSACTION RECORD

Chapter 21.2, Section 10.3 shall govern with the following exceptions that affect inferred mass:

Section 10.3.1.1, item f shall be limited to "Meter Factor *(MF)* and/or K-Factor *(KF)*.

Sections 10.3.1.1, items g, h and i do not apply.

Section 10.3.1.1, item l is changed to, "Weighted average flowing density".

Section 10.3.1.1, item m does not apply.

Section 10.3.1.1, item n is changed to "Indicated volume *(IV)*".

Section 10.3.1.1, item p is changed to "Inferred mass".

Section 10.3.1.2 has no relevance for this addendum and shall be disregarded.

8.4 VIEWING ELM DATA

Chapter 21.2, Section 10.4 shall govern inferred mass.

8.5 DATA RETENTION

Chapter 21.2, Section 10.5 shall govern with the exception that "mass" is to replace "volume" in paragraph 10.5.1.

9 Equipment Calibration and Verification

Chapter 21.2, Section 11 shall govern.

10 Security

Chapter 21.2, Section 12 governs with the exception that "mass" is to replace "volume" in paragraph 12.3.2.

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This standard is under the jurisdiction of the API Committee on Petroleum Measurement, Subcommittee on Liquid Measurement. This standard shall become effective January 1, 1999, but may be used voluntarily from the date of distribution. Suggested revisions are invited and should be submitted to the Measurement Coordinator, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

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Chapter 21—Flow Measurement Using Electronic Metering Systems Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters

1 Scope

1.1 GENERAL

1.1.1 This standard provides guidance for effective utilization of electronic liquid measurement systems for custody transfer measurement of liquid hydrocarbons:

a. Within the scope and field of application of API *MPMS* Chapter 12.2.
b. Which are single-phase liquids at measurement conditions.
c. For systems utilizing turbine or positive displacement meters.
d. For systems using on-line *CTL* and *CPL* compensation.

1.1.2 The procedures and techniques discussed in this document are recommended for use with new measurement applications. Liquid measurement using existing equipment and techniques not in compliance with this standard may have a higher uncertainty than liquid measurement based on the recommendations contained in this document.

1.2 ELECTRONIC LIQUID MEASUREMENT (ELM)

The term "electronic liquid measurement," or ELM, will be freely used throughout this document to denote liquid measurement using electronic metering systems. (Also see 3.20.)

2 Referenced Publications

If the wording of this document conflicts with a referenced standard, the referenced standard will govern.

API
Manual of Petroleum Measurement Standards

Chapter 1		"Vocabulary"
Chapter 4	Section 2	"Conventional Pipe Provers"
Chapter 4	Section 3	"Small Volume Provers"
Chapter 4	Section 6	"Pulse Interpolation"
Chapter 5	Section 2	"Measurement of Liquid Hydrocarbons by Displacement Meters"
Chapter 5	Section 3	"Measurement of Liquid Hydrocarbons by Turbine Meters"
Chapter 5	Section 4	"Accessory Equipment for Liquid Meters"
Chapter 5	Section 5	"Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"
Chapter 7	Section 2	"Dynamic Temperature Determination"
Chapter 9		"Density Determination"
Chapter 11		"Physical Properties Data"
Chapter 12	Section 2	"Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volume Correction Factors"
Chapter 13		"Statistical Aspects of Measuring and Sampling"
Chapter 14	Section 6	"Continuous Density Measurement"
Chapter 21	Section 1	"Electronic Gas Measurement"
RP 500		*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2*

ASTM[1]

D5002	*Test Methods for Density and Relative Density of Crude Oil by Digital Density Analyzer*

3 Definitions and Symbols

3.1 INTRODUCTION

The purpose of these definitions is to clarify the terminology used in the discussion of this standard only. The definitions are not intended to be an all-inclusive directory of terms used within the measurement industry, nor are they intended to conflict with any standards currently in use.

3.2 WORDS AND TERMS

3.3 accounting period: A duration of time usually of fixed length, such as a day or week, or the period of time required to transfer all or part of a batch.

3.4 analog to digital (A/D) converter: A signal processor that converts electrical analog signals to a corresponding digital number.

3.5 accuracy: The extent to which the results of a calculation or the readings of an instrument approach the true value.

3.6 audit trail: The record of an electronic liquid measurement (ELM) system containing verification or calibration measurements for all tertiary and secondary devices, actual specifications for the primary device, constant values, times and dates of any changes affecting reported volumes and all

[1]American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428.

documentation required under audit and reporting requirements; it may also include identification of those making the changes. The audit trail may consist of single or multiple records in electronic or hard copy form.

3.7 batch: A discrete shipment of commodity defined by volume, accounting time interval, or quality.

3.8 calibration: The testing and adjustment of an ELM system or system components to conform with traceable reference standards to provide accurate values over the ELM's prescribed operating range.

3.9 calibration span: The difference between the calibrated maximum and minimum range limits.

3.10 certified equipment: Equipment whose performance is traceable to primary standards maintained by an internationally recognized standards organization, such as the National Institute of Standards and Technology, and that has been provided with documentation (Certificate of Conformance) stating the traceability.

3.11 combined correction factor (*CCF*): A factor that combines two or more correction factors that may include a correction for the effect of temperature on liquid (*CTL*), a correction for the effect of pressure on liquid (*CPL*), a meter factor (*MF*), and others. The intent of *CCF* is to limit the effects of rounding and truncation errors in volume measurement and proving calculations. See API *MPMS* Chapter 12.2 for further discussion.

3.12 composite meter factor (*CMF*): A factor that combines a meter factor along with a correction for the compressibility of the fluid between normal operating pressure and base pressure. A composite meter factor may be used for meter applications where the pressure is considered constant during the ticket period.

3.13 configuration log: A record that contains and identifies all selected flow parameters used in the generation of a quantity transaction record.

3.14 contract day: A time period of 24 consecutive hours beginning at the time specified in the contract, except for days which have been adjusted for Daylight Savings Time.

3.15 date period: The specific year, month, and day logged at the beginning or completion of the quantity transaction record.

3.16 densitometer: A transducer and associated signal conditioning equipment that are used to convert the density of a fluid to an electronic signal.

3.17 digital to analog (D/A) converter: A signal processor that converts digital numbers to corresponding electrical analog signals.

3.18 downstream electronic device: Any device receiving outputs from a tertiary device.

3.19 event log: A record that notes and records all exceptions and changes to the system parameters or flow parameters contained within the configuration log that have an impact on a quantity transaction record.

3.20 electronic liquid measurement (ELM): A metering system utilizing electronic calculation equipment with API liquid measurement algorithms and security/auditing features, on-line temperature and pressure inputs, and linear meter pulse inputs. ELM provides real-time, on-line measurement. Application of *CPL*/*CTL* calculations at a minimum time period, adherence to verification/calibration recommendations, use of an optional live density variable, and attention to system secondary devices help to reduce any inaccuracies of meter measurements.

3.21 flow computation device: An arithmetic processing unit with associated memory that accepts electrically converted signals representing input variables from a liquid measurement system and performs calculations for the purpose of providing flow rate and total quantity data. It is sometimes referred to as a flow compilation device, flow computer, or tertiary device.

3.22 gross standard volume (*GSV*): The volume at base conditions corrected for the meter's performance (*MF* or *CMF*).

3.23 *GSVm*: The volume at base conditions shown by the meter at the time of proving.

3.24 *GSVp*: The volume at base conditions shown by the prover at the time of proving.

3.25 indicated volume (*IV*): The change in meter readings that occurs during a receipt or delivery.

3.26 indicated standard volume (*ISV*): The indicated volume (*IV*) of the meter corrected to base conditions. It is not corrected for meter performance (*MF* or *CMF*).

3.27 input variable: For the purposes of electronic liquid measurement, an input variable is a data value associated with the flow or state of a liquid that is put into the flow computation device for use in a calculation. This input may be a measured variable from a transducer/transmitter or a manually entered fixed value. Pressure, temperature, and relative density are examples of input variables.

3.28 isolator: A device that separates one portion of an electrical circuit from another to protect against grounding and voltage reference problems and that can be used to replicate or convert signals and protect against extraneous signals.

3.29 main calculation period (*mcp*): The computational time period between two consecutive combined correction factor (*CCF*) calculations.

3.30 master meter factor: A dimensionless term obtained by dividing the gross standard volume (*GSVp*) of the liquid that passed through the master prover (by the master meter) by the indicated standard volume (*ISVm*) as registered by the master meter during proving.

3.31 meter factor (*MF*): A dimensionless term obtained by dividing the volume of liquid passed through the prover (corrected to standard conditions during proving) by the indicated standard volume (*ISV*) as registered by the meter.

3.32 meter factor linearization: A process to correct a metering device for deviations in performance or trial results over a declared operating range caused by variations in process or operating conditions, such as flowrate or viscosity.

3.33 no-flow: An absence of fluid passing through the primary device.

3.34 nonresettable totalizer: An accumulating register that records and sums the quantity of fluid passing into or through a quantity measurement device. The totalizer is not reset during normal operations (such as after the completion of a batch or quantity transaction record period).

3.35 off-site: A location not in close proximity to the primary measurement device.

3.36 on-site: A location in close proximity to the primary measurement device.

3.37 on-line *CPL/CTL* compensation: The continuous computation of *CPL* and *CTL* during each main calculation period.

3.38 performance uncertainty: The ability of a device or system to repeat test parameters within an anticipated range of operating conditions.

3.39 point of custody transfer: The physical location at which a quantity of petroleum that is transferred between parties changes ownership.

3.40 quantity transaction record (QTR): A set of historical data, calculated values, and information in a preset format that supports the determination of a quantity over a given accounting period. The QTR has historically been known as a "measurement ticket."

3.41 random error: A deviation in measure from a true value in an unpredictable fashion over a series of repeated measurements under the same conditions of testing. A large number of such repeated measurements will show that larger errors occur less frequently than smaller ones, and that a majority of the deviations characteristically fall within defined limits.

3.42 sampling frequency: The number of samples per unit of time of an input variable that is retrieved for monitoring, accumulation, or calculation purposes.

3.43 sampling period: The time in seconds between the retrieval of flow parameters for monitoring, accumulation, and calculation purposes.

3.44 sensor: A device that provides a usable output signal by responding to a measurand. A measurand is a physical quantity, property, or condition that is measured. The output is the electrical signal, produced by the sensor, which is a function of the applied measurand.

3.45 signal conditioner: Amplifying the signal or otherwise preparing a signal for input to a tertiary device. One example is a turbine meter pre-amplifier.

3.46 systematic error: An error prevalent throughout a series of measurements. This error will result in a consistent deviation from true and, if traced, can usually be reduced to an assignable cause within the system performing the measurement.

3.47 traceability: The property of a measurement or the value of a standard whereby it can be related to stated references, usually national or international standards, through an unbroken chain of comparisons.

3.48 transducer: A device that generates an electrical signal, either digital or analog, that is proportional to the variable parameter that is to be transmitted to the tertiary device.

3.49 transmitter: A device that converts the signal from a sensor into a form suitable for propagating the measurement information from the site of measurement to the location where the signal is used. The signal is typically converted into a current, pulse train, or serial digital form. The sensor may be separate or may be part of the transmitter.

3.50 turndown ratio—meters: The maximum usable flow-rate of a meter under normal operating conditions divided by the minimum usable flow-rate.

3.51 turndown ratio—transmitters: The ratio of the upper range value (*URV*) to the lower range value (*LRV*) for which a transmitter is designed. For example, if the transmitter has a rated span of 0 to 15 psi (minimum) and 0 to 150 psi (maximum), then the turndown ratio is 10:1.

3.52 uncertainty: The amount by which an observed or calculated value may depart from the true value.

3.53 verification: The process of confirming or substantiating the accuracy of input variables to a measurement system at normal operating conditions, using reference equipment traceable to certified standards.

3.54 weighted average: The average of a variable weighted by the flow rate or incremental volume. It can be the average of the variable values sampled at uniform volume intervals, or it can be the average of variable values sampled at uniform time intervals and weighted by the incremental volume that occurred during that time interval.

For time-based methods, the weighted average temperature/pressure is the sum of the temperature/pressure values sampled during the time interval, multiplied by the volume during the same interval and divided by the entire volume measured.

4 Field of Application

The procedures and techniques in this standard apply to new metering systems that perform continuous on-line gross standard volume (*GSV*) calculations. The standard provides hardware, algorithm, and calibration recommendations for design, installation, and operation purposes. The standard sets minimum guidelines for electronic flow measurement systems, including tertiary device configuration, auditing and security features, and calibration procedures.

Not all metering systems must conform to this ELM standard. There are other API *MPMS* chapters that apply to individual segments of other measurement systems. These other systems utilize combinations of electronic, mechanical, and manual measurement to gather data and provide computations.

Single-phase liquid hydrocarbon streams may include permissible amounts of water or other nonsalable components. Measurement of gas/liquid two-phase mixtures is not covered.

5 Description of an Electronic Liquid Measurement System

5.1 ELEMENTS OF AN ELECTRONIC LIQUID MEASUREMENT SYSTEM

5.1.1 Primary Devices

The primary device or meter converts fluid flow to a measurable signal, such as an electrical pulse generated by a turbine or positive displacement meter. In determining ELM system uncertainty, this standard does not address the *uncertainty* of the primary device itself. See Figure 1 for an example of a typical ELM system.

5.1.2 Secondary Devices

In ELM systems, secondary devices respond to inputs of pressure, temperature, density, and other variables with corresponding changes in output values. These devices are referred to as transmitters when they have been specifically designed to transmit information from one location to another by the addition of an electronic circuit that converts the device's output to a standard signal. This signal may be an analog, digital, or frequency signal.

5.1.3 Tertiary Devices

A tertiary device is sometimes referred to as the flow computing device, flow computation device, or flow computer. It receives information from the primary and secondary devices and, using programmed instructions, calculates the custody transfer quantity of liquid flowing through the primary device.

5.2 PLACEMENT OF ELM SYSTEM COMPONENTS

Primary and secondary devices are considered by definition to be located on-site. Tertiary devices may be located on-site or off-site.

5.3 DATA PROCESSING

Output from the tertiary device must comply with auditing, reporting, and security requirements discussed in this standard.

6 System Uncertainty

6.1 GENERAL

6.1.1 Uncertainty in the gross standard volume (*GSV*) attributable only to the electronic liquid measurement system is dependent upon the combined uncertainties of its parts, which include, but are not limited to, the following:

a. The performance of the devices comprising the system.
b. Conformance to installation requirements.
c. The method used to transmit data signals (analog, frequency, or digital).
d. The integrity of the signal path from sensor to tertiary device input.
e. The method of calculation.
f. Sampling and calculation frequencies.

6.1.2 An electronic liquid measurement system (tertiary and secondary devices) shall be designed to meet an uncertainty of ±0.25 percent of flow to a 95 percent level of confidence over the expected operating range as determined from calibration results and when compared to the uncertainty of an identical measurement system. Refer to Appendices F and G for further explanation of accuracy requirements and the methodology to determine the uncertainty of specific systems.

6.1.3 ELM uncertainty is based on secondary inputs sampled at a minimum of once every five seconds. This standard provides the procedures to be used to calculate uncertainty based on the selected individual measurement system components. It includes the uncertainty of nonlinear volume corrections but not the uncertainties of default inputs.

6.1.4 To reduce system uncertainty, it is advisable to install and maintain on-line secondary equipment. For secondary device values that do not change appreciably (determined by agreement among interested parties), fixed or default secondary inputs can be used and, for uncertainty calculation, maximum expected deviations can be substituted directly for standard tolerances. It is important that fixed input values be revalidated periodically because, once set, they become easy to ignore.

6.1.5 For the purposes of uncertainty calculations, all secondary input devices are considered to be maintained within the tolerances listed in Figure 2 from the sensor to the tertiary device (including any signal conditioning) specified in the standards listed in the figure. Any error as a result of deviation from zero is considered systematic for the quantity transaction period. The reader is referred to API *MPMS* Chapter 13.1 for the statistical background.

6.1.6 Different system configurations are possible. The calculations described here should be adaptable to many of them, but they are not representative of all possible system configurations. The diagram in Figure 2 describes a particular system configuration, and the results of example calculations using it are summarized in Table G-1 in Appendix G. These results are specific to the examples provided for natural gas liquid (NGL) and crude oil and include the components shown in Figure 2 but exclude the uncertainties of the primary elements, the meters, and provers.

7 Guidelines for Design, Selection, and Use of ELM System Components

7.1 PRIMARY DEVICES—SELECTION AND INSTALLATION

7.1.1 Meter selection is based on operational requirements (such as rate, viscosity, and throughput) and physical needs

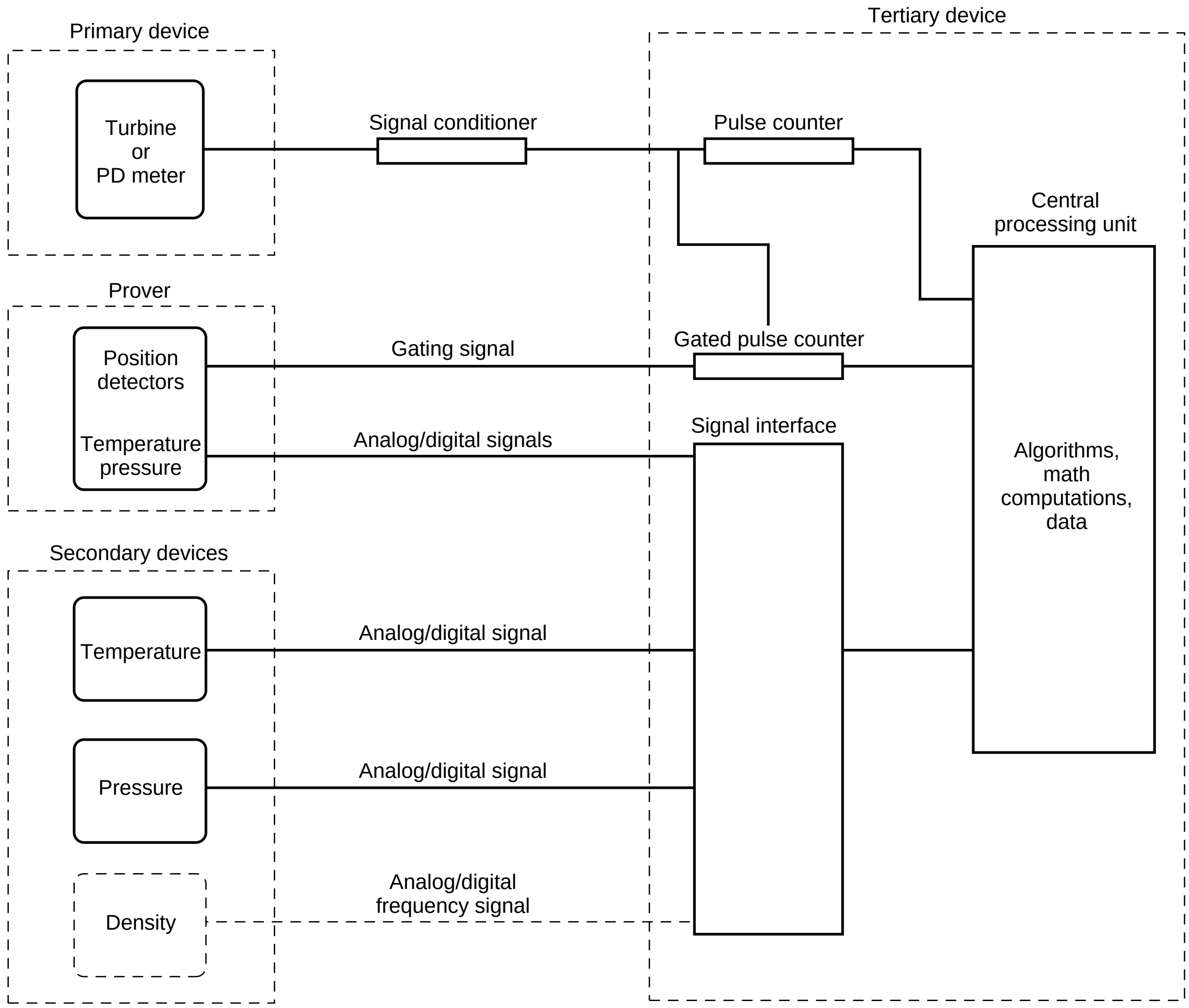
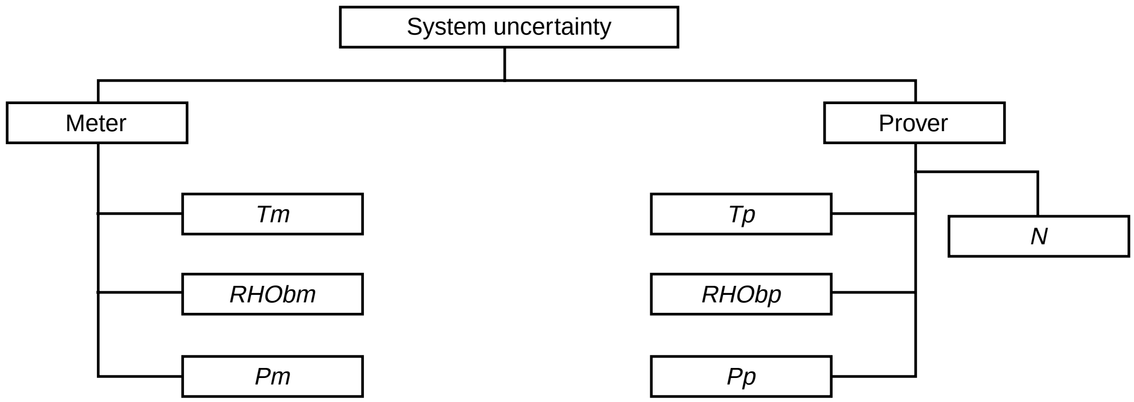


Figure 1—Typical ELM System



Measure	Description	Allowable Deviation	Source
Tm	Temperature of the liquid at the meter	0.5°F (0.25°C)	Chapter 7.2
RHObm	Base density at meter	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pm	Pressure of the liquid at the meter	3 psig (20 kPag)	Chapter 21.2
Tp	Temperature of the liquid at the prover	0.2°F (0.1°C)	Chapter 7.2
RHObp	Base density at prover	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pp	Pressure of the liquid at the prover	3 psig (20 kPag)	Chapter 21.1
N	Least discernible increment	1 part in 10,000	Chapter 4.8

Note: This example does not reflect every possible source of error that could add to the uncertainty of the measurement system, nor does it imply better resolution or accuracy cannot be attained.

Figure 2—Example of System Uncertainty Calculation

(such as environment, accessibility, or frequency of operation)—see API *MPMS* Chapters 5.2 and 5.3. This document covers turbine and positive displacement meters as the primary device. A primary device has two components: a rotating measurement element, and an output device to report the unit volume passing through the meter.

7.1.2 The meter in an ELM system either electrically or electro-mechanically produces pulses representing discrete units of volume passing through it. Methods for producing pulse outputs depend on the meter type. Electro-mechanically produced meter pulses are common to positive displacement and some turbine meters. Meters are also manufactured to provide both electro-mechanical and electrical outputs. The ELM system must be designed to accommodate the characteristics of pulse outputs by allowing it to accurately detect the signal over all possible flow rates.

7.2 SECONDARY DEVICES—SELECTION AND INSTALLATION

7.2.1 General

7.2.1.1 Secondary devices provide real-time loop data, excluding flow data from primary devices, that can be transferred to a tertiary device. Secondary devices can be divided into five classifications:

a. Sensors.
b. Transmitters.
c. Signal to digital converters.
d. Isolators.
e. Signal conditioners.

7.2.1.2 Signal to digital converters read sensor output or any analog signal and convert the signal to a digital value ready for processing. A signal converter can be built inside a transmitter, a flow computation device, or some other intermediate device.

7.2.1.3 An isolator separates one portion of a loop from another to protect against grounding and voltage reference problems, and can be used to replicate or convert signals and to protect against the introduction of extraneous signals.

7.2.1.4 Operating limits and environmental impacts on the accuracy of all secondary devices shall be clearly stated. The effect of temperature changes on a specified operating range should also be stated.

7.2.1.5 The maximum effects of all the factors that may degrade accuracy, such as ambient temperature, humidity, static pressure, vibration, power supply variances, and mounting position sensitivity, shall be stated by the manufacturer.

7.2.1.6 Temperature thermowells and sensors must be properly matched. The thermowell hole diameter and depth must ensure proper heat transfer to the sensor. Spring devices are available that ensure that the sensor is against the bottom or the side of the thermowell hole. A thermal conducting medium should be used for proper heat transfer between the thermowell and the sensor. The depth of insertion of the thermowell into the pipe whose fluid temperature is being measured must be adequate to faithfully transfer the fluid temperature to the active portion of the sensor probe.

7.2.1.7 Reference (sometimes known as test) thermowells adjacent to temperature-sensing thermowells are recommended. The inside well should be properly sized for the reference equipment.

7.2.1.8 Pressure sensing taps should be located at the same elevation as the primary device to eliminate head losses or gains. Transmitters should be located level with or below the tap to maintain a liquid fill.

7.2.1.9 All secondary devices shall be installed and maintained in accordance with the manufacturer's guidelines and the most current revision of the *National Electric Code (NEC)* or other applicable federal, state, and local codes.

7.2.1.10 All secondary devices used for custody transfer electronic liquid measurement that cannot meet the operating limits for exposure to temperature, humidity, or other environmental conditions should be appropriately protected.

7.2.1.11 Frequent verification or calibration of secondary devices can reduce the effects of seasonal temperature changes on the accuracy of the equipment. Devices with microprocessors may electronically compensate for operational and environmental effects.

7.2.2 Selection and Installation

7.2.2.1 Smart Transmitters vs. Conventional Transmitters

7.2.2.1.1 Smart transmitters may offer benefits not found in conventional analog transmitters, such as:

a. Wider rangeability.
b. Calibration procedures.
c. Improved performance.
d. Lower drift rate.
e. Elimination of loop errors (analog drift, analog conversions, etc.).

7.2.2.1.2 It is important to read the specifications for a transmitter carefully. Sections 7.2.2.2, 7.2.2.3, and 7.2.2.4 describe important aspects of transmitter specification.

7.2.2.2 Transmitter Accuracy

7.2.2.2.1 The "stated" accuracy of a transmitter can be expressed as: a) a percentage of the upper range value (*URV*), b) a percentage of the calibrated span, or c) a percentage of the reading. Consider, for example, a transmitter with a *URV* of 500 psig that has been calibrated for a span of 0 to 300 psig. Also assume normal line pressure of 200 psig.

7.2.2.2.2 If accuracy is stated as 0.25 percent of the URV, then the accuracy is 1.25 psi.

7.2.2.2.3 If accuracy is stated as 0.25 percent of the calibrated span, then the accuracy is 0.75 psi.

7.2.2.2.4 If accuracy is stated as 0.25 percent of the reading, then the accuracy is 0.50 psi.

7.2.2.3 Process and Installation Effects on Transmitter Accuracy

7.2.2.3.1 Transmitter specifications often have a statement of accuracy, as described in 7.2.2.2. This is called the stated accuracy or laboratory accuracy. The accuracy of installed transmitters, however, can be influenced by:

a. Ambient temperature—expressed as a percentage of the *URV* or the span per degrees of temperature change.
b. Vibration effect—expressed as a percentage of the *URV* or the span per unit of G force.
c. Power supply—expressed as a percentage of the *URV* or the span per volt of power supply.
d. Mounting position—expressed as a percentage of the calibration of zero or span.

7.2.2.3.2 Evaluation of these conditions is important, since they can significantly influence the accuracy of an installed transmitter. To state the installed accuracy of a transmitter, all possible errors can be calculated by using the root of the sum of the squares, or RSS, method. In many cases, the installed conditions may produce as much error as is found in the stated or laboratory accuracy of the transmitter.

7.2.2.3.3 Transmitters installed in locations subject to extreme temperature swings should be mounted in a temperature-controlled environment or enclosure.

7.2.2.4 Turndown Ratio

In conventional transmitters, the selection of an operational range is critical to its ultimate accuracy. Smart transmitters may be designed to have greater turndown ratios, more easily allowing them to be spanned for nearly any application in the field. Conventional transmitters typically have less than a 10:1 turndown ratio, while smart transmitters may have a turndown ratio of 50:1 or more.

7.3 TERTIARY DEVICES—SELECTION AND INSTALLATION

7.3.1 A tertiary device receives data from the primary and secondary devices for flow computation. The tertiary device is programmed or configured to collect data, calculate flow and volume, and provide an audit trail.

7.3.2 The following should be considered when choosing a tertiary device:

a. Degree of configurability.
b. Number and type of process inputs and outputs.
c. Electrical requirements.
d. Environmental requirements.
e. Sampling frequency.
f. Ability to generate an audit trail and related reports.
g. Data and algorithm security.

7.3.3 The manufacturer shall state the effects of linearity, hysteresis, and repeatability for the specified range of operation. The effects of ambient temperature change on zero and span for a specific operating range should also be provided.

7.3.4 The tertiary device shall meet the operating limits for exposure to temperature, humidity, or other environmental conditions, or the device shall be appropriately protected.

7.3.5 The tertiary device shall be installed and maintained in accordance with manufacturers' guidelines. Installation shall comply with 7.4.

7.3.6 Refer to Appendices A, B, and E for further explanations.

7.4 ELM DEVICES AND ASSOCIATED EQUIPMENT

7.4.1 An ELM device and its associated equipment, including communication equipment and signal conditioners, shall be installed and maintained in accordance with the manufacturer's guidelines and the *National Electrical Code (NEC)* or similar national, state, or local electrical codes. All installation materials shall be compatible with the service and/or environment, including ambient temperature swings, presence of toxic or corrosive material, moisture, dust, vibration, and hazardous area classification. The ELM device shall have radio frequency interference protection and electromagnetic interference protection suitable for the expected operating environment.

7.4.2 The ELM system shall include electrical transient suppression on all power, communication, and data inputs and outputs to provide protection from transient over-voltages. Transients appear on signal lines from a number of sources, including static discharge, inductive load switching, induced lightning, and coupled power lines. Transient suppressors are designed to either clamp and/or discharge the transient over-voltage, or to fail, thus shorting the over-voltage to the ground. They are either of nonfaulting type that continue to operate many times or of the faulting type that require replacement following a substantial transient. A good earth ground is essential for the suppressor to operate properly. Consult manufacturer for the proper type of suppressor to use.

7.4.3 If the ELM device is not approved for installation in a hazardous area for electrical equipment, as defined by the *NEC* or similar electrical regulatory code, and the site of the measurement device is classified as hazardous, follow the recommended design guidelines given in API Recommended Practice 500.

7.4.4 ELM devices should be powered with a continuous and reliable power source that is adequate for proper operation.

7.4.5 ELM equipment intended to perform proving operations must be designed to meet the sphere detection switch timing requirements set out in API *MPMS* Chapter 4, Section 2, and must respond by starting or stopping the prover pulse accumulator at the beginning or end of a proving pass within one pulse and must accumulate each and every pulse from the meter during the proving pass. Additional requirements for ELM equipment intended to perform proving operations using small volume provers are that it must be able to handle pulse interpolation or otherwise meet timing requirements set out in API *MPMS* Chapter 4, Sections 3 and 6.

7.4.6 ELM devices are often installed in an uncontrolled environment. The responses of these devices under a variety of weather conditions can affect the performance and accuracy of flow measurement. Ambient temperature changes or extremes may cause a significant systematic deviation in measurement accuracy. The operating temperature range and its corresponding effect on measurement uncertainty should be considered when selecting and installing ELM equipment.

7.4.7 Refer to Appendix B for details on A/D converters and their resolution.

7.5 CABLING

All cabling shall be approved for the class of service and installed in accordance with *NEC* or similar applicable electrical regulatory agency requirements. Signal cabling shall be properly protected from environmental elements and shielded from outside electrical interference. Signal interference should be minimized by providing proper electrical isolation between alternating current (AC) power and signal wires at all times. Electrical isolation may be achieved by using specially designed cable or by routing power cables and signal cables in different conduits.

8 Commissioning New and Modified Systems

8.1 GENERAL

8.1.1 New or newly modified systems must be checked to ensure that all components are compatible. Panel mounted equipment that requires grounding should be grounded to the instrument common ground. Power supply voltages should be checked for proper potential and for presence of noise. All signals should be checked from the source to their converted value in engineering units within the ELM system. Each 4-20 mA transmitter loop should be checked to ensure that the total loop resistance is within the specification for that transmitter operating at the supplied voltage level. Cause each transmitter to generate its maximum output signal either manually (for a smart transmitter) or by simulating maximum input signals to each transmitter to ensure that all analog output signals are capable of achieving 100 percent of full signal. Excess loop resistance can limit a transmitter's ability to supply full output in a current loop. Likewise, an excessive load can limit the ability of a transmitter to supply full output to a voltage controlled loop. Also verify the transmitter's zero percent signals.

8.1.2 Any pulse-generating equipment should be checked from source to accumulator. If possible, generate pulses by subjecting the sensor to the actual physical environment, flow, temperature, pressure, and density, at both minimum and maximum levels. This will test the compatibility between the primary element and any pulse-generating and/or sensing devices. If it is not possible to simulate flow conditions, use a pulse generator with amplitude, frequency, and wave shape characteristics that approximate the primary element to test the signal. The final pulse rate, shape, width, and upper and lower levels should be checked against the requirements of the tertiary device.

8.1.3 The ELM pulse accumulator should be tested to confirm that it agrees with a reference totalizer to ±2 counts or better for accumulations of at least 200,000 pulses. Calibration of the electronic accumulator is not possible, although sensitivity thresholds and filter constants may be adjustable. These should be adjusted during commissioning of the system and should not require further adjustment.

8.1.4 Tertiary devices should be checked for any hardware malfunctions. Check the internal power supply for proper levels. With no pulses being generated by primary devices, operate various devices that are potential generators of noise while checking the tertiary devices for receipt of false pulses. Particularly suspect are radio communications equipment and solenoid valve or motor control circuits with wiring in close proximity to the metering/proving installation.

8.1.5 Programmable devices must be checked for proper functionality and accuracy. Identical program and configuration tables need to have only one representative program or table verified if they are electronically reproduced. Fixed variables should be entered, and each factor should be confirmed against hand-calculated or table values. Manually entered programs, tables, and parameters must all be checked individually.

9 Electronic Liquid Measurement Algorithms

9.1 GENERAL

The intent of this section is not to define all the variations of flow equations but rather to provide specific guidelines for algorithms that are consistent in application for all electronic liquid measurement systems.

9.2 GUIDELINES

9.2.1 Algorithms

9.2.1.1 This section defines algorithms for volumetric liquid measurement. The algorithms define sampling and calculation methodologies and averaging techniques.

9.2.1.2 When applying these methods to turbine and displacement measurement, the appropriate algorithms, equations, and rounding methods are found in, or referenced in, the latest revision of API *MPMS* Chapter 12.2, including Chapter 12.2, Part 1, Appendix B. To reduce cumbersome cross-referencing, some of the text of Chapter 12.2 is included in this standard.

9.2.1.3 All supporting algorithms and equations referenced, such as determination of the base density, temperature, and pressure correction factors for the measured liquid, shall be applied consistent with the latest revision of the appropriate standard.

9.2.1.4 To calculate equivalent base volumetric quantities, algorithms must be used to determine liquid base density, temperature, and pressure correction factors. The correction algorithms to be used for a specific liquid are defined in API *MPMS* Chapter 12.2.

9.2.1.5 These temperature and pressure correction factors are combined, and may also be combined with the meter factor if applicable, by serial multiplication into a combined correction factor (*CCF*). The multiplication sequence and rounding method are detailed in API *MPMS* Chapter 12.2, Part 2.

9.2.1.6 In liquid metering applications, a total quantity is determined by summation of the discrete quantities measured for a defined flow interval. In equation form, the calculation of total quantity is expressed as the following:

$$Qtot = \sum_{p = t_O}^{t - t_O} Qp \qquad (1)$$

where

Σ = summation operation for p time intervals,

$Qtot$ = quantity accrued between time t_0 and time t,

Qp = indicated volume (*IV*) measured at flowing conditions for each sample period p,

t_0 = time at beginning of operation,

t = time at end of operation.

9.2.1.7 The process variables that influence a flow rate normally vary during a metered transfer. Therefore, to obtain the total quantity requires the summation of flow over the transfer period, with allowance made for continuously changing conditions.

9.2.1.8 In liquid metering applications, the primary device provides measurement in actual volumetric units at flowing conditions. The volumetric units for an interval of time are provided as counts or pulses that are linearly proportional to a unit volume such that:

$$Qp = \frac{counts}{KF} \qquad (2)$$

where

counts = accumulated counts from primary device for time period p seconds,

KF = K-factor (counts per unit volume).

9.2.1.9 The instantaneous quantity flow per unit time—for example, flow rate per hour or flow rate per day—can be calculated as follows:

$$q_p = \frac{Qp}{p} \times k \qquad (3)$$

where

q_p = instantaneous quantity flow rate based on time period p,

Qp = total volume,

p = sample period (seconds),

k = conversion factor.

for example

k = 60 for minute based flow rates,

k = 3600 for hourly based flow rates,

k = 86,400 for 24-hour based flow rates.

9.2.1.10 The discrimination of quantity flow rate q_p in Equation 3 is proportional to the number of counts accumulated during the sample period and inversely proportional to the sample period.

9.2.2 Liquid Volume Correction Factors

Liquid volume correction factors are employed to account for changes in density and volume due to the effects of temperature and pressure upon the liquid. These correction factors are:

CTL—correction for effect of temperature on liquid at normal operating conditions.

CPL—correction for compressibility of liquid at normal operating conditions.

9.2.3 Correction for Effect of Temperature on Liquid (*CTL*)

9.2.3.1 If a petroleum liquid is subjected to a change in temperature, its density will decrease as the temperature rises or increase as the temperature falls. This density change is proportional to the thermal coefficient of expansion of the liquid, which varies with base density (*RHOb*) and liquid temperature.

9.2.3.2 The appropriate standards for correction factor (*CTL*) can be found in API *MPMS* Chapter 12.2, Part 1, Appendix B.

9.2.3.3 The weighted average *CTL* calculated by the appropriate standard and averaged in accordance with 9.2.1.3 will be stored as part of the quantity transaction record described in Section 10.

9.2.4 Correction for Effect of Pressure on Liquid (*CPL*)

9.2.4.1 If a petroleum liquid is subjected to a change in pressure, its density will increase as the pressure increases and decrease as the pressure decreases. This density change is proportional to the liquid's compressibility factor (*F*), which depends upon both the liquid's base density (*RHOb*) and temperature. The appropriate standards for correction factor (*CPL*) may be found in API *MPMS* Chapter 12.2, Part 1, Appendix B.

9.2.4.2 The correction factor for the effect of pressure on the liquid's density (*CPL*) can be calculated using the following expression:

$$CPL = \frac{1}{(1 - [P - (Pe_a - Pb_a)] \times [F])} \qquad (4)$$

and,

$$(Pe_a - Pb_a) \geq 0$$

where

Pb_a = base pressure, in absolute pressure units.

Pe_a = equilibrium vapor pressure at the temperature of the liquid being measured, in absolute pressure units.

P = operating pressure, in gauge pressure units.

F = compressibility factor for liquid.

9.2.4.3 The liquid equilibrium vapor pressure (Pe_a) is considered to be equal to base pressure (Pb_a) for liquids that have an equilibrium vapor pressure less than or equal to atmospheric pressure at flowing temperature.

9.2.4.4 The weighted average *CPL* calculated by the appropriate standard and averaged in accordance with 9.2.1.3 will be stored as part of the quantity transaction record described in Section 10.

9.2.5 Application of *CTL* and *CPL* for ELM Systems

Electronic liquid measurement systems allow compensation of the metering system for pressure and temperature effects on the volume of the fluid by the real-time electronic calculation of *CPL* and *CTL* during metering. Where proving control and calculations are performed within the tertiary device, or where an output of the tertiary device representing the compensated volume is used as an input to a prover, *CTL* and *CPL* may also be applied by the ELM system during proving.

Care must be taken to ensure that compensation is only applied once to metered quantities and to quantities used during proving to determine meter factors.

9.2.5.1 Proving

9.2.5.1.1 When proving a meter using a tertiary device to calculate a meter factor and the meter pulse input to the tertiary device is not compensated for temperature and/or pressure, the respective corrections must be manually entered into the tertiary device (*CTLm*, *CPLm*, *CTLp*, and *CPLp*).

9.2.5.1.2 When on-line pressure compensation is performed by a tertiary device, a composite meter factor must not be calculated during proving.

9.2.5.2 Normal Operation

Volumes calculated and accumulated during an accounting period by a tertiary device using on-line *CTLm* and *CPLm* are gross standard volumes. Temperature and/or pressure corrections must not be applied, either manually or by other systems, to the gross standard volume in a quantity transaction record after the gross standard volume has been generated by the tertiary device.

9.2.6 Calculation Intervals

9.2.6.1 Frequent samples of the pulse accumulator will be taken and the incremental volume calculated (using Equation 1) to allow flow weighting of the live process variables and accurate determination of the corrected volume. The sample period may be a fixed or variable time interval not to exceed 5 seconds.

9.2.6.2 In all cases, every pulse from the primary device shall be counted. Calculations of the combined correction factor (*CCF*) will be performed on a main calculation period (*mcp*) of one minute or less. Longer main calculation periods may be specified if any differences are acceptable to all parties involved.

9.2.6.3 At the end of each main calculation period (*mcp*), a combined correction factor (*CCF*) is calculated using the flow variable inputs as determined by the techniques given in 9.2.8 and the averaging techniques given in 9.2.1.3. Recording the *CCF* in the quantity transaction record is not required.

$$CCF_{mcp} = CTL_{mcp} \times CPL_{mcp} \qquad (5)$$

where

CCF_{mcp} = combined correction factor for the main calculation period,

CTL_{mcp} = correction for the effect of temperature on the liquid during normal operating conditions in the main calculation period,

CPL_{mcp} = correction for the effect of pressure on the liquid during normal operating conditions in the main calculation period.

9.2.7 Calculation of Volume

9.2.7.1 At the end of each main calculation period (*mcp*), temperature and pressure correction factors (*CTL* and *CPL*) are calculated using the flowing variable inputs as determined by the techniques given in 9.2.8. Equations 6 and 7 ensure that the resultant *CCF* factor used to correct *Qp* to base conditions is representative of the flowing conditions that existed when the meter pulses used to calculate *Qp* were accumulated.

9.2.7.2 Unless agreed upon differently by all parties, main calculation periods (*mcp*) greater than five seconds require that the calculated *CCF* is used to correct only the volume quantity accumulated during the same main calculation period (*mcp*) that the *CCF* factor is based on.

$$Qb_{mcpi} = Qp_{mcpi} \times CCF_{mcpi} \tag{6}$$

where

Qb_{mcpi} = volume quantity at base condition for the main calculation period *i*,

Qp_{mcpi} = volume quantity measured at flowing conditions for the main calculation period *i*,

CCF_{mcpi} = combined correction factor based on the main calculation period *i*.

9.2.7.3 In cases when the main calculation period is five seconds or less, or when all interested parties agree, the most recently calculated combined correction factor can be used to correct the volume quantity (*Qp*) calculated using Equation 7:

$$Q_b = Q_p \times CCF_{pmcp} \tag{7}$$

where

Q_b = volume quantity at base conditions for sample period *p*,

Q_p = indicated volume (*IV*) measured at flowing conditions for each sample period *p*,

CCF_{pmcp} = combined correction factor based on the previous main calculation period (*pmcp*).

9.2.7.4 When the volumes calculated by an ELM device are reviewed, it should be possible to reproduce the results of an individual volume calculation (using a single set of input pressures, temperatures, densities, etc.) to within 1 part in 10,000 or better using check calculations.

9.2.8 Sampling Flow Variables

9.2.8.1 The algorithms used to calculate base volumetric quantities require sampling of dynamic variables, such as flowing temperature, pressure and, optionally, density. The sampling interval for a dynamic input variable shall be at least once every five seconds. Multiple samples taken within the five-second time interval may be averaged using any of the techniques given in 9.2.1.3.

9.2.8.2 When the volumetric method of weighted averaging techniques is used, the sample volume size should be selected so that flow variables are sampled within the five-second requirements for the minimum flow rate during normal operating conditions.

9.2.8.3 When the count output of the primary sensor is less than one pulse every five seconds, input variables may be sampled once per count.

9.2.8.4 A less frequent sampling interval may be used if it can be demonstrated that the increase in uncertainty is no greater than 0.05 percent and the longer sampling interval is agreeable to the parties involved.

9.2.8.5 Sampling rates required for correcting the prover volume will be identical to those required for quantity determination—that is, sample at least every five seconds or take at least one sample per pass of the prover displacer.

9.2.9 No-Flow Condition

No-flow is the absence of fluid passing through the primary device. During no-flow conditions, input variables may continue to be sampled and displayed for monitoring purposes, but they will have no effect on the averages used in volume calculations.

9.2.10 Determining Transaction Quantities

9.2.10.1 Indicated volume (*IV*) is determined at flowing temperature and pressure for a custody transfer transaction using the following equation:

$$IV = \sum_{p=1}^{n} Q_{Tp} \tag{8}$$

where

Σ = summation operation for all sample periods during transaction,

IV = indicated volume accrued during transaction,

Q_{Tp} = actual volume measured at flowing conditions for each sample period *p* during the transaction *T*, sample period *p* not to exceed one minute,

n = last sample taken at the end of the transaction.

9.2.10.2 Indicated standard volume (*ISV*) is determined at base or reference temperature and pressure for a custody transfer transaction. *Corrections for meter performance (MF) are **not** applied.*

$$ISV = \sum_{p=1}^{n} Q_{Tp} \times CCF_{Tp} \tag{9}$$

where

Σ = summation operation for all sample periods during the transaction,

ISV = indicated standard volume accrued during the transaction,

Q_{Tp} = actual volumetric quantity measured at flowing conditions for each sample period p during the transaction T, sample period p not to exceed one minute,

n = last sample taken at the end of the transaction,

CCF_{Tp} = combined temperature and pressure correction factor in effect for each sample period p during the transaction T.

9.2.10.3 Gross standard volume (*GSV*) is determined at base or reference temperature and pressure for a custody transfer transaction, and corrections are made for the meter factor (*MF*).

9.2.10.4 When the meter factor is not applied until some time after the transaction is complete, the following equation is used.

$$GSV = ISV \times MF \tag{10}$$

where

MF = meter correction factor in effect during the transaction.

9.2.10.5 In cases where more than one meter factor is used, *MF* is the weighted average meter correction factor for the transaction; the methods described in 2.9.13 are used to determine the average.

9.2.10.6 When the meter factor is applied continuously during the transaction, the gross standard volume is calculated by the following:

$$GSV = \sum_{p=1}^{n} Q_{Tp} \times CCF_{Tpgsv} \tag{11}$$

where

GSV = gross standard volume accrued during the transaction,

Q_{Tp} = actual volumetric quantity measured at flowing conditions for each sample period p during transaction T, sample period p not to exceed one minute,

CCF_{Tpgsv} = combined temperature, pressure, and meter correction factors in effect for each sample period p during transaction T, sample period p not to exceed one minute.

9.2.11 Rounding Rules to Be Used by Tertiary Devices

9.2.11.1 Differences between the results of mathematical calculations can occur in different equipment or programming languages because of variations in multiplication sequence and rounding procedures. To ensure consistency, individual correction factors are multiplied serially and rounded once to the required number of decimal places. API *MPMS* Chapter 12.2 details the correct sequence and the rounding and truncating procedures to be used in *CCF* calculations.

9.2.11.2 The incremental volumes calculated for each *mcp* should not be rounded or truncated. The method of rounding or truncation of volumes, such as gross standard volume (*GSV*), at the end of the quantity transaction record period, should be per API *MPMS* Chapter 12.2 unless otherwise agreed upon by the parties involved.

9.2.12 Verifying Quantities Calculated by Real Time Flow Computation Devices

9.2.12.1 Electronic flow computation devices present unique problems when attempts are made to verify the resultant quantity calculated using real time methods versus the quantity calculated at the end of a transaction using the methods discussed in API *MPMS* Chapter 12.2.

9.2.12.2 The following example illustrates the limitations of checking calculations that involve correction factors that are rounded to a certain decimal resolution. For calculation simplicity, the example involves transferring (as one transaction) the contents of two storage tanks, each containing exactly 100,000 barrels of identical crude but at different temperatures delivered at different pressures. The actual temperatures, pressures, and API gravities used in the example are chosen only to illustrate a point. The equilibrium pressure is assumed to be < 0 psig.

Example: Crude oil, 65 API_{60} gravity, 100,000 gross indicated barrels are transferred at 75°F and 195 psig. Then

100,000 gross indicated barrels are transferred at 76°F and 205 psig.

Based on equal volumes at differing temperatures and pressures, the flow weighted averages and correction factors are:

$$\text{temperature} = \frac{(100{,}000 \times 75) + (100{,}000 \times 76)}{200{,}000}$$

$$= 75.5°\text{F}$$

CTL = 0.9898 (*MPMS* Chapter 11.1, Table 6A)

$$\text{pressure} = \frac{(100{,}000 \times 195) + (100{,}000 \times 205)}{200{,}000}$$

$$= 200 \text{ psig}$$

CPL = 1.0018 (*MPMS* Chapter 11.2.1)

Combined Correction Factor

CCF = *CTL* x *CPL*

= 0.9898 x 1.0018

= 0.9916 (rounded per *MPMS* Chapter 12.2)

Gross Standard Volume or check quantity, calculated in accordance with Chapter 12.2 using flow weighted average method:

GSV = 200,000 x 0.9916

= 198,320 barrels

The flow computational device integrates the same indicated volume as many smaller sample quantities. Each sample quantity is corrected individually using the appropriate factors.

The first 100,000 indicated barrels are corrected as follows:

temperature = 75°F

CTL = 0.9901 (*MPMS* Chapter 11.1, Table 6A)

pressure = 195 psig

CPL = 1.0017 (*MPMS* Chapter 11.2.1)

Combined Correction Factor

CCF = 0.9918 (*MPMS* rounding per Chapter 12.2)

Gross Standard Volume for the first 100,000 indicated barrels

GSV = 100,000 x 0.9918

= 99,180 barrels

The second 100,000 indicated barrels are corrected as follows:

temperature = 76°F

CTL = 0.9894 (*MPMS* Chapter 11.1, Table 6A)

pressure = 205 psig

CPL = 1.0018 (*MPMS* Chapter 11.2.1)

Combined Correction Factor

CCF = 0.9912 (rounded per *MPMS* Chapter 12.2)

Gross Standard Volume for the second 100,000 indicated barrels

GSV = 100,000 x 0.9912

= 99,120 barrels.

Gross Standard Volume for the total transaction using real time electronic flow computing device is

= 99,180 + 99,120

= 198,300 barrels.

In the example above, the two calculation methods produce quantities that differ by 20 barrels, or about 0.01 percent. This difference can range from 0 to approximately 0.01 percent, due to the discrimination and rounding levels of the correction factors.

9.2.13 Averaging Techniques

9.2.13.1 Two different averaging techniques may be performed on the sampled flow rate variables or input variables used to calculate the flow quantities or for providing values as detailed in Section 10, "Audit and Reporting Requirements."

9.2.13.2 These techniques are the following:

a. Volumetric method—the weighted average (*WA*) of a variable is the average of the variable values sampled at uniform volume intervals and is representative of the total volume sample.

$$WA = \frac{\sum_{i=1}^{n} Var_i}{n} \tag{12}$$

where

WA = weighted average of a variable value (*Var*),

Var_i = value of the variable sampled at the time of volume interval *i*,

n = the number of uniform volume intervals.

b. Time-based method—the weighted average (*WA*) of a variable is the sum of the variable values sampled during the time interval, multiplied by the volume determined during the same time interval and divided by the entire volume measured.

$$WA = \frac{\sum_{t=t_o}^{t_{tot}-t_o} Var_i \times Q_1}{Q_{tot}} \tag{13}$$

where

WA = weighted average of a variable value (Var) for the total volume measured,

Var_i = value of the variable sampled at time interval i,

Q_i = volume measured during time interval i,

Q_{tot} = total volume measured,

t_{tot} = total time interval.

9.2.14 Weighted Averages and No-Flow Conditions

9.2.14.1 Weighted average calculations must not take place during no-flow conditions.

9.2.14.2 The averaging equations stated above achieve zero flow as follows:

Equation 12—If no flow occurs, there is no volume interval and the equation is not performed.

Equation 13—The variable value is summed after first being multiplied by Q_i, which is equal to zero during no-flow conditions.

9.2.15 Liquid Density

9.2.15.1 The density of the liquid at base conditions (*RHOb*) must be accurately known to calculate the correction factors *CTL* and *CPL*.

9.2.15.2 The density of the liquid at base conditions (*RHOb*) can be determined by one of the following methods:

a. An empirical density correlation.
b. An equation of state.
c. An appropriate technical expression.

9.2.15.3 It is important to recognize that the density of the liquid at flowing temperature and pressure conditions (*RHOtp*) is related to the density of the liquid at base conditions (*RHOb*) by factors *CTL* and *CPL*. In cases where flowing density (*RHOtp*) is measured using an on-line densitometer, density at base conditions (*RHOb*) can be determined from the following expression:

$$RHOb = \frac{RHOtp}{CTL \times CPL} \tag{14}$$

9.2.15.4 Appendix B of API *MPMS* 12.2 contains a list of recommended correlations between liquid density, temperature, and pressure for different liquids. Where an API correlation does not exist, an appropriate ASTM or GPA standard, technical paper, or report is referenced.

9.2.15.5 The method selected for determining the liquid density at base conditions (*RHOb*) shall be mutually agreed upon by all parties involved in the measurement.

9.2.16 Principle Correction Factors

9.2.16.1 The calculations in this section are used to correct the measured volume of petroleum liquid in relation to its volume at base conditions. Correction factors are provided to adjust the metered volume and the volume of prover and/or test measurements to base conditions.

9.2.16.2 It is strongly recommended that both the meter and the prover measure both pressure and temperature to effectively correct the meter and the prover for those effects. Placement of pressure and temperature devices should be in accordance with recommendations in API *MPMS* Chapter 4.8.

9.2.17 Prover Steel Correction Factors

9.2.17.1 Prover steel correction factors are employed to account for changes in the prover volume due to the effects of temperature and pressure upon the steel. These correction factors are:

a. *CTS*—corrects for thermal expansion and/or contraction of the steel in the prover shell due to the average prover liquid temperature. (See 9.2.18.)
b. *CPS*—corrects for pressure expansion and/or contraction of the steel in the prover shell due to the average prover liquid pressure. (See 9.2.19.)

9.2.17.2 When the volume of the container at base conditions (Vb) is known, the volume at any other temperature and pressure (Vtp) can be calculated from the following equation:

$$Vtp = Vb \times CTS \times CPS \tag{15}$$

9.2.17.3 Conversely, when the volume of the container at any temperature and pressure (Vtp) is known, the volume at base conditions (Vb) can be calculated by:

$$Vb = \frac{Vtp}{(CTS \times CPS)} \tag{16}$$

9.2.18 Correction for the Effect of Temperature on Steel (*CTS*)

Any metal container, be it a pipe prover, a tank prover, or a portable test measure, will change its volume when subjected to a change in temperature. The volume change, regardless of prover shape, is proportional to the cubical coefficient of thermal expansion of the material. The cubical coefficient of thermal expansion is valid when the calibrated section and its detector switch mountings are constructed of a single material (pipe provers, tank provers, and field measures).

9.2.18.1 Corrections for Single-Walled Container or Prover

9.2.18.1.1 The *CTS* for pipe provers, open tank provers, and portable test measures assumes a single construction material and may be calculated from:

$$CTS = 1 + [(T - Tb) \times Gc] \tag{17}$$

where

Gc = mean coefficient of cubical expansion per degree temperature of the material of which the container is made between Tb and T,

Tb = base temperature,

T = mean liquid temperature in the container.

9.2.18.1.2 The mean coefficient of cubical expansion (*Gc*) for a pipe prover or open tank prover shall be the one for the materials used in the construction of the calibrated section. However, the *Gc* values contained in Table 1 shall be used if the coefficient of cubical expansion is unknown.

9.2.18.1.3 The mean coefficient of cubical expansion (*Gc*) in the report of calibration furnished by the calibrating agency should be used for that field measure.

9.2.18.2 Corrections for Small Volume Provers with External Detectors

9.2.18.2.1 While the mean coefficient of cubical expansion is used in calculating *CTS* for pipe provers, tank provers, and field measures, a modified approach is needed for certain small volume provers because of their design. The detector(s) are mounted externally, rather than on the prover barrel itself. Thus, the volume changes that occur due to temperature are defined in terms of the area change in the prover barrel and the change in distance between detectors. Occasionally, these detector positions may be on a carbon or stainless steel mounting, but it is much more likely that they will be on a mounting made of a special alloy that has a very small linear coefficient of expansion.

9.2.18.2.2 For small volume provers that utilize detectors not mounted on the calibrated section of the pipe, the correction factor for the effect of temperature (*CTS*) may be calculated from:

$$CTS = (1 + [(Tp - Tb) \times (Ga)]) \times (1 + [(Td - Tb) \times (Gl)] \tag{18}$$

where

Ga = area thermal coefficient of expansion for prover chamber,

Gl = linear thermal coefficient of expansion on displacer shaft,

Tb = base temperature,

Td = temperature of the detector mounting shaft or displacer shaft on small volume prover (*SVP*) with external detectors,

Tp = temperature of the prover chamber.

Table 1—Coefficients of Thermal Expansion for Steel (*Gc, Ga, Gl*)

Type of Steel	Thermal Expansion Coefficient (per °F)	Thermal Expansion Coefficient (per °C)
A. Cubical Coefficient, *Gc*		
Mild Carbon	1.86E-05	3.35E–05
304 Stainless	2.88E–05	5.18E–05
316 Stainless	2.65E–05	4.77E–05
17-4PH Stainless	1.80E–05	3.24E–05
B. Area Coefficient, *Ga*		
Mild Carbon	1.24E–05	2.23E–05
304 Stainless	1.92E–05	3.46E–05
316 Stainless	1.77E–05	3.18E–05
17-4PH Stainless	1.20E–05	2.16E–05
C. Linear Coefficient, *Gl*		
Mild Carbon	6.20E–06	1.12E–05
304 Stainless	9.60E–06	1.73E–05
316 Stainless	8.83E–06	1.59E–05
17-4PH Stainless	6.00E–06	1.08E–05

9.2.18.2.3 The linear and area thermal coefficients of expansion should be the same as those for the materials used in the construction of the prover. The values contained in Table 1 shall be used if the coefficients are unknown.

9.2.19 Corrections for the Effects of Pressure on Steel (*CPS*)

If a metal container, such as a conventional pipe prover, a tank prover, or a test measure, is subjected to an internal pressure, the walls of the container will stretch elastically and the volume of the container will change accordingly.

9.2.19.1 Corrections for Single-Walled Container or Prover

9.2.19.1.1 Although simplifying assumptions are used in the equations below, for practical purposes the correction factor for the effect of internal pressure on the volume of a cylindrical container, *CPS*, may be calculated from:

$$CPS = 1 + \frac{[(P - Pb) \times ID]}{(E \times WT)} \qquad (19)$$

Assuming *Pb* is zero gauge pressure, the equation simplifies to:

$$CPS = 1 + \frac{(P \times ID)}{(E \times WT)} \qquad (19a)$$

and,

$$ID = OD - (2 \times WT)$$

where

P = internal operating pressure of prover in gauge pressure units,

Pb = base pressure in gauge pressure units,

ID = internal diameter of container,

E = modulus of elasticity for container material,

OD = outside diameter of container,

WT = wall thickness of container.

9.2.19.1.2 The modulus of elasticity (*E*) for a pipe prover or open tank prover shall be the one for the materials used in the construction of the calibrated section. The values contained in Table 2 shall be used if the modulus of elasticity is unknown.

Table 2—Modulus of Elasticity for Steel Containers, *E*

Type of Steel	Modulus of Elasticity (per psi)	(per Bar)	(per kPa)
Mild Carbon	3.00E+07	2.07E+06	2.07E+08
304 Stainless	2.80E+07	1.93E+06	1.93E+08
316 Stainless	2.80E+07	1.93E+06	1.93E+08
17-4PH Stainless	2.85E+07	1.97E+06	1.97E+08

9.2.19.1.3 The modulus of elasticity (*E*) on the report of calibration furnished by the calibrating agency is the one used for that individual field measure. The values contained in Table 2 shall be used if the modulus of elasticity is unknown.Corrections for Double-Walled Container or Prover

Some provers are designed with a double wall to equalize the pressure inside and outside the calibrated chamber. In this case, the inner measuring section of the prover is not subjected to a net internal pressure, and the walls of this inner chamber do not stretch elastically. Therefore, in this special case:

$$CPS = 1.0000$$

9.2.20 Combined Correction Factors (*CCF*, *CCFp*, *CCFm*)

9.2.20.1 When multiplying a large number (for example, an indicated volume) by a small number (for example, a correction factor) over and over again, a lowering of precision may occur. In addition, errors can occur in mathematical calculations because of differences in sequencing and rounding between different machines and/or programs. To minimize these errors, a method was selected by the industry that combines correction factors in a specified sequence and maximum discrimination levels. The method for combining two or more correction factors is to first obtain a combined correction factor (*CCF*) by serial multiplication of the individual correction factors and rounding the *CCF* to a required number of decimal places.

9.2.20.2 Three combined correction factors have been adopted to minimize errors in calculations. They are combined correction factor (*CCF*), combined correction factor for the meter (*CCFm*), and combined correction factor for the prover (*CCFp*).

a. For measurement ticket calculations to determine *GSV*:

$$CCF = CTL \times CPL \times MF \qquad (20)$$

or,

$$CCF = CTL \times CPL \times CMF \qquad (20a)$$

Note: If the indicated volume is temperature compensated, the *CTL* value shall be set to 1.0000 for *CCF* measurement ticket calculations.

Note: When using a *CMF*, the *CPL* value shall be set to 1.0000 for *CCF* for ticket calculations.

b. For proving calculations to determine *GSVP*:

$$CCFp = CTSp \times CPSp \times CTLp \times CPLp \qquad (21)$$

c. For proving calculations to determine *ISVm*:

$$CCFm = CTLm \times CPLm \quad (22)$$

Note: When using temperature compensated meter readings (*ISVm*), the *CTL* value shall be set to 1.0000 for *CCFm* proving report calculations.

9.2.21 Meter Factors and Composite Meter Factors

9.2.21.1 General

Meter factors and composite meter factors are used to adjust for inaccuracies associated with the meter's performance as determined at the time of proving. Unless the meter is equipped with an adjustment that alters its registration to account for the meter factor, a meter factor must be applied to the indicated volume of the meter.

9.2.21.1.1 Meter Factors

The meter factor (*MF*) is determined at the time of proving by the following expression (gross standard volume in prover divided by the indicated standard volume through the meter):

$$MF = \frac{GSVp}{ISVm} \quad (23)$$

where

$GSVp = BPV \times CCFp,$

$ISVm = IVm \times CCFm,$

$IVm = \frac{\text{average pulses}}{KF},$

KF = K-factor,

BPV = base prover volume.

9.2.21.1.2 Composite Meter Factor

The composite meter factor (*CMF*) may be used in applications where the density, temperature, and pressure are considered to be constant throughout the QTR period or anticipated changes in these parameters result in uncertainties acceptable to the parties or as agreed to by the parties as a convenience. The composite meter factor is determined at the time of proving by the following expression:

$$CMF = CPLm \times MF \quad (24)$$

9.2.21.2 Meter Factor Linearization

9.2.21.2.1 Consideration may be given to meter factor linearization within the tertiary device when operating flowrates or viscosities vary enough to influence the meter factor. One linearization method consists of tables of meter factors versus flow rate or viscosity for each meter or product. Systems with significant process variable excursions benefit the most from meter factor linearization. Linearization systems can be implemented that allow for periodic provings at single flow rates, provided the meter is being operated within the recommended range. Such linearization attempts will not remove the obligation to establish a meter factor by proving or to substitute previously obtained meter factors when encountering shifts in viscosity as a result of changes in product and/or temperature.

9.2.21.2.2 Given that there are no specific API-approved methods for applying linearization, interested parties should agree on a methodology prior to implementing an ELM system.

9.2.22 K-Factors and Composite K-Factors

For some applications, new K-factors (*KF*) and composite K-factors (*CKF*) are utilized to eliminate the need for applying meter correction factors to indicated volume (*IV*). By changing the *KF* or *CKF* at the time of proving, the meter is electronically adjusted at the time of proving to ensure that the meter factor is approximately unity.

9.2.22.1 K-Factor

A new K-factor is determined at the time of proving by the following expression:

$$\text{New } KF = \frac{(\text{Old } KF)}{MF} \quad (25)$$

9.2.22.2 Composite K-Factor

A new composite K-factor (*CKF*) may be used in applications where the density, temperature, and pressure are approximately constant throughout the measurement ticket period. The new composite K-factor is determined at the time of proving by the following expression:

$$\text{New } CKF = \frac{(\text{Old } CKF)}{CMF} \quad (26)$$

10 Auditing and Reporting Requirements

10.1 GENERAL

10.1.1 An electronic liquid measurement system shall be capable of establishing an audit trail by compiling and retaining sufficient information to verify custody transfer quantities. Since the accuracy of an ELM system is also affected by the calibration provided by a prover, an audit trail is also necessary for the prover. The audit trail shall include quantity transaction records, configuration logs, event logs, alarm logs, corrected quantity transaction records, and field test records. **Audit trail information may be retained in paper or electronic format.**

10.1.2 Audit trail requirements apply only to data that affect net volumetric calculations and the custody transfer quantity. Off-site systems often perform functions other than those described in the standard. These other functions are not a part of this standard. Only data associated with measurement is to be included under auditing and reporting requirements.

10.1.3 The following subsections define the purpose of each type of record, the required data contained therein, and the minimum retention time for that information so that the integrity of custody transfer quantities calculated by the flow computation device can be verified.

10.1.4 The primary reason for retaining historical data is to provide support for the current and prior quantities reported in measurement and quantity statements for a given accounting cycle. The data will provide sufficient information to apply reasonable adjustments if electronic liquid measurement equipment stops functioning or is inaccurate, or when measurement parameters are incorrectly recorded.

10.1.5 When data must be edited because it is erroneous, original values must be available so that the validity of estimated values can be confirmed. Methods of determining estimates of corrected values are beyond the scope of this standard.

10.2 CONFIGURATION LOG

10.2.1 A configuration log is one source of the information required to audit calculated quantities for an accounting period. The required information may be generated from data within the flow computation device, prove reports, or other sources. The log will contain and identify all constant flow parameters used in the generation of a quantity transaction record. The terms "constant flow parameters" or "fixed data" do not imply that the information will never change once entered, but it is not likely to change with each accounting period or batch. The meter factor, for example, is considered to be a constant flow parameter, even though it may vary on a weekly or monthly basis when a meter is proved. The configuration log will be generated from data and information listed below, along with any additional items that are deemed necessary.

10.2.1.1 Linear meter:

a. Meter identifier and/or serial number.
b. Meter factor.
c. Base temperature.
d. Equilibrium pressure.
e. Base pressure.
f. Meter K-factor.
g. Input/output assignments.
h. Engineering units.
i. Configuration log printout date and time.
j. Product internal diameter (*ID*).
k. Span/zero information, dead band, and offsets used.
l. High and low flow alarm limits.
m. Out of range alarm limits for measured values.
n. Software revision number.
o. Algorithm identifier (e.g., standard used to calculate *CTL* and *CPL*).
p. Coefficient of thermal expansion if not already specified in the tables used.
q. Default values for any live inputs in case of failure such as temperature, pressure, density, vapor pressure, sediment and water (S&W).

10.2.1.2 Prover data (if applicable):

a. Prover identifier.
b. Base prover volume.
c. Serial number for prover.
d. Inside diameter of prover.
e. Wall thickness.
f. Input/output assignments.
g. Metallurgical data to calculate *CTSp* and *CPSp*.
h. Prove acceptance criteria; repeatability, reproducibility, number of runs.

10.2.1.3 Master meter:

a. Meter factor.
b. Meter identifier.
c. Serial number.
d. K-factor.

10.2.1.4 Optional data:

a. Expected total measured quantity to be used in sampling calculation.
b. End of batch percentage for warning of batch completion.
c. Sampler pulse information (flow or time proportional).
d. Sampler volume expected.
e. Sampler grab size.
f. RTD characterization curve.
g. Constants related to densitometer operation.
h. Default values for vapor pressure, S&W.

10.2.2 Where multiple algorithms may be selected for the calculation of a quantity or factor (such as Table 6A or Table 6C temperature correction factors), the configuration log shall record what selection was made. Where the algorithm selection is dictated by the product type or other logic, the criteria for algorithm selection must be clear.

10.3 QUANTITY TRANSACTION RECORD (QTR)

This record includes critical information relating to custody transfer of fluids. This information consists of the final custody transfer quantity at reference conditions, certain properties of the fluid, correction factors and readings used in the calculation of the custody transfer quantity, meter identification, and timing of the transaction. While it may be possible to exactly calculate the final calculated custody transfer quantity from other information in the quantity transaction record, this is not normally true because of the averaging of variables and rounding in calculations. The quantity transaction record is used to convey information about fluid movement from operations to accounting and between parties in a custody transfer agreement. In batch operations (discrete product movements), the QTR relates to a specific shipment of product (batch of product), usually of pre-determined quantity. In continuous operations the QTR relates to a quantity movement during a specific accounting time period, such as a day, week, or month.

The units of measure for all variables in the QTR must be explicitly stated.

10.3.1 Required Information

10.3.1.1 The quantity transaction record must include the following:

a. Opening and closing date and time.
b. Opening and closing readings (*MRo*, *MRc*).
c. Product type identifier where multiple products are measured with a single meter.
d. Meter bank identifier where there is more than one bank.
e. Meter identifier.
f. Meter factor (*MF*) or composite meter factor (*CMF*) and/or K-factor (*KF*).
g. Average temperature correction factor (*CTL*).
h. Average pressure correction factor (*CPL*).
i. Observed density and temperature when a sample is used to determine density at base conditions.
j. Weighted average pressure (*PWA*).
k. Weighted average temperature (*TWA*).
l. Weighted average density (*DWA*) or default density, at reference conditions.
m. S&W or correction for S&W (*CSW*) where water or sediment exists in nonmarketable quantities.
n. Net standard volume (*NSV*).
o. QTR identifier (e.g., meter ticket number).
p. Gross standard volume (*GSV*).

10.3.1.2 Where no sediment or water exist in the custody transfer stream, or where they are considered part of the salable product, the net standard volume (*NSV*) will be identical to the gross standard volume (*GSV*).

10.3.1.3 A provision should be in place to prevent multiple QTRs from being generated for the same product delivery batch at different times during the delivery such that it is uncertain which is the "official" quantity transaction record. This may take the form of a required reset of the volume accumulator each time a QTR is generated, the use of an "Official/Interim QTR Flag," the use of separate reports for operational volume checks and QTRs, or other appropriate method.

10.3.2 Data Revisions

Should it be necessary to make a revision to any data in the quantity transaction record, a revision date and the name/identifier code of the party making the revision must be recorded. Some way of identifying which data was changed must be included as well. The original quantity transaction record must be retained.

10.3.3 Data Sources

10.3.3.1 All of the information required in the quantity transaction record may not be available at the time the commodity transfer is made, nor will it necessarily all be captured by one device or on one hard copy record. This is acceptable providing all parties to the transfer agree, and all required information is ultimately captured and can be readily related to the transaction.

10.3.3.2 The quantity transaction record, which may be generated manually or by the tertiary device, is normally signed or somehow marked with some identifier by the person or parties who confirm that the information contained within is correct.

10.3.4 Multiple Meter Factors

When multiple K-factors or meter factors are used, or when a mathematical relationship is used to vary them based on some product or operating characteristic, the flow-weighted average K-factor or meter factor shall be displayed on the quantity transaction record, and all factors or constants shall be retained in the configuration log. Where multiple provings are conducted during the delivery of a single batch or during a single accounting period, a separate QTR may be generated for each proving.

10.4 VIEWING ELM DATA

In order to verify proper operation of the ELM system and provide the current status of the measurement system, a means of viewing ELM parameters is required. This may take the form of a local display, a hand-held viewing/configuration device, a hard copy printout on demand, or some means of remote access monitoring. The following information must be accessible:

a. Process variable inputs, in engineering units.
b. Pulse accumulator registers.

c. Alarm conditions.

d. Accumulated volume in the batch or accounting time period.

10.5 DATA RETENTION

10.5.1 Retention of hourly records is not required. In those transactions where batch delivery takes less than a day and where the loss or corruption of a daily or batch quantity transaction record would result in no information upon which to base any estimate of the transaction volume, hourly information would be useful in reconciling data.

10.5.2 Regulation, tariff, or contract will specify the minimum retention period for all audit trail data.

10.6 EVENT LOG

10.6.1 The event log shall be part of the audit package for the accounting period. The event log is used to record exceptions and changes to the flow parameters or fixed data contained in the configuration log that have an impact on the quantity in a quantity transaction record, whether caused by system hardware or by an operator. The events include, but are not limited to, changes or modifications in 10.2.

10.6.2 Each time a constant flow parameter or fixed data that can affect the QTR is changed in the system, the old and new value, along with the date and time of the change, shall be logged in chronological order. It is desirable to capture the nonresettable totalizer reading(s) whenever a flow value is changed that could affect the QTR.

10.6.3 In addition to configuration log changes, the following are representative of the events that may be captured.

a. System power failure time and/or start-up time.

b. ELM hardware error diagnostic messages.

c. Sign-on and sign-off times for password-protected ELM systems.

d. Forcing a default value in place of a live input or output.

e. Download time to install a new program or configuration file during which data is not collected.

10.7 ALARM OR ERROR LOG

This log is used to note any system alarm or user-defined alarm or error conditions (such as temperature or pressure out of range) that occur. This includes a description of each alarm condition and the times the condition occurred and cleared. This log is primarily used to support the operation of the ELM system by providing the user with process information and information on equipment failure. At a minimum, an alarm must be logged whenever any input exceeds its defined span of operation.

10.8 TEST RECORD

A test shall be part of the audit package and should consist of any documentation or record (electronic or hard copy) produced in the testing or operation of metering equipment that would affect the calculation of measured quantities. The documentation shall include, but not be limited to:

a. Calibration/verification reports, as defined in Section 11, below.

b. Equipment change tickets.

c. Peripheral equipment evaluation reports.

11 Equipment Calibration and Verification

11.1 DEVICES REQUIRING CALIBRATION/ VERIFICATION

The following ELM devices require calibration/verification:

a. ELM input signal processing devices, such as A/D converters and frequency or pulse input cards.

b. ELM output signal generation, such as D/A converters and digital or pulse output cards.

c. Temperature transmitters.

d. Pressure transmitters.

e. Pulse transmitters and pickup coils.

f. Intermediate signal conditioning or isolating devices.

g. On-line densitometers.

h. Transmission signals to downstream electronic devices.

11.2 VERIFICATION AND CALIBRATION—PURPOSE AND USE

11.2.1 Verification is the process of comparing the actual field parameters (or simulated parameters representative of actual field conditions as measured by a traceable reference device) to the tertiary display device. Verification confirms whether the device is operating within some specified tolerance or requires calibration or repair. It typically would be the last step in a calibration procedure. Verifications should be performed periodically between calibrations as a check for conformity or drift when the time between calibrations is lengthy.

11.2.2 Calibration is the process of testing and adjusting ELM system components to conform with traceable reference standards to provide accurate values over the ELM's prescribed operating range. Calibration procedures should include the sensing device. This is inherent with pressure transmitters. If a bath is used in the calibration procedure for temperature transmitters, the sensor will be included. However, it is common to use resistance substitution when calibrating RTD temperature transmitters. When this is the case, a verification step involving the sensor is required.

11.3 VERIFICATION AND CALIBRATION FREQUENCY

11.3.1 Reference instruments and systems used in ELM calibration/verification shall be checked periodically against an instrument or system that is at least one level higher in the chain of traceability and then calibrated or replaced if appropriate. The recommended period is two years, and is not to exceed five years. Field conditions and frequency of use may dictate shorter calibration intervals.

11.3.2 The accuracy of all electronic liquid measurement (ELM) equipment should be verified quarterly. This interval is a recommended maximum and does not preclude verification and inspection on a more frequent basis when required by operating conditions or contractual agreements. The maximum verification interval may be extended by mutual agreement or when warranted by measurement and calibration/verification data. At least annually, a verification at a minimum of three points across the range of operation, or a calibration, should be performed. Also at this time, transmitters whose analog output is being utilized should be tested at the 0 percent and 100 percent output points to ensure that the transmitter can reach the end points.

11.3.3 Calibration will be necessary whenever a verification test produces an unacceptable difference between the value measured or produced by the traceable reference standard and that of the value measured and utilized by the ELM, and at contractually stipulated intervals.

11.4 VERIFICATION AND CALIBRATION EQUIPMENT

11.4.1 The maximum allowed uncertainty for calibration/verification equipment shall be no more than one-half of the accuracy desired from the device to be calibrated. For crude oils and products with densities heavier than 85 API (0.6535 relative density), the overall accuracy of temperature measurements shall be ±0.5°F (0.3°C), pressure measurements shall be ±3 PSI (20 kPa), and relative density measurements shall be ±0.001. Hydrocarbons lighter than 0.6535 relative density may require tighter tolerances to maintain suitable accuracy of the resulting *CTL* and *CPL* factors. Appendix F contains tables showing the effect of temperature, pressure, and density errors upon the corresponding correction factors used in volume corrections and may be used as a guide to determine the sensitivities for individual applications. An analysis of the impact of each input variable upon the final quantity transaction record quantity, using techniques discussed (see Section 6, "System Uncertainty"), may also be undertaken in order to determine the actual required accuracy for each parameter, stated in units appropriate for that parameter (°F, °C, psi, kPa, etc.).

11.4.2 Uncertainty for readout or measurement devices is usually related to a percent of full scale reading. The uncertainty for a desired reading must be calculated for each point. For example, a device with a stated accuracy of 0.05 percent over a range of 0 to 100 would correspond to an accuracy of only 0.2 percent for a reading of 25 (0.05 percent of 100 = 0.05, 0.05/25 = 0.2 percent). Also, sufficient significant digits must be present on a digital readout to ensure a suitably accurate measurement.

11.5 CALIBRATION PROCEDURES

ELM devices and their individual sensors, transmitters, and analyzers are substantially different in their methods of calibration. Some have zero, span, and linearity adjustments, while some have only zero and span. Others are calibrated via adjustments to firmware parameters (smart transmitters) and require no mechanical adjustments. Their signal output can be a voltage, current, or pulse frequency, or may be digitally communicated. For these reasons, the user must refer to the manufacturer's operation guide for step-by-step calibration procedures.

11.5.1 Multi-component Signal Loops

11.5.1.1 The majority of signal loops will consist of a transmitter that sends its signal directly to the ELM device input. In some cases, additional components may form part of the loop. During commissioning of the equipment, each component within the ELM I/O signal loop needs to be calibrated individually, using traceable equipment. An overall system calibration then needs to be performed by exposing the sensor to a known physical condition (temperature, pressure, etc.) and adjusting a single device until a final converted digital value agrees with the known physical quantity within the required tolerance. It is preferable, and may be necessary, to perform these same steps for routine calibrations.

11.5.1.2 Even with each individual component in the loop properly calibrated, the combined components may not properly reproduce a reference input at the tertiary device because of the cumulative effect of each device's errors. As a result, it will be necessary to determine for each system which device should receive the final adjustment. In the case of conventional transmitters, that device is typically the transmitter. Some smart transmitters do not provide for easy final adjustment, and the tertiary device would be the preferred choice. Where multiple devices are present in a signal loop, the same device should always be adjusted for each loop calibration. It is not desirable to recalibrate the range of a tertiary device input, say, from 0–300 to 3–303, in the case of a signal that was 1 percent low, in order to calibrate the overall loop. However, if the tertiary device has a provision for digitally adjusting the values of the analog span, this is acceptable.

11.5.1.3 When process variable signals are calibrated, regardless of which device in a loop is adjusted, the final outcome must be that the tertiary device representation of the signal must match the reference signal within the required tolerance.

11.5.2 Calibration of ELM Tertiary Device Input

It may be possible to calibrate the signal processing for analog inputs within an ELM tertiary device. If an ELM tertiary device receives analog signals, and the signal processing for those inputs can be calibrated, it may be necessary to individually adjust them prior to overall signal loop calibration. This calibration is frequently not performed because these inputs are quite stable or lack adjustments. A known traceable signal source, current, pulse, etc., is impressed upon the tertiary input at a minimum of three points across its span. The tertiary device will be calibrated to be within the required tolerance.

11.5.3 Calibration of Intermediate Devices

The use of intermediate signal conditioning and isolating devices is discouraged due to the additional uncertainties introduced. The devices must be calibrated individually and prior to system calibration. These devices are typically calibrated by impressing zero and full scale input signals and calibrating for the proper output signal. It is also acceptable to use the tertiary device as the readout device by first calibrating it, then calibrating intermediate devices by working towards the sensor.

11.5.4 Calibration of Temperature Devices

11.5.4.1 Transmitter calibration is accomplished by verifying the sensor and transmitter together as a unit, with the sensor placed in a controlled temperature environment or by simulation of the temperature sensor input for the given temperature. Sensor simulation is best done when the characteristics of the individual sensor are known and are used, as opposed to the use of normalized standard tables. Simulation equipment should have a minimum resolution and accuracy of 0.1°F or 0.05°C.

11.5.4.2 If a sensor is changed in a smart temperature transmitter, and a transmitter is required to meet strict accuracy requirements, the entire transmitter should be returned to the manufacturer or a qualified metrology lab for recalibration as a unit to ensure that performance will be maintained.

11.5.4.3 The charts in Figure 3 depict the IEC (International Electrotechnical Commission) 751 tolerances for Class A and Class B RTD sensors. These are also referred to by manufacturers as interchangeability or accuracy ratings. Individual manufacturers may have other tolerance ratings for their particular sensors. As can be seen from the charts, an error of more than 1.8°F (0.9°C) could be introduced by a class B RTD, depending upon operating temperatures. For this reason, if resistance substitution calibration methods are used, individual RTD resistance-temperature tables should be used. Increasingly, manufacturers are making provisions in their equipment for using the Callendar-Van Dusen, IPTS68, ITS90, or similar calibration constants. These constants are derived by testing individual RTD sensors. The constants for the individual RTD are then loaded into their respective transmitter.

11.5.4.4 Regardless of whether a sensor simulation or a temperature bath is used, a minimum of three points should be checked. If any adjustments are made, both the "as found" and the "as left" readings should be logged. If linearity adjustments are made, follow the manufacturer's procedure for determining the point at which this adjustment is made.

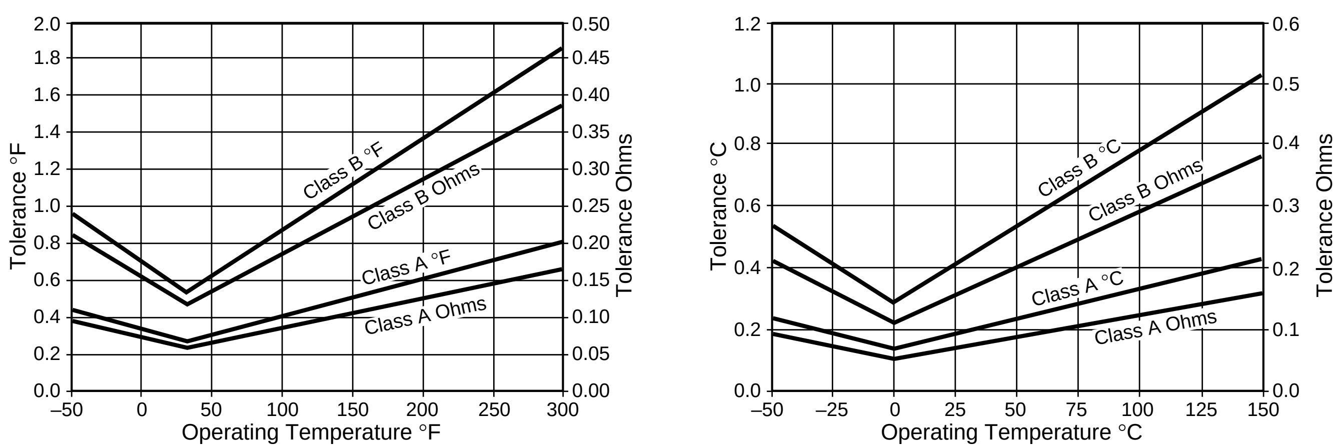


Figure 3—100 Ohm RTD Tolerance Plots

11.5.4.5 Calibration of the actual temperature sensor is not possible by the user, but the sensor must be included in the loop during verification of the system. If only a single point verification of the temperature element is performed, it should be performed at or very near the flowing temperature. If a two or more point verification is performed, the points should cover the range of expected operation.

11.5.4.6 A final verification at normal operating conditions should be made by placing the sensor and transmitter back into service and checking the reading on the ELM against the traceable thermometer. It is important to specify the correct immersion type sensor (partial, full) and utilize a thermal conductive medium to ensure proper transfer of heat from the thermowell to the sensor. Refer to 11.6.1 for information on correct use of thermometers.

11.5.5 Calibration of Pressure Devices

11.5.5.1 Transmitter calibration is accomplished by impressing known pressures upon the pressure sensor. The transmitter should be checked at a minimum of three points. If any adjustments are made, both the "as found" and the "as left" readings should be logged. If linearity adjustments are made, follow the manufacturer's procedures for determining the point at which this adjustment is made. Note that elevation differences between pressure sources and sensors can introduce errors when the medium is liquid. This becomes more significant when the pressures are low (100 psi/700 kPa or less). Transmitters and reference devices should not be located above the flow line being sensed.

11.5.5.2 A final verification at normal operating conditions should be made by placing the sensor and transmitter back into service and checking the reading on the tertiary device against a traceable pressure reference.

11.5.6 Calibration of Downstream Electronic Devices

Downstream electronic devices that are digitally linked to the tertiary device should provide a means to ensure that the data transmitted from the tertiary device and the received data is one and the same.

11.5.7 Proving of Densitometer Devices

11.5.7.1 Proving of a density meter is typically accomplished by calculation of a density meter factor. The calibration procedure for custody transfer applications is provided in API *MPMS* Chapter 14, Section 6—"Continuous Density Measurement." A density meter factor (*DMF*) is determined using the equation:

$$DMF = \frac{\rho_{tp}}{\text{Density Meter Reading}}$$

where

ρ_{tp} = reference density in same units as on-line density meter.

11.5.7.2 If the density meter produces an analog output signal that is used as an input to the tertiary device, this signal must be calibrated per the manufacturer's recommendation.

11.5.8 Calibration of Conventional Transmitters

Conventional transmitters that produce analog output signals provide for zero, span, and sometimes linearity adjustments. When calibrating a conventional transmitter, apply the process variable corresponding to the lower range value and adjust the zero. Apply the full scale process variable and adjust the span. Check the linearity at the midpoint, the normal operating point, or where specified by the manufacturer. All values need to be within the stated accuracy of the transmitter. Adjust the linearity adjustment if applicable. Any adjustment of the linearity must typically be followed by adjusting the zero and span again.

11.5.9 Calibration of Smart Transmitters

11.5.9.1 Smart transmitters contain both analog and digital sections, with the input and output sections being analog and the middle signal conditioning section being digital. Also, the conditioned digital output, prior to being converted to analog, is often available as a digital signal into the tertiary device. Use of digital transmission capabilities is desirable because it eliminates two analog/digital conversions. If the digital signal is being used, and if the input analog section cannot be adjusted by the user, it may be necessary for the tertiary device to perform corrections for the secondary devices. It is therefore important to understand the calibration of the different parts of smart transmitters.

11.5.9.2 Smart pressure transmitter manufacturers typically match the sensor and the electronics, since both are normally present within the transmitter housing and are supplied as a unit. Temperature sensing systems usually consist of separate sensors and electronics. While some manufacturers can match a smart transmitter to a temperature sensor, it is common for the user to do this for convenience.

11.5.9.3 Unless the digital output signal is being used, the transmitter output analog signal should be calibrated first. This needs to be done using either precision reference equipment or the tertiary device. If the tertiary device is used for a readout, any intermediate devices and the input section of the tertiary device must be calibrated prior to calibrating the smart transmitter.

11.5.9.4 For best accuracy, the input section of the temperature transmitter needs to be matched to the sensor. Not all transmitters allow the user access to this function. In the case of RTD and thermistor sensors, the resistance at a minimum of three temperatures, two of which match the end points of the range of calibration, should be known.

11.6 VERIFICATION PROCEDURES

Verification tests are a valuable troubleshooting tool (but not a replacement for calibration) and shall be conducted by comparing the ELM measured value (the digital value provided by the tertiary device) at normal operating conditions of each input variable to the value determined by a traceable reference standard. By utilizing the displayed value, the accuracy of the electrical signals between the sensors and the flow computation device will also be verified. Control limits should be established for acceptable variance between the reference standard and the tertiary device. A sensitivity analysis will determine appropriate limits for each variable. Appendix F has been provided as an aid in evaluating the effects of temperature, pressure, and density upon the *CTL* and *CPL* factors. See Section 6 for a more complete discussion of sensitivity and its effects upon uncertainty. Verifications, done more frequently than calibrations, provide assurance that secondary and tertiary devices are continuing to perform within acceptable control limits. If results of the verification test fall outside acceptable control limits, a calibration and possible troubleshooting will be required.

11.6.1 Verification of Temperature Devices

11.6.1.1 Sensor/transmitter verification is accomplished by comparing the temperature of the stream at normal conditions, as indicated by the ELM equipment, to a reference thermometer. This is best done by use of a reference thermowell adjacent to the ELM sensor thermowell and with sufficient flow to eliminate temperature stratification. The temperature should be at normal operating conditions. Electronic thermometers may be a better choice if thermowells interfere with the proper use of glass thermometers. Electronic thermometers must meet the requirements of *MPMS* Chapter 7. Alternatively, a temperature bath, set at the normal operating temperature, can be used to accommodate both the ELM sensor and reference thermometer.

11.6.1.2 Precision glass thermometers have scale graduation tolerances of 0.2°F to 0.5°F and should be supplied with a scale correction table. They may be of the partial or full immersion type. Partial immersion thermometers should be immersed to the proper level as marked on the thermometer. Use at different immersion depths or at significantly different ambient temperatures from those which the thermometer was certified for may require that stem corrections be made. Full immersion thermometers are typically partially immersed in a thermowell. The portion of the stem that is outside the thermowell will respond to the ambient temperature, which may cause a significant error in the reading, depending on the difference between the temperature being measured and the ambient temperature, and the amount of stem that is exposed to the ambient condition. Corrections can be made, and a correction method for full immersion thermometers appears in Appendix C.

11.6.1.3 When a verification test is performed, the "as found" reading should be recorded and compared to the reference device. Should the "as found" reading fail to agree with the reference device within the required control limit, a calibration of that device will be required. The reference thermometer should have a minimum resolution of 0.2°F (0.1°C). If the device being verified is to supply data for use during proving, it should agree within 0.2°F (0.1°C) of the reference device (see *MPMS* Chapter 7.2, Table 2).

11.6.2 Verification of Pressure Devices

11.6.2.1 Sensor/transmitter verification is accomplished by measuring the pressure of the stream at the same tap location as the ELM pressure sensor or a tap in near proximity to the sensor tap. No significant source of differential pressure should be located between these two taps. The pressure should be checked at normal operating conditions.

11.6.2.2 The effects of pressure changes on volume for heavier hydrocarbons is much less, relatively, than the effect due to temperature. An accuracy of ± 3 psi (20 kPa) for the pressure sensing device is more than adequate when using Table 11.2.1 (see note 1). When using factors from *MPMS* Chapter 11.2.2 for light hydrocarbons, a minimum accuracy of ± 3 psi (20 kPa) may be required at the most sensitive portion of the table at low operating pressures (see note 2). At high pressures and other areas of the table, up to an order less accuracy is needed. Light hydrocarbons are very sensitive to temperature and pressure, and a sensitivity analysis is highly recommended when using *MPMS* Chapter 11.2.2 or other math models, such as an equation of state. Refer to Appendix F for specific information. See Section 6 for additional information on uncertainty.

Notes:
1. At the most sensitive portion of the temperature and pressure correction tables in *MPMS* Chapters 11.1 and 11.2.1, the change in volume caused by a temperature change of 1°F (0.56°C) matches the volume change caused by a pressure change of 26 psi (179.3 kPa).
2. The most sensitive area is approximately at relative density of 0.390 at the maximum temperature of 82.5°F (28.1°C).

11.6.3 Verification of Density Measuring Devices

Routine verification of density measuring equipment can be accomplished by one of the following methods. However, the proving of density measuring equipment for custody transfer applications should be accomplished in accordance with API *MPMS* Chapter 14, Section 6, using the pycnometer method:

a. Comparison of live sample using a pycnometer.
b. Comparison of live sample with a lab densitometer.
c. Comparison of live sample with a hydrometer.

d. Comparison with in-line or parallel master densitometer.
e. Verification using reference fluids.

The appropriate method will depend upon the required accuracy. Cleaning, repair, or calibration of the on-line densitometer is warranted if the results of the comparison are beyond the stated accuracy of the equipment or such value as stipulated by agreement. Use solvents suitable for the fluid being measured. Mechanical cleaning needs to be accomplished with care so as to not damage the surfaces of the sensing device. Remove any deposits found on the sensor. After a densitometer is cleaned, it will be necessary to perform another verification comparison with a reference fluid or device.

11.6.3.1 Densitometer Verification Using a Pycnometer

Pycnometers obtain a sample that is at the same density, temperature, and pressure as the on-line densitometer at the time the sample is taken. Log the actual density being indicated by the on-line meter at the time the pycnometer sample is taken. See API *MPMS* Chapter 14, Section 6, for a complete description.

11.6.3.2 Densitometer Verification Using Lab Densitometers and Hydrometers

The use of lab densitometers and hydrometers requires that density, temperature, and pressure be obtained at the time the sample is taken, or that the indicated density has been corrected to standard conditions. Volatile fluids must be sampled and tested under pressure. Since it is not normally possible to recreate the same conditions in the lab densitometer or a hydrometer that were present in the on-line densitometer, corrections are typically made to both the on-line densitometer and the reference density readings to obtain densities at standard conditions. Lab densitometers usually have a temperature controlled chamber that can be set to match the standard temperature; thus, no temperature correction to standard conditions will be necessary. If the fluid is stable at the reference condition such that pressure can be removed, no pressure correction will be required either. Refer to ASTM D 5002 for the laboratory densitometer method and API *MPMS* Chapter 9, Sections 1, 2, and 3 for hydrometer methods.

11.6.3.3 Densitometer Verification Using In-Line Densitometers

Periodic comparisons to a reference or redundant in-line densitometer allow the actual density to be compared, provided the same temperature and pressure are present in each meter. If that is not the case, the temperature and/or pressure will need to be measured at each meter and corrections made to correct the readings to reference conditions.

11.6.3.4 Densitometer Verification Using Reference Fluids

The use of reference fluids requires that the on-line densitometer be isolated from the process fluid. If the reference fluid is compatible with and near the density of the process, cleaning may not be necessary. Two fluids that are readily available are air and deaerated distilled water. It will be necessary to clean the wetted parts of the densitometer prior to testing with these two fluids. Hydrocarbons must be removed and the final solvent must be water compatible. The Wagenbreth equation may be used to determine the density of water at various temperatures. API *MPMS* Chapter 14, Section 6, contains equations for air as well as the Wagenbreth equation.

11.6.4 Verification of Pulse Generating Devices

The security and fidelity of pulse signals can be improved by using pulse comparison methods as described in API *MPMS* Chapter 5, Section 5. This, along with regular proving, will assure pulse accuracy. Positive displacement meters are typically supplied with either dual pick-ups or a verification reference pulse output. Oscilloscopes can be used to evaluate the pulse level and shape. Equipment should be available to verify the pulses for whichever method is employed. This check can be made either periodically with separate check equipment or continuously within the ELM tertiary device.

11.6.5 Verification of Pulse Input Channel

11.6.5.1 It should be noted that most pulse input channels used in an ELM tertiary device have no adjustments to alter the input signal. Trigger threshold adjustments may affect the number of pulses that are detected. In a diagnostic mode in the tertiary device with input signal displayed, the indicated frequency should equal the induced frequency from the traceable frequency calibrator. An alternative method is to take accumulator values at known times and calculate a frequency for comparison to the calibrator.

11.6.5.2 To verify that displayed quantities are correct for the amount of pulses entered into the tertiary device from pulse generation, trigger a discrete number of pulses from a traceable pulse generator into the tertiary device. Calculate the gross flow using the pulses generated and the K-factor. Compare this quantity to the displayed quantity.

11.7 AMBIENT TEMPERATURE CONSIDERATIONS

11.7.1 ELM devices are often installed in an uncontrolled environment. Responses of these devices under a variety of weather conditions could affect the performance and accuracy of flow measurement. Ambient temperature changes or extremes may cause a significant systematic deviation and have adverse effects on measurement accuracy. Ambient temperature range and its corresponding effect on measurement uncertainty (i.e., percent full scale/degrees temperature change from reference) should be listed in the manufacturer's performance specifications and should be considered when selecting and installing ELM equipment.

11.7.2 A bench calibration should be considered if ambient conditions compromise a field calibration. During a field verification/calibration, the ambient temperature should be recorded. Seasonal temperature swings should be taken into consideration when time schedules are being prepared for verification and calibration. Significant changes in ambient temperature can impact the calibration equipment as well as the EFM devices being calibrated.

11.7.3 Secondary equipment protected from the environment by the use of enclosures or insulating materials should be similarly protected during calibration or removed to a controlled environment under similar conditions. Verification of such equipment should be performed with the equipment stabilized in its environmentally controlled enclosure.

12 Security

12.1 ACCESS

Only the owner of the meter or the owner's contractually designated representative has the right to calibrate or alter the function of the metering system in any way. Additionally, the owner or the owner's contractually designated representative are restricted to activities contractually recognized as necessary and appropriate, considering industry practices and contractual obligations.

12.2 RESTRICTING ACCESS

12.2.1 Systems shall be designed to limit access for the purpose of altering any input variables that may affect measurement to those persons who are authorized to do so. A recommended method to achieve this goal is the required entry of a unique security code of at least four characters prior to performing any operation that might affect measurements. Owners should consider assigning unique codes or security measures to individuals in order to ensure that all parties attempting access are identifiable and accountable.

12.2.2 Alternate security measures may also be utilized to control access to the system. These measures may include mechanical devices and/or additional levels of electronic security.

12.2.3 A security code may be utilized at any time data is collected from the system. A security code shall be used every time any changes or edits are performed that will alter the quantities being measured.

12.3 INTEGRITY OF LOGGED DATA

12.3.1 Changes to any flow parameter shall be captured in the audit trail as part of an event log, as described in Section 10.

12.3.2 Each time a flow parameter constant is changed in the system that affects the calculated volume, the old and new value, along with the date and time of the change, shall be logged using either electronic or hard copy means. It is also desirable to capture the nonresettable totalizer reading(s) whenever a flow value is changed that could affect the QTR.

12.3.3 Any adjustments or corrections to the original data or calculated values shall be stored separately and shall not alter the original data. Both the original and the final adjusted data shall be retained. These adjustments or corrections shall be shown in the audit trail and shall clearly indicate the old and new values and the dates and times of the period or periods affected by the change. Some means of effectively determining the date of the changes shall be provided.

12.4 ALGORITHM PROTECTION

12.4.1 All algorithms used to calculate quantities shall be protected from alterations at the field or accounting office levels, even by persons provided with the security code necessary to perform all other routine functions. Changes to algorithms will require buyer and seller approval and authorization by affected parties (government, equipment manufacturers, buyer, seller, as appropriate).

12.4.2 Separation of programs and configurations used for flow calculations and related activities from those used for other functions is recommended.

12.4.3 The use of different physical devices is the preferred means of separation. However, separation of custody measurement functions from other programs within a single device may be acceptable if adequate security arrangements are made and it is acceptable to all parties involved. It is desirable to have separate access limitations, such as different passwords, so that maintenance or control functions cannot affect flow computations or vice versa.

12.4.4 Following changes to algorithm or control functions, the system must be thoroughly tested to verify correct operation of custody flow computation functions.

12.5 MEMORY PROTECTION

12.5.1 In order to provide maximum security and integrity for the data, the ELM tertiary device shall provide a backup power source or a nonvolatile memory capable of retaining all data in the unit's memory for a period of not less than the normal data collection interval for the unit.

12.5.2 When primary power is interrupted, the time and date of the failure and the time and date of the return to normal status shall be logged in the event log.

APPENDIX A—COMPUTER MATH HARDWARE AND SOFTWARE LIMITATIONS

A.1 General Information

A.1.1 Appendix A is not written as a tutorial or complete source of information regarding computer mathematics. It is written solely to alert the users of flow computation devices as to potential sources of errors that can occur when data is manipulated improperly.

A.1.2 Digital computers store numerical values as binary information in memory registers. The number of binary bits and the specific format of the bits vary according to the data type and the computer model type.

A.1.3 The computer performs mathematical operations by manipulating these registers, either by a programmed sequence of instructions (i.e., software), or by using a specialized math co-processor integrated circuit (i.e., hardware).

A.1.4 In practice, there is no difference between performing mathematical operations using software or hardware. Either method can be as accurate as the other and are subject to the same potential errors if the operations are not performed correctly. The major difference between software-based math and hardware-based math is that hardware performs the math operations faster.

A.1.5 The intrinsic bit width of a microprocessor or computer is a function of the internal data registers used to manipulate data (i.e., 8-bit, 16-bit, 32-bit, etc.). The bit size of these internal registers should not be confused with the bit size of the numeric values being operated on. An 8-bit microprocessor can accomplish the same math operations that a 32-bit microprocessor performs, but it will take more time.

A.2 Number Types Used by the Computer

A.2.1 GENERAL

Numeric data within the computer usually falls into two main types: integer and floating point data.

A.2.2 INTEGER NUMBERS

A.2.2.1 Integer numbers are registers or pseudo registers made up of memory locations. These integers are some number of binary bits wide (for example 8-bit, 16-bit, 32-bit, or greater). The largest numeric value that can be stored as an Integer is $2^n - 1$ where n equals the bit size of the integer register.

A.2.2.2 A 16-bit integer can therefore represent $2^{16} - 1$ or 65,535. Similarly a 32-bit integer can represent any nonfractional whole number as large as $2^{32} - 1$ or 4,294,967,294. An integer can also represent a signed number (for example, +2501 or –1235). The largest positive signed integer value that can be stored is $2^{n-1} - 1$ (because zero is counted as a positive value). The largest negative signed integer value that can be stored is $2^n - 1$ where n equals the bit size of the integer register.

For example, a 32-bit signed integer can represent any whole number between $2^{31} - 1$ (2,147,483,646) and minus 2^{31} (–2,147,483,647).

A.2.2.3 An integer can **exactly** represent any whole number that falls within the range criterion.

A.2.3 FLOATING POINT NUMBERS

A.2.3.1 Floating point numbers are also registers or pseudo registers made up of memory locations. The bit formats of floating point numbers are more complex, consisting of an exponent field and a mantissa field.

A.2.3.2 The use of a binary scientific notation storage method trades absolute *resolution and accuracy* of a number for a much greater *range* of numbers.

A.2.3.3 *Floating point numbers are able to represent a large range of positive and negative values, whole or fractional, but may not be able to represent the number exactly.*

A.2.3.4 The number of bits assigned to the mantissa or fractional part of the number determines the maximum resolution or accuracy of the number. The number of bits assigned to the exponent part of the number determines the maximum range of the number.

A.2.3.5 The bit sizes of the exponent and mantissa field can vary between different computer systems, but two types of floating point numbers as defined by *IEEE Standard for Binary Floating Point Arithmetic* are commonly used:

a. Single Precision:
- Approximate range $\pm 1.7 \times 10^{38}$ to $\pm 1.7 \times 10^{-38}$
- Resolution is approximately 1 part in 1.6×10^{6}

b. Double Precision:
- Approximate range $\pm 18 \times 10^{308}$ to $\pm 18 \times 10^{-308}$
- Resolution is approximately 1 part in 4.5×10^{15}

A.3 Problems That May Occur

A.3.1 GENERAL

The errors described below are typical of the types of errors that can occur when data is manipulated improperly within the computer.

A.3.2 INTEGER OVERFLOW AND UNDERFLOW

Integer overflow and underflow errors occur when multiplying or dividing integer numbers, and the result, or intermediate result, exceeds the storage capacity of the system registers used in the operation. Symptoms of this are numbers that sporadically change their sign, and/or sudden large unexpected changes in the value of a result under certain operating conditions.

A.3.3 FLOATING POINT RESOLUTION ERRORS

A.3.3.1 Floating point resolution errors occur when subtracting or adding small floating point numbers to large floating point numbers. These errors occur because the computing hardware or software must first normalize (make equal) the exponent fields of the two numbers before adding the mantissa fields of the numbers. This is done by shifting the mantissa field of the smaller number right and incrementing its exponent field until the two exponents are equal. The computing device must provide enough register bit width during the arithmetic operation to ensure that the least significant bits of the mantissa are not truncated, thereby reducing the resolution of the number.

A.3.3.2 Symptoms of this problem are totalizers that stop totalizing when the totalizer reaches a certain value or when flow rate is below a certain value. Other symptoms are convergence calculations that will not converge and weighted averages that are accurate for small delivery quantities but inaccurate for larger delivery quantities.

A.3.4 INTEGRATION ERRORS

Most flow computing devices compute total flow quantities by adding many relatively small calculated quantities for the total delivery period. For example, a custody transfer transaction lasting 24 hours would require 86,400 one-second calculations and sums (assuming a one-second main calculation period). It is important to calculate and correctly integrate each of these individual sample quantities accurately. For example, a consistent error of 0.0001 in quantity units when adding each one-second sample would mean an accumulated error of 8.6 quantity units every 24 hours.

A.3.5 INTEGER INTEGRATION

A.3.5.1 Because of their ability to represent a range of numbers exactly, in many cases, quantity totals are stored in integer registers. In these cases, individual sample quantities are calculated at some acceptable resolution and must be summed at maximum resolution until the summed quantity is equal to or greater than the integer totalizer resolution. The integer portion of the summed quantity must be transferred into the integer totalizer without error, and the *remaining fractional quantity saved* to be summed with the following quantity samples. For example, a typical flow computation device is calculating a quantity of 0.5555555556 barrels for each one-second sample (this equals 2000 barrels/hour). It is accumulating total quantity in units of one barrel in a integer register.

	1-second Sample Quantity	Sum of 1-Second Quantities	Totalizer Quantity
Sample Period 0	0.555555556	0.555555556	0
Sample Period 1	0.555555556	1.111111112	0
after integer portion is moved into totalizer		0.111111112	1
Sample Period 2	0.555555556	0.666666668	1
Sample Period 3	0.555555556	1.222222224	1
after integer portion is moved into totalizer		0.222222224	2
Sample Period 4	0.555555556	0.777777780	2
Sample Period 5	0.555555556	1.333333336	3
after integer portion is moved into totalizer		0.333333336	3

A.3.5.2 The example illustrates a method that can be used to implement integer integration with acceptable error. Note that a small error in the one-second quantity exists, even though it is calculated to 10 significant digits per API *MPMS* Chapter 12.2. The one-second sample quantity in this case cannot **exactly** represent the flow rate, which was 2000 barrels per hour.

APPENDIX B—A/D CONVERTERS AND RESOLUTION

B.1 General

B.1.1 The number of bits supported by an A/D converter defines the converter's range, usually expressed as counts or segments, which can be used to define resolution. Resolution is related to the number of segments into which a data converter divides an analog signal. Resolution is different from accuracy, which for an A/D converter is the error in deciding a signal's magnitude. Accuracy is determined primarily by the stability, linearity, and repeatability of the A/D converter, but inadequate resolution may limit the achievable accuracy of any device. See Table B-1.

B.1.2 Total counts (or segments) can be computed by raising two to the power of the total bits as follows,

$$\textit{total counts} = 2^{\textit{total bits}}$$

Knowing the total possible **counts**, the resolution can be computed in percent full scale as:

$$\textit{resolution} = 100 \times \frac{1}{\textit{counts}}$$

For example, assume a 12-bit A/D converter is being used. Then,

$$\textit{total counts} = 2^{12} = 4096\ \textit{counts}$$

and resolution is therefore 1 part in 4096, or in percent full scale is

$$\textit{resolution}_{\%FS} = 100 \times \frac{1}{4096} = 0.0244\%FS$$

B.1.3 In practice, some implementors utilize only a portion of the A/D converter's full range to track the sensor's normal calibrated range. The remaining A/D counts are used to track the sensor into over- and under-range regions. See Figure B-1 below.

B.1.4 The basic resolution of the A/D converter remains unchanged. However, the input signal range spanned by the A/D converter could be something other than the calibrated operating range.

Table B-1—A/D Converter Resolutions in Percent of Full Scale

Number of Bits	Total Counts	Resolution (% *FS*)
8	256	0.390625
12	4096	0.024414
14	16,384	0.006103
16	65,536	0.001526
18	262,144	0.000381
24	16,777,216	0.000006

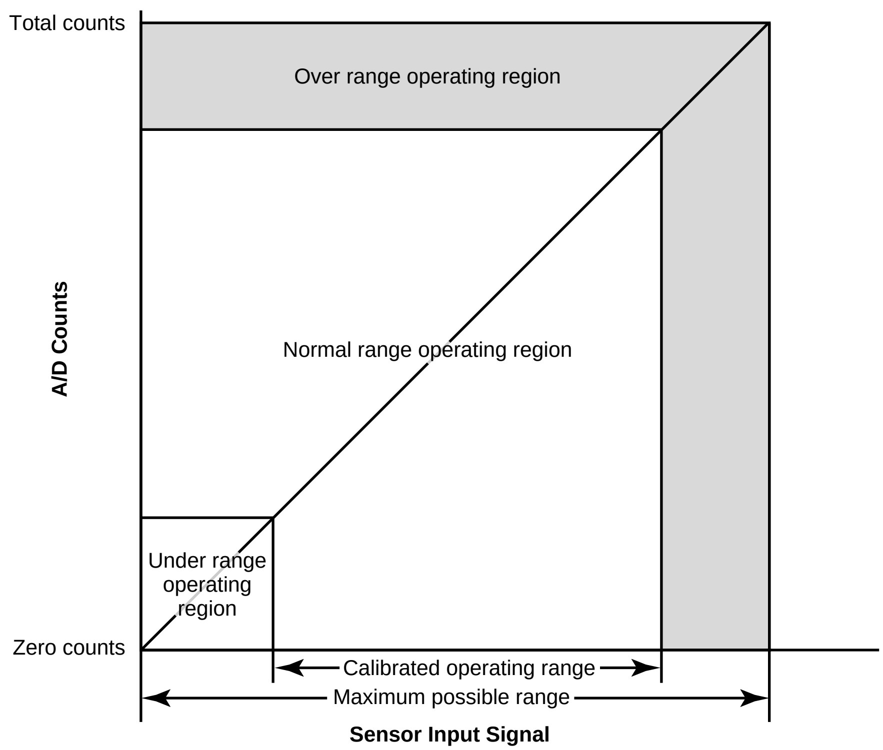


Figure B-1—A/D Counts vs. Sensor Input Showing Support for Over/Under Range Regions

APPENDIX C—EMERGENT STEM CORRECTION FOR LIQUID-IN-GLASS THERMOMETERS

Precision thermometers are typically calibrated with the entire stem immersed in the bath which determines the temperature of the thermometer bulb. However, it is common practice when using a thermometer to permit its stem to extend out from the thermowell or liquid. Under these conditions, both the stem and the mercury in the exposed stem are at a temperature different from the bulb. This introduces an error into the observed temperature. Since the coefficient of thermal expansion of glass is less than that of mercury, the observed temperature will be less than the true temperature if the bulb is hotter than the stem and greater than the true temperature if the thermal gradient is reversed. For exact work, the magnitude of this error can only be determined by experiment. However for most purposes, and where specific manufacturer's information is lacking, it is sufficiently accurate to apply the following equation, which takes into account the difference of the thermal expansion between glass and mercury.

$$T_c = T + kn\,(T - t)$$

where

T_c = corrected temperature,

T = observed temperature,

t = average temperature of exposed stem,

n = the number of degrees emergent above the surface of the liquid whose temperature is being determined,

k = mercury-glass-correction factor: for degrees Fahrenheit, use 0.00009; for Celsius, use 0.00016.

Note: Extracted from ASTM E 77.

APPENDIX D—RESISTANCE VERSUS TEMPERATURE FOR INDUSTRIAL PLATINUM RTDS

D.1 General

D.1.1 Some smart temperature transmitters can be adjusted to one or two points on their curve but require that input values be in standard table value Ohms instead of in degrees of temperature. The following Callendar-Van Dusen correlation is one method that can be used to calculate the RTD table resistance if the temperature is known for a 0.00385 alpha platinum RTD. Similar techniques can be used for other standard RTD types. If the specific constants are known for an RTD sensor, table values unique to that sensor can be computed using these equations.

For the range 0°C to +850°C:

$$R_t = R_0\,[1 + \mathrm{A}t + \mathrm{B}t^2]$$

For the range –200°C to 0°C:

$$R_t = R_0\,[1 + \mathrm{A}t + \mathrm{B}t^2 + \mathrm{C}(t - 100)t^3]$$

where

		IPTS-68	ITS-90
A	=	3.90802×10^{-3}	$3.9083–3 \times 10^{-3}$
B	=	-5.802×10^{-7}	-5.775×10^{-7}
C	=	-4.2735×10^{-12}	-4.183×10^{-12}

R_0 = nominal resistance of RTD at 0°C (32°F), typically 100 Ohms.

R_t = resistance of RTD at observed temperature.

t = observed temperature °C.

D.1.2 The ITS-90 constants are from IEC 751 *Amendment 2* and update the Callendar equation (0°C and above) and the Callendar-Van Dusen equation (below 0°C) that were used in DIN 43760 and other standards based upon IPTS-68 to bring it up to ITS-90. Users of thermometers are cautioned to specify on which temperature scale the temperatures are reported, and when using or referring to a standard, to be aware of which temperature scale the standard employs.

D.1.3 Conversely, the Callendar-Van Dusen correlation can be use to determine the temperature from the RTD resistance. For temperatures above 0°C, a direct calculation can be made. For temperatures below 0°C, an iteration is necessary. However, for the range of temperatures over which the hydrocarbon volume correction tables are applicable, a suitably accurate result can be obtained with a single iteration. To –50°C, the error is only 7×10^{-8}°C. The error increases to 0.0025°C at –200°C. While the A, B, and C constants for each RTD should be used for best accuracy, the standard constants from IEC 751 are shown for those instances when the specific constants are lacking. The actual R_0 at 0°C should always be used, however.

For the range 0°C to +850°C:

$$t = \frac{\sqrt{\mathrm{A}^2 - 4 \times \mathrm{B}\left(1 - \frac{R_t}{R_0}\right)} - \mathrm{A}}{2 \times \mathrm{B}}$$

For the range –200°C to 0°C:

$$t_i = \frac{\sqrt{\mathrm{A}^2 - 4 \times \mathrm{B}\left(1 - \frac{R_t}{R_0}\right)} - \mathrm{A}}{2 \times \mathrm{B}}$$

$$W1 = 1 + \mathrm{A}t_i + \mathrm{B}t_i^2 + \mathrm{C}t_i^3\,(t_i - 100)$$

$$S = \mathrm{A} + 2\mathrm{B}t_i + 4\mathrm{C}t_i^2\,(t_i - 75)$$

$$t = t_i + \frac{\left(\frac{R_t}{R_0} - W1\right)}{S}$$

where

$$\mathrm{A} = \mathrm{Alpha}\left(1 + \frac{\mathrm{Delta}}{100}\right)$$

$$\mathrm{B} = \frac{-\mathrm{Alpha} \times \mathrm{Delta}}{10^4}$$

$$\mathrm{C} = \frac{-\mathrm{Alpha} \times \mathrm{Beta}}{10^8}$$

Where Alpha, Delta, and Beta are not known, the following constants may be substituted with some loss of accuracy.

		IPTS-68	ITS-90
A	=	3.90802×10^{-3}	$3.9083–3 \times 10^{-3}$
B	=	-5.802×10^{-7}	-5.775×10^{-7}
C	=	-4.2735×10^{-12}	-4.183×10^{-12}

R_0 = resistance of RTD at 0°C (32°F), typically 100 Ohms, use actual R_0 if known.

R_t = resistance of RTD at temperature being measured.

S = shape factor.

t = temperature °C.

t_i = initial temperature calculation.

$W1$ = resistance ratio.

APPENDIX E—CALIBRATION AND VERIFICATION EQUIPMENT

E.1 Pressure

Pressure verification and calibration equipment is used to accurately determine or produce a pressure signal on the pressure sensing element of a static pressure transmitter. The pressure used for calculating the pressure transmitter may be supplied from various sources. The electronic output of the pressure transmitter is then adjusted or calibrated to correspond to the pressure signal.

Pressure calibration/verification equipment is divided into the following three main types:

E.1.1 DEADWEIGHT CALIBRATION EQUIPMENT

E.1.1.1 A device that generates a hydraulic or pneumatic signal by placing known weights on a piston of known size is generally referred to as a "deadweight tester." By using accurate weights and a piston of accurately determined area, these devices form a secondary standard for pressure measurements.

E.1.1.2 Due to the sensitivity of calibration/verification equipment, consideration should be given to gravitational constants, elevation, temperature, vibration, air movement, and other environmental influences. At latitudes of less than 40 degrees or greater than 50 degrees, or at altitudes that exceed 5,000 feet, deadweight testers can be in error by more than 0.05 percent if proper corrections are not made. The weights can often be trimmed by the manufacturer for local gravity, or appropriate corrections can be made to calculate the actual pressures produced. The local gravity can be obtained from:

NOAA, National Geodetic Survey, N/NGS12
1315 East-West Highway, Station 09202
Silver Spring, MD 20910
Telephone: (301) 713-3242; Fax: (301) 713-4172

E.1.1.3 The NGS will need the latitude, longitude, and elevation. The first equation below can then be used to compute a correction factor. The last set of equations can be used to compute the local gravity with sufficient accuracy for most calibration work.

$$P = P_{dw} \times g / 980.665$$

where

g = value of local gravity in cm/sec^2 as predicted by National Geodetic Survey or equation below,

P_{dw} = deadweight pressure at 980.665 cm/sec^2 (45 degrees).

for 30 to 60 degrees:

$$g = 980.665 + [0.087(L - 45)] - 0.000094H$$

for 0 to 90 degrees:

$$g = 978.01855 - 0.0028247L + 0.0020299L^2 - 0.000015058L^3 - 0.000094H$$

where

L = latitude in degrees,

H = elevation in feet above sea level.

Temperature will affect the piston and cylinder areas of a deadweight tester. The following correction can be applied for this error.

$$C_t = \frac{1}{1 + (ac + ap)(T - Tref)}$$

where

ac = Linear thermal expansion coefficient of the cylinder,

ap = Linear thermal expansion coefficient of the piston,

$C1$ = Correction factor for nonstandard temperature,

T = Temperature of the piston-cylinder assembly in degrees F,

$Tref$ = Reference temperature used by deadweight tester manufacturer, usually 77°F.

E.1.2 ADJUSTABLE CALIBRATION EQUIPMENT

Adjustable pressure devices generate a pressure signal and measure the signal generated. The signal is adjusted to a desired pressure as indicated by the measurement device. The signal generator may be combined with the measuring device—the combination generally referred to as a calibrator—or the pressure generator and measuring instrument combination may consist of two or more separate devices.

E.1.3 PRESSURE READOUT CALIBRATION EQUIPMENT

Readout devices measure only the pressure signal applied to the pressure transmitter from the process or external source.

E.2 Temperature

E.2.1 Flowing temperature calibration/verification equipment is used for verification and calibration of the instruments measuring the temperature of the flowing fluid. Temperature measurement of the flowing fluid is made by a temperature element with suitable mechanical provisions for insertion in the flow stream. The measurement made by the sensing element may be either used directly by the ELM equipment or converted into other electrical signals, such as 4–20 milliamperes, by a transmitter for input into the ELM equipment.

E.2.2 During verification/calibration, the sensor may be placed in a controlled temperature environment (a temperature bath or block). The accuracy of the calibration environment should be ±0.2°F (0.1°C) or better. This accuracy requirement includes the nonuniformity of the bath or block and the accuracy of the temperature standard. Care should be taken in placement of the sensor in the environment to minimize the effects of thermal conductivity through the sensor to atmosphere, uneven heating, or other factors.

E.2.3 Another common method of calibrating RTD transmitters is by duplicating the RTD resistance using a precision resistance box. The temperature signal into the transmitter is simulated by substituting a resistance equivalent to the RTD at the desired temperature points. This eliminates the need for a controlled temperature environment in the field. After the transmitter is calibrated using the resistance substitution method, it is connected to the RTD sensor. A test thermowell adjacent to the RTD thermowell is then used for measuring the flowing temperature by use of a precision temperature reference device. The fluid must be moving past the wells to eliminate surface stratification. A final adjustment is then made at the normal operating temperature that corrects for any offsets caused by the RTD element or wiring. Any corrections at this point should be minor or the cause will need to be investigated. Figure 3 illustrates the need to include the sensor in the calibration.

E.2.4 Portable electronic thermometers must meet the requirements of API *MPMS* Chapter 7, Section 3.

E.3 Electronic Signal Generators

E.3.1 ANALOG SIGNAL GENERATORS

E.3.1.1 Analog signal generators are used for verification/calibration of ELM equipment that receives an electronic analog input. Standard analog signals include volts (V) and milliamperes (mA). Typical ELM applications requiring analog signal inputs for verification/calibration include flow computers that receive analog signals from pressure, temperature, densitometer elements, and/or other transmitters.

E.3.1.2 An analog signal generator may consist of either a composite device incorporating both a signal source and readout device (calibrator) or separate devices connected to provide a signal source with a separate readout or indicator. Each portion of a composite device or assembled system that is used for ELM verification/calibration shall meet the requirements established in this standard that apply to that portion of the device or system utilized.

E.3.1.3 Devices generating an analog signal (voltage, frequency, or current) shall meet the following standards for stability and composition of signal:

a. Stability means that voltage or current sources shall not exhibit a level fluctuation of greater than ±0.1 percent over a period of 150 percent of the period of time in which the measurement is required to be made.
b. Composition of signal is limited to a maximum allowable ripple of 0.1 percent.
c. Devices measuring digital or pulse signals, or readout devices on composite devices or calibrators, shall meet the standard required for "electronic digital multimeters" as defined in E.3.6.

E.3.2 PULSE SIGNAL GENERATORS

E.3.2.1 Pulse signal generators are used for verification/calibration of ELM equipment that receives a pulse signal input. Pulse signals are typically generated by turbine and positive displacement meters.

E.3.2.2 The maximum and minimum pulse amplitude of the generator should be capable of being adjusted to 5 percent beyond the worst case levels produced by the device being simulated. The pulse generator output frequency must be capable of being adjusted between a maximum frequency of twice that of the device being simulated and a minimum frequency of half that of the device being simulated. For checking level A and B pulse security, it will be necessary to have a two-channel pulse generator that can electrically vary the phasing of the pulse signals for simulating a linear meter with two pulse inputs.

E.3.3 FREQUENCY SIGNAL GENERATORS

Pulse signal generators that are used for verification/calibration of ELM equipment that receive a pulse signal input from density measurement devices (densitometers) should comply with the pulse amplitude requirements stated in E.3.2 above and generate a frequency/periodic time interval whose stability and accuracy is at least two times better than the device being simulated.

E.3.4 DIGITAL SIGNAL GENERATORS

E.3.4.1 Digital signal generators are used for verification/calibration of ELM equipment that receives a digital electronic signal.

E.3.4.2 This standard does not include requirements for digital communication protocols or methods, such as RS-232, RS-485, and so forth. Requirements for use and verification/calibration of such digital communication methods are covered under standards issued by various groups and organizations, such as the Institute of Electrical and Electronics Engineers (IEEE) and Electronics Industries Association (EIA).

E.3.4.3 A digital signal generator may consist of either composite devices incorporating both a signal source and readout device (calibrator) or separate devices connected to provide a signal source with a separate readout or indicator. Each portion of a composite device or assembled system that is used for ELM verification/calibration shall meet the requirements established in this standard for that portion of the device or system utilized for verification or calibration.

E.3.5 RESISTANCE SUBSTITUTION DEVICES

E.3.5.1 Resistance substitution devices are used to simulate resistance temperature detector (RTD) inputs in the calibration of ELM equipment.

E.3.5.2 Resistance devices shall be of the decade bridge type or individual resistor elements that have been prepared for use as a resistance standard. Resolution should be 0.01 Ohm with a minimum accuracy of 0.05 percent.

E.3.6 ELECTRONIC DIGITAL MULTIMETERS

E.3.6.1 Electronic digital multimeters (DMM) are readout devices used to measure the various electronic parameters associated with the verification/calibration of ELM instruments. Parameters measured include voltage, current, frequency, and resistance. Specifications and requirements listed in this section for multimeters shall also apply to devices measuring only one or more parameters and to the readout devices of integrated source/measurement units or calibrators.

E.3.6.2 All DMMs will have, at a minimum, four significant digits displayed for all measurements used in the verification/calibration of ELM instruments. Analog or mechanical type meters will not be used. The minimum total accuracy specifications for parameters and ranges commonly used on ELM instruments is 0.05 percent. Densitometers and similar oscillating equipment will require frequency measuring equipment with an accuracy of 0.005 percent or better. Note that those tolerances include the effect of the uncertainty of the last digit.

E.4 Frequency of Calibration of Reference Equipment

E.4.1 It is recommended that all reference electronic instruments used in ELM verification or calibration be checked and calibrated periodically. The recommended period for field electronic verification/calibration equipment is two years or less. The recommended period for pressure equipment or mercury-in-glass thermometers is five years or less. Field conditions and frequency of use may dictate shorter calibration intervals. Standards used for verification/calibration shall be traceable to primary standards maintained by an internationally recognized standards organization, such as the National Institute of Standards and Technology (NIST).

E.4.2 Calibration stickers or tags shall be attached showing the date of calibration or verification, party or person performing the inspection, and the due date of the next certification.

E.4.3 Instruments subject to harsh field conditions may require calibration/verification on a more frequent period as determined by actual experience. Instruments dropped or damaged shall not be used until they are verified or calibrated.

APPENDIX F—REQUIRED ACCURACY IN MEASURED TEMPERATURE, PRESSURE, AND DENSITY FOR DESIRED ACCURACY OF CORRECTION FACTORS *CTL* AND *CPL*

The accuracy of *CTL* and *CPL* calculations is affected by the accuracy of temperature, pressure, and density measurements. Tables F-1 through F-32 tabulate the required accuracy of the measured temperature, pressure, and density to achieve the desired accuracy in the resulting *CTL* and *CPL* calculations. All target accuracies were set to 0.02 percent, with the exception of the light hydrocarbon tables utilizing GPA *Research Report 148*. The light hydrocarbon tables were set to 0.05 percent due to their greater volatility. An individual analysis should be conducted when operation is near the critical region, since sensitivity to pressure, temperature, or density can change dramatically.

Linear interpolation can be used to scale the required temperature, pressure, and/or density measurements to different *CTL* and *CPL* tolerance targets.

Table F-1—Temperature Tolerance in °F for Generalized Crude Oil and JP4 to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6A

	Temperature °F						
API	0	50	100	150	200	250	300
0	0.68	0.68	0.67	0.67	0.66	0.66	0.66
20	0.52	0.51	0.51	0.50	0.50	0.49	0.49
40	0.41	0.40	0.39	0.39	0.39	0.38	—
60	0.33	0.32	0.31	0.31	0.31	—	—
80	0.27	0.26	0.26	0.25	0.25	—	—
100	0.23	0.22	0.21	0.21	0.21	—	—

Table F-2—Temperature Tolerance in °F for Generalized Crude Oil and JP4 to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 24A

	Temperature °F						
Relative Density	0	50	100	150	200	250	300
1.076	0.68	0.68	0.67	0.67	0.66	0.66	0.66
1.000	0.59	0.59	0.58	0.58	0.57	0.57	0.56
0.900	0.48	0.47	0.47	0.47	0.46	0.46	0.46
0.800	0.38	0.38	0.37	0.37	0.36	0.36	—
0.700	0.30	0.29	0.28	0.28	0.28	—	—
0.611	0.23	0.22	0.21	0.21	0.21	—	—

Table F-3—Temperature Tolerance in °C for Generalized Crude Oil and JP4 to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54A

	Temperature °C							
Density kg/m^3	–18	0	25	50	75	100	125	150
1075	0.38	0.38	0.38	0.37	0.37	0.37	0.37	0.36
1000	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.31
900	0.27	0.27	0.26	0.26	0.26	0.26	0.25	0.25
800	0.21	0.21	0.21	0.20	0.20	0.20	0.20	—
700	0.16	0.16	0.16	0.16	0.15	—	—	—
610	0.13	0.12	0.12	0.12	0.12	—	—	—

Table F-4—Gravity Tolerance in °API for Generalized Crude Oil and JP4 to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6A

	Temperature °F						
API	0	50	100	150	200	250	300
0	0.75	4.46	1.11	0.49	0.31	0.23	0.18
20	0.65	3.88	0.96	0.42	0.27	0.20	0.15
40	0.58	3.42	0.84	0.37	0.24	0.17	—
60	0.52	3.07	0.75	0.33	0.21	—	—
80	0.48	2.78	0.68	0.30	0.19	—	—
100	0.44	2.55	0.62	0.27	0.17	—	—

Table F-5—Relative Density Tolerance for Hydrocarbon Liquids to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 24A

	Temperature °F						
Relative Density	0	50	100	150	200	250	300
1.076	0.0061	0.0365	0.0091	0.0040	0.0025	0.0019	0.0015
1.000	0.0049	0.0293	0.0073	0.0032	0.0020	0.0015	0.0012
0.900	0.0036	0.0214	0.0053	0.0023	0.0015	0.0011	0.0009
0.800	0.0026	0.0150	0.0037	0.0016	0.0010	0.0008	—
0.700	0.0017	0.0101	0.0025	0.0011	0.0007	—	—
0.611	0.0012	0.0067	0.0016	0.0007	0.0005	—	—

Table F-6—Density Tolerance for Hydrocarbon Liquids to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54A

	Temperature °C							
Density kg/m^3	–18	0	25	50	75	100	125	150
1075	6.2	13.5	20.2	5.7	3.3	2.3	1.8	1.4
1000	5.0	10.9	16.2	4.6	2.7	1.9	1.4	1.2
900	3.7	8.0	11.8	3.3	1.9	1.4	1.0	0.84
800	2.6	5.6	8.3	2.3	1.4	0.95	0.73	—
700	1.7	3.8	5.5	1.6	0.90	—	—	—
610	1.2	2.5	3.7	1.0	0.59	—	—	—

Table F-7—Temperature Tolerance in °F for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6B

	Temperature °F						
API	0	50	100	150	200	250	300
0	0.59	0.59	0.58	0.58	0.57	0.57	0.57
20	0.50	0.49	0.48	0.48	0.48	0.47	0.47
40	0.42	0.41	0.41	0.40	0.40	0.40	—
60	0.30	0.29	0.29	0.28	0.28	—	—
80	0.26	0.25	0.25	0.24	0.24	—	—
85	0.25	0.24	0.24	0.23	0.23	—	—

Table F-8—Temperature Tolerance in °F for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 24B

	Temperature °F						
Relative Density	0	50	100	150	200	250	300
1.076	0.59	0.59	0.58	0.58	0.57	0.57	0.57
1.000	0.54	0.54	0.53	0.52	0.52	0.52	0.51
0.900	0.47	0.47	0.46	0.46	0.45	0.45	0.45
0.800	0.39	0.39	0.38	0.38	0.37	0.37	—
0.700	0.28	0.27	0.27	0.26	0.26	—	—
0.654	0.25	0.24	0.24	0.23	0.23	—	—

Table F-9—Temperature Tolerance in °C for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54B

	Temperature °C							
Density kg/m^3	–18	0	25	50	75	100	125	150
1075	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.31
1000	0.30	0.30	0.30	0.29	0.29	0.29	0.29	0.29
900	0.26	0.26	0.26	0.26	0.25	0.25	0.25	0.25
800	0.22	0.22	0.21	0.21	0.21	0.21	0.21	—
700	0.15	0.15	0.15	0.15	0.14	—	—	—
653	0.14	0.14	0.13	0.13	0.13	—	—	—

Table F-10—Gravity Tolerance in °API for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6B

	Temperature °F						
API	0	50	100	150	200	250	300
0	1.0	6.1	1.5	0.67	0.43	0.31	0.25
20	1.0	5.8	1.4	0.63	0.40	0.29	0.23
40	0.60	3.5	0.87	0.38	0.24	0.18	—
60	0.63	3.7	0.91	0.40	0.25	—	—
80	0.59	3.5	0.85	0.37	0.24	—	—
85	0.59	3.4	0.83	0.36	0.23	—	—

Table F-11—Relative Density Tolerance for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 24B

	Temperature °F						
Relative Density	0	50	100	150	200	250	300
1.076	0.0084	0.0500	0.0124	0.0055	0.0035	0.0025	0.0020
1.000	0.0071	0.0419	0.0104	0.0046	0.0029	0.0021	0.0017
0.900	0.0055	0.0324	0.0080	0.0035	0.0022	0.0016	0.0013
0.800	0.0026	0.0155	0.0038	0.0017	0.0011	0.0008	—
0.700	0.0021	0.0124	0.0030	0.0013	0.0008	—	—
0.654	0.0018	0.0103	0.0025	0.0011	0.0007	—	—

Table F-12—Density Tolerance for Generalized Products to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54B

	Temperature °C							
Density kg/m^3	–18	0	25	50	75	100	125	150
1075	8.5	18.6	27.6	7.8	4.5	3.2	2.4	2.0
1000	7.1	15.6	23.1	6.6	3.8	2.7	2.0	1.7
900	5.5	12.1	17.9	5.1	2.9	2.1	1.6	1.3
800	2.7	5.8	8.6	2.4	1.4	0.98	0.75	—
700	2.1	4.6	6.8	1.9	1.1	—	—	—
653	1.8	3.8	5.6	1.6	0.91	—	—	—

Table F-13—Temperature Tolerance in °F for Lubricating Oils to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6D

	Temperature °F						
API	0	50	100	150	200	250	300
–10	0.68	0.67	0.66	0.66	0.65	0.65	0.65
0	0.62	0.62	0.61	0.61	0.60	0.60	0.60
10	0.58	0.57	0.57	0.56	0.56	0.56	0.55
20	0.54	0.54	0.53	0.53	0.52	0.52	0.52
30	0.51	0.50	0.50	0.49	0.49	0.49	0.48
40	0.48	0.47	0.47	0.46	0.46	0.46	0.45
45	0.47	0.46	0.45	0.45	0.45	0.44	0.44

Table F-14—Temperature Tolerance in °C for Lubricating Oils to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54D

	Temperature °C							
Density kg/m^3	–20	0	25	50	75	100	125	150
1164	0.38	0.37	0.37	0.37	0.36	0.36	0.36	0.36
1100	0.36	0.35	0.35	0.35	0.34	0.34	0.34	0.34
1075	0.35	0.34	0.34	0.34	0.34	0.33	0.33	0.33
1050	0.34	0.34	0.33	0.33	0.33	0.33	0.32	0.32
1000	0.32	0.32	0.32	0.31	0.31	0.31	0.31	0.31
950	0.31	0.30	0.30	0.30	0.30	0.29	0.29	0.29
900	0.29	0.29	0.29	0.28	0.28	0.28	0.28	0.28
850	0.28	0.27	0.27	0.27	0.26	0.26	0.26	0.26
800	0.26	0.26	0.25	0.25	0.25	0.25	0.25	0.24

Table F-15—Gravity Tolerance in °API for Lubricating Oils to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 6D

	Temperature °F						
API	0	50	100	150	200	250	300
–10	1.4	8.1	2.0	0.89	0.57	0.42	0.33
0	1.4	8.1	2.0	0.89	0.57	0.41	0.33
10	1.4	8.1	2.0	0.88	0.56	0.41	0.33
20	1.4	8.1	2.0	0.88	0.56	0.41	0.33
30	1.4	8.1	2.0	0.88	0.56	0.41	0.32
40	1.4	8.1	2.0	0.88	0.56	0.41	0.32
45	1.4	8.1	2.0	0.88	0.56	0.41	0.32

Table F-16—Density Tolerance for Lubricating Oils to Maintain Accuracy in *CTL* of ±0.02 Percent Using API *MPMS* Chapter 11.1, Table 54D

Density	Temperature °C							
kg/m^3	–20	0	25	50	75	100	125	150
1164	12	29	43	12	7.1	5.0	3.8	3.1
1100	11	26	38	11	6.3	4.4	3.4	2.8
1075	11	25	37	10	6.0	4.2	3.2	2.6
1050	10	24	35	10	5.7	4.0	3.1	2.5
1000	9.2	21	32	9.0	5.2	3.6	2.8	2.3
950	8.3	19	29	8.1	4.7	3.3	2.5	2.0
900	7.5	17	26	7.3	4.2	2.9	2.3	1.8
850	6.7	15	23	6.5	3.8	2.6	2.0	1.6
800	5.9	14	20	5.7	3.3	2.3	1.8	1.4

Table F-17—Temperature Tolerance in °F for Light Hydrocarbons to Maintain Accuracy in *CTL* of ±0.05 Percent Using GPA *Research Report 148*

Relative Density	Temperature °F					
	–50	0	50	100	150	200
0.700	0.77	0.78	0.77	0.75	0.73	0.69
0.650	0.67	0.66	0.64	0.61	0.57	0.51
0.600	0.56	0.54	0.51	0.47	0.42	0.36
0.550	0.47	0.44	0.40	0.35	0.29	0.21
0.500	0.39	0.35	0.31	0.25	0.17	—
0.450	0.32	0.28	0.23	0.16	0.05	—
0.400	0.26	0.22	0.17	0.08	—	—
0.350	0.20	0.16	0.10	—	—	—

Table F-18—Temperature Tolerance in °C for Light Hydrocarbons to Maintain Accuracy in *CTL* of ±0.05 Percent Using GPA *Research Report 148*

Relative Density	Temperature °C					
	–45	–30	0	30	60	90
0.700	0.43	0.43	0.43	0.42	0.41	0.39
0.650	0.37	0.37	0.36	0.35	0.32	0.29
0.600	0.31	0.31	0.29	0.27	0.24	0.20
0.550	0.26	0.25	0.23	0.20	0.17	0.12
0.500	0.21	0.20	0.18	0.15	0.11	0.03
0.450	0.18	0.17	0.14	0.10	0.05	—
0.400	0.14	0.13	0.10	0.06	—	—
0.350	0.11	0.10	0.07	0.008	—	—

Table F-19—Relative Density Tolerance for Light Hydrocarbons to Maintain Accuracy in *CTL* of ±0.05 Percent Using GPA *Research Report 148*

Relative Density	Temperature °F					
	–50	0	50	100	150	200
0.700	0.0027	0.0046	0.0253	0.0058	0.0024	0.0014
0.650	0.0019	0.0029	0.0154	0.0034	0.0014	0.0008
0.600	0.0013	0.0021	0.0114	0.0025	0.0009	0.0005
0.550	0.0010	0.0016	0.0083	0.0018	0.0006	0.0003
0.500	0.0007	0.0011	0.0058	0.0011	0.0003	—
0.450	0.0005	0.0007	0.0034	0.0006	0.0001	—
0.400	0.0003	0.0005	0.0021	0.0002	—	—
0.350	0.0002	0.0002	0.0008	—	—	—

Table F-20—Relative Density Tolerance for Light Hydrocarbons to Maintain Accuracy in *CTL* of ±0.05 Percent Using GPA *Research Report 148*

Relative Density	Temperature °C					
	–40	–30	0	30	60	90
0.700	0.0029	0.0035	0.0093	0.0092	0.0027	0.0015
0.650	0.0020	0.0023	0.0057	0.0054	0.0016	0.0008
0.600	0.0014	0.0016	0.0042	0.0040	0.0011	0.0005
0.550	0.0010	0.0012	0.0031	0.0028	0.0007	0.0003
0.500	0.0008	0.0009	0.0022	0.0019	0.0004	0.0001
0.450	0.0005	0.0006	0.0013	0.0010	0.0001	—
0.400	0.0004	0.0004	0.0009	0.0005	—	—
0.350	0.0002	0.0002	0.0004	0.0000	—	—

Table F-21—Pressure Tolerance in PSI for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1
Assumed pressure above equilibrium was 500 psi.

	Temperature °F					
API	–20	0	50	100	150	200
0	77	74	66	59	53	48
20	62	59	51	44	39	33
40	49	45	38	32	27	22
60	37	34	27	22	18	14
80	27	25	19	14	11	8
90	23	21	15	11	9	6

Table F-22—Pressure Tolerance in kPa for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C				
	–30	0	30	60	90
1074	532	474	422	376	334
1000	482	422	369	323	283
900	404	344	292	248	211
800	316	258	210	171	139
700	221	170	130	99	76
638	162	118	85	62	45

Table F-23—Temperature Tolerance in °F for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1
Assumed pressure above equilibrium was 500 psi.

	Temperature °F					
API	–20	0	50	100	150	200
0	72.0	69.0	62.0	55.0	50.0	45.0
20	44.0	42.0	36.0	32.0	27.0	24.0
40	27.0	26.0	21.0	18.0	15.0	12.0
60	17.0	15.0	12.0	9.9	7.9	6.4
80	10.0	9.2	7.0	5.4	4.1	3.1
90	8.0	7.1	5.3	3.9	2.9	2.2

Note: This table is very sensitive to pressure and is not valid for pressures greater than 500 psi.

Table F-24—Temperature Tolerance in °C for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C				
	–30	0	30	60	90
1074	39.0	35.0	31.0	28.0	25.0
1000	31.0	27.0	24.0	21.0	18.0
900	21.0	18.0	15.0	13.0	11.0
800	13.0	11.0	8.8	7.2	5.9
700	7.2	5.5	4.2	3.2	2.5
638	4.4	3.2	2.3	1.7	1.2

Note: This table is very sensitive to pressure and is not valid for pressures greater than 3500 kPa.

Table F-25—Gravity Tolerance in °API for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1
Assumed pressure above equilibrium was 500 psi.

	Temperature °F					
API	–20	0	50	100	150	200
0	16.0	14.0	11.0	8.8	7.1	5.8
20	11.0	10.0	7.4	5.7	4.4	3.5
40	7.6	6.7	4.9	3.6	2.7	2.1
60	5.2	4.5	3.1	2.2	1.6	1.2
80	3.5	2.9	2.0	1.3	0.9	0.6
90	2.8	2.4	1.5	1.0	0.7	0.5

Note: This table is very sensitive to pressure and is not valid for pressures greater than 500 psi.

Table F-26—Density Tolerance for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.1M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C				
	–30	0	30	60	90
1074	125.0	96.0	74.0	59.0	47.0
1000	92.0	69.0	53.0	41.0	32.0
900	56.0	41.0	30.0	23.0	18.0
800	31.0	22.0	15.0	11.0	8.1
700	15.0	10.0	6.4	4.3	3.0
638	8.1	5.0	3.2	2.0	1.3

Note: This table is very sensitive to pressure and is not valid for pressures greater than 3500 kPa.

Table F-27—Pressure Tolerance in PSI for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2
Assumed pressure above equilibrium was 500 psi.

Relative Density	Temperature °F				
	–50	0	50	100	140
0.637	29.0	23.0	18.0	14.0	11.0
0.600	24.0	19.0	14.0	10.0	7.1
0.550	19.0	14.0	10.0	6.3	4.2
0.500	15.0	10.0	6.7	3.9	2.3
0.450	11.0	7.5	4.4	2.1	—
0.400	8.9	5.5	2.7	—	—
0.350	7.3	4.3	1.9	—	—

Table F-28—Pressure Tolerance in kPa for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C					
	–45	–20	0	20	40	60
637	200	164	139	115	93	74
600	167	132	108	86	66	49
550	130	99	77	58	42	29
500	101	73	54	38	26	16
450	78	54	37	24	14	—
400	61	39	25	14	—	—
350	50	31	18	—	—	—

Table F-29—Temperature Tolerance in °F for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2
Assumed pressure above equilibrium was 500 psi.

Relative Density	Temperature °F				
	–50	0	50	100	140
0.637	14.0	9.8	6.6	4.3	2.9
0.600	10.0	6.5	4.1	2.3	1.4
0.550	6.4	3.9	2.2	1.1	0.6
0.500	4.2	2.4	1.2	0.5	0.2
0.450	2.7	1.4	0.6	0.2	—
0.400	1.8	0.8	0.2	—	—
0.350	1.4	0.5	0.1	—	—

Note: This table is very sensitive to pressure and is not valid for pressures greater than 500 psi.

Table F-30—Temperature Tolerance in °C for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C					
	–45	–20	0	20	40	60
637	7.5	5.5	4.2	3.1	2.3	1.6
600	5.4	3.7	2.7	1.8	1.2	0.7
550	3.5	2.3	1.5	1.0	0.6	0.3
500	2.3	1.4	0.8	0.5	0.3	0.1
450	1.5	0.8	0.4	0.2	0.1	—
400	1.0	0.5	0.2	0.1	—	—
350	0.7	0.3	0.1	—	—	—

Note: This table is very sensitive to pressure and is not valid for pressures greater than 3500 kPa.

Table F-31—Relative Density Tolerance for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2
Assumed pressure above equilibrium was 500 psi.

Relative Density	Temperature °F				
	–50	0	50	100	140
0.637	0.0115	0.0075	0.0047	0.0028	0.0017
0.600	0.0095	0.0060	0.0036	0.0020	0.0011
0.550	0.0072	0.0043	0.0024	0.0012	0.0006
0.500	0.0053	0.0029	0.0014	0.0006	0.0002
0.450	0.0039	0.0019	0.0008	0.0002	—
0.400	0.0032	0.0015	0.0004	—	—
0.350	0.0040	0.0023	0.0009	—	—

Note: This table is very sensitive to pressure and is not valid for pressures greater than 500 psi.

Table F-32—Density Tolerance for Hydrocarbon Liquids to Maintain Accuracy in *CPL* of ±0.02 Percent Using API *MPMS* Chapter 11.2.2M
Assumed pressure above equilibrium was 3500 kPa.

Density kg/m^3	Temperature °C					
	–45	–20	0	20	40	60
637	11.2	7.7	5.5	3.9	2.6	1.7
600	9.2	6.2	4.3	2.9	1.8	1.1
550	7.0	4.4	2.9	1.8	1.1	0.6
500	5.1	3.0	1.8	1.0	0.5	0.2
450	3.8	2.0	1.1	0.5	0.2	—
400	3.1	1.5	0.7	0.2	—	—
350	4.0	2.5	1.5	—	—	—

Note: This table is very sensitive to pressure and is not valid for pressures greater than 3500 kPa.

APPENDIX G—UNCERTAINTY CALCULATIONS

G.1 Uncertainty Calculations

G.1.1 The calculations involve three distinct steps:

a. Identify the components to be included in the uncertainty calculation.

b. Determine their significance in terms of volume (usually in percent).

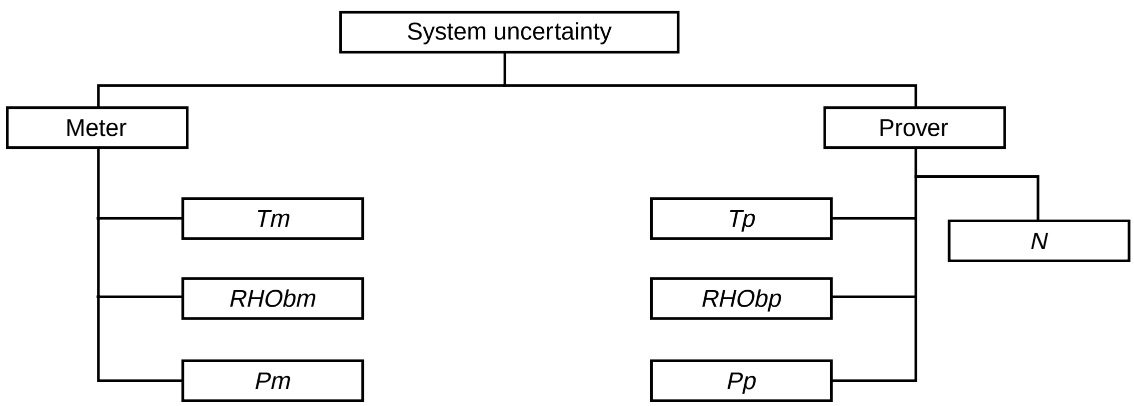
c. Combine them statistically.

G.1.2 The components to be used in the example in Table G-1 have been identified in Figure G-1. For the quantity transaction period, metering and proving secondary and tertiary device errors and the nonlinearity of volume corrections are considered systematic (assumed to be the maximum possible error outlined in Figure G-1 and to be constant for the transaction). Uncertainties for pulse count sampling in proving are considered random.

G.1.3 In the calculations that follow, systematic and random errors that produce less than 0.001 percent volume uncertainty have been ignored. Two standard deviations about the mean have been used to represent approximately 95 percent of the sample population beneath a curve of normal distribution. A 95 percent level of confidence means that 95 percent of the samples or tests used to develop it had results that fell within the limits specified.

G.2 Procedure for Calculating the Systematic Uncertainty of a Secondary Device

G.2.1 From the appropriate volume correction tables, determine the amount of change in volume per unit change of input. Because of rounding in the tables, it is necessary to use a span sufficient to yield suitable accuracy of the computed change per unit of the physical measurement. For example,



Measure	Description	Allowable Deviation	Source
Tm	Temperature of the liquid at the meter	0.5°F (0.25°C)	Chapter 7.2
RHObm	Base density at meter	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pm	Pressure of the liquid at the meter	3 psig (20 kPag)	Chapter 21.2
Tp	Temperature of the liquid at the prover	0.2°F (0.1°C)	Chapter 7.2
RHObp	Base density at prover	0.5 API (1.0 kg/m^3)	Chapter 14.6
Pp	Pressure of the liquid at the prover	3 psig (20 kPag)	Chapter 21.1
N	Least discernible increment	1 part in 10,000	Chapter 4.8

Note: This example does not reflect every possible source of error that could add to the uncertainty of the measurement system, nor does it imply better resolution or accuracy cannot be attained.

Figure G-1—Example of System Uncertainty Calculation calculate the difference in volume correction factors for the next increment change in temperature on either side of the average temperature for the batch, using it as the change in volume per unit temperature change. Multiply this by the allowable deviation in calibration, in units of the input value, to produce the maximum expected uncertainty for that component. This uncertainty will be assumed to be systematic for temperature and pressure corrections in both metering and proving operations at the 95 percent level of confidence.

G.2.2 In the NGL service example of Table G-1, the volume correction per unit change was calculated for a 10°C interval around the average temperature of 25.0°C and for an average density of 525.0 kg/m^3. The *CTL* for 20.0°C and 525.0 kg/m^3 can be found in Table 54 as 0.986. The *CTL* for 30.0°C and 525.0 kg/m^3 is 0.958. The change in volume per unit temperature change (DV/°C) is then:

$$\frac{\Delta V}{\Delta T} = \left[\frac{(0.958 - 0.986)}{(30.0 - 20.0)°\mathrm{C}}\right] = -0.0028\Delta V/°\mathrm{C}$$

G.2.3 For the allowable deviation of 0.25ºC between a reference device and the temperature measurement device, the significance in terms of volume becomes:

$$-0.0028\ \Delta V / °\mathrm{C} \times 0.25°\mathrm{C} \times 100 = -0.070\%$$

G.2.4 The negative sign here can be ignored because it will be lost in the total system uncertainty calculation.

G.2.5 In customary units, the volume correction per unit change could be calculated for an 18°F interval around the average temperature of 77.0°F and for an average relative density of 0.525. The *CTL* for 68.0°F and 0.525 can be found in Table 24 as 0.988. The *CTL* for 86.0°F and 0.525 is 0.960. The change in volume per unit temperature change is then:

$$\left[\frac{(0.960 - 0.988)}{(86.0 - 68.0)°\mathrm{F}}\right] = -0.0016\Delta V/°\mathrm{F}$$

G.2.6 For the allowable deviation of 0.50°F between a primary and the secondary temperature measurement, the significance in terms of volume becomes:

$$-0.0016\ \Delta V / °\mathrm{F} \times 0.50°\mathrm{F} \times 100 = -0.080\%$$

G.2.7 Differences between Tables 54 and 24 and rounding °F temperatures in conversion from °C are the reasons for the two different answers obtained using metric and customary units.

G.2.8 Temperature measurement errors will also affect *CPL* corrections but only to a small degree. Uncertainties in these examples of less than 0.001 percent have been ignored. Errors caused by the mismeasurement of NGL density will have a significant effect on both *CTL* and *CPL* but the volume uncertainties will be offsetting for temperatures above the reference temperature, and additive for temperatures below the reference temperature. Here, the negative sign should be carried until the component uncertainty calculation has been completed. For average values of temperature (25°C), of pressure (17.5 bar), and density (525.0 kg/m^3), a positive error in density will cause a 0.016 percent error in *CTL*, a –0.006 percent error in *CPL*, and a combined error in volume of –0.010 percent. The combined error was the only one reported in the Table G-1 NGL example.

G.3 Procedure for Calculating the Systematic Uncertainty of Nonlinearity

G.3.1 Calculate the nonlinear component of uncertainty as the difference between the average *CTL* and the *CTL* determined at the weighted average temperature for the quantity transaction period. Using *CTL*s determined for the extremes of the range of temperature should give an outside estimate of uncertainty.

G.3.2 The graph for a temperature change over a quantity transaction period in Figure G-2 may help to illustrate the uncertainty of nonlinearity. A constant flow rate was used to simplify the averaging of temperature.

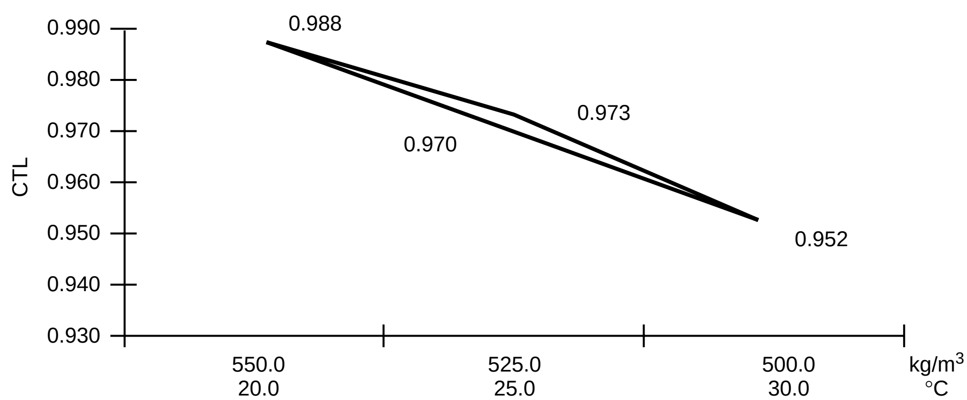


Figure G-2—Nonlinearity Example for NGL

G.3.3 The average of *CTL*s determined for 20.0 and 30.0°C, across the range of densities encountered for the transaction, was 0.970. The *CTL* determined for the average temperature of 25°C was 0.973. The maximum difference, under these conditions, was 0.003 or 0.3 percent. This uncertainty was spread over the transaction volume trigonometrically by dividing this maximum difference by two. The resulting uncertainty due to nonlinearity was then 0.15 percent at the 95 percent level of confidence. Pressure has not been included because its effect was negligible under the conditions of the example.

G.3.4 In customary units, the average of *CTL*s determined for 68.0 and 86.0°F, across the range of relative densities encountered for the transaction (0.500 to 0.550), would have been 0.972; the *CTL* determined for the average temperature of 77.0°F, 0.974; and the maximum difference, 0.002 or 0.2 percent. This uncertainty, spread over the transaction volume, would have been 0.10 percent. Differences in results between metric and customary units correspond to differences between Tables 54 and 24. Note that a density of 500.0 kg/m^3 is actually equivalent to a relative density of 0.499.

G.4 Procedure for Calculating Random Uncertainty

G.4.1 The allowable deviation of the one pulse count error is a range value. Random uncertainty cannot be determined without consideration of the number of sample runs that created the range. For a number of comparisons around five, the uncertainty in the average deviation can be assumed to be half of the allowable deviation range. As well, a multiplier, representative of the level of confidence for the number of samples used, a Students *t*, must be factored into the equation. The random uncertainty of the one pulse count error in meter proving is calculated as follows:

$$\frac{t \times s}{\sqrt{n}}$$

where

t = value in statistical t table, 95 percent confidence and $n - 1$ degrees of freedom,

s = the sample standard deviation,

n = number of sample runs.

Substituting values:

$$\left(\frac{2.87 \times 0.005\%}{\sqrt{5}}\right) = \pm 0.006\% .$$

G.4.2 The sign can be plus or minus, given that the uncertainty is random, but can be dropped at this point, as it will be lost in the calculation of total system uncertainty. The standard deviation here has been determined to be half of the allowable deviation range (0.01 percent, or one part in 10,000).

G.5 Total System Uncertainty

G.5.1 The component uncertainties are then combined by taking the square root of the sum of the individual uncertainties squared. Both systematic and random uncertainties are combined in this manner.

$$c = \sqrt{a^2 + b^2}$$

where

a = random uncertainty (95%),

b = systematic uncertainty (95%),

c = total uncertainty (95%).

Note: Systematic uncertainties used in these examples assume that the allowable deviation already represents 95 percent of the possible distribution. In examples where this is not the case, multiply the allowable deviation by 0.95.

G.5.2 With the terms listed in the NGL example of Table G-1, the total system uncertainty was calculated as a root sum square (RSS) as follows:

$$c = \sqrt{(.070)^2 + (.010)^2 + (.010)^2 + (.028)^2 + (.010)^2 + (.010)^2 + (.006)^2 + (.150)^2}$$

$$c = 0.169\%$$

G.5.3 The RSS analysis is normally performed on single standard deviations, but steps can be saved without loss of accuracy by working directly in two standard deviations. The total system uncertainty will be determined directly in two standard deviations (approximately 95 percent confidence). More rigorous estimations of uncertainty are available using the techniques of differential equations, simulation, and numerical analysis. The tables of volume corrections are considered to be more universally available, however, and can be used with little loss in accuracy.

G.6 Results

G.6.1 The examples of Table G-1 have been taken from representative ELM operations for NGL and for crude oil, and show the results for configurations described in Figure G-1. Component system uncertainties have been provided to allow the user of the standard to adapt the total system uncertainty calculations to other configurations.

G.6.2 System uncertainty evaluation can be a valuable measurement tool. It can be used to assess system capabilities, to assess the performance of one system versus another, to highlight design sources of potential error, to allow the design of new facilities, to consider component sensitivities, to facilitate maintenance resource management, and to benchmark expected performance for inspection.

Table G-1—ELM System Uncertainty Example

Example Ranges	Units		NGL	Crude Oil
Temperature	°F		68.0 to 86.0	50.0 to 86.0
	°C		20.00 to 30.00	10.00 to 30.00
Density	Relative Density		0.550 to 0.499	0.8003 to 0.9007
	kg/m^3		550.0 to 500.0	800.0 to 900.0
Pressure	psi		218 to 290	145 to 290
	bar		15.0 to 20.0	10.0 to 20.0
Vapor Pressure	psia		145	
	bar absolute		10.0	
Average Pulse Count			10,000	10,000
	Allowable Deviation		Uncertainty % Volume (95%)	Uncertainty % Volume (95%)
Measure	Customary	Metric		
Tm	0.5°F	0.25°C	0.070	0.021
RHObm	0.001	1 kg/m^3	0.010	0.001
Pm	3.0 psi	0.2 bar	0.010	0.002
Tp	0.2°F	0.1°C	0.028	0.009
RHObp	0.5°API	1 kg/m^3	0.010	0.001
Pp	3.0 psi	0.2 bar	0.010	0.002
N	1	1	0.006	0.006
CTL Linearity			0.150	0.050
Total System Uncertainty			0.169	0.055

Note: This example does not include the uncertainty of the primary device nor does it imply that the results are applicable to all ELM systems. Results determined using customary and metric tables may be different.

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