

Manual of Petroleum Measurement Standards Chapter 20.5

Recommended Practice for Application of Production Well Testing in Measurement and Allocation

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Foreword

This edition of API Manual of *Petroleum Measurement Standards (MPMS)* Chapter 20.5 supersedes the below listed sections of API *MPMS* Chapter 20.1, *Allocation Measurement*, First Edition, 1993:

- 1.7.2.2.2 Test Separator;
- 1.11.1 Well Tests;
- 1.16.3.2 Field Test Separators;
- 1.16.3.3 Portable Test Separators;
- 1.16.5.1 Full-Scale Separator Test Report;
- Appendix J.

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Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Washington, DC 20001, standards@api.org.

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Introduction

This document establishes a framework to conduct and apply production well testing for well rate determination in measurement and allocation. Production well testing addressed in this document refers to measurement of gas, oil, and water quantities from a single well during a specified length of time under controlled operational conditions. The intent of this document is to provide operators with a consistent and transparent approach for conducting, applying, and managing production well testing within an upstream measurement and allocation system. It is not intended to prescribe a particular production well test method, or particular application of production well test data use in allocation. Allocation methodologies are addressed in API *MPMS* Ch. 20.1.

Recommended Practice for Application of Production Well Testing in Measurement and Allocation

1 Scope

This document provides recommendations and guidelines for the application of production well testing in production measurement and allocation. The recommendations and guidelines apply to conducting a production well test, calculating production well test volumes and rates, and the application of production well test data for use in measurement and allocation. This includes production well testing preparation, initiation, measurement, validation, and volume and rate calculations for separator, multiphase flow meter, and tank production well test systems. Additionally, this document addresses the proration of production well test results for use in allocation, the application of production well tests for validation and update of well flow models and virtual flow metering, and the adjustment of gas well continuous measurement results with production well test data.

This document also provides recommendations and guidelines for the application of well flow modeling and virtual flow metering in production measurement and allocation.

2 Normative References

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

API Draft Standard *Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems*

API Manual of Petroleum Measurement Standards (MPMS), Chapter 3.1A, *Standard Practice for the Manual Gauging of Petroleum and Petroleum Products*

API MPMS Chapter 3.1B, *Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging*

API MPMS Chapter 3.3, *Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging*

API MPMS Chapter 3.6, *Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems*

API MPMS Chapter 8.1, *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*

API MPMS Chapter 8.2, *Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products*

API MPMS Chapter 11.1, *Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils*

API MPMS Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer*

API MPMS Chapter 18.1, *Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck*

API MPMS Chapter 20.1, *Production Measurement and Allocation Systems*

API MPMS Chapter 20.2, *Production Allocation Measurement Using Single-phase Devices*

API MPMS Chapter 20.3, *Measurement of Multiphase Flow*

API MPMS Chapter 21.1, *Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement*

API Recommended Practice 85, *Use of Subsea Wet-gas Flowmeters in Allocation Measurement Systems*

API Recommended Practice 87, *Recommended Practice for Field Analysis of Crude Oil Samples Containing from Two to Fifty Percent Water by Volume*

API Recommended Practice 551, *Process Measurement*

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

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

3.1.1

actual conditions

measurement conditions

line conditions

flowing conditions

Conditions of pressure and temperature of the fluid at the point where fluid properties or flows are measured.

3.1.2

allocation

The mathematical process of determining the proportion of produced fluids from individual entities (zones, wells, fields, leases, or producing units) when compared to the total production from the entire system (reservoir, production system, and gathering systems) in order to determine value or ownership to attribute to each entity.

3.1.3

bubble point

When the pressure is lowered on a liquid held at a constant temperature, the pressure at which the first bubble of vapor forms is the bubble point.

3.1.4

condensate–gas ratio

CGR

The ratio of liquid hydrocarbon volume flow rate to the gas volume flow rate at any point, expressed at standard conditions, usually in barrel per thousand standard cubic feet (bbl/mscf) or standard cubic meters of liquid hydrocarbon per thousand cubic meters of gas ($\text{m}^3/10^3\text{m}^3$).

3.1.5

equation of state

EOS

Thermodynamic equation describing the state of matter under a given set of physical conditions.

NOTE An EOS provides a mathematical relationship among the state variables pressure, temperature, and molar volume.

3.1.6

gas–liquid ratio

GLR

The ratio of gas volume flow rate to the total liquid volume flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (scf/bbl) or standard cubic meters of gas per cubic meter of total liquid (m^3/m^3).

3.1.7**gas–oil ratio****GOR**

The ratio of gas volume flow rate to the liquid hydrocarbon volume flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (scf/bbl) or standard cubic meters of gas per cubic meter of liquid hydrocarbon (m^3/m^3).

3.1.8**gas volume correction factor** B_g

Ratio of hydrocarbon gas volume at elevated pressure and temperature conditions to the hydrocarbon gas volume at standard conditions (ft^3/scf , m^3/m^3).

3.1.9**gas volume fraction****GVF**

The fraction of the total volumetric flow rate at actual conditions in the pipe that is attributable to gas flow, often expressed as a percentage.

3.1.10**hold-up**

The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position, at actual conditions.

3.1.11**hydrocarbon dew point**

A temperature at a given pressure at which hydrocarbon vapor condensation begins.

3.1.12**multiphase flow**

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

3.1.13**nodal analysis**

A method to model well multiphase production through an integrated oil and gas production system with multiple points of measurement (nodes). The models are based on fundamental mechanistic physics principles that estimate well production using input pressures and temperatures, and flow correlations.

3.1.14**oil volume correction factor** B_o

Ratio of the hydrocarbon liquid volume at elevated pressure and temperature conditions to the hydrocarbon liquid volume at standard conditions (bbl/bbl, m^3/m^3).

NOTE The oil volume correction factor B_o , is the inverse of the shrinkage correction factor, $1/B_o$.

3.1.15**pressure, volume, temperature****PVT**

The phase behavior and description of hydrocarbon fluid physical properties for a given set of composition, pressure, and temperature.

NOTE Physical properties of interest include relative phase fraction, GOR, bubble point and hydrocarbon dew point, density, formation volume factors, compressibility, and viscosity.

3.1.16**production well test**

The measurement of gas, oil, and water quantities from a single well during a specified length of time under controlled operational conditions.

3.1.17**rangeability**

The capability of a meter or flow measuring device to operate between the minimum and maximum flow range within a specified uncertainty; expressed as the ratio of maximum flow rate to the minimum flow rate.

3.1.18**solution condensate–gas ratio** R_s

Ratio of condensed hydrocarbon liquid volume at standard conditions (condensed from gas as it is lowered in pressure and temperature from elevated pressure and temperature conditions to standard conditions) to the hydrocarbon gas volume at standard conditions (bbl/mscf, $\text{m}^3/10^3\text{m}^3$).

3.1.19**solution gas–oil ratio** R_s

Ratio of evolved hydrocarbon gas volume at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from elevated pressure and temperature conditions to standard conditions) to the hydrocarbon liquid volume at standard conditions (mscf/bbl, $10^3\text{m}^3/\text{m}^3$).

NOTE The evolved hydrocarbon gas is sometimes referred to as flash gas.

3.1.20**virtual flow meter****VFM**

Real-time computer-based well rate determination method that utilizes well flow models in conjunction with real-time well/process sensor and instrumentation data for continuous multiphase well rate estimation.

3.1.21**water–gas ratio****WGR**

The ratio of water volume flow rate to the gas volume flow rate at any point, expressed at standard conditions, usually in barrel per thousand standard cubic feet (bbl/mscf) or standard cubic meters of liquid hydrocarbon per thousand cubic meters of gas ($\text{m}^3/10^3\text{m}^3$).

3.1.22**water–liquid ratio****WLR**

The water volume flow rate, relative to the total liquid volume flow rate (oil and water), at actual conditions (operating pressure and temperature), expressed as a percentage.

3.1.23**water volume correction factor** B_w

Ratio of water volume at elevated pressure and temperature conditions to the water volume at standard conditions (bbl/bbl, m^3/m^3).

3.1.24**well flow model**

Mathematical equation, correlation, or algorithm relating well physical parameters or data to flow.

3.1.25

well rate determination

The process to quantify an oil well's production of gas, oil, and water, or a gas well's production of gas, condensate, and water.

3.2 Acronyms, Abbreviations, and Symbols

For the purposes of this document, the following acronyms, abbreviations, and symbols apply.

B_g	gas volume correction factor
B_o	oil volume correction factor
B_w	water volume correction factor
bbl	barrel
bbl/d	barrels per day
CGR	condensate–gas ratio
EOR	enhanced oil recovery
EOS	equation of state
ft ³	cubic feet
GLR	gas-liquid ratio
GOR	gas–oil ratio
GVF	gas volume fraction
mcf	thousand cubic feet
mscf	thousand standard cubic feet (at standard conditions)
mscf/d	thousand standard cubic feet per day (at standard conditions)
m ³	cubic meter
m ³ /d	cubic meters per day
PVT	pressure, volume, temperature
R_s	solution gas–oil ratio
r_s	solution condensate–gas ratio
S&W	sediment and water
scf	standard cubic foot
VFM	virtual flow meter
WGR	water–gas ratio
WLR	water–liquid ratio

4 Production Well Testing in Upstream Measurement and Allocation

4.1 Introduction

Although preferred, continuous direct measurement of well production for use in upstream measurement and allocation is usually not a practical option for most operators. Periodic direct measurement is achievable, however, and can be used for determining applicable well rates. Thus, the periodic direct measurement, or well test, becomes an integral activity in upstream measurement and allocation.

Well testing provides a means of determining the production characteristics of a well. A well test can be conducted for a variety of reasons, including an evaluation of the productive potential of a well (incorporating wellbore flow capacity and reservoir limits), a measurement of the gas–oil ratio (GOR), a means to sample reservoir fluids, or some other specific item (refer to Annex A for a more detailed description of the various well tests for oil and gas wells).

For use in upstream measurement and allocation, a well test is referred to as a production well test and is defined as the fluid measurement of gas, oil, and water from a single well during a specified length of time under controlled operational conditions. In the case of an oil well, it is the ability of the well to produce oil, water, and gas. For a gas well, it is the ability of the well to produce gas, and sometimes accompanying fluids, such as condensate and water. In each case, the reported volumes are corrected to some agreed standard conditions of pressure and temperature, for example 101.325 kPa and 15 °C (14.696 psia and 60 °F).

4.2 Reasons for Production Well Testing

4.2.1 General

Efficient management of well production depends upon the timely detection of well changes and the ability to measure and accurately control the forces influencing well performance. A major well management component is well rate determination through production well testing. Determining well rates is not only essential for efficient production operations, it is also a reporting requirement for state and federal agencies, can impact revenue, and is necessary for a complete and accurate historical accounting of reservoir and well performance. Important decisions such as production methods and optimization schemes, enhanced oil recovery (EOR) programs, and development drilling are made from this information.

4.2.2 Regulatory/Statutory Requirements

Regular reports of production from oil and gas wells are required by the states and the U.S. Government for federal and Indian leases. There are several reasons why governmental agencies require well production information. In states with proration laws, and on federal lands, well rates are reported to provide conservation commissions and regulatory bodies with data necessary for establishing production rates that prevent waste and for allocating production between fields and wells within individual fields. Taxes such as severance taxes (direct tax on production) and ad valorem taxes (mineral and property taxes based on value) are levied against oil and gas production, with the reported well rates sometimes serving as a basis for tax determination. Regulatory agencies generally stipulate the method for determining reported well rates (e.g. periodic production well test) and the frequency of reporting.

An additional production reporting consideration involves the statutory requirements of the Sarbanes–Oxley Act. The U.S. Government requires the full accountability and verification of corporate financial statements, which includes the proper measurement and accounting of oil and gas production. Depending on the production allocation scenario, production well testing can be a key factor in the reporting process.

4.2.3 Economics

There are numerous economic reasons for determining well rates, but all revolve about the advantage gained from knowing the production trends and characteristics of individual wells. Maximum daily revenue can only be achieved when timely and accurate well rates reflect the producing capability of each well on a lease.

many producing situations, such as where operators are competitive in a common reservoir, high-volume reservoir pattern flooding is being conducted, or wells are restricted to producing allowables set by regulatory agencies, the revenue from oil and gas not produced because of well failure is either lost or drastically reduced. Moreover, commingled production between partner companies can create allocation scenarios where well rates are used as the basis for revenue splits among the producers. Similar to regulatory requirements, commercial agreements can stipulate the method of well rate determination and production well testing, and the frequency of reporting.

4.2.4 Reservoir Management

Reservoir management involves strategies based on analyses of geologic, reservoir, and production data to optimize the development of a reservoir in an efficient and effective manner. The collection and analyses of rock and fluid property data, reservoir pressures, and temperatures, along with reservoir production data, enable reservoir engineers to construct both geological and reservoir flow models that are crucial in creating and updating reservoir management strategies. The reservoir flow models are vital for understanding the driving forces (either naturally occurring or artificially created) that combine to move fluids in a reservoir. Production well tests allow reservoir engineers to recognize these driving forces and initiate programs that affect them.

4.2.5 Production Management

Production management involves strategies based on analyses of process and production data to optimize the design and operation of both wells and production facilities in an efficient and effective manner. The collection and analyses of fluid property data, process pressures, and temperatures, along with well production data, enable petroleum engineers to construct both well and facility models that are crucial in creating and updating production management strategies. Production well tests allow petroleum engineers to optimize wellbore hydraulics and evaluate wellwork benefits. Furthermore, analysis of well and process production data is utilized in optimizing process production throughput, pipeline flow assurance activities, and facility design such as separation, water disposal, pumping, and compression.

4.3 Production Well Testing and Additional Methods for Determining Well Rates

4.3.1 General

The traditional method of well rate determination has predominantly been the periodic production well test through direct measurement of gas, oil (condensate), and water. The introduction of new technologies and complex commingled production scenarios (e.g. subsea wells commingled and flowing to a single offshore installation) have expanded the scope of well rate determinations to include inline multiphase flow measurements, rate calculations, and three-phase fluid modeling.

Shown in Figure 1 is a well rate determination tree that summarizes the various methods for ascertaining well production rates and outlines the necessary equipment, techniques, and application.

Well rate determinations can either be from direct measurement or from estimates. Measured well rates can be generated via continuous measurement systems, such as dedicated separators or inline meters, or via periodic measurement systems such as test separators or test meters. Estimated well rates can be derived through subtraction or by-difference calculations of direct measurements of commingled flow, or by use of flow models.

Inherent to all well rate determination methods is a direct measurement of well production. When continuous measurement systems are not used on a well, a production well test becomes imperative to periodically directly measure well rates. This is required to validate by-difference estimated well rates (i.e. validate and/or update well flow rate models) or adjust the well rates (i.e. gas well single-phase measurement) for use in upstream measurement and allocation.

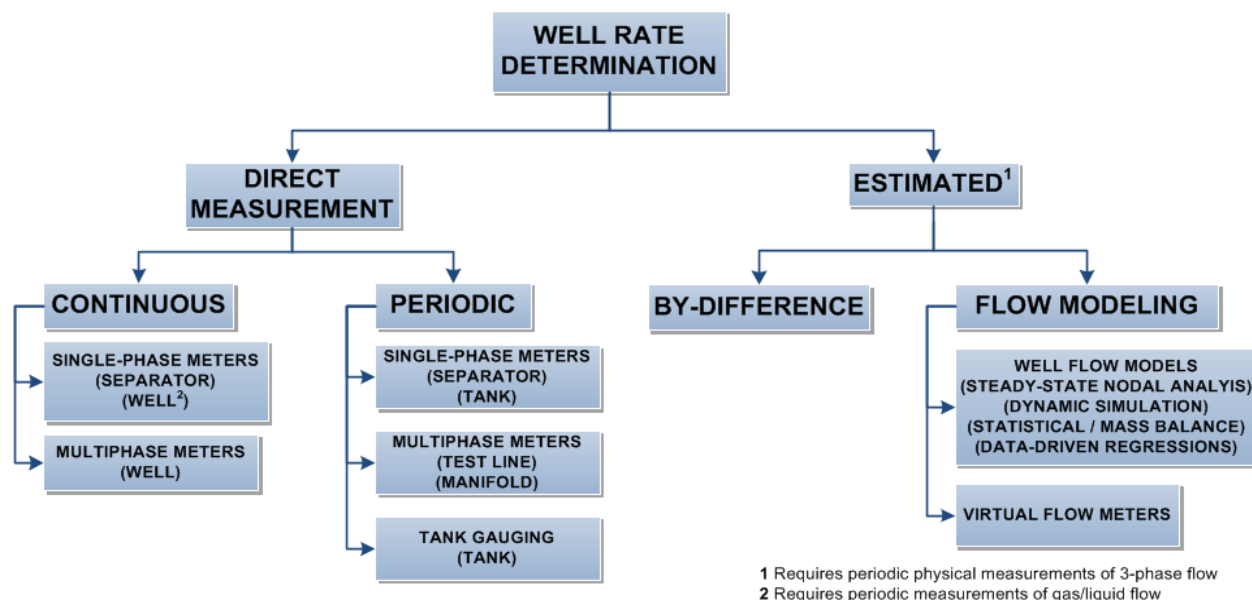


Figure 1—Well Rate Determination Tree

4.3.2 Direct Measurement

Well rate determination through direct measurement has traditionally been via multiphase flow separation into multiple single-phase streams, where single-phase flow meters and online water determination devices (when applicable) are applied to independently measure the flow. Separation can be two-phase (gas and liquids) or three-phase (gas, oil/condensate, water) and is ordinarily accomplished with gravity separation in the form of a large vessel or a compact separator if total separation can be achieved. Separation and single-phase flow measurements can be applied for either continuous or periodic well rate determination, depending on the well and production facility alignments. Typically, several wells utilize the same separation vessel for production, necessitating the process of periodically sampling the flow rate of each individual well. The periodic measured flow rates are generally only representative of well production for conditions (e.g. wellhead pressure) that resemble those during the measurement timeframe.

A more recent direct measurement method involves the application of multiphase flow meters. As with separation-based measurement systems, multiphase flow meters can be applied for either continuous or periodic well rate determination (i.e. production well testing). Multiphase flow meters can be located directly on the wellhead or production flowline, in production manifolds, or dedicated production well testing flowlines, where the same periodic flow rate sampling methodology for a separation-based production well test applies.

An additional direct measurement method for gas wells employs single-phase meters directly on the wellhead or production flowline. The single-phase devices are typically differential pressure meters, and individual gas flow rates can be continuously monitored. Liquid production is not measured, and in situations where liquid production is significant (adversely impacting the gas measurement), corrections to the gas measurement can be applied. When corrections are used, periodic direct measurement of both gas and liquids is generally required.

4.3.3 Estimated

Well rate determination by estimating three-phase flow rates is accomplished either through by-difference calculations or by applying well flow models or virtual flow metering. By-difference well rate determination is a subtraction of a directly measured well (or wells) production from a commingled point direct measurement total, and an assignment of production to an unmeasured well included in the original commingled production measurement. This method is not a true measurement, but a calculation (inferred measurement). As with

periodic direct flow measurement techniques, by-difference estimation provides a flow rate sample applicable for the conditions at which it was derived.

With well pressure and temperature data, it is also possible to use well flow models to provide estimates of three-phase flow information. Such well flow models can be used based on data regressions or more rigorous well models used in nodal analysis. Additionally, simple rate tables relating well flow to temperature and pressure are sometimes applied.

A newer estimation method using VFMs automates the use of models relating measured quantities (e.g. pressure, temperature) to flow, providing continuous real-time three-phase flow information. Such VFMs utilize computer software and real-time sensor data from well, flowlines, and production facilities for continuous multiphase flow estimation. The models can range from simple to complex, are in most cases proprietary, and periodically are updated with direct flow measurement information.

5 Conducting a Production Well Test

5.1 Preparation

5.1.1 General

The most efficient and productive attempt at production well testing is made possible through organized preparation. Operators should understand their responsibilities and all production well testing requirements, then implement planning and test preparation activities prior to initiating a production well test. These activities should include the development and maintenance of applicable production well testing objectives, acceptance criteria, procedures, and contingency plans. Additional verification on the condition of the complete production well test system (reservoir, well, flow delivery, separation, and fluid measurement) should also be implemented.

NOTE API RP 11V5^[1] and API RP 11V8^[2] provide specific production well testing recommendations for gas-lifted wells.

5.1.2 Responsibility

The production well test shall be the responsibility of the operator.

Production well testing may be conducted by the operator or contracted to a service company that specializes in well testing.

The operator or contracted service company may utilize the installed equipment at the facility for production well testing. To avoid the expense of a number of widely scattered stationary well test installations, some operators might prefer to purchase or lease portable well test units (separator-based or multiphase flow meters) that may be aligned with individual wells for the desired production well test and then moved to another location.

5.1.3 Requirements

Production well testing requirements are often cited in regulatory permits, commercial agreements, and operator's policies. This can include test frequency and duration, and the use of the production well test measurement in well rate determination scenarios and/or allocations. The application of this document shall be in conformance with all applicable regulations, permits, and agreements.

All production well test requirements outlined in regulations, permits, or agreements shall be documented.

5.1.4 Objectives

Objectives of the production well test should be established from the documented requirements outlined in regulations, permits, and agreements. The objectives should also include reservoir and production management considerations, along with practices and policies specific to each operator.

The production well test objectives should clearly define:

- production well test frequency, duration, and reporting;
- fluid sampling activities during production well testing;
- production well test use in well rate determination and production allocations;
- production well test use in well or reservoir evaluation.

Production well test objectives are critical to understanding the motivation for the test and any special considerations that can influence the design and execution of the production well testing operation. Consultation with applicable reservoir, production, and flow assurance engineers should be ongoing as part of defining the production well test objectives.

5.1.5 Documentation and Record Retention

Documentation and record retention policies shall be instituted by the operator to provide an audit trail of the production well testing operation and results. In addition to documented production well test requirements, recorded information and data should include:

- process flow diagram(s) denoting all equipment and flow paths in the production well test system;
- equipment list for the production well test system (e.g. meters, transmitters, samplers, analyzers, separators, etc.);
- performance specifications associated with the production well test equipment (e.g. meter uncertainty);
- established procedures associated with certification, calibration, verification, testing, and inspection of all production well test equipment;
- established procedures for conducting the production well testing operation;
- description of associated sampling methods, analysis, and frequency (all fluids);
- applicable well-specific fluid property information (e.g. oil and gas compositions);
- applicable well-specific equation of state (EOS) or fluid property correlations (PVT characterization);
- software versions for all associated computer calculations;
- historical accounting of previous production well tests;
- acceptance criteria used to evaluate the production well tests;
- contingency plans.

5.1.6 Acceptance Criteria

Acceptance criteria for use in production well test evaluation should be established and documented prior to conducting production well testing operations. The acceptance criteria should be based on consideration of the entire production well testing system (reservoir, well, flow delivery, separation, fluid measurement). Sections 5.3.2 and 5.3.3 provide various acceptance criteria for consideration.

5.1.7 Procedures

Procedures for conducting production well testing should be established and documented prior to production well testing operations. The procedures should include information relevant before and during the production

well test, such as the sequence of events, equipment adjustments, data acquisition, and logging. In addition, pre-production well test activities such as fluids, production, and equipment verification steps should be included (refer to 5.2.2, 5.2.3, and 5.2.4).

Procedures specific to the operation of the production well test system will differ by system and are at the discretion of the operator.

5.1.8 Contingency Plans

Contingency plans for production well testing operations should be established and documented prior to initiating a production well test. Specific considerations for inclusion in a contingency plan include:

- production well test system equipment failure;
- adverse well flow conditions (e.g. nonstabilized flow; test conditions different from normal conditions);
- low-energy wells unable to flow in isolation to the measurement point;
- production well test data that do not meet acceptance criteria.

5.2 Initiation and Measurement

5.2.1 General

Production well testing initiation and measurement constitutes the active operation of conducting a production well test. Several verifications should be implemented concurrently prior to measurement and data collection for the production well test, including fluid, production, and equipment verification. These verification activities encompass the entire production well testing system (refer to Annex B for a description of the production well test system) and are vital to ensuring a comprehensive understanding for the production well test. Individuals should be assigned to perform the verification activities in alignment with their normal duties (e.g. a reservoir engineer for fluid verification). Once verification has been completed, the production well test should be performed as follows:

- well isolation;
- system purge and well flow stabilization;
- well measurement;
- data recording.

Figure 2 summarizes the initiation and measurement steps and workflow of a production well test.

5.2.2 Fluid Verification

Initiating a production well test should include a verification of the applicable reservoir fluid properties and flow conditions, particularly if any changes are anticipated from the previous production well test. Initiating a production well test should therefore include knowledge of the type of reservoir, reservoir recovery mechanism and any potential production chemistry or flow assurance issues (e.g. paraffins, asphaltenes, hydrates, scale) that can invalidate the production well test.

NOTE The production well test system should be maintained and operated in a manner that reflects the changes in the reservoir and subsequent well production over time. The production well test system should be capable of accommodating both the change in fluid properties that can accompany an EOR method (e.g. an EOR miscible gas injection flood alters the composition of the produced hydrocarbons) and the possible increase in additional fluids recovered (e.g. increased water production from an EOR waterflood).

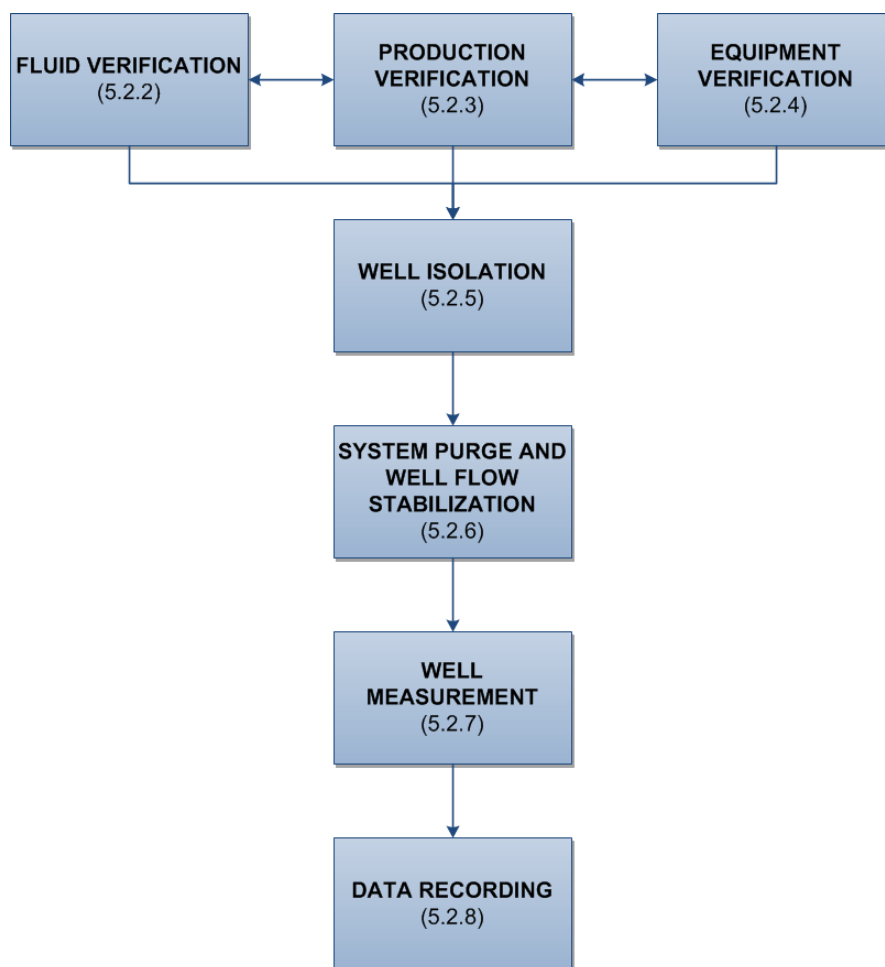


Figure 2—Production Well Test Initiation and Measurement Workflow

A sampling plan should be developed for initiation during the production well test to update if necessary the information incorporated in the fluid verification, and should be based upon an understanding of the phase behavior of the reservoir fluids (Annex B provides a brief overview and description of reservoir fluid classifications and phase behavior). A PVT analysis (for production well test phase behavior application data, refer to 6.2) of the reservoir fluids should be included in the sampling plan if prior PVT analysis is no longer representative of the reservoir fluids.

Highly variable flow rates and dynamic flow conditions due to the various fluid properties and flow regimes at the sampling point should be evaluated for any impact on the production well test sampling operation. This includes both online and manual sampling systems and methods for hydrocarbons, and manual watercut sampling where online water determination devices are not used.

There are several types of liquid and gas sampling systems or procedures that are available for use in production well testing. It is not the intent of this document to specify a sampling system or procedure for the production well testing system. Nor is it the intent of this document to encourage the use of one system or approach over another. However, liquid and gas sampling systems and procedures should be capable of obtaining fluid samples that are deemed to be representative and within the operator's acceptable tolerances for fluid quality.

Applicable standards that should be referenced for liquid sampling in production well testing include API MPMS Ch. 8.1, API MPMS Ch. 8.2, and API 87.

An applicable standard that should be referenced for gas sampling in production well testing is API *MPMS* Ch. 14.1.

NOTE 1 Consideration for EOR sampling requirements should be included in the production well testing process, as accurate production well test data along with EOR evaluation data can be leveraged to increase reservoir recovery.

NOTE 2 There are no industry standards on multiphase sampling and analysis. Additionally, with the exception of API 87, the sampling standards referenced were not written for direct application in a production well testing environment. This does not preclude the use of the standards, but the operator should be aware of any limitations of the standard in the applied sampling application.

Table 1 provides suggested focus areas and associated activities for verifying fluid information. The information should be applicable at the individual well level and used as a tool in fluid verification prior to each production well test. It is at the operator's discretion to determine which fluid verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing fluid verification activities.

5.2.3 Production Verification

In the process of initiating a production well test, operators should verify if any changes in wellbore configuration or operation have occurred since the previous production well test. Production well testing should always be performed in a manner that takes into account any previous well workovers or interventions, with recognition for the potential impact of changed well performance (i.e. wellbore hydraulics and well flow patterns).

Depending on the type of workover or intervention, produced fluid properties and phase behavior can change and should be addressed prior to conducting a production well test on the worked-over well (refer to fluid verification, 5.2.2). In addition, any drawdown limitations should be acknowledged prior to conducting a production well test and not exceeded during stabilization or production well testing measurement.

Production well testing of cyclical wells should take into account the variable nature of the producing well flow (i.e. production declines and dynamic GORs). In addition, wells that are prone to liquid loading (e.g. low rate gas well with high liquid–gas ratio) should be evaluated for any induced slugging impact on the production well test system.

During production well testing, there should be no change in chemical treatment from normal operations, unless a treatment program is specifically required to conduct the production well test (e.g. de-emulsification to promote separation in a test separator, or methanol treatment in a long subsea flowline used for production well testing). Production well testing should be performed with an awareness of the various chemical treatment programs and the potential impact on produced well flow.

Production well testing operations should always include a verification on the flow delivery system between the well and measurement point. Flowline elevation and geometry configurations that can affect the well flow pattern (e.g. liquid hold-up or slugging) should be evaluated, and dynamic flow behavior should be analyzed prior to and during a production well test, as dynamic conditions can take several hours or days to stabilize.

Production well testing operations should always include knowledge of any potential flow assurance or production chemistry threats to the production well test system that can introduce an impact on the flow dynamics and well flow pattern of the applicable well.

Table 1—Summary of Suggested Fluid Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Reservoir classification	Classify reservoir as: — dry gas, — wet gas, — gas condensate, — critical fluid, — volatile oil, — black oil. Understand the depletion path (pressure reduction) in the reservoir and if phase boundaries have been crossed (i.e. the bubble point or hydrocarbon dew point).	Reservoir depletion across a phase boundary (i.e. bubble point or hydrocarbon dew point) can alter reservoir fluid properties (particularly for gas condensates) from values used in previous production well tests. Two-phase flow (liquid/gas) in the reservoir can influence wellbore hydraulics, leading to non-stable (e.g. slugging) well flow during production well testing.
Reservoir recovery mechanisms	Classify reservoir recovery mechanism as: — solution-gas drive, — gas-cap drive, — water drive, — gravity drainage. Verify EOR methods (e.g. miscible or thermal processes). Assess potential for such factors as: — increased water production (e.g. aquifer support in a water drive, or waterflooding in an EOR application); — changing water properties (e.g. changing salinity between formation water and injected water); — hydrocarbon compositional changes (e.g. from miscible gas injection).	Fluid property changes (hydrocarbon and water) from previous production well test. Increased production volumes (e.g. water) exceeding the capacity of the production well test system.
Fluid properties	Verify the following reservoir fluid properties: — composition (e.g. N_2, CO_2, C_1, C_2, C_3, etc.); — bubble point pressure or hydrocarbon dew point pressure, PVT studies (phase envelopes); — API gravity/density; — viscosity; — B_o, B_g, B_w, R_s, r_s applicable for production well test conditions (refer to 6.2); — paraffin content, wax appearance temperature, and pour point; — asphaltene content and asphaltene onset pressure; — sulfur content (including H_2S). Verify water chemistry, including: — physiochemical parameters (e.g. pH, resistivity, conductivity, density, total dissolved solids, total suspended solids, dissolved CO_2); — soluble anionic and cationic species (e.g. chloride, bromide, phosphate, barium, strontium, lithium); — neutral species (e.g. sulfur). Assess potential for production chemistry and flow assurance threats such as: — scale deposition; — corrosion; — hydrates; — wax, paraffin deposition; — asphaltene precipitation and deposition; — emulsions, foams; — material compatibility. Assess fluid property requirements for applicable measurement systems (refer to Table 3).	Production well test system hydraulics can be negatively impacted by production chemistry and flow assurance threats. Outdated fluid property information (e.g. compositions, PVT characterization) used in meter configuration or calculations can compromise the production well test results.
Sampling plan	Establish (or update) sampling plan with the following activities: — determine fluid sample requirements (through fluid, production, and equipment verification activities); — evaluate flow conditions at the sample point, and sampling infrastructure; — coordinate with any other engineering disciplines requiring fluid sampling; — establish specific sampling (and analysis) techniques, protocols, and procedures, along with the frequency of sampling. Initiate sampling during the production well test (well measurement).	Sample and analysis activity can provide updated fluid property information for production well test use. Sampling during production well testing can require a coordination of activities and timing between various parties (e.g. sample after system purge and well flow stabilization and during well measurement).

Table 2 provides suggested focus areas and associated activities for verifying production information. The information should be applicable at the individual well level and used as a tool in production verification prior to each production well test. It is at the operator's discretion to determine which production verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing production verification activities.

5.2.4 Equipment Verification

Initiating a production well test should include a verification of the equipment used, including flow isolation, separation, and measurement equipment. The equipment verification should assess general equipment viability. Unmaintained equipment, noncalibrated instruments, and improper operation of production well test equipment can invalidate the production well test results. The production well test equipment should be viable over the life of the facility. Viable refers to equipment that is sized for the anticipated well flows, the correct application of technology, and a system that is inclusive of all the measured parameters of interest. This can result in replacement or upgrading equipment to satisfy the desired objectives, or alternatively, it can mean that a higher uncertainty is accepted for the production well test result.

NOTE Viability also applies to the operation and maintenance of the production well test equipment.

A periodic, routine check should be made of all production well test equipment to ensure that the equipment is in good working order. The frequency for checking the equipment will vary depending on the producing characteristics of the wells and associated problems (if apparent). If a production well test appears inaccurate, or does not meet acceptance criteria requirements, a check of the production well test equipment should be conducted to determine if the issue is a result of faulty or misapplied equipment.

Flow isolation is imperative to production well testing, and processes should be implemented to verify that the production well testing system is capable of isolation of single well flow.

For the production well test information to be representative of the normal flow from a well, the operator should verify that the test separation vessel is sized appropriately to handle the produced fluids from the applicable well. This includes:

- test separators sufficiently sized to allow for full separation (i.e. sufficient residence time, in either two-phase or three-phase operation);
- test separators sufficiently sized to allow normally producing full well flow (e.g. separation efficiency might not be compromised, but a large producing well might need to be choked back to accommodate the test separator).

NOTE Production well testing a well at a reduced volume (rate) due to separator size constraints and extrapolation of the measured volume (rate) to an estimated quantity at normal conditions is not within the scope of this document. In most cases, a linear relationship between well choke setting and production does not exist.

To handle flow variations with incoming flow rates, separator liquid level sensors and control valves should be included in the design and operation of a production well test separator. The extent of automatic and manual controls on the separator should be known and understood during production well testing operations.

Fluid emulsions and the impact on inefficient separation should be understood and managed accordingly. The addition of heat and/or chemical (e.g. demulsifiers) might be required and should be initiated prior to engaging in the production well test. Moreover, periodic vessel cleaning should be considered if sand production is significant.

Production well testing using partial separation techniques should be conducted with full knowledge of any limitations introduced by measuring fluid phases that are not completely single-phase (refer to Annex B).

Table 2—Summary of Suggested Production Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Well configuration	Classify well completion, evaluating: — completion type: open-hole, cased-hole, number of production strings (tubing); — wellbore trajectories; — number of producing zones, number of laterals; — dry-tree or wet tree (subsea); — surface or subsurface choke. Classify artificial lift mechanism as: — rod pump; — plunger; — electrical submersible pump; — subsurface hydraulic piston pump; — subsurface hydraulic jet pump; — gas lift. Assess potential for altered well production and fluid properties due to well completion or artificial lift mechanism modifications, such as: — access to new production zones (e.g. new perforations, opening a sliding sleeve, a new side-track); — recompletions (e.g. new tubing, velocity string); — wellbore interventions (e.g. cleanouts, scale squeeze, fracturing); — addition, removal, or conversion of artificial lift mechanism.	Access to new production zones can alter the fluid properties of the well from values used in previous production well tests. Modifications to artificial lift mechanisms can alter wellbore hydraulics and observed well flow patterns. Additionally, increased production volumes (e.g. water) can exceed the capacity of the production well test system.
Well operability	Verify well operability factors such as: — drawdown limitations (choke settings); — chemical treatment type and amount (e.g. methanol, de-emulsifiers, foam breakers); — artificial lift settings; — cycle well production (i.e. intermittent production due to either artificial lift mechanism or well shut-in and recharge); — production volumes (gas, oil, water, and sand or solids). Evaluate well configuration and operability factors and assess potential impacts on wellbore hydraulics, separation, and measurement such as: — production volumes relative to equipment capacity; — multiphase flow (i.e. flow regimes); — liquid hold-up, gas line pack, slugging flow (i.e. dynamic conditions); — gas–oil ratio (GOR), gas–liquid ratio (GLR), water–liquid ratio (WLR) (watercuts), gas volume fraction (GVF); — emulsions, foaming; — well flow pattern at the measurement point and flow stabilization.	Well operability factors can introduce flow regimes that present challenges for efficient separation and/or measurement, particularly well flow stabilization for production well testing. Drawdown limitations can constrain the producing potential of the well (e.g. to minimize sand production and downhole completion damage) and subsequent flow isolation for production well testing.
Flow delivery	Verify flow delivery factors (between the well and the measurement point) such as: — flowline length, topography, and geometry; — flow isolation (e.g. flow diverter valves); — commingled well production; — production volumes (gas, oil, water, and sand or solids); — potential production chemistry and flow assurance threats (refer to Table 1); — transient effects (e.g. valve openings or closures); — flowline pigging. Evaluate flow delivery and assess potential impacts on flowline hydraulics, separation, and measurement such as: — production volumes relative to equipment capacity; — multiphase flow (i.e. flow regimes); — liquid hold-up, gas line pack, slugging flow (i.e. dynamic conditions); — GOR, GLR, WLR (watercuts), GVF; — emulsions, foaming; — well flow pattern at the measurement point and flow stabilization.	Flow delivery factors can introduce flow regimes that present challenges for efficient separation and/or measurement, particularly well flow stabilization for production well testing. Production well test system hydraulics can be negatively impacted by production chemistry and flow assurance threats.

It is not the intent of this document to specify a meter type, tank gauging method, or measurement approach for the production well testing system. Nor is it the intent of this document to encourage the use of one approach over another. However, single-phase and multiphase flow metering systems should be capable of measuring the flow within the operator's acceptable tolerances for flow measurement. Manual tank gauging methods or automatic tank gauging systems should be capable of measuring the liquid volume within the operator's acceptable tolerances for volumetric measurement. This should also include sediment and water (S&W) determination. Additionally, online water determination devices should be capable of measuring the full range of expected watercuts.

The application of single-phase flow metering in separator and tank-based production well testing should follow API *MPMS* Ch. 20.2.

NOTE API *MPMS* Ch. 20.2 addresses the configuration and operation of flow metering equipment, and the effects on the quality of the flow measurement result due to fluid properties, production processing, and associated flow conditions for meters used in separation-based measurement, including test separators.

The application of multiphase flow metering in production well testing should follow API *MPMS* Ch. 20.3.

The application of manual tank gauging for tank-based production well testing should follow API *MPMS* Ch. 3.1A and API *MPMS* Ch. 18.1.

The application of automatic tank gauging for tank-based production well testing should follow API *MPMS* Ch. 3.1B, API *MPMS* Ch. 3.3, and API *MPMS* Ch. 3.6.

The application of temperature and pressure transmitters for production well testing should follow API RP 551 and API *MPMS* Ch. 21.1.

NOTE For the application of online water determination devices for production well testing, refer to API TR 2570^[3].

Table 3 provides suggested focus areas and associated activities for verifying equipment information. The information should be applicable at the production well test system level and used as a tool in equipment verification prior to each production well test. It is at the operator's discretion to determine which equipment verification activities are warranted, based on reasonable expectations that relevant factors have changed since the previous production well test.

NOTE Annex B provides additional information that can be used in establishing equipment verification activities.

Table 3—Summary of Suggested Equipment Verification Activities

Focus Area	Verification Activity	Potential Impact on Production Well Test
Flow isolation	Verify ability to isolate single well flow (or multiple wells if production well testing by-difference) throughout the production well test system. Where applicable, periodically conduct zero-rate testing of the production well test system (i.e. a no-flow test of the system to ensure no volumetric flow is measured).	Other flow sources beyond the well(s) evaluated can compromise the production well test.
Separation system	Classify separation system, evaluating: - separator technology (i.e. two-phase or three-phase separator, heater-treater, partial separation system); - number of separators (e.g. high pressure, low pressure); - separator size (e.g. gas and liquid capacity); - level, temperature, and pressure control; - separator operation (e.g. continuous or batch); - additional operability factors (e.g. solids removal, chemical additions, compatibility with fluids). With production verification information (refer to Table 2), evaluate separation systems and assess potential for such factors as: - insufficient separator size for full separation (i.e. residence time); - insufficient separator size to accommodate production well testing at	Insufficiently sized separators (or insufficient residence time) and/or inefficient separator operation can lead to challenging flow regimes for measurement systems.

Focus Area	Verification Activity	Potential Impact on Production Well Test
	normal flow rates; — inefficient separator operation (e.g. level, temperature, pressure, fluid emulsions, solids accumulation, dump cycles); — liquid carry-over, gas carry-under; — operation outside the separator operating envelope; — the need for additional heat and/or chemical treatments.	
Measurement systems	Classify measurement systems, evaluating: — meters (e.g. single-phase, multiphase); — tank measurement (e.g. manual, automatic); — fluid quality systems (e.g. sample systems, online water determination devices); — applicable fluid flows (i.e. an account of gas, oil, water production, gas lift, power fluid). Verify meters are configured with the required fluid property information. For example, single-phase meters: — composition, — density (standard and flowing conditions), — dynamic viscosity, — specific gravity, — compressibility factor (standard and flowing conditions), — velocity of sound. For multiphase flow meters: — constituent compositions (including H₂S, CO₂, and total sulfur); — constituent phase densities (function of temperature and pressure); — bulk gas and liquid viscosities (function of temperature and pressure); — water chemistry (salts, conductivity, salinity); — heavy metals; — B_o, B_g, B_w, R_s, r_s applicable for production well test conditions (refer to 6.2); — normally occurring radioactive material; — foaming and emulsion tendencies; — production chemicals. With production verification information (refer to Table 2), evaluate measurement systems and assess potential for such factors as: — exceeding meter rangeability; — unrepresentative fluid properties (meter configuration); — installation effects (e.g. nonideal flow patterns, two-phase flow through the primary element); — adverse process conditions (e.g. temperature, pressure, vibrations, or pulses). Understand the impact on measurement uncertainty and if acceptable uncertainty tolerances have been exceeded.	Outdated fluid property information (e.g. compositions, PVT characterization) used in meter configuration can compromise the production well test results. Insufficiently sized meters and/or installation effects can adversely impact measurement uncertainty and exceed acceptable tolerances for the production well test.
General equipment check	Verify equipment viability with the following check list. — Check for leakage along the entire flow path of the production well test system. This includes any diverter valves, flowlines, separators, and tanks used in the production well test system. — Check the operation of all associated control valves, dump valves, and back-pressure valves in the production well test system. — Check that the well choke is not cut or obstructed and that in the case of an adjustable choke check it will zero properly. — Check that the positions of all isolation valves are in the correct position and that the proper valves for well alignment into the measurement system (separator, multiphase flow meter, or tank) are open. — Check for any accumulations of paraffin, sand, or scale in the production well test vessels, tanks, or meters. — Check applicable temperature and pressure monitoring devices are operational (in addition, ensure the devices are properly calibrated). — Check applicable measurement devices or systems (e.g. multiphase flow meters, single-phase meters, online water determination devices, tank gauging systems, tank tables) are operational (in addition, ensure the devices are properly calibrated).	An operational checklist can ensure equipment readiness and viability for the duration of the production well test.

5.2.5 Well Isolation

Gas, oil (condensate), and water measurements obtained during the production well test shall be applicable to the well under test only and shall not include production from another source. Production well tests shall be conducted such that a well is isolated in the production well testing system, with no leakage or commingling of production with other wells.

Where more than one well is producing to a separator, tank battery, or multiphase flow meter, provisions shall be made to separate production of the individual well to be production well tested from the other wells producing in the system. This can be in the form of a test flow header into a separate separator, tank battery, or multiphase flow meter. Or, production from the wells not undergoing a production well test can be shut-in.

NOTE For production well testing by-difference, it is understood that the “single well flow” will actually encompass multiple, commingled wells. All requirements and recommendations addressed in 5.2 are applicable to commingled well flows measured in by-difference production well testing, and throughout 5.2 the term “well” can be interchanged with “commingled wells” when referring to by-difference production well testing. Refer to 5.5 for more information on by-difference production well testing.

5.2.6 System Purge and Well Flow Stabilization

A well that is aligned to a production well testing system where fluids from previous well production exist shall be flowed for a time sufficient to purge the previous well fluids prior to measurements on the well under test. The production well testing system retention time and liquid hold-up (due to elevation changes in the flowline) should be accounted for in calculating the purge time. This should include consideration of the flow delivery and separation applicable to the production well test system.

To ensure that the production data obtained during a production well test is representative of actual well performance, the production well test shall be conducted under similar physical conditions as the well normally produces, including back pressure, chemical and heat treatments, and flow rates. Wells aligned to a production well test system may require adjustments to choke and artificial lift settings in order to produce at the well's normal physical conditions of back pressure and flow rate.

NOTE If the well is tested at a wellhead pressure in excess of normal operating values, the observed production rate will be reduced from normal conditions. Increased back pressure on the well might be unavoidable due to production well test system constraints (e.g. well productivity, artificial lift settings, test separator pressure controls). In this scenario, the repeatability of production well test measurements is important and the operator should conduct the production well testing under the same set of operating conditions (i.e. the same elevated wellhead pressure) for valid comparisons.

The well flow should be stabilized prior to and during the production well test in accordance with the controlled operational conditions validation acceptance criteria for flow stability (refer to 5.3.2). The pre-stabilization period prior to a production well test should be based on any anticipated temporary wellbore or flow delivery hydraulic-induced instabilities. A well is considered to have stabilized or reached stabilized flow when, for a given choke size or producing rate, the flowing tubing head or pumping bottomhole pressure reaches equilibrium and remains relatively constant at a pressure similar to normal operations. For both flowing and pumping wells, this condition is evidenced at the surface by a relatively constant wellhead pressure, in equilibrium and similar to normal operations.

Production flow rates at the measurement point should be stabilized prior to and during the production well test in accordance with the controlled operational conditions validation acceptance criteria for flow stability (refer to 5.3.2). Flow rates at the measurement point are considered to have stabilized once equilibrium is achieved for the production well test system (e.g. flowlines, test separator, or multiphase flow meter). This is monitored through system temperatures, pressures, levels, and flow rates. When wells are aligned to a production well test system, transient conditions and flowline dynamics can impact the stabilization period prior to the production well test. In these situations, production well testing should account for the transient effects when evaluating for flow stability and representative flow both before and during the production well test. Considerable time should be afforded to allow for the transients to dissipate and conditions to stabilize. Liquid hold-up in long flowlines can extend the time prior to stabilization, separator purge times and flow

stabilization periods might not coincide, and both wellbore and flowline slugging can create flow regimes that never fully stabilize.

API RP 11V8 includes more detailed recommendations on evaluating well stability and purge times following transient events (i.e. aligning a well from a production header to a test header) and a preferred method to estimate the time required for pipeline purging (accounting for liquid hold-up).

There should not be any change in operation of production well test system equipment after the stabilizing period begins and during the production well test. Any adjustment of equipment that causes a change in the pressure upstream of the choke on a flowing well under test (or in the casing or wellhead pressure on a pumping well) can result in erroneous production well test data. If a change is made, the stabilizing period should be started over prior to conducting the production well test.

Production well test results on nonstabilized well flow are not readily reproducible and generally do not directly compare with previous or future test data. However, there are production scenarios where stabilized flow conditions (particularly at the measurement point) are not attainable during the production well testing timeframe. These can include conditions arising from severe well slugging (either naturally or through improperly configured or operating artificial lift systems), subsea riser slugging, or artificial lift systems that normally produce a pulsed flow output from the well (e.g. plungers or rod pumps). In these cases, the production well test should reflect “representative” flow conditions in lieu of stabilized flow (refer to 5.2.7).

NOTE “Representative” flow conditions refer to flow conditions that are representative of normal well operating conditions (i.e. the observed well slugging or cyclical behavior during the production well test is similar to that observed during normal operations). This is at the operator’s discretion and typically will vary on a well by well basis.

The artificial lift method should also be considered when evaluating the producing well for flow stability or representative flow characteristics prior to and during the production well test. Adjustments to artificial lift systems should not be made during the stabilization period, as this constitutes a change in well operations.

NOTE In some cases daily variations in temperature are sufficient to affect gas volumes. Gas volume variation caused by daily temperature changes should not be considered as a variation resulting from stabilization.

5.2.7 Well Measurement

When evaluating stabilized or representative flow during a production well test, production well test durations should be over a time period sufficient to ensure enough flow information is obtained to reliably measure volumes indicative of the well’s normal production. Production well testing should account for transient effects when evaluating for flow stability and representative flow both before and during the production well test.

All produced fluids (gas, oil, and water) shall be accounted for during the measurement of the production well test. This includes any side streams that might be a result of multiple vessels used in separation (e.g. water exiting a free water knockout vessel ahead of a heater-treater).

Fluid production measured by tank gauging should be accomplished by gauging the tank at the beginning and end of the production well test, with the total fluid production determined by difference of the two readings. Indicated oil volume should be sampled and corrected for S&W content.

Artificial lift fluids introduced into the production well (e.g. gas lift gas or power fluid) shall be accounted for in the production well test. The artificial lift fluids should be separately measured and subtracted from the measured fluids during the production well test (e.g. gas lift gas volumes subtracted from the measured production well test gas volume). Adjustments to artificial lift systems should not be made during the production well test.

Flow measurement reporting requirements should be understood and applied using the correct PVT information (i.e. correct fluid measurements to standard conditions) for the well during a production well test. Fluid quality information used in the measurement systems should be applicable to the fluids and process conditions (i.e. pressure and temperature) during the production well test.

Flow measurement data should be the totalized volume for the associated meter during the production well test. If an automatic meter totalizer is not used, then the operator should use the meter totalizer initial and final readings that correspond to the production well test start and end times, respectively.

Instantaneous flow measurement data can be used for well flow rate stability determination.

Refer to Section 6 for detailed information on production well test volume and rate calculations.

During production well testing, there should be no change in chemical treatment from normal operations, unless a treatment program is specifically required to conduct the production well test (e.g. demulsification to promote separation in a test separator, or methanol treatment in a long subsea flowline used for production well testing).

Applicable sampling operations that relate to the production well test should be conducted during the well measurement period. This can include compositional information regarding the fluids, sampling for production well testing PVT application, and/or watercut determination.

NOTE Extreme caution should be exercised in handling gases and fluids containing hydrogen sulfide (H_2S). This hazardous substance is highly toxic and under certain concentration can cause illness and death. Special precautions should be taken when testing wells where H_2S is present to be assured that exposure will not exceed the safe maximum allowable concentration for the work period required. Self-contained breathing apparatus should be worn when H_2S concentrations are present that might be injurious to health.

Watercut determination on liquid flows (oil and water) may be obtained through manual or automatic sampling or an online water determination device.

Manual sampling in the presence of emulsions (flowing or tank measurements) should include multiple samples (e.g. three) for analysis of water content. For tanks, several samples of fluid should be taken at different levels in the tank to find the average water content of the oil.

The duration of the production well test is determined by the operator and should be based on historical performance and parameters relating to the applicable well. Important aspects to consider when establishing production well test duration include:

- well producing performance (i.e. whether the well is a cyclical producer);
- flow variability or slugging at the measurement point (due to various factors such as inefficient separation, inefficient separator level control, or batch “dump” cycle volumes exiting a test separator);
- production deferrals (for production well tests that might require other wells to be shut-in);
- availability of production well test equipment.

Understanding flow variability or slugging at the measurement point and how this can affect production well test duration is one of the more challenging considerations when establishing production well test start and stop times. Annex C provides guidance in this regard and an example to aid the operator.

Figure 3 summarizes the key elements and workflow that should be conducted during a production well test.

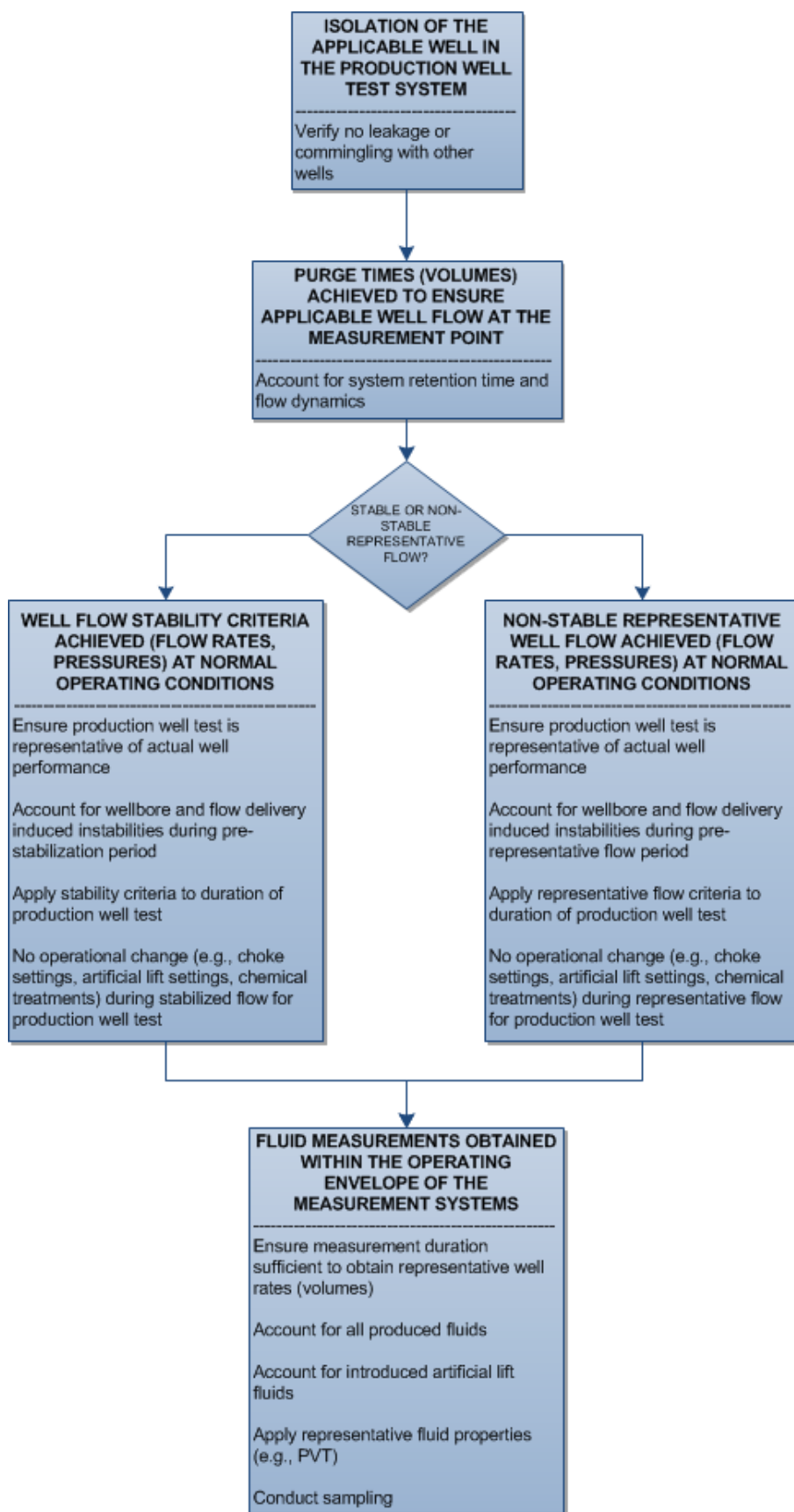


Figure 3—Summary of Production Well Test Elements and Workflow

5.2.8 Data Recording

Recording of the data is an important component of the production well test. The principle method of data recording is at the discretion of the operator (e.g. electronic or paper). Individuals should be assigned to perform data recording activities in alignment with their normal duties (e.g. production personnel for meter data). Reports and the data requirements for a production well test can vary, depending on the applicable regulations, permits, agreements, and operator requirements. For this reason it is not the intent of this document to provide a required universal production well test report. However, an example is provided in Annex D.

The operator shall record the production well test data accurately and completely. Any assumptions regarding equipment status or production well test data should be verified prior to final recording of the information.

5.3 Validation

5.3.1 General

Validation of the production well test is necessary to assure representative well rates. Operators should utilize an evaluation of identified parameters to validate a production well test prior to accepting its use in a well rate determination application. Validation should be through an evaluation of production well test parameters against a set of acceptance criteria for controlled operational conditions during the production well test and in comparison with historical well performance.

5.3.2 Controlled Operational Conditions Validation

It is important that the production well test is validated as representing a measurement of gas, oil, and water from a single well during a specified length of time under controlled operational conditions. The operator should establish and document acceptance criteria for controlled operational conditions validation. The following list provides suggested acceptance criteria parameters for inclusion in controlled operational conditions validation of a production well test:

- well isolation in the production well test system for the duration of the purge, flow pre-stabilization, and production well test measurement period;
- purge times (volumes) sufficient to ensure representative single well flow at the measurement point;
- demonstrated well flow stability for the duration of the production well test:
 - wellhead and/or bottomhole pressure relatively constant and within $\pm 5\%$ of normal operating conditions,
 - wellhead and/or bottomhole temperature relatively constant and within $\pm 5\%$ of normal operating conditions,
 - flow rate variation within $\pm 5\%$ for each phase being tested,
 - watercut variation within $\pm 5\%$,
 - measured GOR variation within $\pm 5\%$,
 - minimum of 4 hours of stable flow.
- fluid measurement obtained within the operating envelope of the measurement system;
- no changes to equipment (e.g. chokes settings, artificial lift settings, chemical injections) for the duration of the production well test.

The range of values for well flow stability is only a starting point. The operator should establish the well flow stability criteria and ranges through evaluation and analysis. Controlled operational conditions validation acceptance criteria might be production well test system specific or well specific. In many cases, historical well performance can be used as a basis to guide establishing the controlled operational conditions validation acceptance criteria.

In situations where well flow does not achieve fully stable conditions (i.e. subsea riser slugging, or artificial lift systems that normally produce a pulsed flow output from the well), the operator should compare the production well test to “representative” flow conditions defined for the well in normal operation.

In situations where validation to controlled operational conditions cannot be obtained for the production well test, the operator should determine if corrections can be applied (e.g. if the wellhead pressure is out of range of the acceptance criteria, the operator may apply a correction factor to the rates/volumes that corresponds to previous production signature information for the well).

5.3.3 Production Signature Validation

When a production well test has been validated, it should be used with previous tests to establish a production signature (or footprint) for the applicable well and production well test system. In turn, the production signature should be utilized as a historical record of well performance to validate subsequent production well tests (it is useful to compare historical trends for a specified set of parameters).

A production signature should be used to validate the representative flow characteristics of a production well test for validation. The operator should establish and document acceptance criteria for production signature validation. The following list provides suggested parameters for inclusion in production signature validation of a production well test:

- gas compositions mole fraction within ± 2 %;
- characterization of the liquid hydrocarbon (e.g. API gravity);
- individual gas, oil (condensate), and water flow rates (or volumes) within ± 5 %;
- measured GOR within ± 10 %;
- well pressures (wellhead and bottomhole) within ± 5 %;
- separator pressures and temperatures within ± 5 %;
- well choke setting unchanged;
- well artificial lift (e.g. power fluid or gas) settings unchanged;
- duration of purge time and flow pre-stabilization period;
- duration of production well test.

The range of values for production signature validation is only a starting point. The operator should establish the acceptance criteria and ranges through evaluation and analysis. Production signature validation acceptance criteria might be production well test system specific or well specific. In many cases, historical well performance can be used as a basis to guide establishing the production signature validation acceptance criteria.

There can be any number of reasons why a production well test might not meet the production signature acceptance criteria. First and foremost, the well might be exhibiting changing performance that was not anticipated prior to the production well test. Second, the restrictions placed on the range of the acceptance

criteria might be too stringent and do not adequately reflect the characteristic behavior of the well. Third, the production well test was in actuality not a valid test and not representative of the well (controlled operational conditions not achieved). Finally, data collection during the production well test (e.g. pressure, temperature, flow measurements) might be erroneous or subject to high uncertainty. Regardless of reason, the entire production well test (system, data collection) should be reviewed and analyzed for contributing factors.

Consideration of historical well production decline is warranted and should be included when acceptance criteria and a production signature are specified. Wells exhibiting a high production decline rate require more production well tests to establish a production signature that is representative of the well's performance. Conversely, when well production declines have leveled off, the number and frequency of production well tests necessary for a representative production signature decreases.

Changes to the well (e.g. well workover or intervention) or flow delivery system (e.g. introduction of riser gas lift or a different routing of flowlines between the well and measurement point) can alter the flowing conditions of the well and the subsequent production signature such that comparison and validation with historical data is no longer applicable. In this scenario, a new production signature should be established for the new flowing conditions and used to valid future production well tests.

5.3.4 Production Well Test Measurement Uncertainty

Measurement in upstream production has a much higher level of uncertainty when compared to measurement at custody transfer conditions. For production well testing, oil is saturated with gas at production pressures and temperatures. Gas is saturated with hydrocarbon and water, and might include entrained liquids. Additionally, oil and water emulsions might be present. It is recognized that these conditions result in the elevated uncertainties relative to custody transfer, where treated gas and de-watered oil pumped from atmospheric tanks are measured.

Owing to the challenges of measurement in an upstream production environment, and the potential complexities of a production well test system, uncertainties associated with the individual phase (i.e. gas, oil, water) measurement results can range from as low as $\pm 2\%$ to as high as $\pm 10\%$ or greater. It is not the intent of this document to specify an uncertainty range acceptable for production well testing. However, the operator should evaluate the importance of the data and assign an acceptable tolerance on uncertainty accordingly. In this endeavor, uncertainties associated with the measurement systems may be evaluated and applied to the final measurement results.

NOTE This can include uncertainties associated with both fluid property and PVT information used in deriving the final measurement result. For more information on calculating measurement uncertainties, refer to API *MPMS* Ch. 13.3 ^[4].

5.4 Special Case: Continuous Measurement

For wells that are aligned to a continuous measurement system (e.g. a well that is flowing in isolation into a dedicated multiphase flow meter or separator) the need for periodic production well testing might be for reporting purposes only. For example, regulator or partner reporting might require a reported production well test on a periodic basis, such as monthly or every six months. Conducting a production well test on a well aligned to a continuous measurement system should be approached with the methodology described in 5.1, 5.2, and 5.3 (i.e. the same process to determine production well test timing, length, and validation hold true for a periodic "snapshot" of a continuously measured well, as for a well periodically aligned to a production well test system).

As with a periodic production well test conducted with a test separator, multiphase flow meter, or tank battery, the operator should ensure that the production well test with a continuous measurement system is representative of the well's performance in normal operations. With the well continuously isolated in the production well testing system, purging and stabilizing periods prior to the production well test measurement might not be applicable (i.e. no other well fluids and no transient conditions).

5.5 Special Case: Production Well Test By-difference

5.5.1 General

Production well testing by-difference refers to the practice of estimating well rates via subtraction of measured well(s) production from a commingled measurement and an assignment of production to an unmeasured well included in the original commingled measurement. This typically involves shutting in or diverting to another flowline the well to be by-difference production well tested.

This approach to production well testing is often agreed to be acceptable in subsea developments where more than one well produces via a single riser to a surface production facility, and only the commingled production rates of gas, oil, and water are measured. Production well testing by-difference is then executed in preference to a conventional isolation production well test. In many cases, the single well cannot flow stably by itself due to multiphase flow issues.

NOTE Acceptance of by-difference production well testing can also apply onshore, where some wells cannot physically flow alone into a production well test system and are tested by-difference through “piggy-back” testing with another well. Additionally, production well test systems might not be capable of accurately measuring well production (e.g. oversized relative to the well flow rates), thus necessitating the inclusion of another well for both a commingled measurement and a by-difference estimation of the unmeasured producer.

5.5.2 Production Well Test By-difference Process

The two production measurements used in the production well test by-difference subtraction should be conducted in the same manner as a single isolated production well test (refer to 5.2.5). It is important to keep the production levels of the flowing wells constant during the periods the commingled production are measured for the computation of the by-difference result.

A suggested outline of the production well test by-difference process is as follows.

- The by-difference production well tested well is flowed with one or more other wells into the measurement system used for the production well test (e.g. two-phase/three-phase separator or multiphase flow meter).
- The stable total production flows (averaged over at least 6 hours) through the system are recorded as “The Production Level Before Shut-in.” Wellhead and/or bottomhole pressures should be relatively constant and within ± 5 % of normal operating conditions.
- The well to be production well tested by-difference is shut-in. Wellhead and/or bottomhole pressures for all the other wells are adjusted to be the same (within a few percent) as before the shut-in. This is achieved by varying the production chokes of the wells.
- The stable total production flows (averaged over at least 6 hours) through the system are recorded as “The Production Level After Shut-in.” This should be at most 80 % of the “The Production Level Before Shut-In”.
- The difference between “The Production Level Before Shut-in” and “The Production Level After Shut-in” is taken to be the by-difference production well test of the shut-in well.

NOTE Quantities such as “at most 80 % of The Production Level Before Shut-in” or “averaged over at least 6 hours” are for guidance purposes only. The operator should establish these values through evaluation and analysis. In many cases, historical well performance should be used to inform the evaluation. Additionally, consideration of the measurement uncertainty impact on the by-difference result is warranted (refer to 5.5.3). In commingled production flow, by-difference production well testing of the lowest flow rate well will result in higher relative measurement uncertainties for that well, than if the higher producing well(s) was/were by-difference tested. If possible, direct measurement of the lowest flow rate well is preferred [i.e. by-difference testing the highest flow rate well(s)]. However, in many cases the lowest flow rate well cannot be production well tested in isolation, and higher measurement uncertainties will result.

5.5.3 Special Considerations

Production well testing by-difference is less accurate compared to direct measurement. However, such a production well testing approach is often agreed to be necessary for the economic development of reserves (e.g. deepwater). One source of added measurement uncertainty is the subtraction of two quantities; hence, the percentage uncertainty of the resulting difference is more than the two original individual measurement uncertainties. For example, to achieve a 15 % uncertainty on a 25 % difference, the original measurements are required to be at 3 % uncertainty. This might be difficult to verify in practice. Another potential source of uncertainty relates to the PVT information applied to obtain the production well test result (refer to 6.2). Applied PVT information might be significantly different between measured flows with and without the well to be tested by-difference.

Production well test by-difference requires a well to be shut-in, thereby leading to deferred production and the various operational challenges occasionally encountered with starting up a well. This typically leads to a requirement to minimize production well testing by-difference by extending periods between production well tests. If production well testing by-difference is acceptable or necessary, then the maximum period between production well tests by-difference should be stipulated.

In such cases, production well test by-difference results are typically used as part of a continuous well rate estimation system, for example the validation or tuning of online multiphase flow meters or VFMs (refer to 7.4). Computing continuous well rate estimates based on the results of production well testing by-difference allow the sum of the resulting well rate estimates to be tracked and validated against the commingled flow meters on a daily basis. If the sum of the well daily estimates exceeds, for example, 10 % of the total commingled production consistently over a number of days, this is indicative that the production well test by-difference might no longer be representative of the production for some wells, and testing of selected wells might be required to be brought forward.

NOTE The quantity “If the sum of the well daily estimates exceeds 10 % of the total commingled production” is for guidance purposes only. The operator should establish the value through evaluation and analysis. In many cases, historical well performance should be used to inform the evaluation.

6 Calculating Production Well Test Volumes and Rates

6.1 General

The desired production volume and rate output from a production well test includes the following:

- total volume (mscf, 10^3m^3) or volumetric rate (mscf/d, $10^3\text{m}^3/\text{d}$) of produced gas for the applicable well, corrected to standard conditions;
- total volume (bbl, m^3) or volumetric rate (bbl/d, m^3/d) of produced oil (condensate) for the applicable well, corrected to standard conditions;
- total volume (bbl, m^3) or volumetric rate (bbl/d, m^3/d) of produced water for the applicable well, corrected to standard conditions.

NOTE For production well testing by-difference, it is understood that the “applicable well” will actually encompass multiple, commingled wells. All correction factors and calculations addressed in 6.2, 6.3, 6.4, and 6.5 are applicable to commingled well flows measured in by-difference testing, and the term “well” can be interchanged with “commingled wells” when referring to by-difference production well testing. Refer to 5.5 for more information on by-difference production well testing.

Volume and rate calculations for production well tests vary depending on the type of measurement systems used and artificial lift mechanism deployed. Hydrocarbon phase behavior, watercuts, and introduced artificial lift fluids (i.e. power fluid oil or water, or gas lift gas) shall be accounted for in the calculation of production well test volumes and rates. It is not the intent of this document to specify a calculation approach for every production well test scenario. Nor is it the intent of this document to encourage the use of one approach over

another. However, for guidance applicable to the majority of production well test scenarios, production well test volume and rate calculations are provided for separator, multiphase flow meter, and tank measurement systems.

NOTE 1 When calculating production well test volumes and rates, ensure that the duration of the production well test (i.e. start and stop times) is the same for all of the calculations.

NOTE 2 The gas calculations for single-phase meters provided in this document do not apply to situations where free liquid is present in the gas.

NOTE 3 The liquid calculations for single-phase meters provided in this document do not apply to situations where free gas is present in the liquid.

6.2 Phase Behavior (Production Well Testing PVT Application)

6.2.1 General

At production well test conditions of temperature and pressure, a hydrocarbon liquid is typically at bubble point and a hydrocarbon gas is at dew point. As the hydrocarbon liquid continues through the production process to standard conditions (e.g. atmospheric), the light hydrocarbon components evolve out of the liquid, causing a reduction in liquid volume. Conversely, heavier hydrocarbon components condense out of the gas, causing a reduction in gas volume. To account for the volumetric changes and phase conversions in production well testing calculations, the following PVT properties are applied:

- oil volume correction factor, B_o (the inverse of shrinkage correction factor);
- gas volume correction factor, B_g ;
- water volume correction factor, B_w ;
- solution GOR, R_s ;
- solution condensate–gas ratio (CGR), r_s .

If production well testing is conducted in an environment where the phase behavior cannot be easily represented with B_o , B_g , B_w , R_s , and r_s as described in this document, the operator should refer to the API Draft Standard *Application of Hydrocarbon Phase Behavior Modeling in Upstream Measurement and Allocation Systems* for guidance.

NOTE 1 Throughout the calculations addressed in 6.3, 6.4, and 6.5, B_o , B_g , B_w , R_s , and r_s are denoted with subscripts defining the applicability of the term relative to the production well test conditions of pressure and temperature. For example, $B_{o,sep}$ refers to B_o at separator conditions of pressure and temperature, while $B_{o,mpfm}$ refers to B_o at pressure and temperature conditions at the multiphase flow meter. $B_{o,sep}$ and $B_{o,mpfm}$ are not necessarily equal (only if conditions of pressure and temperature and downstream processing are equivalent), and should be independently determined.

NOTE 2 B_o , B_g , R_s , and r_s as applicable in production well testing (i.e. at production well test conditions of pressure and temperature, e.g. $B_{o,sep}$ or $B_{o,mpfm}$) might or might not be included in a typical reservoir PVT analysis as conducted for reservoir engineering purposes. A typical reservoir PVT analysis is based on PVT studies of either single-phase reservoir fluid (e.g. from a downhole sample) or recombined surface fluids (e.g. separator gas and liquid hydrocarbon) and, depending on the reservoir classification (e.g. black oil or gas condensate), generally include:

- (1) single-stage flash for determination of total hydrocarbon composition;
- (2) constant composition expansion for determination of oil bubble point, undersaturated oil density and isothermal compressibility, two-phase volumetric fluid behavior below bubble point, gas hydrocarbon dew point, gas compressibility, and B_g at hydrocarbon dew point (not production well test conditions of temperature and pressure);

- (3) multistage separator test for determination of total B_o and R_s relative to reservoir conditions of pressure and temperature (not production well test conditions of temperature and pressure, unless specified by the operator in the PVT analysis); differential liberation expansion for determination of residual oil volume, oil density, oil gravity, gas compressibility, and residual B_o and R_s relative to reservoir conditions of pressure and temperature (not production well test conditions of temperature and pressure) that are used to determine the total B_o and R_s (in conjunction with data from the multistage separator test); and
- (4) constant volume depletion for determination of total hydrocarbon composition, two-phase volumetric behavior (i.e. reservoir yields), B_g and r_s as a function of simulated reservoir pressure depletion (not production well test conditions of temperature and pressure). As such, determination of B_o , B_g , R_s , and r_s for production well testing PVT application might require a separate PVT analysis (using similar methods, in particular the multistage separator test) from the typical reservoir studies, using fluid samples obtained at the measurement point (e.g. production well test separator). For more information on PVT studies and analysis, refer to the SPE text *Phase Behavior*^[5].

NOTE 3 B_o , B_g , B_w , R_s , and r_s as applicable in production well testing (i.e. at production well test conditions of pressure and temperature, e.g. $B_{o,sep}$ or $B_{o,mpfm}$) become more relevant at higher pressures and temperatures (i.e. elevated pressures and temperatures lead to greater volumetric changes and phase conversions). Large errors in production well test calculations can result if these properties are not properly determined, such as high-pressure and high-temperature applications of production well test separators or multiphase flow meters. Conversely, B_o , B_g , B_w , R_s , and r_s might not be of enough significance to use in production well testing calculations. It is at the discretion of the operator to assess the validity of the parameters, whether or not estimates for the parameters are warranted, and any associated uncertainty on the production well test result.

6.2.2 Oil Volume Correction Factor

The oil volume correction factor, or B_o , is the ratio of the hydrocarbon liquid volume at elevated pressure and temperature conditions of the production well test system to the hydrocarbon liquid volume at standard conditions (bbl/bbl, m^3/m^3).

NOTE The oil volume correction factor B_o , is the inverse of the shrinkage correction factor, $1/B_o$.

The B_o can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon liquid at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_o is measured as the ratio of hydrocarbon liquid volume at elevated pressure and temperature conditions to the measured hydrocarbon liquid volume at standard conditions. The B_o can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of B_o . The B_o is generally determined in the laboratory at the same time as the GOR, R_s .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculation.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the B_o .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

- *Field Measurement.* The B_o can be determined in the field with the procedure outlined in Annex E.

6.2.3 Gas Volume Correction Factor

The gas volume correction factor, or B_g , is the ratio of hydrocarbon gas volume at elevated pressure and temperature conditions of the production well test system to the hydrocarbon gas volume at standard conditions (ft^3/scf , m^3/m^3).

The B_g can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced hydrocarbon gas at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_g is measured as the ratio of measured hydrocarbon gas volume at elevated pressure and temperature conditions to the measured hydrocarbon gas volume at standard conditions. The B_g can be determined in a single-stage flash or under multistage flash conditions. Depending on the process downstream, a multistage flash can lead to a more accurate determination of B_g . The B_g is generally determined in the laboratory at the same time as the CGR, r_s .

NOTE A multistage flash experiment should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

- *Calculated.* A sample of hydrocarbon liquid and a sample of hydrocarbon gas (both in equilibrium) at elevated pressure and temperature conditions of the production well test system are subject to laboratory recombined fluid analysis to obtain the total hydrocarbon composition. EOS modeling using the total hydrocarbon composition and either a simulated single-stage or multistage flash calculation from production well test conditions to standard conditions can provide a calculated estimate of the B_g .

NOTE 1 A simulated multistage EOS flash calculation should reproduce the thermodynamic equilibrium points (i.e. major separation stages) downstream of the production well test system.

NOTE 2 The EOS should be capable of determining the PVT properties of interest over the applicable pressure and temperature range. This can include the use of an EOS that has been previously validated against data obtained from a reservoir PVT analysis.

6.2.4 Water Volume Correction Factor

The water volume correction factor, B_w , is the ratio of water volume at elevated pressure and temperature conditions of the production well test system to the water volume at standard conditions (bbl/bbl , m^3/m^3).

The B_w can be determined with the following methods.

- *Laboratory Measurement.* A sample of produced water at elevated pressure and temperature conditions of the production well test system is subject to reduction in temperature and pressure to standard conditions. The B_w is measured as the ratio of measured water volume at elevated pressure and temperature conditions to the measured water volume at standard conditions.
- *Calculated.* The B_w can be determined with the procedure outlined in Annex F.

6.2.5 Solution GOR

The solution GOR, or R_s (also referred to as the gas-in-solution factor, or GIS), is the ratio of evolved hydrocarbon gas volume at standard conditions (evolved from hydrocarbon liquid as it is lowered in pressure and temperature from elevated pressure and temperature conditions of the production well test system to standard conditions) to the hydrocarbon liquid volume at standard conditions (mscf/bbl , $10^3\text{m}^3/\text{m}^3$).

NOTE The evolved hydrocarbon gas is sometimes referred to as flash gas.