API Manual of Petroleum Measurement Standards

COLM TR 25XX

MEASUREMENT OF PRODUCED WATER FOR CUSTODY TRANSFER

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Measurement of Produced Water for Custody Transfer

1 Introduction

This Technical Report (TR) provides users with guidance for applying metering technology to achieve uncertainties of better than or equal to +/- 5.0% or to meet the contractual obligations established between the buyer and seller.

Produced water gross quantity (mass or volume) does not require temperature or pressure correction to standard conditions. However, temperature and pressure may be measured to ensure operational safety and to provide the user with ancillary information.

This Technical Report is not intended to cover produced water quality, emulsions, or separator/allocation measurement.

2 Scope

This technical report provides guidance for dynamic quantity measurement of produced water. This technical report provides additional direction for the design, selection, and maintenance of a produced water measurement system for custody transfer applications.

3 Normative References

There are no documents referred to in the text in such a way that some or all of their content constitutes requirements of this document.

4 Terms and Definitions

4.1 Produced Water

produced water will be known as a homogeneous liquid that is produced from an oil and natural gas well, injection water, and any added chemicals.

4.2 Flow Assurance

flow assurance refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the point of sale.

4.3 Calibration

a set of operations which establish, under specified conditions, the relationship between the values indicated by a measuring device and the corresponding known values indicated when using a suitable measuring standard.

4.4 Verification

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

4.5 Self-monitoring and diagnostics

hardware, software, or firmware internal or external to a flow meter for the purpose of monitoring, analyzing, and/or identifying functionality, status, or performance of the flow meter

4.6 Gross Volume

the actual volume of fluids at flowing temperature and pressure

5 Selection of Methods for Dynamic Measurement Quantity Determination Using Available Equipment

5.1 Measurement Considerations

Selecting the measurement technology to be used for custody transfer of produced water requires the user to consider the technology best suited the application and the manufacturers recommendation for use. Considerations include:

Technology	Preplanning	Operational	Maintenance and Repair
Select the technology best suited for the application. Capacity, accuracy (uncertainty), available pressure, power availability and installation space should be assessed.	☐ Area classification ☐ Power availability ☐ Flow capacity ☐ Line pressure ☐ Max / Min Temp ☐ Flow conditioning and straight pipe runs ☐ Remote / Local access ☐ Mounting to maintain full pipe	☐ Power consumption ☐ Non resettable totals ☐ Uncertainty limits ☐ Remote connectivity ☐ Proving frequency ☐ Multivariable measurement ☐ Operating temperature and pressure ranges ☐ Oil in water content ☐ Gas breakout or leaking into produced water:	☐ Mechanical wear ☐ Replacement parts ☐ Diagnostics available ☐ Ancillary equipment needed ☐ Software and hardware tools required ☐ Brine / corrosion ☐ Calcium buildup or coating

5.2 Produced Water Contract Conditions

For purposes of this Technical Report, produced water is different than hydrocarbons in the sense that oil and gas are part of the mineral estate in situ, and produced water generally is not (e.g., State of Texas). Since this difference ends as soon as any of these products are severed and produced, upon being produced (and prior to delivery to the midstream company) all these products become personal property which can be addressed in contractual obligations for possible proving, master metering or verification of produced meter systems.

Contractors should address how produced water metering to purchase or sell produced water will be quantified. This requires following accepted standards that ensure a mutually agreeable level of uncertainty. The contract should also clarify who will bear the expense of installation, cooperation, and maintenance of the produced water meter systems. The following issues are typically covered in measurement clause of the contracts:

- Quantity of Product
- Point of Delivery
- Product Quality
- Measurement Station Design
- Operating Parameters and Conditions
- Sharing of Data

Produced water contracts usually specify the measurement equipment verifications/calibration/proving and tolerances of measured versus actual values. They also specify that equipment verifications/calibration/proving be scheduled in advance and that non-operating parties be allowed to witness all these activities, as well as supplied raw data for auditing.

6 Guidance for Design of Measurement Equipment

6.1 General Considerations

When discussing and designing for produced water quantity measurement, assumptions are that the fluid is greater than 50 % water, may have high salinity, may have trace amounts of hydrocarbons entrained, may have varying amounts of fluids and particulate associated with the drilling, production, and fracturing stages, and may occasionally have varying amounts and sizes of solids. As a result, each technology has advantages and limitations, and there is often overlap when attempting to narrow down to a best choice for your needs. As such, in addition to the above assumptions, there are many factors to consider when choosing what technology is best suited for each situation. API *MPMS* Chapter 5.1 [1] provides some flow meter considerations, in addition to the below common factors:

6.1.1 Process Conditions & Flow Assurance:

- Expected volumes
- System pressures
- System temperatures
- Stability of conditions
- Propensity for plugging
- Propensity for pulsation or vibration
- Fluid properties such as propensity to cause corrosion or erosion, scaling, coating or build-up, abrasiveness, density, viscosity, solids content, presence of gas/liquid entrainment, vapor pressure, cleanliness, lubricating qualities, etc.

6.1.2 Transmitter/Operator Interface:

- Diagnostics requirements
- Control system requirements
- Communications protocol requirements
- Input/Output type and quantity requirements (need better word for “quantity” of I/O channels)
- Requirement for multiple variables
- Alarming capabilities
- Need for display/buttons, totalizer functions, auditing, security, and/or printing capabilities (where do we talk about data collection, records, etc? Jeff’s section??)

6.1.3 System Design:

- Pipe diameter, material, and connection type
- Flow rate turndown needs
- Desire to measure in mass or volume
- Importance of accuracy vs repeatability
- Uni- or bi-directional measurement
- Requirements for proving or calibration
- Orientation requirements
- Power supply availability, requirements, or limitations
- Permanent pressure loss through the flow meter
- Secondary containment requirements
- Whether meter will be used for a single product or for multiple products
- Single or multiple meters being required due to flow rate

6.1.4 Sensor:

- Materials of construction
- Physical dimensions and weight
- Straight run and/or flow conditioning requirements
- Degree of accuracy or repeatability required or preferred
- Velocity limitations
- Maintenance requirements
- New installation or retrofitting
- Ambient conditions and exposure
- Other manufacturer suggested best practices
- Potential for damage or error due to foreign materials or pulsation
- Ability to be serviced, tested, or repaired under operating conditions
- Potential accessories, peripheral, or tertiary equipment needed

6.2 Best Practices for Flow Meter Sizing and Selection

Sizing of the flow meter is a critical step and should be performed based on manufacturer's recommendations by qualified personnel, using associated tools. Proper sizing ensures that the application in question will fall within the selected flow meter's operating window. Different technologies and manufacturers require varying amounts of data to perform this task, but at a minimum the user should supply the following parameters:

- Min/Norm/Max Flow Rate
- Min/Norm/Max Process Pressure
- Min/Norm/Max Process Temperature
- Process Fluid: Produced Water

API *MPMS* provides detailed guidance on the selection of various flow meter technologies in the following sections:

- **Chapter 5.2 [2]:** Measurement of Liquid Hydrocarbons by Displacement Meters
- **Chapter 5.3 [3]:** Measurement of Liquid Hydrocarbons by Turbine Meters
- **Chapter 5.6 [4]:** Measurement of Liquid Hydrocarbons by Coriolis Meters
- **Chapter 5.8 [5]:** Measurement of Liquid Hydrocarbons by Ultrasonic Flowmeters
- **Chapter 14.3 (all sections) [11]:** Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square edged Orifice Meters

- **Vortex:** TR 2577 [16] – Performance of Full Bore Vortex Meters for Measurement of Liquid Flows

From the British Standards Institute:

- **Clamp-On Ultrasonic:** BS 8452 [19] Use of Clamp-On (externally mounted) ultrasonic flow-metering techniques for fluid applications - Guide

6.3 Magnetic Flow Meter Installation

Exercise considerable care when the magnetic flow meter's primary element is installed in the pipeline. Special care should be taken to prevent damage to the liner and to ensure that grounding requirements are met. The manufacturer's installation recommendations should be followed, including consideration of upstream and downstream piping requirements. For custody transfer, bypasses are not permitted.

The transmitter, if not a part of the instrument, is to be on a rugged piece of pipe, but it should be handled as a precision instrument. The transmitter should be accessible from grade or from a platform with enough space around it to permit removal of at least the top housing if necessary. Sufficient access should be available for removal of any inspection plates.

The magnetic flow transmitter tube may be installed in any position (vertical, horizontal, or at an angle), but it should run full of liquid to ensure accurate measurement. If the tube is mounted vertically, flow should be from bottom to top to ensure that the pipe is full. If the tube is mounted horizontally, the electrode's axis should not be in a vertical plane. A small chain of bubbles moving along the top of the flow line can prevent the top electrode from contacting the liquid.

6.3.1 Magnetic Flow Meter Installation

Power for magnetic flow meters should be supplied at a voltage and frequency within the tolerance specified by the manufacturer.

Special low-capacitance cable is used to carry the generated signal from the primary element to the transmitter. The signal cable should not be installed close to the power cable or in the same conduit as the power supply. The manufacturer’s recommendations should be observed.

The importance of proper grounding, which is necessary for personnel safety and satisfactory flow measurement, cannot be overemphasized.

The manufacturer’s instructions for grounding should be followed carefully. A continuous electrical contact to the same ground potential is necessary between the flowing liquid, the piping, and the magnetic flow meter. This continuous contact is especially important if the conductivity of the liquid is low. How contact is achieved depends on the meter’s construction and whether adjacent piping is unlined metal, lined metal, or nonmetallic.

Jumpers from the meter body to the piping are always required. If the meter is installed in nonmetallic piping, it is always necessary to make a grounding connection to the liquid. This connection is achieved by means of a metallic grounding ring between the flanges, unless internal grounding has been provided in the transmitter. The grounding connection is extremely important and should be installed as recommended if the system is to operate properly.

Most magnetic flow meters have their signal and power connections enclosed in splash proof or explosion proof housings. The connections should be sealed in accordance with the manufacturer’s instructions and any applicable codes. Great care should be exercised in this area.

6.3.2 Start-up and Calibration

No special procedures need be observed during start-up, since the magnetic flow meter is free of obstruction, but there are often electrical adjustments that should be made. The manufacturer's instructions should be consulted regarding these procedures.

6.4 Turbine Meters

6.4.1 General

Turbine meters are used where their accuracy and rangeability are required. Their major application is for custody transfer and in-line product blending. The pulse outputs of turbine meters may be scaled for direct totalization in engineering units. Outputs from turbine meters are suitable for control or recording applications and are ideally suited for batch control applications. Compensation for non-linearity due to viscosity is also available.

Turbine meters have the following advantages:

a. Accuracy of 0.25 percent of rate with a repeatability of 0.10 percent or better is normal. (To obtain the highest accuracies, some form of meter proving is recommended.)

b. Rangeability varies depending on meter design, fluid viscosity, density, and meter size.

c. A high flow rate for a given line size is obtainable.

d. Designs for very low flow rates are available.

e. Turbine meters are available for a wide range of temperature and pressure ratings.

f. Specially designed turbine meters are available for bidirectional flow.

Turbine meters are limited by the following characteristics:

a. They are susceptible to wear or damage if the process stream is dirty or non-lubricating.

b. They are susceptible to damage from over-speed and pulsing flow.

c. They require maintenance and may require return to the manufacturer for recalibration after a bearing change or other maintenance.

d. Their rangeability is affected by high viscosity and low density.

e. Their cost is relatively high.

f. They require strainers.

g. Provers are required to maintain calibration accuracy.

6.4.2 Installation

6.4.2.1 General

Turbine meters are installed directly in the process line. The line should be relatively free from vibration. Meters with integrally mounted, direct-reading registers should be positioned so that they can be easily read and maintained. Turbine meters are normally installed in horizontal lines but may be installed in vertical up-flow lines.

6.4.2.2 Piping

The accuracy and repeatability of measurements from turbine meters depend on the upstream and downstream piping. In addition to sufficiently long straight runs upstream and downstream, straightening vanes are required for high accuracy.

6.4.2.3 Bypass Piping

The need for bypass piping for turbine meters is determined by the application. It may be necessary to isolate or disassemble the meter for maintenance purposes. In continuous-service applications, where shutdown is considered undesirable, block and bypass valves should be provided to permit process operation while the meter is being serviced. Conditions that may necessitate disassembly of the meter include damage caused by foreign material, wear, or buildup of solids. If the meter is bypassed, it should be in the main run, with the line-size block valves placed beyond the meter's required upstream and downstream piping runs. The bypass valves should be capable of positive shutoff to prevent measurement errors. The bypass piping installation should be free draining. Bypasses are not permitted for custody transfer applications.

6.4.2.4 Strainers

All turbine meter installations should have strainers to prevent damage to the meter rotor. The strainer should be capable of removing particles of a size that might damage the rotor and bearings. The strainer should be located upstream of the required meter run.

6.4.2.5 Electrical Installation

The signal from a turbine meter is a low-level pulse, which makes it especially susceptible to noise pickup. Shielding of signal wires is recommended to eliminate spurious counts. If the transmission distance is more than 10 feet (3 meters), a preamplifier is recommended. The manufacturer's instructions should be consulted for details.

6.4.2.6 Start-up and Calibration

Care should be taken to prevent damage to the turbine meter at initial start-up. The meter should be placed in service only after the process line has been flushed and hydrostatically tested. If strainers are used, they should be cleaned after flushing and periodically during operation. Flow should be introduced slowly to the meter to prevent damage to the impeller blades as a result of sudden hydraulic impact or over-speed. The calibration factor, expressed in electrical pulses generated per unit volume of throughput, is normally called a K (meter) factor. The K factor depends on fluid conditions, it is determined when the flow meter is calibrated, and is inherent for the particular meter rotor. K factors of meter rotors vary within the same meter body size. No field adjustment may be made to the primary sensor.

6.5 Positive Displacement Flow Meters

6.5.1 General

The basic types of positive-displacement meters are nutating disk, oscillating piston, fluted rotor, rotary (lobed impeller and sliding vane), and oval-shaped gear. Positive-displacement meters measure flow by mechanically trapping successive volumetric segments of the liquid passing through the meter. The number of segments is converted to shaft rotation. A gear train and calibrator convert shaft rotation to the appropriate volumetric units.

Temperature compensators are available to correct the output as the fluid temperature changes.

Pulse generators are available to provide pulse outputs for meter proving or remote readout.

Positive-displacement meters are used because of their excellent repeatability over wide flow ranges. They are used for heavy or viscous fluids in custody transfer and product blending applications.

Positive-displacement meters have the following advantages:

a. Attainable accuracies are 0.05-0.15 percent of actual flow. Typical repeatability is 0.02-0.05 percent.

b. Rangeability is normally 10:1. Positive displacement meters have excellent rangeability and accuracy, particularly with heavy or viscous fluids.

c. Positive-displacement meters come in a range of sizes.

Positive-displacement meters have the following disadvantages:

a. They are subject to mechanical wear.

b. They are not interchangeable and should be supplied to match the service.

c. They require filter strainers.

d. Their installation requires special considerations.

6.5.2 Installation

Positive-displacement meters are installed directly in the process piping and can be a source of vibration. Adequate foundations should be provided (refer to the manufacturer's recommendations).

Positive-displacement meters are normally installed in horizontal lines.

Certain types are specifically designed for vertical lines.

Meters should be installed so that the meter case or body is not subject to piping strain. The piping should be arranged so that the meter is always full of liquid. Adequate back pressure may be required to eliminate the possibility of vapor release.

For continuous process services, a bypass around a positive-displacement meter is recommended.

For custody transfer, bypasses are not permitted. Positive-displacement meters should always be installed with an adequate strainer to prevent foreign matter from damaging the meter or causing excessive wear; the manufacturer's recommendation on mesh size should be observed. Where excessive amounts of debris are entrained in the fluid, strainer pressure drop should be monitored.

The installation of a positive-displacement meter should be designed to avoid air or vapor in the piping. Where the design does not allow for this, air eliminators should be considered. Air eliminators can leak or have inadequate capacity to protect the meter from slugs of air or vapor; such eliminators should be removed and replaced.

6.5.3 Start-up and Calibration

Positive-displacement meters can be damaged or destroyed during initial start-up. The manufacturer's instructions, as well as the following general guidelines, should be followed during start-up:

a. Positive-displacement meters and air eliminators should be installed in the line only after the piping has been flushed and hydrostatically tested.

b. The meter and strainer basket should be installed after the piping has been flushed.

c. Strainer pressure drop should be monitored, and strainers should be cleansed as required.

d. Extreme care should be taken to vent air from the piping. Flow should be introduced slowly to prevent hydraulic shock.

e. Custody transfer meters should be proved initially and at regular intervals.

6.6 Mass Flow Meters

Generally, Mass flow meters are of two basic types and have limited use in the refining industry. The installation and use of these instruments should closely follow the manufacturer's recommendations. This section is intended to summarize the features and philosophy of these devices.

Mass Flow meter-Coriolis Coriolis mass flow meters measure mass units directly. Fluid flow through a tube vibrating at its natural frequency produces a Coriolis force. The resulting tube deflections are measured and signaled proportionally to generate mass flow. A Coriolis meter can be used with liquids, including liquids with limited amounts of entrained gas, and slurries.

Although Coriolis meters are nonintrusive, in some designs the flow path through the meter is circuitous. In addition, the flow is generally separated into two tubes that are much smaller in cross-sectional area than is the inlet process piping. For this reason, it is relatively easy for any secondary phase to build up in a meter that has not been carefully installed. The pressure loss can be substantially higher than that in other types of nonintrusive elements, and cavitation and flashing can be problems with volatile fluids.

Start-up problems with Coriolis meters are typically due to improper installation. Installation shall be strictly in accordance with the manufacturer's recommendations. Pressure containment enclosures are available when required.

These meters are not affected by distortion of the velocity profile and do not require metering runs. Although Coriolis meters generally cost much more than other types.

They measure mass flow rate without the need for additional elements.

The applications for these meters have been limited to difficult fluids or applications in which their accuracy justifies the higher cost (such as in billing, custody transfer, and batching and blending services).

6.7 Other

There are other types of metering technology suitable for the measurement of produced water. Some of these additional metering technologies can be referenced in the technology chart shown in Annex A. Cost (capital & operational), maintenance, operation, performance, process conditions, and flow assurance should all be considered when evaluating different metering technologies.

7 Measurement Equipment for Produced Water

7.1 General

Produced water has a multitude of characteristics that can vary by location, region, fluid properties, chemistry, infrastructure, well traits, etc. No single quality standard has been created or agreed to that defines what produced water's composition should be. As such, this technical report does not prevent the use of any flow meter technology for custody transfer quantity measurement of produced water. Some technologies are more commonplace within the produced water industry, and it may be beneficial to reach to others within your organization or industry. Typical flow measurement technologies in use are (but not limited to):

- **Turbine:** A flow measuring device in which the action of the fluid stream passing through the devices turns a bladed turbine and produces an electrical output signal having a frequency proportional to the turbine speed

- **Magnetic:** A device that uses magnetic principles of induction and conductivity to determine the rate of flow (not available in Chp 1 or elsewhere)

- **Coriolis:** Also referred to as Coriolis mass meter or Coriolis force flow meter. A Coriolis meter is a device which by means of the interaction between a flowing fluid and the oscillation of a tube(s), measures mass flow rate and density. The Coriolis meter consists of a sensor and a transmitter

- **Ultrasonic:** A device that uses the transit time of ultrasonic signals through a fluid or gas to determine flow rate

- **Positive Displacement:** A flow measurement device in which the measuring element measures a volume of liquid by mechanically separating the liquid into discrete quantities of fixed volume and counting the quantities in volume units

- **Vortex:** A device that induces and uses the vortex shedding effect to create electrical pulses, which are proportional to rate of flow

- **Differential Pressure:** A device that induces and uses pressure loss across an obstruction to determine the rate of flow

7.2 Metering System Accessories

7.2.1 Strainers and Filters

Suspended solids in the fluid being measured can cause inaccuracy and even damage metering equipment. Solid particulates should be prevented from reaching the meter by using an appropriate strainer or filter per meter manufacturer recommendations. Filters are typically utilized in jet fuel, biofuels, and distillate applications in lieu of strainers. The strainer or filter should be monitored and/or checked periodically to avoid restricting flow which could lead to vaporization or reduce the normal flow rate and thereby affect accuracy by causing the system to deviate from the flow conditions when the metering system was proved.

7.2.2 Air Eliminators

Air eliminators are required in systems where air or vapor can be introduced into the system. If not eliminated, air will adversely affect measurement and can cause damage.

If air eliminators are installed, they should be installed upstream of the meter, and their purpose is to dispose of any air or vapor in the delivery line before it passes through the meter. If a system is designed so that significant amounts of air, vapor, or both cannot be introduced, an air eliminator is not required.

A sight glass can be located between the air eliminator and the flow meter to monitor the functionality of the air eliminator and to ensure the piping between the unloading arm coupler and meter is always full of product during metering operations.

7.2.3 Insulation or Heat Tracing

See API *MPMS* Chapter 6.1A [6] for information related to insulation and heat tracing.

7.2.4 Thermal Relief Systems

See API *MPMS* Chapter 6.1A [6] for information related to thermal relief systems.

7.2.5 Vents

See API *MPMS* Chapter 6.1A [6] for information related to vents.

7.2.6 Drains

See API *MPMS* Chapter 6.1A [6] for information related to drains.

7.2.7 Pumps

System hydraulics can affect meter performance. System pumps and controls should be designed to meet the desired operation of the facility such that adequate pressure and flow are provided. The ability to prime the pump and the effect of fluid properties, such as density and viscosity, should be considered when selecting pumps.

8 Record Keeping

8.1 General

The requirements of this section are intended to ensure that the minimum necessary data is documented and retained in order to reflect that accepted standards were adhered to and reflect the necessary documents to ensure the level of uncertainty was accomplished. Electronic flow measurement “EFM” or manual record keeping methodologies may be applied. The basis of this section is for gross volumes (GV) only. Additional data points (e.g., temperature and pressure) can be used to improve the overall accuracy and to potentially reduce the uncertainty of volumes.

GV calculations do not require temperature or pressure measurement inputs. References to temperature and pressure inputs and/or averages in this section may be applied where applicable.

8.2 Data Availability

The suggestions of this section are intended to ensure that the minimum necessary data is collected and retained in order to allow proper determination of the quantities measured through the primary device and allow a thorough audit of the system operation and quantity determinations

8.2.1 Differential Meter and Linear Installations

For differential and linear metering systems where custody transfer measurement (calculations) are performed on-site, the information required in 8.2.1.1 through 8.2.1.5 may be made available on-site, or be collectable on-site with a portable data collection device.

8.2.1.1

Data collected or utilized since the last completed data may include, but are not limited to the following:

a. Dates and times for all averages and totals.
b. Total quantity accumulated during each contractually specified measurement period.

8.2.1.2

Input variable values affecting measurement may include, but are not limited to the following:

a. Meter run reference diameter, orifice bore reference inside diameter, and the calibrated span of the pressure, differential-pressure, and temperature transducers as applicable.
b. Meter and/or K factors and the calibrated span of any span adjustable values for pressure and temperature as applicable.

8.2.1.3

An electronic or hard copy record should include, but is not limited to, the following:

a. “As found” and “as left” equipment calibration values for differential pressure~~,~~ pressure, temperature, and meter and/or k factors as applicable.
b. Old and new values for changes to any input value that will affect calculated quantities.
c. A complete summary of all alarm or error conditions affecting measurement, including a description of each alarm condition as applicable.
d. A daily summary indicating the hours or percent of time for flow or no flow as applicable.
e. The date and time of all events in the log shall be identified chronologically as applicable.

8.2.1.4

A quantity statement should include, but is not limited to, daily custody transfer quantity totals and average pressure, differential pressure, and temperature as applicable.

8.2.1.5

The unique identification number of the metering system shall be available on-site.

8.3 Audit and Reporting Requirements (or Recommendations)

Refer to API *MPMS* Ch. 21.2 [15] Audit and Reporting section for requirement specifics.

8.3.1 Algorithm Identification

An algorithm identification shall be provided to identify the calculations performed in the electronic liquid measurement system, such as software or manufacturer’s version.

8.3.2 Configuration Log

The configuration log shall be part of the audit package for the accounting period. The log will contain and identify all constant flow parameters used. The configuration log will be generated from data and information listed in API *MPMS* Ch. 21.1 [14].

8.3.3 Event Log

The event log should be a part of the audit package for the accounting period. The event log is used to note and to record exceptions and changes to the flow parameters, contained in the configuration log, that occur and that have an impact on a measurement volume (API *MPMS* Ch. 21.1 [14] states quantity transaction records).

Each time a constant flow parameter that can affect the quantity transaction record is change in the system, the old and new value, along with the date and time of the change, shall be logged.

\The data and time of all events in the log shall be identified chronologically.

8.3.4 Test Record

A test shall be part of the audit package and consists 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 may include, but not limited to, calibration/verification reports, orifice plate and equipment change tickets; and peripheral equipment evaluation reports.

8.3.5 Data Retention

Unless specified by regulation, tariff, or contract, the minimum retention period for the electronic flow measurement audit trial data shall be two years.

8.4 Performance Records

Results based performance monitoring records should also be maintained and kept. System balances within a contractually or company defined tolerance may indicate the flow meters measuring the produced water of a system are all performing as desired. Additionally, control charts which track the results of meter maintenance activities (e.g., proving, calibration, verification, etc.) may support less frequent maintenance activities.

8.5 Security

Transmitters should be secured against tampering or unauthorized or un-documented changes to any variable or parameter that can alter the quantity measurement. This can be achieved by several methods such as including passwords, or tamper evident seals, internal write protection switches, or other lock out methods. See API *MPMS* Ch. 21.2 [15].

9 Capability and Uncertainty

It is up to the user to understand the differences between the two types of uncertainty; uncertainty of the individual components of the system, versus the uncertainty of all components combined as a functioning system.

The methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (*MPMS*), Chapter 13 [10], or the latest edition of the International Standard Organization (ISO) Standard 5168 [20]: Measurement of Fluid Flow – Estimation of Uncertainty of a Flow-rate measurement. API *MPMS* Chapter 14.13 [12] may also be referenced for additional performance-based methodologies.

10 Procedures for Confirmation of Performance

Procedures for confirming the performance of produced water measurement systems varies by user, region, contract, compliance requirements, and quantities. Initial calibration of the flow meter to be used should be performed.

Periodic re-calibration, verification, and/or use of self-monitoring and diagnostics is recommended. Users shall define their performance goals/requirements and decide the frequency and methods best suited for their application.

Typical accepted procedures suggested by API and/or manufacturers:

a. Calibration at factory when new, transferred to field
b. In-situ secondary and/or tertiary device verification or calibration;
c. Primary element inspection;
d. Off-site meter proving;
e. In-situ meter proving (master meter, displacement, or tank);
f. Verification of self-monitoring and diagnostic results;
g. Comparison of values to another calibrated device

Annex A
(Informative)
Flow Meter Technology Advantages and Limitations

FLOW METER TECHNOLOGY	CALIBRATED METER PERFORMANCE (UNCERTAINTY)	SIZE RANGES	ADVANTAGES IN PRODUCED WATER APPLICATIONS	LIMITATIONS IN PRODUCED WATER APPLICATIONS
Coriolis	0.1 - 0.75%	Up to 16"	- Higher accuracy, turndown, and repeatability -Ability to measure in mass or volume -No moving parts = low/no maintenance -Bi-directional -No flow conditioning or straight runs required	-Usually create pressure loss -Can be larger footprint -Typically limited to 16" and below -Possible velocity limitations based on size/type of prover
Differential Pressure	0.5 - 2%	Up to 24"	-Trusted and understood technology -Variety of primary elements to fit needs -Low power requirements -Multi-Variable options available	-Creates pressure loss Lower turndown -Lower accuracy than some technologies -Requires most straight runs of upstream and downstream piping
Displacement Meter	0.1 - 1%	Up to 16"	-Trusted and understood technology -Lower up-front cost for most sizes -Cooperative with typical proving methods -Low pressure drop -Some models have very high accuracy	-Typically requires more maintenance or repairs due to wear -Larger footprint than some technologies -Requires upstream protection (i.e. strainer, filter, etc)
Magnetic	0.25 - 1%	Up to 72"	-Low or no pressure loss -Bi-directional -Wide variety of materials for chemical and temperature compatibility -No moving parts = low/no maintenance -Minimal flow conditioning required	-Requires straight runs of upstream and downstream piping -Liner and electrode chemical compatibility is critical -Coating/Scaling of electrodes can cause error/uncertainty -Larger line sizes can be heavy

Turbine	0.25 - 1%	up to 18"	-Trusted and understood technology -Low pressure drop -Some models have very high accuracy -Pulse train type output widely accepted by most flow computers	-Typically requires more maintenance or repairs due to wear -Requires upstream protection (i.e., strainer, filter, etc) -Requires straight runs of upstream and downstream piping -Typically requires flow conditioning
Ultrasonic	0.25 - 1%	Up to 72"	-Available for in-line and external installations -Low or no pressure loss -Bi-directional -No moving parts = low/no maintenance	-Requires straight runs of upstream and downstream piping -Typically requires flow conditioning -External sensitive to improper or un-maintained pipe coupling -External, non-intrusive installations can often lower accuracy
Vortex	0.5 - 1%	Up to 14"	-Low/no maintenance -Low power requirements (typically loop-powered, AKA 2-wire) -Multi-Variable options available -Low pressure drop	-Requires upstream protection (i.e. strainer, filter, etc) -Requires straight runs of upstream and downstream piping -Susceptible to vibration and pulsation -Obstruction in flow path

Bibliography

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[2] API *MPMS* Chapter 5.2, *Measurement of Liquid Hydrocarbons by Displacement Meters*
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[4] API *MPMS* Chapter 5.6, *Measurement of Liquid Hydrocarbons by Coriolis Meters*
[5] API *MPMS* Chapter 5.8, *Measurement of Liquid Hydrocarbons by Ultrasonic Flowmeters*
[6] API *MPMS* Chapter 6.1A, *Metering Assemblies – General Considerations*
[7] API *MPMS* Chapter 6.2A, *Truck and Rail Loading and Unloading Measurement Systems*
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[16] API TR 2577, *Performance of Full-bore Vortex Meters for Measurement of Liquid Flows*
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[19] British Standards Institution, BS 8452, *Use of clamp-on (externally mounted) ultrasonic flow-metering techniques for fluid applications. Guide*
[20] ISO Standard 5168, *Measurement of fluid flow — Procedures for the evaluation of uncertainties*