

Manual of Petroleum Measurement Standards Chapter 20.2

Production Allocation Measurement Using Single-phase Devices

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Foreword

This edition of *API Manual of Petroleum Measurement Standards (MPMS) Chapter 20.2* supersedes the below-listed sections of *API MPMS Chapter 20.1, Allocation Measurement*, First Edition, 1993:

- Section 1.5 Liquid Quantity Measurement (subsections not superseded by *MPMS Chapter 20.2* include 1.5.2.4 Tanks and 1.5.2.5.2 Indirect Mass Measurement);
- Section 1.7.2.2.3 Flow Meters;
- Section 1.8 Liquid Proving and Calibration Techniques;
- Section 1.10 Gas Quantity Measurement;
- Section 1.11.4 Meter Calibration;
- Section 1.14 Gas Calibration and Proving Techniques.

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Introduction

This standard covers the application of production allocation (determination of flow quantities and rates of oil, gas, water, and other constituents) using single-phase measurement devices in combination with a two- or three-phase production separator.

When fluid flow from different wells' production streams are commingled into a single processing facility or flow line, it is preferred to measure the flow from each production stream separately, either continuously or on a specified interval, before it enters the common processing facility or flow line. Periodic measurement at a specified interval is the common practice since continuous measurement of an individual well production stream is normally not an available option.

On a production facility, it is common to have multiple production separators continuously measuring multiple combined production streams. Normally, these production separators (bulk separators) are dedicated to the same production streams.

The measurement of these well production streams (both combined and individual) is used in the process of allocating the facility production quantities (gas, oil, and water) back to the producing wells.

The traditional method of measuring multiphase flow has been to separate the flow into multiple single-phase streams (two- or three-phase separation). Single-phase flow meters are then applied to measure the flow of these separated streams.

Factors that can impact measurement include, but are not limited to, the following:

- varying fluid properties,
- varying operating conditions,
- varying flow rates,
- well flow dynamics,
- varying flow line lengths,
- separator and process design,
- piping configuration.

Measurement error, due to these characteristics, can result in inaccurate measurement of production streams and can cause inequitable allocation of the commingled streams.

This document provides guidance with respect to the major factors that could contribute to measurement uncertainty for single-phase devices used in production allocation. It is not intended to prescribe a particular meter type or allocation method. Allocation methodologies are addressed in API *MPMS* Chapter 20.1.

Production Allocation Measurement Using Single-phase Devices

1 Scope

This standard is applicable to single-phase measurement techniques upstream of the custody transfer points where custody transfer conditions are not possible. The standard presents single-phase flow measurement used in the allocation process and located downstream of the first stage of separation on a production facility.

This standard addresses common allocation single-phase flow measurement devices for liquid hydrocarbons, water, and gas including ancillary flow measurement systems such as fuel, flare, and recirculation.

This standard discusses configuration and operation of flow measurement equipment, fluid properties, production processing, associated flow conditions, and their effects on the quality of the flow measurement results. This standard discusses the possible impacts on these devices during inefficient and/or ineffective separation.

2 Normative References

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

API *Manual of Petroleum Measurement Standards (MPMS) Chapter 4 (all sections), Proving Systems*

API MPMS Chapter 4.5, *Master Meter Provers*

API MPMS Chapter 5.2-2005, *Measurement of Liquid Hydrocarbons by Displacement Meters*

API MPMS Chapter 5.3-2005 (including Addendum 1-2009), *Measurement of Liquid Hydrocarbons by Turbine Meters*

API MPMS Chapter 5.6-2002, *Measurement of Liquid Hydrocarbons by Coriolis Meters*

API MPMS Chapter 7-2001 (including Addendum 1-2011), *Temperature Determination*

API MPMS Chapter 11 (all parts), *Physical Properties Data*

API MPMS Chapter 12.2 (all parts), *Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors*

API MPMS Chapter 12.2.3-1998, *Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Corrections Factors, Part 3—Proving Reports*

API MPMS Chapter 13.2-1994, *Methods of Evaluating Meter Proving Data*

API MPMS Chapter 14.2/AGA Report No. 8¹, *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*

API MPMS Chapter 14.3 (all parts), *Concentric Square-edged Orifice Meters*

API MPMS Chapter 14.9, *Measurement of Natural Gas by Coriolis Meter*

API MPMS Chapter 20.1, *Allocation Measurement*

¹ American Gas Association, 400 N. Capitol St., NW, Suite 450, Washington, DC 20001, www.aga.org

API MPMS Chapter 21.1/AGA Report No. 3, *Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement*

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

AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters*

ASME Performance Test Code 19.3-2010², *Temperature Measurement*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1

allocation measurement

Measurement systems and procedures required to perform a fair and equitable allocation. Such systems and procedures may not meet full custody transfer standards of measurement while still being sufficient for allocation purposes.

3.1.2

axial asymmetry

Asymmetry around an axis; an object is axially asymmetric if its appearance lacks the mirror image if rotated around an axis.

3.1.3

base prover volume

BPV

The volume of the prover at base conditions as shown on the calibration certificate.

3.1.4

bias

Estimate of a systematic measurement error.

3.1.5

commingle

To combine the hydrocarbon streams from two or more wells, units, leases, production zones, or production facilities into common vessels or pipelines.

3.1.6

custody transfer point

The physical location at which a quantity of petroleum that is transferred between parties changes ownership.

3.1.7

dump cycle

The time between the opening and closing of the dump valve on a separator liquid outflow.

3.1.8

dump valve

A valve on the separator liquid outflow that travels between fully open and fully closed based on the liquid level within the separator.

² ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

3.1.9**emulsion**

A suspension of fine particles or globules, or both, of one or more liquids in another liquid.

3.1.10**flare system**

A system of pressure-relief valves, piping, and gas combustion devices used to burn off flammable gases released during over pressure situations or other operational requirements.

3.1.11**gas carry-under**

A flow condition where gas bubbles are entrained within the separator liquid outflow.

3.1.12**indicated volume****IV**

The transferred quantity, in indicated (uncorrected) volume units, at operating conditions, that occurs between opening and closing gauges on a tank, during a meter proving with each run, or that occurs from start to stop of a receipt or delivery being measured by a flow meter.

3.1.13**K-factor****KF**

The number of pulses generated by the meter per unit volume.

3.1.14**liquid carry-over**

Free liquid normally flowing as an aerosol mist with the gas flow from the top of the separator.

3.1.15**meter factor****MF**

A factor used to correct the indicated volume (IV) of the meter at operating conditions to the gross volume of the meter at operating conditions.

3.1.16**multiphase flow**

Flow of a composite fluid that includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

3.1.17**nominal K-factor**

The number of pulses generated or electronically manufactured by the meter per indicated unit volume.

3.1.18**quasi-single phase**

Resembling or having a likeness to single-phase fluid (e.g. wet gas).

3.1.19**three-phase separator**

A separator having three independent outflow paths for hydrocarbon liquid, hydrocarbon gas, and produced water.

3.1.20**turndown ratio**

In reference to meters, the maximum usable flow rate of a meter under normal operating conditions divided by the minimum usable flow rate.

3.1.21

two-phase separator

A separator with only two operational outflows: one for hydrocarbon gases, and one for a combined hydrocarbon liquid and produced water outflow.

3.1.22

watercut

WC

The water volume flow rate, relative to the total liquid volume flow rate (oil and water), both converted to volumes at standard pressure and temperature.

NOTE The WC is normally expressed as a percentage.

3.2 Acronyms and Abbreviations

BPV	base prover volume
DP	differential pressure
IV	indicated volume
KF	<i>K</i> -factor
KPI	key performance indicator
LACT	lease automatic custody transfer unit
MF	meter factor
MPFD	measurement process flow diagram
SCADA	supervisory control and data acquisition
S&W	sediment and water

4 Overview

4.1 Production Processes

This standard assumes the user has a general understanding of oil and gas production, equipment, and fluid properties. These areas of knowledge are fundamentally important for proper design and operation of an allocation measurement system.

NOTE Such allocation measurement systems and procedures might not meet full custody transfer standards of measurement while still being sufficient for allocation purposes.

Wells produce oil, natural gas, and water. The export systems receiving and transporting the production (often pipelines) can only accept pure hydrocarbons relatively free of contaminants and meeting pipeline quality specifications. Once the hydrocarbons have been stabilized and decontaminated, they can be sold through custody transfer measurements at the sales point.

The primary functions of the production process are to separate the oil from the gas and to remove impurities, which are predominantly water but can also include solids such as sand. Within the separation process, meters can be measuring multiphase flow directly in a full well stream application or they can be measuring single-phase or quasi-single (i.e. wet gas) phase fluids in a separator outflow or well test applications.

Metering in these conditions is challenging, but necessary, to ensure that sales volumes are properly allocated to the oil and gas wells. Hydrocarbon allocation is used for distribution of volumes and costs and

therefore revenue. Where the ownership royalty interests vary within the commingled streams, metering capability can have a direct impact on the equity of the allocation.

The lowest metering uncertainty is generally associated with custody transfer metering (e.g. sales meters). Metering upstream of the custody transfer point, near the wellhead, usually has a higher uncertainty due to the various conditions that exist in production operations.

See Annex A (Figure A.1) for a measurement process flow diagram (MPFD). Production processes are generally the same where fluids exiting the wellhead travel to a facility where separation occurs through a separator or series of separation vessels and other facilities in an ever decreasing pressure environment. At wellhead conditions, the liquid hydrocarbons contain varying amounts of dissolved natural gas. Furthermore, at the wellhead condition, a significant amount of natural gas will be mixed with the liquid flow. And finally, in addition to the hydrocarbon constituents, produced water is normally present in varying amounts.

During the production process through the various stages of separation, the liquid hydrocarbons approach atmospheric pressure conditions and contain no dissolved natural gas (i.e. they are atmospherically stable). The produced water has also been removed. At this point, hydrocarbon liquids are considered merchantable. Throughout the process, the natural gas has been gradually removed and collected in a compression arrangement such that it becomes pressurized for transport in natural gas pipelines. If necessary, the gas passes through dehydration units where excess water vapor is removed. The end result of the process is atmospherically stable hydrocarbon liquids and dehydrated natural gas for measurement through a custody transfer measurement system and eventual transport to facilities further downstream. Some of this natural gas may be consumed for fuel or burned as flare.

Within the process, stabilized and predictable flow conditions might not be fully achievable. For example, depending on pressure, process control, and the makeup or composition of hydrocarbon fluids, there will generally be some level of gas bubbles within the liquid outflow from separators. This is called gas carry-under. Likewise, it is not uncommon for the phenomenon to occur where some free liquid flows as an aerosol mist with the gas flow from the top of the separator. This is called liquid carry-over. Both conditions reduce the ability of single-phase gas and liquid meters to achieve their intended accuracy. It is important to understand and account for the inaccuracies encountered due to intermittent and low-level two-phase conditions.

4.2 Single-phase Meters Used for Production Allocation Measurement

4.2.1 General

Metering the produced quantities throughout the process is very important for varying reasons. The most critical metering occurs at the end of the process, where the products are transferred (or sold) from the producers to (normally) transporters. Sometime these are called sales meters or lease automatic custody transfer unit (LACT) meters, and they are normally the basis of revenue and taxation. These systems (i.e. sales meters) are expected to meet a tighter tolerance or “lower uncertainty” than could be achievable for the flow measurement systems located upstream towards the production sources (often called allocation meters).

4.2.2 Separator-based Metering Applications

A primary function of the production process is phase separation. Separators take in a mixed flow of oil, gas, and water and through a series of internal arrangements allow for a gas to flow to the top and a liquid to flow to the bottom. The efficiency of a production separator is generally a function of separator size, fluid properties, and temperature. To the extent that the fluid conditions allow, separators should be designed to deliver single-phase fluids to the associated measurement equipment. Typically, allocation metering exists at the outflow of separators.

There are several types of separators, each designed with a specific purpose. There are production separators where flow through the separator happens on a continual basis, and there are test separators that are used on a periodic basis. Generally, production separator metering systems and test separator metering

systems are similar. However, the test separator metering system might need to accommodate a wider range of flows given the various wells that it will be testing.

Separators are of two basic configurations: three phase or two phase. For three-phase separators, a single-phase liquid flow meter(s) located at each outlet of the separator is normally used to determine both the quantity of liquid hydrocarbon and water being produced. Because no separator is 100 % efficient, on a three-phase separator the oil outlet will contain some water and can contain some gas, and the water outlet can contain some liquid hydrocarbon and small amounts of gas. While three-phase separators are designed to avoid oil water emulsions, any emulsions in the three-phase separators might have added uncertainty in the measurements.

A two-phase separator does not have a produced water leg. Two-phase separators present greater opportunity for fluctuation in produced water levels at the separator liquid outflow, which in turn can affect measurement accuracy. On two-phase separators, hydrocarbon and water are also measured as a single liquid phase using meters similar to those on a three-phase separator. A single-phase meter in oil/water mixture service can be challenged by the process fluid condition changes including density ratio, oil/water fraction, droplet size, viscosity, density, composition, and flow regime. This fact inherently increases the measurement uncertainty versus a three-phase separator where hydrocarbon and water are metered separately.

Regardless of the separator type, the water content should be measured in conjunction with single-phase meter quantities to determine the net oil content of the liquid stream. On a three-phase separator, the water content of the oil outlet might vary from a few tenths of a percent to several percent. On two-phase separators, water content is relative to the watercut (WC) of the well stream, which could vary from 0 % to 100 %, especially on an instantaneous basis. The range of water content will impact the technology used to measure or sample product.

The gas outlet of a separator can contain entrained liquids due to several factors, including improper separator sizing and slugging. Additional meter uncertainty and bias will result if liquid carry-over occurs.

4.2.3 Non-separator-based Metering Applications

There are a variety of non-separator-based metering points within the process that are also important. For example, in some cases artificial lift is used to increase formation production by injecting a portion of the produced gas into the wellbore or the flow riser system. This is called gas lift, and it is necessary that it be metered. Normally, the source of the lift gas is taken further downstream in the production process where the natural gas is closer to custody transfer quality and a higher degree of measurement accuracy might be achieved.

Often fuel in the form of natural gas is consumed within the production process from its own production source. Because this production is consumed and needs to be accounted for, it is metered as fuel gas. Fuel gas for compressors or other gas-fueled equipment is generally sourced from the pipeline or custody transfer quality portion of the process facility and is normally measured. Where there is a shortage of fuel gas production, it can actually be obtained from pipeline facilities outside of the production operation itself.

NOTE For more information on fuel gas measurement, refer to API Technical Report 2571 ^[1].

Likewise, any gas that is flared might need to be metered for reporting purposes. Flare meters are present in some production facilities. Flare systems generally act to address upset conditions resulting in high, low, or accelerating flow rates that can exceed meter parameters and result in higher uncertainty levels.

NOTE For more information on flare measurement, refer to API MPMS Chapter 14.10 ^[2].

Lastly, there are a variety of meters associated with circulated fluids or quantities introduced from outside the production process. Start-up gas ensures that gas turbines and other equipment have a fuel supply before the production process can produce enough fuel for this purpose. Meters associated with circulated fluids can

also include gas or liquid pigging meters that are used to measure the gas or liquid volumes needed to drive scraper pigs through production flow lines.

Annex A contains an MPFD highlighting all the various metering points within the process.

4.3 Capability and Uncertainty

All of the various single-phase metering applications have varying levels of uncertainty due to the production processes to which they are exposed. Some will be capable of achieving greater accuracy than others due to prevailing flow conditions. The guideline for a single-phase metering system for allocation is generally targeted to achieve a measurement uncertainty no better than $\pm 5.0\%$. It is not uncommon for allocation measurement systems to exceed $\pm 5.0\%$. Actual flow and fluid conditions such as proximity to gas hydrocarbon dew point or liquid bubble point, higher pressure and temperature, slugging, inconsistent flow velocity, and other conditions can cause much higher uncertainty levels to be realized.

The meter manufacturer should be consulted to obtain measureable performance criteria [e.g. linearity, zero span, single or stacked differential pressure (DP) transmitters, etc.] that correspond to the overall meter uncertainty goal.

A main concern with liquid metering applications within the production process is the presence of gas bubbles in a liquid flow. Likewise, a concern for single-phase gas meters is the presence of liquid mist in the gas flow. For example, some meter types will register a volume considered to be liquid even though a portion of the volume consisted of gas bubbles. This constitutes an over-registration of the assumed liquid volume. Similarly, certain gas metering types can over register an assumed gas volume when liquids are present. The amount of acceptable bias is dependent upon the particular application. A small amount of bias due to typical gas carry-under or liquid carry-over might be an acceptable inequity among the parties if all parties are exposed to that same bias. However, an imbalance in the system can occur and the system imbalance is an indicator of metering system performance.

Many liquid meters are mechanical in nature and subject to wear and degradation. The meter proving process is used to validate the meter's mechanical performance and establish a base correction to a known quantity such as a base prover volume (BPV). In situ proving of a meter with typical fluid and flow conditions is a best practice; however, in situ proving can be difficult because the fluids are not fully stabilized. The pressure drop between the operational meter and the proving source (usually master meter) can cause enough gas to break out to introduce bias errors. Therefore, it is typical to remove some types of production allocation liquid meters and transport them to a central proving facility. The central proving facility's replication of actual flowing conditions is important in maintaining accuracy.

Regardless of the particular situation and the associated metering uncertainty, it is important for production allocation metering systems to be evaluated from a capability perspective. The evaluation takes into consideration the metering types, prevailing flow conditions, and the surrounding facility. A meter on a separator without effective back pressure or flow control will likely yield less accurate results. Malfunctioning level control or improper level setting can lead to gas carry-under in the liquid line or liquid carry-over in the gas line. Dump cycles are common in production separator operations. Changes in dump cycle frequency can impact flow metering capability by introducing flow conditions outside of the speed of response of the measuring system.

Other factors such as WC variability, meter ranges, and production fluid properties should be considered. Ultimately, the capability or range of expected performance can be established. This range from the lowest expected level of uncertainty to the highest allowable level of inaccuracy can be evaluated against the risk level for any particular production allocation measurement system operation. Sometimes these evaluations will suggest areas that can be improved upon or reveal technical limitations of metering technology at prevailing flow conditions. Facility design limitations can be highlighted if separation facilities are incapable of creating the single-phase conditions needed for single-phase meters to be effective.