

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

Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters

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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:

- Within the scope and field of application of API MPMS Chapter 12.2.
- Which are single-phase liquids at measurement conditions.
- For systems utilizing turbine or positive displacement meters.
- 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	<i>Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2</i>

ASTM¹

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

¹American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19380

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 GSV_m: The volume at base conditions shown by the meter at the time of proving.

3.24 GSV_p: 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:

- The performance of the devices comprising the system.
- Conformance to installation requirements.
- The method used to transmit data signals (analog, frequency, or digital).
- The integrity of the signal path from sensor to tertiary device input.
- The method of calculation.
- 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

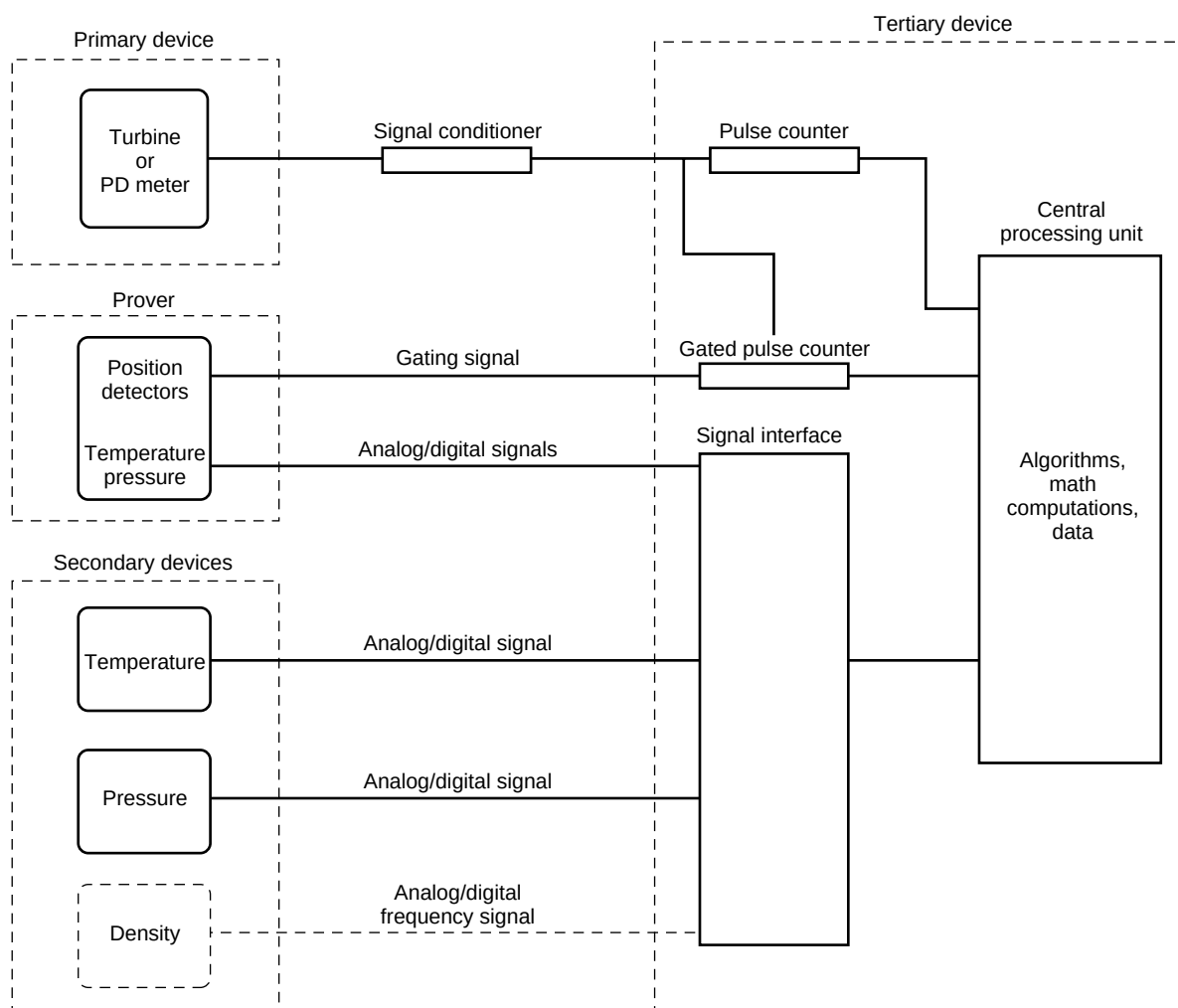
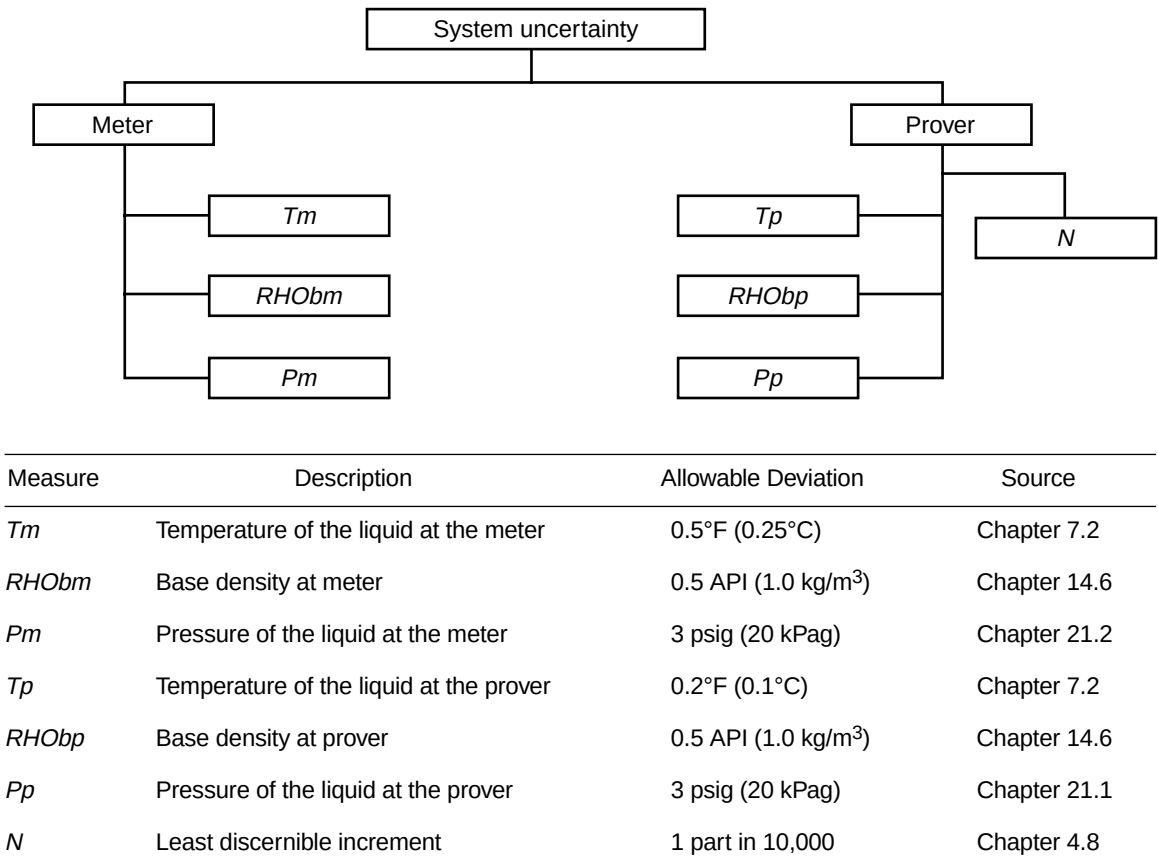


Figure 1—Typical ELM System



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:

- Wider rangeability.
- Calibration procedures.
- Improved performance.
- Lower drift rate.
- 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:

- Ambient temperature—expressed as a percentage of the URV or the span per degrees of temperature change.
- Vibration effect—expressed as a percentage of the URV or the span per unit of G force.
- Power supply—expressed as a percentage of the URV or the span per volt of power supply.
- 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:

$$Q_{tot} = \sum_{p=t_0}^{t-t_0} Q_p \quad (1)$$

where

Σ = summation operation for p time intervals,

Q_{tot} = quantity accrued between time t_0 and time t ,

Q_p = 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:

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

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:

$$q_p = \frac{Q_p}{p} \times k \quad (3)$$

where

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

Q_p = 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:

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

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 (CTL_m , CPL_m , CTL_p , and CPL_p).

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 CTL_m and CPL_m 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.

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

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.



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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.

$$Qb_{mcp_i} = Qp_{mcp_i} \times CCF_{mcp_i} \quad (6)$$

where

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

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

CCF_{mcp_i} = 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:

$$Q_b = Q_p \times CCF_{pmcp} \quad (7)$$

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:

$$IV = \sum_{p=1}^n Q_{Tp} \quad (8)$$

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.

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

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.

$$GSV = ISV \times MF \quad (10)$$

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:

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

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 API₆₀ gravity, 100,000 gross indicated barrels are transferred at 75°F and 195 psig. Then