BC Measurement Guideline

Version 2.4: October 2023

About the Regulator

The BC Energy Regulator (Regulator or BCER) is the single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Regulator's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected by ensuring public safety, protecting the environment, conserving petroleum resources, and ensuring equitable participation in production.

Vision, Mission and Values

Vision

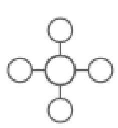
A resilient energy future where B.C.'s energy resource activities are safe, environmentally leading and socially responsible.

Mission

We regulate the life cycle of energy resource activities in B.C., from site planning to restoration, ensuring activities are undertaken in a manner that:

Protects public safety and the environment

Supports reconciliation with Indigenous peoples and the transition to low-carbon energy



Conserves energy resources

Fosters a sound economy and social well-being

Values

Respect is our commitment to listen, accept and value diverse perspectives.

Integrity is our commitment to the principles of fairness, trust and accountability.

Transparency is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation is our commitment to learn, adapt, act and grow.

Responsiveness is our commitment to listening and timely and meaningful action.

Additional Guidance

As with all Regulator documents, this document does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Regulator staff for clarification.

The Regulator publishes both application and operations manuals and guides. The application manual provides guidance to applicants in preparing and applying for permits and the regulatory requirements in the planning and application stages. The operation manual details the reporting, compliance, and regulatory obligations of the permit holder. Regulator manuals focus on requirements and processes associated with the Regulator's legislative authorities. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities. For example, Federal Fisheries Act, Transportation Act, Highway Act, Workers Compensation Act and Wildlife Act.

Throughout the document there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- Glossary and acronym listing on the Regulator website.
- Documentation and guidelines on the Regulator website.
- Frequently asked questions on the Regulator website.
- Advisories, bulletins, reports and directives on the Regulator website.
- Regulations and Acts listed on the Regulator website.

In addition, this document may reference some application types and forms to be submitted outside of the Application Management System but made available on the Regulator's website. Application types and forms include:

- Heritage Conservation Act, Section 12
- Road use permits
- Water licences
- Master licence to cut
- Certificate of restoration
- Waste discharge permit
- Experimental scheme application
- Permit extension application

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Guideline Revisions

The BCER is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the Documentation Section of the BCER's website. Stakeholders are invited to provide input or feedback on BCER documentation to ServiceDesk@BC-ER.ca or submit feedback using the feedback form.

1. Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
2.0	Nov 2, 2018	Nov 5, 2018	Various	Convert document to standard BCER format.
2.1	June 1, 2020	July 1, 2020	Various	Updates to harmonize with AER D17.
2.2	June 22, 2020	June 22, 2020	6.12	Updated requirements for Petrinex submissions.
2.3	Nov, 2021	Nov, 2021	Various	Updates to harmonize with AER D17.
2.4	Oct 25, 2023	Nov 1, 2023	1.9 and 2.2	Update name, logo, and links. Align wording and add links to applicable D&PR sections.

Introduction

The BC Measurement Guideline has been prepared by the BCER to provide regulatory guidance regarding a permit holder's measurement obligations under section 53 of the Drilling and Production Regulation, B.C. Reg. 282/2010 Drilling and Production Regulation - DPR

Permit holders, facility owners and operators may have tax reporting and payment obligations under British Columbia's Motor Fuel Tax Act, and/or Carbon Tax Act. For information, please see Motor Fuel Tax & Carbon Tax or contact the Ministry of Finance (FIN); Toll free in Canada at 1-877-388-4440, or by email at CTBTaxQuestions@gov.bc.ca. Meters used to report motor fuel or carbon tax are considered to be fuel gas meters and are within the scope of this Guideline.

In this Guideline, the term "measurement" is used to include measurement, estimation, accounting, and reporting. While measurement allows the determination of a volume, accounting and reporting are integral components of measurement in that after a fluid volume is "measured", mathematical procedures (accounting) and/or estimation may have to be employed to arrive at the desired volume to be "reported".

This Guideline is not intended to take the place of the applicable legislation. Adherence to the standards and practices in this Guideline are considered an effective way for permit holders to achieve compliance with the applicable regulatory requirements relating to measurement. Deviation from these standards and practices will be evaluated on their demonstrated effectiveness, in accordance with the objectives for measurement as set out in this Guideline.

Permit holders may choose to include some or all of this Measurement Guideline into their own internal standards and practices. To facilitate such adoption, the guidance contained in this Guideline has been written in normative (or mandatory) language.

Intent: This Guideline specifies:

1) what and how volumes must be measured,
2) what, where, and how volumes may be estimated,
3) if accounting procedures must be performed on the measured volumes and what these procedures are,
4) what data must be kept for audit purposes, and
5) what resultant volumes must be reported to the Ministry of Finance (FIN).

British Columbia Adopts Petrinex

British Columbia, represented by the Ministry of Finance (FIN), the BC Energy Regulator (BCER), and the Ministry of Energy, Mines and Low Carbon Innovation (EMLI), has initiated a project to move aspects of oil and gas reporting to Petrinex, Canada's Petroleum Information Network.

Petrinex is a proven, internet-based, joint strategic organization and system, for managing and exchanging volumetrics, royalty billing, regulatory activities, and commercial information, supporting Canada's upstream oil and gas industry. Both Industry and Government represent it. The Canadian Association of Petroleum Producers (CAPP) and the Explorers and Producers Association of Canada (EPAC) represent industry.

Petrinex contributes to substantial improvement in the efficiency, accessibility and quality of information communicated between oil and gas permit holders, operators, producers, Government, and industry partners. See the Petrinex website at Petrinex.ca.

In Alberta, oil and gas operators have been using Petrinex for volumetric, infrastructure, and royalty-related reporting, since October 2002, and March 2012 in Saskatchewan. Petrinex reporting includes the mandated reporting to provincial ministries and regulators, as well as non-mandatory reporting, such as Industry-to-Industry partner reporting. Benefits from the move to Petrinex, include:

- A single-window venue for all stakeholders to access to secure, timely, and accurate volumetric data.
- A standardization of interfaces, enhanced completeness and reporting accuracy with company production accounting, financial, and other systems.
- Tools to assure submissions for Government and Industry processes are timely, correct, and complete.
- Opportunity for greater transparency, paperless partner reporting of production data information and business processes between all stakeholders.
- Consultation mechanisms that provide opportunities for Industry and Government to work together to achieve the best possible administrative processes for all stakeholders.

See – Appendix H - PETRINEX Facility Types and Subtypes for volumetric reporting in BC.

Contact Information

Petrinex support web site: Petrinexsupport@**Petrinex**.ca ; phone 1-800-992-1144
BCER Petrinex Info ; BCER measurement contact ; Brian Summers, brian.summers@bc-er.ca ; phone 250-794-5315
Ministry of Finance; Oil&GasRoyaltyQuestions@gov.bc.ca ; phone 1-800-667-1182
Ministry of Energy, Mines Low Carbon Innovation; servicebc@gov.bc.ca ; phone 1-800-663-7867

Content Additions

Additions to content from the previous release have been identified by blue text throughout this manual. The following list provides a summary to identify the additions that have been applied to this guideline from the last release in Nov, 2021.

What's New in this Edition?

1. **1.9 Measurement Schematic**- added "A facility permit holder must maintain up-to-date metering schematics" to align with the Drilling and Production Regulation 78 (1).
2. **1.9.1.1(1)** added "BCER" facility "(FAC)" and "Petrinex Identifier" to clarify what associated battery facility codes are required.
3. Various – as applicable, where it makes sense, change "accounting" to reporting to better align with the D&PR 53 a (iii) wording "each product stream used for reporting purpose at a facility, and"

Content Omissions

None

Definitions

Many terms used in this Guideline are defined in the Glossary However, many critically important definitions are also included within applicable Chapters throughout the manual.

1. Chapter 1- Standards of Accuracy

1.1. Introduction

The BCER has adopted standards of accuracy for gas and liquid measurement that take into account such concerns as royalty, equity, reservoir engineering, declining production rates, and aging equipment. These standards have evolved, but originated from a 1972 Energy Resources Conservation Board hearing decision that determined a need for pool production accuracy standards of 2.0 per cent for oil, 3.0 per cent for gas, and 5.0 per cent for water. The current standards of accuracy stated as "maximum uncertainty of monthly volume" and/or "single point measurement uncertainty." The uncertainties must be applied as "plus/minus" (e.g., ±5%).

Measurement at delivery and sales points must meet the highest accuracy standards because volumes determined at these points have a direct impact on royalty determination. Other measurement points that play a role in the overall accounting process are subject to less stringent accuracy standards to accommodate physical limitations and/or economics.

Out-of-province fluid deliveries involve a model of delivery and sales point requirements that are covered in Chapter 7 Cross Border Measurement.

The specific standards of accuracy are summarized in section 1.7 of this Chapter.

1.2. Applicability and Use of Uncertainties

The BCER has adopted the following uncertainty level requirements for equipment and/or procedures relating to measurement, accounting, and reporting for various aspects of oil and gas production and processing operations.

Deviations from the minimum requirements for equipment and methods may be considered if it is in accordance with the following:

1) No royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the operator is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties.

2) In some cases, as described in Chapter 5 Site-Specific Deviation from Base Requirements the operator may deviate from the minimum requirements without BCER approval, provided that specific criteria are met. Operators may also apply for approval to deviate from the minimum requirements if the specific criteria are not met.

3) If royalty, equity, or engineering concerns are associated with the volumes being measured, an operator may be allowed, on application, to deviate from the minimum requirements. The application must demonstrate that the proposed alternative measurement equipment and/or procedures will either provide measurement accuracy within the applicable uncertainties or meet specific criteria described in Chapter 5 Site Specific Deviation from Base Requirements. Applications will also be considered if measurement accuracy will be marginally outside the uncertainty limits or if the specified criteria will be marginally exceeded. In such cases, BCER inspectors and auditors will review the operators' records for documentation to confirm that approval has been obtained to deviate from the minimum requirements and for compliance with the approval conditions.

1.3. **Maximum Uncertainty of Monthly Volume**

FIN requires production data to be reported on a calendar month basis. “Maximum Uncertainty of Monthly Volume” relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume. Total monthly volumes may result from a single month-long measurement, but more often result from a combination of individual measurements and/or estimations.

For example, consider a well in an oil proration battery/facility to which a maximum uncertainty of the monthly volume would apply:

1) First, the well is tested, and the oil test rate is used to estimate the well’s production for the period until the next test is conducted.
2) The well’s total estimated oil production for the month is combined with the month’s estimated oil production from the other wells in the battery/facility to arrive at the total estimated monthly oil production for the battery/facility.
3) The total actual monthly oil production for the battery/facility is determined based on metered deliveries out of the battery/facility and inventory change.
4) A proration factor is determined by dividing the actual battery/facility production by the estimated battery/facility production.
5) The proration factor is multiplied by the well’s estimated production to determine the well’s actual monthly production.

1.4. **Single Point Measurement Uncertainty**

“Single point measurement uncertainty” relates to the limits applicable to equipment and/or procedures used to determine a specific volume at a single measurement point. The oil volume determined during a 24-hour well test conducted on a well in a proration battery/facility is an example of a specific volume determination to which a single point measurement uncertainty limit would apply.

1.5. **Confidence Level**

The stated uncertainties are not absolute limits. The confidence level, which indicates the probability that true values will be within the stated range, is 95%. This implies that there is a 95% probability (or 19 chances in 20) that the true value will be within the stated range.

1.6. **Determination of Uncertainties**

The uncertainties referred to relate to the accuracies associated with measurement devices, device maintenance, sample gathering and analysis, variable operating conditions, etc. These uncertainties are for single-phase specific volume determination points of specific fluids (i.e., oil, condensate, gas, or water) or for combinations of two or more such points. These uncertainties do not relate to comparisons of two or more measurement points, such as comparison of inlet volumes to outlet volumes. Such comparisons are typically expressed as proration factors, allocation factors, or metering differences.

The uncertainties are relevant to equipment at the time of installation. No uncertainty adjustment is required to account for the effects of multiphase fluids, wear, sludge or scale buildup, etc., as it is accepted that such conditions would constitute a bias error to be monitored and accounted for through the use of proration factors, allocation factors, or metering differences.

The methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards (MPMS)*, Chapter 13, "Statistical Aspects of Measuring and Sampling" or in the latest edition of the International Organization for Standardization (*ISO) Glossary*, Standard 5168: *Measurement of Fluid Flow—Estimation of Uncertainty of a Flow-Rate Measurement*.

1.6.1. Sample Calculation

Determination of single point measurement uncertainty for well oil (proration battery/facility) using "root sum square" methodology:

For oil/emulsion measurement,

Oil meter uncertainty = 0.5% (typical manufacturer's specification)
Meter proving uncertainty = 1.5%
Sediments and water (S&W) determination uncertainty = 0.5%
Combined uncertainty = $\sqrt{[(0.5)^2 + (1.5)^2 + (0.5)^2]}$ = 1.66% (rounded to 2.0%)

For delivery point gas measurement,

Primary measurement device – gas meter uncertainty = 1.0%
Secondary device – (pulse counter or transducer, etc.) uncertainty = 0.5%
Secondary device calibration uncertainty = 0.5%
Tertiary device – (flow calculation, EFM, etc.) uncertainty = 0.2%

Gas sampling and analysis uncertainty = 1.5%

Combined uncertainty = $\sqrt{[(1.0)2 + (0.5)2 + (0.5)2 + (0.2)2 + (1.5)2]}$

= 1.95% (rounded to 2.0%)

1.7. Explanation of Standards of Accuracy

The following section explains standards of accuracy for oil, gas, and injection/disposal systems.

For further details pertaining to fluid deliveries involving Cross Border Measurement, refer to Chapter 7 Cross Border Measurement.

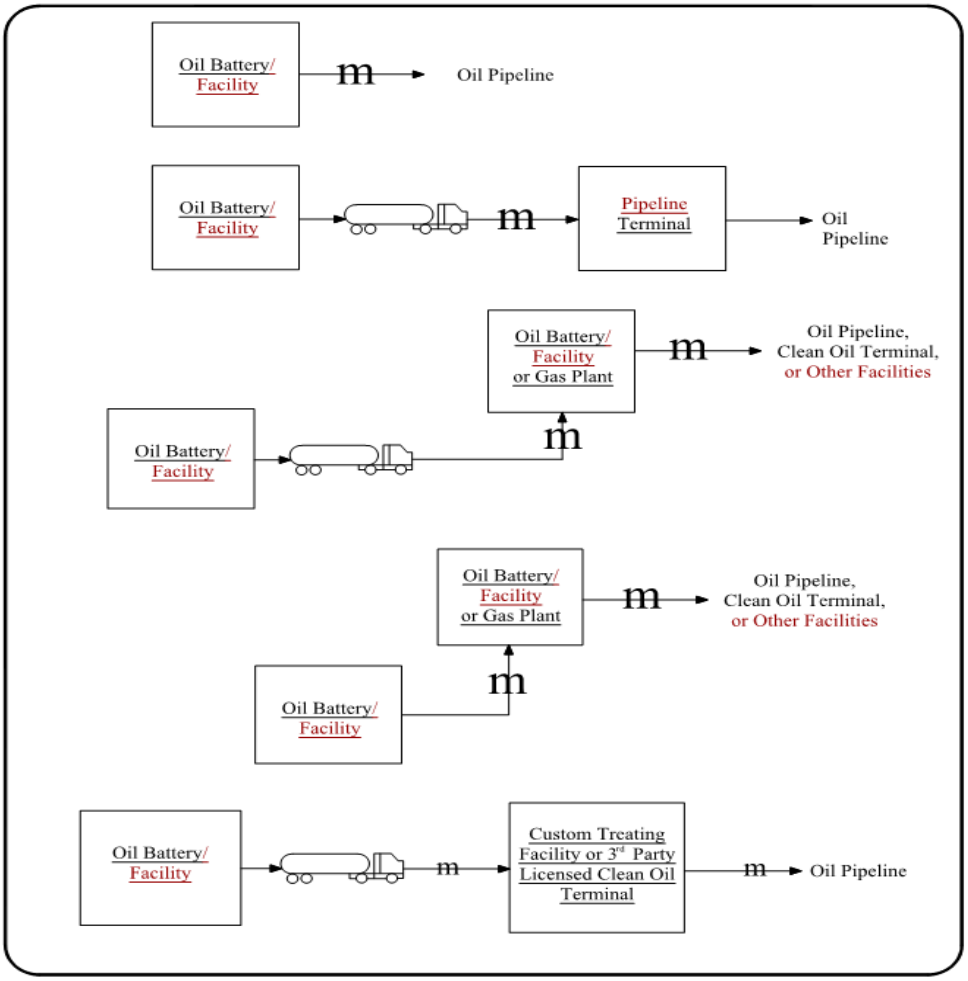
1.7.1. Oil Systems

1.7.1.1. Total Battery/Facility Oil (delivery point measurement), including Single-Well Batteries/Facilities.

For the schematic below:

m = single point measurement uncertainty
M = Maximum uncertainty of monthly volume

Figure 1.7-1 Total Battery / Facility Oil (Delivery Point Measurement)



Single point measurement uncertainty:

Delivery point measures greater than 100m³/d = 0.5%
Delivery point measures less than or equal to 100m³/d = 1%
Maximum uncertainty of monthly volume = N/A

The uncertainty of the monthly volume will vary, depending on the number of individual measurements that are combined to yield the total monthly volume.

The term "delivery point measurement" refers to the point at which the oil production from a battery/facility is metered. If clean oil is delivered directly into a pipeline system (Lease Automatic Custody Transfer [LACT] measurement) or trucked to a pipeline terminal, this point can also be referred to as the "custody transfer point". The "delivery point" terminology is from the perspective of the producing battery/facility, but the receiving battery/facility (pipeline, terminal, custom treating facility, other battery/facility, etc.) may refer to this point as their "receipt point". The oil volume determined at the delivery point is used in all subsequent transactions involving the oil from the battery/facility.

The measurement equipment and/or procedures must be capable of determining the oil volume within the stated uncertainties if clean oil is being metered.

If the oil volume delivered out of a battery/facility is included in an oil/water emulsion, the stated uncertainties apply to the total emulsion volume determination only. It is accepted that potential errors associated with obtaining and analyzing a representative emulsion sample may prevent the oil volume from being determined within the stated uncertainties.

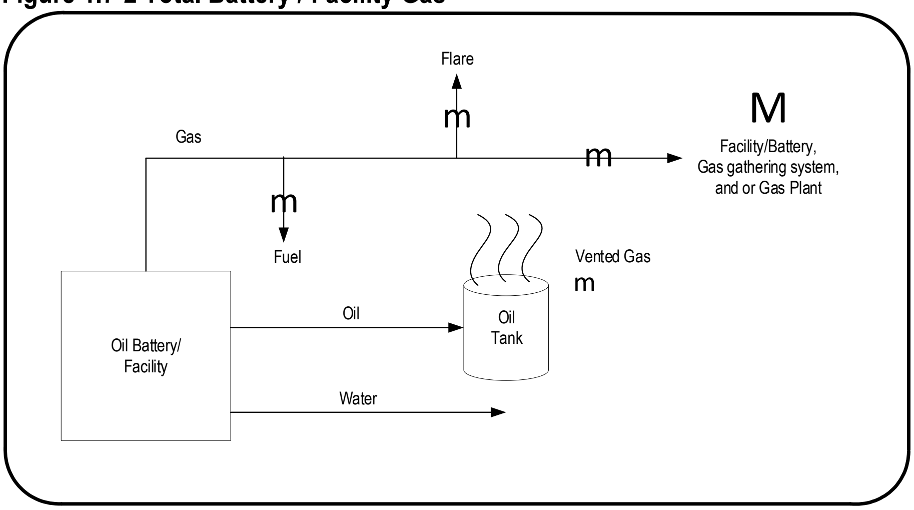
For facilities that receive oil volumes from other batteries/facilities totaling 100m3/d or less, the single point measurement uncertainty has been increased to allow for the economical handling of oil when minimal receipt volumes would not justify the added expense for improved measurement equipment and/or procedures.

1.7.1.2. **Total Battery / Facility Gas**

Includes gas that is vented, flared, or used as fuel, including single-well batteries/facilities also referred to as “associated gas”, as it is the gas produced in association with oil production at oil wells.

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-2 Total Battery / Facility Gas



Single point measurement uncertainty:
>$16.9e^3m^3/d$ = 3%
>$0.5e^3m^3/d$ but ≤$16.9e^3m^3/d$ = 3%
≤$0.5e^3m^3/d$ = 10%
Maximum uncertainty of monthly volume:
>$16.9e^3m^3/d$ = 5%
>$0.5e^3m^3/d$ but ≤$16.9e^3m^3/d$ = 10%
≤$0.5e^3m^3/d$ = 20%
Note that **M** is dependent on combined deliveries, fuel, flare, and vented gas measurement.
The maximum uncertainty of total monthly battery/facility gas volumes allows for reduced emphasis on accuracy as gas production rates decline. For gas rates up to $0.5e^3m^3/d$, the gas volumes may be determined by using estimates;

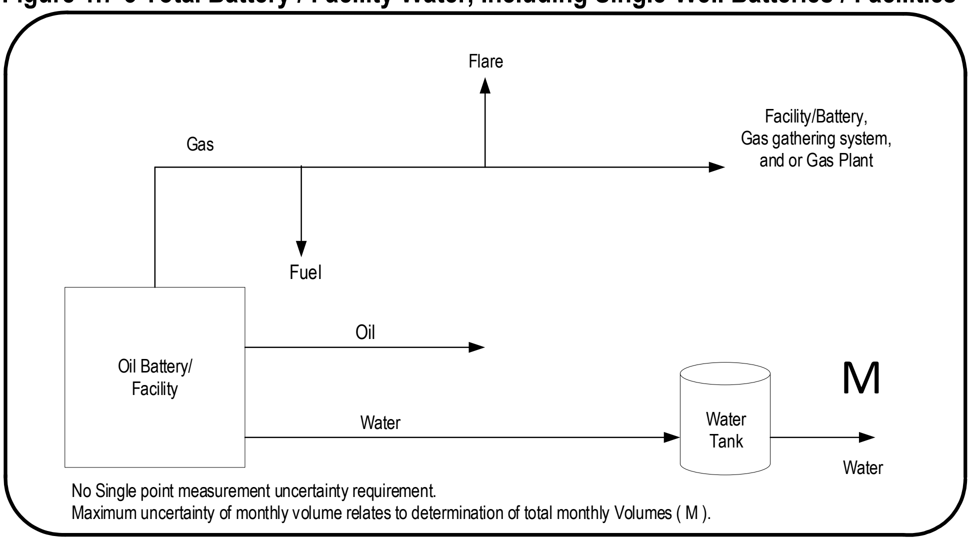
therefore, the maximum uncertainty of monthly volume is set at 20%. If gas rates exceed 0.5e^{3}m^3/d, the gas must be metered; however, a component of the total monthly gas volume may include estimates for low volumes of fuel, or vented or flare gas that may add to the monthly uncertainty. At the highest gas production rates, it is expected the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured gas volumes (when measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Because of the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes where rates do not exceed 0.5e^{3}m^3/d are expected to be capable of meeting a 10% single point measurement uncertainty.

1.7.1.3. **Total Battery / Facility Water, including Single-Well Batteries / Facilities**

For the schematic below:
M = maximum uncertainty of monthly volume

Figure 1.7-3 Total Battery / Facility Water, Including Single-Well Batteries / Facilities



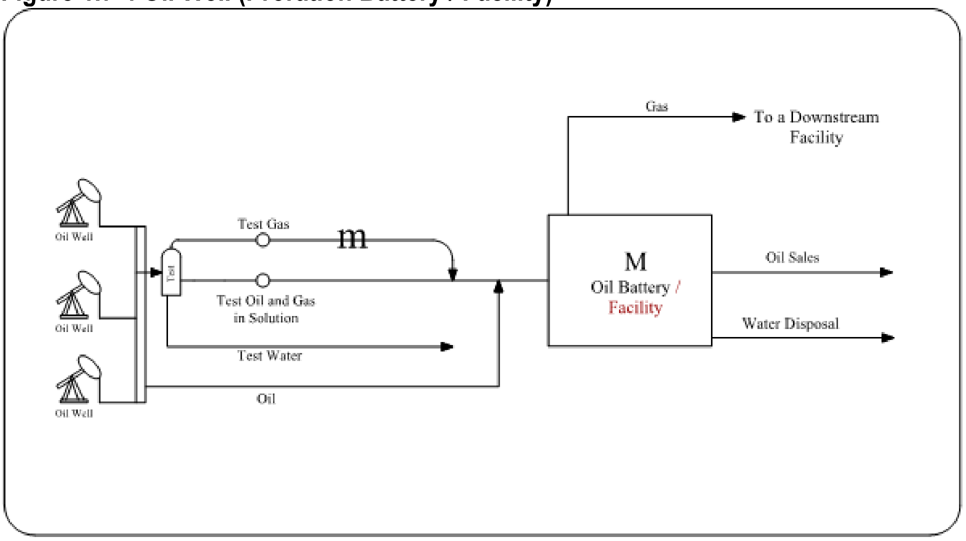
Maximum uncertainty of monthly volume:
>50m^3/month = 5%
≤50m^3/month = 20%
Single point measurement uncertainty = N/A
Total battery/facility water may be determined by measurement or estimation, depending on production rates, so no basic requirement has been set for single point measurement uncertainty.

Total battery/facility water production volumes not exceeding 50m^3/month may be determined by estimation; therefore, the maximum uncertainty of monthly volume is set at 20%.
If the total battery/facility water production volumes exceed 50m^3/month, the water must be separated from the oil and metered; therefore, the maximum uncertainty of monthly volume is set at 5%.

1.7.1.4. **Well Oil (Proration Battery / Facility)**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-4 Oil Well (Proration Battery / Facility)



Single point measurement uncertainty:
All classes = 2%
Maximum uncertainty of monthly volume:
High >30m³/d = 5%
Medium >6m³/d but ≤30m³/d = 10%
Low >2m³/d but ≤6m³/d = 20%
Stripper ≤2m³/d = 40%

M is dependent on oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly well oil production volumes for light and medium density oil wells in proration batteries/facilities has been developed to allow for reduced emphasis on accuracy as oil production rates decline. Rather than being determined by continuous measurement, monthly well oil production volumes are estimated from well tests and corrected by the use of proration factors to result in “actual” volumes. Two factors contribute to a reduced certainty that the reported monthly oil production volume will be accurate: lower rate wells are allowed reduced testing frequencies and wells may exhibit erratic production rates between tests.

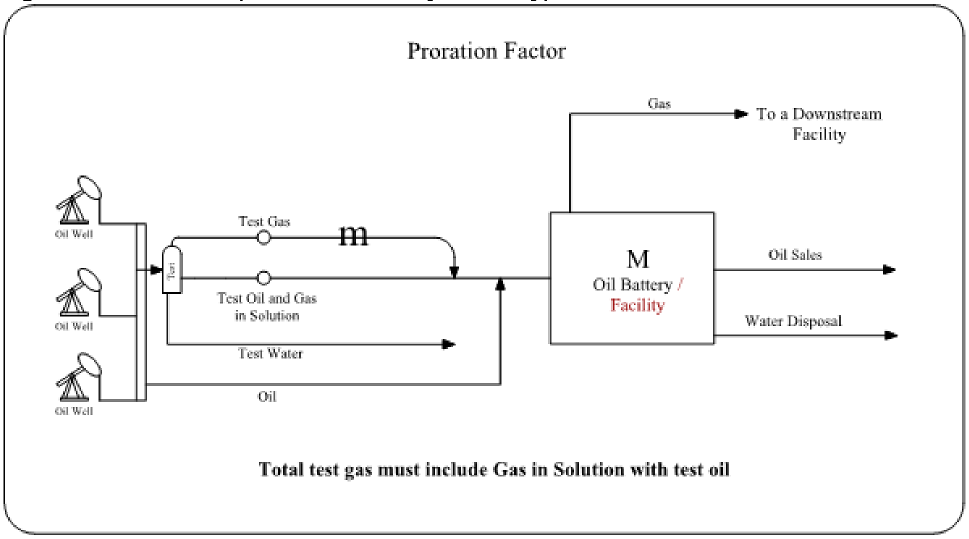
The equipment and/or procedures used to determine oil volumes during the well tests must be capable of meeting a 2% single point measurement uncertainty for all classes of wells.

1.7.1.5. **Well Gas (Proration Battery / Facility)**

Oil well’s “well gas” production is also referred to as “solution or associated gas” because it is the gas produced in association with oil production at oil wells.

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-5 Oil Well (Proration Battery / Facility)



Single point measurement uncertainty
>16.9e³m³/d = 3%
>0.5e³m³/d but ≤16.9e³m³/d = 3%
≤0.5e³m³/d = 10%

Maximum uncertainty of monthly volume:
>16.9e³m/d = 5%
>0.5e³m³/d but ≤16.9e³m³/d = 10%
≤0.5e³m³/d = 20%

M is dependent on oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly oil well gas volumes has been developed to allow for reduced emphasis on accuracy as gas production rates decline. Rather than being determined by continuous measurement, monthly oil well gas production volumes are estimated from well tests and corrected by the use of proration factors to result in “actual” volumes. Two factors contribute to a reduced certainty that the reported monthly oil production volume will be accurate: lower rate wells are allowed reduced testing frequencies and wells may exhibit erratic production rates between tests.

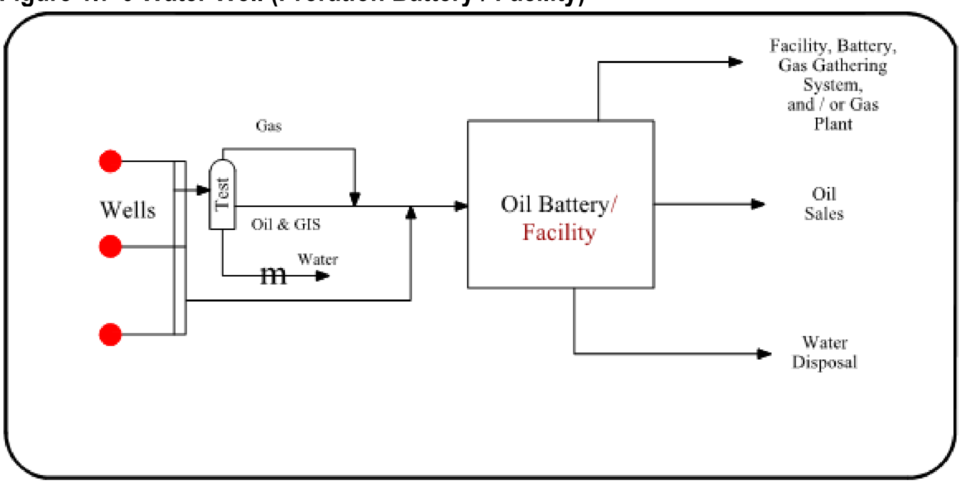
For gas rates up to 0.5e³m³/d, the well test gas volume may be determined by using estimates; therefore, the maximum uncertainty of monthly volume is set at 20%. If gas rates exceed 0.5e³m³/d, the test gas must be metered, however a component of a well's total test gas volume may include estimates for solution gas dissolved in the test oil volume (gas-in-solution), which may add to the monthly uncertainty. At the highest gas production rates, it is expected that the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured test gas volumes (if measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Because of the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed 0.5e³m³/d are expected to be capable of meeting a 10% single point measurement uncertainty.

1.7.1.6. **Well Water (Proration Battery / Facility)**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-6 Water Well (Proration Battery / Facility)



Single point measurement uncertainty = 10%
Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending on the method used to determine test water rates and the frequency of well tests.

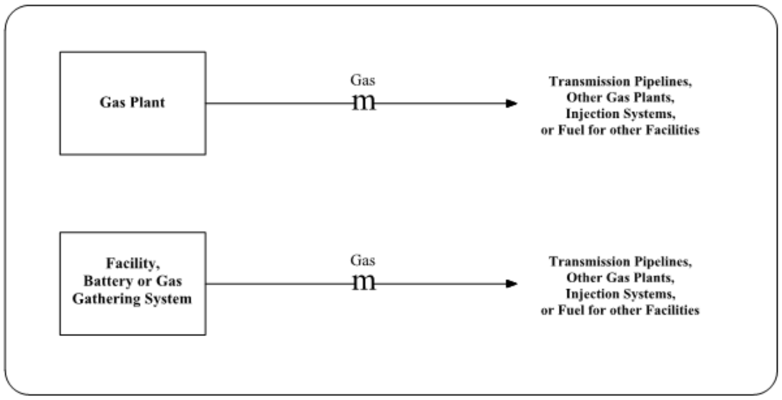
Rather than being determined by continuous measurement, monthly oil well water production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. The water rates determined during the well tests may be inferred from determining the water content of emulsion samples, and in some cases, estimates may be used to determine water rates. Therefore, the single point measurement uncertainty is set at 10%.

1.7.2. Gas Systems

1.7.2.1. Gas Deliveries

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-7 Gas Deliveries (Sales Gas)



Single point measurement uncertainty = 2%
Maximum uncertainty of monthly volume = N/A

The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Gas deliveries in this context will typically be clean, processed sales gas that is delivered out of a gas plant or gas battery/facility into a transmission pipeline. The measurement at this point determines the gas volumes on which royalties will be based. Therefore, a stringent expectation is set for the single point measurement uncertainty.

In some cases, this type of gas may be delivered to other plants for further processing or to injection facilities; thus delivery point measurements are required at the following locations:

a. gas plant dispositions.

b. sales to downstream – TC Energy, ATCO Gas, etc.

c. purchase from downstream facilities – co-ops, ATCO Gas, TC Energy, etc.

d. gas delivered from one upstream battery/facility to another that is not tied to the same system for FUEL, such as from a gas battery/facility to an oil battery/facility.

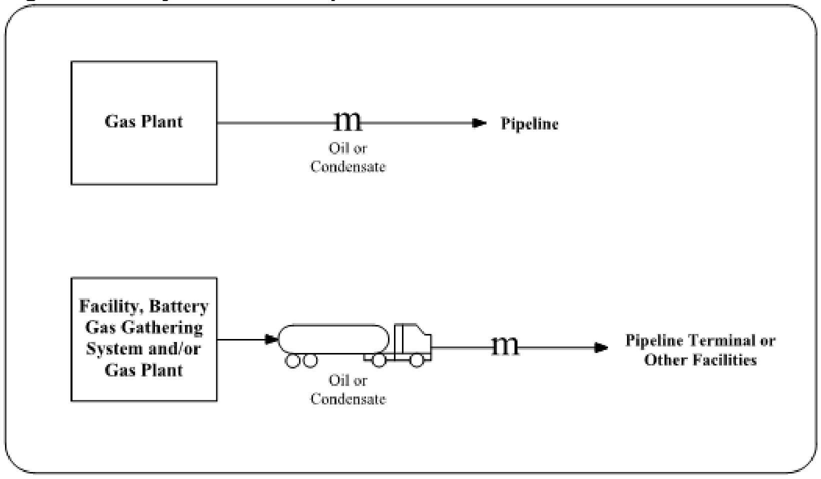
e. condensate disposition to an oil battery/facility or for sales.

Excluded: Return fuel to the original source battery/facility after the gas has been sweetened.

1.7.2.2. **Hydrocarbon Liquid Deliveries**

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-8 Hydrocarbon Liquid Deliveries



Single point measurement uncertainty:
Delivery point measures >100m^3/d = 0.5%
Delivery point measures ≤100m^3/d = 1%
Maximum uncertainty of monthly volume = N/A

The uncertainty of the monthly volume will vary, depending on the number of individual measurements that are combined to yield the total monthly volume. The term “delivery point measurement” refers to the point at which the hydrocarbon liquid production from a battery/facility is metered. The point at which clean hydrocarbon liquids are delivered directly into a pipeline system (Lease Automatic Custody Transfer [LACT] measurement) or trucked to a pipeline terminal can also be referred to as the “custody transfer point”. The “delivery point” terminology is from the perspective of the producing battery/facility, but the receiving battery/facility (pipeline, terminal, custom treating facility, other battery/facility, etc.) may refer to this point as its “receipt point”. The hydrocarbon liquid volume determined at the delivery point is used in all subsequent transactions involving that liquid.

Hydrocarbon liquids delivered out of a gas system at the well, battery/facility, or plant inlet levels are typically condensate, and in some cases, they may be considered to be oil. The hydrocarbon liquids delivered out of a gas plant may be pentanes plus, butane, propane, ethane, or a mixture of various (NGL/LPG) components. The volumes determined at this point are the volumes on which royalties are based.

The measurement equipment and/or procedures must be capable of determining the hydrocarbon liquid volume within the stated limits.

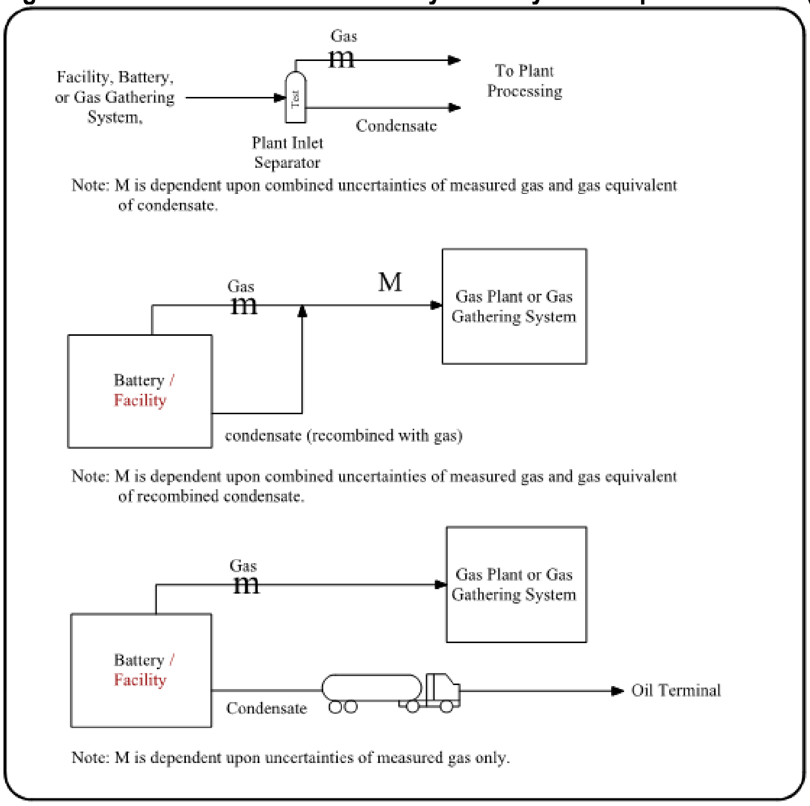
For facilities where the hydrocarbon liquid delivery volumes total ≤100m^3/d, the single point measurement uncertainty has been increased to allow for the economical handling of hydrocarbon liquids when minimal volumes would not justify the added expense for improved measurement equipment and/or procedures.

Another component of determining the total battery/facility hydrocarbon liquid volume may be the determination of monthly inventory changes. The gross monthly opening and closing inventory volumes must be measured using equipment and/or procedures that would provide no more than the allowed uncertainty stipulated for the hydrocarbon liquid deliveries out of the battery/facility. This does not include uncertainties for basic sediments and water (S&W) determination or temperature correction, which may or may not be required in a specific situation.

1.7.2.3. **Plant Inlet, Total Battery / Facility Group Gas**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-9 Plant Inlet or Total Battery / Facility or Group Condensate (Recombined)



Single point measurement uncertainty = 3%
Maximum uncertainty of monthly volume = 5%

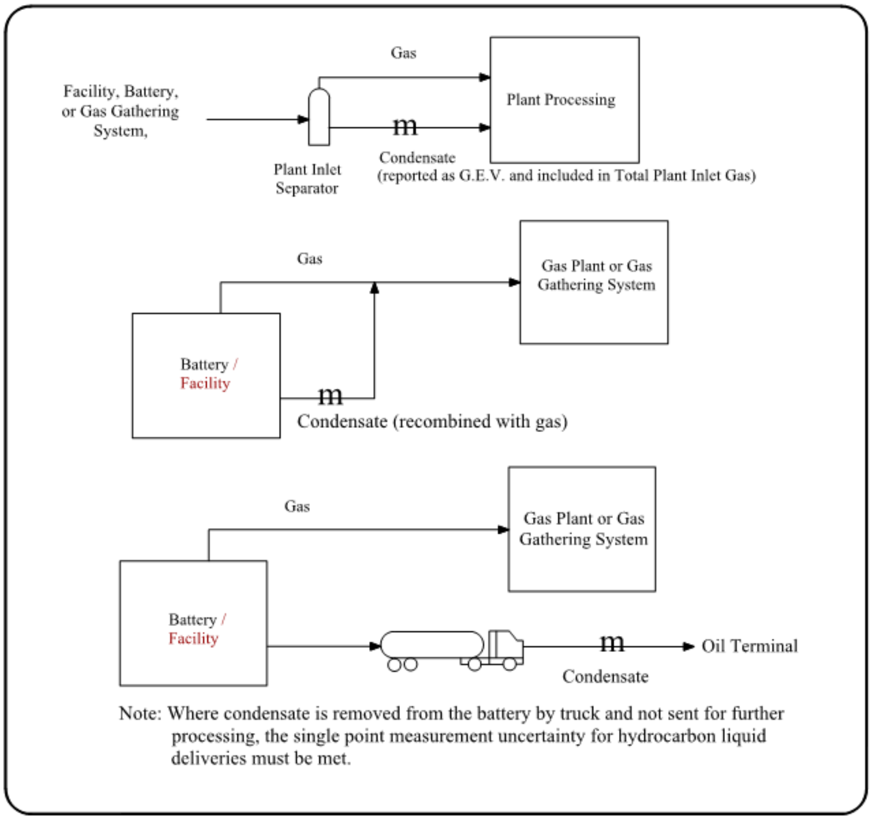
Plant inlet gas or total battery/facility or group gas is typically unprocessed gas that may vary in composition and may contain entrained liquids. The total reported gas volume could result from combining several measured volumes from various points and may also include the calculated gas equivalent volume of entrained hydrocarbon liquids (typically condensate). The expectation for the maximum uncertainty of monthly volume is set at 5% to allow for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the measured gas volumes must be capable of meeting a 3% single point measurement uncertainty.

1.7.2.4. **Plant Inlet, Total Battery / Facility Group Condensate (recombined)**

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-10 Plant Inlet or Total Battery / Facility or Group Condensate (Recombined)



Single point measurement uncertainty = 2%
Maximum uncertainty of monthly volume = N/A

The condensate volume is included in the total gas volume for reporting purposes and is therefore covered by the maximum uncertainty of monthly volume for the plant inlet, total battery/facility group gas. Plant inlet condensate is typically separated from the inlet stream and sent through the plant for further processing. For reporting purposes, the gas equivalent of the plant inlet condensate is included in the total plant inlet gas volume. If total battery/facility or group condensate upstream of the plant inlet is separated and metered prior to being recombined with the gas production, the condensate is converted to a gas equivalent volume and included in the gas production volume. In either case, the condensate single point measurement uncertainty is set at 2% for the liquid volume determination.

Note that if plant inlet or total battery/facility or group condensate is separated and delivered out of the system at that point, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries (see above).

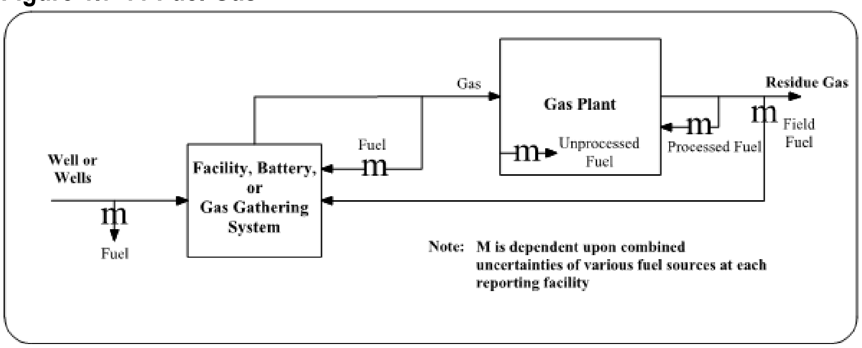
1.7.2.5. **Fuel Gas**

Fuel gas: Gas that is combusted and the released energy is used in upstream oil and gas operations. Types of gas that must be reported as fuel gas include gas burned by the following:

a) engines,
b) catalytic heaters and other building heaters,
c) process vessel burners,
d) sulphur recovery unit reaction furnaces,
e) line heaters, and
f) thermoelectric generators

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-11 Fuel Gas



Single point measurement uncertainty:
>0.5e³m³/d = 3%
≤0.5e³m³/d = 10%

Maximum uncertainty of monthly volume:
>0.5e³m³/d = 5%
≤0.5e³m³/d = 20%

The maximum uncertainty of monthly fuel gas volumes allows for reduced emphasis on accuracy as gas flow rates decline for all upstream oil and gas facility locations such as well sites, multi-well sites, batteries, compressor sites, or gas plants, if the annual average fuel gas rate is 0.5e³m³/d or less on a per-site basis, the gas volume may be determined by using estimates. Therefore, the maximum uncertainty of the monthly volume is set at 20.0%. If the annual average fuel gas rates exceed 0.5e³m³/d on any location, the gas must be metered, but since the gas being used as fuel may be unprocessed gas and part of the total fuel gas volume may include some estimated volumes (up to 0.5e³m³/d), the maximum uncertainty of the monthly volume is set at 5.0% to allow for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the measured gas volumes (if measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Because of the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed $0.5e^3m^3/d$ are expected to be capable of meeting a 10% single point measurement uncertainty.

Permit holders must report fuel/vent/flare volumes in Petrinex where the activity occurred for all reporting facilities, and for all non-reporting facilities. Fuel/vent/flare volumes for non-reporting facilities such as compressor stations must be reported at the appropriate battery or gathering system.

1.7.2.6. **Flare / Vent Gas**

Flare gas: Gas that is combusted in a flare or incinerator at upstream oil and gas operations. Types of gas, if combusted in a flare or incinerator (including an enclosed combustor), that must be reported as flare gas include the following:

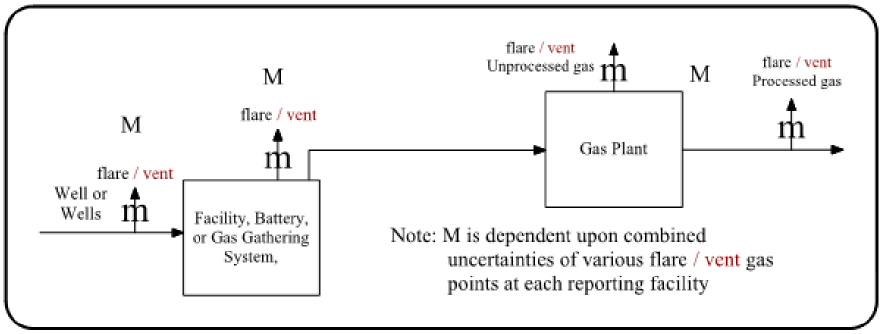
a) waste gas;
b) pilot gas;
c) dilution and makeup gas added to a flare gas stream before flaring or incineration;
d) acid gas (routine and non-routine);
e) blanket gas, purge gas, and sweep gas;
f) gas used to operate pneumatic devices (instruments, pumps, and compressors starters);
g) gas from dehydrator still columns;
h) gas produced during well completions;
i) gas produced during well unloading operations; and

Vent gas: Un-combusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas does not include fugitive emissions, but does include:

a) waste gas;
b) gas used to operate pneumatic devices;
c) gas from compressor seals, starters, and blowdowns;
d) gas from facility upsets and emergency shutdowns;
e) gas from dehydrator still columns;
f) gas from production tanks, not including methanol and chemical tanks;
g) gas released during pigging operations;
h) gas produced during well completions;
i) gas produced during well unloading volumes; and
j) blanket gas

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-12 Flare / Vent Gas



Single point measurement uncertainty = 5%
Maximum uncertainty of monthly volume = 20%

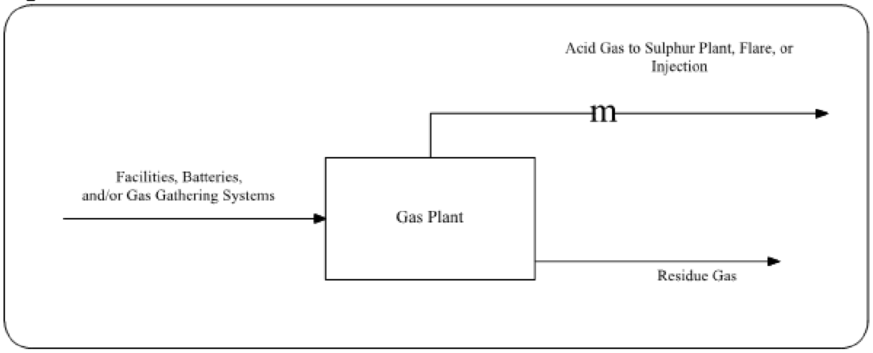
Flare pilot and purge gas must be reported as flared gas. The supply may be taken off upstream of the battery/facility fuel gas meter, separately metered or estimated, and reported. If it is taken off downstream of the battery/facility fuel gas meter it must be separately metered or estimated and the fuel gas volume reported must be corrected by subtracting the purge and pilot gas volumes. Continuous or intermittent flared streams (excluding purge and pilot gas) at oil and gas production and processing facilities, where the annual average of the total flared volumes per battery/facility exceeds 0.5e3m3/d, must be metered. If flaring or venting is infrequent. the flare/vent volumes must be estimated and reported. Vent sources such as compressor distance pieces, pump drives, valve controllers, and production tanks may be estimated. Therefore, the maximum uncertainty of the monthly volume is set at 20%, to allow for the erratic conditions associated with flare/vent measurement.

The equipment and/or procedures used to determine the metered gas volumes (not an estimate), must be capable of meeting a 5% single point measurement uncertainty.

1.7.2.7. **Acid Gas**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-13 Acid Gas



Single point measurement uncertainty = 10% for low pressure acid gas before compression, and = 3.0% after compression.
Maximum uncertainty of monthly volume = N/A

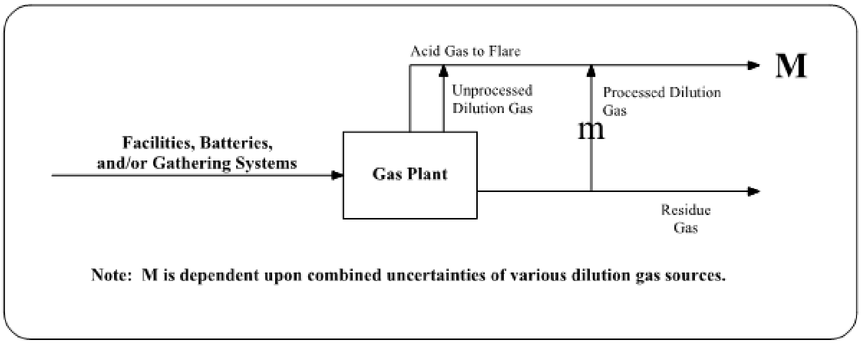
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Acid gas usually contains a great deal of water vapour and has other conditions associated with it, such as very low pressure, which affect measurement accuracy. Therefore, the single point measurement uncertainty is set at 10%. When the acid gas is compressed and then injected into a well, the single point measurement uncertainty is set at 3.0%.

1.7.2.8. **Dilution Gas**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-14 Dilution Gas



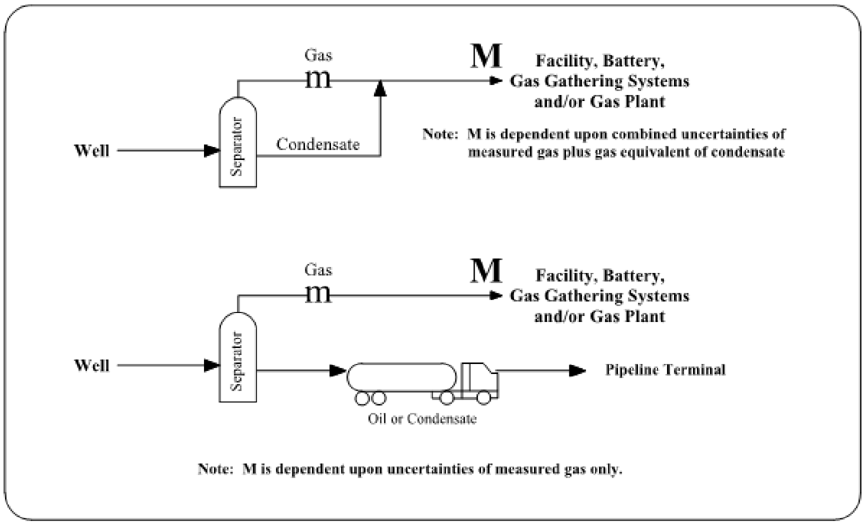
Single point measurement uncertainty = 3%
Maximum uncertainty of monthly volume = 5%

Dilution gas is typically gas used to provide adequate fuel for incineration or flaring of acid gas. In acid gas applications, dilution gas and pilot gas for incineration must be reported as flared gas and not as fuel gas Since it must be measured, it is subject to the same uncertainties as those for fuel gas that must be determined by measurement, as stated in section 1.7.2.5 above.

1.7.2.9. **Well Gas (well site separation)**

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-15 Gas Well (Well-Site Separation)



Single point measurement uncertainty = 3%
Maximum uncertainty of monthly volume:
>16.9e^{3}m^3/d = 5%
≤16.9e^{3}m^3/d = 10%

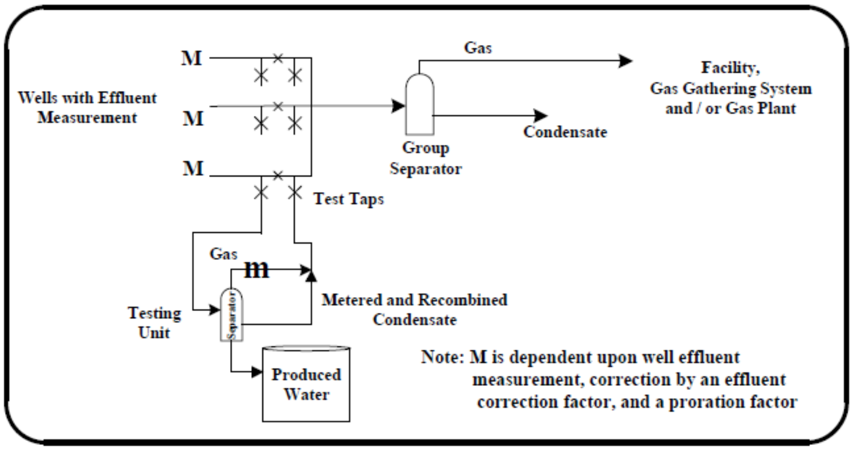
If production components from gas wells are separated and continuously metered, the maximum uncertainty of monthly well gas volumes allows for reduced emphasis on accuracy as gas production rates decline. Since the separated gas is unprocessed and may still contain entrained liquids at the measurement point and a component of the total reported well gas production may include the calculated gas equivalent volume of the well's condensate production, the maximum uncertainty of monthly volumes also allows for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the separated metered well gas volumes must be capable of meeting a 3% single point measurement uncertainty.

1.7.2.10. Well Gas (effluent proration battery/facility)

For the schematic below:
m = single point measurement uncertainty
M = maximum uncertainty of monthly volume

Figure 1.7-16 Well Gas (Effluent Proration Battery / Facility)



Single point measurement uncertainty = 3%
Maximum uncertainty of monthly volume = 15%

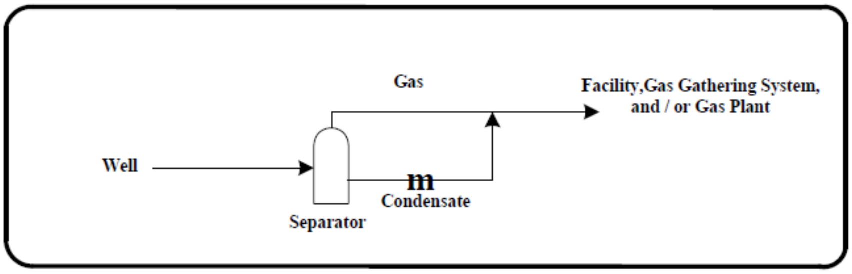
If production components from gas wells are not separated and continuously metered, the gas wells are subject to a proration accounting system. “Wet” gas wells have continuous effluent measurement, and the “actual” production is prorated based on the measurement of group gas and liquid components following separation at a central location. The maximum uncertainty of the monthly well gas volume is set at 15% to allow for the inaccuracies associated with these types of measurement systems.

The equipment and/or procedures used to determine the metered well test gas volumes downstream of separation during effluent meter correction factor tests or during the periodic dry gas well tests must be capable of meeting a 3% single point measurement uncertainty.

1.7.2.11. **Well Condensate (recombined)**

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-17 Well Condensate (Recombined)



Single point measurement uncertainty = 2%
Maximum uncertainty of monthly volume = N/A

The gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes and is therefore covered by the monthly uncertainty for the well gas.

If condensate produced by a gas well is separated and metered at the wellhead prior to being recombined with the gas production, the volume of the condensate is mathematically converted to a gas equivalent volume and added to the well gas production volume. In this case, the condensate single point measurement uncertainty is set at 2% for the liquid volume determination. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

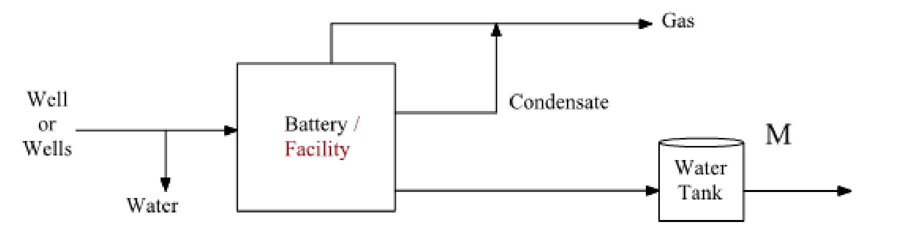
In the case of a gas well subject to effluent measurement, the gas equivalent of the condensate volume is included in the well's total gas production volume. The liquid volume determination, which is done during the effluent meter correction factor test, is subject to a single point measurement uncertainty of 2%. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

Note that if condensate produced by a gas well is separated at the wellhead and delivered out of the system at that point, the condensate is reported as a liquid volume. In this case, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries.

1.7.2.12. **Total Battery / Facility Water**

For the schematic below:
M = maximum uncertainty of monthly volume

Figure 1.7-18 Total Battery / Facility Water



Note: Total battery / facility water may be the water separated at the battery / facility, the sum of the water separated at the wells or a combination. M is dependent upon the method used to determine the total water volume.

Maximum uncertainty of monthly volume = 5%
Single point measurement uncertainty = N/A

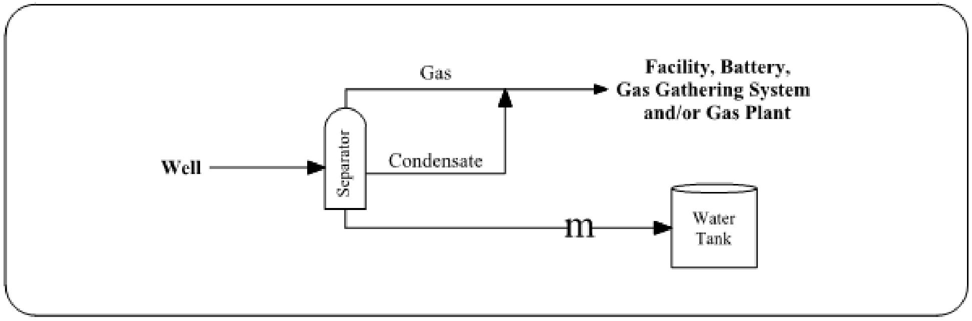
Total battery/facility water may be determined by an individual group measurement, that is, by totaling individual well measurements; therefore, no basic requirement for measurement uncertainty has been set.

Total battery/facility water in a gas system may be collected at a central location where it can be metered prior to disposal. Alternatively, the total battery/facility water may be a summation of individual well estimates or measurements of water collected at well sites and disposed from those sites. The 5% maximum uncertainty of monthly volume allows for some leeway in volume determination.

1.7.2.12.1. Well Water

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-19 Well Water



Single point measurement uncertainty = 10%
Maximum uncertainty of monthly volume = N/A

The uncertainty of the monthly volume will vary, depending on whether produced volumes are subject to individual well measurement, estimation, or proration.

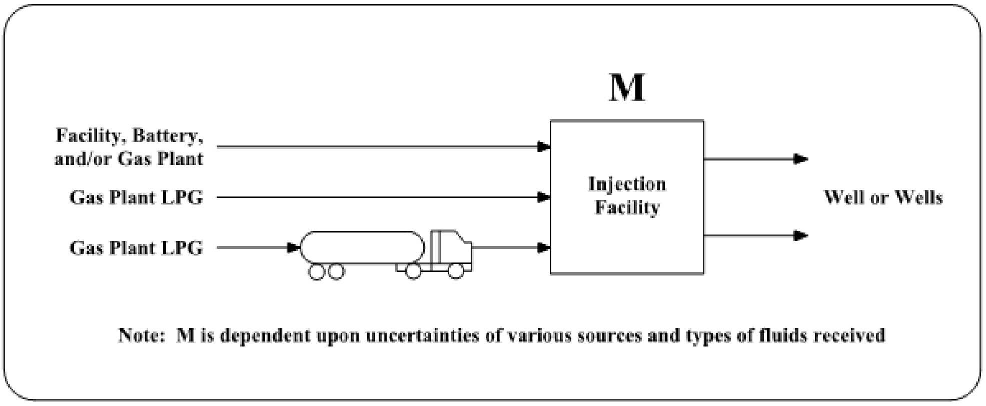
Water production at gas wells may be determined by measurement after separation, or, if separators are not used, water production may be determined by using water-gas ratios determined from engineering calculations or semi-annual tests. To allow for the various methods used to determine production volumes, the single point measurement uncertainty is set at 10%.

1.7.3. Injection/Disposal Systems

1.7.3.1. Total Gas

For the schematic below:
M = Maximum uncertainty of monthly volume

Figure 1.7-20 Total Gas



Maximum uncertainty of monthly volume = 5%
Single point measurement uncertainty = N/A

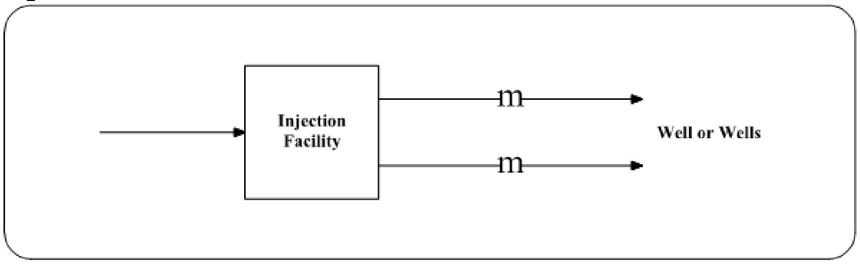
The single point measurement uncertainty will vary depending on the source and type of fluids received.

Gas used in injection/disposal systems may be clean processed gas or unprocessed gas that may contain entrained liquids, and in some cases, several sources may make up the total gas volume received by an injection system. The expectation for the maximum uncertainty of monthly volume is set at 5% to allow for the uncertainties associated with measuring gas under those conditions.

1.7.3.2. **Well Gas**

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-21 Well Gas



Single point measurement uncertainty = 3%
Maximum uncertainty of monthly volume = N/A

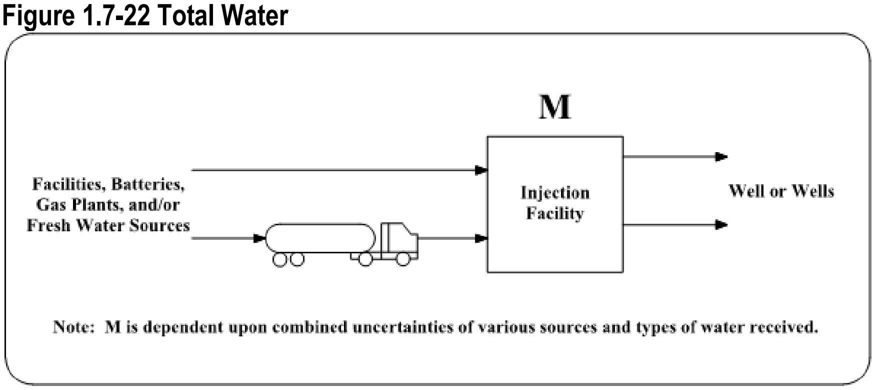
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The gas injected/disposed into each well must be metered and may consist of clean processed gas and/or unprocessed gas that may contain entrained liquids. The equipment and/or procedures used to determine the gas volumes injected/disposed into each well must be capable of meeting a 3% single point measurement uncertainty.

1.7.3.3. **Total Water**

For the schematic below:
M = maximum uncertainty of monthly volume

Figure 1.7-22 Total Water



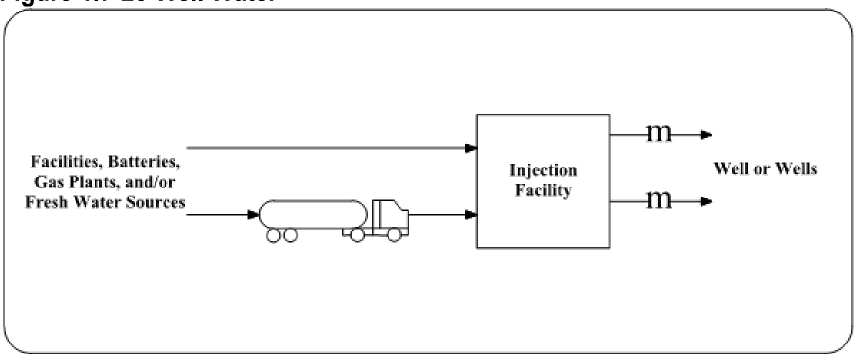
Maximum uncertainty of monthly volume = 5%
Single point measurement uncertainty = N/A

Water used in injection/disposal systems may be produced water from oil or gas batteries/facilities, fresh water from water source wells, and/or wastewater. To be equivalent to the requirements for total oil and gas battery/facility water, the expectation for the maximum uncertainty of monthly volume is set at 5%.

1.7.3.4. **Well Water**

For the schematic below:
m = single point measurement uncertainty

Figure 1.7-23 Well Water



Single point measurement uncertainty = 5%
Maximum uncertainty of monthly volume = N/A

The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The water injected/disposed into each well must be metered. The expectation for the single point measurement uncertainty is set at 5%.

1.8. Standards of Accuracy – Summary

The following summary tables cover oil systems, gas systems, and injection systems.

Table 1.8-1 Measurement Uncertainty - Oil Systems

	Maximum Uncertainty of Monthly Volume	Single Point Measurement Uncertainty
1) Total Battery/Facility Oil (Delivery Point Measurement)		
Delivery point measures >100m³/d	NA	0.5%
Delivery point measures ≤100m³/d	N/A	1%
2) Total Battery/Facility Gas (Includes produced gas that is vented, flared, or used as fuel)		
>16.9e³m³/d	5%	3%
>0.5e³m³/d but <16.9e³m³	10%	3%
≤0.5e³m³/d	20%	10%
3) Total Battery/Facility Water		
>50m³/month	5%	N/A
≤50m³/month	20%	N/A
4) Well Oil (proration battery/facility)		
High >30m³/d	5%	2%
Medium >6m³/d but <30m³/d	10%	2%
Low >2m³/d but ≤6 m³/d	20%	2%
Stripper ≤2m³/d	40%	2%
5) Well Gas (proration battery/facility)		
>16.9e³m³/d	5%	3%
>0.5e³m³/d but ≤16.9e³m³/d	10%	3%
≤ 0.5e³m³/d	20%	10%
6) Well Water	N/A	10%

Table 1.8-2 Measurement Uncertainty - Gas Systems

	Maximum Uncertainty of Monthly Volume	Single Point Measurement Uncertainty
1) Gas Deliveries (sales gas)	N/A	2 %
2) Hydrocarbon Liquid Deliveries		
Delivery point measures >100m^3/d	N/A	0.5 %
Delivery point measures ≤100m^3/d	N/A	1%
3) Plant Inlet or Total Battery/Facility Group Gas	5%	3%
4) Plant Inlet or Total Battery/Facility Group Condensate (recombined)	N/A	2%
5) Fuel Gas		
>0.5e^3m^3/d	5%	3%
≤0.5e^3m^3/d	20%	10%
6) Flare and Vent Gas	20%	5%
7) Acid Gas		
Before compression	N/A	10%
After compression	N/A	3%
8) Dilution Gas	5%	3%
9) Well Gas (well site separation)		
>16.9e^3m^3/d	5%	3%
≤16.9e^3m^3/d	10%	3%
10) Well Gas (proration battery/facility)	15%	3%
11) Well Condensate (recombined)	N/A	2%
12) Total Battery/Facility Water	5%	N/A
13) Well Water	N/A	10%

Table 1.8-3 Measurement Uncertainty - Injection Systems

	Maximum Uncertainty of Monthly Volume	Single Point Measurement Uncertainty
1) Total Gas	5 %	N/A
2) Well Gas	N/A	3%
3) Total Water	5%	N/A
4) Well Water	N/A	5%

1.9. Measurement Schematics

This section presents the requirements for measurement schematics used for measurement, accounting, and reporting of oil and gas facilities. Measurement schematics are required to ensure measurement, accounting, and reporting compliance and is a visual tool showing the current physical layout of the battery/facility. A facility permit holder must maintain up-to-date metering schematics - see Drilling Production Regulation 78(1). Schematics should be regularly reviewed and used by groups such as operations, engineering, and accounting to ensure a common understanding. A facility's reporting configuration in the production accounting system must be consistent with the facility's measurement schematic and be based on the physical flow of fluids through the facility. For the purpose of this manual, process flow diagrams (PFD), and piping and instrumentation diagrams (P&ID), are not considered measurement schematics.

Definitions:

Process flow diagram — A PFD is a diagram commonly used in chemical and process engineering to indicate the general flow of plant processes and equipment, including:

a) process piping, major bypass, and recirculation lines.

b) major equipment symbols, names, and identification numbers.

c) flow directions.

d) control loops that affect operation of the system.

e) interconnection with other systems.

f) system ratings and operational values as minimum, normal, and maximum flow; temperature; and pressure.

g) composition of fluids.

Piping and instrumentation diagram — A schematic diagram showing piping, equipment, and instrumentation connections within process units.

Measurement schematic — A diagram used to show the physical layout of facilities that traces the normal flow of production from left to right as it moves from wellhead through to sales. A schematic must include the elements identified in section.

Gas Gathering Schematic — A line diagram showing the delineation of facilities and the connectivity of wells to compressors, gathering systems, batteries/facilities, and/or gas plants.

Equipment, vessels, meters, and sample points are typically not shown on gas gathering schematics. A gas gathering schematic contains:

a. well location by unique well identifier (UWI).

b. producing company, battery facility codes

c. well type (oil or gas), and if gas, wet or dry metered.

d. compressors complete with legal survey location (LSL).

e. final destination – battery/facility, plant, etc.

f. direction of flow for all metered fluids.

1.9.1. **Measurement Schematics Requirements**

The operator responsible for submitting volumes into Petrinex is responsible for creating, confirming, and revising any measurement schematics. The schematics must be used by the Permit Holder operations and production accounting to ensure that the reported volumes follow the BCER reporting and licensing requirements. How the required information below is shown on a measurement schematic is up to the operator to decide, as long as the schematic is clear, and comprehensive.

The measurement schematic can be stored electronically or in hard-copy format. A master copy of the measurement schematic must be retained at a central location and previous versions must be stored for a minimum of 72 months.

1.9.1.1. **General Content Requirements**

1) The general requirements of a measurement schematic include the following:

   a. Battery/Facility name, battery/facility permit holder name, and operator name if different.

   b. LSL of the surface battery/facility and UWI, including downhole location if different.

   c. Battery/Facility boundaries between each reporting battery/facility with associated BCER facility (FAC) and Petrinex Identifier codes. For larger facilities, an optional gas gathering schematic may be used to show battery/facility delineation (See Appendix–D Schematic Example for an example).

   d. Flow lines with flow direction that move fluids in and out of the battery/facility(s) and those that connect the essential process equipment within the battery/facility, including recycle lines and bypasses to measurement equipment. Identify if oil is tied into a gas system.

   e. Flow split or diversion points (headers) with LSL if not on a well or battery/facility lease site.

   f. Process equipment that changes the state or composition of the fluid(s) within the battery/facility, such as separators, treaters, dehydrators, compressors, sweetening and refrigeration units, etc.

   g. All measurement points, storage tanks, or vessels that are used for estimating, accounting, and reporting purposes, including - types of measurement (meter, weigh scale, or gauge).

      i. type of instrumentation (charts, EFM, or readouts).

      ii. type of meter(s) if applicable.

      iii. testing or proving taps required by the BCER.

   h. Fuel, flare, or vent take-off points – defaults to estimate if a meter is not shown.

   i. Energy source (gas, propane, electricity) used for equipment if not measured or estimated as part of total site fuel.

   j. Permanent flare points.

k. Fresh water sources, such as lakes and rivers UWIs and LSLs must be in a delimited format, such as 100/16-06-056-02W5/02 and 16-06-056-02W5, respectively. Multiple facilities can be on the same page and a typical schematic may be used for wells or facilities with the same measurement configuration. Additional information required on the schematic, as well as exceptions, is set out below.

2) Well detail indicated on a schematic must include the following:

   a. All producing wells indicating:

      i. water source, injection/disposal, and shut-in wells.

      ii. reporting event for wells with downhole commingled zones.

      iii. Split well production events being reported.

   b. Identify if artificial lift is utilized, such as plunger lift, pump jack, etc. Suspended wells are optional; if shown, identify them as suspended.

   c. Include normally closed valves that can change production flow.

   d. For compressors, identify if electric or gas drive. If gas drive, then the HP or KW rating is required unless fuel gas is measured as part of total fuel within a battery/facility. Some Cross Border facilities may be required to measure fuel for some compressors individually.

   e. Normally open valves, such as emergency shutdown valves (ESDs), pressure control valves (PCVs), and block valves, are not required as they can be considered default flow.

   f. Pressure safety valves (PSV) are not required measurement points.

   g. Identify non-reporting meters if shown.

   h. Originating battery/facility ID or UWI / LSL for truck-in receipt points is not required.

3) Storage tanks and vessels indicated on a schematic must include the following:

   a. Include fluid type for these tanks, vessels, and caverns, such as oil, emulsion, condensate, plant product, waste, or water; tank and vessel capacity may be shown on separate document and should be available upon request.

   b. Identify if the tank or vessel is underground or default to aboveground.

   c. Identify optional non-reporting chemical storage or pop tanks if shown.

   d. Identify if the tank or vessel is tied into a vapour recovery system (VRU) or flare system; default to vented.

Changes affecting reporting must be documented at the field level when they occur and communicated to the production accountant at a date set by the operator to facilitate accurate reporting before the FIN submission deadline.

Physical changes, such as wells, piping, or equipment additions or removal, require a schematic update. Temporary changes within the same reporting period do not require a schematic update. The master copy of the measurement schematic must be updated annually to reflect any changes or deletions. There must be verification of the revisions or, if no revisions, confirmation of no change. Documentation of the verification may be stored separately from the schematic but must be available on request.

1.9.2. **Implementation**

a. No grandfathering for active facilities.

b. Any reactivated battery/facility must have an up-to-date schematic within three months of reactivation or after the implementation period, whichever is later.

1.9.3. **Schematic Availability**

Schematics must be provided by the operator of record to the following external parties upon request:

a. Battery/Facility permit holder of the subject battery/facility.

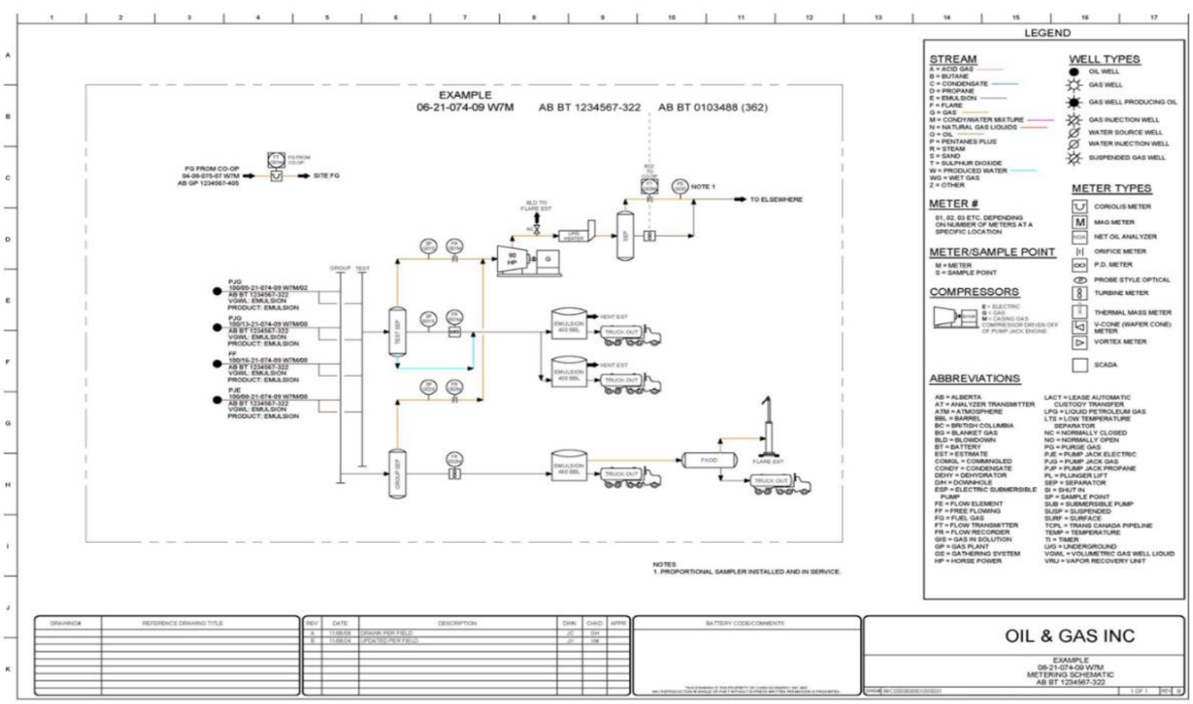
b. The company that performs the reporting for the battery/facility.

c. The company that performs the product and residue gas allocations up to the allocation point(s).

d. BCER, FIN, or cross-border regulatory bodies.

e. The operator (physical or reporting) of receipt/disposition points — all reporting measurement points for the battery/facility only.

1.9.4. **Schematic Example**



2. Chapter 2- Calibration and Proving

2.1. Introduction

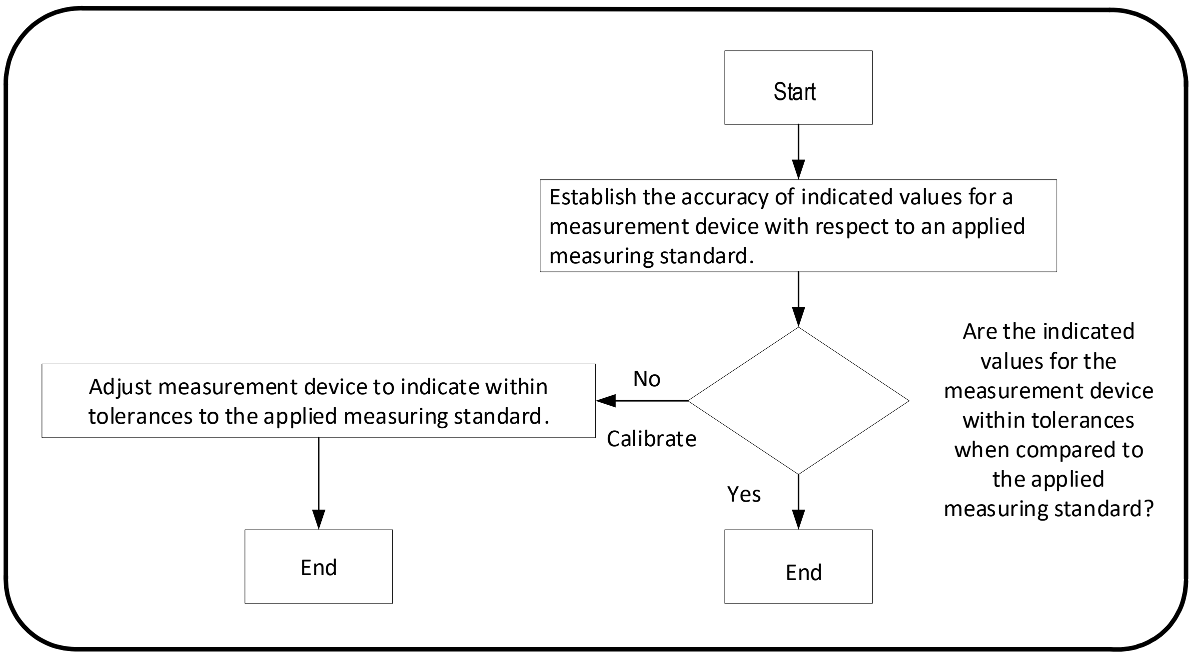
Metering devices all require various types of maintenance to ensure operating conditions meet the uncertainty requirements outlined in Chapter 1- Standards of Accuracy. This Chapter presents the base requirements and exceptions for maintaining metering devices.

2.2. Applicability

The maintenance (i.e., calibration, verification, proving, diagnostics, etc.) requirements stipulated here are applicable to measurement devices used for reporting purpose in British Columbia to meet section 53 of the DPR. These requirements are not applicable to measurement devices used only for a permit holder's internal accounting purposes. Operators must tag meters not utilized for reporting purposes as "non-reporting". The requirements identified here are considered minimums, and a permit holder may choose to apply more stringent requirements.

The decision tree below clarifies when a calibration or verification may be utilized.

Table 2.2-1 Calibration vs. Verification Decision Tree



2.3. Frequency

The accuracy of measurement devices may deviate over time, due to wear, changes in operating conditions, changes in ambient conditions, etc. Generally, the more important the accuracy of a measurement device, the more frequently maintenance should be conducted.

For the purposes of this manual, maintenance frequencies have the following meanings:

a. Monthly means at least once per calendar month.

b. Bimonthly means at least once every two calendar months.

c. Quarterly means at least once per calendar quarter.

d. Semi-annually means at least once every second calendar quarter.

e. Annually means at least once every fourth calendar quarter.

f. Biennially means at least once every eighth calendar quarter (once every two years).

g. Triennially means at least once every twelve calendar quarters (once every three years).

Calendar quarters are January to March, April to June, July to September, and October to December.

2.3.1. **Frequency Exceptions**

1) If the use or operation of a measurement device requiring monthly or quarterly maintenance is suspended for a significant period (at least seven consecutive days), the scheduled maintenance may be delayed by the number of days the device was not in use. Documentation of the amount of time the device was not in service must be kept and made available to the BCER upon request. If this exception is being applied, the operator must attach a tag to the meter indicating that this exception is in effect and the next scheduled maintenance date. This exception is not applicable to measurement devices subject to maintenance frequencies that are semi-annual or longer.

2) If a liquid meter is removed from service for bench proving but is put “on the shelf” and not returned to service for a considerable period of time, the countdown to the next required bench proving does not start until the meter is returned to service. The permit holder must attach a tag to the meter indicating the installation date but leaving the original proving tag intact.

3) The BCER may request that maintenance of a meter be done at any time or may extend the due date for scheduled maintenance, depending on the specific circumstances at a measurement point.

2.4. **Accuracy of Instruments Used to Conduct Maintenance**

2.4.1. **Instruments**

Instruments utilized for maintenance at a Cross Border Measurement battery/facility must adhere to the requirements outlined in Chapter 7 Cross Border Measurement. Instruments used in non-Cross Border applications to conduct maintenance of measurement devices must be tested for accuracy prior to first being used, immediately following any repairs or alterations being conducted on them (and before use), and periodically, in accordance with the following:

1) Portable provers must be calibrated (water drawn) biennially using measurement standards.

2) Stationary provers must be calibrated (water drawn) every four years using measurement standards.

3) Calibration instruments used for verification/calibration of **non-delivery** point meters, such as manometers, thermometers, pressure gauges, deadweight testers, electronic testers, etc., must be certified for accuracy at a minimum **biennially** against measurement standards.

4) Calibration instruments used for verification/calibration of **delivery point** and **custody transfer** point meters, such as manometers, thermometers, pressure gauges, deadweight testers, electronic testers, etc., must be certified for accuracy at a minimum **annually** against measurement standards.

5) Pressure and Temperature instruments installed on provers must be calibrated annually against measurement standards.

6) Master meters must be proved quarterly using a calibrated (water drawn) prover. The fluid used to prove the master meter must have properties (density, viscosity) similar to the fluids measured by the meters it will be used to prove. The master meter must be proved at flow rates that are comparable to the conditions it will be used for.

7) The measurement uncertainty of the proving or calibrating device must be equal to or better than the uncertainty of the device being proved or calibrated.

2.4.2. **Procedures**

The procedures to be followed for these accuracy tests must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of BCER preference from first to last):

1) Procedures specified by Measurement Canada, an agency of Industry Canada

2) Procedures described in the API *Manual of Petroleum Measurement Standards*

3) The device manufacturer's procedures

4) Other applicable industry-accepted procedures that utilize auditable methods (i.e., sound engineering practices, industry IRP manuals, etc.)

If none of the foregoing exists, the BCER will consider applications for and may grant approval of appropriate procedures.

Records of the foregoing accuracy tests must be kept for at least 72 months following the expiry of the applicable test and provided to the BCER on request.

2.5. **Gas Meters**

For gas meter maintenance requirements at a Cross Border Measurement Battery/Facility, please refer to Chapter 7 Cross Border Measurement.

2.5.1. **General Maintenance Requirements**

The term "gas meter" is broadly used to describe all of the equipment or devices that are collectively used to arrive at an indication of a gas volume. Typically, various values (e.g., differential pressure, static pressure, temperature) must be determined and used to calculate a gas volume. Depending on the specific gas meter, each of those values may be determined by individual devices or equipment.

Typically, maintenance of gas meter equipment requires the various meter elements to be subjected to various actual pressures, temperatures, and other values that are concurrently subjected to the calibration equipment. If the end device does not indicate the same value as the calibration equipment, adjustments must be made to the meter element and/or end device. A dry pressure source, such as nitrogen or air, must be used for the calibration/verification of pressure and differential pressure measurement devices.

Some meter equipment technologies may require alternative equipment and procedures for regular maintenance. This is acceptable provided the equipment and procedures are capable of confirming that the meter elements are functioning properly and are sensing and transmitting accurate data to the end device. This may be referred to as a Functionality Test.

Orifice meters are commonly used to measure gas volumes. The orifice plate changer must be maintained and be functional to facilitate orifice plate inspection and cleaning. The gas orifice meter itself (the meter run and orifice plate-holding device) does not require proving. The associated meter elements and the end devices to which they are connected must be calibrated or verified, as described in section 2.5.5 Orifice Meters (below).

If devices other than orifice meters are used to measure gas, the associated meter elements and the end devices to which they are connected must be maintained at the same frequency as orifice meters. The required procedures must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of BCER preference from first to last):

1) Procedures specified by Measurement Canada
2) Procedures described in the API *Manual of Petroleum Measurement Standards*
3) The device manufacturer's procedures
4) Other applicable industry-accepted procedures that utilize auditable methods (i.e., sound engineering practices, industry IRP manuals)

If none of the foregoing exists, the BCER will consider applications for and may grant approval of appropriate procedures.

2.5.2. Gas Meter Maintenance Frequency

All meters utilized for reporting purposes must have their respective maintenance conducted within the first calendar month after being installed or put into service. Should operations have a need to service or repair a meter, that meter must have the required maintenance conducted for that metering technology conducted by the end of the calendar month.

The frequency of the associated meter element calibrations must be the same as an orifice meter. For example, should an operator have a turbine meter installed for a fuel gas application, the primary measurement element (the turbine body) must be proved once every seven years, however, the related pressure and temperature elements must be calibrated annually.

Table 2.5-1 Gas Meter Maintenance Frequency

Metering Technology	Service	Maintenance Frequency	Maintenance Method
Orifice meters, meter elements, transmitters, and end devices.	Delivery Point and gas plant meters used for reporting purposes.	Semi-Annual	Verification/Calibration/Orifice plate inspection and cleaning
	Reporting gas meters located at both oil and gas facilities/batteries. Well head gas meters.	Annual	Verification/Calibration/Orifice plate inspection and cleaning
Ultrasonic (primary device)	Delivery Point	Once every seven years	Verification/Calibration
	Non-Delivery Point	Annual	Self-diagnostics
Positive displacement, turbine or other rotary meters used in a fuel gas application (primary device)	Delivery Point (see definition in Orifice above)	Semi-annual	Proving – see note below.
	Non-Delivery Point – including fuel applications	Once every seven years	Proving – see note below.
Coriolis (primary device)	Delivery Point	Semi-annual	Proving – see note below.
	Non-Delivery Point – including fuel applications	Annual	Proving - see note below or Self-diagnostics if equipped.
All meters	Cross Border	Refer to Cross Border Measurement Chapter 7 Staging Tables.	Verification/Calibration
Any meter not covered by above	Delivery Point	Semi-annual	Verification/Calibration
	Non delivery point	Annual	Verification/Calibration
All reporting meters, meter elements, and end devices.	Any	Upon BCER request if there is reasonable doubt concerning the measurement accuracy of the meter.	Verification/Calibration/ Internal inspection and cleaning

Note: The maintenance of these meters may be done with the meter in service, or the meter may be removed from service and maintained in a Measurement Canada accredited test facility at a pressure that is within the normal operating condition for that meter location unless it can be shown that calibrating/proving at a lower pressure condition will not change the uncertainty of the meter.

2.5.3. Gas Meter Internal Inspection / Functionality Test

A key contributor to meter accuracy is the condition of the internal components of the gas meter. Examples of internal components include orifice plates, vortex shedder bars, and turbine rotors. The internal components must be removed from service, inspected, cleaned, replaced, or repaired if found to be damaged, and then placed back in service, in accordance with the following:

The required frequency for inspection of internal gas meter primary measurement element (orifice plate) components is semi-annually for delivery point meters and gas plant meters used for reporting purposes. Annually for all other reporting gas meters.

1) Whenever possible, the inspection should be done at the same time as the maintenance conducted of the meter elements and end device; however, to accommodate operational constraints, the inspection may be conducted at any time, provided the frequency requirement is met.
2) Inspections must be done in accordance with procedures specified by the American Petroleum Institute (API), the American Gas Association (AGA), or other relevant standards organizations, or the device manufacturer's procedures, or other applicable industry-accepted procedures that utilize auditable methods (i.e., sound engineering practices, industry IRP manuals), whichever are most applicable and appropriate.
3) A tag or label must be attached to the meter or end device that identifies the meter serial number, the date of the internal inspection, and any other relevant details.
4) A detailed record of the inspection, documenting the condition of the internal components as found and any repairs or changes made to the internal components must be kept for at least 72 months and provided to the BCER on request.

2.5.4. Gas Meter, Meter Element, and End Device Exceptions for Verification/Calibration

1) Non-delivery point reporting meters: If the "As Found" verification/calibration check for the static and differential pressure transmitter confirms the accuracy of all readings or outputs are within +/- 0.25% of full scale and the temperature transmitter readings or outputs are within +/- 1°C when compared to a certified reference standard, with accuracy equal to or better than the instrument being calibrated, then no adjustment is required.
2) Delivery point and custody transfer reporting meters: If the "As found" verification/calibration for the static and differential pressure transmitter confirms the accuracy of all readings or outputs are within +/- 0.10 % of full scale and temperature transmitter readings or outputs are within +/- 0.25 C when compared to a certified reference standard, with an accuracy equal to or better than the instrument being calibrated, then no adjustment is required.
3) The "As Found" calibration/verification check must encompass a confirmation that the orifice meter run upstream diameter and orifice plate diameter recordings on the chart or in the EFM system are correct.
4) If an analog end device connected to an EFM at a non-delivery measurement point has been found not to require adjustment for three consecutive maintenance cycles, as indicated in Item 1 above, the minimum time between routine maintenance may be doubled (as per Table 2.5-1 Gas Meter Maintenance Frequency).
   A tag must be attached to the meter, indicating that this exception is being applied and have the date of the next scheduled calibration.

5) If a digital smart transmitter, multi-variable-sensor (MVS), or multi-variable transmitter (MVT) is connected to an EFM at a non- delivery measurement point, the maintenance frequency of the transmitter may be extended up to a maximum period of five years in accordance with the following:

   a. This exception applies only to digital smart transmitters as described above and does not apply to analog transmitters.

   b. Newly installed digital smart transmitters must be initially set-up in accordance with the procedures described in the most current version of the Industry Measurement Group's Intelligent Transmitter Commissioning and Verification Industry Recommended Practice (IRP), and verified/calibrated at the time of installation and must be verified /calibrated within one year of operation (the first year), no sooner than 6 months. Note: During the first-year verification on new or newly installed digital transmitters the differential pressure transmitter must be zero verified by equalizing the sensor at the operating static pressure and adjusted if required. If the first-year verification / calibration results in no calibration or adjustment required, in accordance with item 2.5.4.1, then the next verification/calibration performed by an instrument technician may be extended up to a maximum period of five years. If calibration is required after the first year of operation, then the transmitter must be verified / calibrated in the subsequent year. The only exception is for the situation where digital transmitters are used at a gas plant inlet that has multiple inlet separators. In this case the inlet separator meter transmitter verification/calibration frequency may only be extended to biennial. For gas plants with a single inlet separator, the verification/calibration frequency of the meter transmitters may be extended up to a maximum period of five years.

   c. Existing transmitters can use the last verification/calibration results and if all outputs are within +/- 0.25 % of full scale (with the exception of +/- 1°C for the temperature element) then the next verification/calibration by an instrument technician may be extended up to a maximum period of five years. The only exception is where digital transmitters are used at a gas plant inlet that has multiple inlet separators. In this case the inlet separator meter transmitter calibration frequency may be extended to biennial. For gas plants with a single inlet separator, the maintenance frequency of meter transmitters on the inlet separator may be extended up to a maximum period of five years.

   d. Annually, the orifice plate must be inspected, cleaned, and replaced if damaged. This should be done at zero flow, or when the EFM is in an orifice plate change mode.

   e. A tag or inspection report for the maintenance activity (calibration/verification or the orifice plate inspection and cleaning) must be attached to the digital smart, MVS or MVT, transmitter, and be in accordance with section 2.5.5.2(h).

   f. A qualified instrument technician is required to adjust the transmitter if calibration is required at any time within the maximum five-year verification/calibration period. If calibration is required, the transmitter maintenance period starts again.

   g. A digital smart transmitter that is on a reduced maintenance frequency must revert back to the required maintenance frequency if:

      i. It fails to meet the requirements that allowed it to be placed on a reduced maintenance frequency.
      ii. The digital smart transmitter is removed from service and repaired.

6) The records of the maintenance that qualify the meter for any exception must be kept for 72 months and made available to the BCER on request.

7) If redundant gas meters are installed for a measurement point or redundant meter elements and/or end devices are installed on a single gas meter, the minimum time between routine maintenance of the meter elements and end devices may be doubled, provided that daily volumes from each end device are compared at least monthly and found to be within 0.25% of each other. If the daily volumes are not found to be within 0.25% of each other, immediate maintenance of both sets of equipment is required. A tag must be attached to the meter, indicating that this exception is being applied and the date of the next scheduled maintenance. The records of the monthly comparisons and any maintenance that are done must be kept for at least 72 months and made available to the BCER on request.

8) If rotary, turbine, or other types of gas meters with internal moving parts are used to measure gas, such as fuel gas, they must be proved at a frequency of once every seven years following an initial proving prior to installation; the calibration of related meter elements must follow section 2.5.2. These meters must also be proved immediately following any repairs or alterations being conducted on them. The proving may be done with the meter in service, or the meter may be removed from service and proved in a shop at a pressure that is within the normal operating condition for that meter location unless it can be shown that proving at lower pressure conditions will not change the uncertainty of the meter, such as in the case of a rotary meter. A tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the meter factor determined by the proving.

9) For meters used in effluent (wet gas) measurement that require proving, such as a turbine meter, the proving must be performed by using a gas master meter or other provers in single-phase proving runs. For ECF-WGR testing, (see section 6.5).

10) If the internal components of gas meters have been inspected and found to be clean and undamaged for three consecutive inspections, the minimum time between inspections may be doubled. When the internal components are found to be dirty or damaged on any subsequent inspection, the frequency for inspections will revert back to the original requirement.

11) If the inspection of internal components of a gas meter requires the meter to be removed from service and there is no meter bypass installed, it is acceptable to defer a scheduled internal component inspection until the next time the gas meter run is shut down (except at a Cross Border battery/facility), provided that any one of the following conditions exists:

    a. Shutting down and depressurizing the gas meter run to remove and inspect the internal components would be very disruptive to operations.

    b. Inspection would require excessive flaring/venting.

    c. Performing the inspection would create a safety concern, and internal component inspections have historically proven to be satisfactory.

    d. The meter run is installed in a flow stream where the risk of internal component damage is low (e.g., sales gas, fuel gas).

    e. The measurement system at the battery/facility provides sufficient assurance, through volumetric and/or statistical analysis, that internal component damage will be detected in a timely manner.

12) An inspection must not be delayed if the meter is not measuring accurately.

13) If the orifice plate is mounted in a quick-change/dual chamber orifice meter assembly, and during an inspection of the orifice plate, the fitting is found to be leaking between the chambers, such that the meter run must be shut down and depressurized to safely remove the orifice plate, it is acceptable to defer a scheduled orifice plate inspection until the next time the gas meter run is shut down (except at a Cross Border battery/facility), provided that:

    a. Shutting down and de-pressuring the gas meter run to remove the orifice plate would be very disruptive to operations.

    b. The inspection would require excessive flaring/venting.

    c. Performing the inspection would create a safety concern, and

        i. The next time the gas meter run is shut down, the orifice meter assembly is scheduled for repairs to eliminate the cause of the leak and scheduled for future orifice plate inspections.

        ii. Orifice plate inspections have historically proven to be satisfactory.

    d. The meter run is installed in a flow stream where the risk of orifice plate damage is low (e.g., sales gas, fuel gas, etc.).

    e. The measurement system at the battery/facility provides sufficient assurance, through volumetric and/or statistical analysis, that orifice plate damage will be detected in a timely manner.

14) Internal metering diagnostics may be used to determine if the integrity of the primary measurement element is within acceptable operating parameters and checked at the same required intervals as an internal inspection. Then internal inspection is not required until an alarm or error is generated by the device or as specified by the manufacturer. The operator must maintain documentation on the diagnostic capability of the meter and make it available to the BCER on request. An initial baseline diagnostic profile must be performed and documented during the commissioning process.

15) Single phase in-line proving of the gas meter may be used to determine if the primary measurement element/meter element is within acceptable operating parameters and proved at the same required intervals as an internal inspection. Then internal inspection is not required until the uncertainty limits are exceeded.

If the primary measurement element inspections are deferred in accordance with any of the preceding exceptions, the operator must be able to demonstrate to the BCER, on request, that the situation meets the conditions identified. If these exceptions are being used, this must be clearly indicated on a tag or label attached to the meter (or end device). Evidence in the battery/facility logs that the internal component inspection has been scheduled for the next shutdown must be available for inspection by the BCER. For the purposes of these exceptions, “shutdown” means any scheduled discontinuation of flow through the meter that is of sufficient duration to allow the operations needed to remove and inspect the internal component. If an unscheduled shutdown occurs that will allow sufficient time to conduct internal component inspection operations, the operator should consider conducting those inspections prior to the conclusion of this unscheduled shutdown.

2.5.5. Orifice Meters

1) The procedure for orifice meter chart recorder (end device) calibration/verification must be in accordance with the following:
   a. Pen arc, linkage, pressure stops, and spacing must be inspected and adjusted, if necessary.
   b. The differential pressure element must be calibrated at zero, full span, and nine ascending / descending points throughout its range. A zero check of the differential under normal operating pressure must be done before and after the calibration.
   c. The static pressure element must be calibrated at zero, 50% of full span, and full span.
   d. If a temperature element is in place, the temperature element must be calibrated at three points (operating temperature, one colder temperature, and one warmer temperature).
   e. If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points and replaced if found not to read accurately within ±1°C (operating temperature and one other temperature).
   f. If a thermometer or other temperature measuring device is not left in place (transported by an operator and used to determine flowing gas temperatures at multiple sites), the accuracy of that device must be verified at the same frequency and in the same manner as a thermometer left in place, and the record of that verification must be readily available for inspection by the BCER.
   g. Subsequent to the maintenance activity, a tag or label must be attached to the meter (or end device) and must identify:
      i. The meter serial number.
      ii. The date of the maintenance
      iii. The site surface location.
      iv. The meter element calibration/verification ranges.
      v. The full name of the person performing the maintenance.
   h. A detailed report indicating the tests conducted on the meter during the calibration/verification and the conditions "As Found" and "As Left" must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.
2) The procedure for calibration of an orifice meter electronic flow measurement (EFM) system must be in accordance with the following:
   a. The indicated process variable value in the EFM must be calibrated using a measurement device that has a valid certification of calibration to a reference standard. See section 2.4 for accuracy of instruments.
   b. For digital transmitters, the differential pressure element must be calibrated at zero, 50% of full span, and at 100% of full span.

c. For analog transmitters, the differential pressure element must be calibrated at zero, 50% of full span, and at 100 % of full span (ascending), as well as 80% and 20% (or 75% and 25%) of full span (descending). A zero check of the differential under normal operating pressure must be done before and after the calibration.

d. For digital and analog transmitters, the static pressure element must be calibrated at zero, 50% of full span, and at 100 % of full span.

e. If a temperature transmitter is in place, it must be calibrated at two points (near operating temperature and one colder or one warmer temperature). The temperature element and transmitter must be verified as a single unit i.e. not decoupled and verified separately.

f. If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points and replaced if found not to read accurately within ±1°C (operating temperature and one other temperature).

g. If a thermometer or other temperature measuring device is not left in place (transported by an operator and used to determine flowing gas temperatures at multiple sites), the accuracy of that device must be verified at the same frequency and in the same manner as a thermometer left in place, and the record of that verification must be readily available for inspection by the BCER.

h. Subsequent to the maintenance activity, a tag or label must be attached to the meter (or end device). This tag or label must identify:

   i. The meter serial number.

   ii. The date of the maintenance activity.

   iii. The maintenance frequency or date when next scheduled maintenance is due.

   iv. The site surface location.

   v. The meter element calibration/verification ranges.

   vi. The full name of the person performing the maintenance.

i. A detailed report indicating the tests conducted on the meter during the calibration and the conditions "as found" and "as left" must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met. If data from the instrumentation are sent to another location(s) for flow calculations via DCS, SCADA, RTU, or other means of communication, the reading of the calibration must be verified at the receipt location of such data to ensure accurate data transmission.

2.6. **Oil Meters**

Oil production and disposition volumes must always be reported as liquid volumes at 15°C and either equilibrium pressure (equilibrium pressure is assumed to be atmospheric pressure at the point of production or disposition) or 101.325kPa absolute pressure. However, there are two basic ways in which oil is metered, requiring distinctly different proving procedures:

1) If oil production is metered prior to being reduced to atmospheric pressure, the proving procedures must allow for the volume reduction that will occur when the gas in solution with the "live" oil is allowed to evolve on pressure reduction.

2) No consideration for gas in solution is required when proving meters used to measure "dead" oil

2.6.1. Live Oil Meter Proving Requirements

Table 2.6-1 Live Oil-Group Meter Proving Requirements

Group Oil	Proving Frequency	Temperature Measurement	Volumetric Compensation Temperature	Pressure Measurement	Volumetric Compensation Pressure
Custody Transfer – Pipeline with meter	Monthly	Continuous	Continuous	Continuous	Continuous
Delivery Point – Pipeline with meter	Monthly	Continuous	Continuous	N/A	N/A
Delivery Point – Truck-in meter	Monthly	Continuous	Continuous	N/A	N/A
Delivery Point – Receipt – Tank Gauging	BCER Site Specific	Single Point or Continuous	Single Point or Continuous	N/A	N/A
Delivery Point – Pipeline Batch – Tank Gauging	BCER Site Specific	Single Point or Continuous	Single Point or Continuous	N/A	N/A
Cross Border Delivery	See: Chapter 7 Cross Border Measurement				

Table 2.6-2 Live Oil – Test Meter Proving Requirements

Test Oil	Proving Frequency	Temperature Measurement	Volumetric Compensation Temperature	Pressure Measurement	Volumetric Compensation Pressure
Well Test - Meter	Annual	Single or Continuous	Single or Continuous	N/A	N/A
Well Test – Tank Gauging	Annual	Single or Continuous	Single or Continuous	N/A	N/A

Notes:

1) Where temperatures and/or pressures are required to be continuously measured, the live temperature and/or pressure correction values must be continuously applied to the raw volume data.
2) The temperature measuring element must be installed in the flow stream and be representative of the stream temperature. The surface temperature of the piping will **not** be allowed as a satisfactory temperature measurement nor will the installation of the temperature measuring element be installed where there is normally no flow.

Live oil meters are typically those used to measure volumes of oil or oil/water emulsion produced through test separators, but also includes meters used to measure well or group oil or oil/water emulsions that are delivered to other batteries/facilities or facilities by pipeline prior to the pressure being reduced to atmospheric pressure.

To account for the shrinkage that will occur at the metering point due to the gas held in solution with live oil, the proving equipment and procedures may determine the amount of shrinkage either by physically degassing the prover oil volumes or by calculating the shrinkage based on an analysis of a sample of the live oil. Calculation of shrinkage volumes is most often used to mitigate safety and environmental concerns if the live oil volumes are metered at high pressures or if the live oil contains hydrogen sulphide (H_2S).

Meters used to measure live oil are subject to the following proving requirements:

2.6.1.1. **Proving Requirements for Group Oil Meter**

1) A new group oil meter must be initially proved within the first calendar month of operation. The resultant meter factor must be applied to all volumes produced prior to the determination of the meter factor from the prove.

2) The group oil meter must be proved by the end of the calendar month following any repairs being conducted on the meter or any changes to the meter installation. The resultant meter factor must be applied back to the volumes metered after the repair or change.

    a. An acceptable initial proving must consist of three consecutive runs (one of which may be the "as found" run), each providing a meter factor that is within ±0.25% of the mean of the three factors. The resultant meter factor will be the average of the three applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the operator can demonstrate that the alternative procedures provide a meter factor that is of equal or better accuracy).

    b. A meter used to measure group oil or oil/water emulsion volumes to or at a battery/facility must be proved monthly thereafter.

    c. If a consistent meter factor is unattainable, the meter must be replaced.

    d. Following the initial proving:

        i. Each group oil meter must be proved at least every month.

        ii. One proving run is sufficient if the new meter factor is within 0.5% of the previous mean factor.

        iii. If the new meter factor is not within 0.5% of the previous meter factor, the meter must be proved in the same manner as the initial proving run.

2.6.1.2. **Proving Requirements for Test Oil Meter**

1) A new test oil meter at a well or a battery/facility must be proved within the first three months of operation.

    a. The test oil meter must be proved immediately (by the end of the calendar month) following any repairs on the meter or any changes to the meter installation (note that the resultant meter factor must be applied back to the volumes metered after the repair or change).

    b. A meter used to measure test oil or oil/water emulsion volumes must be proved annually thereafter.

    c. An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor that is within ±1.5% of the mean of the four factors. The resultant meter factor will be the average of the four applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the operator can demonstrate that the alternative procedures provide a meter factor that is of equal or better accuracy.)

d. When proving a test oil meter, a well that is representative of the battery's/facility's average well production characteristics must be directed through the test separator for each of the four runs. If there are wells in the battery/facility with production characteristics that vary significantly from the average, consider determining specific meter factors to be used for each of those wells.

2.6.1.3. **Proving Requirements for Group and Test Oil Meters**

1) The meter must be proved in-line under normal operating conditions (pressure and flow rates).
2) The design and operation of the meter installation must ensure that the conditions of fluid flow through the meter are within the manufacturer's operating range.
3) The meter must be installed upstream of either a throttling control valve with snap-acting on/off control or a snap-acting dump valve.
4) A uniform flow rate must be maintained through the meter.
5) The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter.
6) If the proving procedure will include degassing the prover to physically reduce the pressure of the oil to atmospheric pressure, then:
   i. The prover taps must be located downstream of the throttling/dump valve, such that the proving device will not interfere with the normal interaction of the meter and the throttling/dump valve.
   ii. The prover must be a tank-type volumetric or gravimetric prover.
   iii. Each proving run must consist of a representative volume of oil or oil/water emulsion that is directed through the meter and into the prover and then the liquid volume is reduced in pressure to atmospheric pressure. The resultant volume determined by the prover, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
   iv. The amount of time required to degas the prover volume and arrive at a stable atmospheric pressure in the prover will vary, depending on the initial fluid pressure and the fluid characteristics.
7) If the proving procedure involves using a shrinkage factor (rather than degassing) to adjust the prover volume to atmospheric conditions, then:
   i. The location of the prover taps depends on the type of proving device to be used to prove the meter, such that the proving device will not interfere with the normal interaction of the meter and the throttling/dump valve. Tank-type volumetric or gravimetric provers will require the taps to be downstream of the throttling/dump valve, while non-tank-type volumetric provers such as ball provers, pipe provers, or master meters will require the taps to be upstream of the valve. Unconventional proving that does not meet the above requirements must be approved by the BCER.
   ii. If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
   iii. Each proving run must consist of a representative volume of oil or oil/water emulsion being directed through the meter and into the prover or through the master meter. The resultant volume determined by the prover or master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.

iv. A shrinkage factor representative of the fluid passing through the meter must be determined and used to adjust the meter volumes to atmospheric conditions. The shrinkage factor may either be incorporated into the meter factor or be applied to metered volumes after they are adjusted by the meter factor. The shrinkage factor must be based on analysis of a sample of the metered fluid taken at normal operating conditions prior to and within one month of the proving.

v. Whenever operating conditions at the meter experience a change that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based on analysis of a sample of the metered fluid taken at the new operating conditions. Consideration should also be given to proving the meter at the new operating conditions to determine if the meter factor has been affected.

vi. When this option is used, the tag attached to the meter must indicate that a shrinkage factor was used instead of degassing the prover and whether the shrinkage factor was incorporated into the meter factor or will be applied separately.

8) If a meter is proved after a period of regular operation, an “As Found” proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

i. In the case of a test oil meter, the meter factor must include a correction factor to adjust the metered volume to 15°C (unless the meter is temperature compensated). Although the actual fluid temperature may vary with ambient temperature, it is acceptable to assume that the temperature observed at the time of proving is reasonably representative of the temperature experienced at the meter until the next proving. This requirement does not apply to meter technologies that do not require correction for temperature.

ii. In the case of a Group Oil - Live Oil delivery point or custody transfer meter, the meter factor must not include a correction factor for temperature. The meter must be continuously temperature compensated in accordance with the American Petroleum Institute (API) – Chapter 11. This requirement does not apply to meter technologies that do not require correction for temperature. The metered volume must be corrected to 15°C.

iii. In the case of a Group Oil - Live Oil custody transfer measurement meter, the meter factor must not include a correction factor for pressure. The meter must be continuously pressure compensated in accordance with the American Petroleum Institute (API) – Chapter 11. This requirement does not apply to meter technologies that do not require correction for pressure. The metered volume must be corrected to 101.325kPa.

9) Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

a) The meter serial number.

b) The date of the proving.

c) The site surface location.

d) The average meter factor.

e) The type of prover or master meter used.

f) Whether the volume readout is meter-factor corrected or if the volume readout is meter-factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes.

g) If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

h) The name of the person performing the prove.

10) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met. If the proving involved the use of a shrinkage factor instead of degassing, a copy of the sample analysis must be attached to the proving report.

2.6.1.4. **Group and Test Oil Meter Proving Exceptions – Live Oil**

1) In situations where individual well production rates are so low that proving a test oil meter in accordance with the requirements listed above would require excessive time, it is acceptable to modify the proving procedures. Complete, individual proving runs requiring more than one hour are considered excessive. The following modifications, in order of BCER preference, may be used to reduce proving time:

a) Produce several wells through the test separator at one time to increase the volume available for the proving runs.

b) If the degassing procedure is being used, degas the first run only, and then use the data to calculate a shrinkage factor, which can be applied to subsequent runs conducted without degassing.

c) Use the highest rate well for all proving runs.

d) Conduct only three proving runs.

Note: The detailed proving report must clearly indicate if any of the foregoing modifications were used to prove the meter.

2) A live oil meter may be removed from service and proved in a meter shop, in accordance with the following:

a) If the meter is used to measure test volumes of conventional oil/emulsion, the average rate of flow of oil of all the wells that are tested through the meter must be less than or equal to 2m^3/d and no well may exceed 4m^3/d of oil production.

b) Any meter used to measure test volumes of oil (density greater than 920kg/m^3) may be proved in a meter shop.

c) If the gas held in solution with the fluid produced through the meter is of sufficient volume to significantly affect the fluid volume indicated by the meter, consideration should be given to determining an appropriate shrinkage factor to correct for the effect of the solution gas and provide that factor to the meter calibration shop so it may be built into the meter factor.

d) The meter installation must be inspected as follows, and corrective action must be taken where required:

i) The flow rate through the meter must be observed in order to verify that it is within the manufacturer's operating ranges.

ii) The dump valve must not be leaking (no flow registered between dumps).

e) The shop proving may be conducted with a volumetric or gravimetric prover or with a master meter, as follows:

i) Water is typically used as the proving fluid, but varsol or some other light hydrocarbon fluid may be used for the proving.

ii) Corrections for the temperature and pressure of the proving fluid must be made, where applicable.

iii) If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.

iv) If a meter is proved after a period of regular operation, an “As Found” proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

v) An acceptable proving must consist of four consecutive runs (one of which may be the “as found” run), each providing a meter factor that is within ±0.5% of the mean of the four factors. The resultant meter factor must be the average of the four applicable meter factors.

f) Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

i) The meter serial number.

ii) The date of the proving.

iii) The fact the proving was done in a shop.

iv) The average meter factor.

v) The type of prover or master meter used.

vi) The name of the person performing the calibration.

vii) Whether the volume readout is meter-factor corrected or if the volume readout is meter-factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

3) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If a report is left with the meter, then the requirement for the tag is met.

2.6.2. **Dead Oil Meter Proving Requirements**

Table 2.6-3 Dead Oil – Group Meter Proving Requirements

Group Oil	Proving Frequency	Temperature Measurement	Volumetric Compensation Temperature	Pressure Measurement	Volumetric Compensation Pressure
Custody Transfer – Pipeline with meter	Monthly *1	Continuous	Continuous	Continuous	Continuous
Delivery Point – Pipeline with meter	Monthly *1	Continuous	Continuous	N/A	N/A
Delivery Point – Truck with meter	Monthly *1	Continuous	Continuous	N/A	N/A
Delivery Point – Receipt – Tank Gauging	BCER Site Specific	Single Point or Continuous	Single Point or Continuous	N/A	N/A
Delivery Point – Pipeline Batch – Tank Gauging	BCER Site Specific	Single Point or Continuous	Single Point or Continuous	N/A	N/A
Cross Border Delivery	See Chapter 7 Cross Border Measurement				

Note: *1 (see section 2.6.2.2 for Dead Oil Meter Proving Exemptions)

Table 2.6-4 Dead Oil – Test Meter Proving Requirements

Test Oil	Proving Frequency	Temperature Measurement	Volumetric Compensation Temperature	Pressure Measurement	Volumetric Compensation Pressure
Well Test - Meter	Annual	Treat as Live Oil – Test Oil			
Well Test – Tank Gauging	Annual	Treat as Live Oil – Test Oil			

Notes:

1) Where temperatures and/or pressures are required to be continuously measured, the live temperature and/or pressure correction values must be continuously applied to the raw volume data.
2) The temperature measuring element must be installed in the flow stream and be representative of the stream temperature. The surface temperature of the piping will not be allowed as a satisfactory temperature measurement nor will the installation of the temperature measuring element be installed where there is normally no flow.

Dead oil meters are typically those used for delivery point (custody transfer point) measurement of clean oil that has been degassed to atmospheric pressure. These meters may be found measuring oil being pumped from a battery/facility into a pipeline or measuring oil being pumped from a truck into a pipeline terminal, or other battery/facility.

Meters used to measure dead oil are subject to the following proving requirements:

2.6.2.1. **Group Oil Meter Proving Requirements**

1) A new meter must initially be proved within the first calendar month of operation. The resultant meter factor must be applied to all volumes produced prior to the determination of the meter factor from the prove.

2) The group oil meter must be proved by the end of the calendar month following any repairs being conducted on the meter or any changes to the meter installation. The resultant meter factor must be applied back to the volumes metered after the repair or change.

3) An acceptable initial proving (the first proving of a new or repaired meter) must consist of three consecutive runs, each providing a meter factor that is within ±0.25% of the mean of the three factors. The resultant meter factor will be the average of the three applicable meter factors (proving procedures using more than three runs will be allowed if the operator can demonstrate that the alternative procedures provide a meter factor that is of equal or better accuracy).

4) A meter used to measure group oil or oil/water emulsion volumes to or at a battery/facility must be proved monthly thereafter.

   a. If a consistent meter factor is unattainable, the meter must be replaced.

   b. Following the initial proving, each meter must be calibrated at least every month.

      i. One proving run is sufficient if the new meter factor is within 0.5% of the previous mean factor.

      ii. If the new meter factor is not within 0.5% of the previous meter factor, the meter must be calibrated in the same manner as the initial proving run.

   c. The meter must be proved in-line under normal operating conditions.

   d. The design and operation of the meter installation must ensure that the conditions of fluid flow through the meter are within the manufacturer's operating range.

   e. The location of the prover taps depends on the type of proving device to be used to prove the meter, such that the proving device will not interfere with the normal interaction of the meter and the throttling/dump valve. Tank-type volumetric or gravimetric provers will require the taps to be downstream of the throttling/dump valve, while non-tank-type volumetric provers such as ball provers, pipe provers, or master meters will require the taps to be upstream of the valve. Unconventional proving that does not meet the above requirements must be approved by the BCER.

   f. The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter.

   g. Proving may be done with any suitable volumetric or gravimetric prover or a master meter.

   h. If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.

   i. Each proving run must consist of a representative volume of oil being directed through the meter and the prover or master meter. The volume measured by the prover or by the master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.

j. Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

   i. The meter serial number.

   ii. The date of the proving.

   iii. The average meter factor.

   iv. The type of prover or master meter used.

   v. The name of the person performing the prove.

   vi. Whether the volume readout is meter factor corrected or whether the volume readout is meter factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

k. A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

l. In the case of a Group Oil - Dead Oil delivery point or custody transfer meter, the meter factor must not include a correction factor for temperature. The meter must be continuously temperature compensated in accordance with the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards (MPMS)*, Chapter 11. This requirement does not apply to meter technologies that do not require correction for temperature. The metered volume must be corrected to 15°C.

m. In the case of a Group Oil - Dead Oil custody transfer measurement meter, the meter factor must not include a correction factor for pressure. The meter must be continuously pressure compensated in accordance with the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards* (*MPMS*), Chapter 11. This requirement does not apply to meter technologies that do not require correction for pressure. The metered volume must be corrected to 101.325kPa.

n. For Group Oil – Dead Oil delivery point or custody transfer applications where in-line proving must be performed, proving taps and a double block and bleed divert valve must be installed. For positive displacement (PD) and coriolis meters, proving taps may be upstream or downstream of the meter if a ball prover, pipe prover, or master meter is used. For other types of linear meters or tank provers, the proving taps must be downstream of the meter. No exemptions are granted for unconventional proving methods that do not meet the above requirements.

o. All delivery point meters must be proved in accordance with the procedures of this Chapter. LACT meters may use the proving procedure in API-MPMS, Chapter 4: Proving Systems, rather than the procedures in this Chapter should these practices be desired.

p. For meters to be proved using a conventional displacement prover (e.g., ball prover) or a captive displacer prover (piston and shaft), pulse outputs are required. For master meter proving, pulse outputs are only recommended.

2.6.2.2. Dead Oil Meter Proving Exceptions

2.6.2.2.1. Group Oil Meter Proving Exceptions – Dead Oil Meter

1) If the volume of fluid metered by a delivery point or LACT meter does not exceed 100m^3/d, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter measures ≤100m^3/d and that the meter is on a quarterly proving frequency. The required proving frequency will revert back to monthly if the meter begins measuring volumes greater than 100m^3/d.

2) For delivery point or LACT meters, if the meter factor is within 0.5% of the average meter factors from the previous three consecutive proves, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter has been found to have consistent meter factors and is on a quarterly proving frequency. The required proving frequency will revert back to monthly whenever the meter factor determined during a proving is found not to be within 0.5% of the previous of the average of the meter factors from three consecutive proves.

3) For delivery point meters that measure trucked-in oil, oil emulsion and condensate and that have no moving parts (e.g., coriolis meter, ultrasonic meter, orifice meter, vortex meter, cone meter), the meter may be proved semi-annually if the current meter factor is within +/-0.5 % of the average of the meter factors from previous three consecutive proves. A tag must be attached to the meter and clearly indicate that he meter has been found to have consistent meter factors and is on a semi-annual proving frequency. The required proving frequency will revert back to monthly whenever the meter factor determined during a prove is not within +/- 0.5 % of the average of the meter factors from the previous three consecutive proves. The meter must re-qualify for the exemption before the proving frequency can be extended to semi-annual. The meter must be proved following repairs to the meter or changes to the metering installation or if production operations change in a way that may impact the accuracy of the metering.

2.7. Condensate Meters

Condensate is subject to two differing sets of measurement, accounting, and reporting rules. If condensate volumes are metered and delivered at atmospheric pressure or equilibrium pressure, the volume must be determined and reported as a liquid volume at 15°C and equilibrium pressure (equilibrium pressure is assumed to be either atmospheric pressure at the point of production or disposition or the actual equilibrium pressure). If condensate volumes are metered and delivered at flow-line conditions, the volume is determined at flow-line pressure and temperature and corrected to 15°C and 101.325kPa, but the volume may be reported as a gas equivalent volume at standard conditions (101.325kPa absolute and 15°C) as well as in liquid (m3).

2.7.1. Condensate Meter Proving Requirements

Table 2.7-1 Proving Requirements for Condensate at Equilibrium Conditions

Equilibrium Conditions	Proving Frequency	Temperature Measurement Frequency	Volumetric Compensation Temperature	Pressure Measurement Frequency	Volumetric Compensation Pressure
Delivery Point and LACT Meters	Monthly	Treat as Dead Oil – Group Oil			
Cross Border Delivery	See Chapter 7 Cross Border Measurement				

Table 2.7-2 Proving Requirements for Delivery Point/Custody Transfer Condensate

Flow Line Conditions	Proving Frequency	Temperature Measurement Frequency	Volumetric Compensation Temperature	Pressure Measurement Frequency	Volumetric Compensation Pressure
Well Test Meter	Monthly	Treat as Dead Oil - Group Oil			
Gas Plant Inlet Separator Meter	Semi-annual	Continuous	Continuous	Continuous	Continuous
Cross Border Delivery	See Chapter 7- Cross Border Measurement				

Table 2.7-3 Proving Requirements for Non-Delivery/ Non Custody Transfer Condensate

Flow Line Conditions	Proving Frequency	Temperature Measurement Frequency	Volumetric Compensation Temperature	Pressure Measurement Frequency	Volumetric Compensation Pressure
Well /Battery or Test Meter	Annual	Treat as Live Oil – Test Oil			
Cross Border Delivery	See Chapter 7 Cross Border Measurement				

2.7.2. Condensate at Equilibrium Conditions

Meters that measure condensate that is stored and delivered as a liquid at atmospheric pressure or equilibrium pressure are typically delivery point meters and are therefore subject to the same proving requirements and exceptions applicable to meters used for dead oil measurement.

2.7.3. Condensate at Flow-Line Conditions

When a meter that requires proving is used to measure condensate at flow-line conditions are subject to the following proving requirements:

1) A new meter must be proved within the first calendar month of operation. The resultant meter factor must be applied to all volumes produced prior to the determination of the meter factor from the prove.

2) The meter must be proved as in applicable table above.

3) The meter must be proved immediately (by the end of the calendar month) following any repairs being conducted on the meter or any changes to the meter installation. The resultant meter factor must be applied to all volumes produced prior to the determination of the meter factor from the prove.

4) Condensate meters used for delivery point measurement are subject to the same proving frequency and proving frequency exceptions applicable to meters used for dead oil measurement. For condensate meters at flow-line conditions designated as Cross Border meters, the meters must follow the frequency as stipulated in Chapter 7 Cross Border Measurement.

5) The meter must be proved in-line under flow-line conditions at normal operating conditions.

6) The design and operation of the meter installation must ensure that the flow through the meter is within the manufacturer's operating range. The meter must be installed upstream of either a throttling control valve with snap-acting on/off control or a snap-acting dump valve for separator designs.

7) The size of the prover taps, and operation of the prover must not restrict or alter the normal flow through the meter.

8) The location of the prover taps must be such that the connection of the proving device will not interfere with the normal interaction of the meter and the dump valve:

    a. If a tank-type volumetric or gravimetric prover is used, the prover taps must be located downstream of the dump valve, and the pressure in the prover must be regulated such that reduction of the condensate volume due to flashing is minimized. The dump valve must be allowed to control the flow of condensate into the prover through its normal operation. Flow into the prover is not to be controlled by manual manipulation of the prover inlet valve.

    b. If a ball or piston-type volumetric prover or a master meter is used, the prover taps must be located upstream of the dump valve, so that the prover or master meter will be subjected to the same flow and pressure conditions as the condensate meter.

    c. Unconventional proving that does not meet the above requirements must be approved by the BCER.

9) If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.

10) Each proving run must consist of a representative volume of condensate being directed through the meter and the prover or master meter. The volume measured by the prover or by the master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.

11) If a meter is proved after a period of regular operation, an "As Found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

12) An acceptable proving must consist of four consecutive runs (one of which may be the "As Found" run), each providing a meter factor that is within ±2% of the mean of the four factors. The resultant meter factor must be the average of the four applicable meter factors. Proving procedures using more than four runs will be allowed, provided that the operator can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.

13) Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

   a. The meter serial number.

   b. The date of the proving.

   c. The average meter factor.

   d. The type of prover or master meter used.

   e. The name of the person performing the prove.

14) Whether the volume readout is meter factor corrected or whether the volume readout is meter factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

15) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

16) A detailed record of the internal components inspection documenting any repairs or changes made to the internal components must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

2.7.4. Condensate Meter Proving Exceptions

1) A meter used to measure condensate at flow-line conditions may be removed from service and proved in a meter shop, in accordance with the following:

   a. If the meter is used to measure condensate production on a continuous or non-continuous basis, the rate of flow through the meter must be ≤2m^3/d, or the rate of flow through the meter must be ≤3m^3/d with the gas equivalent volume of the daily condensate volume being ≤3% of the daily gas volume related to the condensate production.

   b. If the meter is used on a portable test unit, there is no volume limitation, but consideration should be given to proving the meter in-line if significant condensate production is observed during the test.

c. The meter installation must be inspected as follows, and corrective action must be taken where required:

i. The flow rate through the meter must be observed to verify that it is within the manufacturer's operating ranges.

ii. The dump valve must not be leaking (no flow registered between dumps).

d. The shop proving may be conducted with a volumetric or gravimetric prover, or with a master meter, as follows:

i. Water is typically used as the proving fluid, but varsol or some other light hydrocarbon fluid may be used for the proving.

ii. If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.

iii. Corrections for the temperature and pressure of the proving fluid must be made, where applicable.

iv. If a meter is proved after a period of regular operation, an "As Found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

v. acceptable proving must consist of four consecutive runs (one of which may be the "As Found" run), each providing a meter factor within ±0.5% of the mean of the four factors. The resultant meter factor is the average of the four applicable meter factors.

vi. Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

a) The meter serial number.

b) The date of the proving.

c) The name of the person performing the calibration.

d) The average meter factor.

e) The type of prover or master meter used.

2) Whether the volume readout is meter factor corrected or whether the volume readout is meter factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

3) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

4) A detailed record of the internal components inspection documenting the condition of the internal components "As Found" and any repairs or changes made to the internal components must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

5) If a meter used to measure non-delivery point or non-custody transfer condensate at flow-line conditions is a type that uses no internal moving parts (e.g., orifice meter, vortex meter, v-cone meter, coriolis, ultrasonic meter), the primary device does not require proving, provided that the following conditions are met:

   a. Flow through the meter must be continuous and maintained within the rates specified by the meter manufacturer as providing accurate measurement or be a coriolis-type meter with meter tube integrity internal diagnostics.

   b. If there is a dump valve as part of the measurement system, the dump valve must be checked for leaks and it documented at the same inspection or proving frequency.

   c. The design and operation of the entire meter system is in accordance with the meter manufacturer's specifications.

   d. The meter secondary and tertiary devices are calibrated at the frequencies specified above for meters used to measure condensate at flow-line conditions, using procedures specified by the American Petroleum Institute (API) in the Manual of *Petroleum Measurement Standards*, the AGA, the device manufacturer, or other applicable industry-accepted procedures, whichever are most appropriate and applicable.

6) The internal components of the primary meter device removed from service annually, inspected, cleaned, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by API in the Manual of *Petroleum Measurement Standards*, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's procedures, whichever are most applicable and appropriate. The internal inspection requirement can be met by using self-diagnostics of the primary element if equipped. A base line must be done when the meter is first installed. A report must be generated to document that the internal inspection was completed. Whenever possible, the inspection of internal components should be done at the same time as the meter end device maintenance, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.

   a. A tag or label is attached to the meter (or end device) and must identify:

      i. The primary device serial number.

      ii. The date of the maintenance.

      iii. Inspection date.

      iv. The name of the person performing the maintenance.

      v. Other relevant details (e.g., orifice plate size).

7) A detailed report indicating the tests conducted on the meter during the calibration and the conditions "As Found" and "As Left" is either left with the meter (or end device) or readily available for inspection by the BCER. If the report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

8) A detailed record of the internal components inspection documenting the condition of the internal components "As Found" and any repairs or changes made to the internal components is either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

2.7.4.1. **Other Liquid Hydrocarbon Meter Proving Requirements**

Meters used to measure other liquid hydrocarbons, such as Propane, Butane, Pentanes plus, Natural Gas Liquid (NGL), Liquefied Petroleum Gas (LPG), Liquefied Natural Gas (LNG) etc., are subject to the same proving requirements and exceptions as are meters used for measurement of condensate at equilibrium conditions or measurement of dead oil.

2.8. **Water Meters**

If a meter is used to measure water production, injection, or disposal or injection or disposal of other water-based fluids, the meter must be proved:

1) Within the first three months of operation. The meter factor may be assumed to be 1.0000 until the first proving is conducted.

2) Annually thereafter.

3) Immediately (by the end of the calendar month) following any repairs being conducted on or replacement of the meter. The resultant meter factor must be applied back to the volumes metered since the date of repair/change.

4) The proving may be conducted in line at field operating conditions, or the meter may be removed from service and proved in a meter shop, using water as the test fluid. The proving may be conducted using a volumetric prover, a gravimetric prover, or a master meter. Where a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove. Correction factors, as appropriate, must be used to adjust volumes to 15°C.

5) If a meter is proved after a period of regular operation, an "As Found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.

6) An acceptable proving must consist of four consecutive runs (one of which may be the "As Found" run), each providing a meter factor within ±1.5% of the mean of the four factors. The resultant meter factor is the average of the four applicable meter factors. Proving procedures using more than four runs will be allowed if the operator can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.

7) Subsequent to the meter proving, a tag or label must be attached to the meter and must identify:

    a. The meter serial number.

    b. The date of the proving.

    c. The name of the person performing the maintenance.

    d. The fact the proving was done in a shop.

    e. The average meter factor.

    f. The type of prover or master meter used.

8) Whether the volume readout is meter factor corrected or whether the volume readout is meter factor uncorrected. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to get the corrected volumes.

9) A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

10) A detailed record of the internal components inspection documenting any repairs or changes made to the internal components must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

2.8.1. **Water Meter Proving Exceptions**

If a meter used to measure water or other water-based fluids is a type that uses no internal moving parts (e.g., orifice meter, vortex meter, v-cone meter, coriolis, mag flow, etc.), the primary device does not require proving provided the following conditions are met:

1) Flow through the meter must be continuous (not intermittent) and maintained within the rates specified by the meter manufacturer as providing accurate measurement or be a coriolis-type meter with meter tube integrity internal diagnostics.
2) The design and operation of the entire meter system must be in accordance with the meter manufacturer's specifications.
3) The internal components of the primary meter device must be removed from service annually, inspected, cleaned, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by API in the Manual of Petroleum Measurement Standards, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's procedures, whichever are most applicable and appropriate. The internal inspection requirement can be met by using self-diagnostics of the primary element if equipped. A base line must be done when the meter is first installed. A report must be generated to document that the internal inspection was completed.

4) The meter end devices must be calibrated at the frequencies specified above for Water Meters, using procedures specified by the API in the Manual of Petroleum Measurement Standards, the AGA, the device manufacturer, or other applicable industry-accepted procedures.

5) A tag or label must be attached to the meter (or end device) and must identify:

   a. The primary device serial number.

   b. The date of the maintenance.

   c. Inspection date.

   d. The name of the person performing the maintenance.

   e. Other relevant details (e.g., orifice plate size).

f. A detailed report indicating the tests conducted on the meter during the inspection and the conditions "As Found" and "As Left" must be either left with the meter (or end device) or readily available for inspection by the BCER. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

2.9. Product Analyzers

If a product analyzer (water cut analyzer) is used to determine water production, it must be calibrated annually using procedures by the manufacturer.

Following the calibration, a tag or label must be attached to the product analyzer and must identify:

1) The primary device serial number.
2) The date of the calibration or prove.
3) The name of the person performing the calibration or proving.

A detailed report indicating the calibration procedure used and the calibration details must be either left with the analyzer or readily available for inspection by the BCER. If the detailed report is left with the analyzer or readily available, the foregoing requirement relating to the tag or label is considered to be met.

2.10. Automatic Tank Gauges

2.10.1. Inventory Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for monthly inventory measurement, they must be calibrated on site within the first month of operation and annually thereafter. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of BCER preference from first to last):

1) The device manufacturer's procedures.
2) Procedures described in the American Petroleum Institute *Manual of Petroleum Measurement Standards.*
3) Other applicable industry-accepted procedures that utilize auditable methods (i.e., sound engineering practices, industry IRP manuals, etc.).

If none of the foregoing exists, the BCER will consider other appropriate procedures. A record of the calibration and the procedure used must be made available to the BCER on request.

2.10.2. Tank Guage Delivery Point Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for delivery point measurement of hydrocarbon liquid or emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, they must be calibrated on site within the first month of operation and monthly thereafter. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of BCER preference from first to last):

1) The device manufacturer's procedures.
2) Procedures described in the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards*.

3) Other applicable industry-accepted procedures that utilize auditable methods (i.e., sound engineering practices, industry IRP manuals, etc.).

If none of the foregoing exists, the BCER will consider applications for and may grant approval of appropriate procedures. A record of the calibration and the procedure used must be made available to the BCER on request.

2.10.3. **Tank Guage Delivery Point Measurement Exception**

Where the accuracy of an automatic tank gauge is found to be within 0.5% of full scale for three consecutive months, the calibration frequency may be extended to quarterly. The record of calibration must clearly indicate that the device has been found to demonstrate consistent accuracy and is on a quarterly calibration frequency. The records of the calibrations that qualify the device for this exception must be kept and made available to the BCER on request. The calibration frequency will revert back to monthly whenever the accuracy is found not to be within 0.5% of full scale.

2.11. **Weigh Scales**

Weigh scales used to measure oil/water emulsion and clean oil receipts, Natural Gas Liquids (NGLs) or condensate at batteries/facilities, custom treating facilities, pipeline terminals, and other facilities must be approved and inspected prior to use, in accordance with Measurement Canada requirements.
Weigh scales must be tested for accuracy in accordance with the following schedule:

1) Monthly.

2) Immediately (by the end of the calendar month) following any incident in which the scale may have been damaged.

3) Immediately (by the end of the calendar month) following any changes or modifications being made to the scale.

4) The complete set of procedures set out by Measurement Canada for determining weigh scale accuracy must be used following any damage or modifications and at least annually. The monthly accuracy tests may be done using the complete set of procedures set out by Measurement Canada or, as a minimum, using the following abbreviated procedure:

   a) Zero check: Determine if the scale reads zero with no weight on the scale.
   b) Add a 10kg standard weight: Determine if the scale reads 10kg.
   c) Remove the 10kg standard weight: Determine if the scale returns to zero.
   d) Add a test load consisting of 10,000kg of standard weights or, alternatively, durable object(s) of known weight (minimum 5000kg): Determine if the scale reads the correct weight of the test load (acceptable error is ±0.2% of the test load).
   e) Add a loaded truck, typical of the loads routinely handled by the scale: Note the total weight of the test load and truck.
   f) Remove the test load and note the weight of the truck alone: Determine if the scale reading correctly indicates the removal of the test load (acceptable error is ±0.2% of the test load).
   g) Remove the truck: Determine if the scale returns to zero with no weight on the scale.

5) If as a result of the foregoing tests the weigh scale is found to not be accurate, it must be calibrated and retested until found to be accurate and then sealed by a heavy-duty scale service company. The service company must then send a written report to Measurement Canada documenting the adjustment and/or repairs.

6) A detailed record of the accuracy tests and any calibration activities must be kept in close proximity to the weigh scale, retained for at least one year, and made available to the BCER on request. This record must include the following information:

a) Make, model, serial number, and capacity of the weigh scale and any associated equipment.

b) Date of the accuracy test.

c) Details of the tests performed, and the results noted.

d) Details regarding any alterations or calibration performed on the weigh scale.

2.11.1. Weigh Scale Exceptions

1) If the volume of fluid measured by a weigh scale does not exceed $100m^3/d$, the monthly accuracy test frequency may be extended to quarterly. The detailed record of the accuracy tests must clearly indicate that the weigh scale measures $\leq 100m^3/d$ and that the weigh scale is on a quarterly testing frequency. The required testing frequency will revert back to monthly if the weigh scale begins measuring volumes in excess of $100m^3/d$.

2) If the weigh scale has been found to not require calibration adjustments for three consecutive months, the monthly accuracy test frequency may be extended to quarterly. The required accuracy test frequency will revert back to monthly whenever a quarterly accuracy test determines that the weigh scale requires calibration adjustments.

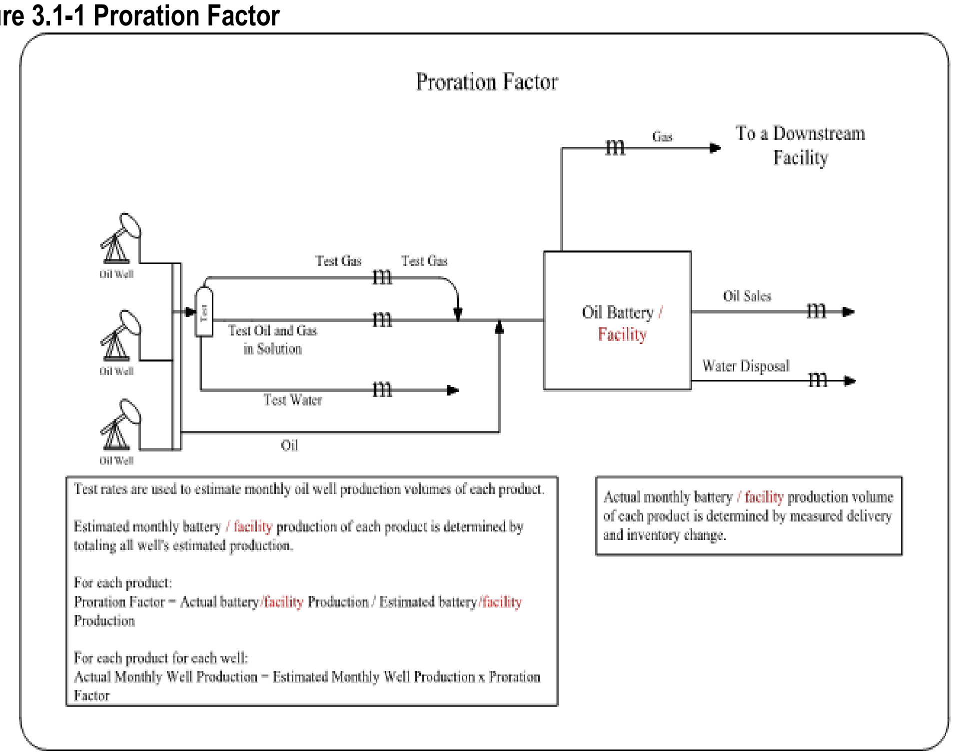
3. Chapter 3- Proration Factors, Allocation Factors and Metering Difference

3.1. Description

Proration is an accounting system or procedure where the total actual monthly battery/facility production is equitably distributed among wells in the battery/facility. This system is applicable when the production of wells producing to a battery/facility is commingled before separation and measurement, and each well's monthly production is initially estimated, based on well test production data. In this type of system, proration factors are used to correct estimated volumes to actual volumes.

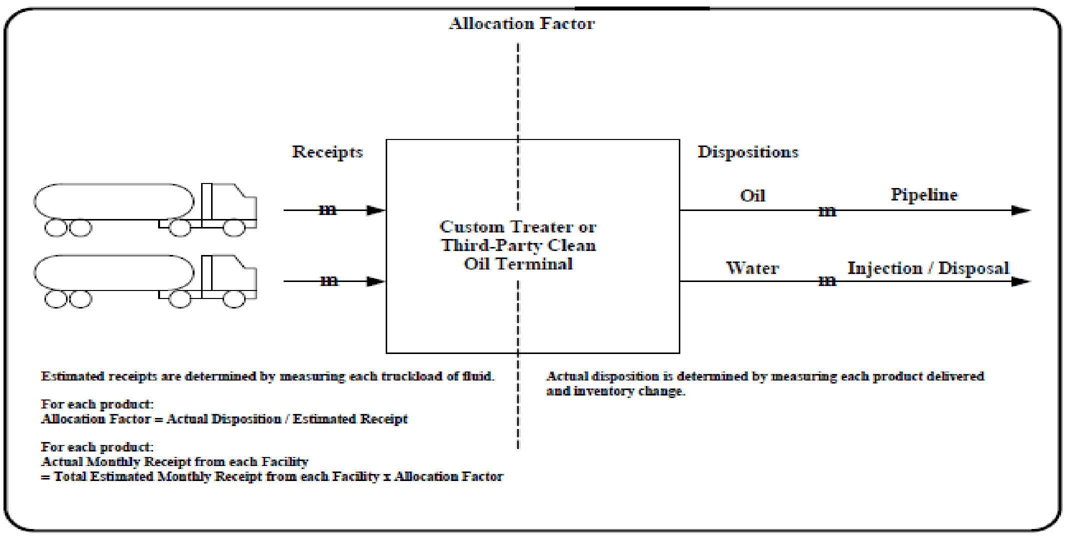
In the case of an oil proration battery/facility (see Figure 3.2-1 below), the oil, gas, and water produced by individual wells are not continuously metered. Instead, the wells are periodically tested to determine the production rates of oil, gas, and water. The rates determined during the well test are used to estimate the well's production for the time period beginning with the well test and continuing until another test is conducted. The estimated monthly production so determined for each well in the battery/facility must be used to arrive at the battery/facility total monthly estimated production. The total actual oil, gas, and water production volumes for the battery/facility are determined by means of separation, and for each fluid the total actual volume is divided by the total estimated production to yield a "proration factor." The proration factor is multiplied by each well's estimated production to yield the well's actual production. Similar accounting procedures are used for gas batteries/facilities subject to proration.

Figure 3.1-1 Proration Factor



An “allocation factor” is a type of proration factor. It is used at facilities where only fluids received by truck are handled, such as custom treating facilities and third party-operated clean oil terminals (see Figure 3.2-2 below). The name of the factor has been chosen to reflect the differences between batteries/facilities that receive fluids from wells through flow lines (where proration factors are used) and facilities that receive fluids from batteries/facilities only by truck (where allocation factors are used). The purpose of an allocation factor is similar to a proration factor, in that it is used to correct fluid receipt volumes (considered estimates) to actual volumes based on disposition measurements taken at the outlet of the battery/facility (and also considering inventory change). The allocation factor is determined by dividing the monthly total actual volume for each fluid by the monthly total estimated volume for each fluid. The total estimated volume of each fluid received from each source is multiplied by the allocation factor for that fluid to yield the actual volume received from that source.

Figure 3.1-2 Allocation Factor



The allocation factors discussed in this Chapter are not to be confused with the process whereby products delivered out of a gas plant are “allocated” back to each well in the system, based on individual well production volumes and gas analyses.

Measurement accuracy and uncertainty generally relate to random errors, and, as such, are not directly comparable to proration and allocation factors, which generally relate to bias errors. The Standards of Accuracy (Chapter 1) focus on specific measurement points (i.e., inlet or outlet), whereas proration and allocation factors relate to a comparison of inlet (or estimated production) to outlet measurement. It is important to note that target factors for different products may be different because of the products’ being subjected to different levels of uncertainty. For example, the target factors for oil and water in a conventional oil proration battery/facility are different because while the estimated production volumes of oil and water are determined by the same type of measurement, the outlet volumes of the clean oil and water are not determined by the same type of measurement.

When measurement equipment and procedures conform to all applicable standards, it is assumed that generally the errors that occur in a series of measurements will be either plus or minus and will cancel each other out to some degree. Where a bias error occurs in a series of measurements, there will be no plus/minus and all of the measurements are assumed to be in error by the same amount and in the same direction. Proration factors and allocation factors are therefore used to equitably correct all measurements for biased errors.

3.1.1. **Target Factors**

If measurement and accounting procedures meet applicable requirements, any proration factor or allocation factor should be acceptable, since it is assumed that the factor will correct for a bias error that has occurred. However, the BCER expects proration factors and allocation factors to be monitored by operators and used as a "warning flag" to identify when the measurement system at a battery/facility is experiencing problems that need investigation.

The BCER deems the ranges of proration factors and allocation factors indicated below to be acceptable targets. When a factor is found to exceed these limits, the operator is expected to investigate the cause of the factor being outside the target range and document the results of the investigation and the actions taken to correct the situation. The BCER acknowledges that in some batteries/facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where factors are consistently in excess of the targets indicated below. In that case, the operator must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the BCER but must be available to the BCER on request for audit.

If the cause of a factor being outside these ranges is determined and the error can be quantified, the BCER expects the reported production data to be amended, thereby bringing the factor back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

3.2. **Introduction**

No two metering devices will measure the same stream exactly. This Chapter presents the requirements for addressing the variances in metering within different types of batteries and facilities.

3.2.1. **Target Factor Exception**

An exception to the foregoing procedure is allowed for conventional oil proration batteries/facilities if based on average rates determined semi-annually:

1) All wells in the battery/facility produce ≤2m^3/d of oil, or

2) The majority of the wells in the battery/facility produce ≤2m^3/d of oil and no well produces greater than 6m^3/d of oil.

In this case, the operator should still be aware of the proration factors and take corrective action where necessary, but need not expend a great deal of effort to conduct an investigation and document the results.

3.2.2. **Acceptable Proration Factors and Allocation Factor Ranges**

This section describes acceptable proration factors for a conventional oil battery/facility and a gas battery/facility (effluent measurement). Allocation factors are noted for a custom treating facility and clean oil terminal.

3.2.3. Proration Factors

Table 3.2-1 Oil Battery / Facility (Petrinex 322)

Type of Fluid	Low	High
Oil	0.95	1.05
Gas	0.90	1.10
Water	0.90	1.10

Table 3.2-2 Proration Gas Battery / Facility (Petrinex 364)

Type of Fluid	Low	High
Gas	0.90	1.10
Water	0.90	1.10
Condensate (If applicable – volumes are tanked at the battery/facility).	0.90	1.10

Table 3.2-3 Gas Multi-well Effluent Measurement Battery / Facility (Petrinex 362)

Type of Fluid	Low	High
Gas	0.95	1.05
Water	0.90	1.10
Condensate	0.95	1.05

3.2.4. Allocation Factors

Table 3.2-4 Custom Treating Facility (Petrinex 611)

Type of Fluid	Low	High
Oil	0.95	1.05
Water	0.90	1.10

Table 3.2-5 Clean Oil Terminal (Third Party operated, where applicable)

Type of Fluid	Low	High
Oil	0.95	1.05

3.2.5. **Metering Difference Description**

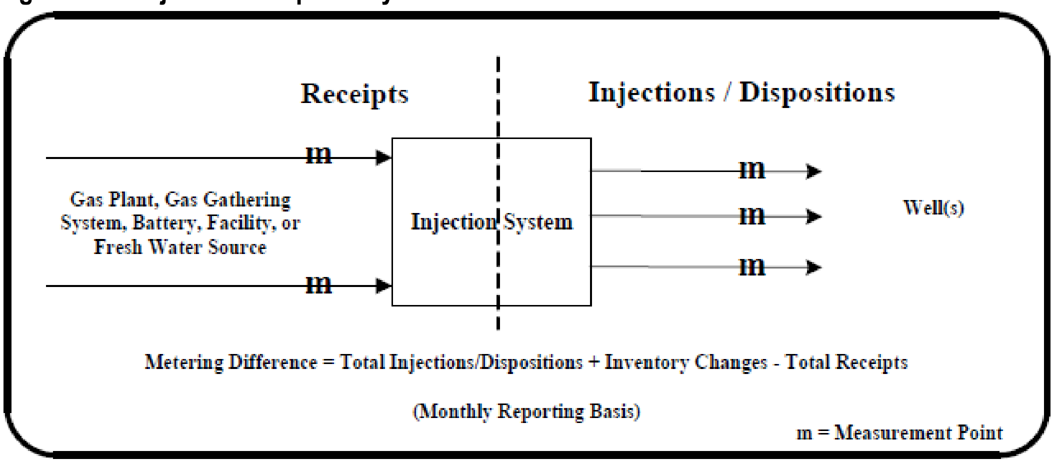
For BCER and FIN production reporting purposes, a "metering difference" is used to balance monthly, any difference that occurs between the metered inlet/receipt volumes and the metered outlet/disposition volumes at a battery/facility. Metering difference is generally acceptable as an accounting and reporting procedure if a difference results from two or more measurements of the same product. Metering differences occur because no two measurement devices provide exactly the same volume due to the uncertainties associated with the devices. However, a more significant cause of metering differences is that the product metered at the inlet to a battery/facility is usually altered by the process within the battery/facility, resulting in a different product or products being metered at the outlet of the battery/facility. It should be noted that metering difference differs from proration and allocation factors in that for batteries/facilities where those factors are used, the difference occurs between "estimated" and "actual" volumes.

A metering difference may be used as follows:

3.2.5.1. **Injection/Disposal Systems**

Receipts into these facilities are typically metered prior to being split up and delivered to individual wells, where each well's volume is metered prior to injection/disposal.

Figure 3.2-1 Injection / Disposal Systems



3.2.5.2. **Batteries/Facilities**

A metering difference may be used for gas and water production only, and only in limited, specific situations where there is both inlet and outlet measurement, for example, at a crude oil group battery/facility where each well's gas production is metered, and the combined gas stream is metered again before being sent to a gas gathering system or gas plant. Metering differences would not be appropriate for use in a proration battery/facility.

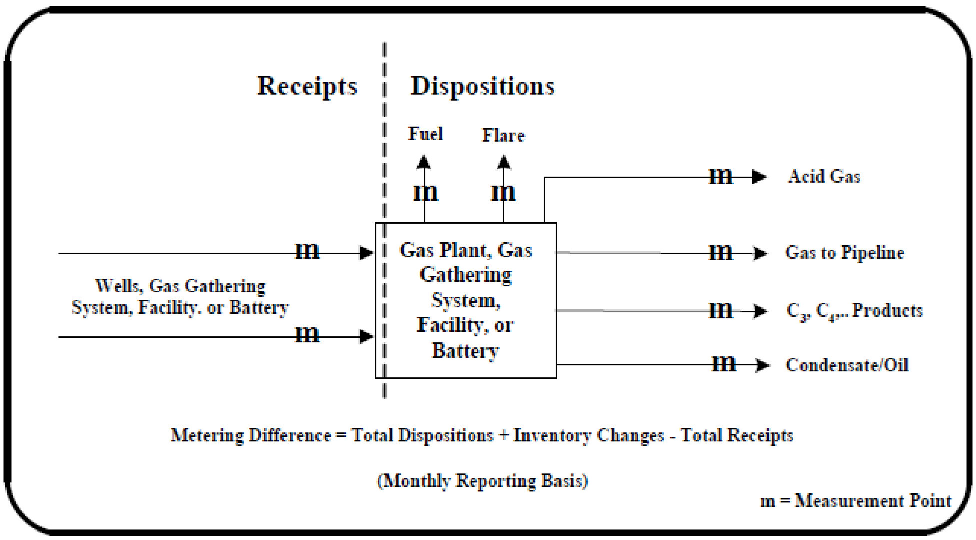
3.2.5.3. **Gas Gathering Systems – Limited Application in British Columbia**

Receipts into these facilities are typically metered prior to being subjected to some sort of limited processing, which may include liquids removal and compression. The resultant product(s) are metered prior to delivery to a sales point or to a gas plant for further processing.

3.2.5.4. **Gas Plants**

Receipts into these facilities are typically metered prior to being processed into saleable products, and those products are metered prior to delivery to a sales point.

Figure 3.2-2 Metering Difference



3.2.6. **Target Metering Difference**

If measurement and accounting procedures meet applicable requirements, metering differences up to ±5% of the total inlet/receipt volume are deemed to be acceptable. The BCER expects the metering difference to be monitored by operators and used as a "warning flag" to identify when the measurement system at a battery/facility is experiencing problems that need investigation.

When a metering difference is found to exceed 5%, the operator is expected to investigate the cause of the poor metering difference and document the results of the investigation and the actions taken to correct the situation. The BCER acknowledges that in some batteries/facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where the metering difference is consistently in excess of the target indicated. In such cases, the operator must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the BCER but must be available to the BCER on request for audit purposes.

If the cause of a poor metering difference is determined and the error can be quantified, the BCER expects the incorrectly reported production data to be amended, thereby bringing the metering difference back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

4. Chapter 4 - Gas Measurement

4.1. Introduction

Dealing with gas measurement from any source in the upstream and midstream oil and gas industry, this Chapter presents the base requirements and exceptions used to determine volumes for reporting to FIN.

4.2. General Requirements

All gas production and injection volumes must be continuously and accurately metered with a measurement device or determined by engineering estimation if exception conditions described are met or site-specific BCER approval has been obtained. A gas measurement system is in compliance if the base requirements throughout this manual are met. It should be noted that the BCER may stipulate additional requirements for any specific situation.

Monthly gas volumes must be reported in units of e^3m^3 and rounded to 1 decimal place. Standard or base conditions for use in calculating and reporting gas volumes are 101.325kPa (absolute) and 15°C.

4.3. Gas Measurement and Accounting Requirements for Various Battery / Facility Types

4.3.1. Oil Facilities

4.3.1.1. General Requirements

1) All wells in the battery/facility must be classified as oil wells.
2) All wells in a multi-well battery/facility must be subject to the same type of measurement.
3) Production from gas wells, gas facilities, or other oil facilities must not be connected to an oil proration battery/facility upstream of the oil battery/facility group gas measurement point unless specific criteria are met and/or BCER approval of an application is obtained. For examples see section 5.6

4.3.1.2. Single-Well Battery / Facility (Petrinex subtype 311)

1) Gas must be separated from oil, or oil emulsion and measured (or estimated where appropriate) as a single phase.

4.3.1.3. Multi-Well Group Battery / Facility (Petrinex subtype 321)

1) Each well must have its own separation and measurement equipment, similar to a single-well battery/facility.
2) All equipment for the wells in the battery/facility must share a common surface location.

4.3.1.4. **Proration Battery / Facility (Petrinex subtype 322)**

1) All well production is commingled prior to the total battery/facility gas being separated from oil or emulsion and measured (or estimated where appropriate) as a single phase.

2) Individual monthly well gas production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

4.3.2. **Gas Facilities**

4.3.2.1. **General Requirements**

1) Well production volumes must be determined as per Chapter 6 Determination of Production at Gas Wells.

2) All wells in the battery/facility must be classified as gas wells.

3) Gas wells may produce condensate.

4) All wells in a multi-well battery/facility must be subject to the same type of measurement. If there are mixtures of metered and prorated wells (mixed measurement) within the same battery/facility, BCER exception criteria in Chapter 5, "Site-Specific Deviation from Base Requirements," in section 5.6 be met or BCER site-specific approval must be obtained, and the metered well(s) must have their own separate battery/facility code(s) to deliver gas into the proration battery/facility. Conversely, well(s) with no phase-separated measurement, including effluent wells, are not allowed to tie into a multi-well group battery/facility unless there is a group measurement point before the tie-in.

5) All wells in a multi-well battery/facility must be connected by pipeline to a common point.

6) Gas production from oil wells or facilities or from other gas wells or facilities must not be connected to a gas proration battery/facility upstream of the gas proration battery/facility group measurement point unless BCER exception criteria in Chapter 5 "Site-Specific Deviation from Base Requirements" under "Measurement by Difference" are met or BCER site-specific approval is obtained.

7) Any oil and gas battery/facility, such as a well site, gas plant, battery/facility, or individual compressor site, that is designed to consume fuel gas exceeding $0.5e^3m^3/d$ on a per site basis must have fuel gas measurement installed. If it is part of another battery/facility located on the same site, the overall site fuel gas used must be metered.

4.3.2.2. **Single-Well Battery / Facility (Petrinex subtype 351)**

1) Gas must be separated from water and condensate or oil (if applicable) and continuously metered as a single phase.

2) Condensate produced must be reported as a liquid if it is disposed of from the well site without further processing. For wells that produce ≤ 2.0 m3/d of total liquid (i.e., condensate or oil and water) and that direct condensate or oil and water production to lease tanks or to a single emulsion tank, operators may use the disposition equals production reporting methodology for reporting condensate or oil and water production. This reporting methodology eliminates the requirement to report monthly condensate or oil and water tank inventories.

If operators choose to use this reporting method:

a) they must account for existing tank inventories of condensate or oil and water with the initial reporting, and

b) if the well status is changed to inactive after implementation, the condensate or oil and water tank inventories must be disposed of (i.e., tanks emptied) in the reporting month that the well status is changed.

3) The disposition equals production method of reporting may also be used for water reporting in the case where the separated condensate or oil is recombined with the gas stream and sent to a gathering system and the separated water is directed to a lease tank for disposition.

4) Condensate that is recombined with the gas production after separation and measurement or trucked from the well site to a gas plant for further processing must be converted to a gas equivalent volume and added to the metered single-phase gas volume for reporting purposes.

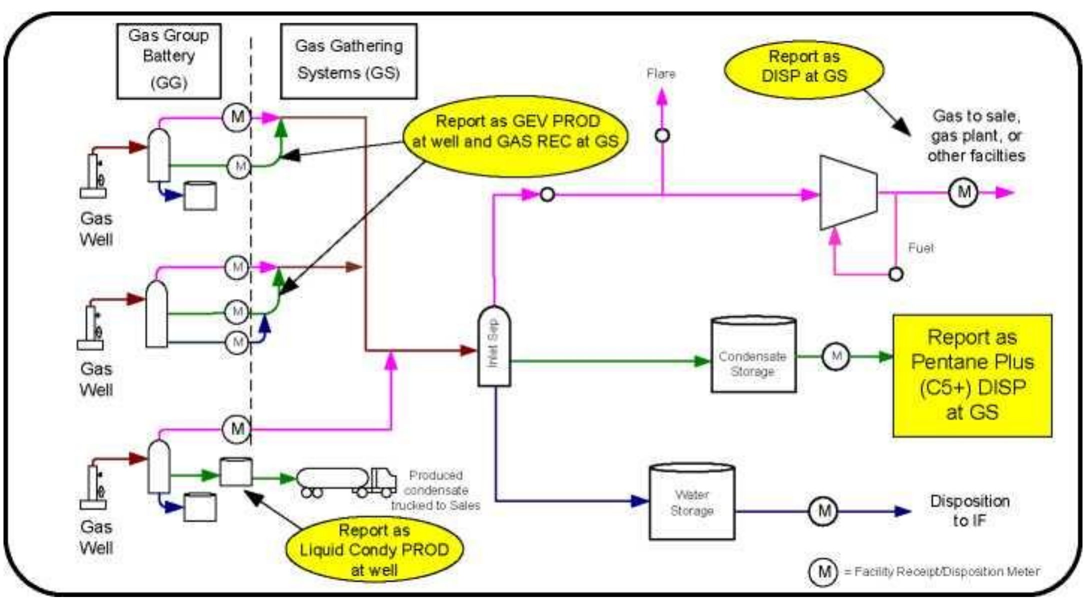
5) Oil produced in conjunction with the gas must be reported as oil at stock tank conditions. The gas-in-solution (GIS) with the oil at the point of measurement must be estimated and added to the gas production volume (see section 4.4.6).

4.3.2.3. **Multi-Well Group Battery / Facility (Petrinex subtypes 361, 365)**

1) Each well must have its own separation and measurement equipment, similar to a single-well battery/facility.

2) The wells in the group battery/facility may all be identical with regard to handling of condensate and water, or there may be a mixture of methods for handling condensate. The rules for reporting condensate as a gas equivalent or as a liquid are the same as those for single-well gas facilities (see above).

3) The volumes metered at each well separator must be used to report the production to the "PROD" volume in Petrinex. There must not be any proration from any downstream measurement point.



4) There is no group measurement point requirement for fluids from the gas group wells, but the wells must deliver to a common battery/facility. Hydrocarbon liquids and/or water may be tanked and disposed of by truck and reported as liquid disposition. Recombined hydrocarbon liquids (reported as gas equivalent volume) and water (reported as liquid water) must be sent to the same common battery/facility as the gas. Multiple gas facilities can deliver to a common battery/facility.

5) If the gathering system further disposes of the fluids, similar to the above schematic, each fluid type (gas, hydrocarbon liquids, water) disposition must be measured and reported. The gathering system must also report a metering difference.

4.3.2.4. **Multi-well Proration Battery/Facility (Petrinex subtype 364)**

A production facility and reporting entity consisting of two or more gas wells where production from the wells in the battery is commingled before measurement. The battery group production must be prorated to the individual wells based on test data. This battery configuration requires specific approval from the BCER Pipelines & Facilities Engineering Branch.

4.3.2.5. **Gas Multi-well Effluent Measurement Battery / Facility (Petrinex subtype 362)**

1) The production from each well is subject to total effluent (wet gas) measurement, without separation of phases prior to measurement.

2) Estimated well gas production is the effluent metered volume multiplied by an Effluent Correction Factor (ECF) that is determined from periodic tests conducted at each well in which a test separator is connected downstream of the effluent meter and the volumes measured by the test separator are compared to the volume measured by the effluent meter.

3) Estimated well water production is determined by multiplying the water-gas ratio (WGR), which is determined from the periodic tests, by the estimated well gas production.

4) At royalty trigger points, where delivery point measurement is required, the combined (group) production of all wells in the effluent proration battery must have three-phase separation and be measured as single-phase components. At delivery points that are not royalty trigger points and where delivery point measurement is not required, the group production may be measured using “two-phase separation with three-phase measurement.” This means that a two-phase separator with an on-line product analyzer on the liquid leg of the separator may be used provided that:

    a) the condensate and water is recombined and delivered to a gas gathering system or gas plant for further processing.

    b) The resulting total actual battery/facility gas volume (including gas equivalent volume [GEV] of condensate) and total actual battery/facility water volume must be prorated back to the wells to determine each well’s actual gas and water production. If condensate is trucked out of the group separation and measurement point without further processing to a sales point, condensate production must be reported at the wellhead based on the condensate-gas ratio (CGR) from the well test. If liquid condensate is trucked to the same gas plant that gas delivers to for further processing, the condensate must be reported as a gas equivalent.

4.3.3. **Gas Gathering System (Petrinex subtype 621)**

A battery/facility consisting of pipelines used to move gas production from oil batteries/facilities, gas batteries/facilities, and/or other batteries/facilities to another battery/facility (usually a gas plant) is considered to be a gas gathering system. The system may include compressors, line heaters, dehydrators, and other equipment.

Inlet measurement usually consists of the battery/facility group measurement point. Outlet measurement usually consists of the gas plant inlet measurement.

4.3.4. **Gas Processing Plant (Petrinex subtypes 401, 402, 403, 404, 405, 406,408)**

A "gas processing plant" is a plant where hydrogen sulphide, carbon dioxide, helium, ethane, natural gas liquids, or other substances are extracted from raw gas. It does not include a facility that :

a) uses, for the exclusive purpose of processing low-volume fuel gas,

   viii) a regenerative system for the removal of hydrogen sulphide or carbon dioxide and emits less than 2 tonnes/day of sulphur, or

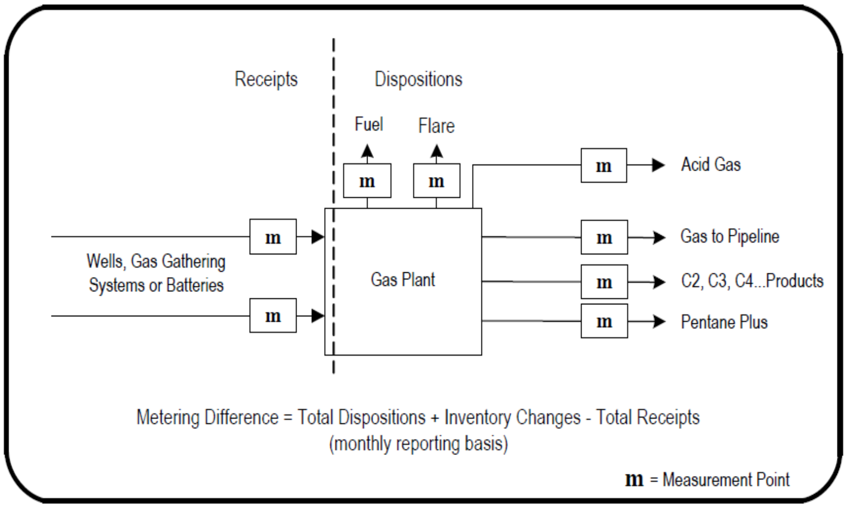
   ii) a liquid extraction process such as refrigeration to extract hydrocarbon liquids from a gas stream, or

b) uses a non-regenerative system for the removal of hydrogen sulphide or carbon dioxide.

Each plant inlet stream must have inlet separation and continuous measurement for all liquids and gas before commingling with other streams and must be used to report volume to Petrinex for the plant receipt from upstream facilities and for plant balance. However, there are situations where the raw gas has been stripped of its liquid (not recombined downstream) and metered upstream of the plant site. If all streams entering a gas plant on the same gas gathering system are "dry" (the absence of free liquids via dehydration or equivalent process), the gas plant inlet measurement may consist of the gas gathering system outlet measurement or battery/facility group measurement.

Measurement of all gas deliveries out of a gas plant, such as sales, lease fuel for other facilities, flare and vent gas, acid gas disposition, and any volumes used internally, is required unless otherwise exempted by the BCER. Monthly liquid inventory change must be accounted for and reported to Petrinex (see Figure 4.3-1 Typical Gas Plant Measurement and Reporting Points.

Figure 4.3-1 Typical Gas Plant Measurement and Reporting Points

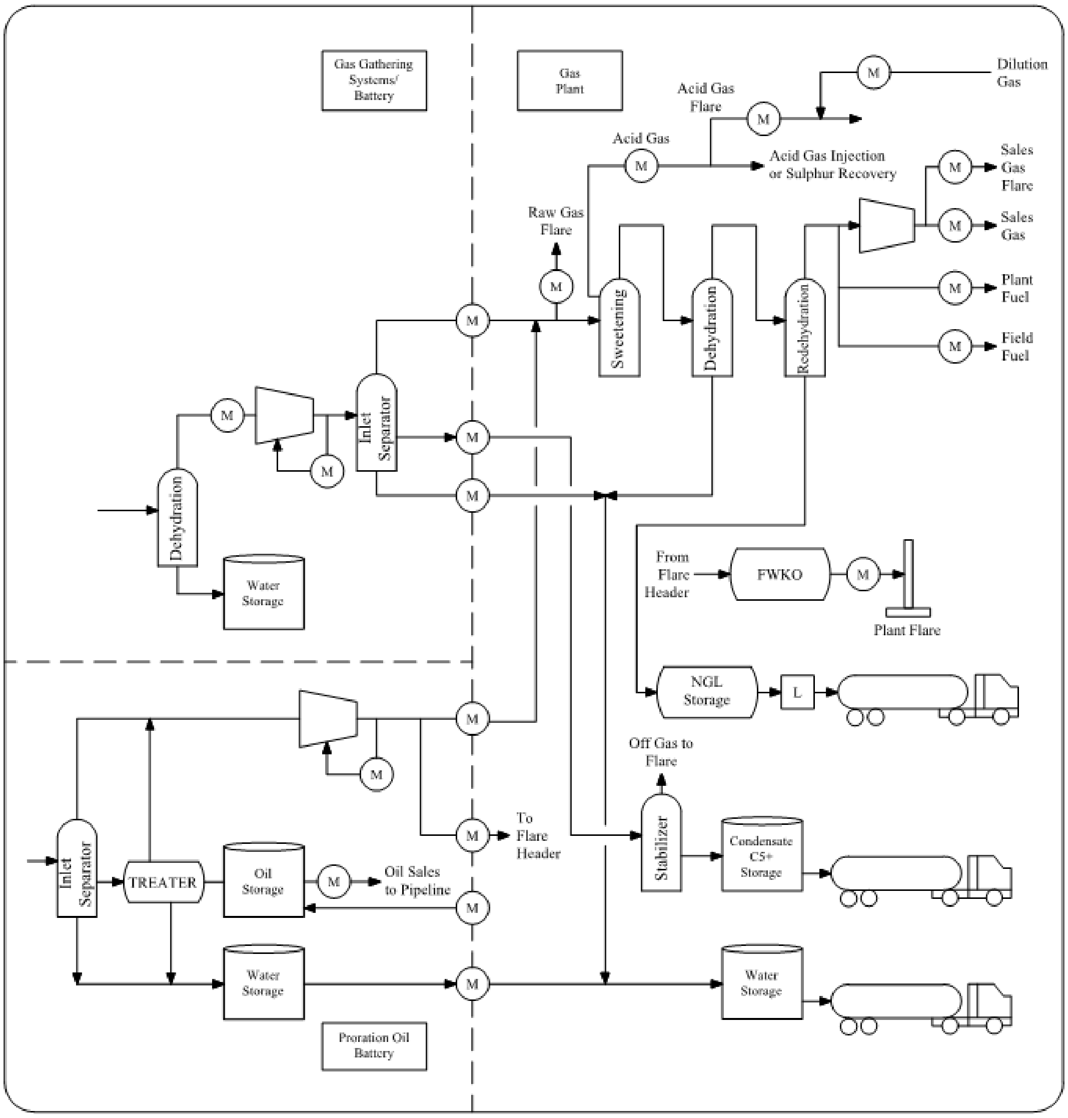


4.3.4.1. **Delineation for an Oil Battery / Facility delivering to or receiving from a gas plant same site**

Oil battery/facility gas and water sent to a gas plant for further processing or disposition and gas for flaring must be metered and reported as disposition from the oil battery/facility to the gas plant. The gas plant must report the receipts, total flare, and dispositions.

Gas plant condensate, C5+, and/or NGL sent to an oil battery/facility must be metered and reported as disposition to the oil battery/facility. This is a royalty trigger point requiring delivery point measurement. Oil must not be combined with any other royalty payable product (i.e., NGL, C5+ and/or condensate) without all products being measured and reported.

Figure 4.3-2 Oil Battery / Facility Delivering to, or Receiving from a Gas Plant



4.3.4.2. **Gas Fractionation Plant (Petrinex subtype 407)**

Condensate delivered to a gas fractionation plant permitted by the BCER as a facility must be measured and reported in m3 by the operator of the fractionation facility as condensate received and reported, in accordance with existing BCER requirements for trucked production.

4.4. Base Requirements for Gas Measurement

4.4.1. Design and Installation of Measurement Devices

The design and installation of measurement devices must be in accordance with the following or as approved by Measurement Canada.

4.4.1.1. Orifice Meter

1) If an orifice meter is used to measure gas, it must be designed and installed according to the applicable American Gas Association (AGA) Report #3: *Orifice Metering of Natural* Gas *and Other Related Hydrocarbon Fluids* (AGA3) listed in Table 4.4-1 and Figure 4.4-3 Typical Gas Orifice Meter Run

Table 4.4-1 Orifice Meter Design Requirement

Meter Run Date of Manufacture	Applicable AGA3 (API *MPMS* 14.3, Part 2) Version
Before January 2008	**Non-AGA** meter run or run not marked with upstream and downstream ID-markings are grandfathered for the existing volumetric throughput application; however, if the meter is **relocated**, it must be **refurbished** to AGA3 (1985) or later specification, but cannot be used for sales/delivery point or Cross Border measurement. AGA3 1991 or earlier meter run with upstream and downstream ID marking may be reused or relocated except to replace a meter where AGA3 2000 specification is required.
After January 2008 (Except for sales/delivery point meters or Cross Border measurement volumes)	February 1991 (AGA3 1991) or April 2000 (AGA3 2000)
All sales/delivery point meters manufactured after January 2008	April 2000 (AGA3 2000)
Cross Border measurement Volumes (Refer to Cross Border measurement, chapter 7)	April 2000 (AGA3 2000)

2) When a meter such as a gas plant outlet meter is used to check sales/delivery point (royalty trigger point) measurement and is not normally used to report volumes to FIN, it does not require AGA3 April 2000 specification. However, when another gas source ties into the sales pipeline between the check meter and the sales/delivery point meter (royalty trigger point), the check meter could be used to report volumes to the FIN. In this case, the AGA3 April 2000 specification is required if the meter is manufactured after January 2008 as shown in the following figures below.

Figure 4.4-1 Orifice Meter AGA3 2000 Specification - Optional

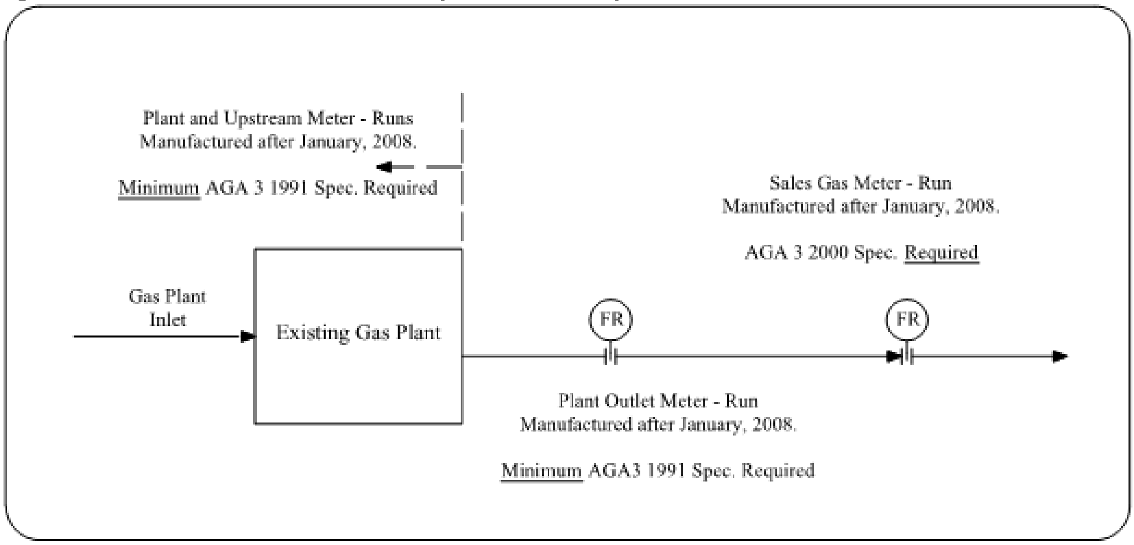
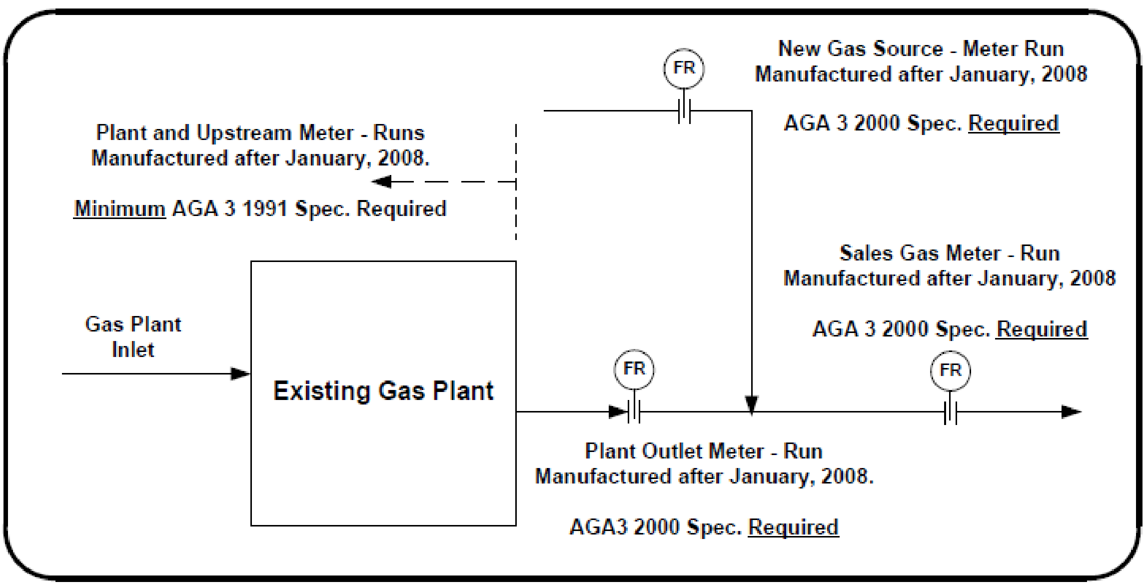


Figure 4.4-2 Orifice Meter AGA3 2000 Specification - Mandatory



3) A permanently marked plate with the following information must be attached to each meter run. This plate must be maintained in readable condition (not painted over or covered with insulation, etc.) for inspection:

a) Manufacturer's name

b) Serial number.

c) Date of manufacture.

d) Average upstream inside diameter (U/S) of the meter run at 25.4mm upstream of the orifice plate, to one decimal place if in millimeters, or to three decimal places if indicated in inches.

e) AGA3 Version/year (for new runs only after January 2008), e.g., "AGA3/1991" or "AGA3/2000."

4) Meter runs that are manufactured before January 2008 and designed to the AGA3 1991 or earlier specifications complete with the upstream and/or downstream ID markings may be relocated or reused for the application they are designed for. (See Table 4.4-1 Orifice Meter Design Requirement).

   a. For existing in-service meter runs that are manufactured before January 2008 and are not designed to the AGA3 2000 or earlier specifications at the time of manufacture or not marked with upstream and/or downstream internal diameter(s) [ID(s)], nominal pipe ID can be used for flow calculations. These meter runs are grandfathered for the existing volumetric throughput. If new gas volumes are added to such an existing meter run or if a meter run must be relocated, it must be inspected or refurbished to ensure that it meets the minimum of AGA3 1985 specifications, but it must not be used for sales/delivery point (royalty trigger point) measurement.

   b. The orifice plate must be permanently marked with the plate bore in millimetres to two decimal places (or to three decimal places if indicated in inches), preferably within 6mm of the outside edge of the plate, to avoid interfering with normal flow if the marking creates a dent or protrusion on the plate surface.

4.4.2. **General Installation**

All meters, regardless of the metering technology, must utilize the following installation requirements as appropriate:

1) Reporting meters using differential pressure sensing devices must be equipped with full port valves at the metering tap on the sensing lines. The valves must be the same size as the sensing lines (12.7 mm [1/2 inch] minimum for meter runs 102 mm [4 inches] in diameter or larger, and 9.5 mm [3/8 inch] minimum for meter runs less than 102 mm). All metering design and installation must ensure that the sensing line diameter does not change from the sensing tap valve to the manifold for delivery point, group point, and sales point measurement.

2) Sensing lines must be self-draining such that they drain towards the sensing taps to prevent liquid from being trapped in the line and disrupting measurement accuracy. This means that sensing lines should not exceed 1m in length and should have a slope of 25.4mm per 300mm from the transmitter to the changer.

3) Drip pots are **not** permitted to be installed on sensing lines for delivery point or sales point measurement points. All other reporting meters installed after June 1st, 2013, are **no** longer permitted to have drip pots installed to ensure measurement integrity.

4) Sharing of metering taps by multiple differential pressure devices is **not** allowed if it will cause increased measurement uncertainty, such as painting or spiking charts, or under pulsation conditions.

5) A separate set of valve manifolds must be used for each device.

6) Any measurement under vacuum conditions must have absolute pressure measurement to accurately measure the static pressure.

4.4.2.1. **Exceptions - Sensing Line Tap Valves and Changes in Sensing Line Diameter**

1) Grandfathering of existing differential pressure-sensing tap valves for installation before Jan, 2008, is granted without application unless:

   a) the metering device is being upgraded, refurbished, and commissioned within a new application or relocated; or
   b) the metering device does not meet the single point uncertainty limit, as detailed in section 1, “Standards of Accuracy;” or
   c) the metering point is subject to noticeable pulsation effects, such as physical vibration or audible flow noise, or is downstream of a reciprocal compressor on the same site; or
   d) the metering point is at a delivery point, group point, sales point (royalty trigger point), or custody transfer point.

2) Grandfathering of changes in sensing line diameter from the sensing tap to the manifold, such as drip pots, installed before Jan, 2008, is granted without application unless:

   a) the metering device does not meet the single point uncertainty limit, as detailed in section 1, “Standards of Accuracy;” or
   b) the metering point is subject to noticeable pulsation effects, such as physical vibration or audible flow noise, or is downstream of a reciprocal compressor on the same site; or
   c) the metering point is at a delivery point, group point, sales point (royalty trigger point), or custody transfer point; or
   d) the fuel measurement point has a clean, dry fuel source at a facility, such as a gas plant.

If the current metering installation does not meet the grandfathering requirement, operators must make any necessary changes required to bring the installation into compliance with this section.

7) Orifice Meters

Chart recorders, sensing lines, and other piping must be in good operating condition and suitably winterized to prevent them from freezing and disrupting measurement. The exception is clean dry sales specification gas with minimal moisture, which is acceptable not to winterize.

   a. Orifice plate sizes must follow the latest AGA Report No. 3, *General Equations and Uncertainty Guidelines*, Chapter 1.12.4.3.

   b. Secondary measurement equipment on an orifice meter run must be connected to one non-shared set of orifice flange taps.

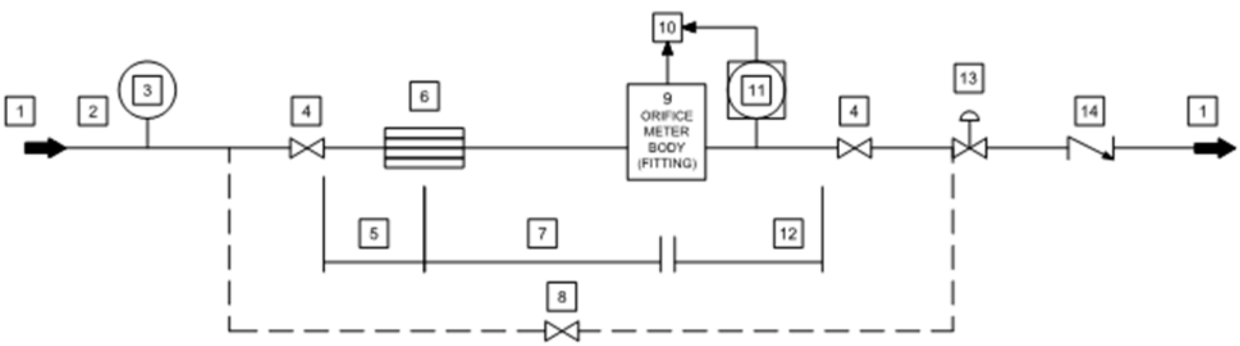
   c. The plate bore diameter compared to the meter tube internal diameter or Beta Ratio must be in a range from 0.15 to 0.75.

   d. The orifice meter must be in good operating condition.

e. The chart drive for a circular chart recorder used to measure gas well gas production or group oil battery/facility gas production must not be more than 8 days per cycle unless the exception criteria specified in Chapter 5, “Site-Specific Deviation from base Requirements,” are met or BCER site-specific approval is obtained. A 24-hour chart drive is required for gas measurement associated with single well oil wells and oil well test gas measurement unless the exception criteria specified in Chapter 5,“Site-Specific Deviation from Base Requirements,” are met or BCER site-specific approval is obtained. If the mode of operation causes painting on the chart because of cycling or on/off flows, a 24-hour chart is required for any gas measurement point or EFM must be used.

f. Temperature measurement equipment must be installed according to AGA3 specifications, and the temperature must be determined as per item 15 below. The tip of a thermowell must be located within the center third of the pipe.

Figure 4.4-3 Typical Gas Orifice Meter Run



1. Flow direction
2. Upstream sample point straight length requires 5 diameters prior to sample point
3. Manual sample point or auto sampler with probe
    i. To be installed as required (see section 1)).
4. Block valve, if required
5. Straight length required upstream of flow conditioner / straightening vane
    i. To be installed as per AGA 3 or manufacturer’s specifications
6. Flow conditioner / straightening vane
    i. To be installed as per AGA 3 or manufacturer’s specifications
7. Straight length required upstream of orifice meter body
8. Meter bypass (optional) with block valve
    i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
9. Orifice meter body (fitting)
10. Electronic flow measurement (EFM) device (optional)
11. Temperature transmitter
    i. To be installed as per AGA 3 or manufacturer’s specifications
12. Straight length required downstream of orifice meter body (fitting)
13. Control valve (as required)
14. Check valve (as required)

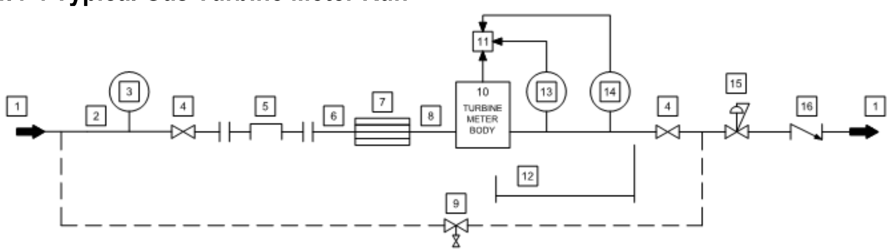
8) Linear Meter

a. If a turbine or vortex meter is used to measure gas, it must be designed and installed according to the provisions of the 1985 or later editions of the AGA Report #7: *Measurement of Gas by Turbine Meters* (AGA7), the manufacturer's installation requirements, or Figure 4.4-4 Typical Gas Turbine Meter Run

b. Temperature measurement equipment must be installed according to AGA7 (i.e., between one and five pipe diameters downstream of the meter) or the meter manufacturer's specifications, and the temperature must be determined as per item 16 below. The tip of the thermowell must be located within the center third of the pipe diameter.

c. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, electronic flow measurement) or at a later date (e.g., pressure and temperature charts).

Figure 4.4-4 Typical Gas Turbine Meter Run



1. Flow direction
2. Upstream sample point straight length requires 5 diameters prior to sample point
3. Manual sample point or auto sampler with probe
    i. To be installed as required (see section 1)).
4. Block valve, if required
5. Strainer
6. Straight lengths required upstream of flow conditioner / straightening vane
    i. To be installed as per AGA 7 or manufacturer's specifications
7. Flow conditioner / straightening vane
8. Straight lengths required upstream of turbine meter body.
    i. To be installed as per AGA 7 or manufacturer's specifications.
9. Meter bypass (optional) with block valve
    i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
10. Turbine meter body
11. Electronic flow measurement (EFM) device (optional)
12. Straight length required downstream of turbine meter body as per AGA 7
13. Pressure measurement device
14. Temperature measurement device
15. Control valve (as required)
16. Check valve (as required)

9) Rotary Meter

a. If a rotary meter is used to measure gas, it must be designed and installed according to the provisions of the 1992 or later edition of the American National Standards Institute (ANSI) B109.3: Rotary Type Gas Displacement Meters, the manufacturer's specifications, or Figure 4.4-5 Typical Positive Displacement Meter Run

b. Install pressure taps not more than 20 pipe diameters upstream and downstream of the meter, to allow for measuring pressure drop across the meter and determining if the meter is over-ranging, if required. It is acceptable for the tap openings to be present within the meter body. The upstream tap must be used for pressure measurement and must be reading the metering pressure (i.e., there must be no pressure restriction between the tap and the meter, such as a regulator).

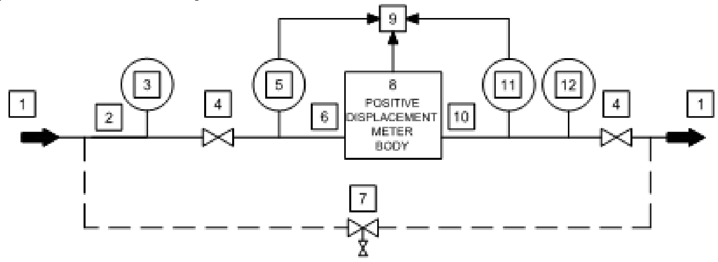
c. Equip the meter with a non-reset counter. This can be mechanical or electronic.

d. Install temperature measurement equipment according to the meter manufacturer's specifications or less than 20 pipe diameters downstream of the meter, with no restrictions between the meter and the temperature probe. The temperature must be determined as per item 16 below. The tip of the thermowell must be located within the center third of the pipe diameter.

e. Fuel gas meters that are operating under constant pressure, such as continuous measurement downstream of a pressure regulating valve, may utilize seasonal pressure and temperature correction factors for volumetric calculations that are determined from the measurement devices installed in subsections (b) and (d) above.

f. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, electronic flow measurement) or at a later date (e.g., pressure and temperature charts).

Figure 4.4-5 Typical Positive Displacement Meter Run



1. Flow direction.
2. Upstream sample point straight length requires 5 diameters prior to sample point.
3. Manual sample point or auto-sampler with probe.
   i To be installed as required (see section 1)).
4. Block valve, if required.
5. Pressure indicating device.
   i. To be installed as per manufacturer's specifications or within 20 pipe diameters upstream of meter body.
   ii. To be utilized for live pressure compensation for cross border, delivery point and custody transfer installations.
6. No upstream pipe run required for positive displacement meters.
7. Meter bypass (optional) with block valve.
   i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
8. Positive displacement meter body.
9. Electronic flow measurement (EFM) device (optional).
10. No downstream pipe run required for positive displacement meters.
11. Temperature transmitter.
    i. To be installed as per manufacturer's specifications or within 20 pipe diameters downstream of meter body.
    ii. To be utilized for live temperature compensation for cross border, delivery point and custody transfer installations.
12. Pressure transmitter.
    i. To be utilized for meter body integrity only (e.g., large pressure differential indicates meter failure).

10) Diaphragm Meter

a) If a diaphragm displacement meter is used to measure gas, it must be designed and installed according to the provisions of the 1992 or later edition of the American National Standards Institute (ANSI) B109.1: *Diaphragm Type Gas Displacement* Meters *(up to 500 cubic feet/hour capacity),* or American National Standards Institute (ANSI) B109.2: *Diaphragm Type Gas Displacement Meters (over 500 cubic feet/hour capacity),* and/or the manufacturer's specifications.

b) Other conditions are the same as for the rotary meter above.

11) Venturi and Flow Nozzle

a. If a venturi or flow nozzle type of meter is used to measure gas, it must be installed according to the provisions of the 1991 or later edition of the International Organization for Standardization (ISO) Standard 5167: *Measurement of Fluid Flow by Means of Orifice Plates, Nozzles and Venturi Tubes Inserted in Circular Cross-Section Conduits Running Full* (ISO 5167) or the meter manufacturer's specifications. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site or at a later date.

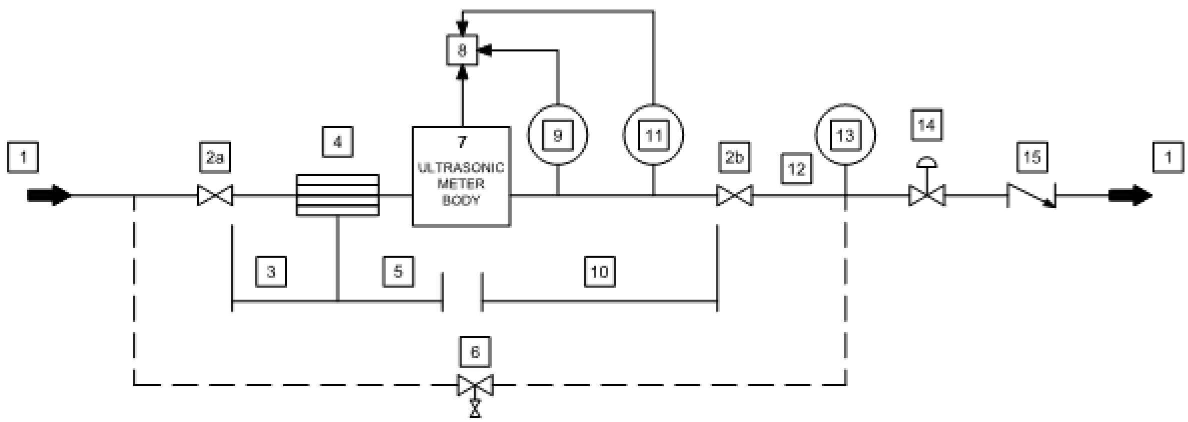
12) Ultrasonic Meters

a. Delivery point ultrasonic metering systems must be designed and installed according to Figure 4.4-7 Typical Bidirectional Gas Ultrasonic Meter Run as applicable, the provisions of the 1998 or later editions of AGA Report No. 9: Measurement of Gas by Multipath Ultrasonic Meters (AGA9), the 2012, or later edition of ISO 17098-2 *Measurement of Fluid Flow in Closed Conduits Ultrasonic Meters for Gas Part 2: Meters for Industrial Applications*, or the 2007, or later version of API 14.10 *Measurement of Flow to Flares*. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections.

Exception

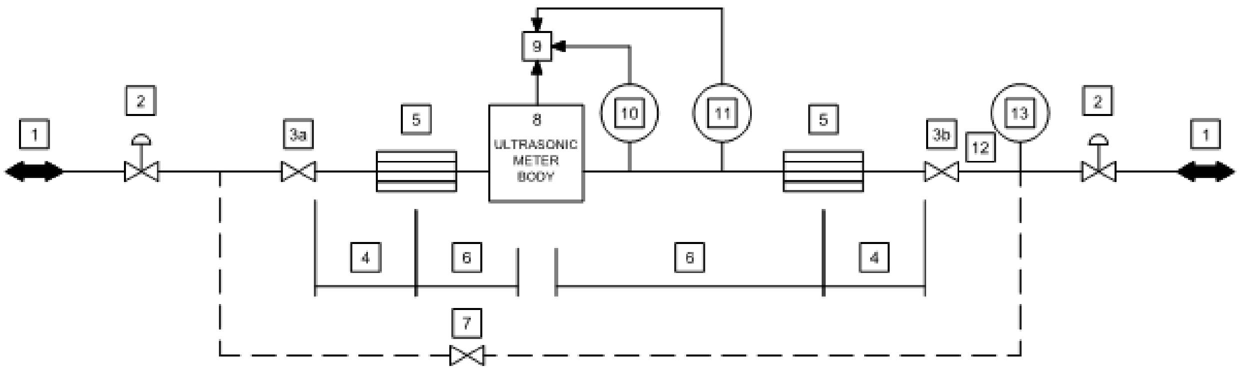
Ultrasonic metering systems used at measurement points that do not require delivery point measurement uncertainty, e.g. flare gas measurement, may be installed without live temperature compensation and in accordance with the manufacturer's specifications. In this case the flowing gas temperature must be obtained at least once per quarter, the measurement uncertainty requirement for the measurement point specified in Section 1 must be met, and the operator must be to demonstrate to the BCER, upon request, that the required measurement uncertainty is being met.

Figure 4.4-6 Typical Unidirectional gas Ultrasonic Meter Run



1. Flow direction.
2. Block valve, if required.
3. Straight length required upstream of flow conditioner / straightening vane.
    i. To be installed as per AGA 9 or manufacturer's specifications.
4. Flow conditioner (optional). May be required by the manufacturer if the straight pipe diameter requirement can not be met.
    i. To be installed as per AGA 9 or manufacturer's specifications.
5. Straight length required upstream of ultrasonic meter body.
    i. To be installed as per AGA 9 or manufacturer's specifications.
6. Meter bypass (optional) with block valve.
    i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
7. Ultrasonic meter body.
8. Electronic flow measurement (EFM) device.
9. Temperature indicating device.
    i. To be installed as per AGA 9 or manufacturer's specifications.
10. Straight length required downstream of ultrasonic meter body.
    i. To be installed as per AGA 9 or manufacturer's specifications.
11. Pressure indicating device.
    i. To be installed as per AGA 9 or manufacturer's specifications.
12. Sample point location as per AGA 9 or API 14.1.
    i. Upstream sample point straight length requires 5 diameters prior to sample point.
13. Manual sample point or auto sampler with probe (see section 1)).
    i. Sample point may be installed either upstream of 2a or downstream of 2b as this metering technology doesn't create a pressure drop.
14. Control valve (as required).
15. Check valve (as required).

Figure 4.4-7 Typical Bidirectional Gas Ultrasonic Meter Run



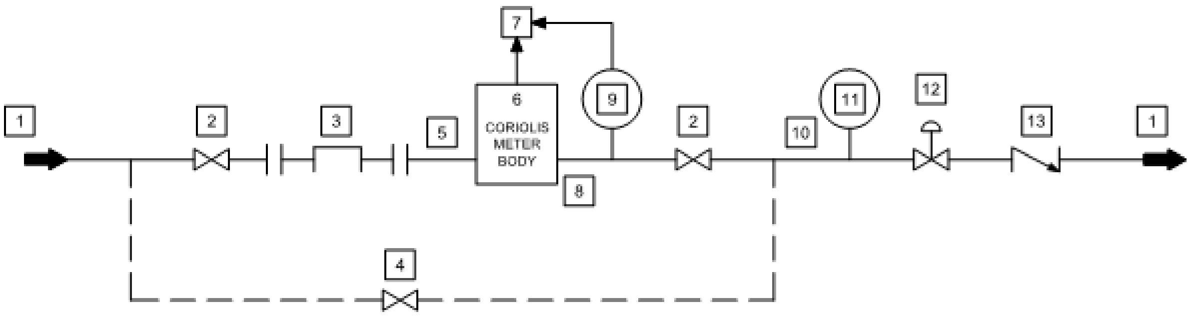
1. Flow direction.
2. Control valve (as required).
3. Block valve, if required.
4. Straight lengths required outside of flow conditioner / straightening vane.
    i. To be installed as per AGA 9 or manufacturer's specifications.
5. Flow conditioner (optional). May be required by the manufacturer if the straight pipe diameter requirement can not be met.
    i. To be installed as per AGA 9 or manufacturer's specifications.
6. Straight length required inside of flow conditioner / straightening vane.
    i. To be installed as per AGA 9 or manufacturer's specifications.
7. Meter bypass (optional) with block valve.
    i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
8. Ultrasonic meter body.
9. Electronic flow measurement (EFM) device (optional).
10. Temperature indicating device.
    i. To be installed as per AGA 9 or manufacturer's specifications.
11. Pressure indicating device.
    i. To be installed as per AGA 9 or manufacturer's specifications.
12. Sample point location as per AGA 9 or API 14.1.
    i. Sample point straight length requires 5 diameters prior to sample point
13. Manual sample point or auto sampler with probe.
    i. To be installed as required (see section 1)).
    ii. Sample point may be installed either upstream of 3a or downstream of 3b as this metering technology does not create a pressure drop.

13) Coriolis Meters

a. Coriolis mass metering systems must be designed and installed as per Figure 4.4-8 Typical Coriolis Meter Run, the manufactures specifications, or the provisions of the latest edition of AGA Report No. 11: *Measurement of Natural Gas by Coriolis Meter.* External gas sample analysis and density must be used to determine the gas volume at base conditions.

b. As applicable, the tip of the thermowell must be located within the center third of the pipe.

Figure 4.4-8 Typical Coriolis Meter Run



1. Flow direction.
2. Block valve, if required.
3. Strainer/air eliminator (optional).
4. Meter bypass (optional) with block valve.
   i. The bypass valve when closed must effectively block all flow through the bypass and be locked or car sealed in the closed position when the meter is operating normally.
5. No upstream pipe run required with coriolis meters.
6. Coriolis meter body.
7. Electronic flow measurement (EFM) device (optional).
8. No downstream pipe run required for coriolis meters.
9. Density measurement verification point (optional).
10. Upstream sample point straight length requires 5 diameters prior to sample point.
11. Manual sample point or auto sampler with probe.
    i. To be installed as required (see section 1)).
12. Control valve (as required).
13. Check valve (as required).

14) Thermal Mass Meters

a. Thermal mass meters that depend on gas density to determine the volume may only be used if:

i. the density does not change, or

ii. the manufacture can verify that the effect of the density change on the volume will meet the BCER's uncertainty requirements for that application, or the density can be determined and recorded for flow calculation.

b. Thermal mass meters are not to be utilized for use at gas plant flare stacks unless the criteria above can be met in subsection 14(a).

15) Other Meters

a) If meters other than those listed above, such as-cones, and wedge meters, are used to measure gas; they must be installed according to the meter manufacturer's specifications. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections (where required) either on site or at a later date.

a. As applicable, the tip of the thermowell must be located within the center third of the pipe.

16) Electronic Flow Measurement (EFM)

a) Any electronic gas measurement system must be designed and installed according to the requirements as stated in section Electronic Flow Measurement (EFM) for Gas of this document. Any EFM designed and installed in accordance with the American Petroleum Institute Manual *of Petroleum Measurement Standards (MPMS)*, Chapter 21.1 is considered to have met the audit trail and reporting requirements. However, the performance evaluation is still required in accordance with section Performance Evaluations in this this document. All EFM devices must have a continuous temperature reading for flow calculation.

17) Gas Temperature Reading

a. The flowing gas temperature must be measured and recorded according to Table below.

Table 4.4-2 Gas Meter Temperature Reading Frequencies

Minimum Temperature Reading Frequency	Criteria
Continuous	Sales/delivery points (royalty trigger point) and/or EFM devices
Daily	>16.9e^3m^3/d
Weekly	≤16.9e^3m^3/d
Daily	Production (proration) volume testing or non-routine or emergency flaring and venting

b) The temperature-measuring element must be installed on the meter run if present or near the meter such that it will be sensing the flowing gas stream temperature. That is, the operator cannot use the surface temperature of the piping or use a thermowell location where there is normally no flow. A meter equipped with a temperature compensation device is considered to have continuous temperature measurement.

4.4.3. **Fuel Gas**

For all upstream oil and gas facility locations such as well sites, multi-well sites, batteries, compressor sites, or gas plants, the fuel gas must be metered if the annual average use volume is greater than 0.5 e3m3/d. The permit holder may estimate the fuel gas at the location if annual average use volume is 0.5 e3m3/day or less.

A fuel gas calculation with regard to a metering requirement will consider the combined usage at a location for a piece or pieces of equipment. It is expected that the operator will meter the whole volume consumed rather than just a specific stream for which the $0.5e^3m^3/d$ threshold has been exceeded. If there are multiple reporting facilities on the same site, with common working interest ownership and no royalty trigger measurement points across the facilities, only the total location fuel gas must be metered; the fuel use must be allocated and reported to each individual battery/facility. If there is no common working interest ownership, or there are royalty trigger measurement points across the facilities, then any fuel gas volumes crossing reporting facility boundaries must be metered.

The tables below provide further details regarding when fuel gas estimates are acceptable and when measurement is required. See Appendix B for guidance on estimating fuel gas volumes.

Table 4.4-3 Well Fuel Gas Measurement Requirements

Volume	Tap Location	Estimate *	Meter	Comments
$\leq 0.5e^3m^3/d$	Between Well Production Meter and Sales/Delivery Point Meter or Cross Border Delivery Meter	Yes	No	N/A
$>0.5e^3m^3/d$	Between Well Production Meter and Sales/Delivery Point Meter or Cross Border Delivery Meter	No	Yes	N/A

Table 4.4-4 Battery / Facility Fuel Gas Measurement Requirements

Volume	Tap Location at Well Production Meter	Estimate *	Meter	Comments
$\leq 0.5e^3m^3/d$	Upstream of Well Production Meter	Yes	No	Add to Well Production Volume
$>0.5e^3m^3/d$	Upstream of Well Production Meter	No	Yes	Add to Well Production Volume

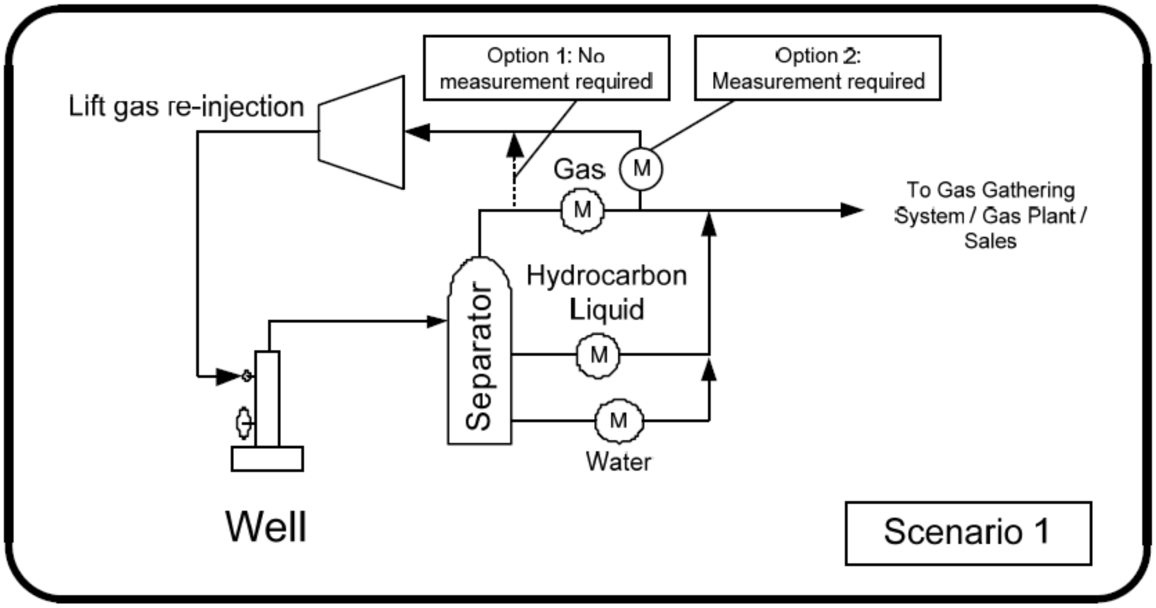
4.4.4. **Gas Lift Systems for Both Oil and Gas Wells**

There are four gas source scenarios, and each one may be subject to different measurement, reporting, and sampling and analysis requirements when gas is injected into the wellbore to assist in lifting the liquids to the surface.

Scenario 1

There is no external gas source for the lift gas used; the raw gas is being separated and recirculated continuously at the well site with compressor(s). Regular sampling and analysis frequency for the well type applies as indicated in section 8.4.

Figure 4.4-9 Lift Gas from Existing Well – Scenario 1



Option 1: If the lift gas is taken from upstream of the production measurement point, then there is no reporting requirement.

Option 2: If the lift gas is taken from downstream of the production measurement point, then measurement of the lift gas is required and the total well gas production will be the difference between the total metered production volume and the metered lift gas volume.

Scenario 2

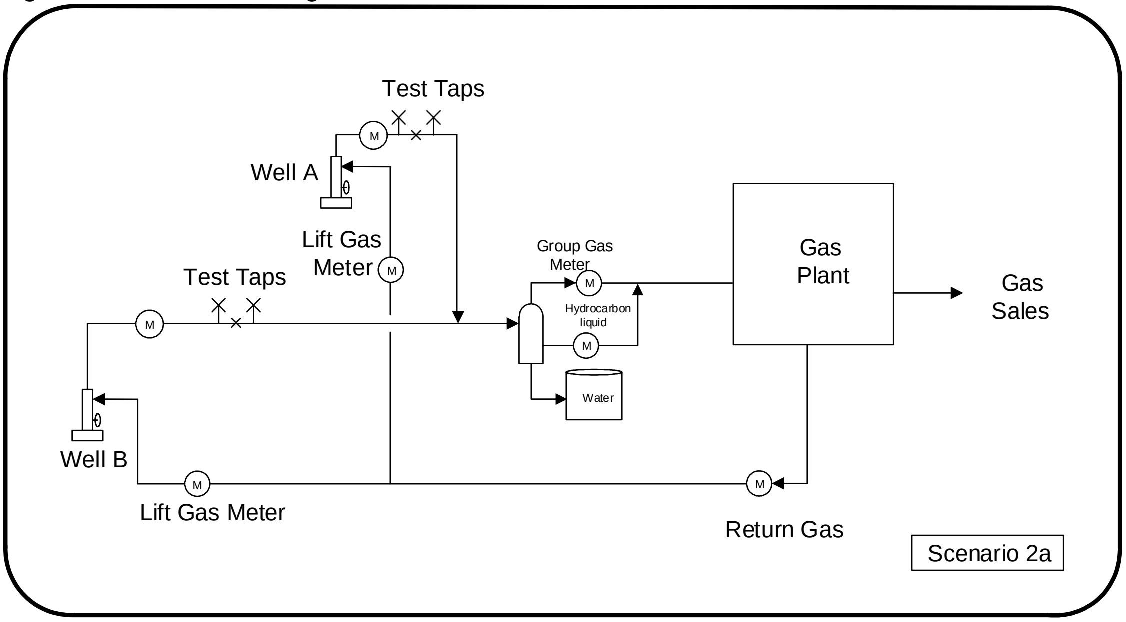
The lift gas is received back from a downstream gas plant or battery/facility that is classified as "return gas" (no royalty implications).

Measurement is required at the battery level for any gas coming back from a gas plant or battery/facility after sweetening/processing and reported as "REC". Part of this return gas could be used for fuel at the well. The lift gas injected into the wellbore must be metered and regular sampling and analysis frequency for the well type applies as indicated in section 8.4.

There are two possibilities under scenario 2 (see below).

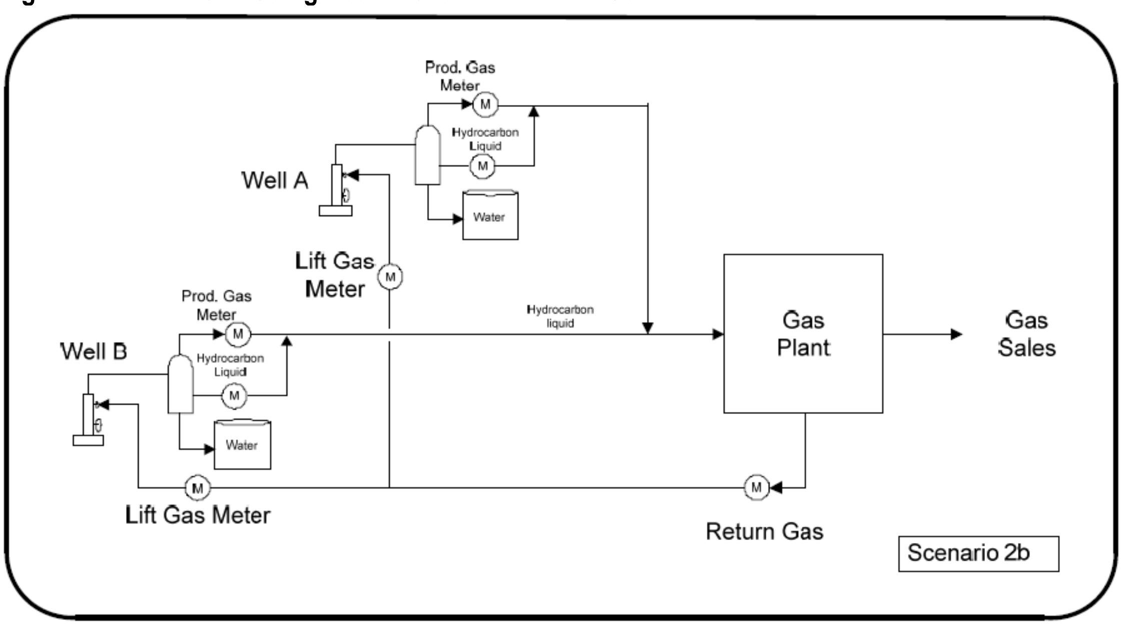
1) For proration tested wells, the gas lift volume during the test period must be netted off the total test gas production volume to determine estimated gas production volume for each well.

Figure 4.4-10 Lift Gas Using Return Gas from Plant – Scenario 2a



2) For continuously metered wells, the gas lift volume must be netted off the total metered gas production volume to determine the actual gas production volume for each well.

Figure 4.4-11 Lift Gas Using Return Gas from Plant – Scenario 2b



Scenario 3

The lift gas comes from external sources with royalty implications.

Any gas coming from a non-royalty paid gas source must be metered and reported at the battery/facility level. The well measurement and reporting requirement is the same as scenario 2 above and the gas sampling and analysis frequency for this type of gas lift well is semi-annual.

Scenario 4

The lift gas comes from royalty exempted sources, such as TC Energy or ATCO Gas.

The measurement and reporting requirement is the same as scenario 2 with the additional requirement that prior approval must be obtained from the BCER and FIN to use.

The gas sampling and analysis frequency for this type of gas lift well is semi-annual.

4.4.5. **Base Requirements for Creating Acceptable Gas Charts and Properly Reading Gas Charts**

4.4.5.1. **Chart Operation**

Field (chart) operation personnel **must** ensure:

1) The identification of the gas stream being metered (i.e., meter location) is properly identified on the chart.
2) The time and the date of start and finish of the record.
3) On and off chart times are recorded on the chart to the nearest quarter hour.
4) The correct orifice plate size is recorded on the chart.
5) The correct upstream meter tube size is identified on the chart.
6) The time (to the nearest quarter hour) of any orifice plate change is indicated on the chart and the new orifice size is properly indicated relative to the chronology of the chart.
7) It is noted on the charts if the differential pressure, static pressure, or temperature range has been changed or if they are different from the values printed on the chart.
8) A copy of the chart calibration report is kept on site or readily available for on-site inspection if it is a manned battery/facility.
9) The flowing gas temperature is recorded on the chart in accordance with Temperature Reading Frequency Table for Gas Measurement –Table 4.4-2 Gas Meter Temperature Reading Frequencies.
10) When the pen fails to record because of sensing line freezing, clock stoppage, pens out of ink, or other reasons, proper chart reading instructions are provided: draw in the estimated traces, request to read as average flow for the missing period, or provide estimate of the differential and static pressures.
11) Any data or traces that require correction must not be covered over or obscured by any means.

Field (chart) operation personnel **should** ensure that:

1) A notation is made on the chart with regard to whether or not the meter is set up for atmospheric pressure (for square root charts).
2) The accuracy of the meter clock speed is checked, and the chart reader is instructed accordingly of any deviations.
3) The differential pen is zeroed once per chart cycle.
4) Differential pen recordings are at 33% or more within the chart range.
5) Static pen recordings are at 20% or more within the chart range.
6) When there is a painted differential band, instructions are provided as to where it should be read. There are various ways to read a painted chart:
    a. If the differential pen normally records at the top of the painted band but spikes quickly down and up during separator dump cycles, it is reasonable to read the differential near the top of the band (or vice versa).
    b. If the differential pen is in constant up and down motion, it is reasonable to read the differential near the centre of the band or in a sine wave motion, alternating between the top and bottom of the painted area.
7) Pens are not over-ranged or under-ranged.
8) Pen tracings are not over-lapping.
9) Pen trace colours conform to the industry-accepted practice (RED for differential, BLUE for static, and GREEN or BLACK for temperature); however, any colour may be used, provided the colour used is documented.

4.4.5.2. **BCER Site-Specific Requests:**

If an inspection of a measurement device or of procedures reveals unsatisfactory conditions that significantly reduce measurement accuracy, a request in writing by the BCER inspector or auditor to implement changes to improve measurement accuracy will become enforceable. Examples of conditions applicable to orifice chart recorders are as follows:

1) Thick pen traces that will cause excessive error when reading the traces.
2) Excessive painting. This is normally associated with the differential pen. Small narrow bands of painting can be dealt with as noted by Item 6 above; however, large bands of painting suggest that the chart recorder is not able to properly measure the process, and remedial action is required.
3) Differential or static pens recording too low on the chart—in some cases, this cannot be avoided because of low flow rate, high shut-in pressure, and equipment or operating pressure range limitations.

4.4.5.3. **Chart Reading**

The chart integrator / planimeter operator must ensure the following:

1) Visible gaps between the integrator / planimeter traces and chart traces are minimized.
2) The counter is read correctly.
3) The integrator is calibrated periodically and after each change of pens.
4) The correct integrator or square root planimeter constants are noted.
5) The correct integrator setback is recorded.
6) The correct coefficient, using all of the required factors, is recorded.

4.4.5.4. **Alternative Chart Reading Technology**

The base requirements for alternative methods developed to read orifice meter charts, other than conventional manual methods (planimeters, integrators), is as follows. An example of such technology is the use of digital scanning technology to scan and store an image of the chart and the use of computer programs to read and interpret the digital image of the chart and the pen traces.

The use of alternative technologies to read charts does **not** require prior approval of the BCER, but the permit holder using any new technology must be able to demonstrate that the following requirements are met:

1) The equipment and/or procedures used to read the chart must not alter or destroy the chart such that it cannot subsequently be read using conventional equipment and/or procedures.
2) The accuracy and repeatability of the new equipment and/or procedures must be equal to or better than conventional equipment and/or procedures.

The following requirements are specific to the use of digital scanning technology for reading charts:

1) The original chart must be retained for at least 72 months, or alternatively the permit holder may choose the following procedure for audit trail:
   a. An original scanned image of the chart (both front and back) must be stored so that it cannot be changed. If the chart back is blank, the back does not need to be scanned provided there is a statement entered in the record to that effect. There must be a method to confirm that a set of front and back scans belong to the same chart if scanned and stored. No alteration or editing of the original scanned image is allowed.
   b. At least two separate electronic copies of the scanned images must be retained and one copy must be stored off site at a different physical address/location for the applicable required period. Note that although the BCER accepts the above electronic submission for audits, other jurisdictions might not. Therefore, the original chart should be kept for other jurisdictional audits.
2) Editing or alterations may only be made to a copy of the original scanned image of the chart. If the edited version is used for reporting purposes, the edited or altered image must be stored for the applicable required period and in the same manner as in item 1.

3) An image of the chart showing how the chart pen traces were read or interpreted must be stored for the applicable required period and in the same manner as in item 1 above.

4) The requirements in section Chart Reading of this Guideline must be adhered to. If there are any changes or additions to those requirements specific to chart reading, these must be documented and made available for instructing chart analysts. An additional requirement specific to chart scanning is as follows:

   a. When a differential pen is not zeroed correctly, the zero line must be adjusted to the correct position if it is obvious on the chart (such as when the zeroing was out when hanging charts, but the pen was not adjusted) and/or as documented by the operator. Other situations will require the judgment of the chart analyst and confirmation from the battery/facility operator. Any zero adjustment must only reposition the zero line and must maintain the entire span of the pen. (The distance between the actual zero and the pen trace must not be altered.)

5) For BCER inspection/audit purposes, the permit holder must upon request:

   a. Submit any original paper charts or the scanned original images or make them available for on-line viewing, and

   b. Submit all edited images or make them available for on-line viewing.

Note that the software used to open the scanned images should be readily and freely available on the market. In case there is any specific/proprietary image reader software required to view the scanned and stored chart images, it must also be submitted.

6) Upon request, the repeatability of the scanning technology must be demonstrated by performing three consecutive scans with a rotation of the chart image of about 120° before each scan and integrations of the same chart image. The calculated volumes from each reading must be within ±0.5% of the average of the three scans and integrations.

7) The BCER may check the accuracy of the chart-reading technology and volume calculations by providing charts with known calculated volumes. The volumes determined by the chart reading technology must be within ±0.5% of the BCER's known values.

4.4.6. **Gas in Solution (GIS) with Oil Volumes under Pressure**

In some cases, a gas volume must be determined where the gas is dissolved in an oil volume under pressure, and there is no opportunity to measure the gas volume prior to its being commingled with other gas volumes. In that case, the gas volume may be determined by estimation, regardless of its daily volume rate. An example of such a gas volume is the gas held in solution with oil volumes leaving a test separator at an oil proration battery/facility, where the test oil volumes are combined with production from other wells downstream of the test separator. The purpose of estimating the gas in solution must determine the total gas produced by a well during a production test, since the gas volume measured by the test gas meter will not include the gas that is still in solution with the test oil volume.

A single gas-in-solution (GIS) factor may be determined and used to estimate the gas volume held in solution with the oil stream for each oil stream where the production sources (producing formation) are the same and test separator operating conditions are similar. Additional gas-in-solution (GIS) factors are required for wells in the battery/facility that produce from different formations and where other test separators operate at different pressure and/or temperature conditions. Operators should also consider determining seasonal gas-in-solution (GIS) factors where ambient temperature differences may significantly affect the factors or when operating conditions change significantly.

The gas-in-solution (GIS) factor may be determined by one of the following applicable tests/procedures:

1) A 24-hour test may be conducted such that the production from a well (or group of wells) is directed through the test and group separation/treating equipment, with all other wells shut in or directed around the equipment. The total volume of gas released from the oil after it leaves the test separator must be metered; this volume divided by the stock tank volume of oil determined at the test separator provides a gas-in-solution (GIS) factor.

2) A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple stage flashing. The gas-in-solution (GIS) factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.

3) A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GIS factor based on the compositional analysis.

4) A "rule of thumb" estimate (0.0257m^3 of gas/m^3 of oil/kPa of pressure drop) may be used as the gas-in-solution (GIS) factor for conventional light-to-medium oil production until a more accurate, specific gas-in-solution (GIS) factor is determined. This estimate may be used on a continuous basis, without the need for determining a more accurate GIS factor, if well oil production rates do not exceed 2m^3/d or if all battery/facility gas production is vented or flared.

5) Other methods listed in the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used.

4.4.6.1. **Gas Produced in Association with Conventional Oil Well and Gas Well Production**

If a gas stream volume associated with a conventional oil well or gas well production does not exceed 0.5e^{3}m^3/d at any given measurement/disposition point, the volume may be determined by estimation instead of measurement. No specific approval is required, but the operator must keep the estimation/testing documentation for BCER audit. See Appendix B – Determining Fuel Gas Estimates for suggested guidance on estimating fuel gas volumes.

Examples of the gas streams that may be estimated if the daily volume limitation is not exceeded include battery/facility group gas, single-well battery/facility gas, fuel gas, and oil/condensate tank vented gas.

A gas stream that must be metered regardless of daily volume is dilution (fuel) gas added to an acid gas stream to ensure complete combustion (because of the importance of accurately determining those volumes).

Initial qualification of gas streams where volumes may be estimated can be based on existing historical data or determined by conducting one of the applicable tests/procedures in section Sample Calculations for Estimating Gas Volumes Using GOR and GIS Factors.

Qualifying gas volumes may be estimated by using a gas-oil-ratio (GOR) factor if gas volume estimates will vary in conjunction with oil volumes or by using an hourly rate if gas volumes are not dependent on oil volumes. These factors must be updated annually to confirm continuing eligibility for estimation and to update the factors used to estimate gas volumes. The factors must also be updated immediately following any operational changes that could cause the factors to change. Operators should also consider determining seasonal gas-oil-ratio (GOR) factors if ambient temperature differences may significantly affect the factors. Updated factors may be determined by one of the applicable tests/procedures described below.

4.4.6.2. **Methods for Determining Factors/Rates Used in Estimating Gas Volumes If gas volumes will be estimated using a gas-oil ratio (GOR):**

1) A 24-hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured (including vented gas). The gas volume must be divided by the oil volume to result in the gas-oil-ratio (GOR) factor.

2) A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions the oil sample would be subjected to downstream of the sample point. The gas-oil-ratio (GOR) factor must be calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.

3) A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the gas-oil ratio (GOR) based on the compositional analysis.

4) Other methods listed under the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation and Venting Volumes from Upstream Oil and Gas Facilities* may be used.

If gas volumes will be estimated using an hourly rate:

5) A meter may be used to measure the gas stream for a minimum of one hour. The gas volume metered during this test may be used to determine the hourly rate that will be used to estimate gas volumes.

6) If applicable, such as for fuel gas volumes, the hourly rate may be determined based on the equipment manufacturer's specified gas consumption rates and the actual operating conditions.

4.4.6.3. **Sample Calculations for Estimating Gas Volumes Using GOR and GIS Factors**

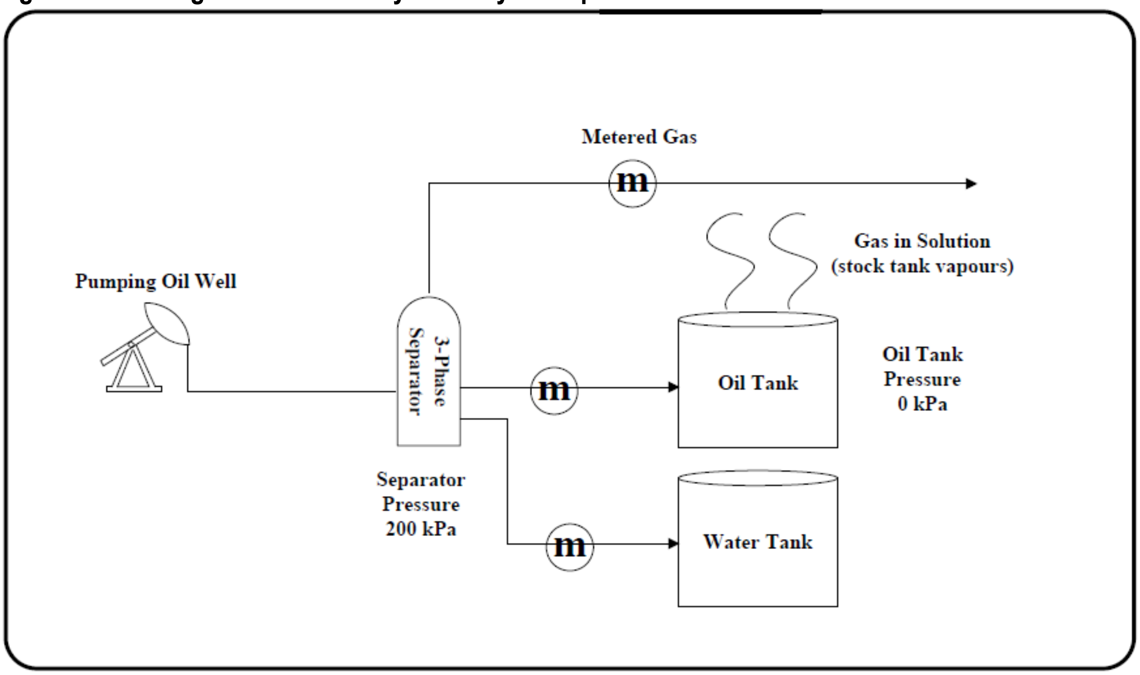
Example 1 Determination of Total Produced Gas for a Single-Well Oil Battery / Facility

Figure 4.4-12 below, depicts a single-well battery/facility where a three-phase separator is used to separate oil, gas, and water production from a well. The oil in the separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the gas-in-solution (GIS) within the oil will be released. The gas leaving the separator in this example is metered, while the gas-in-solution (GIS) released at the tank is estimated using a gas-oil-ratio (GOR) factor. Total gas production from the well is determined by adding the metered gas and the gas-in-solution (GIS) released at the oil storage tank.

If a single-well battery/facility uses a two-phase separator, the procedure for determining total gas production is the same as for a three-phase separator.

If the gas production rate meets the qualifying criteria for estimation and all production from the well produces directly to a tank without using a separator, the total gas production may be determined by using only a gas-oil-ratio (GOR) factor.

Figure 4.4-12 Single-well Oil Battery / Facility Example



Sample Calculation: Total Gas Volume at a Single-Well Battery / Facility (Figure 4.4-12)

Monthly well data (hypothetical) given for this example:

Gas meter volume = 96.3e^{3}m^3 (from chart readings) Oil meter volume = 643.3m^3 (from meter or tank gauging) Pressure drop = 200kPa GOR factor = 6.37m^{3}gas/ m^3 oil or 0.03185m^{3}gas/m^3 oil/kPa pressure drop [determined using a method other than the “rule of thumb” described above in Gas in Solution (GIS) with Oil Volumes under Pressure].

Step 1: Calculate GIS volume.

$6.37m^3/m^3 \times 643.3m^3 = 4097.8m^3 = 4.10e^3m^3$

or

$0.03185m^3/m^3/kPa \times 643.3m^3 \times 200kPa = 4097.8m^3 = 4.10e^3m^3$

Step 2: Calculate the total battery/facility gas production for the month.

$96.3e^3m^3 + 4.1e^3m^3 = 100.4e^3m^3$

Note that total reported battery/facility gas production must be rounded to one decimal place.

Example 2 Determination of Total Produced Gas for an Oil Proration Battery / Facility

Figure 4.4-13 Multi-well Oil Battery / Facility Example, below, depicts a multi-well oil proration battery/facility where production testing of individual wells is done by directing individual well production through a test separator at the main battery/facility site or through a test separator at a satellite located away from the main battery/facility site.

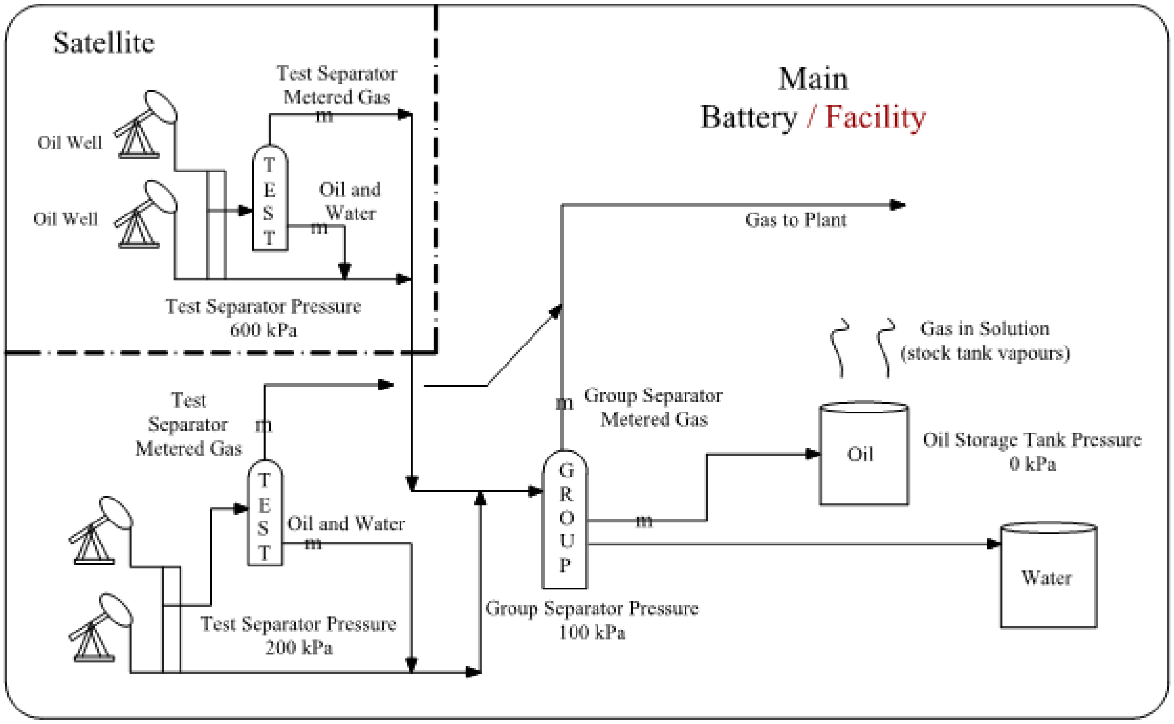
In this example, the oil, gas, and water leaving the test separator at the satellite are recombined with the satellite group production and directed to the group separation and measurement equipment at the main battery/facility site. The oil and water leaving the test separator at the main battery/facility site are recombined with the battery/facility group production, but the gas leaving the test separator recombines with the group gas downstream of the group gas measurement point. The oil in the group separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the gas-in-solution (GIS) with the oil will be released.

The total gas production at the battery/facility must be the sum of all the metered test gas at the battery/facility site, the metered group gas at the battery/facility, and the gas-in-solution (GIS) released at the oil storage tank.

Trucked oil volumes received at the battery/facility must not be included with the total battery/facility oil volume when determining the gas-in-solution (GIS) released at the oil storage tank.

At some facilities, a vapour recovery unit (VRU) may be installed to collect any gas-in-solution (GIS) that may be released at the oil storage tank. If the vapour recovery unit (VRU) is equipped with a meter or the recovered gas is directed through the group gas meter, a gas-in-solution (GIS) calculation will not be required because the metered vapour recovery unit (VRU) gas must be either be added to or included in the other metered gas volumes.

Figure 4.4-13 Multi-well Oil Battery / Facility Example



Sample Calculation: Total Gas Production at the Oil Proration Battery / Facility (Figure 4.4-13)

Monthly battery/facility data (hypothetical) given for this example: Oil production at the proration battery/facility =745.0m^3 for the month (from meter and/or tank gauging)

Total test gas metered at the battery/facility site = 30.0e^{3}m^3 (from chart readings) Metered group gas production = 67.4e^{3}m^3 (from chart readings) Pressure drop from the group vessel to oil storage tank =100kPa GOR factor = 3.99m^3 gas/m^3 oil or 0.0399m^3/m^3/kPa (determined using a method other than the "rule of thumb").

Step 1: Calculate the GIS volume.

3.99m^3/m^3 x 745m^3 = 2972.6m^3 = 2.97e^{3}m^3

or

0.0399m^3/m^3/kPa x 745m^3 x 100kPa = 2972.6m^3 = 2.97e^{3}m^3

Step 2: Calculate the total produced gas volume for the battery/facility.

67.4e^{3}m^3 + 30.0e^{3}m^3 + 2.97e^{3}m^3 = 100.4e^{3}m^3

Note that total reported battery/facility gas production must be rounded to one decimal place.

Example 3 Determination of Individual Well Test Gas for an Oil Proration Battery / Facility

Figure 4.4-13 Multi-well Oil Battery / Facility Example, above, depicts a multi-well oil proration battery/facility where production testing of individual wells is done by directing individual well production through a test separator at the main battery/facility site or through a test separator at a satellite battery/facility located away from the main battery/facility site.

In either case, the oil leaving the test separator is under pressure and must be subjected to two stages of pressure drop—one at the group separator and one at the storage tank. The total gas produced by a well during a test must be the sum of the gas metered as it leaves the test separator and the gas-in-solution (GIS) that will evolve from the test oil volume after leaving the test separator. In the example, the test separators at the battery/facility and satellite operate at significantly different pressures, and the oil leaving the test separator at the satellite will contain more gas-in-solution (GIS) than the oil leaving the test separator at the battery/facility.

Sample Calculation: Test Gas Production for Wells in the Satellite (Figure 4.4-13)

Satellite test data (hypothetical) given for this example for well "A": Measured test oil = 7.22m^3 (from oil meter) Measured test gas = 1.27e^3m^3 (from chart readings) GIS factor = 25.62m^3 gas/m^3 oil or 0.0427m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 600kPa to group pressure at 100kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume

$0.0427m^3/m^3/kPa \times 7.22m^3 \times 600kPa = 185.0m^3 = 0.19e^3m^3$

or

$25.62m^3/m^3 \times 7.22\ m^3 = 185.0m^3 = 0.19e^3m^3$

Step 2: Calculate the total test gas produced for well "A" for this test.

$1.27e^3m^3 + 0.19e^3m^3 = 1.46e^3m^3$

Note that test gas volumes must be determined to two decimal places (in e^3m^3).

Sample Calculation: Test Gas Production for Wells in the Battery / Facility (Figure 4.4-13)

Battery/Facility test data (hypothetical) given for this example for well "X": Measured test oil = 3.85m^3 (from oil meter) Measured test gas = 2.33e^3m^3 (from chart readings) GIS factor = 7.90m^3gas / m^3 oil or 0.0395m^3 gas / m^3 oil / kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 200kPa to group pressure at 100kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume.

$0.0395m^3/m^3/kPa \times 3.85m^3 \times 200kPa = 30.4\ m^3 = 0.03e^3m^3$

or

$7.90m^3/m^3 \times 3.85m^3 = 30.4m^3 = 0.03e^3m^3$

Step 2: Calculate the total test gas produced for well "X" for this test.

$2.33e^3m^3 + 0.03e^3m^3 = 2.36e^3m^3$

Note that test gas volumes must be determined to two decimal places (in e^3m^3).

4.4.7. **Volumetric Calculations**

The gas volume calculations comply if the following requirements are met:

1) If an orifice meter is used to measure gas, the operator must use the 1985 or later editions of the AGA3 to calculate the gas volumes.

2) If a positive displacement meter or a linear type of meter (such as a turbine, ultrasonic, or vortex meter) is used to measure gas volumes must be calculated according to the provisions of the 1985 or later editions of the AGA7. Corrections for static pressure, temperature, and compressibility are required. Meters installed at metering points that do not require delivery point measurement uncertainty and are operating under a fixed pressure setting ≤ 700 kPa(g) (i.e., directly downstream of a pressure regulating valve with no process or other equipment installed between the pressure regulating valve and the meter) do not require continuous pressure and temperature compensation. Instead, operating pressure and temperature correction factors may be used for volumetric correction. The meter operating pressure must be obtained and updated annually and the flowing temperature must be obtained and updated quarterly for volume determination.

3) If a venturi or flow nozzle type of meter is used to measure gas, volumes must be calculated according to the provisions of the 1991 or later edition of the ISO 5167 or the meter manufacturer's calculation procedures.

4) If a coriolis mass meter is used to measure gas, volumes must be calculated from the metered mass flow and the base density derived from a representative gas sample analysis, including corrections for compressibility. The flowing density measured by the coriolis mass meter is of insufficient accuracy in a gas application and must not be used to compute volumes.

5) If meter types other than those listed above, such as v-cones or wedge meters, are used to measure gas, volumes must be calculated according to the applicable industry accepted standard or the meter manufacturer's specifications.

6) If condensate production from a gas well is required to be reported as a gas equivalent volume, the calculation of the gas equivalent factor must be performed in accordance with the methodologies outlined in Appendix A – Gas Equivalent Factor (GEF) Determination. The following are the general requirements:

   a. The Gas Equivalent Volume (GEV) must be determined based on the latest condensate sample analysis.

   b. The Gas Equivalent Volume can be determined using the volume fractions, mole fractions, or mass fractions of the condensate analysis.

   c. The Gas Equivalent Volume can be determined using all of the individual components in the condensate analysis, or the C5 and/or heavier components in the sample can be grouped as C5+, C6+, C7+ or other heavier component groups. If the heavier components are grouped, the gas equivalent factor for the grouped components must be calculated using the molecular weight and/or relative density of the grouped components.

d. Correction for deviation from the Ideal Gas Laws for compressibility must be based on equations published in the November 1992, second edition of the AGA Transmission Measurement Committee Report No. 8 (AGA8): Compressibility *Factors of Natural Gas and Other Related Hydrocarbon Gases* or one of the methods listed below**.** For EFM systems installed before 1994 with software or hardware limitations incompatible with the second edition of AGA8, an earlier version can be used.

4.4.7.1. **Compressibility Factors Used in Gas Volume Calculations**

Produced or injected gas volume measurements must be corrected for pressure, temperature, gas composition, and the compressibility of the natural gas. For meters that do not require delivery point measurement uncertainty, correction for compressibility is not required at operating pressures ≤ 700 kPa(g).

The AGA8 (1992) or Redlich-Kwong with Wichert-Aziz sour gas corrections method should be used for the calculation of the compressibility factors. However, other methods can also be used, provided that the operator documents the reason for their use. Other methods that could be used are:

1) Pitzer et al. with Wichert-Aziz sour gas corrections
2) Dranchuk, Purvis, Robinson with Wichert-Aziz sour gas corrections (Standing and Katz)
3) Dranchuk, Abou-Kassam with Wichert-Aziz sour gas corrections (Starling)
4) Hall, Yarborough with Wichert-Aziz sour gas corrections
5) ISO 20765-2: Natural Gas – *Calculation of thermodynamic Properties – Part 2: Single-phase Properties (Gas, Liquid, and Dense Fluid) for Extended Ranges of Application* (Groupe Européen de Recherches Gazières, 2008).

The BCER will also accept the use of methods other than those mentioned above. If others are used, a suitable reference and comparison to the AGA8 (1992) method or to experimental results and the justification for use must be documented and provided to the BCER for inspection on request.

The AGA8 publication includes several approaches for estimating the properties of natural gas for use in the AGA8 calculation. The full compositional analysis (Detail) method must be used rather than the less accurate partial composition (Gross) method.

If paper charts are used, the compressibility factor should be calculated at least once for each gas chart cycle. Flow computers and other EFM systems used for gas measurement must calculate and update the compressibility, or the supercompressibility, factor at least once for each hourly quantity transaction record and whenever the gas composition is updated. Refer to API MPMS, chapter 21.1, “Flow Measurement Using Electronic Metering Systems – Electronic Gas Measurement.

4.4.7.2. **Physical Properties of Natural Gas Components**

The BCER adopts the physical properties contained in the most recent edition of the Gas Processors Suppliers Association (GPSA) *SI Engineering Data Book* or the Gas Processors Association (GPA) 2145 publication, whichever is the most current. The operator must ensure that it is using the up-to-date list and, if necessary, update its data. If an EFM system does not have the capability to accept updated physical constants, then the existing set of physical constants may be used; however, that type of EFM system must not be used for the measurement of delivery point gas that meets sales specifications. For standards, such as AGA8, that have imbedded physical constants different in value from those in GPA 2145 or GPSA *SI Engineering Data Book*, changes to such standards are not required unless they are made by the relevant standards association.

4.4.8. **Volumetric Data Amendments**

A number of operational, measurement, and production accounting scenarios may occur that can result in errors in volumetric reporting. The errors may need to be corrected and amended volumes reported. Examples of scenarios that require volumetric amendments are described below.

1) A gas metering error is discovered at a well or facility. In this case, the permit holder of the facility must immediately correct the cause of the error and submit amended monthly production reports to correct all affected gas volumes.
2) The cause of a proration factor being outside target range is determined, and the error can be quantified. The reported production data must be amended, thereby bringing the factor back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.
3) The cause of a metering difference being outside target range is determined, and the error can be quantified. The incorrectly reported production data must be amended, thereby bringing the metering difference back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.
4) The volume of gas plus gas equivalent (where applicable) calculated by a substitute gas analysis and condensate analysis (where applicable) is found to be in error > 20 e3 m3, and the per cent change from the originally reported volume is > 2.0 per cent. Retroactive volumetric adjustments must be calculated using the actual gas and, where applicable, condensate compositions. Reported volumes of condensate or NGL that are in error by more than 1.5 per cent and ±5.0 m3/month must be corrected, and retroactive volumetric amendments made.

4.4.9. **Production Data Verification and Audit Trail**

4.4.9.1. **General**

The field data, records, and any volume calculations or estimations (including EFM) related to reporting requirements as outlined in the *British Columbia Oil and Gas Royalty Handbook* and submitted to FIN must be kept for inspection on request. The reported data verification and audit trails must be in accordance with the following:

1) When a bypass around a meter is opened or when, for any reason, gas does not reach the meter or the recording device, a reasonable estimate of the unmetered volume must be determined, the method used to determine the estimate must be documented, and a record of the event must be made.

2) A record must be maintained that identifies the gas stream being metered, the measurement devices, and all measurements, inputs, times, and events related to the determination of gas volumes see section 4.4.5 Base Requirements for Creating Acceptable Gas Charts and Properly Reading Gas Charts. If an EFM is used, the required data must be collected and retained according to section Electronic Flow Measurement (EFM) for Gas.

3) Any documentation produced in the testing or operation of metering equipment that affects measured volumes must be retained for not less than 72 months. This includes the record containing volume verification and calibration measurements for all secondary and tertiary devices.

4) When a gas metering error is discovered, the operator of the battery/facility must immediately correct the cause of the error and submit amended monthly production reports to correct all affected gas volumes.

5) All flared and vented gas must be reported as described in the most recent *Flaring And Venting Reduction Guideline.* Whenever possible, the Permit Holder must report gas as fuel, flared, or vented as occurring at the location where the fuel use, flaring, or venting took place. This will allow industry and BCER staff to match flaring or venting that is observed in the field with that reported.

    a. Vented gas resulting from, depressurizing piping/equipment for maintenance, purging oxygen out of facility piping/equipment for start-up purposes must be reported as vent use on a per-site basis.

6) When the fuel usage, flaring, or venting location is within a gas gathering system but is not at a permitted entity,

    a) it should be reported as an activity associated with the closest permitted facility (e.g., compressor) within the gas gathering system, or
    b) if there is no applicable permitted facility within the gas gathering system, it should be reported as an activity associated with the gas gathering system itself.

7) Permit Holders must not prorate or allocate flared and vented volumes that occur at a facility to other upstream facilities and/or well locations.

8) Production hours for gas wells designed to operate on an on/off cycle, such as intermittent timers, pump-off controls, plunger lifts, manual on/off, or pumpjacks, that are "operating normally and as designed on repeated cycles" and where part of the operation involves shutdown of pump equipment and/or shut in as part of the repeated cycles must be considered on production even when the wells are not flowing. At least one on/off cycle must be completed within a reporting period. Physical well shut-ins (not as part of a repeated cycle) and emergency shutdowns (ESDs) are considered down time. The operation personnel have to make a decision based on the operating environment in other situations where the wells are not shut in but may or may not have production.

9) All gas usage, such as for instrumentation, pumps, purging, and heating, must be reported as fuel use on a per-site basis, even if it is vented afterwards. The volume must be metered on a per site basis if the annual average is greater than 0.5e3m3/d or may be estimated if the annual average is 0.5e3m3/d or less.

If the site has more than one Petrinex reporting facility, only the fuel for the overall site must be metered; it must then be allocated to and reported for each facility, provided that the facilities have common working interest ownership and there are no royalty trigger measurement points across the facilities. If there is no common working interest ownership or there are royalty trigger measurement points across the facilities, then any fuel gas volumes crossing reporting facility boundaries must be metered.

4.4.9.2. **Electronic Flow Measurement (EFM) for Gas**

An Electronic Flow Measurement (EFM) is defined as any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a Distributed Control System (DCS), Supervisory Control and Data Acquisition system (SCADA) or Programmable Logic Controller system (PLC), only the Electronic Flow Measurement (EFM) portion has to meet the requirements in this Chapter.

The following systems are not defined as an EFM:

1) Any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation).

2) A Remote Terminal Unit (RTU) that transmits any data other than flow data and does not calculate flow.

4.4.9.2.1. Base Requirements for EFM

If EFM is used to calculate volumes for FIN reporting purposes, the operator must be able to verify that it is performing within the BCER target limits defined in this Chapter. All data and reports must be retained for a minimum of 72 months. Flow calculation is affected by parameters such as:

1) Orifice plate size.

2) Meter factor.

3) Fluid analysis.

4) Transmitter range.

5) Meter run diameter.

When any of these parameters are changed, a signoff procedure or an event log must be set up to ensure that the change is made in the EFM system and retained for a minimum of 72 months.

Hardware and software requirements:

1) The EFM data storage capability must exceed the time-period used for data transfer from the EFM system.

2) The EFM system must be provided with the capability to retain data in the event of a power failure (e.g., battery/facility backup, UPS, EPROM).

3) System access must have administrative controls and have appropriate levels of security, with the highest level of access restricted to authorized personnel.

4) The EFM system must be set to alarm on out-of-range inputs, such as temperature, pressure, differential pressure (if applicable), flow, low power, and communication failures.

5) Any EFM configuration changes or forced inputs that affect measurement computations must be documented either electronically via audit trails or on paper. The values calculated from forced data must be identified as such.

4.4.9.2.2. Performance Evaluations

A performance evaluation calculation verification must be completed within two weeks after the EFM is put into service and immediately after any change to the computer program or algorithms that affect the flow calculation. It is recommended that a performance evaluation be performed as part of the initial verification/calibration. The performance evaluation must be documented for BCER audit purposes. A performance evaluation must be conducted and submitted for BCER audit purposes on request.

The BCER considers either one of the following methods acceptable for performance evaluation:

1) A performance evaluation test on the system can be conducted by inputting known values of flow parameters into the EFM to verify the volume calculation, coefficient factors, and other parameters. The first seven test cases included in this Chapter are for gas orifice meters (AGA3 flow calculations), each with different flow conditions and gas properties. Test Case 8 is for the AGA7 flow calculation for positive displacement or linear meters. Other manufacturers' equations can also be used to evaluate the EFM performance. The seven AGA3 test cases could also be used to evaluate any compressibility or supercompressibility factors used in other flow calculations using the same gas composition, pressure, and temperature as inputs in the calculation.

2) Evaluate the EFM calculation accuracy with a flow calculation program that performs within the target limits for all the factors and parameters listed in the test cases below. A "snapshot" of the instantaneous flow parameters and factors, flow rates, and configuration information must be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple "snapshots" may have to be taken to provide a representative evaluation.

Note that some Distributed Control Systems (DCS) or other control systems have built-in and/or manual input of pressure and temperature for flow calculations. Since the pressure and temperature are not continuously updated, they are not acceptable for BCER and FIN accounting and reporting purposes unless BCER approval is obtained.

The volumetric flow rate obtained from the flow calculation verification must agree to within ±0.25% of the volumetric flow rates recorded on the sample test cases or other flow calculation programs. If the ±0.25% limit is exceeded, the EFM must be subjected to a detailed review of the flow calculation algorithm to resolve the deviation problem. For gas orifice meters, if no AGA3 factor or parameter outputs are available, the acceptable volumetric gas flow rate limit is lowered to ±0.15%.

4.4.9.2.3. Test Cases for Verification of Orifice Meter Gas Flow Calculation Programs

The BCER uses the following test cases to verify that the EFM correctly calculates gas flow rates from orifice meters.

The seven test cases recognized by the BCER were developed by the AER and based on the following:

1) They are for flange taps only.

2) The atmospheric pressure is assumed to be 93.08kPa(a)(13.5psia).

3) The heaviest carbon component was assumed to be normal heptane.

4) The ideal gas relative density was converted to the real gas relative density.

5) The same static pressure value is used for pressure taps that are located upstream (U/S) or downstream (D/S) of the orifice plate.

6) The AGA3 (1985) results were calculated based on upstream conditions (for both upstream and downstream static pressure tap) in imperial units (the Y2 factor is also provided for reference). The metric conversion factor for the calculated gas volume is 0.02831685. The compressibility factors were calculated using the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.

7) The AGA3 (1990) results were calculated using the Detail AGA8 (1992) compressibility factor calculation and using the upstream expansion factor Y1 by the AGA3 (1990), Part 1, Chapter 1.8, even though the pressure tap may be downstream of the orifice plate. (The Y2 factor is also provided for reference when applicable.)

8) The orifice plate material is assumed to be 316 stainless steel and the meter run to be carbon steel at reference temperature of 20° C, isentropic exponent (k) = 1.3, viscosity = 0.010268 centipoise.

9) The base conditions (101.325kPa[abs] and 15°C) are used in the calculated temperature base factor (Ftb) and pressure base factor (Fpb).

TEST CASE 1 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0184	iC4 - 0.0081
CO_2 - 0.0000	nC4 - 0.0190
H_2S - 0.0260	iC5 - 0.0038
C1 - 0.7068	nC5 - 0.0043
C2 - 0.1414	C6 - 0.0026
C3 - 0.0674	Cm - 0.0022

Ideal gas relative density - 0.7792

Meter Data (flange taps)

Meter run I.D. - 52.370mm (2.0618 inches)   Orifice I.D. - 9.525mm (0.375 inches)

Flow Data (24hr)

Static pressure - 2818.09kPa(a) (408.73psia)

Differential pressure - 10.2000kPa (40.9897 inches H2O)

Flowing temperature - 57.0°C (134.600°F)

Gas Volume Result

AGA3 (1985)			AGA3 (1990)		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	28.4286	28.4286	Cd	0.5990	0.5990
Y1	0.9989	0.9989	Y1	0.9989	0.9989
Y2	N/A	1.0007	Y2	N/A	1.0007
F tb	0.9981	0.9981	Ev	1.0005	1.0005
F gr	1.1308	1.1308	Zb	0.9959	0.9959
Fa	1.0012	1.0012	Zf	0.9280	0.9277
Fr	1.0006	1.0006	Q	2.7478	2.7531 e^3m^3/24hr
F pb	1.0023	1.0023			
Ftf	0.9351	0.9351			
F pv	1.0360	1.0361			
C'	31.175	31.179			
Q	2.7422	2.7475e^3m^3/24hr			

TEST CASE 2 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0156

CO_2 - 0.0216

H_2S - 0.1166

C1 - 0.7334

C2 - 0.0697

C3 - 0.0228

iC4 - 0.0044

nC4 - 0.0075

iC5 - 0.0028

nC5 - 0.0024

C6 - 0.0017

C7 - 0.0015

Ideal gas relative density - 0.7456

Meter Data (flange taps)

Meter run I.D. - 102.26mm (4.026 inches)   Orifice I.D. - 47.625mm (1.875 inches)

Flow Data (24hr)

Static pressure - 9100.94kPa(a) (1319.98psia)

Differential pressure - 11.0000kPa (44.2046 inches H2O)

Flowing temperature - 50.0°C (122.0°F)

Gas Volume Result

AGA3 (1985)			AGA3 (1990)		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	733.697	733.697	Cd	0.6019	0.6019
Y1	0.9996	0.9996	Y1	0.9996	0.9996
Y2	N/A	1.0002	Y2	N/A	1.0003
F tb	0.9981	0.9981	Ev	1.0244	1.0244
F gr	1.1564	1.1564	Zb	0.9967	0.9967
Fa	1.0010	1.0010	Zf	0.8098	0.8097
Fr	1.0002	1.0002	Q	146.08	146.18 e^3m^3/24hr
Fpb	1.0023	1.0023			
F tf	0.9452	0.9452			
Fpv	1.1072	1.1073			
C'	888.905	889.000			
Q	145.93	146.03 e^3m^3/24hr			

TEST CASE 3 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0500	iC4 - 0.0000
CO_2 - 0.1000	nC4 - 0.0000
H_2S - 0.2000	iC5 - 0.0000
C1 - 0.6000	nC5 - 0.0000
C2 - 0.0500	C6 - 0.0000
C3 - 0.0000	C7 - 0.0000

Ideal gas relative density - 0.8199

Meter Data (flange taps)

Meter run I.D. - 590.55mm (23.250 inches)   Orifice I.D. - 304.80mm (12.000 inches)

Flow Data (24hr)

Static pressure - 10342.14kPa(a) (1500.00psia)

Differential pressure - 22.1600kPa (89.0522 inches H2O)   Flowing temperature - 60.0°C (140.0°F)

Gas Volume Result

AGA3 (1985)			**AGA3 (1990)**		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	30429.66	30429.66	Cd	0.6029	0.6029
Y1	0.9993	0.9993	Y1	0.9993	0.9993
Y2	N/A	1.0004	Y2	N/A	1.0004
F tb	0.9981	0.9981	Ev	1.0375	1.0375
F gr	1.1028	1.1028	Zb	0.9968	0.9968
Fa	1.0013	1.0013	Zf	0.8216	0.8213
Fr	1.0001	1.0001	Q	8564.77	8575.48e^3m^3/24hr
Fpb	1.0023	1.0023			
F tf	0.9309	0.9309			
Fpv	1.1076	1.1078			
C'	34636.6	34643.21			
Q	8603.19	8614.04e^3m^3/24hr			

TEST CASE 4 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0029

CO_2 - 0.0258

H_2S - 0.0000

C1 - 0.9709

C2 - 0.0003

C3 - 0.0001

iC4 - 0.0000

nC4 - 0.0000

iC5 - 0.0000

nC5 - 0.0000

C6 - 0.0000

C7 - 0.0000

Ideal gas relative density - 0.5803

Meter Data (flange taps)

Meter run I.D. - 146.36mm (5.7622 inches) Orifice I.D. - 88.900mm (3.500 inches)

Flow Data (24hr)

Static pressure - 9839.99kPa(a) (1427.17psia)

Differential pressure - 6.6130kPa (26.575 inches H2O) Flowing temperature - 22.35°C (72.23°F)

Gas Volume Result

AGA3 (1985)			**AGA3 (1990)**		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	2694.965	2694.97	Cd	0.6047	0.6047
Y1	0.9998	0.9998	Y1	0.9998	0.9998
Y2	N/A	1.0001	Y2	N/A	1.0001
Ftb	0.9981	0.9981	Ev	1.0759	1.0759
F gr	1.3116	1.3116	Zb	0.9980	0.9980
Fa	1.0001	1.0001	Zf	0.8425	0.8425
Fr	1.0002	1.0002	Q	503.44	503.63e^3m^3/24hr
Fpb	1.0023	1.0023			
Ftf	0.9884	0.9884			
Fpv	1.0843	1.0843			
C'	3790.16	3790.31			
Q	501.64	501.82e^3m^3/24hr			

TEST CASE 5 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0235

CO_2 - 0.0082

H_2S - 0.0021

C1 - 0.7358

C2 - 0.1296

C3 - 0.0664

iC4 - 0.0088

nC4 - 0.0169

iC5 - 0.0035

nC5 - 0.0031

C6 - 0.0014

C7 - 0.0007

Ideal gas relative density - 0.7555

Meter Data (flange taps)

Meter run I.D. - 154.05mm (6.0650 inches) Orifice I.D. - 95.250mm (3.750 inches)

Flow Data (24hr)

Static pressure - 2499.9kPa(a) (362.58psia)

Differential pressure - 75.000kPa (301.395 inches H2O) Flowing temperature - 34.0°C (93.2°F)

Gas Volume Result

AGA3 (1985)			AGA3 (1990)		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	3111.24	3111.24	Cd	0.6042	0.6041
Y1	0.9894	0.9897	Y1	0.9894	0.9897
Y2	N/A	1.0044	Y2	N/A	1.0044
Ftb	0.9981	0.9981	Ev	1.0822	1.0822
Fgr	1.1485	1.1485	Zb	0.9962	0.9962
Fa	1.0005	1.0005	Zf	0.9240	0.9217
Fr	1.0001	1.0001	Q	799.83	813.00e^3m^3/24hr
Fpb	1.0023	1.0023			
Ftf	0.9695	0.9695			
Fpv	1.0382	1.0394			
C'	3561.90	3567.34			
Q	800.22	813.37e^3m^3/24hr			

TEST CASE 6 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0268	iC4 - 0.0123
CO_2 - 0.0030	nC4 - 0.0274
H_2S - 0.0000	iC5 - 0.0000
C1 - 0.6668	nC5 - 0.0000
C2 - 0.1434	C6 - 0.0180
C3 - 0.1023	C7 - 0.0000

Ideal gas relative density - 0.8377

Meter Data (flange taps)

Meter run I.D. - 52.500mm (2.0669 inches) Orifice I.D. - 19.050mm (0.750 inches)

Flow Data (24hr)

Static pressure - 2506.33kPa(a) (363.50psia)

Differential pressure - 17.0500kPa (68.5171 inches H2O) Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result

AGA3 (1985)			**AGA3 (1990)**		
Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	115.138	115.138	Cd	0.6005	0.6005
Y1	0.9978	0.9978	Y1	0.9978	0.9978
Y2	N/A	1.0012	Y2	N/A	1.0012
Ftb	0.9981	0.9981	Ev	1.0088	1.0088
Fgr	1.0902	1.0902	Zb	0.9951	0.9951
Fa	0.9996	0.9996	Zf	0.8588	0.8578
Fr	1.0003	1.0003	Q	14.687	14.746e^{3}m^3/24hr
Fpb	1.0023	1.0023			
Ftf	1.0148	1.0148			
F pv	1.0708	1.0714			
C'	136.15	136.22			
Q	14.602	14.660e^{3}m^3/24hr			

TEST CASE 7 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0070	iC4 - 0.0062
CO_2 - 0.0400	nC4 - 0.0090
H_2S - 0.0000	iC5 - 0.0052
C1 - 0.8720	nC5 - 0.0016
C2 - 0.0340	C6 - 0.0000
C3 - 0.0250	C7 - 0.0000

Ideal gas relative density - 0.6714

Meter Data (flange taps)

Meter run I.D. - 52.500mm (2.0669 inches) Orifice I.D. - 12.70mm (0.50 inches)

Flow Data (24hr)

Static pressure - 299.92kPa(a) (43.50psia)

Differential pressure - 6.3455kPa (25.5 inches H2O) Flowing temperature - 1.67°C (35°F)

Gas Volume Result

AGA3 (1985) AGA3 (1990)

Factors	**U/S Tap**	**D/S Tap**	**Factors**	**U/S Tap**	**D/S Tap**
Fb	50.523	50.523	Cd	0.6006	0.6006
Y1	0.9933	0.9935	Y1	0.9933	0.9934
Y2	N/A	1.0039	Y2	N/A	1.0039
Ftb	0.9981	0.9981	Ev	1.0017	1.0017
Fgr	1.2190	1.2190	Zb	0.9973	0.9973
Fa	0.9994	0.9994	Zf	0.9905	0.9903
Fr	1.0018	1.0018	Q	1.4335	1.4489e^3m^3/24hr
Fpb	1.0023	1.0023			
Ftf	1.0250	1.0250			
F pv	1.0035	1.0036			
C'	63.013	63.029			
Q	1.4263	1.4416e^3m^3/24hr			

4.4.9.2.4. Test Case for Verification of AGA7 Gas Flow Calculation Programs

The BCER uses the following test cases to verify that the EFM system correctly calculates gas flow rates using the AGA7 equations.

The test case recognized by the BCER was developed by the AER and based on the following:

1) The heaviest carbon component was assumed to be normal heptane.
2) The compressibility factors were calculated using the Detail AGA8 (1992) or the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.
3) Fpm = Pf /Pb, where Pf = flowing pressure, Pb = base pressure

4) Fpb = 101.5598/Pb

5) Ftm = Tb/Tf, where Tb = base temperature, Tf = flowing temperature

6) Ftb = Tb/519.67

4.4.9.2.5. Flow Calculation Tolerances

The BCER considers a computer program that uses the AGA3 (1985) equation to be correct if for each of the test cases:

1) The calculation of the Y, Fa, Fr, and Ftf factors are within 0.01% of the values determined by the BCER.

2) The calculation of the Fb factor is within 0.1% of the value determined by the BCER.

3) The calculation of the Fgr factor is within 0.2% of the value determined by the BCER.

4) The calculation of the Fpv factor is within 0.2% of the value determined by the BCER.

5) The correct base conditions (101.325kPa [abs] and 15°C) are used in the calculated temperature base factor (Ftb) and pressure base factor (Fpb).

6) The calculation of the gas rate is within 0.25% of the value determined by the BCER.

The BCER considers a computer program that uses the AGA3 (1990) equation to be correct if for each of the test cases:

1) Both the gas expansion coefficient (Y1) and the velocity of approach factor (Eb) calculations are within 0.1% of the values determined by the BCER.

2) The calculation of both the discharge coefficient (Cd) and the base compressibility factor (Zb) are within 0.1% of the values determined by the BCER.

3) The calculation of the compressibility factor at flowing conditions (Zf) is within 0.2% of the value determined by the BCER.

4) The calculation of the gas rate is within 0.25% of the value determined by the BCER.

The BCER considers a computer program that uses the AGA7 equation to be correct if for the test case:

1) The program's calculation of both the flowing pressure factor (Fpm) and the flowing temperature factor (Ftm) are within 0.1% of the value determined by the BCER.
2) The program's calculation of the compressibility factor (S) is within 0.2% of the value determined by the BCER (both AGA8 and RK factors are provided).
3) The correct base conditions (101.325kPa [abs] and 15°C) are used in the calculated temperature gas factor (Ftb) and pressure base factor (Fpb).
4) The program's calculation of the gas rate is within 0.25% of the value determined by the BCER.

TEST CASE 8 (for AGA7 Flow Calculations)

Gas Analysis

N_2 - 0.0268

CO_2 - 0.0030

H_2S - 0.0000

C1 - 0.6668

C2 - 0.1434

C3 - 0.1023

iC4 - 0.0123

nC4 - 0.0274

iC5 - 0.0000

nC5 - 0.0000

C6 - 0.0180

C7 - 0.0000

Flow Data (24hr)

Uncorrected volume - 128.0e^3m^3

Static pressure - 2506.33kPa(a) (363.50psia)

Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result AGA7 (Volumetric Flow)

Factors

Fpm 24.736

Fpb 1.0023

Ftm 1.0298

Ftb 0.9981

Using AGA8 compressibility equations,

S 1.1588 Q 3779.7e^3m^3/24hr

Using RK compressibility equations:S 1.1467 Q = 3740.2e^3m^3/24hr

4.4.9.2.6. EFM Reports

The required information in each report must be stored using electronic/magnetic (not necessarily on the EFM) or printed media and can exist individually on different formats or reports and must be produced for review for audit purposes as follows:

Table 4.4-5 Required EFM Reports

Report Description	Archive Frequency
Daily Report	Daily
Meter Report	Generate On Request for Current and Future Periods
Event Log	Regular Intervals before data is overwritten
Alarm Log	Regular Intervals before data is overwritten

4.4.9.2.7. Daily Report

The daily report must include (as applicable for the given metering technology utilized):

1) Meter identification.
2) Daily accumulated volume, with indicating flags for:
    a. estimated volumes made by the system.
    b. estimated volumes by operational personnel.
    c. alarms for end devices that would impact volumetric calculations.
3) Production hours or hours of flow (specify).
4) Units of measure for volumetric data.
5) Volumetric data audit trail. This must include the instantaneous, hourly accumulated, and average daily values for:
    a. differential pressure (if applicable).
    b. static pressure.
    c. temperature.
    d. flow rate.

6) Time stamp to reflect the time the report was created.

7) Date stamp to reflect the date the report was created.

8) Identify the production date for the daily report.

9) For a Cross Border battery/facility, indicate the jurisdiction from which a well volume originated.

10) Identify wells that use cycling control, plunger lift, pump-off, throttling, gas lift etc.

Where exceptions (indicating flags) are present it is assumed that the data presented has been modified (either automatically or by user intervention) from the original data. In such a case, it is also expected that the original data be maintained on file and that the modified data must have an appropriate comment included to explain the exception.

Production hours for wells with intermittent timers, pump-off controls, plunger lifts, well cycling control, well throttling, etc., that are "operating normally and as designed" must be considered on production even when the wells are not flowing or pumping. Physical well shut-ins and emergency shutdowns (ESDs) are considered downtime.

Existing EFM systems that do not have any of the above audit trail capabilities and cannot develop the capability because of system limitations at the time of implementation must notify the BCER in writing and receive approval to continue operation in the current format. The BCER may request upgrades, where audit/inspection results indicate they are warranted.

4.4.9.2.8. Monthly Report

1) Monthly-accumulated volume.
2) Flags indicating any change made to volumes.
3) Total hours on production or hours of flow.

4.4.9.2.9. Meter Report

The meter report must be generated on request. This report details the configuration of each meter and flow calculation information. These values are used as part of the audit trail to confirm that the flow calculation is functioning correctly. Without them, there is no way of verifying the accuracy of the system.

The meter report must include the following (as applicable for the given metering technology utilized) to be produced on demand:

1) Instantaneous Flow Data

    a. Instantaneous flow rate.

    b. Instantaneous static pressure.

    c. Instantaneous differential pressure.

    d. Instantaneous flowing temperature.

    e. Instantaneous relative density (if live).

    f. Instantaneous compressibility (if live).

   g. Instantaneous gas composition (if live).
   h. Optional: instantaneous (AGA3) factors (see the orifice meter test cases above for output information).

2) Current configuration information for differential meters or other types of meters, whichever are applicable:
   a. Meter identification.
   b. Date and time of meter configuration information.
   c. Contract hour.
   d. Atmospheric pressure.
   e. Pressure base (unless fixed).
   f. Temperature base (unless fixed).
   g. Meter tube reference inside diameter (upstream diameter).
   h. Orifice plate diameter.
   i. Static pressure tap location.
   j. Orifice plate material and reference temperature.
   k. Meter tube (pipe) material and reference temperature.
   l. Calibrated static, differential, temperature range. (an EFM configuration report may be requested at the time of audit as some manufacturers do not include this information in the Meter Report).
   m. High and low static pressure input alarm values.
   n. High and low differential pressure input alarm values.
   o. Hi and low temperature input alarm values.
   p. High/low differential cut off.
   q. Relative density (if not live).
   r. Compressibility (if not live).
   s. Viscosity
   t. Gas composition (if not live).
   u. Meter factor and/or K factor.
   v. Effluent correction factor.
   w. Metric conversion factors for Imperial calculations.

4.4.9.2.10. The Event Log

The event log, which must be generated on request, is used to note, and record exceptions and changes to the flow parameters, configuration, programming, and the database affecting flow calculations. This log must include such events as, but not limited to:

Date and time stamp for the event.

1) New and old values for each item changed.
2) Orifice plate size change.
3) Transmitter range change.
4) Gas/liquid analysis update by component.
5) Algorithm changes
6) Cut off values for measured inputs.
7) Meter factor, K factor, or effluent correction factor changes.
8) Other manual inputs.
9) The event log must contain the following information with each entry:
10) Time stamp for the event.
11) Date stamp for the event.
12) New and old values for each item changed.

4.4.9.2.11. The Alarm Log

The alarm log includes any alarms that may impact the outcome of the calculation of volumes. Alarms to be reported must include, but are not limited to:

1) Master terminal unit failures.
2) Remote terminal unit failures.
3) Communication failures.
4) Low-power warning.
5) High differential pressure (for differential measurement devices).
6) High/low volumetric flow rate (for other types of measurement).
7) Over-ranging of end devices.
8) The alarm log must contain the following information with each entry:
9) The time of each alarm condition.
10) The date of each alarm condition.
11) The time of clearing for each alarm.

5. Chapter 5- Site-Specific Deviation from Base Requirements

5.1. Introduction

Chapter 1, “Standards of Accuracy” states that a permit holder may deviate from the BCER’s minimum measurement, accounting, and reporting requirements without specific approval if no royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the operator is able to demonstrate that the alternative measurement equipment and/or procedures must provide measurement accuracy within the applicable uncertainties. This Chapter describes situations where an operator may deviate from the minimum requirements without BCER approval, provided that specific criteria are met (see section 5.3). Operators may also apply for approval to deviate from the minimum requirements if the specific criteria are not met. This Chapter indicates what information must be included in such an application. If these exceptions or approvals are in use, BCER inspectors and auditors will review the operator’s records for demonstrated compliance with the criteria specified in this Chapter or in the applicable approval.

5.2. Specialized Terminology Defined

Common Ownership	All wells in a battery/facility belong to the same working interest participant, or, if there is more than one working interest participant, each working interest participant has the same percentage interest in each well in the battery/facility.
Common Crown or Freehold Royalty	When all the wells in a battery/facility are produced under Crown mineral leases, the Crown receives the same royalty rate for each well, or, when under leases granted by one freehold mineral holder, the freehold mineral holder receives the same royalty rate for each well. If there is more than one freehold mineral holder for the wells in a battery/facility, the total royalty rate for each well is the same.
Measured Gas Source(s)	These are single-phase measured gas source(s) downstream of separation and removal of liquids. This also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined with the gas downstream of the separator.
Measured Oil	Oil is measured using equipment and/or procedures meeting delivery point measurement uncertainty limits. For emulsion, the delivery point measurement uncertainty limits apply to the total volume determination only.

5.3. Site-Specific Exceptions

Deviation from base measurement, accounting, and reporting requirements is allowed without submission of an application to the BCER, provided that all the initial qualifying criteria listed under the subsequent “Exception” sections are met.

5.3.1. **Initial Qualifying Criteria**

These criteria (detailed in subsequent sections) must be met to qualify for the exception. If the initial qualifying criteria have been met and the exception is implemented, it may remain in place indefinitely, as long as the exception does not meet any of the revocation clauses and no physical additions to the battery/facility are made (i.e., new wells or zones). If the additions or changes are made to the battery/facility, the initial qualifying criteria must be met for all the wells or zones added to the battery/facility for the exception to remain in place. If the operator anticipates that physical additions may not meet the initial qualifying criteria, the operator may reconfigure the battery/facility to meet base measurement, accounting, and reporting requirements or submit an application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation; however, submissions are not necessary if the pertinent audit trail meets the criteria listed in this chapter. Submission of an application does not guarantee that an approval will be granted.

5.3.2. **Documentation Requirement**

The operator must retain the data and documentation to support the initial qualifying criteria and the last three testing records (if applicable) for as long as the exception is in place. The BCER may revoke an exception if an audit or inspection reveals a lack of adequate supporting data or documentation. If the operator cannot provide documentation requested for a BCER audit within 30 days, the operator will be required to meet applicable BCER base measurement requirements immediately. Alternatively, at the BCER's discretion, the operator may propose a plan to comply with the BCER exception requirements within a BCER-approved time-period.

5.3.3. **Site-Specific Approval Applications**

If the exception criteria cannot be met, or if a specific situation is not covered in this Chapter, the operator may be allowed to deviate from base measurement, accounting, and reporting requirements on approval of an application submitted to the BCER.

Approvals will remain in place indefinitely, provided that conditions specified in the approval are met. If a BCER audit or inspection finds that approval conditions are not being met, the approval may be revoked and the operator will be required to meet applicable base requirements immediately. Additional or other appropriate requirements may be specified by the BCER.

If an operator anticipates that proposed changes to the battery/facility may not meet the approval conditions, the operator may reconfigure the battery/facility to meet base measurement, accounting, and reporting requirements or submit a new application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation. Submission of an application does not guarantee that an approval will be granted.

The following information is required for all applications for site-specific deviation from base requirements. Other specific information that may be required is described in the following appropriate sections. All exemption requests must be submitted via email to *Pipelines.Facilities@bc-er.ca*

Well and/or battery/facility list

1) Battery/facility code and locations.

2) Well locations.

3) Respective pool/zone designations and unique identifier for each zone.

4) Indication as to unit or non-unit operation, if applicable

5) Royalty status (freehold/Crown, new/old, etc.).

6) Equity (ownership) issues, if any.

7) Latest six months' gas, oil/condensate, and water flow rates (or expected flow rates for new wells).

8) Up-to-date measurement schematic(s) for the existing system(s) and the proposed new gas or oil source(s), including all tie-in locations, if applicable.

9) Battery/Facility plot plan for the existing system and the proposed new gas or oil source(s), if applicable.

10) Justification for deviation from measurement requirements (e.g., economics, minimal impact on measurement accuracy).

5.4. Chart Cycles Extended Beyond the Required Time Period

Chart cycle is the time required for a circular chart to complete one 360° revolution. An extension of the required chart cycle time may be applicable under the following scenarios:

1) The gas well orifice meter desired chart cycle is greater than 8 days.

2) The single-well oil battery/facility orifice gas meter desired chart cycle is greater than 24 hours.

3) The group oil battery/facility orifice gas meter desired chart cycle is greater than 8 days.

Mixing of wells with EFM systems and wells using extended chart cycle paper charts within the same battery/facility requires approval from the BCER.

Group or sales/delivery point meters and High and Medium oil well test gas meters do not qualify for exception for chart cycle extension, and approvals for extension of the chart cycle for those meters will not normally be granted.

High >30m^3/d - oil
Medium 6m^3/d but ≤30m^3/d - oil
Low >2m^3/d but ≤6m^3/d - oil
Stripper ≤2m^3/d - oil

5.4.1. Exceptions

Orifice meter gas chart cycles may be extended without BCER site-specific approval or application if all the initial qualifying criteria below are met.

5.4.2. **Initial Qualifying Criteria**

1) In the case of gas well measurement, all wells in the multi-well battery/facility are gas wells. A single-well battery/facility does not qualify for this exception on its own; the entire group battery/facility or gas gathering system must be considered.

2) In the case of oil well measurement, all wells in the battery/facility are oil wells, and the well produces either to a single-well battery/facility or to a multi-well oil group where each well has its own separation and measurement equipment.

3) All wells are subjected to the same type of measurement (all well production is separated, and all components are measured, or all well production is subject to effluent measurement) and the same chart cycle.

4) All wells flowing to the battery/facility have common ownership and either common Crown or freehold royalty, or

   a. If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.

   b. If there are no common Crown or freehold royalties and only freehold royalties are involved, written notification has been given to all freehold royalty owners, with no resulting objection received.

   c. If there is a mix of freehold and Crown royalty involved, the operator must apply to the BCER for approval.

5) The monthly average volumetric gas flow rate for each gas meter is **16.9e^{3}m^3/d** or less (including the gas equivalent of condensate in the case of gas well measurement).

6) For wells, producing > 3 e3m3/day, the differential pen records at 33% or more within the chart range, and the static pressure pen should record at 20% or more within the chart range (if possible). Painted traces must not exceed 4% of the differential pressure or static pressure range. Painting occurs when there are quick up and down movements of the pen, so that there is no visible separation between the up and down traces for a period of time.

7) Temperature must be recorded at least once per week, and, if that is not possible, continuous temperature measurement (temperature pen) is required.

8) The wells must not be designed or operate with on/off flows (e.g., plunger lifts, pump-off controls, intermittent timers, flow control valve cycling). Unexpected or occasional well shut-ins are acceptable.

5.4.3. **Revocation of Exceptions**

If any of the following exists or occurs, the exception is revoked, and base measurement requirements must be reinstated:

1) Oil well, battery, or facility gas is added to a gas battery/facility.

2) There is mixed measurement within the battery/facility other than with EFM.

3) The oil well is not produced either to a single-well battery/facility or to a multi-well oil group where each well has its own separation and measurement equipment.

4) The working interest participants for any well flowing to the battery/facility have changed and a new working interest participant object to the exemption.

5) Any well within the battery/facility has exceeded the 16.9e^{3}m^3/d monthly average actual gas production rate (including gas equivalent of condensate for gas wells).

6) Painted traces for any well exceeded 4% of the differential pressure range or the static pressure range.

7) A new well with on/off flows is added to an effluent proration battery/facility, or one or more of the existing wells has been modified to operate on on/off flows but EFM is not used.

5.4.4. **Applications**

The following information must be submitted with an application to extend orifice meter gas chart cycles:

1) All of the information listed in Chapter 5, section 5.3.3 “Site–Specific Approval Applications”, there are no common Crown or freehold royalties or common ownership, documentation to address royalty and equity issues, demonstrating that written notification was given to all freehold royalty holders and working interest participants, with no resulting objection received.

2) A written explanation of the impact on the measurement accuracy of intermingling base chart cycles and extended chart cycles in a common battery/facility, and how it may relate to concerns about working interest equity and/or royalty considerations.

3) A minimum of two current, consecutive, representative gas charts. Additionally, the operator has the option to run the charts on the proposed chart cycle to gather test data for submission and then revert back to the required chart cycle after a maximum test period of 31 days. The original copies of any such charts created must be submitted with the application. The trial run must be clearly identified on the charts.

5.5. **Considerations for Site-Specific Approval**

1) Differential and static pressures are stable, with essentially uninterrupted flow, noting the following:

   a. On/off flow as designed (including plunger lifts, pump-off controls, intermittent timers, etc.), which causes painting or spiking, does not normally qualify for chart cycle extension.

   b. The effects of painting are minimized. The amount of painting that is acceptable is decided case by case.

   c. The differential pen should record at 33% or more within the chart range and the static pressure pen should record at 20% or more within the chart range (if possible).

2) There are minimal equity and royalty concerns.

3) Reservoir engineering concerns: The concern for well measurement accuracy declines, from a reservoir perspective, as the pool depletes. The applicant should provide an assessment/opinion, but the BCER has to decide on a case-by-case basis if the concerns are relevant.

4) All gas meters producing into the same group measurement point use the same chart cycle, so that they are subject to the same type of error.

5.6. **Measurement by Difference**

Measurement by difference (MbD) occurs when an unmeasured volume is determined by taking the difference between two or more metered volumes. It results in the unmeasured volume absorbing all the measurement error associated with the metered volumes. In the case of a proration battery/facility (effluent measurement, or periodic testing without continuous measurement), new gas or oil source errors may be difficult to detect because the proration testing errors in the original system can hide the new source errors. Despite these concerns, a properly designed and operated measurement system can minimize the risk and attain reasonable accuracy, provided that the measured source gas or oil rates are a small proportion of the total system delivery rates. Measurement by difference is not allowed for "multi-well group batteries/facilities", or "single-well batteries/facilities" unless special approval is obtained from the BCER.

5.6.1. **Gas MbD**

For gas proration batteries, measurement by difference can include, but is not limited to, the following situations. (Note: All figures below are examples only; some systems may be configured differently).

Figure 5.6-1 A Measured Gas Source(s) Tied into a Gas Proration Battery/Facility (Petrinex 364)

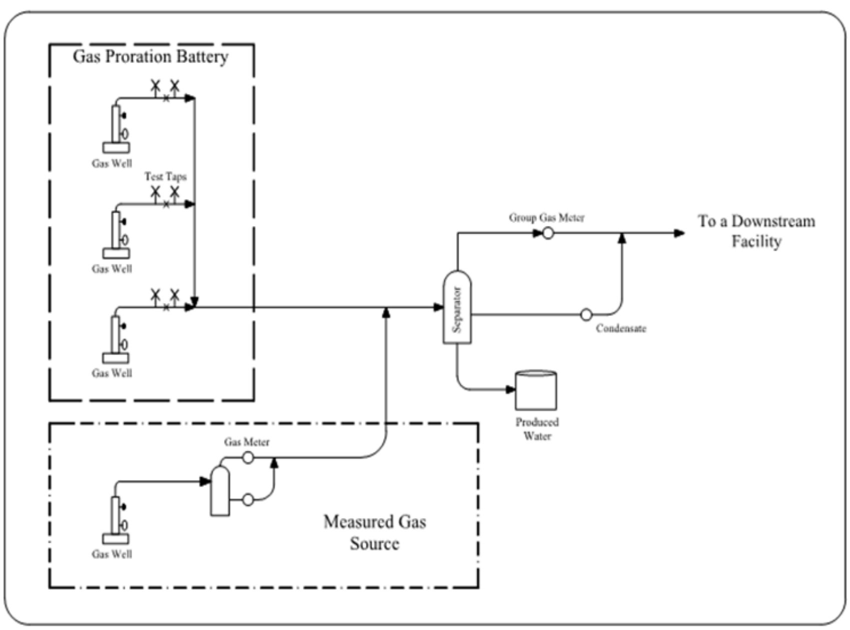


Figure 5.6-2 Measured Gas Sources Delivering into a Gas Multi-well Effluent Measurement Battery/Facility (Petrinex 362) with Battery Condensate Separated, Metered, and Recombined with Battery gas

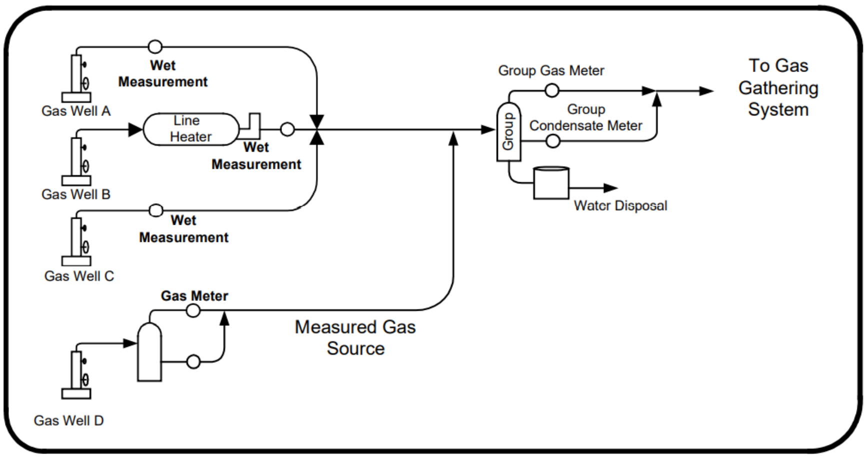
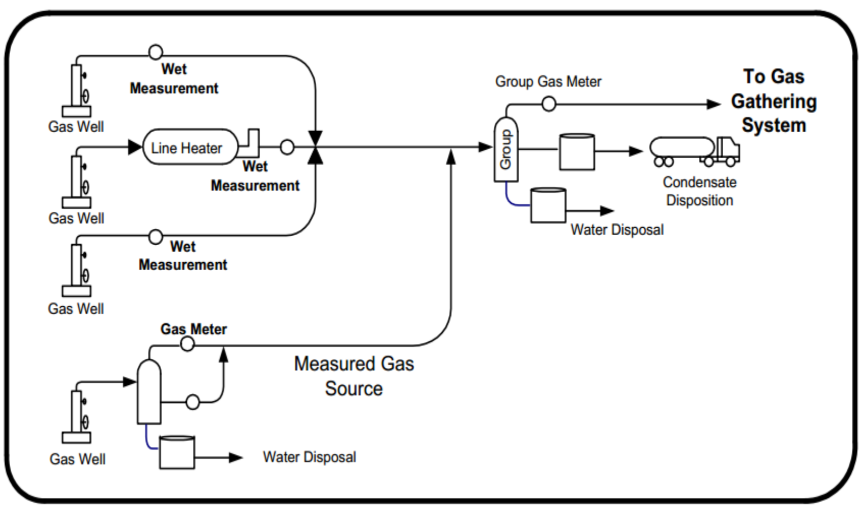


Figure 5.6-3 Measured Gas Source(s) Delivering to an Gas Multi-well Effluent Measurement Battery/Facility (Petrinex 362) with Condensate Separated and Sent to Tank for Disposition to Sales



Measured gas sources delivering into a gas multi-well effluent measurement battery with battery condensate separated and sent to a tank for disposition to sales.

In this case, the condensate from the measured gas source may be reported as a liquid condensate disposition to the effluent battery. If this reporting option is used, Permit holders must adhere to the following conditions:

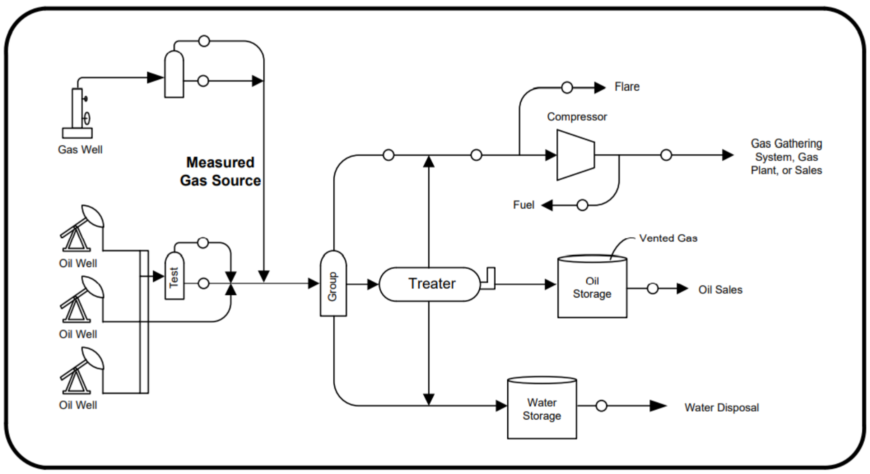
1) MbD ratios and qualifying criteria for both gas and oil (condensate) are applicable at the effluent battery (see section 5.6.3).

2) The condensate meter at the measured gas source must meet delivery point measurement requirements and be proven to stock tank conditions.

3) A live condensate sample and analysis must be obtained at the measured gas source and used to conduct a flash simulation analysis to calculate a GIS at the measured gas source. The liquid condensate disposition from the measured gas source will be the metered condensate and the gas disposition will be the metered gas volume plus the calculated GIS.

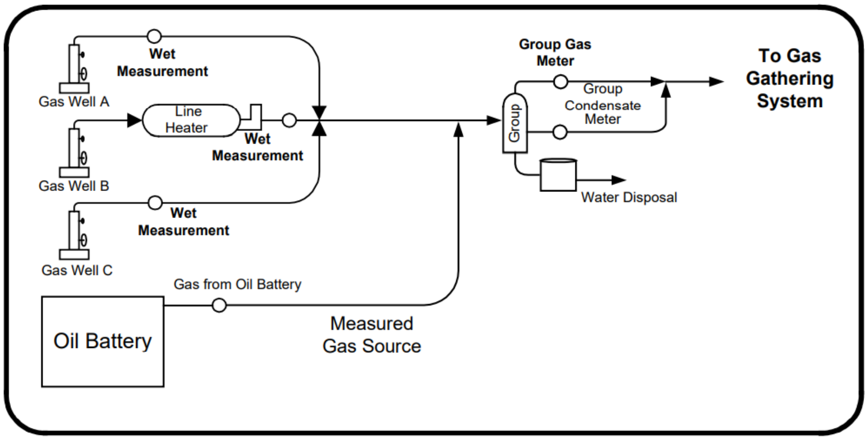
4) The effluent battery condensate production will be the battery condensate disposition minus the measured gas source condensate receipt plus change in inventory.

Figure 5.6-4 Measured Gas Sources Delivering into a Crude Oil Multi-well Proration Battery (Petrinex 322)



For the measured gas sources, the applicable condensate metering and reporting option described in table 5.6-6 in section 5.6.3 must be used.

Figure 5.6-5 Measured Oil Facility Gas Delivering into a Gas Multi-well Effluent Measurement Battery/Facility



5.6.1.1. **If any measured gas source will be tied into a gas proration battery/facility:**

1) The gas and liquids from all tied-in gas sources must be separately and continuously metered. If the R ratio below cannot be met, the operator may consider some of the tied-in measured gas wells as continuous or 31-day test and include them as part of the gas proration battery. These wells, however, must be tagged as "continuous test."
2) The monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery disposition gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

3) The table 5.6-1 below indicates when gas MbD may be acceptable by exception and when submission of an application may be required.

Table 5.6-1 When MbD is Acceptable for a Measured Gas Source tied-in to a Gas Proration Battery/Facility

Prorated gas flow rate (excluding all measured gas source)	R(1)	Application Required
≤ 0.5 e3m3 /d	< 1.00	No
> 0.5 e3m3 /d	≤ 0.35	No
> 0.5 e3m3 /d	> 0.35 and ≤ 0.75	No (2)
> 0.5 e3m3 /d	> 0.75	Yes

1) R = Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to (including fuel, flare, and vent volumes).
2) Must meet additional qualifying criteria in section 5.6.1.2 below.

5.6.1.2. **Qualifying Criteria for R: 0.35 < R ≤ 0.75**

1) Single point measurement uncertainty of the measured gas source gas meter and of the prorated battery group gas meter must be ≤ 2.0 per cent.

2) EFM must be installed on both the gas and condensate meters at the measured gas source meter(s) and the prorated battery group separator.

3) Gas proration factor targets, as set out in section 3.2.3 must be maintained.

4) Potential reservoir engineering / management concerns have been considered and determined to be acceptable the total battery gas disposition volume.

5.6.1.3. **Measured gas source will be tied into an oil proration battery/facility (Petrinex 322)**

If any measured gas source will be tied into an oil battery:

1) The gas and liquids from the tied-in gas source(s) must be separately and continuously metered.

2) The monthly gas volume (including, where appropriate, the GEV of the portion condensate that will flash into the gas phase at the battery) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery/facility gas volume to determine the monthly battery/facility gas production volume. (See table 5.6-6 for reporting options).

3) If liquid condensate is received from a tied-in measured gas source, the monthly liquid condensate volume that will remain in a liquid state at the oil battery must be subtracted from the total monthly oil disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery/facility oil production volume.

4) Table 5.6-2 below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Table 5.6-2 When MbD is Acceptable for a Measured Gas Source tied into an Oil Proration Battery/ Facility

Prorated gas flow rate (excluding all measured gas source)	R[1]	Application Required
≤ 0.5 e3m3 /d	< 1.00	No
> 0.5 e3m3 /d	≤ 0.35	No
> 0.5 e3m3 /d	> 0.35 and ≤ 0.75	No[2]
> 0.5 e3m3 /d	> 0.75	Yes

Note 1. R: Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume (including fuel, flare, and vent volumes).
Note 2. Must meet the qualifying criteria in section 5.6.1.4 below.

5.6.1.4. **Qualifying Criteria for R: 0.35 < R ≤ 0.75**

1) Single point measurement uncertainty of the measured gas source meter and of the prorated battery group gas meter must be ≤ 2.0%

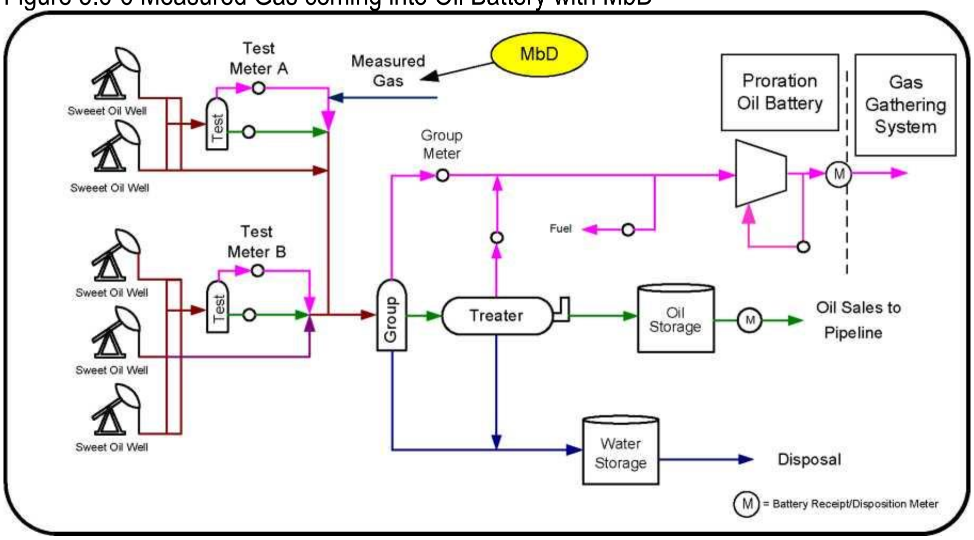
2) EFM must be installed on both the gas and condensate meters at the measured gas source meter(s) and on the proration battery group separator.

3) Gas proration targets set out in section 3.2.3 must be maintained.

4) Potential reservoir engineering/management concerns have been considered and determined to be acceptable.

Scenario 1

Figure 5.6-6 Measured Gas coming into Oil Battery with MbD



Facility delineation is determined by where the measured gas enters the oil battery relative to where the oil battery gas is measured.

Calculate Actual Battery Gas Production

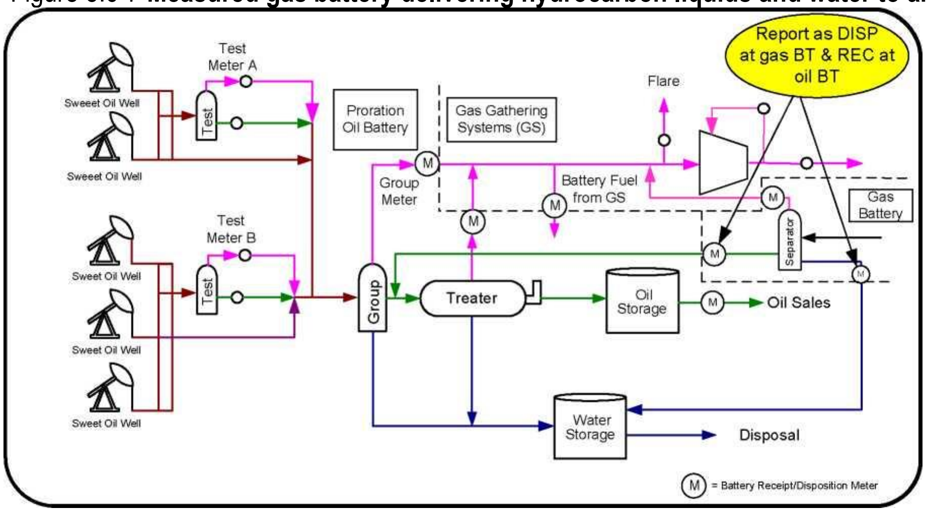
Total battery gas disposition to the gas gathering system is equal to the metered volume after compression. The actual battery gas production is calculated by subtracting the measured gas receipt volume from the sum total of the battery disposition to the gas gathering system, fuel, flare, and vent. The resultant battery gas production volume is then prorated to the flow-lined oil wells. The amount of measured gas that can be delivered into the oil battery is limited by the MbD percentage in Table 5.6-2 When MbD is Acceptable for a Measured Gas Source tied into an Oil Proration Battery/ Facility.

Calculate Battery Oil Production

If the measured gas streams have condensate, see section 5.6.2, Table 5.6-6 Condensate Received at an Oil battery/Facility From all Measured Gas Sources, and section 9.2.4 on how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

Scenario 2

Figure 5.6-7 **Measured gas battery delivering hydrocarbon liquids and water to an oil battery**



Calculate Actual Oil Battery Gas Production

The sum total of the group separator and treater gas is prorated back to flow-lined oil wells. The gas metered from the separator at the measured gas battery is reported as a delivery to the gathering system. This is a preferred scenario as there is no gas MbD restriction, but oil MbD still applies to the measured condensate delivered to the oil battery.

Condensate Receipt into Oil Battery

See section 5.6.2, Table 5.6-6 Condensate Received at an Oil battery/Facility From all Measured Gas Sources, and section 9.2.4 on how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

The table below indicates when gas MbD may be acceptable by exception and when submission of an application may be required.

Table 5.6-3 Measured Gas Battery Delivering Hydrocarbon Liquids and Water to an Oil Battery

Prorated gas flow rate (excluding all measured gas source)	R[1]	Application Required
≤ 0.5 e3m3 /d	< 1.00	No
> 0.5 e3m3 /d	≤ 0.35	No
> 0.5 e3m3 /d	> 0.35 and ≤ 0.75	No[2]
> 0.5 e3m3 /d	> 0.75	Yes

Note 1: R: Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume (including fuel, flare, and vent volumes).
Note 2: Must meet additional qualifying criteria, see section 5.6.1.5 below.

5.6.1.5. **Qualifying Criteria 0.35 < R ≤ 0.75**

1) Single point measurement uncertainty of the measured gas source gas meter and of the prorated battery group gas meter must be ≤ 2.0 per cent.

2) EFM must be installed on both the gas and condensate meters at the measured gas source meter(s) and the prorated battery group separator.

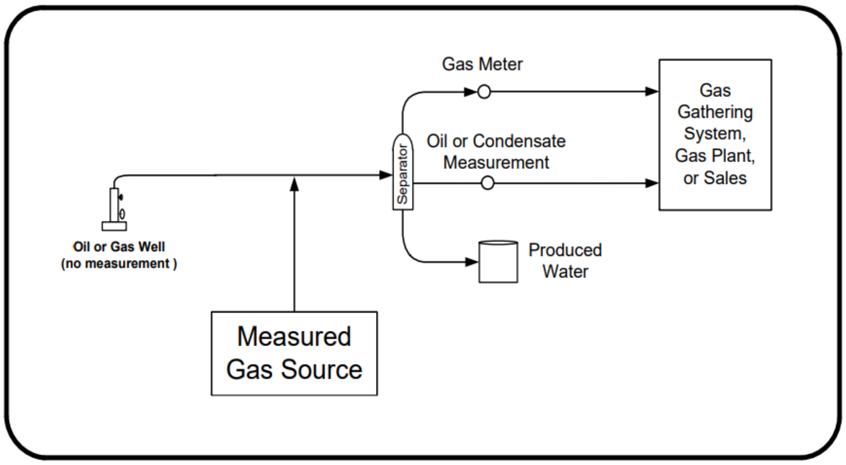
3) Gas proration factor targets, as set out in section 3.2.3 must be maintained.

4) Potential reservoir engineering/management concerns have been considered and determined to be acceptable.

5.6.1.6. **A measured gas source tied into a single well battery/facility**

Where a measured gas source will be tied into a single-well battery, as shown in figure 5.6-8, this situation does not qualify for an exception, and an application must be submitted to and approved by the BCER prior to implementation.

Figure 5.6-8 **Measured Gas Source Delivering into a Single-well Battery**



5.6.2. **Oil/Condensate MbD**

Oil/condensate MbD reported to a gas facility, battery or plant must be reported at a component volume level. For oil streams, MbD can include but is not limited to the following situations.

Figure 5.6-9 Measured Oil/ and/or Oil-Water Emulsion from a Battery / Facility Delivering into a Crude Oil Multi-well Proration Battery/Facility by Truck

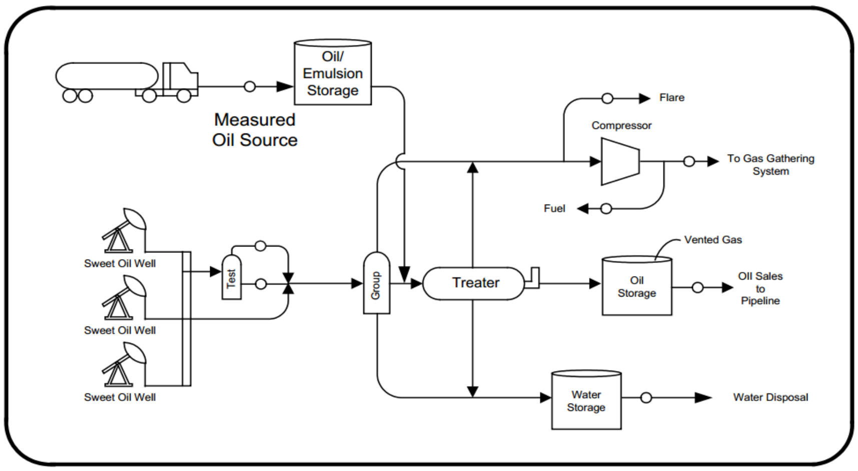
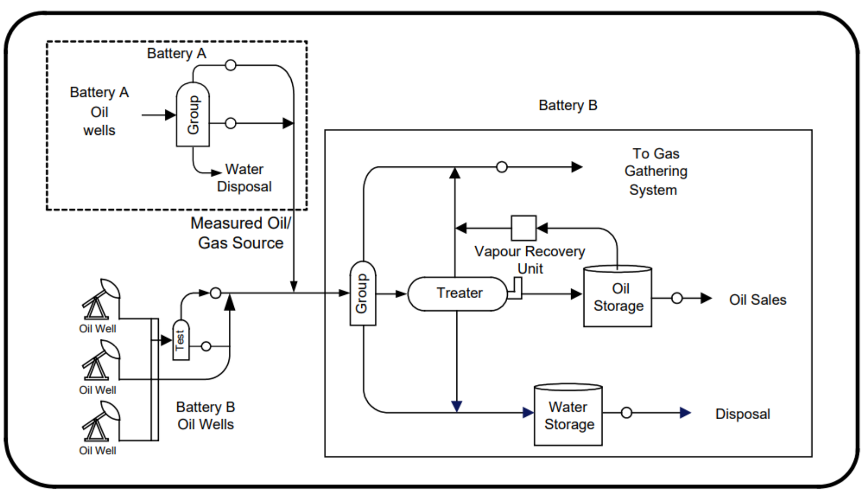


Figure 5.6-10 Measured Oil and/or Oil-Water Emulsion (and gas if applicable) under Pressure from a Battery / Facility Delivering into an Oil Proration Battery / Facility or by Pipeline



5.6.2.1. **If any measured oil/condensate or oil/-water emulsion source will be delivered to battery including trucked-in volumes the following applies:**

1) Measured oil and/or oil-water emulsion delivery/receipt volumes must be determined using equipment and/or procedures that meet delivery point measurement uncertainty requirements. In the case of oil-water emulsions, the measurement uncertainty requirements apply to total volume determination only.

2) Measured oil volumes must be determined and reported at stock tank conditions.

3) The liquids received from the measured oil and/or oil-water emulsion source(s) must be subtracted from the total monthly battery/facility oil and water disposition volumes (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil and water production volumes.

4) When condensate is received by truck at an oil proration battery, gas multi-well effluent measurement battery, or gas plant where a portion of the condensate could flash into the gas phase, the flashed condensate must be reported as a GEV receipt volume and the un-flashed condensate must be reported as a liquid condensate receipt.

5) Table 5.6-4 (below) indicates when oil MbD is acceptable by exception and when submission of an application may be required.

Table 5.6-4 Oil/Condensate or Oil-Water Emulsion Source will be Delivered to a Battery including Trucked-in Volumes

Measured Oil Delivery/Receipt Volume	*R* [1]	Application Required
≤ 1000 m3 / month	Not Applicable	No
> 1000 m3 / month	≤ 0.25	No
> 1000 m3 / month	0.25 < R ≤ 1.00	No[2]
> 1000 m3 / month	> 1.00	Yes

Note 1: R = Total measured oil delivery/receipt volume divided by the monthly battery/facility oil production.
Note 2: Must meet additional qualifying criteria (see 5.6.3.2.2 below).

6) Consideration should be given to incorporating the piped-in measured oil and/or oil-water emulsion source(s) as a satellite of the battery/facility (if the battery/facility is an oil proration battery/facility) and including it in the battery's/facility's proration system. In that case, MbD would be avoided. A pipelined single oil well or oil wells in a multi-well group may also be considered as continuous or 31-day test and included as part of the oil proration battery/facility providing all production streams are flow lined to the receiving battery/facility. These wells, however, must be tagged as continuous test."

5.6.3. **Exceptions**

MbD is allowed without BCER site-specific approval If all the applicable criteria below are met and no application is required.

If the MbD will involve existing production, initial qualifying flow rates must be based on average daily flow rates per calendar day (monthly flow rate divided by number of hours in the month multiplied by 24) recorded during the six months prior to implementation of the MbD. If new measured production is to be connected to a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions.

5.6.3.1. **Exceptions for All Measured Gas Streams**

For measured gas sources from either gas or oil batteries/facilities tied into a gas proration battery/facility or an oil battery/facility, the following applies:

5.6.3.1.1. Initial Qualifying Criteria

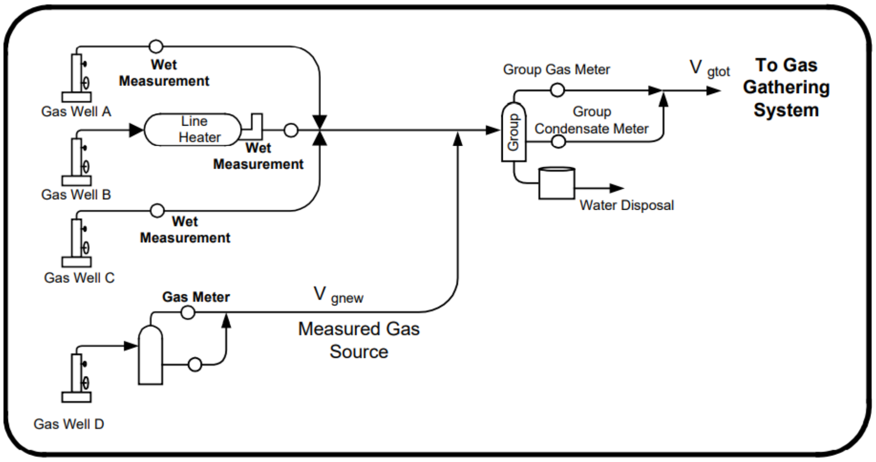
1) Volumetric criteria for measured gas tie-in to a proration battery/facility.

Table 5.6-5 Volumetric Criteria for a Measured Gas Source tying into a proration Battery/Facility

Prorated gas flow rate (excluding all measured gas source)	R[1]	Application Required
≤ 0.5 e3m3 /d	< 1.00	No
> 0.5 e3m3 /d	≤ 0.35	No
> 0.5 e3m3 /d	> 0.35 R ≤ 0.75	No[2]
> 0.5 e3m3 /d	> 0.75	Yes

Note 1: R= Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total gas disposition volume from the receiving battery (including fuel, flare, and vent volumes).
Note 2: Must meet additional qualifying criteria (see 5.6.3.1.2 below).

Figure 5.6-11 Gas Battery Example of Volumetric Criteria for Measured Gas Tying into a Proration Battery / Facility



For the gas battery/facility example in figure 5.6-11:

V gtot = 100e³m³/d (total of measured gas and GEV of condensate delivered out of the battery/facility, including volumes received from Gas Well D).

V gnew = 30e³m³/d (total of measured gas and GEV of condensate delivered to the battery/facility from Gas Well D).

Prorated gas flow rate = V gtot – V gnew = 100 – 30 = 70e³m³/d .

R = 30/100 = 0.3

Since the pro-rated flow rate is above 0.5e³m³/d and R is below 0.35 for the Well D tie-in, it is within the acceptable exception range.

2) All wells flowing to the battery/facility have common ownership and either common Crown or freehold royalty.

   a. If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.

   b. If there is no common Crown or freehold royalty and only freehold royalties are involved, written notification has been given to all freehold royalty owners, with no resulting objection received. If there is a mix of freehold and Crown royalty involved, the permit holder must apply to the BCER for approval if there is any Freehold objection.

3) The gas and liquid phases from the tied-in measured gas source(s) are separately and continuously metered.

4) Gas volumes received at a gas battery/facility from the tied-in measured gas source(s) include the GEV of the measured condensate volumes if the condensate is recombined with the measured gas volumes from the new tied-in gas source.

5) If the tied-in measured gas sources produces condensate and it is connected by pipeline to an oil battery, the applicable condensate metering and reporting option described in Table 5.6-6 must be used.

6) In the case of an oil battery or a gas proration battery, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) is subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

7) In the case of an oil battery, the monthly liquid condensate volume (where appropriate) received from a tied-in measured gas source is subtracted from the total monthly oil disposition (plus inventory changes, shrinkage, if applicable, and minus any other receipts) to determine the monthly battery oil production volume.

8) Oil or oil-water emulsion from a tied-in measured gas source may be delivered to a gas proration, or gas plant in accordance with the following:

   a) The oil or oil emulsion must be measured with a meter proved to stock tank conditions.
   b) A live oil sample must be taken annually, and a multiphase flash liberation or computer simulation must be performed in order to determine the GIS factor of the entrained gas in the oil which must be added to the measured gas volume.
   c) The oil or oil emulsion disposition must be reported as a liquid oil volume and kept whole, as it is reported through the gathering system and gas plant inlet.
   d) Blending shrinkage requirements in section 9.2.4.2 must be adhered to.
   e) The oil and gas MbD exception initial qualifying criteria set out in section 5.6.3 must be adhered to.

Table 5.6-6 Condensate Received at an Oil battery/Facility From all Measured Gas Sources

Condensate received at oil battery/facility (from all measured gas sources)	Condensate Reporting Options
≤ 2.0 m3/day and ≤ 5% of total prorated oil production	1. Prove the tied-in measured gas source condensate meter to live conditions. 2. Obtain a live condensate sample, send to lab, and analysis liquids (to C30+). 3.Multiply the monthly meter condensate volume by the liquid volume fraction from the analysis must derive the component volumes. 4. Report the C6+ (Hexane plus) as a liquid condensate disposition from the measured gas source to the oil battery. 5. Most of the light ends (H2 to NC5) will flash out of the liquid condensate at the oil battery treater. Add the light ends (H2 to NC5) component gas equivalent volumes to the dry flow measured gas component volumes and report this as the total gas disposition from the measured gas source to the oil battery.
> 2.0 m3/day or > 5.0% of total prorated oil production	1. Prove the tied in measured gas source condensate meter to live conditions. 2. Obtain a live condensate liquid sample (to C30+). Perform a computer flash simulation To determine how much gas will flash out of the condensate at each production stage, (i.e. separator and treater) at the oil battery. This will allow for a shrinkage factor to be determined. 3. Report the condensate stock tank volume derived from the metered condensate volume and the simulation shrinkage factor as a liquid disposition from the measured gas source to the oil battery. 4. The flash simulation will also derive the volume and composition of the light ends that will flash out of the condensate at each production stage within the battery. Add the light end (flashed) condensate component gas volumes to the dry flow measured gas component volumes and report this as the total gas disposition from the measured gas source to the oil battery. 5. If there are changes to the process (temperature, pressure) at either the measured gas source or oil battery, or if the measured gas source has new richer or leaner wells tied in, a new condensate sample must be obtained and a new computer flash simulation conducted.

5.6.3.1.2. Additional Qualifying Criteria 0.35 < R ≤ 0.75

9) Single point measurement uncertainty of the measured gas source gas meter and of the prorated battery group gas meter must be ≤ 2.0 per cent.

10) EFM must be installed on both the gas and condensate meters at the measured gas source meter(s) and the prorated battery group separator.

11) Gas proration factor targets, as set out in section 3.2.3, must be maintained.

12) Potential reservoir engineering / management concerns have been considered and determined to be acceptable.

5.6.3.1.3. Revocation of Exceptions for R ≤ 0.35

If any of the initial qualifying criteria in nos. 1 to 8 are not adhered to, then exception is revoked. Base measurement requirements must be reinstated if the exception is revoked.

5.6.3.1.4. Revocation of Exceptions for 0.35 < R ≤ 0.75

If any of the qualifying criteria listed in nos. 1 to 12 above are not adhered to, then the exception is revoked except in the following case:

1) If the gas proration factor at the proration battery exceeds the proration factor targets, as set out in section 3.2.3, the operator must take steps to bring the proration factors back within range within two months of the initial violation month. If the gas proration factors cannot be restored to within the target range within two months, the exception is revoked, and the operator must restore the R factor to 0.35 or lower or obtain a site-specific approval.

   Base measurement requirements must be reinstated if the exception is revoked.

5.6.3.2. **Exception for Measured Oil Received by Truck or Pipeline Into an Oil Proration Battery**

1) Volumetric criteria for measured oil delivered by truck or pipeline to an oil proration battery.

Table 5.6-7 measured oil delivered by truck or pipeline to an oil proration battery.

Measured Oil Delivery/Receipt Volume	R[1]	Application Required
≤ 1000 m3 / month	Not Applicable	No
> 1000 m3 / month	≤ 0.25	No
> 1000 m3 / month	0.25 < R ≤ 1.00	No[2]
> 1000 m3 / month	> 1.00	Yes

Note 1 : R = Total measured oil delivery/ receipt volume divided by the monthly battery oil production
Note 2: Additional qualifying criteria apply. See section 5.6.3.2.2 below.

5.6.3.2.1. Initial Qualifying Criteria

2) The monthly battery/facility oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery/facility oil and water disposition volumes (plus inventory change and minus any other receipts).

3) All wells linked to the proration oil battery (the proration wells) have common ownership and either common Crown or Freehold royalty:

   a) If there is no common ownership, written notification has been given to all working interest participants, with no resulting objections.

   b) If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalties involved, the Permit holder must apply to the BCER for approval if any Freehold royalty owner objects.

4) If measured gas from a measured live oil/emulsion production source is also commingled with the production at an oil battery (pipelined receipt), the exception criteria for gas MbD must also be met.

5.6.3.2.2. Additional Qualifying Criteria for 0.25 < R ≤ 1.00

5) Delivery point measurement must be installed at the proration battery to meter the measured oil receipts (trucked-in or pipelined). The delivery point measurement uncertainty is ≤ 0.5 per cent, regardless of the daily volume of the metered receipts.

6) Oil (and gas, if applicable) proration factor targets, as set out in section 3.2.3, must be maintained.

7) Proving requirements and frequency for the delivery point measurement devices must be adhered to.

8) Blending requirements in section 9.2.4.2 must be adhered to.

9) Potential reservoir engineering / management risks have been considered and determined to be acceptable.

5.6.3.2.3. Revocation of Exceptions for R ≤ 0.25

If any of the qualifying criteria listed in nos. 1 to 4 above are not adhered to, then the exception is revoked and all base measurement requirements must be reinstated.

If an exception is revoked, the operator must:

1) deliver all oil receipts over 1000 m3 /month elsewhere.

2) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the trucked-in or pipelined receipts prior to commingling with the battery production; or

3) obtain a BCER site-specific approval to continue.

5.6.3.2.4. Revocation of Exceptions for 0.25 < R ≤ 1.00

If any of the qualifying criteria listed in nos. 1 to 9 above are not adhered to, then the exception is revoked except in the following cases:

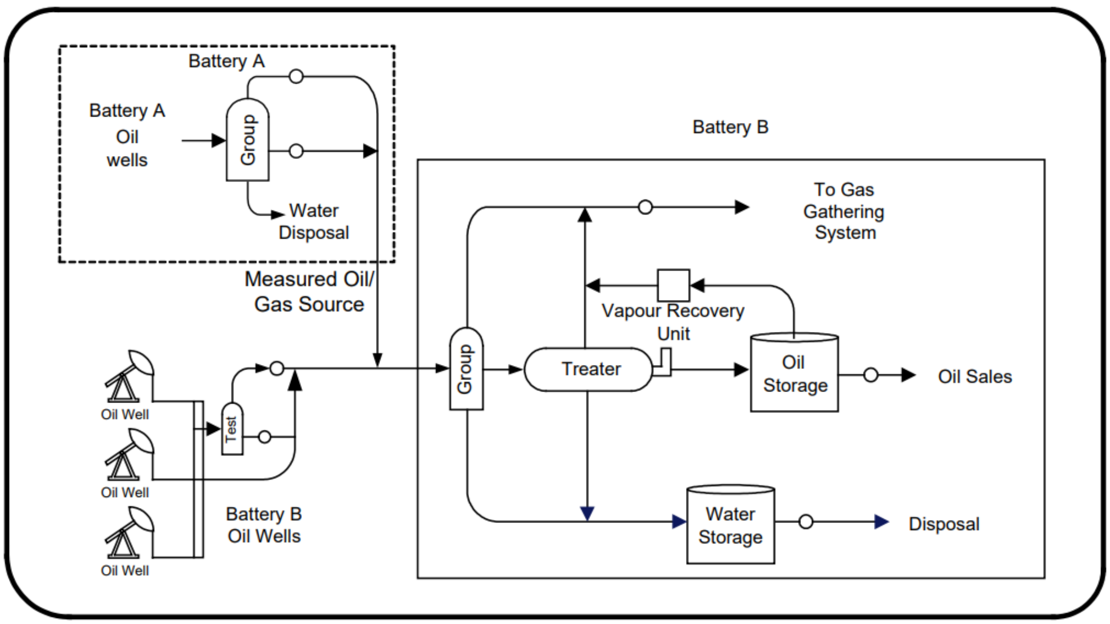
1) If the oil (and gas if applicable) proration factor(s) at the proration battery exceeds the proration factor targets as set out in section 3.1.4, the operator must take steps to bring the proration factors back within range within two months after the initial violation month. If the proration factors cannot be restored to within the target range within two months, the exception is revoked and the operator must restore the R factors to 0.25 or lower for oil and 0.35 or lower for gas or obtain a site-specific approval to continue.

Base measurement requirements must be reinstated if the exception is revoked.

If an exception is revoked, the operator must deliver all oil receipts over 1000 m3 /month elsewhere:

1) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the trucked-in or
2) pipelined receipts prior to commingling with the battery production; or
3) obtain an AER site-specific approval to continue.

Figure 5.6-12 Oil System Example of Volumetric Criteria for Measured Oil tying into a Proration Battery



Note that with the addition of Battery/Facility A production, if the MbD meets all the initial qualifying criteria and the total oil delivery volume at Battery/Facility B is over 100m^3/d, the delivery volume must be determined by a measurement device(s) and/or procedures having ±0.5% uncertainty, which might require changes in measurement equipment and/or procedures at Battery/Facility B.

Given the following data:

Battery/Facility A oil production volume = 20.0m^3/d

Battery/Facility B oil production volume = 90.0m^3/d before tying in Battery/Facility A

Battery/Facility A gas production volume = 15.0e^{3}m^3/d

Battery/Facility B gas production volume = 20.0e^{3}m^3/d before tying in Battery/Facility A

Step 1: Calculate the monthly measured oil volume from Battery/Facility A delivered to the proration battery/facility (Battery/Facility B) and the percentage of the prorated oil production.

Monthly measured oil production volume from Battery/Facility A = 20.0m^3/d x 30 days = 600m^3

Battery/Facility A oil volume as a percentage of Battery/Facility B oil production volume

= 20m^3/d / 90.0m^3/d = 22.2%

Step 2: Calculate the R ratio for the commingled gas:

R = 15.0 / (15.0 + 20.0) = 0.43

Since the Battery/Facility A monthly measured oil volume is below 1000m^3/month, the oil volumetric criteria are met.

However, the gas R ratio is over the 0.35 limit, so an application would be required.

5.6.4. **Applications**

The following information must be submitted with an application to add measured gas or oil/emulsion sources to a proration battery/facility:

1) All of the information listed in section 5.3.3 Site-Specific Approval Applications.
2) A discussion of the stage of depletion for pools involved, and the impact of any reduction in well measurement accuracy that may result from measurement by difference as it relates to reservoir engineering data needs; discussion of this matter by the proponent with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application.
3) If there are no common Crown or freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all freehold royalty holders and working interest participants, with no resulting objection received.

5.6.5. **Considerations for Site-Specific Approval**

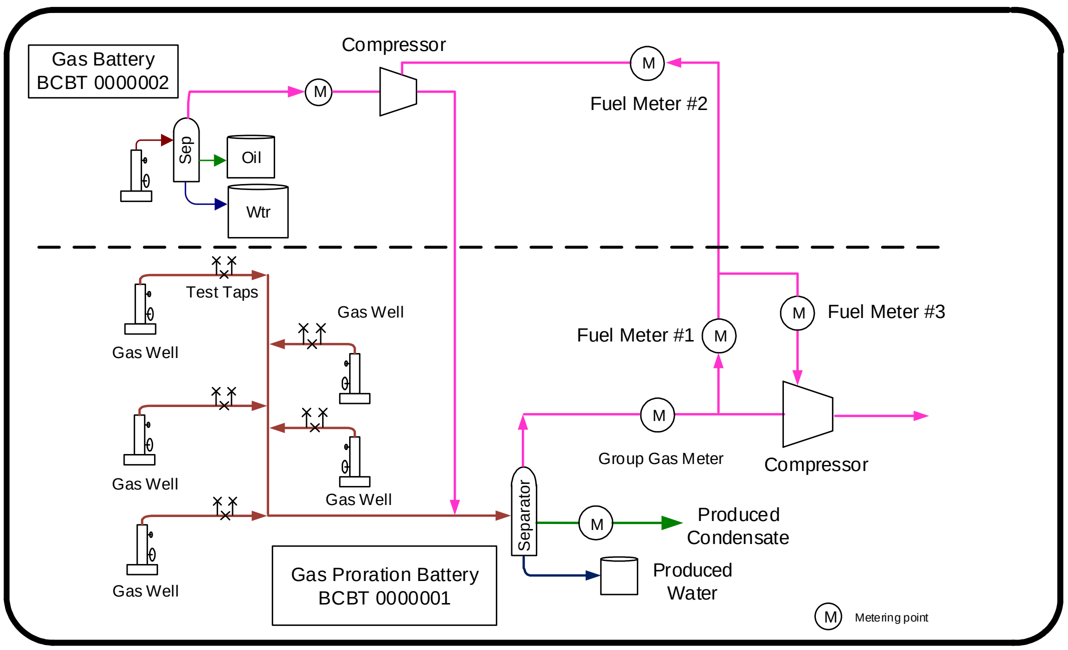
1) There are minimal equity, royalty, and reservoir engineering concerns.
2) Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?
3) The gas and liquids from the tied-in measured source(s) must be separately and continuously metered.
4) If the tied-in measured gas source(s) produces condensate and it must be connected to an oil battery/facility, the operator must choose from the following applicable condensate delivery/reporting options listed in Table 5.6-6.
5) In the case of an oil battery/facility or a gas proration battery/facility, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery/facility gas volume (including GEV of condensate where appropriate) to determine the monthly battery/facility gas production volume.

6) In the case of an oil battery/facility, the monthly liquid condensate, or oil, and/or oil-water emulsion volume (where appropriate) received from a tied-in measured source must be subtracted from the total monthly oil and/or water disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery/facility oil and/or water production volume.

5.6.6. **Fuel Gas MbD**

Section 4.4.9.1 (10) describes the requirements for fuel gas measurement and reporting at sites where there may be multiple facility reporting codes and the fuel gas consumption is > 0.5 $e^3\ m^3$/d. Situations may occur where fuel gas is metered and consumed at one site and some of the metered fuel gas is then sent to another site (separate geographic location) where it is consumed (see figure 5.6-13). Three acceptable fuel gas MbD scenarios are described below.

Figure 5.6-13 Fuel Gas MbD Scenarios



1) Site fuel gas at BCBT 0000001 is measured at fuel meter #1. The volume of fuel gas sent to BCBT 0000002 is ≤ 0.5 $e^3\ m^3$/d, and the volume of fuel gas consumed at the compressor at BCBT 0000001 is > 0.5 $e^3\ m^3$/d. In this case, fuel gas MbD is acceptable for the reported fuel gas at BCBT 0000001, and the reported fuel gas at BCBT 0000001 will equal fuel meter #1 minus fuel meter #2. If the fuel gas sent to BCBT 0000002 is > 0.5 $e^3\ m^3$/d and the fuel gas consumed at the compressor at BCBT 0000001 is ≤ 0.5 $e^3\ m^3$/d then fuel gas MbD is acceptable for the reported fuel gas at BCBT 0000002, and the reported fuel gas at BCBT 0000002 will equal fuel meter #1 minus fuel meter #3.

2) Site fuel gas at BCBT 0000001 is metered at fuel meter #1. The volume of fuel gas sent to BCBT 0000002 is > 0.5 $e^3\ m^3$/d, and the volume of fuel gas consumed at the compressor at BCBT 0000001 is > 0.5 $e^3\ m^3$/d. In this case, MbD is acceptable for the fuel gas used at either BCBT 0000001 or BCBT 0000002, depending on which site is expected to have the higher reported fuel gas volume. If the fuel gas volume at BCBT 0000002 will be less than the fuel gas volume at BCBT 0000001, then fuel gas MbD is acceptable for BCBT 0000001, and the reported fuel gas at BCBT 0000001 will equal fuel meter #1 minus fuel meter #2.If the fuel gas volume at BCBT 0000002 will be less than the fuel gas volume at BCBT 0000001, then fuel gas MbD is acceptable for BCBT 0000002, and the reported fuel gas at BCBT 0000002 will equal fuel meter #1 minus fuel meter #3.

3) Site fuel gas at BCBT 0000001 is measured at fuel meter #1. The monthly volume of fuel gas sent to BCBT 0000002 is < 0.5 $e^3\ m^3$/d, and the monthly volume of fuel gas consumed at the compressor at BCBT 0000001 is < 0.5 $e^3\ m^3$/d. In this case, reported fuel gas volumes for BCBT 0000001 and BCBT 0000002 may be prorated from the metered monthly fuel gas volume at fuel meter #1 and will be based on each battery's percentage of the total estimated monthly fuel gas volumes at both batteries. For example, reported monthly fuel gas volumes at BCBT 0000001 = fuel meter #1 × BCBT 0000001 estimated fuel ÷ (BCBT 0000001 estimated fuel + BCBT 0000002 estimated fuel). Battery fuel gas estimates must be based on sound engineering estimates.

5.6.7. **Surface Commingling of Multiple Gas Zones/Wells**

If gas wells have been completed in multiple zones and those zones are segregated in the wellbore and produced separately to surface or if there are multiple individual gas wells on the same surface location, production from each zone usually must be metered separately prior to commingling. In some cases, that may not be practical for various reasons, such as low volumes or economics. Where applicable, such zones may be commingled at surface prior to the combined production being measured, if the conditions in the "Exceptions" section below are met or on approval of an application. Proportionate monthly production volumes must still be determined and reported for each zone/wells, in accordance with the applicable procedures described below.

Commingled production from two or more hydrocarbon bearing formations in the wellbore requires prior approval from the BCER Reservoir Engineering Branch.

5.6.7.1. **Exceptions**

Surface commingling of two gas zones in a gas well or separate gas wells on the same surface location prior to measurement is allowed without BCER site-specific approval if all the initial qualifying criteria in section 5.6.7.1.1 (below) are met.

5.6.7.1.1. Initial Qualifying Criteria

1) Both zones/wells have common ownership and common Crown or freehold royalty.

a. If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.

b. If there is no common Crown or freehold royalty and only freehold royalties are involved, written notification has been given to all freehold royalty owners, with no resulting objection received.

c. If there is a mix of freehold and Crown royalty involved, the operator must apply to the BCER for approval.

2) Monthly average of total liquid production from both zones is less than or equal to $2m^3/d$.

3) The combined daily flow rate of both zones/wells is $16.9e^3m^3$ or less, including GEV of condensate (if recombined).

   a) If the zones/wells to be commingled will involve existing production, initial qualifying flow rates are based on monthly average flow rates recorded during the six months prior to implementation of the commingling.

   b) If new zones/wells must be commingled, the initial qualifying flow rates are based on production tests conducted under the anticipated operating conditions.

4) Shut-in wellhead pressure of the lower pressure zone/well is greater than or equal to 75% of the shut-in wellhead pressure of the higher-pressure zone.

5) The combined production from both zones/wells is metered continuously. Separation before measurement is required.

6) Check valves are installed on each flow line upstream of the commingling point.

7) Testing requirements:

   a. Each zone/well must be tested once per month for the first six months after commingling. Annually thereafter, and/or immediately following any significant change to the producing conditions of either zone/well.

   b. The tests must be conducted for a period of at least 24 hours and must involve the separation and measurement of all gas and liquid production.

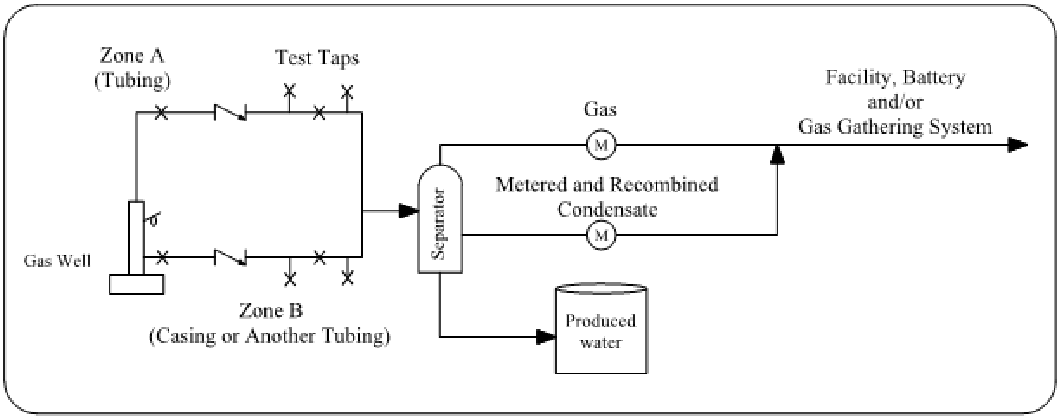
   c. If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor to be used to determine the GEV.

   d. The tests for both zones/wells must be done consecutively with stabilization periods.

   e. Any of the three test methods described below may be used. However, methods (1) and (2) below are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required.

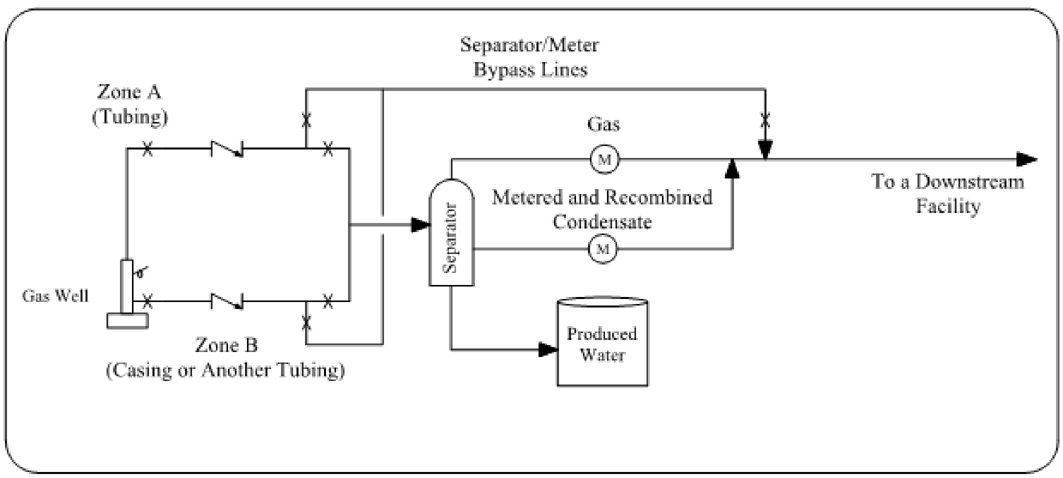
   f. Test taps must be installed upstream of the commingling point but downstream of the check valve so that a test separator unit can be hooked up to test each zone/well individually.

Figure 5.6-14 Test Method 1



i. Install permanent bypasses or taps to hook up temporary bypasses downstream of the check valve so that one zone/well will be bypassing the existing separation and metering equipment while the other zone/well is tested using the existing equipment. Note that the production from the bypassed zone/well must be estimated based on the production test rates.

Figure 5.6-15 Test Method 2



ii. Shut in one producing zone at a time and use the existing separation and measurement equipment to test each zone individually after stabilization.

8) The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone/well.

5.6.7.1.2. Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) The combined production from both zones/wells was not metered continuously or there was no separation before measurement.

2) Check valves were not installed on each flow line upstream of the commingling point.

3) Testing requirements in item 7 under Initial Qualifying Criteria (section 5.6.7.1.1) above were not followed.

4) The gas proration methodology in item 8 under Initial Qualifying Criteria (section 5.6.7.1.1) above was not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.6.8. **Applications**

The following information must be submitted with an application to commingle production at surface prior to measurement from multiple zones in a gas well or multiple wells on the same surface location if the criteria (below) are not met:

1) All of the information listed in section 5.3.3 "Site-Specific Approval Applications". Shut-in and proposed operating pressures at the wellhead for all zones/wells.

2) Operating pressure for the gathering system at the well site measurement point.

3) Proposed testing procedures to determine the individual zone/well production rates.

4) Proposed accounting procedures for pro-rating total volumes to the individual zones/wells.

5) If there are no common Crown or freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all freehold royalty holders and working interest participants, with no resulting objection received.

5.6.9. **Considerations for Site-Specific Approval**

1) Generally, there is 2m^3/d or less of total liquid production from all zones/wells.

2) All zones must be classified as gas zones/wells.

3) There are minimal equity, royalty, and reservoir engineering concerns.

4) The combined production of all zones/wells must be continuously metered. If there are gas and liquid components, they must be separately metered.

5) Check valves must be in place on each zone's flow line upstream of the commingling point.

6) Testing requirements:

   a. Each zone/well must be tested once per month for the first six months after commingling, then annually after that, and/or immediately following any significant change to the producing conditions of either zone/well.

   b. The tests must be conducted for at least 24 hours in duration and must involve the separation and measurement of all gas and liquid production.

   c. If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor that will be used to determine the GEV.

   d. The tests for all zones/wells must be done consecutively, with stabilization periods.

   e. Any of the three test methods described in the exceptions section above may be used, with the consideration that more than two zones/wells may be involved. However, methods (i) and (ii) are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required. The BCER may specify test procedures if specific circumstances warrant them.

   f. The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone.

6. Chapter 6- Determination of Production at Gas Wells

6.1. Introduction

This Chapter sets out the requirements concerning the measurement, accounting, and reporting of production from gas wells. This Chapter:

1) Outlines the methods for determining the total monthly water and hydrocarbon production volumes.
2) Sets out the requirements of what measurement schemes are applicable to gas well production.
3) Sets out the requirements of effluent well testing, including the determination and calculation of a well's Effluent Correction Factor (ECF), Water-Gas Ratio (WGR) and Condensate-Gas Ratio (CGR).
4) Provides the conditions for exemption or reduction in well testing frequency.
5) Provides guidance around reporting production streams.

6.2. Batteries / Facilities

Reporting batteries/facilities can be comprised of production from wells which are all measured (multi-well group), are all effluent (multi-well effluent) or a combination thereof providing the requirements outlined in section 5.6 of this manual are adhered too in the event that there is Measurement by Difference .

Effluent well volumes are prorated, whereas measured well volumes are not. It is possible for a reporting battery/facility to include and report both measured and prorated volumes depending on the configuration of wells linked to a reporting battery/facility. It should be noted that measured batteries/facilities and wells delivering into an effluent system are not subject to the effluent battery's/facility's proration factors as outlined in section 3.2.3 of this manual.

A reporting battery/facility may contain:

1) Measured gas wells which are not to be prorated along with effluent gas wells upstream of group measurement in a reporting battery/facility;
2) Gas from oil wells which is not to be prorated along with effluent wells upstream of group measurement in a reporting battery/facility;
3) Gas from oil wells, along with measured gas wells which are not to be prorated and effluent gas wells upstream of group measurement in a reporting battery/facility.
4) Gas from another reporting battery's/facility's group measurement point along with effluent wells upstream of group measurement in a reporting battery/facility.

A reporting battery/facility **must NOT**:

1) Be commingled with gas from another reporting battery/facility (oil or gas) without group measurement.

6.2.1. **Group Measurement**

Group measurement represents a point of separation of production into individual phases in which the volumes are used for reporting purposes (see Figure 6.2-1). The location of group separation is influenced by a number of factors such as ownership, type of production (conservation and non-conservation), battery/facility design requirements, and proximity to a sales network. For the purposes of group measurement, continuous single-phase measurement can be accomplished by:

1) Metering each of the single-phase production streams (gas, hydrocarbon liquid and water) downstream of a separator. Separators can measure liquid production by one of the following two options:

   a) Utilizing a three-phase separator.

A three-phase separator must be utilized if the hydrocarbon liquid annual average production is equal to or greater than 2.00m^3/day. This requirement is "grandfathered' for separators installed prior to June 1st 2013, however, all two-phase separators left in service are still required to meet the criteria set out in section (b) "Utilizing a two-phase separator" below.

A WGR may be utilized to determine water production volumes on a three-phase separator if the following conditions are met:

i. Drilling and Production Regulation D&PR 69(4) is met.
ii. Water is recombined with the metered gas and the metered hydrocarbon liquid at the well site, and
iii. Production stream (gas, hydrocarbon liquid and water) go to the same reporting facility.
iv. The WGR must be calculated from an annual WGR test. The WGR test must be a minimum of 12 hours in duration. A tag must be attached to the water leg indicating that a WGR calculation is used for volume determination.

   b) Utilizing a two-phase separator.

A two-phase separator is permitted to be utilized to measure a water/condensate mixture prior to having liquids recombined with the gas stream providing that the hydrocarbon liquid production is less than 2.00m^3/day on an annual average. This threshold is "grandfathered' for separators installed prior to June 1st 2013, however, provisions must be used to determine the total S&W of the gross liquid volume. The S&W must be determined by one of the following methods and applied to the wells respective liquid volumes over the course of the year:

i. With the use of a proportional sampler suitable for hydrocarbon liquid applications as not to allow flashing of the hydrocarbon liquids. A proportional sampler must be installed for a minimum of 30 consecutive days once per year to obtain a representative S&W, or
ii. With the use of an in-line water cut analyzer.

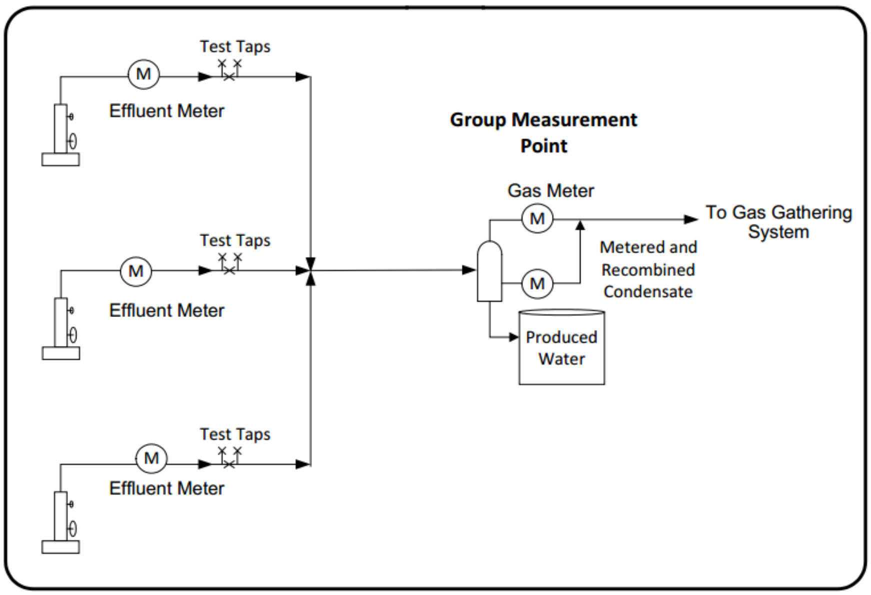
If there is an auditable history of no hydrocarbon liquid production for the well or its respective battery/facility, then a WGR may be used to determine the well's water production. The WGR must be calculated from an annual WGR test. The WGR test must be a minimum of 12 hours in duration. A tag must be attached to the water leg indicating that a WGR calculation is used for volume determination and that no condensate production is present. A WGR cannot be utilized on 2-phase measured wells where there is the presence of hydrocarbon liquid production.

2) Directing water production to a tank and delivering by either truck or pipeline for disposal. The monthly water production volume can then be determined from the sum of delivery point volumes (by the receiving battery/facility) and changes in tank inventory (by gauging the tank).

3) Directing hydrocarbon liquid production to a tank and delivering by either truck or pipeline for processing. The monthly production volume can then be determined from the sum of delivery point volumes (by the receiving battery/facility) and changes in tank inventory (by gauging the tank).

4) Any combination of the above.

Figure 6.2-1 Typical Group Measurement Design



6.3. Gas Well Measurement Scheme Types

Four (4) types of gas well measurement schemes exist within the province of British Columbia:

1) Measured well production (utilizes a separator) – Production volumes are not prorated.

2) Effluent well production with LGR < 0.280 m3/e3m3 (utilizes a wet meter). Production volumes are prorated.

3) Effluent well production with LGR > 0.280 m3/e3m3 (utilizes a wet meter). Production volumes are prorated.

4) Mixed oil and gas well effluent measurement. Production volumes are prorated.

The requirements for determining production vary among these three methods and there are variations within each method. It is imperative that operators understand their battery/facility to ensure all production is accounted for and reported correctly.

Water quantities must be reported to the Ministry of Finance in accordance with the DPR and Directive 2010-07. Water that is in the vapor phase under separator conditions must not be reported as production.

6.3.1. **Measured Gas Well**

A gas well in which production volumes are delivered to a dedicated separator and measured in a manner that meets the requirements outlined in section 6.2.1 Group Measurement.

6.3.2. **Gas Multi-well Effluent Measurement Battery / Facility (Petrinex 362)**

All wells in a effluent gas proration battery must be classified as gas wells and must be connected by flow line to a common group separation and measurement point.

Test taps must be installed at all effluent metered proration gas wells. All effluent gas proration batteries require periodic well tests to be conducted to determine production rates, production ratios, and/or ECF that will be used in the determination of monthly estimated well production volumes. Monthly estimated well production volumes are multiplied by proration factors (see Table 3.2-3) to determine the actual well production volumes for reporting purposes. All wells must be tested annually unless otherwise stated in this chapter.

6.3.3. **Effluent Gas Well - LGR Classification < 0.280 m3/e3m3**

A gas well in which production passes through a multiphase meter and is not configured with separation. This well measurement scheme is commonly referred to as an effluent or wet metered gas well. The effluent well testing must follow sections 6.5.1 and 6.5.3. For each new well:

1) Maintain individual well separation and metering during the initial flowback period.

2) Submit initial well test data to the eSubmission Portal as outlined in the “Well Testing and Reporting Requirements Guideline” found at *Well Testing and Reporting Requirements Guide.* The submission must include:

    a) the depth and target of each well within the submission (i.e., upper, middle, or lower Montney).

    b) analog well description- production rates and ratios (gas, condensate, water) and plots of ECF, LGR, CGR, and WGR, curves for each target zone.

Measurement uncertainty is introduced by the presence of liquids in the gas stream. To correct for the uncertainty of utilizing wet measurement, periodic well tests are conducted to determine a well’s respective ECF, CGR (if applicable) and WGR. The ECF is used to correct for the errors in the effluent meter volume due to the presence of multiphase fluid and to determine monthly estimated well gas production volumes. The CGR is used to determine the monthly estimated well condensate production should the battery/facility tank the condensate production. The WGR is used to determine monthly estimated well water production volumes.

The ECF, CGR (if applicable) and WGR used for reporting wells must be validated against the production history of the well from which the factor was determined. If a well has never had a well test conducted, an ECF of 1.00000 must be applied until such time that an ECF can be determined. Likewise, a CGR (if applicable) and a WGR of 0.000 must be utilized until such time that a test can be conducted. If a well has had a flow-back test during the initial clean-up period, the production data from the most recent well test at the end of the clean-up period should be used to determine the respective factors, unless exempted from testing as per section 6.5.3. Wells that are exempt from testing should utilize an ECF, CGR, and WGR as stated in Appendix C.

Monthly estimated well production volumes are multiplied by battery/facility proration factors to determine the prorated well production volumes for reporting purposes. Total battery/facility production must be metered and prorated back to the individual wells, based on each well's estimated monthly gas production.

6.3.4. **Effluent Gas Well – LGR Classification > 0.280 m3/e3m3**

This measurement approach allows for the use of a test and group separator measurement system to measure production from one or more multi-well pads. Each multi-well pad would utilize either a permanent or portable/temporary test separator measurement system that would allow wells to be regularly tested to provide information for prorating group production measurements to individual wells with the use of effluent (wet) metering. The BCER no longer requires applications for proration measurement for specific sites that apply the following criteria:

1) Production must be from liquids-rich gas reservoirs where the LGR for a well is greater than 0.280 m3/e3m3.

2) A multi-well pad development approach must be used where several wells are drilled at a single surface location.

3) Maintain individual well separation and metering during the initial flowback period. Submit initial well test data to the eSubmission Portal as outlined in the "Well Testing and Reporting Requirements Guideline" found at *Well Testing and Reporting Requirements Guide.* The submission must include:

    a) the depth and target of each well within the application (i.e. upper, middle, or lower Montney).

    b) analog well description- production rates and ratios (gas, condensate, water) and plots of ECF, LGR, CGR, and WGR curves for each target zone.

4) Each test separator may have up to a maximum of 24 wells.

5) The commingled production from all of the tested wells at each pad must be connected to a facility/battery group separator where the well production from all pads is separated and each phase (gas, hydrocarbon liquid, and water) are individually metered. This can be done at the well pad level or at a downstream facility.

6) Each new well must be tested not fewer than once per month with each test being a minimum 12-hour duration. Monthly testing must continue until the difference of the last 3 consecutive ECF tests are within 5%. Upon meeting this condition, the testing period may be extended to once every 6 months as long as the last 3 consecutive ECF tests continue to remain within 5 % and battery/facility group gas and condensate proration targets are met, else revert back to monthly or more frequent testing. If two consecutive tests indicate that the LGR has dropped below 0.280 m3/e3m3 then the well testing frequency in the Well Testing Decision Tree section 6.5.3 will apply.

The methodology for determining the ECF difference is:

$$\frac{\text{Average ECF from last 3 tests} - \text{Smallest ECF (from last 3 tests)}}{\text{Average ECF of the last 3 tests}}$$

7) Each well and the group separator must be sampled as outlined in section 8.4 to obtain an analysis of gas and hydrocarbon liquids (condensate). The gas and condensate analysis for individual wells must be used to calculate the well gas and condensate gas equivalent volumes. The group gas and condensate analysis must be used to calculate the group gas and condensate gas equivalent volumes.

8) The battery group separator must be a three-phase separator and use electronic flow measurement (EFM) for gas and condensate. The condensate measurement must use a mass meter and water cut analyzer.

9) Test separators must have three-phase measurement and use EFM to measure gas and condensate. The test separator may be a three-phase separator measuring gas, condensate, and water, or a two-phase separator with a gas and liquids meter, and a liquid-phase water cut analyzer. Test separators must be sized correctly, have adequate retention time, and provide good separation at the test flow rate. A water cut must be obtained for each new well to establish three phase separator performance. The well condensate recombined must meet the total single point measurement uncertainty (See Table 1.8-2). If the water cut causes the single point measurement uncertainty to be exceeded, then the test hydrocarbon liquid volume must be corrected for water cut on each well ECF test.

10) If condensate at the battery group separator is produced to a tank at the facility/battery and not recombined with the gas and sent to a gas plant for further processing, then:

    a. the condensate tanks must incorporate a vapour recovery system to capture and conserve hydrocarbon vapours that would flash from the condensate, or the flash gas may be flared or incinerated if on a temporary basis (less than 6 months); or
    b. the condensate must be stored in pressure vessels of sufficient pressure rating so that no vapours are vented; or
    c. the condensate must be stabilized to ensure it is at stock tank conditions.

11) The facility/battery gas and condensate proration factors must be within the target range of 0.95000 to 1.05000. If these proration targets are not met all wells within the facility/battery group reporting point must go back to monthly, or more frequent testing (if required) until the proration targets are within range.

12) All wells flowing to the battery must have 100 % working interest ownership. If there are multiple working interest owners, then written notification must be given to all working interest owners with no resulting objection received.

13) If the wells flowing to the battery have a mix of crown and freehold royalties, then written notification must be given to all freehold royalty holders with no resulting objection received.

14) Gas well production/disposition must be reported as a subtype 362, “Gas Multiwell Effluent Proration” battery.

6.4. Decimal Place Holders for Volumetric Calculations in a Gas Proration Battery / Facility

The required decimal places for volumetric calculations in a gas proration battery/facility (effluent measurement scheme) are outlined in Table 6.4-1 below.

Table 6.4-1 Decimal Place Holders

Type of calculations	Number of decimals to be calculated to	Number of decimals to be rounded to
Productions and estimated productions	2	1
Well test gas, Gas Equivalent Volume (GEV) of test condensate, test condensate, or test water	3	2
Water-Gas ratio (WGR), Condensate-Gas ratio (CGR), Liquid-Gas Ratio (LGR)	5	4
Gas Equivalent Factor (GEF), Proration factors, Effluent Correction Factor (ECF)	6	5

6.5. Effluent Well Testing

6.5.1. Frequency

All new wells with a LGR > 0.28 m3/e3m3 must be tested not fewer than once per month with each test being a minimum of 12- hour duration. The monthly testing period must commence after the initial clean-up and flow-back test period and be within 30 days of production. Monthly testing must continue until the difference of the last 3 consecutive ECF tests are within 5%. Upon meeting this condition, the testing period may be extended to 6 months, as long as the difference of the last 3 consecutive ECF tests continue to remain within 5 % and gas and condensate proration targets are met, else revert back to monthly or more frequent testing. If two consecutive tests indicate that the LGR has dropped below 0.280 m3/e3m3 then the well testing frequency in the Well Testing Decision Tree section 6.5.3 will apply.

The methodology for determining the ECF difference is:

$$\frac{\text{Average ECF from last 3 tests} - \text{Smallest ECF (from last 3 tests)}}{\text{Average ECF of the last 3 tests}}$$

An effluent well test is required on a new effluent well with LGR classification < 0.280 m3/e3m3 on an annual frequency unless one of the Well Testing Decision Tree's exemptions can be applied as outlined in section 6.5.3 . The Well Testing Decision Tree outlines the testing frequency requirements for effluent wells that are not being tested on an annual frequency.

All new wells must have a well test conducted within the first 30 days of production. The initial flow back test at the end of the clean-up period will be accepted as the first test that is required within the 30 days.

If the BCER has a concern with the activities, operations, production data, proration targets, or reporting associated with well testing, on notice in writing, the BCER will advise the operator as to the reason for the revocation, provide a reasonable time-period for the operator to meet the conditions set by the BCER, and provide an opportunity for the operator to comment. It will be expected that the operator complies or justify their actions. Failure to do so, may result in revocation of the well testing exemptions and impose, modify, or substitute well testing conditions for any period of time.

Wells that have their operational/production characteristics changed because events altering the flowing characteristics (i.e., compressor installation, a well bore work over, recompletion, inter-well communication, artificial lift installation, or chemical stimulation) must have a well test conducted within 30 days of the event(s) that caused the operational/production characteristics to change. Therefore, a well must be (re)evaluated according to the applicable Well Testing Decision Tree being utilized for each activity in a wellbore that may alter the operating or production characteristics.

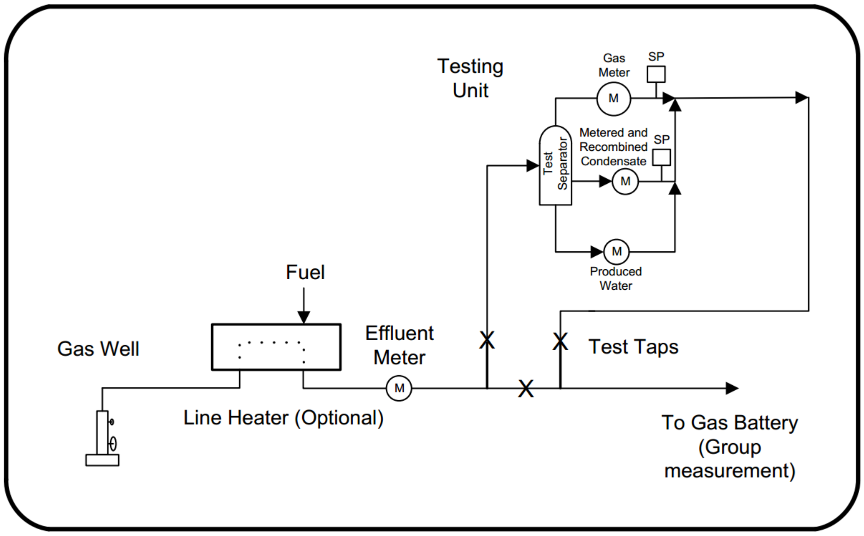
Copies of the results of the ECF tests conducted for each well must be kept at respective field offices and be available upon request. The ECF test document must have the well surface location, testing frequency, date, start and end time of test, the effluent meter volume, the test separator gas volume, the metered condensate volume, the metered water volume, the calculated ECF, CGR, WGR, and LGR.

6.5.2. **Procedure**

Figure 6.5-1 illustrates a typical gas well effluent measurement configuration. Production from the gas well passes through a line heater (optional), where it is heated. This is typically done to vaporize some of the hydrocarbon liquids and heat up the water and the gas in the stream before metering to prevent hydrate formation. The effluent meter's well testing test taps must be located downstream of the effluent meter within the same pipe run.

The well's fuel gas tap, if present, must be located upstream of the effluent meter or downstream of the well testing test taps at the time of testing. This must ensure that the test separator's measurement is subjected to the same conditions and volumes as the effluent meter at the time of testing. Testing practices must account for respective fuel gas volumes that are taken off between the wet meter and test taps. It is preferable that packages be designed such that the fuel gas tap be located downstream of the effluent meter well testing test taps for simplicity.

Figure 6.5-1 Typical Effluent Well Measurement Configuration with Well Test Unit



If a well is required to be tested, then test taps are required and must be installed downstream of the effluent meter. Test taps must be designed in such a manner as not to disrupt the normal operation of the well when being utilized and must be installed downstream of the wet meter run.

For wells requiring well testing, the well test must meet the following:

1) The well test must begin only after a liquid level stabilization period occurs within the test separator. The well test duration must be a minimum duration of 12 hours.

2) Wells that use artificial lift systems or characteristically display slug flow must be tested for a minimum duration that completes multiple flow cycles to accurately determine a representative volume of gas, hydrocarbon liquid, or water. These representative production volumes are then extrapolated to accurately reflect the well's production over an extended period of time. If necessary, the minimum test duration must be increased to ensure that the test is representative (i.e., 24 to 48 hours).

3) The gas, hydrocarbon liquid and water volumes must be separately metered at the time of testing. Where a three-phase separator is not available, alternative equipment, such as a two-phase separator with a total liquid meter and continuous water cut analyzer, is acceptable.

4) Well test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be metered within the defined minimum 12-hour well test duration period.

5) Gas and liquid hydrocarbon sampling follow sections 8.4.3 and 8.4.4. The gas and hydrocarbon liquid must be sampled during the test with an accompanying compositional analysis obtained. This analysis must be used to calculate the GEF as appropriate. The hydrocarbon liquid sample may be taken from the hydrocarbon liquid leg of a three-phase separator or the liquid leg of a two-phase separator (the water must be removed from the hydrocarbon liquid before the analysis is determined).

6) For orifice meters, the well effluent meter and the well testing unit gas meter must each use 24-hour charts unless EFM is used. The well testing unit gas meter must not utilize a chart where the well effluent meter utilizes EFM.

7) Ratios determined from a well test must be used for reporting purposes within 60 days of the well test.

6.5.3. **Well Testing Decision Tree**

The Well Testing Decision Tree is designed around uncertainties developed from traditional orifice metering (i.e., AGA Report No. 3 – Part 2) technology in effluent metering applications. Therefore, orifice measurement is currently the only approved effluent measurement technology accepted within the Province of British Columbia. If an operator wishes to utilize an alternative metering technology for wet metering applications, they must be able to provide upon request, supporting evidence that the metering technology utilized does not provide a volumetric bias from other metering technologies utilized in the field. The applicable Well Testing Decision Tree may require the installation of a separator at a well site.

The implementation of a Well Testing Decision Tree does not alter the requirements outlined in Chapter 3; *Proration Factors, Allocation Factors and Metering Difference*. The proration factor ranges should prompt operators to investigate causes of proration factors that are outside of the defined parameters and to understand the reasons for them being insufficient.

The Well Testing Decision Tree has segregated into 4 parts. These parts include:

1) Entry point for initial well completion, or recompletion (Box 1).
2) Entry point for existing effluent measured wells (Box 2).
3) Battery/Facility Based Testing Exemption (Box 8).
4) Well Based Testing Exemption (Box 10).

Figure 6.5-2 Well Testing Decision Tree Section 1

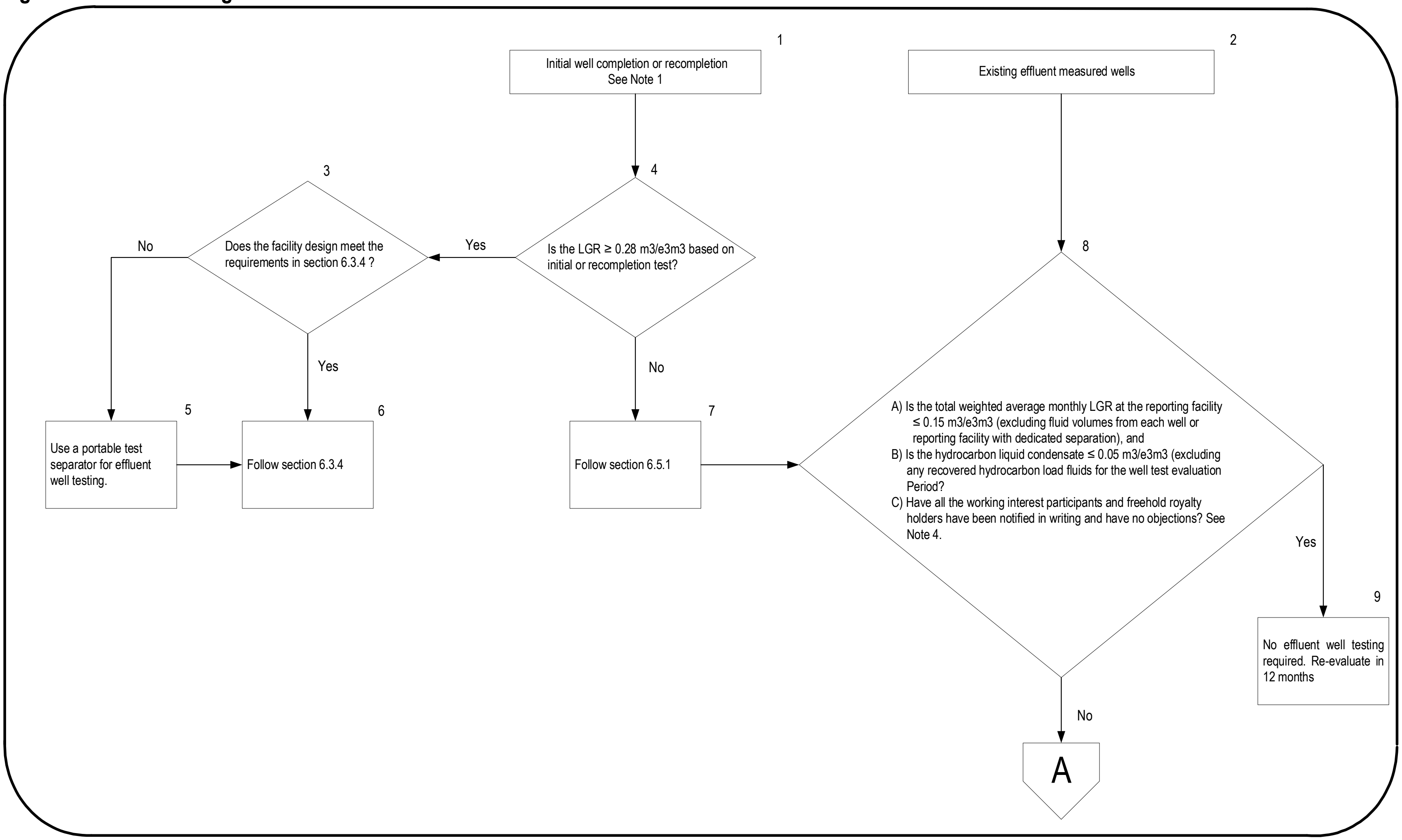
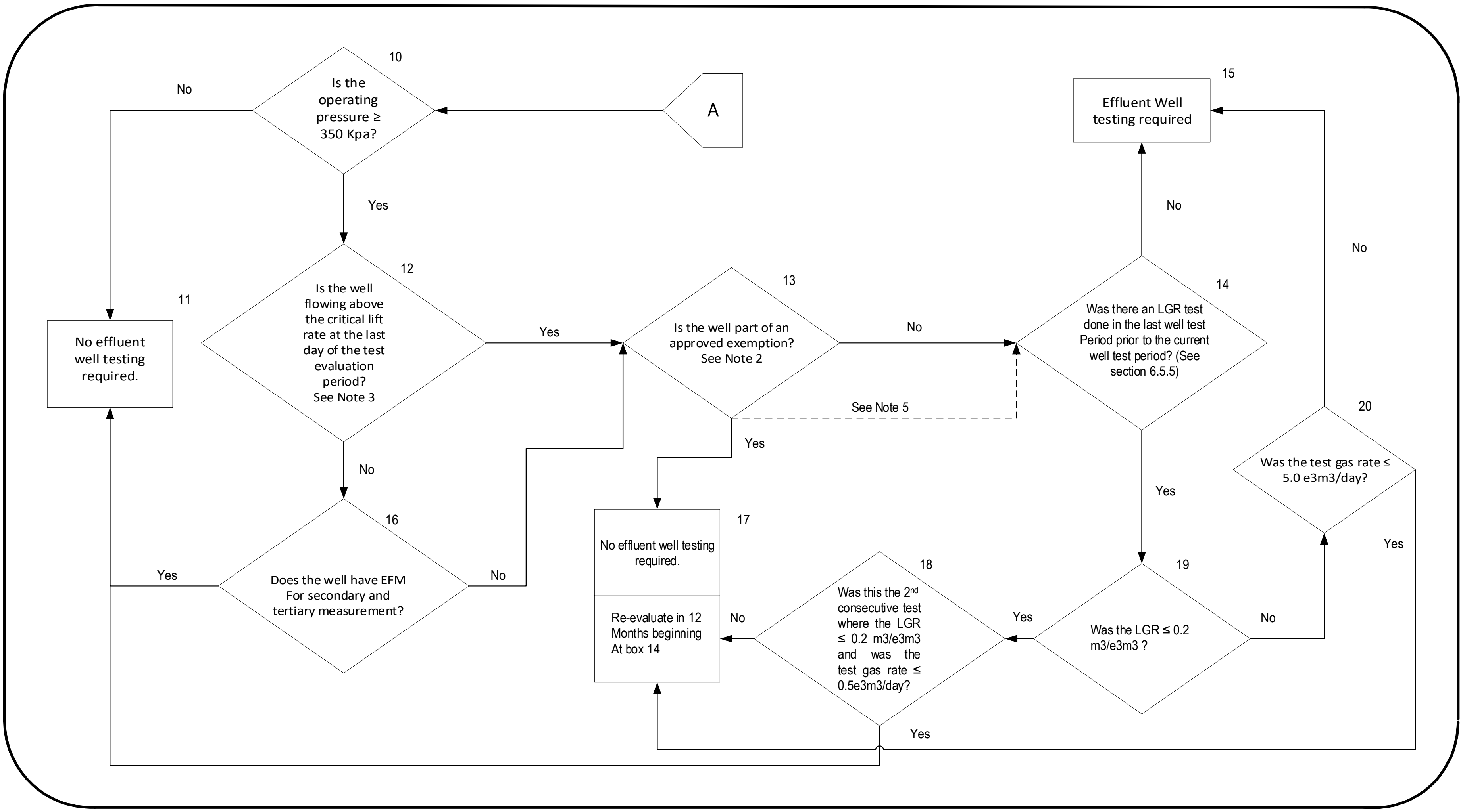


Figure 6.5-3 Well Testing Decision Tree Section 2



6.5.4. **Well Testing Decision Tree – Notes**

Note 1: A new or recompleted well must be tested within 30 days of production being online. Recompletion includes anything that changes the flowing characteristics of a well. This includes but is not limited to: a well bore work over, artificial lift installation or chemical stimulation (see section 6.5.1 Frequency).

Note 2: The BCER zonal measurement exemptions are by special approvals only.

Note 3: The Turner Correlation (Turner et al., 1969) is used as an approximation methodology to ascertain critical lift. The calculation below produces a value in mmscf/day. Conversion to metric units using a factor of 28.3168e^{3}m^3/mmscf must be used. Although there have been further refinements to the Turner Correlation calculation, the formula below will be applied for the purposes of determining critical lift as it is relating to the Applicable Well Testing Decision Tree. These simplified formulae assume fixed gas gravity (G) of 0.6 and fixed gas temperature.

(T) of 120°F

$$v_g(Water) = \frac{5.62(67 - kP)^{0.25}}{(kP)^{0.50}}$$

$$v_g(Condensate) = \frac{4.02(45 - kP)^{0.25}}{(kP)^{0.50}}$$

$$k = \frac{2.693G}{ZT}$$

$$q_g = \frac{3.06Pv_gA}{ZT}$$

G = gas gravity
P = Pressure (absolute) - lb force / square inch
T = Temperature (absolute) – degrees Rankine
Vg = Minimum gas velocity required to lift liquids – ft / second
Z = Compressibility factor
A = Cross sectional area of flow – square feet
Qg = Flow rate – MMscf / day

Note 4: Average Monthly LGR/CGR Calculation Production volumes at a reporting battery/facility will be evaluated against the requirements of the applicable Well Testing Decision Tree in order to determine if a testing exemption is appropriate for specific wells that flow to the reporting battery/facility. Volumes received from another reporting battery/facility would be treated as a measured volume and netted from group production volumes. A simplified summary of the LGR and CGR calculation utilized to determine if a battery/facility based well testing exemption can be applied as follows:

LGR = CGR +WGR

CGR = Battery condensate production/ battery gas production.

Where: (i) Battery condensate production = condensate dispositions + condensate inventory change - condensate receipts.
(ii) Battery gas production = gas dispositions + (fuel + flare + vent) – gas receipts.

WGR = Battery water production/ Battery gas production.

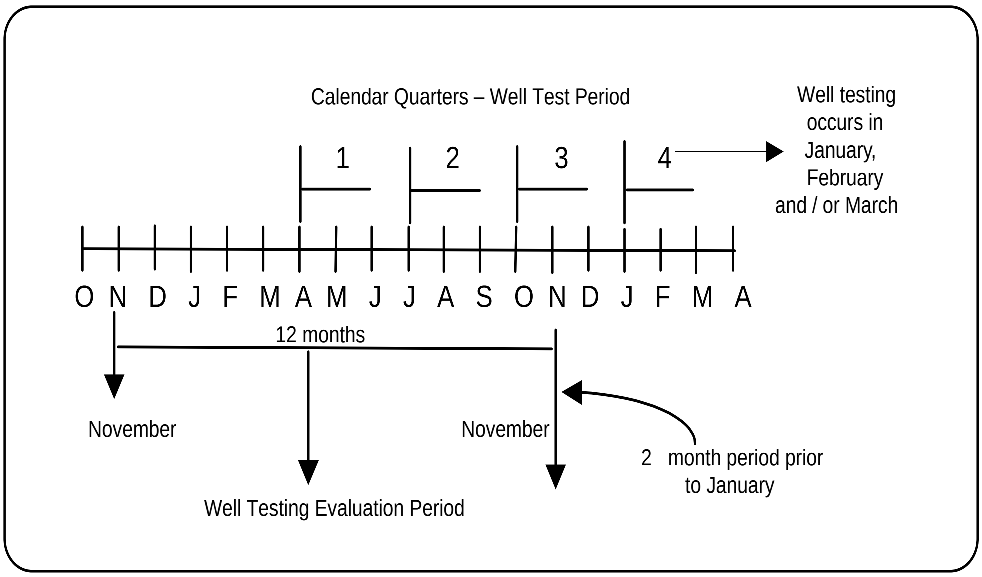
Where: (i) Battery water production = water dispositions + water inventory change – water receipts.
(ii) Battery gas production = gas dispositions + (fuel + flare + vent) – gas receipts.

Note 5: Where all wells in a battery/facility are above critical lift and in a deemed exempted zone, if the LGR is greater than 0.2 m3 (liq) / e3m3 (gas) at the respective battery/facility inlet to which the wells flow, the zone is not exempted, and the note 5 path must be followed.

6.5.5. **Well Testing Evaluation**

The well testing evaluation period is based on a 12 consecutive month cycle, which all wells in a reporting battery/facility will follow. The well test evaluation period must end two months earlier than the planned calendar quarter in which well testing must be conducted for a reporting battery/facility. Once the evaluation period is chosen, it will remain fixed for a reporting battery/facility. When well testing is required, it must occur once in a fixed calendar quarter period and occur once within a 4 consecutive calendar quarter period. Figure 6.5-4 provides an illustrated example.

Figure 6.5-4 Well Test Evaluation Example



Well and battery/facility data is gathered for the 12-month period identified. The wells and/or the reporting battery/facility would be analyzed within the context of the specific part of the Well Testing Decision Tree utilized. Initializing the design will establish the cycle that is repeated year over year. The operator is free to choose the well testing calendar quarter based on operational choices. The illustrated example in Figure 6.5-4 may typically fit a well testing system in which only winter road access is available.

For the purposes of evaluating if a battery/facility based well testing exemption is applicable based on the Well Testing Decision Tree, the reporting battery/facility and all the affected wells (i.e., wells without well separation) must be on the same Well Testing Evaluation Period. If however, a reporting battery/facility has operating characteristics such that a battery/facility well testing exemption is not possible, the Well Testing Evaluation Period can become unique to a well. This means that a well requiring testing to be conducted in accordance with the Well Testing Decision Tree – Well Based Testing Exemption, must maintain a codified Well Testing Evaluation Period, but the Well Testing Evaluation Period may not be the same for all of the wells in a reporting battery/facility. If a battery/facility is of such a size that it would take more than one calendar quarter to test all the wells, an operator can choose the calendar quarter in which a well test must occur, which in turn determines the Well Testing Evaluation Period. Once the well testing period (calendar quarter) is chosen the operator must test once in the fixed calendar quarter period and the well test must occur once within a 4 consecutive calendar quarter period.

The pressure data, as recorded by the well site measurement equipment, must be the monthly average for the last month of the well test evaluation period. If no tubing or casing pressure records is continuously recorded, then the upstream static pressure data from the well's flow meter can be used to approximate the tubing or casing pressure provided that the well's flow meter is located on the same lease site as the wellhead.

6.6. Revocation of Well Testing Exemption

Below are the criteria under which an effluent gas well testing exemption may be revoked. At a minimum, annual baseline well testing for the wells included in an exemption decision must be implemented if any of the following occurs:

1) Non-compliance. The following are outlined as potential areas of non-compliance, but do not represent an exhaustive list:

    a. Exemption calculations are incorrect.

    b. Inadequate recordkeeping.

    c. Source data for exemption calculations cannot be validated.

    d. Incorrect application/implementation of an applicable Well Testing Decision Tree; and

    e. Well installed or recompleted after June 1st, 2013, do not have testing taps installed on wells exempt from testing.

2) All working interest participants and Freehold royalty holders (if present) were notified in writing and a working interest participant or Freehold royalty holder for any wells flowing to the reporting battery/facility objects to the exemption.

Notwithstanding the above, if the BCER has a concern with respect to the activities, operations, production data or reporting associated with well testing and/or well testing activities; upon notice in writing the BCER can partially or fully revoke well testing exemptions and impose, modify or substitute well testing conditions and for any period of time. The BCER will advise the operator in writing as to the nature of a concern, provide a reasonable period of time to meet a request as well as provide an opportunity for an operator to comment.

6.7. Well Testing Exemption Audit Trail

The following list represents the minimum audit trail requirements related to well testing and/or any of the applicable Well Testing Decision Trees. The respective operator implementing a battery/facility-based testing exemption for wet metered wells or individual wet metered well based exemption from testing must retain the following information, as applicable, to the type of well testing exemption being implemented (battery/facility or well based). The following data must be made available upon request. Records must be retained for a minimum of 72 months.

1) Producer
2) Reporting Battery/Facility – Name and Surface Location
3) Well – Name
4) Well – Unique Well Identifier (UWI)
5) Production Formation(s) – Name(s) and/or Zone Codes(s)
6) Current Well Testing Date
7) Last Well Test Date
8) Effluent Well Meter Run – Internal Diameter (mm)
9) Meter Run Orifice size (mm) (if applicable)
10) Test Tap Location (relative to effluent meter)
11) Test Tap Connection – Diameter (mm)
12) Last Gas Sample Date
13) Last Condensate Sample Date
14) Wellhead Tubing Internal Diameter (mm)
15) Wellhead Casing Internal Diameter (mm)
16) Wellhead Tubing Pressure (kPa)
17) Wellhead Casing Pressure (kPa)
18) Effluent Meter Monthly Average D/P for Evaluation Period (kPa) – Listed by Month
19) Effluent Meter Monthly Average Static Pressure for Evaluation Period (kPa) – Listed by Month
20) Effluent Meter Monthly Average Temperature for Evaluation Period (Deg. C) – Listed by Month
21) Test Gas Rate (e^3m^3/day)
22) Test Condensate Rate (m^3/day)
23) Test Water Rate (m^3/day)
24) Current WGR (m^3/e^3m^3)
25) Current CGR (m^3/e^3m^3)
26) Current LGR (m^3/e^3m^3)

27) Last WGR (m^3/e^3m^3)

28) Last CGR (m^3/e^3m^3)

29) Last LGR (m^3/e^3m^3)

30) ECF – Last Value Calculated

31) ECF – Current Value Calculated

32) Evaluation Period Average Reporting Battery/Facility LGR

33) Evaluation Period Average Reporting Battery/Facility CGR

34) Artificial Lift Method (ie: cycling, plunger control)

35) Well EFM – Model and Make or Not Applicable

36) Well Chart – Yes / No

37) Well Test Evaluation Period Starting Month

38) Well Test Evaluation Period Ending Month

39) Date Well Dropped Below Critical Velocity

40) Critical Lift Calculation for Evaluation Period

41) Well Load Fluid Volumes for Evaluation Period

42) Meters used in Battery/Facility LGR Calculations

    a. Meter Tag

    b. Meter Location

    c. Meter Volume

    d. Meter Units (e^3m^3 etc.)

43) Well Flow Volume Prior to Recompletion

44) Well Recompletion Flow Volume

6.8. **Regulatory Audit**

All calculations and records must be auditable and verifiable. Well and battery/facility data must be auditable. Original source records may be requested to validate data. Volumetric data obtained from multiple data sources will require that each data source can be validated by the BCER. All associated records are required to be kept for a minimum period of 72 months.

The BCER expects operators to comply with the requirements at all affected wells and facilities. The BCER further expects that when non-compliance with these requirements is discovered, corrective actions are taken at all similar installations.

6.9. Production Volume Accounting

See Appendix C – Effluent Well Testing Decision Tree Accounting Sample Calculations of this manual for example calculations to be utilized as a result of implementing the Well Testing Decision Tree.

6.10. Sampling and Analysis Requirements

See Chapter 8 for sampling and analysis requirements.

6.11. Testing- Exempted Facilities/Batteries

For testing-exempted facilities/batteries, the well sample and analysis used may be either:

1) The sample and analysis obtained from the most recent ECF test or,

2) The annual sample and analysis obtained from the group separator provided that:

    i. there is common ownership in all in the facility/battery.

    ii. if there is no common ownership, written notification has been given to all working interest participants, with no objection received; and

    iii. if there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the permit holder must apply to the BCER for approval.

6.11.1. Testing –Exempted Facilities/Batteries with Test and Test-exempt Wells

For test-exempt wells in facilities/batteries that have tested and test-exempt wells, the well sample and analysis may be either:

1) The sample and analysis obtained from the most recent ECF test or,

2) The annual sample and analysis obtained from the group separator provided that:

    a) there is common ownership in all of the wells in the battery.

    b) if there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received; and

    c) if there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received.

Regardless of which of the above approaches is used, the operator may, at its discretion, test and sample any well and use the well sample and analysis to calculate well volume.

6.12. Mixed Oil and Gas Well Effluent Measurement - Montney Formation

The unconventional Montney formation includes wells with production ranging from dry gas to oil, with variation based on both area and depth within the formation. Hydrocarbon liquid densities of oil wells (oil) and gas wells (condensate) are very similar and can result in a mix of oil well and gas well classifications on a common development pad. Anomalous individual wells that marginally meet oil primary product policy may be found within a dominantly gas production area, and even on the same well pad. This makes it difficult for operators to design production and measurement systems until the wells are drilled, tested, and classified.

Equipment design, installation, project development delays, and cost challenges associated with high-pressure, high-LGR unconventional oil and gas plays, present an opportunity to implement a pad level measurement and production accounting volumetric reporting system applicable to both oil and gas wells drilled into a common formation that delivers acceptable measurement performance. In order to minimize surface and operational impacts, where well classification differences between oil and gas wells are marginal, oil and gas wells may be commingled on the same pad.

The following discussion describes the qualifying criteria and pad level measurement system and reporting requirements for two operational scenarios where it is acceptable to include effluent- measured, surface-commingled production from oil and gas wells in a common measurement and production accounting system for gathering and determining volumes. After oil and gas well production volumes are determined, those volumes must be reported according to existing reporting requirements. Gas wells report production to a gas multiwell effluent proration battery/facility, and oil wells report production to an oil battery/facility. Gas and oil measurement by difference does not apply.

6.12.1. Initial Qualifying Criteria

Oil and gas wells meeting the following criteria may be included in the mixed oil well / gas well effluent measurement system:

1) All wells are drilled and completed in the Montney formation.

2) LGRs may exceed 0.28 m^3liquid / $e^3\ m^3$, with no upper LGR restriction on the effluent measurement system.

3) Maintain individual well separation and metering during the initial flowback period.

4) Submit initial well test data to the eSubmission Portal as outlined in the “Well Testing and Reporting Requirements Guideline” found at *Well Testing and Reporting Requirements Guide.* The submission must include:

   a) the depth and target of each well within the submission (i.e. upper, middle, or lower Montney).
   b) analog well description- production rates and ratios (gas, condensate, water) and plots of ECF, LGR, CGR, and WGR, curves for each target zone.

5) All wells have common ownership and either common Crown or Freehold royalty.

a. If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.
b. If there are no common Crown or Freehold royalties and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the permit holder must apply to the BCER for approval.

6.12.2. **Common Measurement System Requirements:**

The two effluent measurement operational scenarios described in sections 6.12.3 & 6.12.6 (below) must adhere to the following common requirements:

1) Well and facility developments must include test and group separation.

2) Sampling must comply with the requirements in Chapter 8 – Sampling and Analysis.

3) All wells must calculate monthly estimated condensate/oil, and water volumes using the most recent CGR, OGR, and WGR as determined from ECF testing.

4) Gas and hydrocarbon vapour liquid equilibrium (VLE) sample pairs obtained from each well during each the ECF test must undergo a laboratory flash liberation (FLIB) analysis, or computer simulated FLIB to obtain GIS and shrinkage factors.

5) All reported volumes must be supported by source data, including metered volumes, well test and group sample analysis and laboratory or computer simulated FLIBs. All reported production data must be auditable and comply with the requirements outlined within section 4.4.9 Production Data Verification and Audit Trail.

6) Each new well must be tested not fewer than once per month with each test being a minimum 12-hour duration. Monthly testing must continue until the difference of the last 3 consecutive ECF tests are within 5%. Upon meeting this condition, the testing period may be extended to once every 6 months as long as the last 3 consecutive ECF tests continue to remain within 5 % and battery/facility group gas and condensate proration targets 0.95000 to 1.05000 are met, else revert back to monthly or more frequent testing. If two consecutive tests indicate that the LGR has dropped below 0.280 m3/e3m3 then the well testing frequency in the Well Testing Decision Tree section 6.5.3 will apply.

7) The surface-commingled production from all of the effluent-measured wells must be connected by pipeline to a battery group separator where each phase (gas, hydrocarbon liquid, and water) can be individually metered or tanked.

8) The oil well battery oil production “DISP” to subtype 362, “Gas Multi-well Effluent Measurement Battery”, must be reported as subtype 311, “Crude Oil Single-well Battery”, or subtype 321, “Oil Multi-well Group Battery”.

9) The gas well production/disposition must be reported as a subtype 362, “Gas Multi-well Effluent Measurement Battery.” The Gas Multi-well Effluent Measurement Battery must report the well condensate “PROD” as a liquid volume (m3) and a condensate “DISP” to a downstream battery, or gathering system. The battery “DISP” must be **OIL** when delivering to a custody transfer point. When field condensate is recombined with gas plant C5-SP the gas plant will report a “REC” of **OIL** to trigger the Petrinex pipeline splits/oil valuation process. The custody transfer meter must be at the plant, and the receiving terminal must report the “REC” as C5-SP. Oil and condensate are balanced under the same product group at the BCBT, so there is no imbalance between having the production be COND and the disposition be OIL.

10) The permit holder must notify BCER Pipeline and Facilities of the Petrinex reporting codes for the batteries in the mixed oil and gas effluent measurement system.

11) Prior to implementation the Permit Holder must submit to Pipielines.Facilities@bc-er.ca a description of the steps involved in the production accounting methodology accompanied with a measurement schematic that includes all downstream processing before final disposition. Annually a performance report for the mixed oil and gas well effluent measurement system must be prepared and submitted. A meeting will be arranged with the Permit Holder to discuss and review the performance report.

The report must contain the following for discussion:

a) A chronological listing of the ECF tests conducted including: the test duration, effluent metered volume, test metered gas volume, test FLIB with GIS and shrinkage factors, test hydrocarbon metered volume, calculated test shrunk hydrocarbon volume, calculated test total gas volume, group separator sampling dates, group FLIB with GIS and shrinkage factors, group hydrocarbon metered volume, calculated group shrunk hydrocarbon volume, group gas metered volume, calculated group total gas volume, test and group water volumes, the calculated ECF, CGR, and WGR used in the proration.

b) For each reporting measurement system, a listing of monthly production volumes with associated proration factors for the gas, hydrocarbon liquid, and water production.

c) A general discussion of the performance of the measurement system, examining proration factors, highlighting operational and measurement challenges, and any mitigative measures taken if proration factors trended outside the required tolerances.

d) Additional development plans for the upcoming year.

6.12.3. Operational Scenario 1 - Hydrocarbon Liquids are Recombined into the Gathering System

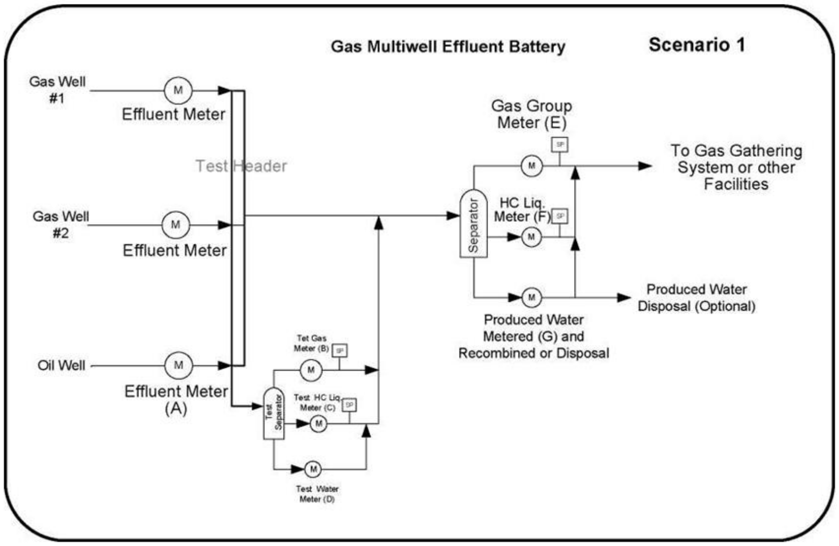


Figure 6.12.3 Mixed effluent measurement with recombined liquids to a gas gathering system

6.12.4. Production Volumes are determined as follows:

1) The production from the gas and oil wells are effluent measured, surface commingled, and sent to the battery group separator where it is separated into three phases, each separately measured.

2) The hydrocarbon liquids and water are then recombined with the gas and sent to a gas gathering system, another battery, or a gas plant.

3) A multi-stage flash liberation must be used in the determination of the total test gas = (shrunk hydrocarbon volume x GIS factor) + dry metered test gas. The ECF = (Test hydrocarbon GIS + dry metered test gas volume) divided by the uncorrected (ECF removed) effluent metered volume. The well ECF testing procedure and volume determination methodology (production accounting) must be consistent from one well to another, whether testing oil wells or gas wells.

4) A multi-stage flash liberation from the group point to the downstream battery or gas plant must be used to determine the battery total GIS to be added to the group dry metered gas for proration and reporting.

6.12.5. Additional Measurement System Requirements:

1) The battery group separator and the well test separator must be three-phase separators and use EFM for the condensate/oil and gas.

2) The battery group separator condensate/oil leg must use a coriolis mass meter and a water-cut analyzer.

3) The well test separator must be a three-phase separator and the hydrocarbon liquid leg must use a water-cut analyzer, proportional sampler, or for each well ECF test a minimum of three appropriately spaced (near the beginning, middle, and end of test) representative grab samples of hydrocarbon liquid must be obtained from the hydrocarbon liquid leg to establish a water cut and to ensure that no water carryover is occurring.

4) The hydrocarbon liquid meters at the test and group separators must be proved to separator operating conditions.

6.12.6. **Operational Scenario 2 - Hydrocarbon Liquids are Delivered to Sales at the Battery**

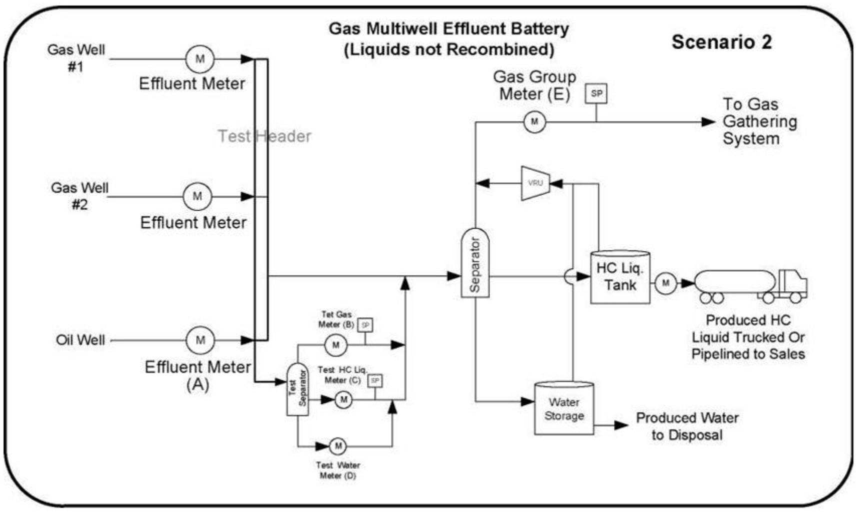


Figure 6.12.6 Mixed oil and gas well effluent proration with trucked or pipeline oil sales

6.12.7. **Production volumes are to be determined as follows:**

1) Production from the gas wells and oil well is effluent metered, surface commingled, and sent to the battery group separator where it is separated into three phases, each separately measured (hydrocarbon liquids and water may be metered at the receiving facility).

2) The hydrocarbon liquids are individually tanked and disposed to sales. The produced water goes to disposal/injection. The gas is metered and delivered to a gas gathering system, battery, or a gas plant.

3) In this scenario the test oil/condy volumes are multiplied by each well's individual flash liberation shrinkage factor to determine the volumes at stock tank conditions. The total test gas = (shrunk hydrocarbon volume x GIS factor) + dry metered test gas. The ECF = (Test hydrocarbon GIS + dry metered test gas volume) divided by the uncorrected (ECF removed) effluent metered volume. The metered group gas, the hydrocarbon liquids, and water production volumes are prorated back to the oil and gas wells by applying effluent well proration methods. See Appendix – D for production accounting example.

6.12.8. **Additional Measurement System Requirements:**

1) The battery/facility group separator must have three-phase separation and use EFM to determine gas volumes.

2) The well test separator must be a three-phase separator and use EFM for condensate/oil and gas and the hydrocarbon liquid leg must use a water-cut analyzer or proportional sampler, or for each well ECF test, at least three appropriately spaced (near the beginning, middle, and end of test) representative grab samples of hydrocarbon liquid must be obtained from the hydrocarbon liquid leg to establish the water cut and to ensure that no water carryover is occurring.

3) The hydrocarbon liquid meter at the test separator must be proved to live conditions.

4) Condensate/oil at the battery must be handled in one of the following ways:

   a) Condensate/oil tanks must incorporate a vapour recovery system to capture and conserve hydrocarbon vapours that would flash from the hydrocarbon liquids.

   b) Condensate/oil must be stored in pressure vessels of a pressure rating sufficient to ensure that no vapours are vented; or

   c) Condensate/oil must be stabilized for storage tanks vented to atmosphere or flared.

6.13. **Surface Comingling Wells During Inline Flow Testing**

Typically, after a well is completed, which may include a multistage fracturing operation, the well is flowed back through a single flowback separator to recover fracture fluids, to clean up the well, and to conduct a flow test prior to being put on permanent production operations and effluent measurement. This process includes an initial flow back where most of the produced fluids are recovered fracturing fluids, which is followed by a cleanup and flow test period.

Flow test production from wells that meet the qualifying criteria below may be comingled and measured in a single flowback separator with the comingled separator volumes prorated to the individual wells based on individual well test rates obtained from the wells prior to comingling. Two or more wells may be flow tested through a single separator in accordance with the following:

1) The wells must be drilled from a common well pad, be completed in the same formation, and have the same royalty structure. Gas wells must qualify for the same deep royalty credit tier.

2) When a well begins its initial flow back, only that well may be flowed through the flowback separator (i.e., no comingling with other wells). At the end of the initial flow back, stabilized well flow and well test rates must be established for gas, hydrocarbon liquid, and water. After stable well test rates are obtained, the well may be temporarily shut in and the same procedure applied to other qualifying wells in order to obtain stable well test rates prior to comingling.

3) After each well's initial flow back, and well test rates have been obtained, two or more wells may be flowed through the single flowback separator until the wells are put on effluent measurement.

4) Comingled well production measured at the flowback separator must be prorated back to the wells flowing through the separator based on each well's number of hours flowing through the separator and the individual well test rates previously obtained.

5) Separator prorated gas production that is flared must be applied to each well's flare volume flare permit.

7. Chapter 7- Cross Border Measurement

7.1. Introduction

When volumes of fluids (i.e., natural gas, condensate, and crude oil) that are subject to royalty payments are transported into or out of the Province of British Columbia and are commingled with fluids from other provincial or territorial jurisdictions (Alberta, Northwest Territories, Yukon) prior to product sales measurement, the allocation of volumes from sales to the volumes from each jurisdiction is a critical factor in determining the royalties payable to each jurisdiction.

Accurate measurement of the fluid streams prior to commingling ensures correct allocation.

At the present time, this direction is given through the Battery/Facility Approval process on a site-specific project basis. However, because of the proliferation in recent years of pipelines transporting fluids into and out of the province, it has become apparent that a document that provides specific guidance is required so that industry may refer to it during the planning stages of their projects.

7.2. Purpose

The Cross Border Measurement Policy is designed to:

1) Ensure volumetric measurement controls are in place.
2) Ensure proper design of gathering system(s).
3) Ensure production accounting system supports volumetrics and allocations.
4) Ensure allocations are supported by sufficient and adequate volumetrics.

7.3. Qualification Criteria - Cross Border Measurement Volumes Battery / Facility

The following criteria must be referenced to determine the applicability of the contents of this guide:

1) The Province of British Columbia volumetrics are or can be impacted by natural gas and/or liquid hydrocarbon volumes belonging to a jurisdiction outside the Province of British Columbia.
2) The Province of British Columbia royalties are or can be impacted by natural gas and/or liquid hydrocarbon volume receipts and/or deliveries belonging to a jurisdiction outside the Province of British Columbia. Royalty impact includes royalty credit allowances and royalty rate reductions.

Below are some of the production scenarios that will provide guidance in determining whether or not a specific circumstance is considered as Cross Border. This is not an exhaustive set of examples.

Figure 7.3-1 Cross Border Case 1

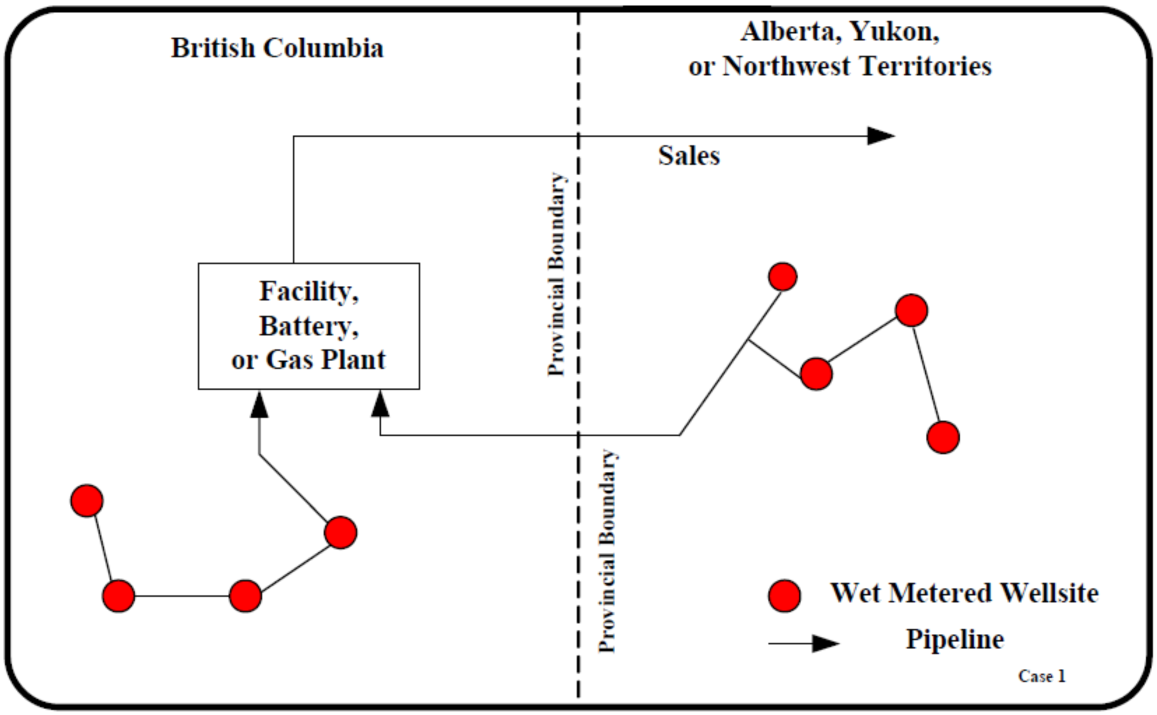


Figure 7.3-2 Cross Border Case 2

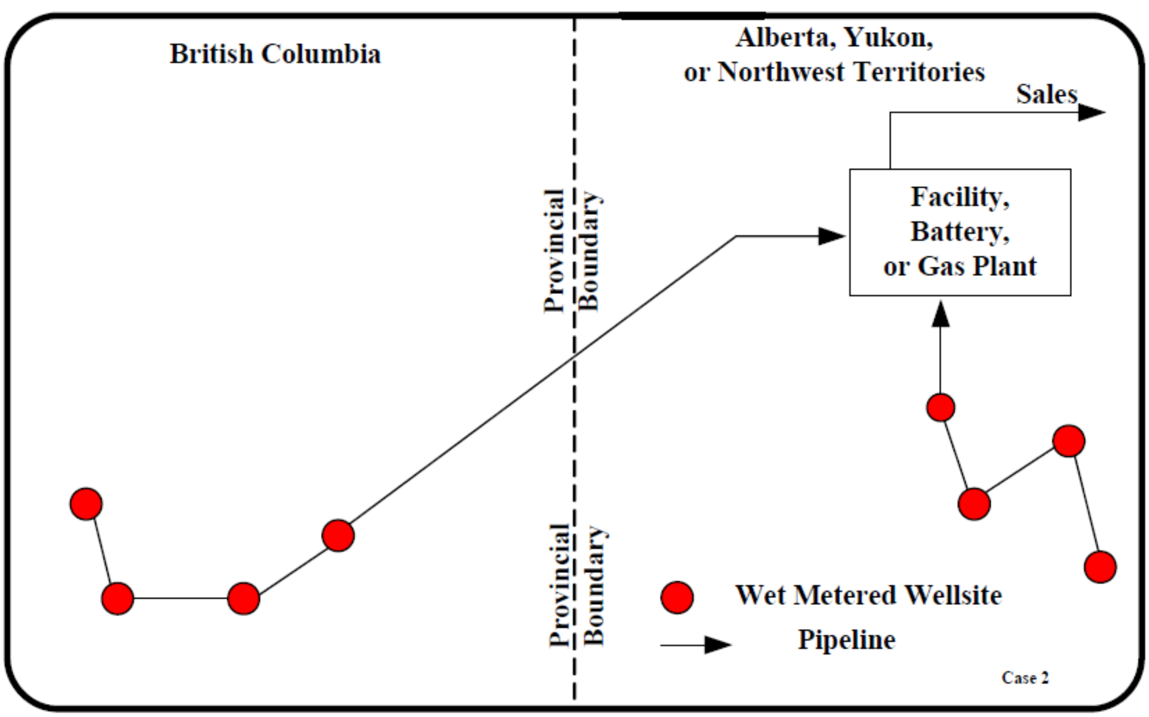


Figure 7.3-3 Cross Border Case 3

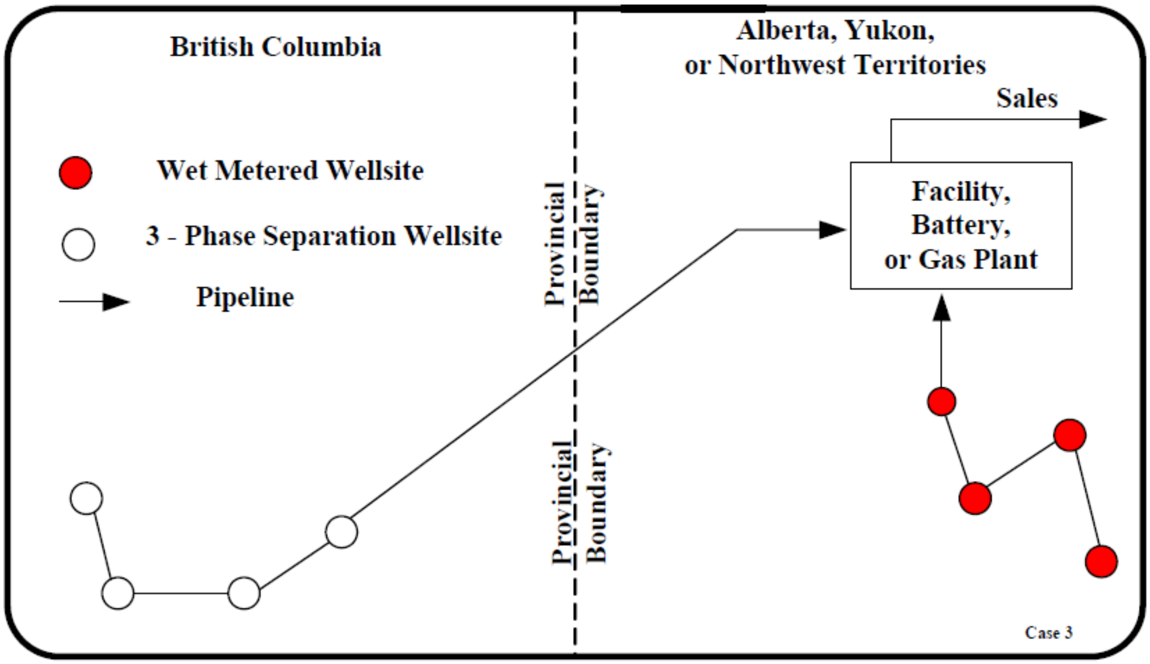


Figure 7.3-4 Cross Border Case 4

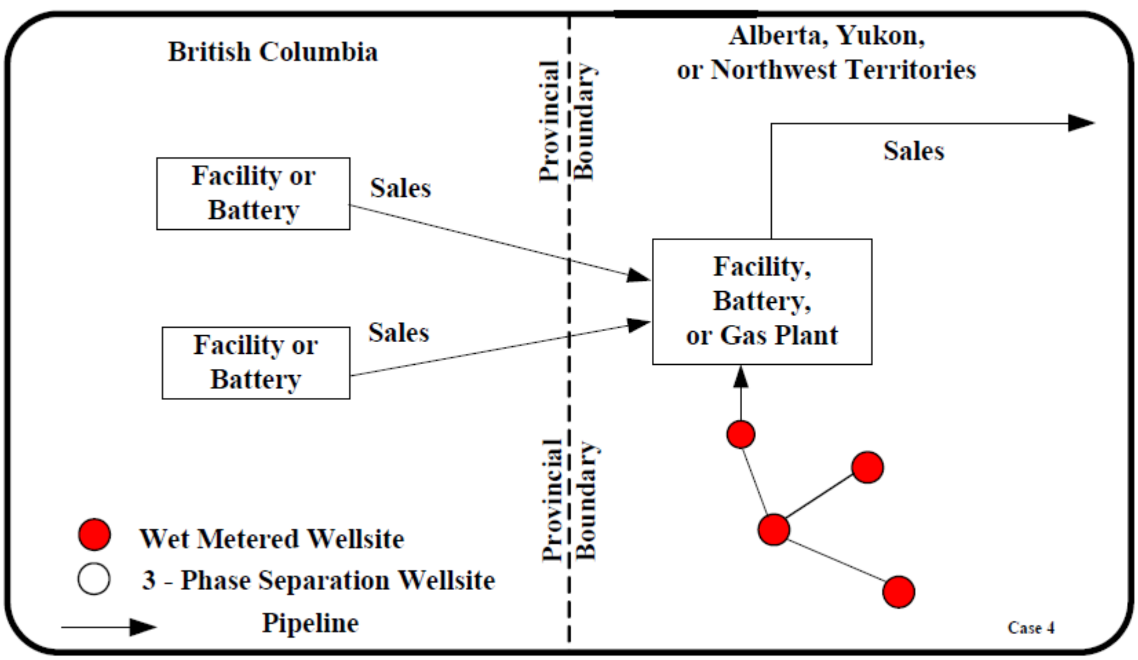


Figure 7.3-5 Cross Border Case 5

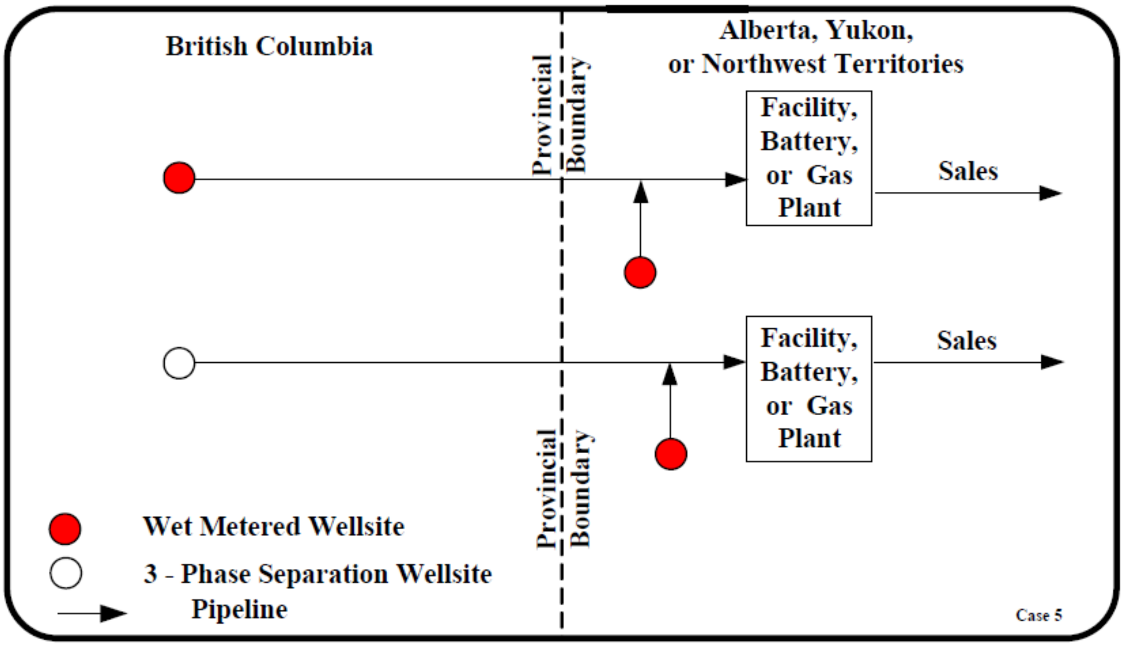


Figure 7.3-6 Cross Border Case 6

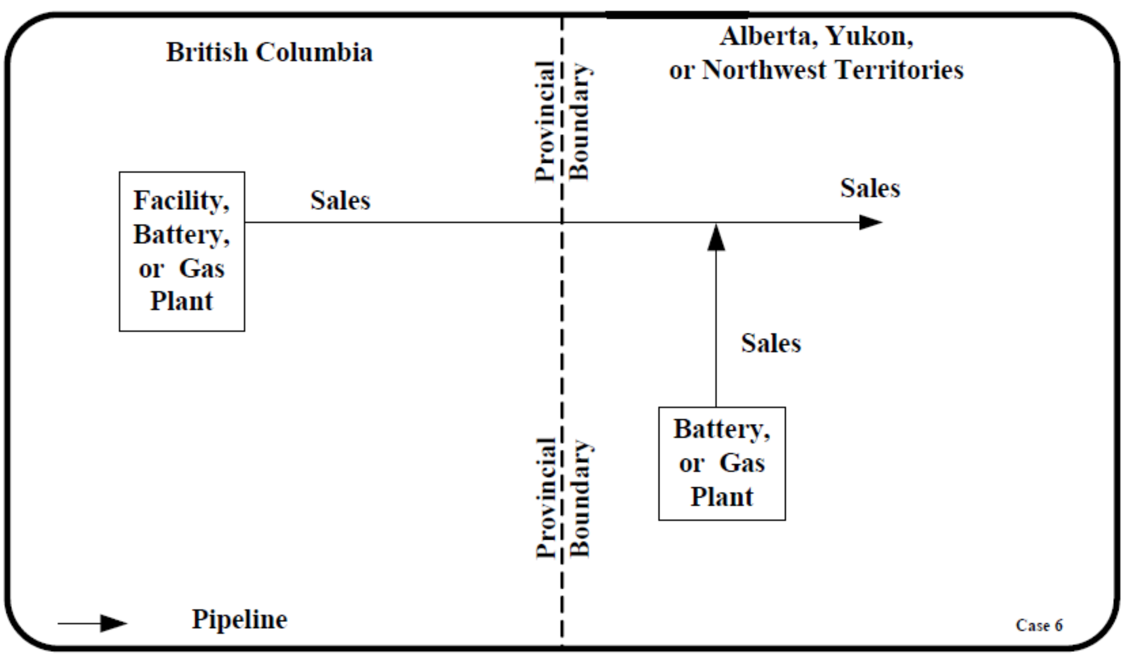


Figure 7.3-7 Cross Border Case 7

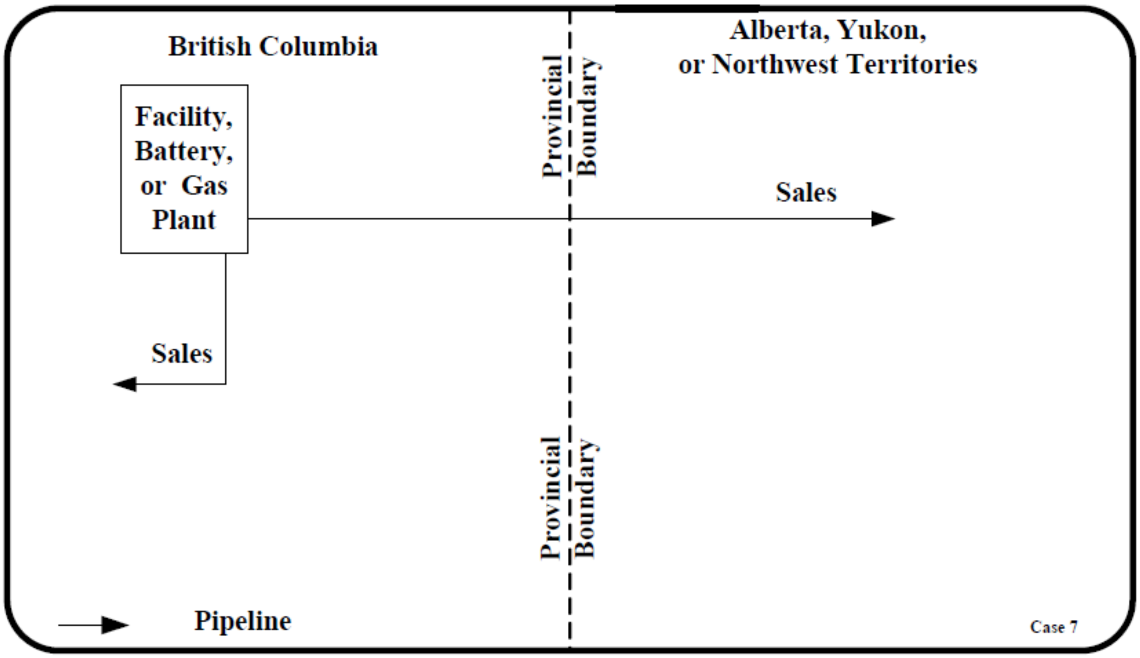
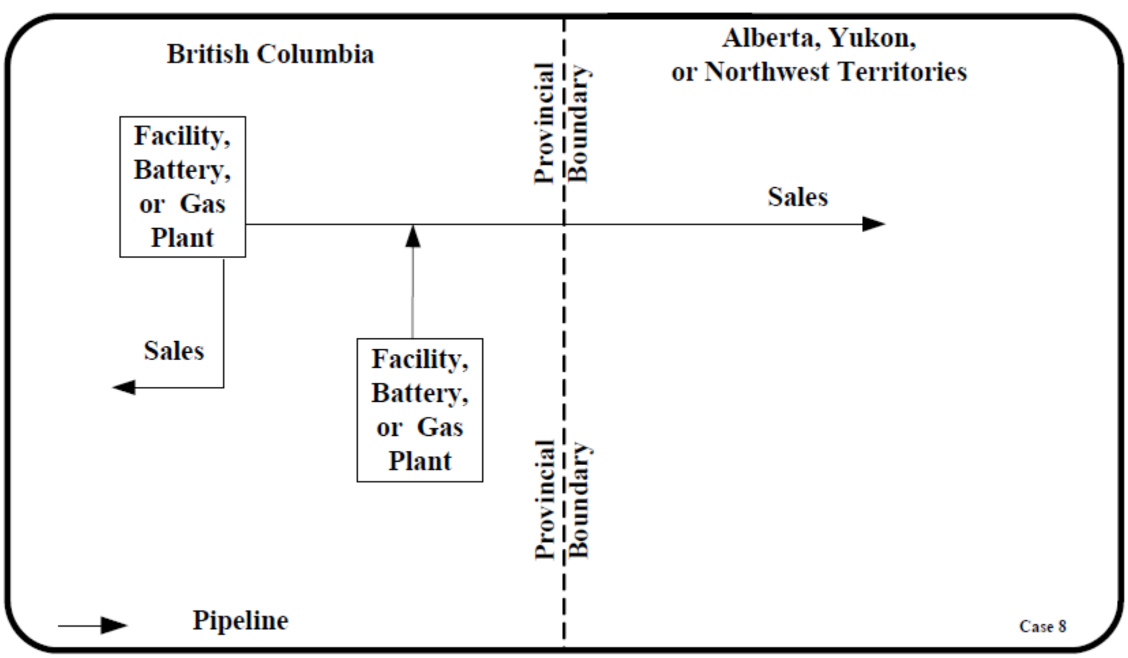


Figure 7.3-8 Cross Border Case 8



7.4. Cross Border Battery / Facility Principle

1) For those facilities or plants located in the Province of British Columbia with British Columbia and/or non-British Columbia production upstream of the battery/facility or plant, each jurisdictional production stream must be isolated and metered, and follow the requirements in this Chapter unless otherwise approved by the BCER.

2) For those facilities or plants located in the Province of British Columbia where British Columbia production is commingled with non-British Columbia production downstream of the battery/facility or plant, the British Columbia production stream must be isolated and metered and follow the requirements in this Chapter unless otherwise approved by the BCER.

3) For those legacy facilities or plants located outside of the Province of British Columbia that process British Columbia volumes, the treatment of volumes is expected as though the battery/facility were in the Province of British Columbia. The BCER does not have regulatory authority outside of the Province of British Columbia, and, in this situation, a battery/facility outside of the Province of British Columbia can present challenges to resolving cross-border measurement issues. The BCER will consult with the appropriate regulatory authority to ensure that an equitable processing arrangement can be reached. Alternately, the BCER may impose measurement requirements on volumes within the Province of British Columbia.

The above principles can produce scenarios from a single well being viewed as a cross-border battery/facility to a gas plant being viewed as a cross-border battery/facility. A battery/facility may receive non-BC production at the inlet (upstream) and commingle deliveries at the outlet (downstream) with non-BC production and consequently both inlet and outlet volumes would be required to follow the Cross Border requirements.

7.5. Application

1) Measurement installations in British Columbia or Alberta that fall under the Cross Border requirements of Chapter 7 must be applied for using the BCER's battery/facility application process through BCER online Application Management System (AMS).

2) On the battery/facility application, indicate in the project description and on the Engineering tab in AMS that the battery/facility being applied for is a Cross Border battery/facility.

3) In circumstances that dictate the involvement of another regulatory authority, the BCER will update and involve that authority.

4) The applicant must provide a Process Flow Diagram and metering schematic for the well sites, gathering systems, and production facilities or plants that are directly and indirectly involved in the Cross Border application.

5) The BCER will perform a site-specific review of each Cross Border Measurement Battery/Facility for approval purposes.

7.6. New Construction or Modifications at a Cross Border Battery / Facility in British Columbia

1) Pipeline or battery/facility construction, modification, additions, deletions, or operating practices that affect, alter, change, or impact the determination of volumetrics and/or allocations for British Columbia production, however determined, will require the approval of the BCER.

2) Modifications to, additions to, or deletions from a Cross Border measurement battery/facility may require upgrades to measurement equipment or alter existing approvals. New construction must follow current requirements. When a combination of new construction and modifications occur, the operator is encouraged to consult with the BCER on a site-specific basis with respect to meeting the requirements.

7.7. Legacy Construction Inside and Outside the Province of British Columbia

British Columbia operators must contact the BCER regarding the design of an existing gathering system that meets the Qualification Criteria. The BCER will advise the operator with regard to the designation, design, and operation of the gathering system.

1) Facilities identified by the BCER as Cross Border Measurement Facilities prior to the release of this document may continue as approved under an existing Cross Border Measurement Battery/Facility approval. New construction or modifications of existing Cross Border facilities must meet the requirements of this manual unless otherwise approved by the BCER.

2) On application, the BCER may modify/grandfather the requirements of this document for existing production systems that pre-date the release of this document. This entitlement will not be extended to new construction or modifications of existing production systems unless otherwise approved by the BCER.

7.8. New Construction, Modifications, or Legacy Construction at a Cross Border Battery/ Facility Outside the Province of British Columbia

1) On application, the BCER may consider production volume processing at a battery/facility outside of BCER legal jurisdictional authority (i.e., the Province of British Columbia) for British Columbia production volumes.

   New production volumes leaving the Province of British Columbia will have to be measured in a manner that is consistent with the BCER Cross Border policy and the measurement battery/facility must be located within the geographic area of the Province of British Columbia unless otherwise approved.

2) Approval for production volume processing outside of BCER legal jurisdictional authority will require the operator to follow the requirements in this Chapter for British Columbia production volumes. The operator must adhere to the same process for approval, etc., as though the battery/facility were located within the Province of British Columbia.

3) For approved production volume processing outside of BCER legal jurisdictional authority, if at any time the BCER deems the design or operational conditions in contravention of this Chapter, the BCER may stipulate requirements on the relevant British Columbia production volumes as it deems necessary within the Province of British Columbia. A permit holder will be notified in writing as to any action taken.

4) For those facilities with British Columbia and/or non-British Columbia production, located at an approved Cross Border battery/facility outside of the Province of British Columbia, any pipeline, battery/facility, or plant construction, modification, addition(s) or deletion(s) that changes or impacts volumetrics or allocations for the Province of British Columbia will require the review and approval of the BCER Operations Engineering Branch. BCER review and approval does not apply to any construction, modification, addition(s) or deletion(s) of equipment used in the production of non-British Columbia volumes upstream of the Cross Border battery/facility.

5) On application, the BCER may modify or grandfather the requirements of this document for production systems that pre-date the release of this document. This entitlement will not be extended to new construction or modifications of existing construction unless otherwise approved by the BCER.

7.9. Inter-Provincial Pipelines

The operator must advise the BCER of proposed, ongoing, or existing construction of inter-provincial pipelines that can or may impact volumetrics or allocations of natural gas production to the Province of British Columbia relative to a Cross Border Measurement Battery/Facility.

7.10. Site Inspections

1) The BCER will conduct a site inspection to determine that construction meets the installation requirements as submitted to and approved by the BCER.

2) The BCER will also witness meter calibrations for start-up purposes. Written (e-mail or fax) notification must be provided to the BCER four working days prior to expected start-up. The notification must include the following:

   a. . Detailed directions to location.

   b. Operator representative at location.

   c. Site contact telephone number.

   d. Time of start for calibration activities to commence.

3) The BCER will note any variances from the requirements and take action appropriate to the nature of the variance.

7.11. Maintenance Schedule

1) The operator is required to provide the BCER, with a written maintenance schedule (i.e., calibrations, proving, and internal inspections) for the calendar year based on the frequencies outlined in this document. The schedule must contain specific dates maintenance will be conducted.

2) The maintenance schedule must be developed effective the commencement of operations and annually thereafter (no later than December 30th for each and every following calendar year).

3) Changes to maintenance dates as a result of a stage change, requires notification to be sent to the BCER's Technical Advisor Responsible for Cross Border Measurement Applications so that their records can be updated accordingly.

7.12. General Design of Cross Border Measurement

7.12.1. Phase Separation

British Columbia or non-British Columbia natural gas and liquid hydrocarbon volumes must be component separated (natural gas, Natural Gas Liquids [NGLs], water, hydrocarbon liquids and/or oil). There are a number of methods to achieve separation and the measurement of Cross Border streams will vary with site-specific design.

1) If a producer uses only vertical or horizontal separation for any jurisdictional (i.e., British Columbia, Alberta, etc.) Cross Border stream, then:

   a. Three component (also known as three phase) separation (natural gas, liquid water, free hydrocarbon liquids or oil) must be used with natural gas/free liquids processing when jurisdictional stream mixing may or does occur. The following are some examples:

      i. liquids are re-injected to the same jurisdictional gas stream from the separator and delivered via pipeline, and the gas stream commingles with another jurisdictional volume.

      ii. liquids from the separator are commingled with another jurisdictional liquid stream(s) via pipeline.

      iii. liquids from the separator are commingled with another jurisdictional gas stream(s).

      iv. oil from a Cross Border BC oil battery/facility is combined with liquid hydrocarbons from a BC Cross Border gas battery/facility.

      v. liquid hydrocarbons from a Cross Border BC gas battery/facility are combined with oil from a Cross Border BC oil battery/facility.

   b. Two component (also known as two phase) separation (natural gas, as well as water and hydrocarbon liquids or oil) may be used with natural gas/free liquids processing when no jurisdictional commingling of liquids may or does occur. The following is a typical example:

      i. BC liquids are produced to dedicated BC production tanks and transported by ground to a delivery point for final measurement. There is no commingling of BC and non-British Columbia liquid volumes. If a producer chooses this option, then the production accounting must use tank measurement and/or delivery point measurement for reporting purposes.

2) If a producer chooses to use refrigeration (in addition to or instead of horizontal or vertical separation) at a Cross Border battery/facility, then an additional stream of stabilized NGLs can be created. Again, component separation (natural gas, liquid water, free hydrocarbon liquids or oil, or NGLs) will be required when jurisdictional stream mixing may or does occur. The design of the battery/facility will dictate how this occurs.

3) If a producer chooses to use dehydration at a Cross Border measurement battery/facility, this process will typically produce a water stream and a gas stream. Again, component separation (natural gas, liquid water, free hydrocarbon liquids or oil, and/or NGLs) will be required when jurisdictional stream mixing may or does occur. The design of the battery/facility will dictate how this occurs.

4) Metering or measurement requirements will be placed on those streams that are deemed to be Cross Border measurement volumes.

5) Tie-in points for gas sources upstream of a designated Cross Border Measurement Battery/Facility or battery/facility inlet must include only well production of the jurisdiction in which measurement at a Cross Border Measurement Battery/Facility or battery/facility inlet takes place unless otherwise approved by the BCER.

6) Commingling of jurisdictional volumes must occur such that jurisdictional fluid commingling occurs downstream of dedicated Cross Border Measurement Battery/Facility or battery/facility inlet measurement.

7) The addition of a non-British Columbia production stream to a designated Cross Border Measurement Battery/Facility for the Province of British Columbia will require the approval of the BCER.

8) For all batteries/facilities with British Columbia and/or non-British Columbia production, located at a battery/facility both in British Columbia and outside of the Province of British Columbia, the Piping and Instrument Drawings (P&IDs) along with the metering schematic must contain a note identifying the requirement that modification(s), addition(s), or deletion(s) to the measurement system require the approval of the BCER.

9) A Cross Border Measurement Battery/Facility located outside of the Province of British Columbia must have a unique sign that states:

   a. Surface Location.

   b. Operator.

   c. The following text: “Province of British Columbia Cross Border Measurement Battery/Facility.”

10) The unique sign may be placed on the road entrance to the battery/facility or located on a site building. The unique sign must be clearly legible to an individual entering the site location via the site road access and must be clearly legible from the air via helicopter if the battery/facility is in a remote location with winter only access.

11) A battery/facility with multiple jurisdictional inlets, of which one or more inlets are used to process only non-British Columbia volumes and of which one or more inlets are used to process only British Columbia production volumes, will cause all inlets to the battery/facility (British Columbia and non-British Columbia) to become “Cross Border” inlets. All inlets will adhere to the Cross Border requirements in both design and operation unless otherwise approved by the BCER.

12) A battery/facility with multiple inlets, of which one or more inlets are used to process commingled British Columbia and non-British Columbia production volumes, will cause all inlets (British Columbia and non-British Columbia) to the battery/facility to become “Cross Border” inlets. All inlets must adhere to the Cross Border requirements in both design and operation unless otherwise approved by the BCER.

13) Ideally, a battery/facility inlet should process only British Columbia or non-British Columbia production volumes. This is also known as a "dedicated inlet." The BCER has developed an option for operators when the economics of a "dedicated inlet" are prohibitive relative to the gas production. Refer to Measurement by Difference below for an alternative to the dedicated inlet concept.

14) Process flow diagrams, metering schematics and accepted accounting practices will be used to determine where Cross Border measurement requirements apply.

15) In no event will Cross Border volumetric production be allowed to bypass measurement (primary, secondary, and tertiary element) at a Cross Border measurement battery/facility except:

    a. during a calibration or verification activity or

    b. as approved in writing by an authorized BCER employee.

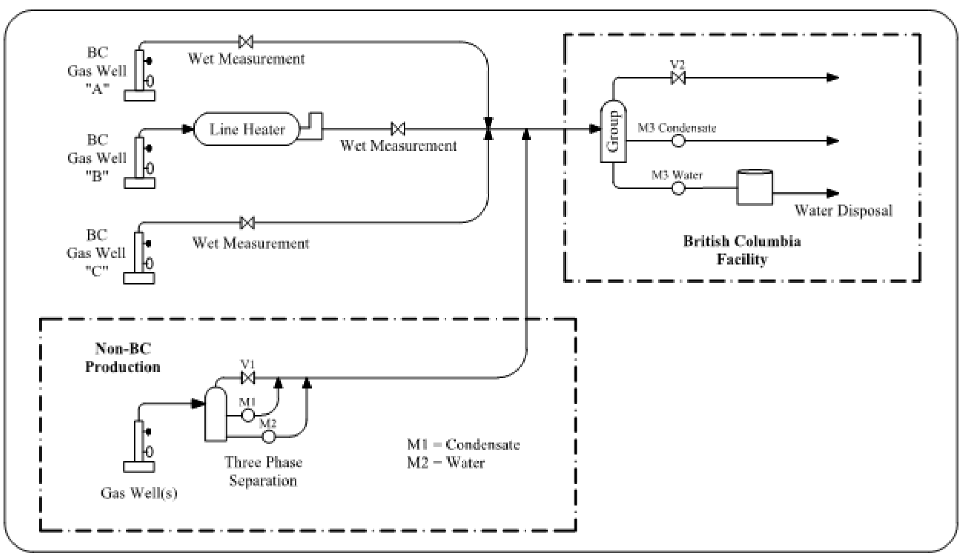
16) Gas meter bypasses are permitted only on Royalty Exempt fuel gas meters.

17) All gas meter bypasses must be double block and bleed.

7.12.2. **Design of Measurement by Difference**

1) For a gathering system that involves commingling non-British Columbia and British Columbia production as per Figure 7.12-1 below, producers may be eligible to follow a "Measurement by Difference" scheme.

Figure 7.12-1 Commingled Non-British Columbia and British Columbia Production



For accounting and reporting purposes, the monthly gas volume (including gas equivalent volume (GEV) of condensate where appropriate) received from a tied-in measured gas source must be subtracted from the total monthly battery/facility gas volume (including GEV of condensate where appropriate) to determine the proration monthly battery/facility gas production volume.

Accordingly, volumes from the non-BC production source and the British Columbia battery/facility will be governed by the ratio “R.” “R” is defined as the ratio of non-BC gas production to total British Columbia battery/facility gas production, i.e., (V1 + GEV M1) / (V2+ GEV M3) from the commingled inlet separator.

The maximum value permitted for “R” is 0.35. On exceeding this value, a producer will be required to construct a “dedicated inlet.”

The calculation of “R” (the ratio) must be determined by the following:

1) Production volumes must be determined on a monthly basis.
2) Measurement data used in the calculations must be that measurement data used to prepare monthly Reports.
3) Currently the BCER has only approved a design based on the diagram above. “R” would be determined according to the design of the gathering system and the approval of the BCER if a different model were considered. The BCER typically would examine a rationalization or consolidation of the gathering systems before looking at a more complex model. On an annual basis, the operator of the British Columbia battery/facility must provide proof to the BCER upon request, of the monthly calculations meeting the ratio requirement. The annual calculation period must be a period of 12 months ending June 30th of a given year.

An operator using the Measurement by Difference production scheme must meet the requirements of this document for the non-British Columbia production volume streams and the commingled non-British Columbia and British Columbia production streams. The BCER will not apply grandfathering of equipment design (i.e., orifice meter run vintage) to the affected separators or processing equipment.

In support of a measurement by difference application, written notification of the proposed measurement by difference model must be given to all working interest participants, with no resulting objections received in writing. The BCER may request the applicant to provide records to verify that no objections were received.

(The BCER will review and approve Measurement by Difference on a site-specific basis.)

7.12.3. Design Requirements For Natural Gas Measurement

7.12.3.1. High Level Emergency Shutdown

1) When the Cross Border gas measurement meter is directly downstream of a separator and there is no processing equipment between the separator and the meter, the separator must have a High-Level Emergency Shut Down (HL-ESD).
2) The HL-ESD must shut in production volumes to the separator and prevent fluid carryover to the gas measurement meter. Separators used in Cross Border applications must have HL-ESDs that are latching and require to be manually reset.
3) The HL-ESD must be logged in the event log of the Cross Border measurement RTU when the HL-ESD is tripped.
4) For those locations with a chart recorder, a note must be made on the chart when the HL-ESD is tripped.

7.12.3.2. Location of Cross Border Meter

1) Where the Cross Border gas measurement meter is not downstream of a gas dehydrator, every attempt should be made to ensure that the location of the Cross Border gas meter run and associated equipment is not subjected to ambient or process temperatures less than the temperature at the separator.

7.12.4. Design of Fuel Gas Measurement

7.12.4.1. Royalty Exempt Fuel Gas

1) Fuel gas taps for standard fuel gas consumption at a Cross Border battery/facility must be located upstream of the Cross Border gas measurement meter unless otherwise approved. Standard fuel gas consumption is consumption of fuel gas sourced on a permanent basis and is required in order to allow a Cross Border battery/facility to operate as designed, whether continuous or non-continuous in duration.

2) Fuel gas taps downstream of the Cross Border battery/facility gas measurement meter are permitted for non-standard fuel gas consumption or under specific BCER approval. Non-standard fuel gas consumption is consumption of fuel gas sourced on a temporary basis and is required in order to allow a Cross Border battery/facility to operate as designed, until such time as the standard fuel gas supply is available. Non-standard fuel gas consumption encompasses situations such as providing fuel gas to BCER and to start a Cross Border Measurement Battery/Facility or in a shut-down situation where standard fuel gas is unavailable to operate a Cross Border measurement Battery/Facility until the battery/facility is restarted.

3) Fuel gas may also be consumed downstream of the Cross Border battery/facility for the processing of British Columbia production volumes; Table 7.12-1 must be adhered to. Additionally, the design of the Cross Border system will dictate how fuel gas is handled in the accounting for reporting and allocation purposes.

4) Design of the fuel gas piping must permit only one fuel gas stream to flow through a fuel gas meter at any given time: either the gas stream from the fuel gas tap located upstream of the Cross Border gas measurement meter or the gas stream from the fuel gas tap located downstream of the Cross Border gas measurement meter.

5) Appropriate check valves may need to be installed in piping to determine fuel gas ownership for accounting and/or royalty purposes when British Columbia and non-British Columbia gas sources are available for consumption at a Cross Border battery/facility.

6) Valves used to source non-standard fuel gas downstream of the Cross Border gas measurement meter must be tagged and identified.

7) Table 7.12-1 below applies to Cross Border fuel gas measurement used for the production of British Columbia natural gas.

Table 7.12-1 Cross Border Fuel Gas Measurement

Volume	Tap Location	Estimate	Meter	Comments
≤0.5e^3m^3/day	Between Well Production Meter and Cross Border Gas Measurement Meter	Yes	No	N/A
>0.5e^3m^3/day	Between Well Production Meter and Cross Border Gas Measurement Meter	No	Yes	N/A
≤0.5e^3m^3/day	Downstream of Cross Border Gas Measurement Meter at Cross Border Battery/Facility	Yes	No *	Subtract from Cross Border Gas Measurement Volume
>0.5e^3m^3/day	Downstream of Cross Border Gas Measurement Meter at Cross Border Battery/Facility	No	Yes	Subtract from Cross Border Gas Measurement Volume

* The BCER prefers that a meter be installed in this instance.

(It is expected that the operator will meter the entire fuel gas volume consumed for a battery/facility rather than just a specific stream for which the 0.5e^3m^3/d threshold has been exceeded.)

7.12.4.2. **Non-Royalty Exempt Fuel Gas**

When fuel gas sourced for equipment (i.e., an Alberta compressor) is used in the processing of non-British Columbia production or when the location of production and use is not held by the same producer, such fuel gas can be subject to royalties on production from a gas well. However, fuel gas sourced for equipment (i.e., an Alberta compressor) used in the processing of production may be approved under a gas swap arrangement as directed by FIN, and royalties may not be directly attached to the metered fuel gas volumes, but indirectly to another gas stream. The following provides direction on treating these gas volumes:

1) Natural gas transacted for fuel gas as noted above will require a gas meter regardless of the volume.

2) A natural gas transaction with an end-use as fuel gas must be reported to the Ministry of Small Business and Revenue as a sale of gas unless otherwise directed by the Ministry of Small Business and Revenue.

3) Fuel gas supplied from a British Columbia fuel gas source to process non-British Columbia natural gas production must be separately metered to the standards outlined in this document.

4) Fuel gas supplied from a British Columbia fuel gas source to jointly process British Columbia and non-British Columbia production must be pro-rated to the fuel gas volumes consumed in the processing relative to the total British Columbia production and non-British Columbia production processed. The fuel gas must be separately metered to the standards outlined in this document.

5) A gas meter used for non-royalty exempt fuel gas must be marked on the Piping and Instrument Drawings (P&ID) and metering schematic drawings as a "Fuel Gas Sales Meter." For a joint processing arrangement, the meter must be identified as shown in Figure 7.12-2

Figure 7.12-2 Joint Processing Agreement Meter Identification

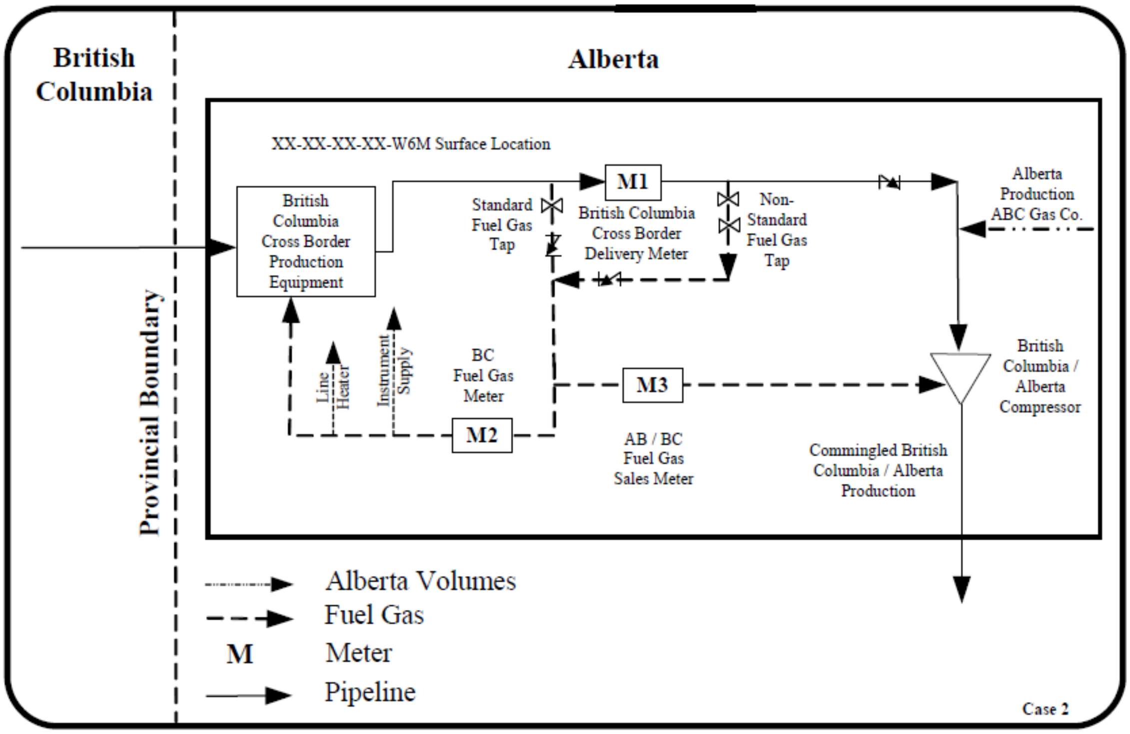
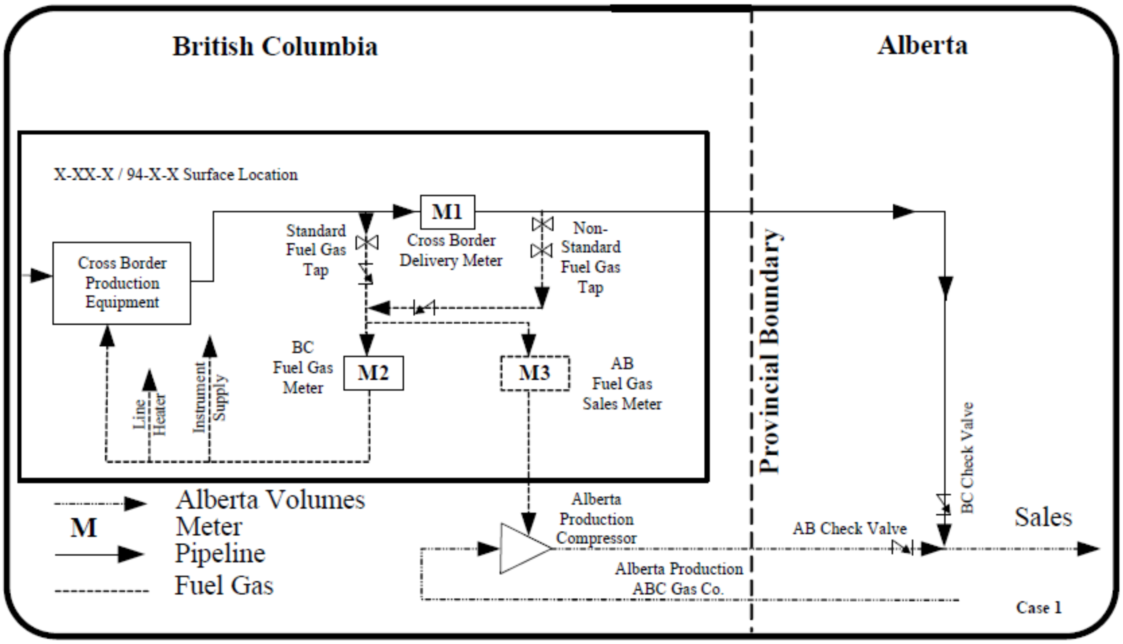


Figure 7.12-3 represents a Cross Border design scenario that may provide some clarity regarding fuel gas measurement. There are other possible design scenarios, and the operator should contact the BCER for further information.

Figure 7.12-3 Cross Border Design Scenario



7.12.5. **Design of Natural Gas Measurement**

For a meter design not included in the discussion below, contact the BCER

7.12.5.1. **Orifice Metering- Design/Construction**

1) Gas meter equipment must be installed in accordance with AGA Report No. 3, 2000 (AGA3) - Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids.

2) Gas meter equipment used for fuel gas purposes:

   a. **Royalty Exempt Fuel Gas** metering equipment must be installed in accordance with AGA Report No. 3, 1991 - Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids or with AGA Report No. 3, 2000 - Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids except when fuel gas is sourced on a permanent basis downstream of a Cross Border meter and the fuel gas meter is used in the accounting. In this circumstance the fuel gas meter must be installed in accordance with AGA Report No. 3, 2000 - Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids.

   b. **Non-Royalty Exempt Fuel Gas** metering equipment must be installed in accordance with AGA Report No. 3, 2000 -Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids.

3) Each orifice meter run must be equipped with a dual chamber fitting to enable the orifice plate to be removed for inspection, with the exception of orifice meter runs for **Royalty Exempt Fuel Gas**, which must be allowed a single chamber fitting.

4) All sensing lines must not exceed 1.0m in length.

5) All sensing lines must have a slope of 25.0mm per 300mm from the transmitter to the changer.

6) The minimum tubing size must be 12.7mm.

7) Full port valves must be used, with an internal diameter no smaller than the internal diameter of the sensing lines.

8) Orifice plate sizing must follow AGA Report No. 3, 1990, *General Equations and Uncertainty Guidelines*, Chapter 1.12.4.3.

9) The orifice plate bore diameter compared to the meter tube internal diameter or Beta Ratio must be in a range from 0.15 to 0.75.

10) Orifice meter runs must be designed based on a maximum differential pressure of 50.0kPa.

11) For EFM, maximum allowable differential pressure range must be 0 to 62.5 Kpa.

12) For EFM, differential and static pressure measurement equipment used in conjunction with the orifice meter must have a reference accuracy of ±0.1% of full span or better.

13) For chart recorders, the static pressure may be taken from the downstream tap on the orifice meter.

14) The thermowell must be located downstream of the orifice fitting as per AGA Report No. 3, 2000 - *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids*, section 2.6.5.

15) The tip of the thermowell must be located within the center third of the pipe.

16) Temperature measurement equipment must be installed with a flexible cable to allow removal from the thermowell for calibration/verification.

17) For EFM, temperature measurement equipment used in conjunction with the orifice meter must have a minimum specified uncertainty of ±0.25°C.

18) Secondary measurement equipment on an orifice meter run must be connected to one non-shared set of orifice flange taps.

7.12.5.2. **Orifice Metering - Volumetric Calculations**

1) Volumes must be calculated in accordance with AGA Report No. 3, 1992 – *Natural Gas Applications*.

   AGA8 – *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases* - Detail Method for compressibility should be used.

7.12.5.3. **Turbine Metering - Design/Construction**

1) Metering equipment must be installed in accordance with the latest edition of the AGA Transmission Measurement Committee Report No. 7, *Measurement of Gas by Turbine Meters* or as per manufacturer's specifications.

2) The turbine meter used must be of a type and quality that meets Measurement Canada specifications.

3) Turbine meters must be installed with a flow conditioner.

4) The flow conditioner must meet Measurement Canada specifications.

5) The measured gas stream must be of sales gas (marketable gas) quality.

6) The meter assembly, complete with flow conditioner, must undergo a standard calibration at a facility accredited by Measurement Canada.

7) Pressure measuring equipment used in conjunction with the turbine meter must have a minimum specified uncertainty of ±0.1% of range.

8) All sensing lines must not exceed 1.0m in length.

9) All sensing lines must to have a slope of 25.0mm per 300mm from the transmitter to the changer.

10) The minimum tubing size must be 12.7mm.

11) Full port valves must be used, with an internal diameter no smaller than the internal diameter of the sensing lines.

12) A thermowell pipe tap should be located within 3-5 pipe diameters downstream of the meter body's flange face. The tip of the thermowell must be located within the center one-third of the inside pipe diameter.

13) Temperature measurement equipment used in conjunction with the turbine meter must have a minimum specified uncertainty of ±0.25°C.

14) Temperature measurement equipment must be installed with a flexible cable to allow removal from the thermowell for calibration/verification.

15) Check valves must be installed downstream of the meter.

16) Pulse inputs to a Remote Terminal Unit (RTU) must be raw pulses from the meter. A pre-amplification card must not be used to scale the raw pulse output from the meter.

7.12.5.4. **Turbine Metering - Volumetric Calculations**

1) Volumes must be calculated in accordance with AGA Report No. 7, 1996 – *Measurement of Gas by Turbine Meters*.

7.12.5.5. **Rotary Metering – Design/Construction**

1) Due to the infrequent use of this type of metering, please consult the BCER

7.12.5.6. **Diaphragm Metering – Design/Construction**

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.12.5.7. Ultrasonic Metering – Design/Construction

1) Metering equipment must be installed in accordance with the latest edition of AGA Report No. 9 – *Measurement of Gas by Multipath Ultrasonic or as per manufacturer's specifications.*

2) The ultrasonic meter must be of a type and quality that meets Measurement Canada specifications.

3) Ultrasonic meters must be installed with a flow conditioner. The flow conditioner must be installed as per the manufacturer's design specifications and as per AGA Report No. 9 – Measurement of Gas by Multipath Ultrasonic Meters.

4) The flow conditioner must meet Measurement Canada specifications.

5) The meter assembly, complete with flow conditioner, must undergo a standard calibration at a battery/facility accredited by Measurement Canada.

6) Pressure measuring equipment used in conjunction with the ultrasonic meter must have a minimum specified uncertainty of ±0.1% of range.

7) All sensing lines must not exceed 1.0m in length.

8) All sensing lines must have a slope of 25.0mm per 300mm from the transmitter to the changer.

9) The minimum tubing size must be 12.7mm.

10) Full port valves must be used, with an internal diameter no smaller than the internal diameter of the sensing lines.

11) A thermowell pipe tap should be located within 3-5 pipe diameters downstream of the meter body's flange face. With bi-directional meters, the thermowell should be located at least 3 pipe diameters from either meter body flange face. The tip of the thermowell must be located within the center one-third of the inside pipe diameter.

12) Temperature measurement equipment used in conjunction with the ultrasonic meter must have a minimum specified uncertainty of ±0.25° C.

13) Temperature measurement equipment must be installed with a flexible cable to allow removal from the thermowell for calibration/verification.

14) Pulse inputs to a Remote Terminal Unit must be raw pulses from the meter. A pre-amplification card must not volumetrically scale the raw pulse output from the meter.

7.12.5.8. Ultrasonic Metering - Volumetric Calculations

1) Volumes must be calculated in accordance with AGA Report No. 7, 1996 – *Measurement of Gas by Turbine Meters* and as discussed in AGA Report No. 9 – *Measurement of Gas by Multipath Ultrasonic Meters*.

7.12.5.9. Coriolis Metering - Design/Construction

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.12.5.10. Natural Gas Measurement - Chart Recorders

1) Chart recorders must follow the following provisions:

   a. The identification of the gas stream being metered (i.e., meter surface location) is properly identified on the chart.

   b. The time and the date of start and finish of the record.

   c. On and off chart times are recorded on the chart to the nearest quarter hour.

   d. The correct orifice plate size is recorded on the chart.

   e. The correct meter tube size is identified on the chart.

   f. The time to the nearest quarter hour of any orifice plate change is indicated on the chart and the new orifice size is properly indicated relative to the chronology of the chart.

   g. It is noted on the charts if the differential pressure, static pressure, or temperature range has been changed, or if these ranges are different from the ranges printed on the chart.

   h. A copy of the chart calibration report is kept on site or readily available for on-site inspection if it is a manned battery/facility.

   i. Proper chart reading instructions (draw in the estimated traces, request to read as average flow for the missing period or provide estimate of the differential and static) are provided when the pen fails to record because of clock stoppage, pens out of ink, or other reasons.

   j. Any data or traces that require correction must not be covered over or obscured by any means.

   k. A notation is made on the chart with regard to whether or not the meter is set up for atmospheric pressure (for square root charts).

   l. The accuracy of the meter clock speed is checked, and the chart reader is instructed about any deviations.

   m. The differential pen is zeroed once per chart cycle.

   n. Differential pen recordings are at 33% or more within the chart range.

   o. Static pen recordings are at 20% or more within the chart range.

   p. When there is a painted differential band, instructions are provided as to where it should be read. There are various ways to read a painted chart:

      i. If the differential pen normally records at the top of the painted band but spikes quickly down and up during separator dump cycles, it is reasonable to read the differential near the top of the band (or vice versa).

   ii. If the differential pen is in constant up and down motion, it is reasonable to read the differential near the centre of the band or in a sine wave motion alternating between the top and bottom of the painted area.

   q. Pens are not over-ranged or under-ranged.

r. Pen tracings are not over-lapping.

s. Chart recorders must be equipped with continuous temperature measurement.

t. Chart recorders used in Cross Border Measurement must be equipped with a 24-hour chart.

u. Chart recorders will not be acceptable for use with production volumes greater than $60e^3m^3/d$.

2) If an inspection of a measurement device or of procedures reveals unsatisfactory conditions that reduce measurement accuracy, a request in writing by the BCER inspector or auditor to implement changes to improve measurement accuracy will become enforceable. Examples of conditions applicable to orifice chart recorders are as follows:

a. Thick pen traces that will cause excessive error when reading the traces.

b. Excessive painting. This is normally associated with the differential pen. Small narrow bands of painting can be dealt with as noted above; however, large bands of painting suggest that the chart recorder is not able to properly measure the process and remedial action is required. Painted traces exceeding 4% of the differential pressure or static pressure range is the base for evaluation purposes.

c. Differential or static pens recording too low on the chart. In some cases, this cannot be avoided because of low flow rate, high shut-in pressure, and equipment or operating pressure range limitations.

7.12.5.11. **Natural Gas Measurement - Electronic Flow Measurement (EFM)**

1) The EFM hardware must be of a type and quality approved by Measurement Canada, an agency of Industry Canada.

2) Alternate Measurement Canada approved equivalents may be considered by the BCER. Written approval must be received from the BCER for an equivalent alternate.

3) Control logic must be minimized in the RTU and is generally restricted to the following:

a. measurement system

b. flow control

c. minimal shutdown processing

4) Some forms of transmitter-Remote Terminal Unit combinations do not create “As Found”-“As Left” audit trails in the Remote Terminal Unit and are logged only in the transmitter(s). The BCER will not accept an audit trail found only in the transmitter(s). The operator must be responsible to ensure that the Remote Terminal Unit has “end to end” audit trail capability either inherent in the Remote Terminal Unit design or by programming a Remote Terminal Unit. This requirement is designed to ensure that the inputs to a transmitter(s) are followed by the Remote Terminal Unit.

7.12.5.12. Natural Gas Measurement - Data Reporting - Electronic Flow Measurement

An EFM device must store (historicize) the following data for gas volumetrics:

1) Orifice Meter
   a. Time on production on an hourly and daily basis.
   b. Hourly volume total.
   c. Average hourly flow rate.
   d. Average hourly differential pressure.
   e. Average hourly static pressure.
   f. Average hourly temperature.
   g. Average daily differential pressure.
   h. Average daily static pressure.
   i. Average daily temperature.
   j. Daily volume total.
   k. Orifice plate size either at top or bottom of the hour.

2) Ultrasonic Meter, Turbine Meter, Coriolis Meter
   a. Time on production on an hourly and daily basis.
   b. Uncorrected hourly volume.
   c. Corrected hourly volume.
   d. Average hourly static pressure.
   e. Average hourly temperature.
   f. Average hourly flow rate.
   g. Corrected daily volume.
   h. Average daily static pressure.
   i. Average daily temperature.
   j. K-Factor.

3) General Reports

On request, the EFM device must be capable of generating a data file that contains the following, as applicable:

a. Gas composition.
b. Orifice diameter.
c. Meter run diameter (1 inch upstream of the orifice plate).
d. Meter identification.
e. Atmospheric pressure.
f. Relative density.
g. Meter Factor (as applicable).
h. K Factor (as applicable).
i. C factors used in flow calculations (Y, etc.).
j. Identify that the upstream tap is used in flow calculation.
k. Contract hour.
l. Pressure base for flow calculations.
m. Temperature base for flow calculations.
n. Orifice plate construction material (as applicable).
o. Meter tube construction material (as applicable).

When the BCER makes a request for information for data from an EFM device, the operator must include the following with the report(s):

1) Date report(s) created.
2) Time report(s) created.
3) Individual creating the report(s).
4) Telephone number for individual creating the report(s).
5) Identify if the information was collected On-Line or Off-Line with the EFM device.

7.13. Liquid Hydrocarbon Measurement – Design

This section covers inventory measurement, tankage of hydrocarbon liquids, delivery point measurement, and re-injection of hydrocarbon liquids.

7.13.1. **Design of Liquid Hydrocarbon Measurement**

1) K plots may be required for those locations with condensate production greater than 10m3/d.
2) Continuous Sediment and Water (S&W) measurement is required if hydrocarbon sampling results in a water content greater than 0.5%.
3) Hydrocarbon liquid installations may be configured according to the following (as applicable).

   a. **Blowcase Installation**
      i. The liquid meter must be located downstream of the blowcase.
      ii. A check valve must be in place between the blowcase and the hydrocarbon liquid meter.

   b. Hydrocarbon Liquid Meter with Re-injection Pump (Continuous Pump Operation)
      i. Installation must meet the manufacturer's specifications. If none exist, the order of installation is typically pump, check valve, pump recycle line and recycle valve, hydrocarbon liquid meter proving taps, and back pressure control valve (as necessary).

4) Liquid meter bypasses must be double block and bleed. If a bypass is installed, they are to be locked or car sealed in the closed position.
5) Proving taps must be the same nominal pipe size or larger than the meter piping.

6) Hydrocarbon or oil volumes transported via ground transport from hydrocarbon or oil storage tanks:

   a. To a delivery point meter
   b. For further processing

c. For market transaction must contain only those volumes produced from the Province of British Columbia.

(For a meter design not included in the discussion below, please contact the BCER.)

7.13.2. **Orifice Metering – Delivery Point Measurement – Design/Construction**

1) Refer to the requirements in section 7.12.5.1 Orifice Metering- Design/Construction

7.13.2.1. **Orifice Metering - Volumetric Calculations**

1) Volumes must be calculated in accordance with AGA Report No. 3, 1990 – *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids.*

7.13.3. **Vortex Shedding Metering – Delivery Point Measurement – Design/Construction**

Due to the infrequent use of this type of metering, please consult the BCER.

7.13.4. **Turbine Metering – Delivery Point Measurement – Design/Construction**

1) Meters must have a linearity of at least 0.5% and a repeatability of at least 0.1%.

2) Turbine meters must be selected such that their design operating point is greater than 30% of their range.

3) Liquid meter installations must be in accordance with manufacturer's specifications; American Petroleum Institute (API) Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters"; Chapter 5.4, "Accessory Equipment for Liquid Meters and the Drilling and Production Regulations" as relevant and/or applicable to the design of the liquid metering system. The design of the liquid metering system must include considerations for the operation of liquid pumps or separator installations as appropriate.

4) Upstream pipe diameters (D) on a turbine meter must be 20 D unless otherwise determined from American Petroleum Institute (API) Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters" which indicates that 10 D can be utilized when a flow conditioner is installed.

5) Temperature measurement equipment used in conjunction with the turbine meter must have a minimum specified uncertainty of ±0.25°C.

6) Static pressure measurement equipment used in conjunction with the turbine meter must have a minimum specified uncertainty of ±0.1% of range.

7) All sensing lines must not exceed 1.0m in length.

8) All sensing lines must have a slope of 25.0mm per 300mm from the transmitter to the changer.

9) The minimum tubing size must be 12.7mm.

10) Full port valves must be used, with an internal diameter no smaller than the internal diameter of the sensing lines.

11) Static pressure measurement equipment must be able to determine the static pressure at the turbine meter.

12) Pulse inputs to a Remote Terminal Unit must be raw pulses from the meter. A pre-amplification card should not scale the raw pulse output from the meter.

7.13.4.1. Turbine Metering – Volumetric Calculations – Delivery Point Measurement

1) Volumes must be calculated in accordance with American Petroleum Institute (API) Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters."

2) Correction to metered volumes measured at pressures other than the greater of an absolute pressure of 101.325kPa or the liquids equilibrium vapour pressure must be determined and applied in all instances as per the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards*, Chapter 11.

3) Volumetric computations must occur in the EFM device.

7.13.5. Positive Displacement Meters – Delivery Point Measurement – Design/Construction

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.13.6. Coriolis Metering – Delivery Point Measurement – Design/Construction

1) Meters must have an accuracy of at least 0.1% and a turndown of at least 10:1.

2) Meter installation must be in accordance with manufacturer's specifications; American Petroleum Institute (API) Chapter 5.6, "Measurement of Liquid Hydrocarbons by Coriolis Meters"; Chapter 5.4, "Accessory Equipment for Liquid Meters." The design of the liquid metering system must include considerations for the operation of liquid pumps or separator installations as appropriate.

3) Temperature measurement equipment used in conjunction with the coriolis meter must have a minimum specified uncertainty of ±0.25°C.

4) Static pressure measurement equipment used in conjunction with the coriolis meter must have a minimum specified uncertainty of 0.1% of range.

5) All sensing lines are not to exceed 1.0m in length.

6) All sensing lines must have a slope of 25.0mm per 300mm from the transmitter to the changer.

7) The minimum tubing size must be 12.7mm.

8) Full port valves must be used, with an internal diameter no smaller than the internal diameter of the sensing lines.

9) Pulse inputs to a Remote Terminal Unit must be raw pulses from the meter. A pre-amplification card must not volumetrically scale the raw pulse output from the meter.

10) Air eliminators must be installed for truck unloading applications.

7.13.6.1. **Coriolis Metering - Volumetric Calculations - Delivery Point Measurement**

1) Volumes must be calculated in accordance with American Petroleum Institute (API) Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters."

2) Correction to metered volumes measured at pressures other than the greater of an absolute pressure of 101.325kPa or the liquids equilibrium vapour pressure must be determined and applied in all instances as per the American Petroleum Institute (API) Chapter 11, "Volume Correction Factors."

3) Volumetric computations must occur in the EFM device.

7.13.7. **Sediment and Water**

1) Sediment and water determinations from a lab analysis/field analysis of a liquid sample must be applied to the hydrocarbon liquid volumes.

7.13.8. **Tank Gauging of Liquid Hydrocarbons**

1) Tank volumes can be determined either by Electronic Tank Gauging, Gauge Boards, or by Manual Tank Gauging.

7.13.9. **Tank Gauging – Inventory Measurement – Design/Construction**

1) A level transmitter or gauge board should have a specified resolution (minor markings) of ±75mm.

2) Gauge board markings (major markings) must be no farther apart than 150mm.

3) Manual tank gauging requires one reading of the tape.

4) A strapping table or calculation used to convert tank levels to a liquid volume must be prepared.

7.13.10. **Hydrocarbon Liquid Measurement – Electronic Flow Measurement (EFM)**

1) The EFM hardware must be of a type and quality approved by Measurement Canada, an agency of Industry Canada.

2) Alternate Measurement Canada approved equivalents may be considered by the BCER. Written approval must be received from the BCER for an equivalent alternate.

3) Control logic must be minimized in the RTU and is generally restricted to the following:
   a. measurement system
   b. flow control
   c. minimal shutdown processing

4) Some forms of transmitter-Remote Terminal Unit combinations do not create "As Found"-"As Left" audit trails in the Remote Terminal Unit and are logged only in the transmitter(s). The BCER will not accept an audit trail found only in the transmitter(s). The operator must be responsible to ensure that the Remote Terminal Unit has "end to end" audit trail capability either inherent in the Remote Terminal Unit design or by programming a Remote Terminal Unit. This requirement is designed to ensure that the inputs to a transmitter(s) are followed by the Remote Terminal Unit.

7.13.10.1. **Liquid Hydrocarbon Measurement Data Reporting – Electronic Flow Measurement**

An EFM device must store (historicize) the following data for hydrocarbon liquid volumetrics:

7.13.10.2. **Orifice Metering**

1) Refer to section 7.12.5.12 - Natural Gas Data Reporting Electronic Flow Measurement (EFM)

7.13.10.3. **Turbine Metering, Coriolis Metering, Vortex Metering**

1) Daily total net standard volume (corrected).

2) Daily total gross volume (uncorrected).

3) Daily total pulse counts (raw pulse counts from meter).

4) Average daily temperature.

5) Average daily static pressure.

6) Meter proving factor (dimensionless).

7) Sediment and water content (% volume).

8) K-Factor.

7.13.10.4. **Positive Displacement Metering**

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.14. Oil Measurement – Design

Oil meters must follow the above requirements as listed above under section 7.13 Liquid Hydrocarbon Measurement-Design.

7.14.1. Verification/Calibration – Natural Gas Measurement, Liquid Hydrocarbon Measurement

7.14.2. Lab Calibration Equipment

1) The minimum uncertainty for calibration equipment at a lab must be one-half the minimum uncertainty of the calibration/verification equipment being calibrated.

7.14.3. Field Calibration Equipment

1) The minimum uncertainty for field calibration equipment must be equal to or better than that of the device under calibration/verification.

2) High-pressure calibrations/verifications (i.e., static pressure) must use nitrogen as a pressure source. Failure to meet this requirement will result in the calibration/verification being null and void.

3) Low-pressure calibrations/verifications (i.e., differential pressure) must use a pressure source that is not liquid based. Failure to meet this requirement will result in the calibration/verification being null and void.

4) Field calibration/verification equipment must be calibrated and certified **annually** by a standards laboratory meeting the criteria under Lab Calibration Equipment.

5) The laboratory Calibration Certificate must be available for inspection during a calibration/verification.

6) Failure to produce the calibration certificate within 24 hours of the calibration/verification may result in the calibration/verifications being declared null and void.

7) Using field calibration/verification equipment that is past the re-certification date will render the calibration/verification null and void.

8) The serial numbers of the certified standard (test equipment) must be recorded on the meter/calibration report.

7.14.4. High Level Emergency Shut Down (ESD)

1) At the frequency stipulated for Natural Gas Measurement - Frequencies, the High-Level Emergency Shut Down on the Cross Border Measurement separator must be checked and the results of the check identified on the meter/calibration report. This applies to those situations where the Cross Border Measurement meter includes the requirement for a High-Level Emergency Shut Down.

7.14.5. **Natural Gas Measurement - Operations**

7.14.5.1. **Calibration/Verification Procedures – Orifice Metering and EFM**

The definition of verification (to compare) and calibration (to correct) are used interchangeably for Cross Border Measurement purposes. The intent of the checking process must ensure that measurement point equipment is reading correctly according to a certified standard.

1) All calibration/verification activities at a metering station must be logged in the Remote Terminal Unit (RTU) such that an audit trail exists in the Remote Terminal Unit (RTU).
2) A meter calibration/verification report must be created during the calibration/verification process for audit purposes.
3) The certified standard must be applied to the secondary element and the indicated value for that standard must be read at the Remote Terminal Unit (RTU) for calibration/verification purposes.
4) A verification/calibration must meet the following conditions:
   a. The acceptable tolerance for calculated gas flow volumes by the EFM device must be within ±0.25% of the correct value as determined by a recognized flow calculation method. This check must be performed at the end of any calibration/verification process.
   b. The static pressure and differential pressure transmitters must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.
   c. At a minimum, one reading must be applied (verified) at the current operating differential pressure to meet the tolerance requirement of ±0.10% of range.
   d. At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.
   e. The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.
   f. At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.
   g. The differential pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points.
   h. The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50%, and 20% (or 25%) points.
   i. The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or as cold as possible when in remote sites), a mid-warm point and a hot point (as hot as possible when in remote sites).

5) An orifice plate inspection must be made. The orifice plate inspection must consist of:

   a. A physical examination for damage of the orifice plate, and cleaning.

   b. A check to ensure that the orifice plate size in the Remote Terminal Unit matches the physical orifice plate size and the Beta Ratio is in the correct range.

7.14.5.2. **Calibration/Verification Procedures – Orifice Metering and Chart Recorders**

1) The procedure for orifice meter chart recorder (end device) calibration must be in accordance with the following:

   a. Pen arc, linkage, pressure stops, and spacing must be inspected and adjusted, if necessary.

   b. The differential pressure element must be calibrated at zero, full span, and nine ascending/ descending points throughout its range.

   c. A zero check of the differential under normal operating pressure must be done before and after the calibration.

   d. The static pressure element must be calibrated at zero, span, 80% (or 75%), 50% and 20% (or 25%) points.

   e. The temperature element must be calibrated at three points: operating temperature, one colder temperature (i.e., ice water if possible), and one warmer temperature.

   f. Subsequent to the meter calibration, a tag or label must be attached to the meter (or end device). The tag or label must identify:

      i. The meter serial number.

      ii. The date of the calibration.

      iii. The site location.

      iv. The meter element calibration ranges.

      v. The full name of the person performing the calibrations.

   g. A detailed report indicating the tests conducted on the meter during the calibration and the conditions "As Found" and "As Left" must be either left with the meter (or end device) or readily available for inspection by the BCER. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

7.14.5.3. **Calibration/Verification Procedures – Turbine Metering and EFM**

1) Turbine meters must undergo a standard calibration at a battery/facility accredited by Measurement Canada.

2) All calibration/verification activities at a metering station must be logged in the Remote Terminal Unit (RTU) such that an audit trail exists in the Remote Terminal Unit (RTU).

3) A meter calibration report must be created during the calibration/verification process for audit purposes.

4) The certified standard must be applied to the secondary element and the indicated value for that standard must be read at the Remote Terminal Unit (RTU) for calibration/verification purposes.

5) A verification/calibration must meet the following conditions:

   a. The static pressure transmitter must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.

   b. At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.

   c. The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.

   d. At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.

   e. The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points.

   f. The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or as cold as possible when in remote sites), a mid-warm point and a hot point (hot as possible in remote sites).

7.14.5.4. **Calibration/Verification Procedures – Ultrasonic Metering and EFM**

1) Ultrasonic meters must undergo a standard calibration at a battery/facility accredited by Measurement Canada.

2) All verification/calibration activities at a metering station must be logged in the Remote Terminal Unit (RTU) such that an audit trail exists in the Remote Terminal Unit (RTU).

3) A meter verification/calibration report must be created during the calibration/verification process for audit purposes.

4) The certified standard must be applied to the secondary element and the indicated value for that standard must be read at the Remote Terminal Unit (RTU) for calibration/verification purposes.

5) A verification/calibration must meet the following conditions:

   a. The static pressure transmitter must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.

   b. At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.

   c. The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.

   d. At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.

e. The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points.

f. The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or as cold as possible when in remote sites), a mid-warm point and a hot point (as hot as possible when in remote sites).

7.14.5.5. Calibration/Verification Procedures - Rotary Metering

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.14.5.6. Calibration/Verification Procedures - Diaphragm Metering

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.14.5.7. Calibration/Verification Procedures – Coriolis Metering and EFM

1) Coriolis meters must undergo a standard calibration at a facility accredited by Measurement Canada.

2) All verification/calibration activities at a metering station must be logged in the Remote Terminal Unit (RTU) such that an audit trail exists in the Remote Terminal Unit (RTU).

3) A meter verification/calibration report must be created during the calibration/verification process for audit purposes.

4) The certified standard must be applied to the secondary element and the indicated value for that standard must be read at the Remote Terminal Unit (RTU) for calibration/verification purposes.

5) A calibration/verification must meet the following conditions:

a. The static pressure transmitter must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.

b. At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.

c. The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.

d. At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.

e. The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points. Nitrogen must be used as a pressure source.

f. The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or a cold as possible when in remote sites), a mid-warm point and a hot point (as hot as possible when in remote sites).

7.14.6. Liquid Hydrocarbon Measurement – Operation

7.14.6.1. Calibration/Verification Procedures – Orifice Metering

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.14.6.2. Calibration/Verification - Turbine Metering and Associated Equipment

1) Use of a volumetric prover, ball prover, or piston prover is accepted; however, the design of the liquid's system will determine the type of prover.

2) Portable proving equipment must be water drawn and calibrated bi-annually.

3) Temperature measuring equipment used in conjunction with the prover must have a specified uncertainty equal to or less than that of the uncertainty specified for the temperature-measuring equipment associated with the meter under prove.

4) The prover operator must attempt to be consistent in the volume of each run during a prove. The volume of condensate used for each prove can be adjusted to the proving volumes of hydrocarbons available.

5) Following the initial meter calibration, a turbine meter must be proved following a change to the meter or repairs to the installation that will affect the meter factor.

6) The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.

7) At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.

8) The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or a cold as possible when in remote sites), a mid-warm point and a hot point (as hot as possible when in remote sites).

9) The static pressure transmitter must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.

10) The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points.

11) At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.

12) A meter is considered successfully proved when the meter factor determined from four consecutive runs are all within ±2% of the mean factor and the new meter factor is not more than ±2% of the previous meter factor nor more than 20% greater than the original meter factor.

13) Other than the initial proving and proving after meter repairs, verification with one proving run is sufficient if the new meter factor is within 0.5% of the previous meter factor. Otherwise, four runs are required as above.

14) When continuous water cut determination is not installed, a liquid analysis is required which must identify the sediments and water (S&W) for the liquid volume. This S&W must be used in determining the total hydrocarbon liquid volume. This S&W percentage may be applied at any point (as a function of the meter factor, in the FDC system, etc.) providing that an audit trail exists that the S&W % has been applied to the gross volume.

15) The K factor for the turbine meter is not changed; rather, after each prove, a Meter Factor must be adjusted.

16) Low volume condensate production (less than $2m^3/d$) must be eligible for bench proving. Alternately, if the rate of flow through the meter is less than or equal to $3m^3/d$ with the gas equivalent volume of the daily condensate volume less than or equal to 3% of the daily gas volume related to the condensate production the meter will be eligible for bench proving.

7.14.6.3. Calibration/Verification Procedures – Positive Displacement Metering

1) Due to the infrequent use of this type of metering, please consult the BCER.

7.14.6.4. Calibration/Verification Procedures – Coriolis Metering

1) Use of a volumetric prover, gravimetric prover, ball prover, or piston prover is acceptable.

2) Portable proving equipment must be water drawn and calibrated bi-annually.

3) The prover operator must attempt to be consistent in the volume of each proving run. The volume of condensate used for each prove should be adjusted to the proving volumes available.

4) Temperature measuring equipment used in conjunction with the prover must have a specified uncertainty equal to or less than the uncertainty specified for temperature measuring equipment associated with the meter under prove.

5) Following the initial meter calibration, a mass meter must be proved following a change to the meter or repairs to the installation that will affect the meter factor.

6) The temperature element and/or transmitter loop must be calibrated if the verified reading is outside the acceptable tolerance limit of ±0.25°C.

7) At a minimum, one reading must be applied (verified) at the current operating temperature or as close as possible to the operating temperature to meet the tolerance requirement of ±0.25°C.

8) The temperature loop calibration must consist of a three-point test. The test must consist of an ice water point (or as cold as possible when in remote sites), a mid-warm point and a hot point (as hot as possible when in remote sites).

9) The static pressure transmitter must be calibrated if the verified readings are outside the acceptable tolerances of ±0.10% of range.

10) The static pressure loop calibration must consist of a check at the zero, span, 80% (or 75%), 50% and 20% (or 25%) points.

11) At a minimum, one reading must be applied (verified) at the current operating static pressure to meet the tolerance requirement of ±0.10% of range.

12) A meter is considered successfully proved when the meter factor determined from four consecutive runs are all within ±2% of the mean factor and the new meter factor is not more than ±2% different from the previous meter factor nor more than 20% greater than the original meter factor.

13) Other than the initial proving and proving after meter repairs, verification with one proving run is sufficient if the new meter factor is within 0.5% of the previous meter factor. Otherwise, four runs are required as above.

14) When continuous water cut determination is not installed, a liquid analysis is required which must identify the sediments and water (S&W) for the liquid volume. This S&W must be used in determining the total hydrocarbon liquid volume. This S&W percentage may be applied at any point (as a function of the meter factor, in the FDC system, etc.) providing that an audit trail exists that the S&W percentage has been applied to the gross volume.

15) The meter factor must be adjusted in the Remote Terminal Unit after each prove as appropriate.

7.14.6.5. Calibration/Verification Procedures – Tank Gauging – Inventory Measurement

1) Electronic level transmitters must be calibrated annually in accordance with the manufacturer's procedures .

2) Calibration of transmitters must include an audit trail to verify that the certified standard applied to the transmitter is read at the termination point (logic device) for calibration/verification purposes. The logic device must be interpreted to be the device that provides indication for the transmitter and is used in volume determinations.

3) Gauge board calibration procedures must be in accordance with the manufacturer's procedure. A copy of the calibration procedure must be produced on request.

7.14.7. Oil Measurement – Operation

Oil meters must follow the above requirements as listed under Liquid Hydrocarbon Measurement except as follows:

1) Three consecutive runs must be used when proving, each with a tolerance of ±0.25 percent of the mean factor, and, following a meter calibration, the average meter factor must be applied to meter readings until the next meter prove.

2) Following the initial proving, each oil meter must be calibrated at least every month for which one run is sufficient if the new meter factor is within 0.5% of the previous mean factor; however, if the new meter factor is not within 0.5% of the previous meter factor, the meter must be proved.

7.14.8. Natural Gas, Liquid Hydrocarbon, and Oil Measurement – Operation – Reporting

7.14.8.1. Remote Terminal Unit Data – Audit Trail

1) Data downloads must be kept for a minimum of one year and made available for viewing by a representative from the BCER.

2) Remote Terminal Unit data downloads can be archived electronically and are not to be submitted to the BCER unless requested.

3) The data must be available in a format that can be interpreted by the BCER (i.e., PDF, Word, Excel).

4) The data downloads must include files as applicable to the Remote Terminal Unit in use that provides the following:

   a. Configuration file: file(s) containing the "load" used to configure the Remote Terminal Unit.

   b. Event log: file used to track changes to the configuration, volumetrics or other system events.

   c. Alarm log: file used to track alarm items.

   d. Daily volume report: file containing the production history.

   e. EFM report: file indicating flow parameters and flow calculations.

   f. Other reports (as applicable): speed of sound calculation verifications (ultrasonic meters), meter self-diagnostic data downloads.

5) Data downloads must occur at the same frequency as the calibration/verification.

6) Gas analysis updates in the production accounting system must have an audit trail to verify that an update has occurred. A paper trail must be available for audit purposes from the field to the production accounting system, specifically to the volumetric and allocation worksheets.

7) Liquid analysis updates in the production accounting system must have an audit trail to verify that an update has occurred. A paper trail must be available for audit purposes from the field to the production accounting system, specifically to the volumetric and allocation worksheets.

7.14.8.2. **Natural Gas Measurement – Operation – Reporting**

1) Natural Gas Sampling

   a. Gas sample analysis, reporting, and updating to the measurement and accounting systems must occur at the same frequency as the gas calibrations/verifications for the measurement point.

   b. The gas sampling points must meet the requirements outlined in section 1).

   c. Automatic gas samplers are an acceptable alternative to spot sampling to determine a representative gas sample.

   d. All gas sampling points must be identified with a tag to ensure a consistent sampling location.

   e. Gas analysis trending is recommended as a check on gas composition change.

   f. As a minimum, gas analysis must determine mole fractions for He, H_2, N_2, CO_2, C_1, C_2, C_3, iC_4, nC_4, iC_5, nC_5, and C_6+~~.~~

   g. The H_2S content in a gas stream with a concentration of 2100mg/m^3 (1500ppm) or less must be obtained by gas sample and examined by gas chromatography.

h. A Tutweiler test must be used to determine the H_2S content when the H_2S concentration exceeds 2100mg/m^3 H_2S.

2) Hydrocarbon Liquid Sampling – Liquid Measurement

a. Hydrocarbon liquid sample analysis for updating the measurement and accounting systems for reporting must occur at the same frequency as the liquid calibrations.

b. The hydrocarbon liquid sampling points must meet the requirements outlined in section 1)

c. Automatic hydrocarbon liquid samplers are also an acceptable alternative to spot sampling to determine a representative liquid sample.

d. All hydrocarbon liquid sampling points must be identified with a tag to ensure a consistent sampling location.

e. As a minimum, hydrocarbon liquids analysis must determine volume fractions for N_2, CO_2, C_1, C_2, C_3, iC_4, nC_4, iC_5, nC_5, and C_6+; however, this is required when hydrocarbon liquids are recombined, not tanked.

f. The hydrocarbon liquid analysis must indicate the following:

   i. Density.

   ii. Sediment and water content (S&W).

   iii. Molecular mass.

g. A vapour-liquid equilibrium ratio (K-Plot) must be performed at three-phase separation facilities as per the following:

   i. When raw condensate production exceeds 10m^3/d average over a reporting period (monthly).

   ii. Unless otherwise approved, K-Plot calculations may be performed on the first two scheduled hydrocarbon liquid sample analyses immediately after reaching the trigger point of 10m^3/d and annually thereafter.

   iii. The producer must be responsible to examine and sign off K-Plot results. An analysis that addresses the following for each K-Plot must be performed:

   - Theoretical K-Value versus Actual K-Value.
   - An explanation for the results of the sample.
   - An interpretation of the data.

   iv. Each K-Plot result must be available upon request by the BCER.

   v. K-Plot results that provide a reasonable doubt as to the quality of separation will be subject to further scrutiny and/or action by the BCER.

h. Analysis trending is recommended to verify liquids composition changes.

i. Hydrocarbon liquid sample analysis for updating to the measurement and accounting systems for reporting must occur at the same frequency as the liquid calibrations.

j. The hydrocarbon liquid sampling points must meet the requirements outlined in section 1)

k. Automatic hydrocarbon liquid samplers are also an acceptable alternative to spot sampling to determine a representative liquid sample.

l. All hydrocarbon liquid sampling points must be identified with a tag to ensure a consistent sampling location. The hydrocarbon liquids analysis must indicate the following:

   i. Density.

   ii. Sediment and water content (S&W).

   iii. Molecular mass.

Analysis trending is recommended to verify liquids' composition changes.

7.15. Natural Gas Measurement – Frequencies – Operation

The frequencies stipulated for natural gas measurement under a Cross Border designation exceed the annual or semi-annual measurement frequencies for natural gas at well sites or plants or facilities.

7.15.1. Operating Principles

1) There are three stages with the following cut-off points:

Table 7.15-1 Cut-Off Points for the Three Stages

Stage	Operand	Volume e^3m^3/day		Operand	Volume e^3m^3/day
1	<	25.0			
2	>	25.0	And	≤	150.0
3	>	150.0			

The volumes indicated in this table are volumes that would be used for reporting purposes. Thus, depending on the situation, the volume may include not only a gas metered volume but additionally a gas equivalent volume of liquid hydrocarbon production.

2) There are two modes:

   a. Initial Period Frequency.

   b. Possible Reduced Period Frequency.

3) On attaining the Cut-Off Point, the operator must move to the next appropriate stage. A Discretionary Allowance of 5% of the Cut-Off Point will be permitted, outside of which the operator will be denied appeal. The cut-off volume must be considered an absolute threshold, i.e., if the cut-off volume is exceeded, then appropriate action must be taken in regard to the three stages.

4) The BCER may use data filed for reporting purposes in ascertaining threshold violations.

5) At the discretion of the BCER, a Grace Period of four days may be used to determine if a Frequency Period has been missed. The four days must not be used to spread out the Frequency Period.

6) Data downloads, meter maintenance reports, gas analysis and liquid analysis data for the Cross Border measurement meter information must be kept up to date and made available upon request by the BCER. Only the first Initial Period following the commencement of Cross Border measurement will applicable documentation be required to be forwarded onto the BCER no later than fifteen days following the month of production or as otherwise directed.

7) Initial Period Frequencies must be maintained for the time indicated or until a Reduced Period Frequency approval is obtained.

8) On completion of the Initial Period, application can be made to the BCER to move to a Reduced Period Frequency.

9) The BCER will approve or reject an application to move to the Reduced Period Frequency. Approval to move to a Reduced Period Frequency must involve a consideration of the following:

   a. Calibration/verification records.

   b. Operator's compliance record with a Cross Border measurement approval. An operator that has had more than three communicated deficiencies relative to Cross Border measurement will be denied the Reduced Period Frequency for a period of three years. A change of operator may allow for a reconsideration of the Reduced Period Frequency.

10) If an operator is following a Reduced Period Frequency mode and production volumes change requiring a stage change, the operator may follow the Reduced Period Frequency for the new stage. Changes to maintenance dates as a result of a stage change, requires notification to be sent to the BCER's Technical Advisor Responsible for Measurement so records can be updated accordingly.

11) Failure to meet an Initial Period Frequency will result in permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages. An inspection/audit that identifies non-compliance at any point in time with an Initial Period Frequency at any stage, past or present, will result in immediate permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages.

12) A notice will be provided in writing to indicate that the operator has been permanently assigned the Initial Period Frequency at the relevant stage and all future stages. The Notice will also identify that the operator is remanded to the Initial Period Frequency because of not meeting Initial Period Frequency calibrations.

13) Failure to meet a Reduced Period Frequency will result in permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages. An inspection/audit that identifies non-compliance at any point in time with a Reduced Period Frequency at any stage, past or present, will result in immediate revocation of a Reduced Period Frequency approval resulting in permanent assignment of the Initial Period Frequency at the relevant stage and all future stages.

14) A notice will be provided in writing to indicate that the operator has been permanently assigned the Initial Period Frequency at the relevant stage and all future stages. The Notice will also identify that the operator is remanded to the Initial Period Frequency because of not meeting Reduced Period Frequency calibrations. Additional site-specific inspections and follow up by the Compliance and Enforcement Branch may result from a failure to meet these requirements.

15) The BCER may relieve or modify a Period Frequency requirement when the operator provides an explanation in writing as to why a Period Frequency was missed. This must be used only in extraordinary circumstances.

7.15.2. **Stage 1: Average Monthly Raw Volume ≤25.0e3m3/day**

1) Orifice Metering

Table 7.15-2 Stage 1 Orifice Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency EFM	Possible Reduced Period Frequency Chart
Temperature Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual	Thirdly
Pressure Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual	Thirdly
Gas Analysis Sampling	3 Months	Monthly	Semi-Annual	Semi-Annual
Update Gas Analysis Measurement	3 Months	Monthly	Semi-Annual	Semi-Annual
Update Gas Analysis Production Accounting	3 Months	Monthly	Semi-Annual	Semi-Annual
Orifice Plate Inspection	3 Months	Monthly	Semi-Annual	Thirdly
ESD High Level Inspection	3 Months	Monthly	Semi-Annual	Thirdly

2) Turbine Metering

Table 7.15-3 Stage 1 Turbine Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency - EFM
Turbine Meter Calibration	3 Months	Quarterly	Semi-Annual
Turbine Meter Inspection	3 Months	Quarterly	Semi-Annual
Temperature Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual
Pressure Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual
Gas Analysis Sampling	3 Months	Monthly	Semi-Annual
Update Gas Analysis Measurement	3 Months	Monthly	Semi-Annual
Update Gas Analysis Production Accounting	3 Months	Monthly	Semi-Annual
ESD High Level Inspection	3 Months	Monthly	Semi-Annual

3) Rotary Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Diaphragm Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

5) Ultrasonic Metering

Table 7.15-4 Stage 1 Ultrasonic Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency - EFM
Ultrasonic Meter Calibration	N/A	6 years	N/A
Temperature Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual
Pressure Transmitter Calibration/Verification	3 Months	Monthly	Semi-Annual
Gas Analysis Sampling	3 Months	Monthly	Semi-Annual
Update Gas Analysis Measurement	3 Months	Monthly	Semi-Annual
Update Gas Analysis Production Accounting	3 Months	Monthly	Semi-Annual
ESD High Level Inspection	3 Months	Monthly	Semi-Annual
Speed of Sound Calculation Independent Verification	3 Months	Monthly	Semi-Annual
Meter Internal Diagnostic Data	3 Months	Monthly	Semi-Annual

6) Coriolis Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

7.15.3. **Stage 2: Average Monthly Raw Volume >25.0e3m3 and ≤150.0e3m3/day**

1) Orifice Metering

Table 7.15-5 Stage 2 Orifice Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency EFM	Possible Reduced Period Frequency Chart
Temperature Transmitter Calibration/ Verification	12 Months	Monthly	Thirdly	Quarterly
Pressure Transmitter Calibration/Verification	12 Months	Monthly	Thirdly	Quarterly
Gas Analysis Sampling	12 Months	Monthly	Thirdly	Thirdly
Update Gas Analysis Measurement	12 Months	Monthly	Thirdly	Thirdly
Update Gas Analysis Production Accounting	12 Months	Monthly	Thirdly	Thirdly
Orifice Plate Inspection	12 Months	Monthly	Thirdly	Quarterly
ESD High Level Inspection	12 Months	Monthly	Thirdly	Quarterly

* Charts recorders will not be acceptable for use with production volumes greater than $60.0e^3m^3$/day.

2) Turbine Metering

Table 7.15-6 Stage 2 Turbine Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency - EFM
Turbine Meter Calibration	12 Months	Semi-annual	Semi-annual
Turbine Meter Inspection	12 Months	Semi-annual	Semi-annual
Temperature Transmitter Calibration/ Verification	12 Months	Monthly	Quarterly
Pressure Transmitter Calibration/ Verification	12 Months	Monthly	Quarterly
Gas Analysis Sampling	12 Months	Monthly	Quarterly
Update Gas Analysis Measurement	12 Months	Monthly	Quarterly
Update Gas Analysis Production Accounting	12 Months	Monthly	Quarterly
ESD High Level Inspection	12 Months	Monthly	Quarterly

3) Rotary Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Diaphragm Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

5) Ultrasonic Metering

Table 7.15-7 Stage 2 Ultrasonic Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency - EFM
Ultrasonic Meter Calibration	N/A	6 years	N/A
Temperature Transmitter Calibration/Verification	12 Months	Monthly	Quarterly
Pressure Transmitter Calibration/ Verification	12 Months	Monthly	Quarterly
Gas Analysis Sampling	12 Months	Monthly	Quarterly
Update Gas Analysis Measurement	12 Months	Monthly	Quarterly
Update Gas Analysis Production Accounting	12 Months	Monthly	Quarterly
ESD High Level Inspection	12 Months	Monthly	Quarterly
Speed of Sound Calculation Independent Verification	12 Months	Monthly	Quarterly
Meter Internal Diagnostic Data	12 Months	Monthly	Quarterly

6) Coriolis Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

7.15.4. Stage 3: Average Monthly Raw Volume >150.0e3m3/day

1) Orifice Metering

Table 7.15-8 Stage 3 Orifice Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency EFM
Temperature Transmitter Calibration/ Verification	12 Months	Monthly	60 days
Pressure Transmitter Calibration/ Verification	12 Months	Monthly	60 days
Gas Analysis Sampling	12 Months	Monthly	60 days
Update Gas Analysis Measurement	12 Months	Monthly	60 days
Update Gas Analysis Production Accounting	12 Months	Monthly	60 days
Orifice Plate Inspection	12 Months	Monthly	60 days
ESD High Level Inspection	12 Months	Monthly	60 days

2) Turbine Metering

Table 7.15-9 Stage 3 Turbine Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency EFM
Turbine Meter Calibration	12 Months	Semi-annual	Semi-annual
Turbine Meter Inspection	12 Months	Semi-annual	Semi-annual
Temperature Transmitter Calibration/Verification	12 Months	Monthly	60 days
Pressure Transmitter Calibration/Verification	12 Months	Monthly	60 days
Gas Analysis Sampling	12 Months	Monthly	60 days
Update Gas Analysis Measurement	12 Months	Monthly	60 days
Update Gas Analysis Production Accounting	12 Months	Monthly	60 days
ESD High Level Inspection	12 Months	Monthly	60 days

3) Rotary Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Diaphragm Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

5) Ultrasonic Metering

Table 7.15-10 Stage 3 Ultrasonic Metering

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency EFM
Ultrasonic Meter	N/A	7 Years	N/A
Temperature Transmitter Calibration/ Verification	12 Months	Monthly	60 days
Pressure Transmitter Calibration/ Verification	12 Months	Monthly	60 days
Gas Analysis Sampling	12 Months	Monthly	60 days
Update Gas Analysis Measurement	12 Months	Monthly	60 days
Update Gas Analysis Production Accounting	12 Months	Monthly	60 days
ESD High Level Inspection	12 Months	Monthly	60 days
Speed of Sound Calculation Independent Verification	12 Months	Monthly	60 days
Meter Internal Diagnostic Data	12 Months	Monthly	60 days

6) Coriolis Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

7.16. Liquid Hydrocarbon Measurement – Frequencies – Operation

The frequencies stipulated for liquid hydrocarbon measurement under a Cross Border designation exceeds the frequencies for liquid hydrocarbon measurement typically found in gathering systems and recognized as condensate or Natural Gas Liquids (NGLs) at flow-line conditions. Liquid hydrocarbon measurement in Cross Border scenarios is typically at flow-line conditions.

If condensate at equilibrium conditions were involved in a Cross Border system, such condensate would be required to meet the frequency requirements in section Operating Principles for dead oil measurement.

7.16.1. **Operating Principles**

There are four Cut-Off Point Stages:

Table 7.16-1 Four Cut-Off Point Stages

Stage	Operand	Volume m^3/day		Operand	Volume m^3/day
1	≤	2.0			
2	>	2.0	And	≤	10.0
3	>	10.0	And	≤	60.0
4	>	60.0			

1) There are two modes:

    a. Initial Period Frequency.

    b. Possible Reduced Period Frequency.

2) On attaining the Cut-Off Point, the operator must move to the next appropriate stage. A Discretionary Allowance of 5% of the Cut-Off Point will be permitted, outside of which the operator will be denied appeal. The cut-off volume will be considered an absolute threshold, i.e., if exceeded then appropriate action must be taken relative to the four stages.

3) The BCER may use data filed for reporting purposes in ascertaining threshold violations.

4) At the discretion of the BCER, a Grace Period of four days may be used to determine if a Frequency Period has been missed. The four days will not be used to spread out the Frequency Period.

5) Data downloads, meter maintenance reports, gas analysis and liquid analysis data for the Cross Border measurement meter information must be kept up to date and made available upon request by the BCER. Only the first Initial Period following the commencement of Cross Border measurement will applicable documentation be required to be forwarded onto the BCER no later than fifteen days following the month of production or as otherwise directed.

6) Initial Period Frequencies must be maintained for the time indicated or until a Reduced Period Frequency approval is obtained.

7) On completion of the Initial Period, application can be made to the BCER to move to a Reduced Period Frequency.

8) The BCER will approve or reject an application to move to the Reduced Period Frequency. Approval to move to a Reduced Period Frequency will involve consideration of the following:

    a. Calibration/verification records.

b. Operator's compliance record with a Cross Border measurement approval. An operator that has had more than three communicated deficiencies relative to Cross Border measurement will be denied the Reduced Period Frequency for a period of three years. A change of operator may allow for a reconsideration of the Reduced Period Frequency.

9) If an operator is following a Reduced Period Frequency mode and production volumes change requiring a stage change, the operator may follow the Reduced Period Frequency for the new stage.

10) Failure to meet an Initial Period Frequency will result in permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages. An inspection/audit that identifies non-compliance at any point in time with an Initial Period Frequency at any stage, past or present, will result in immediate permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages.

11) A Notice will be provided in writing to indicate that the operator has been permanently assigned the Initial Period Frequency at the relevant stage and all future stages. The Notice will also identify that the operator is remanded to the Initial Period Frequency because of not meeting Initial Period Frequency calibrations.

12) Failure to meet a Reduced Period Frequency will result in permanent assignment of the Initial Period Frequency at the relevant stage and permanent assignment of the Initial Period Frequency at all future stages. An inspection/audit that identifies non-compliance at any point in time with a Reduced Period Frequency at any stage, past or present, will result in immediate revocation of a Reduced Period Frequency approval and permanent assignment of the Initial Period Frequency at the relevant stage and all future stages.

13) A Notice will be provided in writing to indicate that the operator has been permanently assigned the Initial Period Frequency at the relevant stage and all future stages The Notice will also identify that the operator is remanded to the Initial Period Frequency because of not meeting Reduced Period Frequency calibrations. Additional requirements, site specific inspections and follow up by the Compliance and Enforcement Branch may result from a failure to meet these requirements.

14) The BCER may relieve or modify a Period Frequency requirement when the operator provides an explanation in writing as to why a Period Frequency was missed. This must be used only in extraordinary circumstances.

7.16.2. **Stage 1: Average Monthly Raw Volume ≤2.0m3/day**

1) Orifice Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

2) Turbine Metering – Delivery Point Measurement

Table 7.16-2 Stage 1 Turbine Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Turbine Meter Calibration/Verification	6 Months	Quarterly	Annual
Temperature Transmitter Calibration /Verification	6 Months	Quarterly	Annual
Pressure Transmitter Calibration/Verification	6 Months	Quarterly	Annual
Liquid Analysis Sampling	6 Months	Quarterly	Annual
Update Liquid Analysis– Measurement	6 Months	Quarterly	Annual
Update Liquid Analysis Production Accounting	6 Months	Quarterly	Annual

3) Positive Displacement Metering

a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Coriolis Metering – Delivery Point Measurement

Table 7.16-3 Stage 1 Coriolis Metering-Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Coriolis Meter Calibration/Verification	6 Months	Quarterly	Annual
Temperature Transmitter Calibration/Verification	6 Months	Quarterly	Annual
Pressure Transmitter Calibration/Verification	6 Months	Quarterly	Annual
Liquid Analysis Sampling	6 Months	Quarterly	Annual
Update Liquid Analysis Measurement	6 Months	Quarterly	Annual
Update Liquid Analysis Production Accounting	6 Months	Quarterly	Annual

7.16.3. Stage 2: Average Monthly Raw Volume >2.0m3 and ≤10.0m3/day

1) Orifice Metering

   a. Due to the infrequent use of this type of metering, please consult the BCER.

2) Turbine Metering – Delivery Point Measurement

Table 7.16-4 Stage 2 Turbine Metering-Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Turbine Meter Calibration/Verification	6 Months	Quarterly	Semi-Annual
Temperature Transmitter Calibration/Verification	6 Months	Quarterly	Semi-Annual
Pressure Transmitter Calibration/Verification	6 Months	Quarterly	Semi-Annual
Liquid Analysis Sampling	6 Months	Quarterly	Semi-Annual
Update Liquid Analysis Measurement	6 Months	Quarterly	Semi-Annual
Update Liquid Analysis Production Accounting	6 Months	Quarterly	Semi-Annual

3) Positive Displacement Metering

   a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Coriolis Metering – Delivery Point Measurement

Table 7.16-5 Stage 2 Coriolis Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Coriolis Meter Calibration/Verification	6 Months	Quarterly	Semi-Annual
Temperature Transmitter Calibration /Verification	6 Months	Quarterly	Semi-Annual
Pressure Transmitter Calibration /Verification	6 Months	Quarterly	Semi-Annual
Liquid Analysis Sampling	6 Months	Quarterly	Semi-Annual
Update Liquid Analysis Measurement	6 Months	Quarterly	Semi-Annual
Update Liquid Analysis Production Accounting	6 Months	Quarterly	Semi-Annual

7.16.4. **Stage 3: Average Monthly Raw Volume >10.0m3 and ≤60.0m3/day**

1) Orifice Metering

    a. Due to the infrequent use of this type of metering, please consult the BCER.

2) Turbine Metering – Delivery Point Measurement

Table 7.16-6 Stage 3 Turbine Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Turbine Meter Calibration/Verification	6 Months	Quarterly	Thirdly
Temperature Transmitter Calibration/Verification	6 Months	Quarterly	Thirdly
Pressure Transmitter Calibration/Verification	6 Months	Quarterly	Thirdly
Liquid Analysis Sampling	6 Months	Quarterly	Thirdly
Update Liquid Analysis Measurement	6 Months	Quarterly	Thirdly
Update Liquid Analysis Production Accounting	6 Months	Quarterly	

3) Positive Displacement Metering

    a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Coriolis Metering – Delivery Point Measurement

Table 7.16-7 Stage 3 Coriolis Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Coriolis Meter Calibration/Verification	6 Months	Quarterly	Thirdly
Temperature Transmitter Calibration/Verification	6 Months	Quarterly	Thirdly
Pressure Transmitter Calibration/Verification	6 Months	Quarterly	Thirdly
Liquid Analysis Sampling	6 Months	Quarterly	Thirdly
Update Liquid Analysis Measurement	6 Months	Quarterly	Thirdly
Update Liquid Analysis Production Accounting	6 Months	Quarterly	Thirdly

7.16.5. **Stage 4: Average Monthly Raw Volume >60.0m3/day**

1) Orifice Metering

   a. Due to the infrequent use of this type of metering, please consult the BCER.

2) Turbine Metering – Delivery Point Measurement

Table 7.16-8 Stage 4 Turbine Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Turbine Meter Calibration/Verification	6 Months	Monthly	60 days
Temperature Transmitter Calibration/Verification	6 Months	Monthly	60 days
Pressure Transmitter Calibration/Verification	6 Months	Monthly	60 days
Liquid Analysis Sampling	6 Months	Monthly	60 days
Update Liquid Analysis Measurement	6 Months	Monthly	60 days
Update Liquid Analysis	6 Months	Monthly	60 days

3) Positive Displacement Metering

   a. Due to the infrequent use of this type of metering, please consult the BCER.

4) Coriolis Metering – Delivery Point Measurement

Table 7.16-9 Stage 4 Coriolis Metering- Delivery Point Measurement

Description	Initial Period	Initial Period Frequency	Possible Reduced Period Frequency
Coriolis Meter Calibration/Verification	6 Months	Monthly	60 days
Temperature Transmitter Calibration/Verification	6 Months	Monthly	60 days
Pressure Transmitter Calibration/Verification	6 Months	Monthly	60 days
Liquid Analysis Sampling	6 Months	Monthly	60 days
Update Liquid Analysis Measurement	6 Months	Monthly	60 days
Update Liquid analysis Production accounting	6 Months	Monthly	60 days

7.17. Oil Measurement Frequencies – Operations

The frequencies stipulated for oil measurement under a Cross Border designation follow this section.

7.17.1. Operating Principles

Oil measurement proving frequencies will be governed by the classification of the oil as follows:

1) Dead oil measurement must be **monthly.**
2) Group oil measurement must be **monthly.**

There will not be consideration given for Group and Test Oil Meter Exceptions or Live Oil and Dead Oil Meter Exceptions for the meters used in the 7.17 above.

The classification will depend on the design of the gathering system and how the oil meters fit into a Cross Border scenario.

1) Turbine Metering – Delivery Point Measurement

Table 7.17-1 Turbine Metering- Oil Measurement- Delivery Point Measurement

Description	Period Frequency
Turbine Meter Calibration/Verification	Monthly
Temperature Transmitter Calibration/Verification	Monthly
Pressure Transmitter Calibration/Verification	Monthly
Liquid Analysis Sampling	Monthly
Update Liquid Analysis Measurement	Monthly
Update Liquid Analysis Production Accounting	Monthly

2) Positive Displacement Metering
   a. Due to the infrequent use of this type of metering, please consult the BCER.

3) Coriolis Metering – Delivery Point Measurement

Table 7.17-2 Coriolis Metering- Oil Measurement- Delivery Point Measurement

Description	Period Frequency
Coriolis Meter Calibration/Verification	Monthly
Temperature Transmitter Calibration/Verification	Monthly
Pressure Transmitter Calibration/Verification	Monthly
Liquid Analysis Sampling	Monthly
Update Liquid Analysis Measurement	Monthly
Update Liquid Analysis Production Accounting	Monthly

For the purposes of this document, calibration or proving frequency has the following meanings:

a. Monthly means at least once per calendar month.

b. Thirdly means at least once each calendar period as follows: January to April, May to August, and September to December.

c. Quarterly means at least once per calendar quarter.

d. Semi-annually means at least once every second calendar quarter.

e. Annually means at least once every fourth calendar quarter.

f. Bi-annually means at least once every eighth calendar quarter.

g. Calendar quarters are January to March, April to June, July to September, and October to December.

7.17.2. **Electronic Flow Measurement for Hydrocarbon Systems**

If an EFM is used to calculate clean hydrocarbon volumes, the operator must be able to verify that it is performing within the BCER target limits defined in this section.

A performance evaluation test must be completed within two weeks after the EFM is put into service and immediately after any change to the computer program or algorithms that affects the flow calculation; documentation must be retained for a minimum of 72 months and provided to the BCER upon request for audit trail purposes. For existing EFM systems, the operator should conduct performance evaluations periodically to ensure that the EFM systems are performing adequately. A performance evaluation must be conducted and submitted for BCER audit on request. The BCER considers either one of the following methods acceptable for performance evaluation:

1) Conduct a performance evaluation test on the system by inputting known values of flow parameters into the EFM to verify the volume calculation and other parameters.

2) The test cases included in this section are for oil/emulsion meters, each with different flow conditions.

Test Cases 1 to 5 are for oil density correction from flowing temperature to 15°C. The hydrometer correction is used to compensate for the glass expansion when used to measure the oil density. Density correction to 15°C is only required for blending shrinkage calculations, mass-based measurement, and the CTL calculation.

Test Cases 6 to 10 are for volume correction using CPL and CTL factors to correct to 101.325kPa and 15°C. Other manufacturers' procedures may also be used to evaluate the EFM performance, provided that the volumes obtained from a performance evaluation test agree to within ±0.1% of those recorded on the sample test cases.

Evaluate the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information must be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

The densities (Test Cases 1 to 5) or volumes (Test Cases 6 to 10) obtained from a performance evaluation test must agree to within ±0.1% of those recorded on the sample test cases. If the ±0.1% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem.

7.17.3. **Test Cases for Verification of Oil Flow Calculation Programs**

Density and volume corrections in the table below are based on API MPMS, Chapter 11.1 (May 2004). The hydrometer correction is based on API MPMS, Chapter 9.3 (November 2002).

The BCER uses the following test cases to verify that an EFM system is correctly calculating oil flow rates. The test cases recognized by the BCER were developed by the AER.

Table 7.17-3 Density Correction to 15 C

	Inputs		Outputs	
	Oil density @ flowing temperature(kg/m^3)	Observed temperature (°C)	Oil density corrected to 15°C (kg/m^3) (with hydrometer correction)	Oil density corrected to 15°C (kg/m^3) (without hydrometer correction)
Test Case 1	875.5	120	942.9	945
Test Case 2	693	11.4	689.9	689.8
Test Case 3	644	84.45	704.7	705.7
Test Case 4	625.5	53.05	660.8	661.4
Test Case 5	779	25	786.7	786.8

Table 7.17-4 Volume Correction Using Pressure and Temperature Correction Factors (CPL and CTL)

	Inputs				Outputs			
	Metered volume (m^3)	Oil density @ 15°C (kg/m^3)	Flowing temperature (°C)	Flowing pressure (kPa [gauge])	CTL to 15°C	CPL to 101.325 kPa	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)
Test Case 6	60	903.5	40.5	700	0.98071	1.0005	58.8	58.9
Test Case 7	15	779	3.9	400	1.0112	1.00034	15.2	15.2
Test Case 8	100	1008	89	3700	.95472	1.00255	95.5	95.7
Test Case 9	250	875.5	5	200	1.00799	1.00013	252	252
Test Case 10	150	640	75	1000	0.90802	1.00365	136.2	136.7

8. Chapter 8- Sampling and Analysis

8.1. Introduction

This section outlines the sampling and analysis requirements for the various categories of production measurement. The requirements vary, depending on a number of factors, such as: production rate, potential for the composition to change over time, and the end use of the fluid. Where appropriate, conditions have been identified under which the sampling and analysis requirements may be altered or eliminated altogether.

8.2. General

Gas and hydrocarbon liquid analyses are required for the determination of gas volumes, conversion of liquid volumes to gas equivalent, and product allocation. Gas density and composition are integral components of gas volume calculations and plant product allocation calculations. The sampling and analysis requirements identified in this section pertain only to those areas that affect the calculations and reporting required by the Ministry.

For differential producing meters, such as orifice meters, venturi meters, and flow nozzles, the accuracy of a computed volume and component allocations are very sensitive to the accuracy of the compositional analysis, which is the basis for compressibility factors and density determination. For linear meters, such as ultrasonic and vortex, the compositional analysis is primarily used to determine the compressibility factors.

Sampling and analysis of oil/emulsion streams at oil batteries/facilities are performed to determine the relative oil and water content of the streams. Sampling and analysis frequencies and updating requirements for the various production types are summarized in the section 8.4 Sampling and Analysis Frequency below. These sampling frequencies are the base requirements for gas and related liquid measurement. Sampling frequencies at a Cross Border Measurement battery/facility must adhere to the requirements outlined in Chapter 7, “Cross Border Measurement” staging tables.

8.2.1. Gas and Hydrocarbon Analysis

The following requirements apply solely to the measurement of Gas and hydrocarbon fluids and are not intended to supersede the business requirements that permit holders are required to meet regarding product allocations:

1. The production accounting system must match the facility design measurement schematic and be reported based on physical flow.

2. The gas and liquid analysis used for measurement must be the same as the gas and liquid analysis reported within the PA system and used for allocation purposes.

3. Gas and liquid analysis reported within the PA system must be supported by actual analysis from a lab unless the analysis is derived.

4. Gas samples taken from the flowline before test separation on effluent metered wells are not permitted to be used to update the gas analysis entered into the EFM.

5. Wells, battery group, compressor stations, and plant inlets with two or three phase separators, where the hydrocarbon liquids and water are produced to a tank, must tie the metered gas volumes to an actual lab gas analysis within the PA system.

6. Wells, battery group, compressor stations, and plant inlets with two or three phase separators, where the hydrocarbon liquids are metered and recombined back into the gas stream, must either tie the recombined gas volume to a recombined analysis, or tie the metered gas volume to a gas analysis and the metered hydrocarbon liquids to a liquid analysis, and have the PA system calculate the recombined volume and recombined analysis. The recombination must utilize a sample/analysis set that was taken on the same date/times for consistency otherwise the sample/analysis set are invalid for measurement and allocation purposes.

7. Effluent metered gas wells producing to a group separator at the battery, where the hydrocarbon liquids and water are produced to a tank, must tie the prorated well gas volume to the well's test gas analysis only, not the recombined gas analysis within the PA system.

8. Effluent metered gas wells producing to a group separator at the battery, where the hydrocarbon liquids are recombined back into the gas stream (or the group separator is the plant inlet separator), must tie the prorated well gas volume to the well test recombined analysis within the PA system.

9. Rich gas (gas with hydrocarbon liquids) a weighted average derived analysis of the wells for battery group, gathering systems and plant inlets must not be used. Actual analysis at the meters will be required. Ideally these rich streams should always use proportional samplers at the group separator for gas and liquids.

10. When a vapour liquid equilibrium (VLE) sample pair is obtained, before the gas and liquid sample can be used for production accounting purpose, the sample integrity must be evaluated using a K-plot to show that both gas and hydrocarbon liquid are in a state of equilibrium and the samples are valid. If the VLE sample pair is not valid, corrective action must be taken and another VLE sample pair obtained.

11. Well, battery, compressor station, and gas plant fuel gas meters should tie the metered volumes to associated source stream gas analysis within the PA system.

12. If liquid condensate produced from gas wells is either recombined with the gas well production or trucked to the inlet of a gas plant for further processing, the compositional analysis from a condensate sample must be used to determine the GEV of the condensate, which must be added to the well gas volume for reporting purposes. A similar procedure applies to gas gathering systems where liquid condensate is delivered to other facilities for further processing and to gas plant inlets. For this reason, the condensate sampling requirements must mirror the gas sampling requirements.

13. If liquid condensate is separated at a well or battery/facility and delivered from that point for sale or other disposition without further processing, the condensate must be reported as a liquid volume. Therefore, a compositional analysis of the condensate is not required for gas equivalent volume determination purposes but may be required for the purposes of the sale.

8.3. **Sampling Requirements**

Sampling must be done in accordance with the Drilling and Production Regulation 67- Analysis of natural gas and hydrocarbon liquid production. [Drilling and Production Regulation- DPR]

Samples and analyses may be obtained by any of the following methods:

1) on-site gas chromatograph (GC)
2) proportional sampling
3) spot or "grab" sampling

Spot or grab samples are acceptable for obtaining gas and liquid analyses once per test or per determination, provided that uncertainty requirements in Chapter 1 are fulfilled. When the uncertainty requirements cannot be met, permit holders must consider more frequent sampling, calculated analyses (see: section 8.4.13), proportional samplers, or chromatographs. For example: If the analysis from one time period to the next is such that the density and/or compressibility changes cause the volume to change by more than the allowable uncertainty, a more frequent analysis is required or an alternative method of obtaining the sample must be used.

The gas and liquid analyses must be updated when operating conditions are significantly altered (i.e., addition / removal of compression or line-heating, addition/removal of production sources in a common stream, wellbore recompletion). If the gas volumes for all meters in the common stream (i.e., sales, fuel, flare, and injection gases) meet the uncertainty guidelines in Chapter 1, the permit holder may use a single gas analysis for all meters on the common stream.

8.3.1. **Sampling Procedures**

1) The Permit holder must locate and identify sampling points to provide a representative sample of the product stream.
2) The analytical company must place a tag where the gas or hydrocarbon liquid sample will be taken. This will ensure consistent sampling.
3) Sample points must not be located within the minimum upstream straight lengths of the meter.
4) Access from grade or platform must be provided for the sample point if required.
5) If sample transfer tubing must be used, its length must be minimized.
6) The sample transfer tubing must be oriented to minimize the potential to trap liquids in gas samples and water in condensate samples.
7) A means must be provided to safely purge sample transfer tubing between the sample point and the connection point of the sample cylinder.
8) There must be no appreciable reduction in pressure and/or temperature between the source and the sample cylinder (i.e., if temperature decreases, this may cause gas to drop below hydrocarbon dew point temperature resulting in a 2-phase condition).

9) Avoid liquid condensation in flow line sample cylinder (omit sample cylinder) by sampling gas upstream of any pressure reducing device.

10) Sample containers must be clean and meet the pressure, temperature, and material requirements of the intended service and have the required regulatory approvals as necessary.

11) The procedures used for sampling, transportation, handling, storage, and analysis must ensure that atmospheric contamination does not occur.

12) The sample containers must be housed in a secured enclosure to prevent any tampering with the sample.

13) Sample lines must be as short as practical and sloped downward to reduce the possibility of plugging up the sample line.

14) Samples must be taken only when a stream is flowing (must not be stagnant or else component stratification may occur within flow line).

15) Samples are not to be taken during periods of chemical injection and therefore the chemical injection point must be located downstream of sample points.

16) H_2S concentration must be measured on site at time of sampling unless there are safety concerns that cannot be mitigated.

The type of analysis must be performed determines the quantity of samples required. A basic routine analysis can be provided within one normal 500cc cylinder; however, a duplicate sample should be collected as back up. Several cylinder sizes in various pressure ranges are available to accommodate special analytical requirements. The laboratory should be consulted to ensure sufficient types and volumes of samples are collected to meet analytical requirements.

All samples must be analyzed using a gas chromatograph or equivalent to determine the components to a minimum of C7+ composition except for sales or delivery points where C6+ composition is acceptable if agreed upon by affected parties. The gas composition analysis must be determined to a minimum of four decimal points (as a fraction of 1.0000) or two decimal points (as a % of 100), and the relative density must be determined to a minimum of three decimal points.

8.3.2. **Fluid Sampling Requirements for Water Cut (S&W) and Density Determination**

Water Cut (S&W) determination procedure including the frequency of sampling must be representative of the entire volume transaction as well as the subsequent S&W sample analysis. There are two methods to obtain this measurement: sampling or on-line analysis using a suitable instrument (water-cut analyzer or product analyzer). Sampling can be categorized by two methods: spot/grab sampling or continuous proportional sampling. It is important that the sample location be carefully selected such that the flowing stream is adequately mixed. This can be achieved by:

1) installing in-line mixers.

2) selecting a sampling point that offers the most practical location for collecting a sample that is mixed, such as after valves, elbows, and reducers.

3) selecting a sampling point that is downstream of a metering point because of the piping elements associated with a meter run; or

4) collecting samples from a number of different locations, analyzing them, and making a selection based on the location that provides the most consistent and reasonable analysis.

Grab or spot sampling may be used if the water cut is below 10% for proration oil testing. Otherwise, continuous proportional sampling or the use of a product analyzer is required.

Water-cut analyzers operate on a number of different principles and often are best suited for specific applications. Analyzers must be installed and maintained in accordance with the manufacturer's specifications.

For a single-well battery/facility or a multiwell group battery/facility, trucking emulsion off-site, the volumes will be determined by the receiving facilities.

For single-well oil batteries with two-phase or three-phase separators delivering produced oil/emulsions by pipeline to another battery/facility, the sample must be taken at or near the oil/emulsion meter using a continuous proportional sampler. An on-line product analyzer is also acceptable for the determination of water cut (see section 9.4.1 Water Measurement and Accounting Requirements for Various Battery / Facility Types for the exception). This is a measurement-by-difference situation at the receiving battery/facility (see section 5.6). For an oil battery/facility with emulsion tanks, the oil and water inventory volumes in the emulsion tanks may be determined by one of the following methods:

1) taking a spot (grab) sample anywhere between the wellhead or separator and the tank and applying the percentage of sediments and water (%S&W) to the tank inventory,

2) using water-indicating paste on the gauge tape to determine the water/oil interface in the tank inventory,

3) using a representative thief sample taken from the tank,

4) taking the average %S&W of the total battery/facility production and applying that to the tank inventory,

5) using the average %S&W of the trucked-out volumes, or

6) deeming the tank inventory to be entirely oil and making changes/amendments based on delivery volumes.

8.3.3. **S&W Determination**

The permit holder must select the most appropriate method for determining the % of S&W. There are three static analysis methods of the sampled fluid generally considered acceptable by the BCER based on the % of S&W:

1) the centrifuge or Karl Fischer method (combined with separate method for sediment determination) for water cuts between 0 and 10%,

2) the graduated cylinder method of a larger sample for water cuts between 10 and 80% and centrifuging the oil emulsion portion, and

3) the graduated cylinder method of a larger sample for water cuts between 80 and 100% and not centrifuging the oil emulsion portion.

Procedures for these three methods are shown in Appendix G – Manual Water-Cut (S&W) Procedures. Any alternative methods must be supported by testing that shows representative results are achieved and these alternative procedures must be made available to the BCER upon request. In some instances, it is possible to use a computer algorithm to determine the oil and water volumes in the emulsion based on the measured densities of the emulsion and the known densities of the oil and water components of the emulsion. The oil and water base densities must be based on an analysis of the actual oil and water production being metered and must be corrected for the temperature at which the emulsion density is measured. Temperature correction for produced water density should be calculated in accordance with API MPMS, Chapter 20.1.

1) For sampling applications where the gas is at or near its hydrocarbon dew point, a sample probe must be used (i.e., any separator application where hydrocarbon liquids are present) for both the gas and hydrocarbon liquid streams.

2) Sample probes must be located at least 5 pipe diameters downstream of any piping disturbances, such as bends, elbows, headers, and tees.

3) The location of the sample point must be such that phase changes due to changes in pressure and/or temperature are minimized. Specifically, for gases at or near their hydrocarbon dew point, sample points must not be located downstream of pressure reducing components, such as control valves, flow conditioners, and regulators, or long lengths of un-insulated piping or within 5 pipe diameters downstream of an orifice plate. Existing separator packages installed prior to a June 1, 2008, will be "grandfathered" to permit an available thread-o-let located downstream of the orifice fitting to be utilized for sampling. However, any temperature measurement device must remain upstream of the sample point.

4) Insulation and heat tracing must be used to eliminate any cold "spots" between the sample point and the entry point into the sample container or gas chromatograph where the sample transfer tubing temperature falls below the hydrocarbon dew point, such as at all separator applications.

5) Sample points used to sample blends of two streams must have provisions for mixing (i.e., upstream static mixer), with due consideration to potential phase changes brought about by a pressure drop associated with the mixing device.

6) Samples are not to be taken off the side of separators/vessels.

7) Suitable sample cylinders and transfer lines must be thoroughly cleaned and free of contaminants prior to sampling.

8.3.4. **Sample Points and Probes**

The sample point location and probe installation requirements that follow apply to all BCER reporting measurement points. A sample probe must be installed according to the requirements below when an installation is relocated (from one location of a production stream to another) or reused for another well or battery/facility.

8.3.4.1. **General Requirements for Both Gas and Hydrocarbon Liquid Sampling**

8.3.4.2. **Additional Requirements for Gas Sampling**

1) Gas samples must be taken off the top of horizontal lines; with an optional location off the side of vertical lines with the use of a sample probe tip sloping 45° downward.

2) Orifice meter impulse lines, or transmitter manifolds lines, must not be used for taking samples.

8.3.4.3. **Additional Requirements for Hydrocarbon Liquid Sampling**

1) Level gauge (sight glasses) connections must not be used for taking samples.

2) A sample probe must be installed for samples to be used to determine water cut when there is emulsion or a mix of water and hydrocarbon, such as two-phase separators. For such applications, the sampling system design must meet the requirements of API MPMS 8.2 with respect to the use of mixers, sample probe location, and design.

3) The location for condensate sample points is the side of horizontal lines as close to the separator/vessel as possible to minimize flashing. An optional location for liquid sample points is the side of vertical lines with the probe tip sloping 45° downward.

4) The location for oil or emulsion sample points is the side of horizontal lines downstream of metering devices to provide "mixing" of the fluid. An optional location for liquid sample points is the side of vertical lines with the probe tip sloping 45° downward.

5) For separator applications, the sample point should be between the separator outlet and the flow/level control valve upstream of the meter, unless a pressure booster pump is used, in which case the sample point is between the pump discharge and the meter.

6) Hydrocarbon liquid samples must be taken from upstream of back pressure valves, dump valves, etc. to minimize flashing.

8.3.5. H2S Sampling and Analysis

This section is applicable to obtaining high pressure samples. Special considerations, such as extra sample(s) or purging, should be taken when obtaining low pressure samples (i.e., boot, treater, stabilizer, acid gas).

Hydrogen sulphide (H_2S) is a reactive molecule, which presents challenges for sampling and analysis of gas mixtures containing it. Typically, H_2S is lost during sampling (and analysis), resulting in underreporting of H_2S concentrations. Factors that affect representative H_2S sampling and analysis accuracy (i.e., the amount of H_2S lost) are the:

1) presence of air, water, or other sulphur-containing molecules.

2) presence of reactive or absorptive sampling container surfaces.

3) presence of a liquid phase, which can absorb H_2S.

4) H_2S concentration.

5) sample pressure and temperature.

6) analysis method; and

7) time lapse between sampling and analysis.

The amount of H_2S lost can be reduced by:

1) proper sample point selection, which minimizes the presence of contaminants such as air, water, and amines;

2) using clean containers made of materials that minimize H_2S reactions or absorption; and

3) minimizing the time between sampling and analysis.

Typical materials of construction for cylinders are stainless steel and aluminum. Inert coated cylinders, glass containers, and non-absorptive elastomer bags can be considered to further minimize H_2S degradation, especially for concentrations of H_2S less than 5000ppm when moisture is present.

The choice of analytical technique also affects the amount of H_2S reported. Instrumental techniques, such as gas chromatography, are typically more precise than chemistry techniques, such as Tutweiler titrations or stain tubes. However, such instrumental techniques are often impractical for well site applications.

Therefore, consideration should be given to method limitations and sample degradation as they relate to the specific reporting requirements in determining the best approach.

See Table 8.3-1 for analysis technique comparison.

With the exception of ppm level concentrations of H_2S in the presence of moisture, a field H_2S determination and a laboratory GC analysis are recommended. These provide a degree of redundancy and a check of the field analysis. Above 5% H_2S, the GC value is typically more reliable. Below 5% H_2S, the higher of the two values should be used. Unexpectedly large variances between lab and field H_2S values need to be investigated.

Table 8.3-1 H_2S Analysis Technique Comparison

Method	Lower detection limit	Advantages	Limitations
On-line GC	500ppm	Real time, accuracy Minimal time lapse	Capital cost, ongoing maintenance
Lab GC	500ppm	Precision, accuracy	Potential degradation during transport (varies with H_2S concentration)
Tutweiler (GPA C-1)	1500ppm	On site	Titration apparatus, reagent quality, variability in operator technique, including visual endpoint detection, computations, mercaptan interference
Stain Tubes (GPA 2377)	1ppm	On site	Poor precision (±25%) Matrix effects, (see manufacturer's specifications)

Analysis by gas chromatography is the preferred method at higher H_2S concentrations.

For H_2S concentrations between 1500 and 5000ppm, both stain tube and Tutweiler values be should be obtained if an on-line GC is not used.

If high accuracy of low-level (below 1500ppm) H_2S concentration is required, consideration should be given to using a low-level sulphur-specific detector, such as a GC sulphur chemiluminescence detector. The use of containers that minimize degradation and the time lapsed between sampling and analysis is recommended in these situations.

8.3.5.1. **On-site Analytical Techniques for H2S Measurement**

On-site measurement of H_2S in natural gas streams can be accomplished by several different methods. The appropriate method should be selected with an understanding of the benefits and limitations of each method.

Length of Stain Tubes (GPA Standard 2377-05): For concentrations below 1500ppm, the most convenient and economical choice is the use of a "length of stain tube." These devices can suffer from some interference, affecting both the precision and the accuracy of the measurements. Nonetheless, for many purposes this technique can provide H_2S measurements of a suitable quality. The understanding is that the measurement uncertainty is potentially less than the risk of H_2S degradation if a laboratory method were employed. If the most accurate measurements are required, a second sample can be collected in a suitably inert container and returned to a laboratory for prompt analysis.

Tutweiler Titration (GPA Standard C-1): This technique is the method of choice for on-site analysis when the concentration of H_2S is greater than 1500ppm. The Tutweiler titration can provide accurate measurements of H_2S using suitably calibrated glassware and chemicals. Operator skill and proper recording of temperatures and barometric pressure are also key elements for this technique.

8.3.5.2. **Instrumental (in-lab) Analytical Techniques for H2S Measurement**

Gas Chromatography with Sulphur Selective Detection (ASTM D-5504-01): Sulphur selective detectors can be coupled with gas chromatographs to achieve a low detection limit for H_2S and other sulphur compounds, such as mercaptans, sulphides, and disulphides. These instruments are ideal for low concentrations ranging from sub ppm up to several thousand ppm. The sulphur selective detectors are much less susceptible to hydrocarbon interferences and can also identify other sulphur-containing compounds in addition to H_2S. Suitable sulphur selective detectors are sulphur chemiluminescence detectors (SCD) and pulsed flame photometric detectors (PFPD).

Gas Chromatography with Thermal Conductivity Detection: Thermal conductivity detectors can be coupled with gas chromatographs to analyze for intermediate to high levels of H2S. H2S can be adequately resolved from hydrocarbon components to allow for specific detection. The columns selected for this type of analysis must offer a good balance between high resolution (specificity of H2S) and low adsorption of H2S. Detection limits for H2S levels as low as 300ppm can be achieved under the right conditions, and the method can also be calibrated for values approaching 100% H2S. The analytical range for these systems should not exceed the linear range of the column and detector combination. Therefore, acceptable calibration ranges must yield a linear calibration curve (minimum 4 points) with an R-squared value of no less than 0.99.

8.3.6. Compositional Analysis of Natural Gas

The two procedures for compositional analysis of natural gas are based on GPA Standard 2286-95: Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography and GPA Standard 2261-00: Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

If a thorough description of the C7+ fraction (molecular weight and density) is required, analytical methods based on GPA Standard 2286 are more accurate and preferred. Specifically, GPA Standard 2286 makes use of a high-resolution column and flame ionization detector to separate and quantify the heavier components (C7+), which is then used for calculation purposes. Extended analysis of natural gases is common but has not been fully standardized; therefore some inter-laboratory bias may occur.

If the C7+ properties are well defined or have been agreed upon by all affected parties, analytical methods based on GPA Standard 2261 are suitable. The principal advantage of the precut method specified in GPA Standard 2261 is that all of the C7+ components can be grouped together into a single sharp chromatographic peak. Grouping of the numerous heavy compounds results in more precise measurement of the combined peak area. The primary disadvantage of GPA Standard 2261 is the lack of information gained with respect to the composition of the C7+ fraction. Inherently, if the composition of the C7+ fraction is unknown, some agreed-upon physical properties must be applied for calculation purposes.

The GC C7+ calibration is also affected, which increases the uncertainty of the C7+ measurement and heating value computation. If detailed information on C7+ physical properties is not available, default values can be applied, as in Table 8.3-2.

Table 8.3-2 Default Values For C7+ Properties *

Component	Molecular mass (grams per mole)	Liquid density (kg/m^3 at 15°C)	Heating value (MJ/m^3)
C7+, Heptanes plus	95.00	735.0	195
*C7+ is a pseudo-compound. The values have in most cases been found to adequately represent the heavier fraction of natural gas samples.			

8.3.6.1. Gas Equivalent Factor Determination from Condensate

GEF is the volume of gas (e^3m^3 at standard conditions) that would result from converting 1.0m^3 of liquid into 1e^3m^3 a gas. GEF is used when there is a requirement to report the gas equivalent volume (GEV) of condensate and other hydrocarbon liquids to the BCER. The GEF of a liquid may be calculated by any one of three methods (see Appendix A – Gas Equivalent Factor (GEF) Determination), depending upon the type of component analysis conducted on the liquid (by volume, mole, or mass fractions) and the known properties of the liquid.

8.4. **Sampling and Analysis Frequency**

8.4.1 Frequency Summary

Table 8.4-1 gives the analysis update frequency for gas and condensate streams. The sampling and analysis of condensate (if applicable) must be done at the same time as the gas sampling. Sampling frequencies are defined as follows:

Initial – an analysis is required within the first six months of operation only, with no subsequent updates required.

Monthly – an analysis is required at least once per calendar month.

Quarterly – an analysis is required at least once per calendar quarter.

Semi-annually – an analysis is required at least once every two calendar quarters.

Annually – an analysis is required at least once every four calendar quarters.

Biennially – an analysis is required at least once every eight calendar quarters.

Calendar quarters are January to March, April to June, July to September, and October to December.

For example, for a biennial frequency, if the last sample was taken in July 2013, the operator has to take another sample by the end of September 2015 (end of the calendar quarter).

New gas and liquid samples must be taken for all new wells and measurement points by the end of the month following the first month of production. For the time period prior to receipt of a new composition, a substitute composition may be used for gas measurement and gas equivalent of liquid calculations. For wells, substitute compositions should be from a well producing from the same pool with similar separator operating conditions or from samples taken during well testing. Compositions taken during well tests should be carefully reviewed prior to use, as samples are typically taken at different conditions from those the well produces at and there are often contaminants in test samples (e.g., nitrogen, frac fluid). For non-well meters, the substitute composition should be as close to what is expected as reasonably possible. If the initial gas volume calculated by a substitute analysis is found to be in error by greater than 2% and the error volume is over $20e^3m^3$/month, retroactive volumetric adjustments must be calculated using the initial gas composition.

Table 8.4-1 Sampling and Analysis Frequencies for Various Types of Facilities

	Type of production battery/facility		Gas rate (e^3m^3/d)	Sample and analysis type	Sampling point	Frequency
Gas wells / batteries / facilities	Gas effluent proration battery (see section 8.4.3)		N/A	Gas / condensate	Test meters or last valid analysis if exempt from testing	At the time of ECF testing, or more frequently at the operator's discretion, or for a set duration as directed by the BCER, unless exempt under section 8.4.4.
					Group meters	Annually > 16.9 e3m3/d Biennially ≤16.9 e3m3/d
	Multiwell group battery or single-well battery		N/A	Gas only	Per meter	Annually first year then biennially after
	Multiwell group battery or single-well battery with condensate		N/A	Gas/condensate	Per meter	Annually >16.9 e3m3/d Biennially ≤ 16.9 e3m3/d
	Gas cycling schemes (See section 8.4.5)	Injection	N/A	Gas/condensate	Per injection meter	Per approval or source requirement (if not in approval)
		Production			Per injection meter	Per approval or semi-annually (if not in approval)
	Gas sales / delivery (see 8.4.6)			Gas only	Per meter	Annually
	Gas plants (see 8.4.7.1)			Gas/condensate	Per meter	Semi-annually
	Gas gathering systems (see 8.4.7.2)		N/A	Gas/condensate	Per inlet meter	Annually > 16.9 e3m3/d Biennially ≤ 16.9 e3m3/d
Conventional oil wells / batteries	Single-well multiwell group (see 8.4.8)	Flared	N/A	Gas only	Per meter	Initial
		Conserved	N/A	Gas only	Per meter	Annually > 16.9 e3m3/d Biennially ≤ 16.9 e3m3/d
	Multiwell proration battery	Primary production and water flood (see 8.4.9)	N/A	Gas only	Per test/group meter per pool	Annually > 16.9 e3m3/d Biennially ≤ 16.9 e3m3/d
		Miscible / Immiscible flood (see 8.4.11)	Production	Gas only	Per test/group meter	Per approval or quarterly (if not in approval)
			Injection		Per meter	Per approval or monthly (if not in approval)
Water source well/battery	Single-well / multiwell group battery	N/A	N/A	Gas only (if present)	Per well	Initial

Permit holders must ensure that analysis data are used to update volumetric calculations by the end of the month following the receipt of the analysis report. The only exception is for effluent wells, for which the analysis must be updated by the end of the second month following receipt of the analysis report. If sampling and analysis are conducted for other purposes (e.g., joint venture and allocation agreements) more frequently than required by this Guideline, the permit holder must use those data to update volumetric calculations and PA systems for allocation purposes.

8.4.2. **Measured Gas Well**

Gas and hydrocarbon liquid samples must be obtained within 30 days of a well being put online and annually thereafter. Respective analyses must be utilized within 60 days for volumetric calculations and product allocations.

8.4.3. **Multiwell Effluent Proration Battery**

Gas and hydrocarbon composition analysis must be updated and aligned with the minimum testing frequency of each effluent well and as follows:

1) Annually at the group gas and condensate meters if the daily group gas rate is > 16.9 e3 m3.

2) Biennially at the group gas and condensate meters if the daily group gas rate is ≤ 16.9 e3 m3.

The gas analysis used for volumetric calculations in the effluent meter may utilize one of the following two options:

Option 1: Use the separated gas analysis from the most recent effluent well test.

Option 2: Use the recombination of the gas analysis and the hydrocarbon analysis from the most recent effluent well test. This option should only be considered if hydrocarbon liquids are recombined back into the gas stream.

It should be noted that either option is acceptable by the BCER; however, operators must make certain that all wells within a reporting battery/facility all utilize the same option when updating applicable well analysis for volumetric calculations.

For effluent proration batteries where all the wells qualify for exemption from LGR testing as they meet the facility/battery level LGR and CGR requirements, the BCER will allow the use of the group separator sample analysis which must be applied at the well level. The effluent proration battery group gas and condensate must be sampled annually if > 16.9 e3m3/d and biennially if ≤ 16.9 e3m3/d. There will be an option to test/sample higher LGR wells if required or at the operator's discretion. The respective analysis must be utilized within 60 days for volumetric calculations and product allocations. Wells installed after June 1st 2013 require sample probes (Refer to sections 8.3.1 & 8.3.2) to be installed for the purposes of obtaining gas samples should a well be exempt from LGR testing.

8.4.4. **Sampling and Analysis Exception**

A permit holder is not required to update the analyses in the meter where three consecutive gas relative density (RD) determinations were conducted at the specified determination frequency or, alternatively, no more frequently than once per year when all are within ±1.0% of the average of the three RDs. Records and data in support of this exception must be retained by the permit holder and made available to the BCER upon request. Notwithstanding this exception, the permit holder must update the gas analyses when changes are made to producing conditions that could affect the gas density by more than ±1.0% of the average of the three qualifying RDs.

A permit holder may utilize a representative analysis for all wells producing to a common gathering system or battery/facility from a common pool if a well daily average liquid condensate volume is less than or equal to 2.0 m3/d for all reporting months in the previous three years and/or the GEV of the condensate is less than or equal to 2.0% of the recombined total monthly gas volume. The permit holder may apply a pool exemption as described in the example below.

Table 8.4-2 Relative Densities Pool Exemption Example

Well	RD	Difference from average
100/01-01-101-01W7/00	0.602	-0.99%
100/02-01-101-01W7/00	0.610	+0.33%
100/03-01-101-01W7/00	0.602	-0.99%
100/04-01-101-01W7/00	0.616	+1.32%
100/05-01-101-01W7/00	0.608	0.00%
100/06-01-101-01W7/00	0.616	+1.32%
100/07-01-101-01W7/00	0.606	-0.33%
100/08-01-101-01W7/00	0.604	-0.66%
Average	0.608	

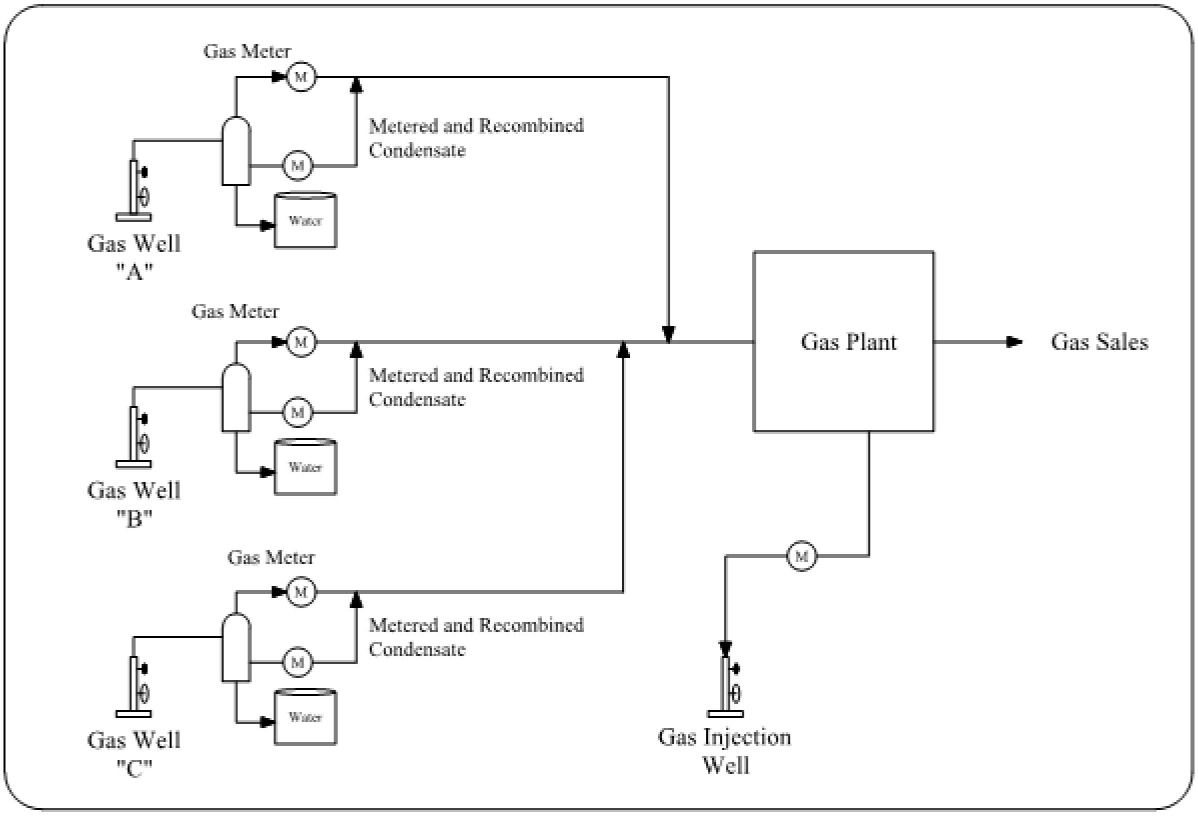
In this case, the analyses from the well with the RD closest to the average (100/05-01-001-01W7/00) for all well meters should be used. The analysis must then be updated annually for (4) wells or 25 %, whichever is greater, and used for all the wells in the pool. This exception will remain in place, provided that the (4) wells or 25 %, whichever is greater, continue to be within ±2.0% of the average of all the RDs. When this criterion is not met, analyses must revert to annual updates for all wells.

In the above situations, there is no need for an application to be submitted to the BCER. Records and data in support of these exceptions must be retained by the permit holder and made available to the BCER upon request. Notwithstanding these exceptions, the permit holder must update the gas analyses when changes are made to producing conditions that could affect the gas RD by more than ±1.0% of the average of the three qualifying RDs, and the permit holder must update the condensate analyses if the liquid condensate volume or GEV% increases beyond the qualifying limits (2.0m^3/d and/or 2.0% respectively).

8.4.5. **Gas Cycling / Injection Scheme**

In the configuration in Figure 8.4-1 Gas Cycling / injection Scheme, analyses must be updated at each well meter and the injection well meter in accordance with the specific scheme approval. If there are no frequencies specified in the approval, the well meters must have analyses updated semi-annually and the gas injection meter(s) must have analyses updated in accordance with the source requirements (i.e., semi-annually for gas plant gas).

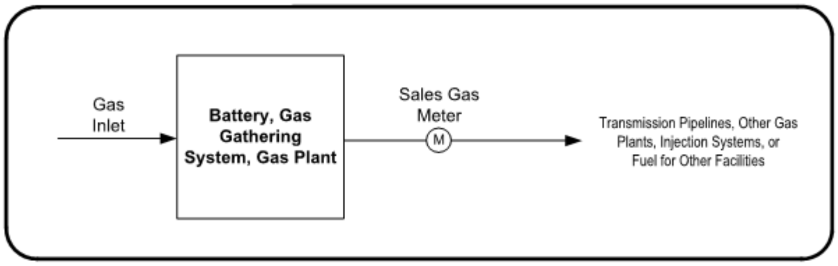
Figure 8.4-1 Gas Cycling / injection Scheme



8.4.6. Gas Sales / Delivery

In the configuration in Figure 8.4-2, gas sales/delivery in this context will typically be clean, processed sales gas that is delivered out of a gas plant or a battery/facility into a transmission pipeline. The measurement at this point determines the gas volumes upon which royalties will be based. In some cases, this type of gas may be delivered to other plants for further processing or fuel or to injection facilities.

Figure 8.4-2 Gas Sales / Delivery



If a meter is used to determine the sales gas/delivery point volume from a battery/facility, gas gathering system, or gas plant, the minimum gas analysis frequency is annual. However, a continuous proportional sampler or a gas chromatograph should be installed to provide more accurate analyses for the gas volume calculation.

8.4.7. **Gas Plants and Gas Gathering Systems**

In the configuration in Figure 8.4-3, only one sample point is required for common gas streams, such as sales gas, which may also be used for fuel, injection, and sales gas flare. An inlet gas sample may be used for inlet gas flare.

The frequency for sampling and analysis is as follows unless a different frequency has been specified in site-specific approvals, such as gas cycling or miscible/immiscible flood schemes. For gas sales measurement point sampling frequency, see section 8.4.6 Gas Sales Delivery.

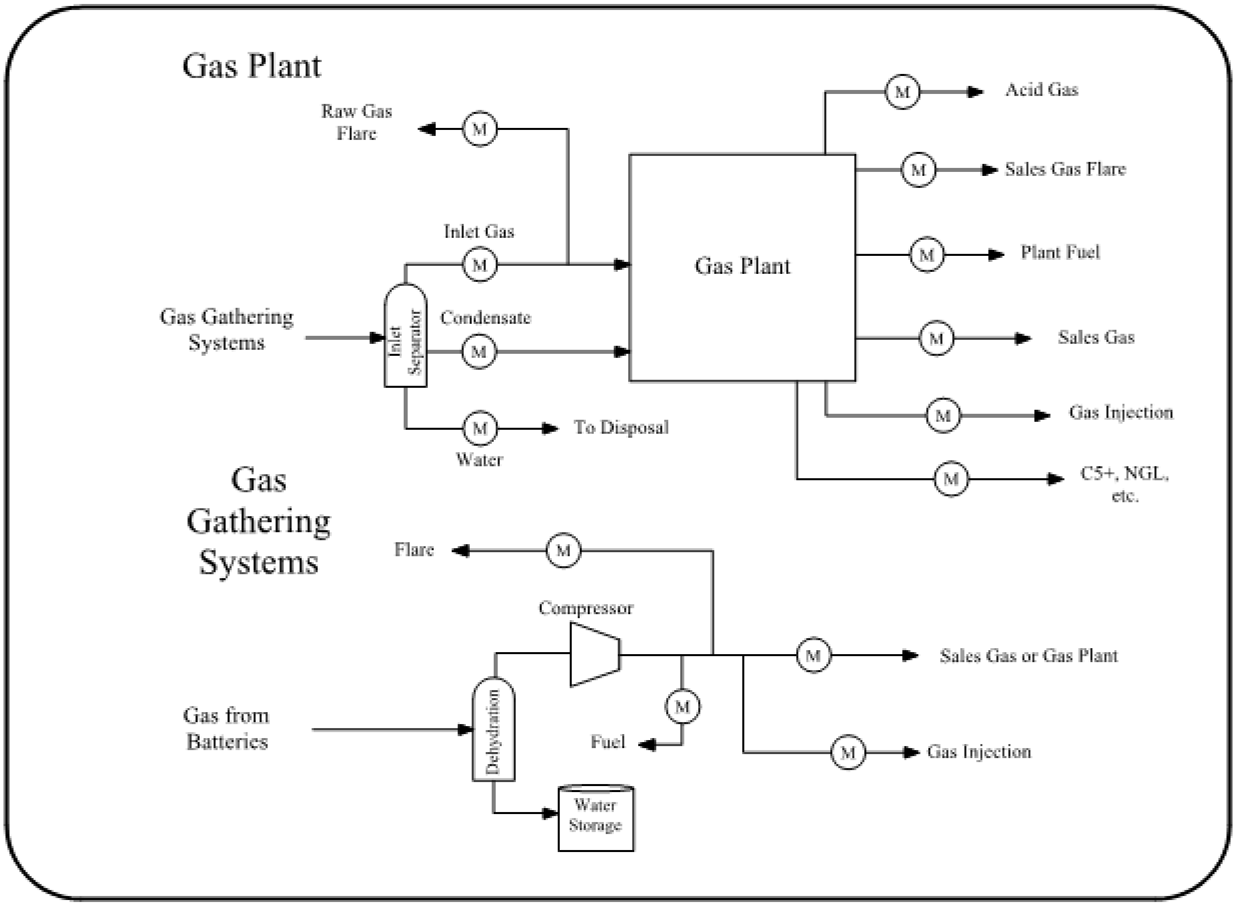
8.4.7.1. **Gas Plants**

The minimum frequency for updating analyses at all reporting meters, including inlets, within gas plants is semi-annual. Inlet condensate is usually reported as a GEV, so analyses are required. High-vapour pressure liquids, such as pentanes plus and NGL, must be reported as liquid volumes on Petrinex, which will then perform the GEV calculation automatically using standard factors for plant balancing.

8.4.7.2. **Gas Gathering Systems**

The minimum frequency for updating analyses at all reporting meters within a gas gathering system (GGS) is annual for all flow rates that exceed 16.9 e3 m3 /d. If the flow rate is less than or equal to 16.9 e3 m3 /d, the frequency is biennial. The flow rate is to be based on a monthly average. Condensate volumes recombined with gas for delivery to other facilities must be reported as GEV, so analyses are required for updating GEFs. Where condensate is delivered out of a GGS without further processing, it is reported as a liquid volume, but analyses for GEV calculation purposes are required for reporting on Petrinex.

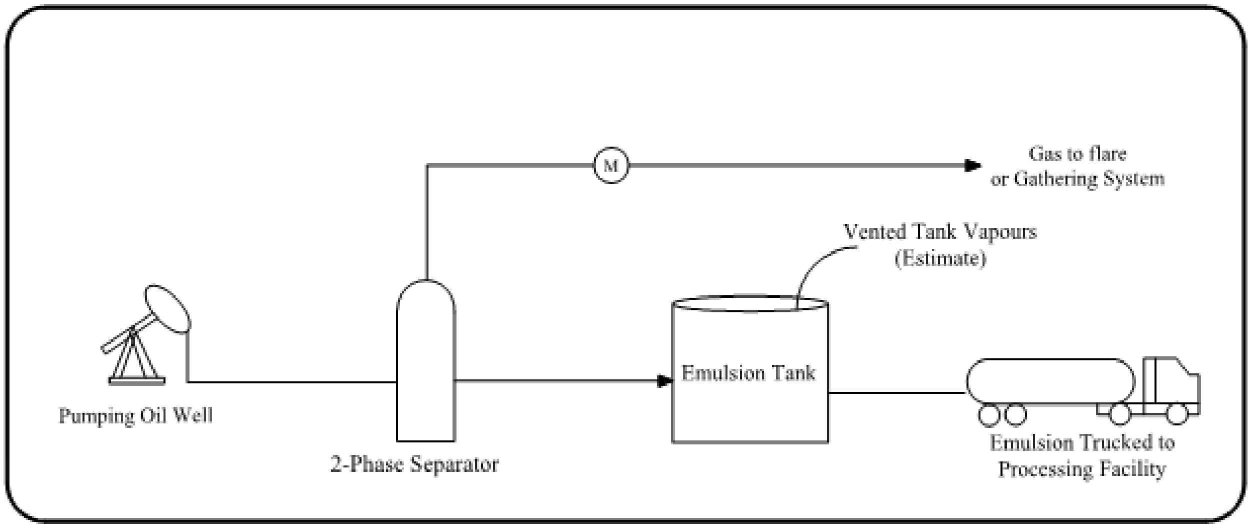
Figure 8.4-3 Gas Gathering Systems



8.4.8. **Conventional Oil Facilities**

In the configuration in Figure 8.4-4, if all solution gas (net of lease fuel) is flared, an initial representative gas analysis is required. If gas is conserved, gas analysis updates are required. If the average flow rate exceeds 16.9 e3 m3 /d, the frequency is annual. If the average flow rate is less than or equal to 16.9 103 m3 /d, the frequency is biennial.

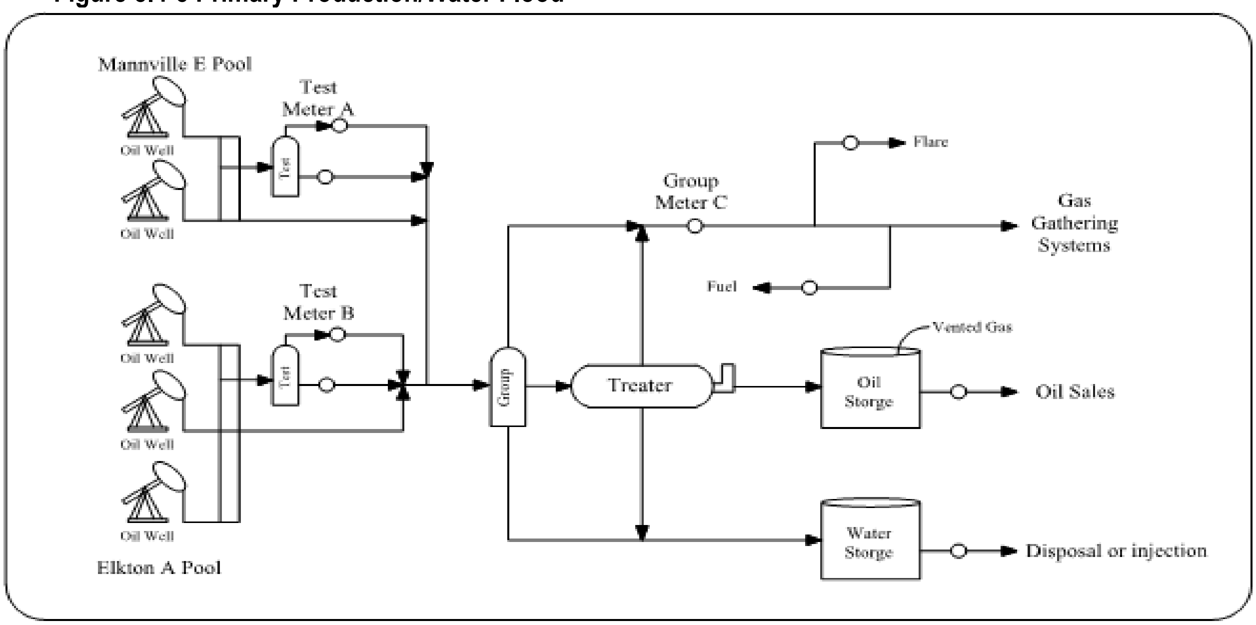
Figure 8.4-4 Single-well or Multiwell Group Oil Battery / Facility



8.4.9. Multiwell Proration Oil Battery / Facility

In the configuration in Figure 8.4-5, the gas analyses must be updated at the test meters (A and B) biennially for maximum test gas rates up to 16.9 e3 m3 /d or annually if the maximum test gas rates exceed 16.9 e3 m3 /d.

Figure 8.4-5 Primary Production/Water Flood



It is acceptable to use the gas analysis from a single representative well for all wells within a single pool. If wells from more than one pool are directed through the same test separator, an analysis must be obtained for each pool.

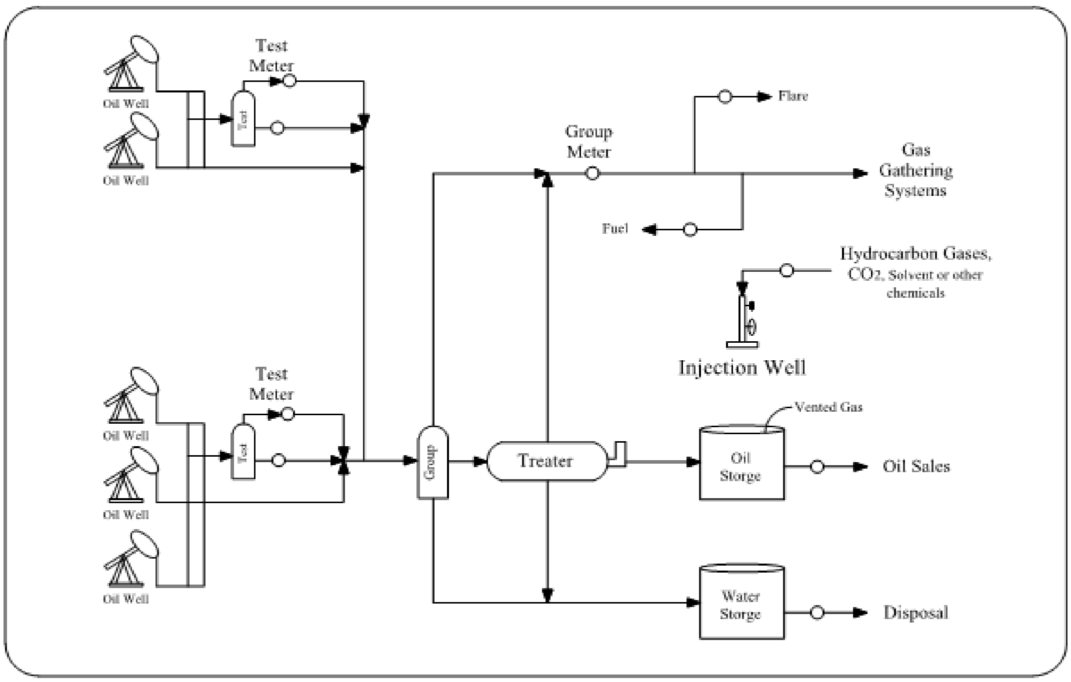
The gas analysis at meter C must be updated annually for gas flow rates exceeding 16.9 e3 m3 /d or biennially if the total rate through the meter is less than or equal to 16.9 e3 m3 /d (based on the monthly average flow rate).

8.4.10. **Exception**

If the total battery/facility gas, net of lease fuel, is flared, an initial pool gas analysis must be determined at meters A and B in Figure 8.4-5. Updates of the gas analysis at meter C, at the annual or biennial frequency as determined by the gas flow rate through the meter, is only required if the gas directed through meter C originates at multiple pools. If the gas directed through meter C originates at a single pool, no updates are required after the initial analysis. However, this exception is revoked as soon as the gas is conserved, and gas analyses must be performed according to the frequencies specified above.

8.4.11. **Miscible/Immiscible Flood**

Figure 8.4-6 Miscible / Immiscible Flood



In the configuration in figure 8.4-6, analyses must be updated at each test and group meter and the injection well meter in accordance with the specific scheme approval. If there are no frequencies specified in the approval, the test and group meters must have analyses updated quarterly and the injection meters must have analyses updated monthly.

8.4.12. **Engineering Data**

Specific constants are used in calculating the GEF. **Absolute density of liquids should be used instead of relative density.**

The examples in Appendix A – Gas Equivalent Factor (GEF) Determination present the different methodologies used to calculate the GEF.

All physical properties are based on GPA Standard 2145-03 (2003 or later) published data.
1kmol = 23.645m^3 @ 101.325kPa and 15°C

8.4.13. **Calculated Compositional Analyses**

In some instances, representative sampling of a hydrocarbon stream is not possible or feasible because of economics, and calculation of a fluid composition is required, as described below.

Calculated Well Stream Analysis: It is not possible to accurately sample multiphase streams, so the composition of a recombined well stream must be determined by calculation. Such an analysis is typically not used for measurement, as it represents a multiphase fluid stream and most gas is measured as single phase. However, some companies use this analysis for calculation of gas volumes from wet-multiphase measured wells. Calculated well stream analyses are most commonly used in product allocation calculations.

Calculated Group Analysis: It is often difficult to accurately determine the average composition of fluids at a commingled group measurement point, as wells/sources to the group system flow at different rates and the composition is constantly changing. The options for sampling these streams are on-line gas chromatographs or proportional sampling systems. However, if the options are not practical or economical, a flow-weighted calculated analysis may be a viable option. Calculated Single Analysis: Sometimes a single analysis cannot represent the composition for an entire measurement period. In such cases, multiple analyses of a single point must be combined to determine the composition for the period. An example of this is a sales gas stream where a proportional sample is taken weekly but a single composition for the month is required. The principles to be followed for each of these calculated analyses are below.

8.4.13.1. **Calculated Well Stream Compositional Analysis**

This type of analysis applies to wells only and is meant to represent the hydrocarbon fluid composition produced from a well and/or delivered to a gathering system. In most cases, it represents the composition of hydrocarbons being produced from the reservoir. The calculation is a flow-weighted recombination of the hydrocarbon gas and liquid streams. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The gas and liquid flow rates are strongly recommended to be used from the same day that the gas and liquid samples were obtained. Use of flow rates from a different period of time than the sample date can result in significant errors because both flow rates and composition will change with changes in process conditions (primarily temperature and pressure); applying flow rates from different periods does not recognize these changes.

Flow rates from the day of sampling are strongly recommended to be used in determining recombined compositions, with the following exceptions:

1) When the daily liquid-to-gas ratio is constant, volumes from an extended period (i.e., multiday, up to monthly) may be used.

2) If some of the liquid stream is not recombined in a month (i.e., it dropped to tank), the composition (flow volume) of the liquids not recombined must be deducted from the initial recombined composition. This is typically done by recalculating the recombined composition with new flow rates, typically the flow rates for the month.

See the example in Appendix F – Calculated Compositional Analysis Examples.

8.4.13.2. Calculated Group Compositional Analysis

This type of analysis is a flow-weighted representation of the hydrocarbon fluid composition produced from a group of wells or meter points. It is often used at commingled group points (inlets, compressors, certain process points) where it is difficult to obtain representative samples using spot sampling techniques. Ideally, proportional samplers should be employed in such situations. However, when proportional sampling is not practical or possible, a calculated group analysis can be determined based on the volume and composition of the wells/meters that flow to the commingled point. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The flow volumes used for each well/meter must be "actual" measured volumes for the period that the analysis is being calculated for, typically monthly.

For example, five gas wells producing from different pools with different composition deliver gas to a compressor station where the gas is metered. Accurate spot sampling at the compressor station is difficult due to changing flow rates at the wells. Using spot samples taken at the wells and monthly flow rates, the producer calculates a group analysis for the compressor station meter. Care must be taken when separator liquids are produced that all hydrocarbons are correctly accounted for, regardless of the phase.

8.4.13.3. Calculated Single Compositional Analysis

This type of analysis is a flow-weighted representation of the hydrocarbon fluid composition determined at a single sample point. It is typically used at sample points that have variable compositions and are sampled frequently (i.e., weekly) using spot or proportional sampling. Ideally, proportional samplers or gas chromatographs should be employed in such situations. However, when proportional sampling is not practical or possible, a calculated single analysis can be determined based on the volume and composition of a group of analyses at the sample point. The accuracy of the flow rates used in this calculation is as important as the gas and liquid composition. The flow volumes used for each sample must be "actual" measured volumes for the period that the analysis is representative of. For example, a producer takes spot samples of an inlet stream weekly because proportional sampling or on-line sampling is not practical. Using weekly flow rates, the producer calculates a monthly flow-weighted composition of the inlet stream.

9. Chapter 9- Liquid Measurement

9.1. Introduction

This Chapter presents the requirements for all liquid hydrocarbon and water measurements from wells and batteries/facilities in the upstream oil and gas industry used in determining volumes for reporting to the Ministry. Liquid measurement requirements at a Cross Border Measurement battery/facility must adhere to the requirements outlined in Chapter 7 – Cross Border Measurement.

9.2. General Hydrocarbon Liquid Measurement Requirements

9.2.1. Application of API Measurement Standards

For hydrocarbon liquids, the API MPMS provides requirements for custody transfer measurement. For the purposes of this Chapter, the degree of application of the API MPMS is determined by the level of uncertainty as required in Chapter 1- Standards of Accuracy.

9.2.2. System Design and Installation

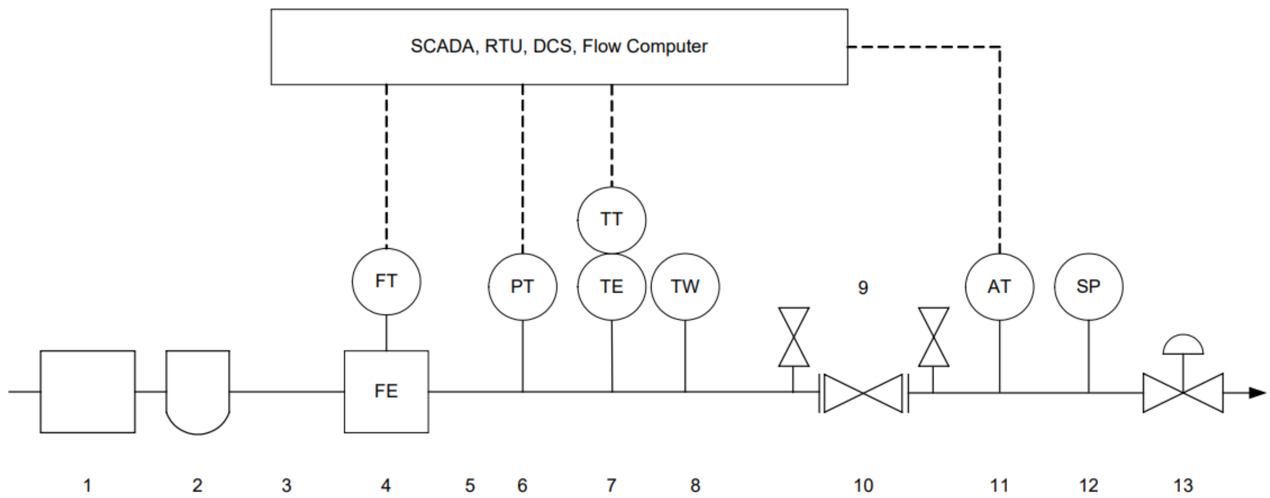
The meter system design must meet the overall uncertainty requirements of Chapter 1- Standards of Accuracy. The BCER considers a liquid measurement system to be compliant if the requirements in this section are met. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.2, is considered to have met the audit trail and reporting requirements, but a performance evaluation is still required in accordance with section Performance Evaluation of this Guideline.

Liquid measurement systems typically consist of a primary measurement element, such as a meter; secondary measurement devices, such as temperature and pressure transmitters, and in some cases, differential pressure transmitters, level transmitters, and densitometers; and tertiary devices collectively termed electronic flow measurement (EFM) (e.g., distributed control system [DCS], supervisory control and data acquisition system [SCADA], and flow computers). In some cases, mechanical totalizers are used in place of EFM. Components of a liquid measurement system are shown in figure 9.2-1.

The meter and its associated peripheral equipment, such as strainers and air eliminators (where installed), proving valves, and piping must be designed and installed according to applicable procedures accepted by an appropriate industry technical standards association or the manufacturer's recommendations.

For delivery point applications where in-line proving must be performed, proving taps and a double block and bleed divert valve must be installed. For positive displacement and coriolis meters, proving taps may be upstream or downstream of the meter if a ball prover, pipe prover, or master meter is used. For other types of linear meters or tank provers, the proving taps must be downstream of the meter.

Figure 9.2-1 Typical Liquid Measurement System



Components

1) Strainer
2) Air eliminator
3) Upstream straight lengths
4) Meter
5) Downstream straight lengths
6) Pressure transmitter (if required)
7) Temperature transmitter
8) Check thermowell
9) Prover valves
10) Double block and bleed prover divert valve
11) Analyzer (e.g., water cut, densitometer)
12) Sample point (manual or on-line)
13) Flow control valve

Notes

1. Schematic is generic in nature and therefore all elements may not be required for a specific application or in that order. For example, for water meters, pressure, and temperature transmitters for compensation to standard conditions are not normally required.
2. Air eliminator is mandatory for truck unloading applications but typically not required for pipeline applications.
3. Strainer required for most but not all meter types.
4. Upstream and downstream meter straight length requirement varies with meter type and upstream piping disturbances.
5. Flow transmitter (FT) may be close coupled to flow sensor (FE) or remote mounted.
6. Analyzers are typically water-cut monitors or densitometers.
7. Flow control valve may be upstream of prover taps for test separator applications.
8. No components such as analyzer fast loops or pressure relief valves should be between meter and prover taps.
9. Pressure relief valves should be located to preclude unmeasured fluids via a leaky relief valve.

9.2.3. Meter Selection

Appropriate engineering practice is required for selection of meter type and size. Specifically, parameters such as the following must be considered:

1) process operating conditions (e.g., pressure, temperature, flow rate),
2) fluid properties (viscosity, density, contaminants, bubble point),
3) required accuracy to meet Chapter 1 uncertainty requirements,
4) meter pressure drop,
5) required straight lengths, and
6) required back pressure.

Parameters known to vary with operating conditions, such as fluid properties (e.g., viscosity) and flow rate, should be considered for all operating scenarios (e.g., start-up, normal, and upset).

If meters are used for delivery point measurements, electronic temperature compensation is required. For existing mechanical automatic temperature compensated meters without gravity selection (ATC) or with gravity selection (ATG), see section 10.4.1 Meters for grandfathering criteria.

In addition to the meter selection parameters listed above, some upstream applications (e.g., propane sales loading rack at gas plants) may also have to meet Measurement Canada requirements.

There are two broad meter types, linear and differential (nonlinear) producer. The output of linear meters is proportional to flow rate. The output of differential producers is proportional to the flow rate squared. Table 9.2-1 lists various meter types for volume determination.

Table 9.2-1 Meter Types

Linear meters	Nonlinear meters
Positive Displacement	Orifice (see section 4.4.1)
Turbine	Venturi
Vortex	Flow nozzle
Coriolis	Cone
Ultrasonic	Wedge
Magnetic (water or conductive fluids only)	Other differential devices

9.2.4. Shrinkage

For the purpose of this Guideline, "shrinkage" refers to a volume reduction associated with one or both of the following two processes:

1) blending of hydrocarbon streams of varying density, and/or
2) loss of volatile components through vaporization (e.g., flashing, weathering) due to a pressure reduction and/or temperature increase or to continued exposure to atmospheric conditions (e.g., conversion of live oil to stock tank conditions).

Petrinex-reported shrinkages other than the above, system loss/gains across facilities, or pipeline systems are outside the scope of this Guideline.

9.2.4.1. Live Oil Shrinkage

Until produced hydrocarbon fluids are stabilized, the oil is normally at its bubble point (equilibrium vapour pressure) condition due to the presence of volatile components. When the oil is discharged to a stock tank at atmospheric condition, the volatile components in the oil evaporate, causing a reduction in liquid volume. When live oils are metered (e.g., test separators), a shrinkage factor must be applied to correct the measured liquid volume from the metering pressure and temperature to stock tank conditions. When the meter is proved to stock tank conditions, the shrinkage factor is incorporated into the meter factor.

9.2.4.2. Hydrocarbon Blending and Flashing Shrinkages

When hydrocarbon molecules of different molecular sizes and intermolecular spacing (i.e., density) are mixed, the smaller molecules fill the spaces between the larger molecules. This results in a volume reduction from the arithmetic sum of the volumes of the blend components. The magnitude of this volume reduction is a function of the relative density and volumes of the hydrocarbon blend components. Calculation of shrinkage factors resulting from hydrocarbon blending without flashing must be performed in accordance with API MPMS, Chapter 12.3, or an equivalent practice supported by sound engineering practices.

In some cases, volume reduction is a combination of the effects of loss of volatile components and intermolecular spacing. The condensate can be introduced in the flow line from the well, at the inlet separator, at the treater, at the storage tank, or at any combination of the above. If condensate is blended with the oil prior to the treater, condensate flashing may also occur.

Blending shrinkage must be determined if the density difference between the hydrocarbon fluids exceeds 40.0kg/m^3 and must be reported if the shrinkage volume causes the delivery point volume to shrink by more than 0.1% and more than the 0.1m^3 reporting limit in Petrinex; permit holders require written permission for this to occur. Flashing shrinkage must be determined if the added diluent volume is > 2.0 m3 /day and/or > 5.0 per cent of total oil production.

The blending and flashing shrinkage is to be reported as an "SHR" disposition of the facility, and the flashing shrinkage is to be reported as a GEV of diluent receipt (REC) into the facility. When reporting the shrinkage, either flashing or blending shrinkages must be applied to the diluent volume, and the (heavier) oil volume must not be reduced by the shrinkage.

9.2.4.3. **Shrinkage Factor Determination**

Live oil shrinkage with entrained gas must be determined by any one of the following techniques:

1) process simulation software,
2) manual sampling and laboratory procedure (see API MPMS, Chapter 20), or
3) physically degassing the prover oil volumes during meter proving of live oils (see section 2.6.1).

Calculation of shrinkage volumes or factors is most often used to mitigate safety and environmental concerns if the live oil volumes are metered at high pressures or if the live oil contains H_2S.

When the manual sampling and laboratory method is used, the shrinkage factor must be based on analysis of a sample of the fluid taken at normal operating conditions. Shrinkage factors must be determined at either a well or battery/facility level. The frequency of shrinkage factor determination should reflect changes in reservoir or operating conditions. Whenever the operating conditions change to a degree that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based upon analysis of a sample of the fluid taken at the new operating conditions.

9.2.4.4. **Shrinkage Factor Application**

Shrinkage factors must be applied by being:

1) incorporated into a meter factor by degassing during proving, or
2) incorporated into a meter factor by adjusting the meter factor numerically based on a

   shrinkage factor determined by process simulation or sampling/analysis, or
3) applied to metered volumes after they are adjusted by the meter factor.

Caution is required to ensure that shrinkage is not applied more than once (i.e., degassing during meter proving and then applying it again as a factor to measured volumes).

9.2.5. **Temperature Measurement**

Temperature measurement used for volume correction must be representative of the actual fluid temperature. Total monthly oil volumes for wells (production) and batteries (production, receipts, dispositions, and delivery point) must be reported in cubic meters at a standard temperature of 15°C and rounded to the nearest tenth of a cubic meter ($0.1m^3$). Battery/Facility opening and closing inventory volumes for monthly reporting must be rounded to the nearest $0.1m^3$ but do not require correction to 15°C. The temperature correction (Correction for the effect of Temperature on Liquids [CTL]) factor must be determined in accordance with API MPMS, Chapter 11.1.

In a proration oil battery/facility, if well test oil volumes are determined by a meter, temperature compensation must be applied using one of the following methods:

1) Apply a composite meter factor that incorporates a CTL factor. To arrive at a composite meter factor, divide the temperature corrected prover volume by the indicated meter volume for each prover run.
2) Apply a CTL factor in real time using an electronic flow measurement system.
3) Apply a CTL factor to the total test volume based on a single temperature measurement taken during the test.

Temperature effects can increase the uncertainty associated with liquid hydrocarbon and water measurements. The magnitude of the effect of temperature measurement errors increases with decreasing hydrocarbon density as illustrated in Table 9.2-2.

Table 9.2-2 Temperature Measurement Error Impact

Fluid	Approximate error per 1°C temperature measurement error (%)
Propane (510 kg/m^3@15°C)	0.29
Butane (600 kg/m^3@15°C)	0.18
Condensate (700 kg/m^3@15°C)	0.12
Crude oil (820 kg/m^3@15°C)	0.09
Crude oil (920 kg/m^3@15°C)	0.07
Water	0.02

Temperature compensation of metered hydrocarbon volumes must be provided as required to meet the uncertainty requirements detailed in Chapter 1 and the requirements of this section. This applies to delivery point measurement, provers, and others (e.g., LACT) that require temperature compensation for volumetric determination.

Thermowells or direct insertion temperature elements must be used for all temperature measurements. Pipe or meter body skin temperature measurements, such as those used by coriolis meter, are not acceptable unless proven to be within the uncertainty requirements.

Thermowells must be installed in such a manner to be representative of the fluid temperature. Thermowells must not be installed in sections of piping where flow may not be present (e.g., dead-ended piping) or in a storage tank above the normal liquid level.

With the exception of coriolis or PD meters, thermowells must be installed 5 to 10 pipe diameters (D) downstream of the meter for liquid applications. For coriolis or PD meters, thermowells must be installed within 10 pipe diameters upstream or downstream of the meter. Valves or pipe restrictions must not be present between the thermowell and the meter's primary measurement element. Meter runs designed for trucked liquid measurement with the existing thermowell(s) within 20 D of the meter are grandfathered for the existing location and usage if installed by June 1 2008. If the meter run is modified or relocated, then the above requirements must be met.

Resistance temperature devices (RTD) are the preferred temperature measurement element. Other types of temperature measurement elements, such as thermocouples and thermisters, are acceptable provided that uncertainty requirements are met. Dial thermometers are not acceptable for pipeline-based delivery point measurement.

For pipelined delivery point and custody transfer measurements, two thermowells must be provided (i.e., one for measurement, one for verification). Mechanical temperature compensators are not acceptable for new installations. For existing installations (installed before June 1, 2008), mechanical temperature compensators are acceptable if the operator can show that the uncertainty requirements of Chapter 1 are met.

Temperature measurement type, resolution, tolerances, and verification/calibration frequency are detailed in table 9.2-3 below.

Table 9.2-3 Temperature Measurement Type, Calibration Frequency, Resolution and Verification Tolerances

Application	Temperature measurement type[1]	Minimum resolution (°C)	Maximum Verification tolerance (°C)[3]	Verification/Calibration frequency[2]
Delivery point with meter	Continuous with EFM	0.1	± 0.5	Monthly[3]
Custody transfer	Continuous with EFM	0.1	± 0.25	Monthly[3]
Well oil (proration battery)	Composite meter factor or continuous with EFM	0.5	± 1.0	Annual
Plant inlet or total battery group condensate (gas gathering system)	Continuous or composite meter factor (See Section 9.2.5)	0.5	± 1.0	Semi-annual
Delivery point batch volumes into a pipeline or receipt at a battery / facility using tank gauging	One reading per load	0.1	± 0.5	Semi-annual
1. For mechanical ATCs, see section 10.4.1 Meters				
2. The verification/calibration must be done at the time of the meter prove.				
3. Calibration must be done if the verification tolerance is exceeded.				
4. The verification/calibration frequency may be changed to bimonthly if three consecutive verification periods pass without the error exceeding the tolerance.				

9.2.6. Pressure Measurement

Pressure compensation of hydrocarbon liquids is required where the meter pressure is above the base pressure for delivery point measurement unless the meter is proved to atmospheric pressure. Correction to a 0.0kPa gauge (atmospheric pressure) must be performed for continuous flow crude oil pipeline measurement where custody transfer measurement is performed.

The pressure correction (Correction for the effect of Pressure on Liquids [CPL]) factor must be determined in accordance with API MPMS, Chapter 11. Continuous pressure measurements and pressure compensation must be installed where required to meet Chapter 1 uncertainty requirements.

Pressure transmitters and gauges must be installed in accordance with applicable API or the manufacturer's specifications, typically 5 to 10 pipe diameters downstream of the meter.

9.2.7. Density Determination

Density may be measured manually from a sample or continuously using either a densitometer or a Coriolis meter. Where manual density is used, the manual density value may be derived from a representative grab or composite sample and a laboratory density determination. Whichever method is used, the derivation of the value must be documented and meet the uncertainty requirement.

Continuous density measurements must be provided for mass measurement, or if the variability in density is such that use of a fixed density value for temperature compensation would preclude meeting the uncertainty requirements.

On-line densitometers must be installed in accordance with manufacturer's specifications, typically 5 to 10 pipe diameters downstream of linear meters, or a Coriolis meter may be used. If a densitometer is used as part of a mass measurement system (e.g., ethane, NGLs), it must be installed in accordance with API MPMS, Chapter 14.6.

Laboratory density determination may be performed using either the hydrometer methods (see API MPMS, Chapter 9) or the precision densitometer method (ASTM D4052). If practical, densitometer measurements should be made at 15°C to preclude the requirement for temperature compensation. If this is not practical, for example when using a hydrometer, manual temperature compensation must be provided using the appropriate API MPMS table.

9.2.8. Tank Measurement

Tanks in this section refer to storage tanks that are open to atmosphere, tanks with and without floating roofs, and tanks with blanket gas, as well as bullets and other pressurized storage vessels. The use of tanks open to atmosphere should be limited to liquids with a Reid Vapour Pressure specification of <103kPa.

Volumetric measurement using storage tanks is based upon a level measurement used in conjunction with a strapping table.

Provided that Chapter 1 uncertainty tolerances are met, the permit holder may use storage tanks for determination of inventory, well test, or delivery point volume measurements. The permit holder must ensure that the tank diameter, gauging equipment (e.g., gauge tape or automatic tank gauge), gauging procedures, and tank strapping table are appropriate for the tank and product being gauged and are capable of achieving the required uncertainty.

Manual gauge boards and automatic tank gauges must be designed, installed, and operated in accordance with manufacturer's specifications and must be maintained in good working order.

9.2.8.1. **Tank Strapping**

Tank strapping tables convert level to indicated volume.

Depending upon the uncertainty required, tank strapping tables may be prepared using either engineering calculations based upon approximate tank dimensions or via the tank strapping procedures detailed in API MPMS, Chapter 2.

9.2.8.2. **Tank Sizing**

The relative error of the level measurement is determined by the absolute error of the level measurement relative to the level measured. The level measured or change in level is in turn determined by the diameter of the tank and transaction size. To improve uncertainty, one can measure the level more accurately or increase the level change measured by changing the ratio of tank height to diameter or by increasing the size of the transaction or test volume compared to the overall tank height.

Tank sizing must address the intended use (e.g., delivery point or well test), level measurement technique (e.g., gauge board, hand dip, radar gauge), and well test or transaction volume.

Knowing the transaction or test volume, one can determine tank diameter as follows:

$$d \leq (V/a)^{0.5}$$

Knowing the tank diameter, one can determine minimum transaction or test volume as follows:

$$V \geq a \times d^2$$

Where:

V = test fluid volume or delivery point batch volume in m^3

d = tank diameter in meters

a = accuracy coefficient

The accuracy coefficients for conventional crude oil applications are:

a = 0.39 for all test fluid volumes

a = 0.39 for delivery point batch volumes $\leq 100 m^3/d$

a = 0.92 for delivery point batch volumes $> 100 m^3/d$

9.2.8.3. **Manual Tank Gauging**

Manual tank gauging can be accomplished using tank dips or a gauge board.

Gauge boards are acceptable for test tanks and inventory measurements but not for delivery point measurements. See Table 9.2-4 for marking gradations.

Gauge tapes must have a minimum resolution of 3mm.

Table 9.2-4 Gauge Board Marking Gradations

Gauge board application	Maximum marking separation (mm)
Conventional oil testing	25
Inventory	150

If safe work conditions permit, gauge boards should be read at eye level. Calibration of gauge boards is not required.

9.2.8.4. **Automatic/Electronic Tank Gauging**

Electronic tank gauges must have a minimum resolution of 3mm. One reading of the instrument is acceptable.

Instruments must be calibrated in accordance with the manufacturer's specifications. See section 2.10 for frequency requirement.

9.2.8.5. **Tank Gauging Applications**

9.2.8.5.1. Inventory Tank Gauging

For monthly inventory measurement gauging, one reading of the gauge tape, gauge board, or automatic tank gauge is acceptable. Levels must be reported to the nearest 75mm.

The tank does not need to be stabilized or isolated for inventory measurements.

9.2.8.5.2. Test Tank Gauging

For gauge measurement on test tanks, one reading of the gauge board or automatic tank gauge is acceptable at the start and end of the test.

Levels are reported to the nearest 10mm.

See section 9.2.8.3 for sizing and test duration requirements for Test Tank applications.

9.2.8.5.3. Delivery Point Measurement

When tank gauging is used to determine an oil/emulsion volume, the gauging procedures must be conducted in accordance with the following:

1) Gauge boards must not be used for delivery point measurement.
2) The permit holder must ensure that the strapping table has been prepared in accordance with API MPMS, Chapter 2.
3) The permit holder must ensure that the tank level is not changing or is stabilized when the gauge readings are taken. This often requires isolating or shutting in the tank before gauging.
4) All gauge tapes and electronic level devices must have a minimum resolution of 3mm.
5) Manual tank dips are performed in accordance with API MPMS, Chapter 3.1A. For tanks with a nominal capacity greater than 160m^3, two consecutive readings within 10mm of each other are required. The two readings are averaged. For tanks with a nominal capacity of 160m^3 or less, one reading is acceptable.
6) Automatic tank gauging is performed in accordance with API MPMS, Chapter 3.1B.
7) Temperature measurements are performed in accordance with API MPMS, Chapter 7.

9.2.9. **Liquid Volume Calculations**

Liquid volume measurements must be determined to a minimum of two decimal places and rounded to one decimal place for monthly reporting in cubic meters. If there is more than one volume determination within the month at a reporting point, the volumes determined to a minimum of two decimal places must be totalled prior to the total being rounded to one decimal place for Petrinex reporting purposes.

Standard or base conditions for use in calculating and reporting liquid volumes are 15°C and 0kPa gauge or the equilibrium vapour pressure at 15°C (whichever is higher).

The liquid volume calculations must adhere to the following:

1) Total indicated volume for the transaction period (daily, weekly, monthly) is measured and recorded. This applies to measurement by meter, weigh scale, or tank gauging.
2) The volumetric meter factor for the flow meter is applied to the total indicated volume.
3) For emulsion, the percentage of water in the gross volume is determined by measuring the %S&W of a representative sample or by continuous on-line measurement. The result is a quantified volume of hydrocarbon liquid and of water.
4) For oil, a shrinkage factor is applied to the volume in order to determine the volume at stock tank conditions (atmospheric pressure). Some applications may already have the shrinkage factor incorporated into the meter factor. Care must be taken to ensure shrinkage factors are not applied twice.

5) Where required, compensation for the effects of pressure and temperature on the liquid must be applied.

6) Composite meter factors that include temperature correction factors (CTL) must not be used for delivery point measurement. However, they are acceptable for other applications, such as test meters, inlet meters, and water meters, provided that the variability of parameters affecting meter performance such as operating temperature, fluid viscosity, and fluid composition is such that the net effect is within the uncertainty requirements for the application.

9.2.9.1. **General Equations for Determining Liquid Volumes at Base Conditions**

9.2.9.1.1. Linear Meters

Indicated Volume (IV)

IV = closing reading – opening reading

or

IV = (closing pulses – opening pulses) / KF

Gross Standard Volume

GSV = IV x CTL x CPL x MF or

GSV = IV x CMF or

GSV = IV x MF x DENobs / DENb or

GSV = Mass / DENb

Net Standard Volume

CSW = 1 - (%S&W / 100)

NSV = GSV x CSW x SF

SF = Shrinkage Factor

Water Cut

DENobs,o = DENb,o x CTLo

DENobs,w = DENb,w x CTLw

Water Cut = (DENobs,e - DENobs,o) / (DENobs,w - DENobs,o)

Where:

CMF – Composite Meter Factor: A meter factor that includes corrections for the effects of any combination of temperature, pressure, or shrinkage.

CPL – Correction for the effect of Pressure on Liquid: Correction for compressibility of liquid at normal operating conditions.

CTL – Correction for the effect of Temperature on Liquid: Correction for effect of temperature on liquid at normal operating conditions.

CTLo – Correction for the effect of Temperature on Oil: Correction for effect of temperature on oil at normal operating conditions.

CTLw – Correction for the effect of Temperature on Water: Correction for effect of temperature on water at normal operating conditions.

CSW – Correction for Sediment and Water: Correction for sediment and water to adjust the gross standard volume of the liquid for these nonmerchantable items.

DENb – Base Density: Liquid density in kilograms per cubic meter at base pressure and temperature.

DENb,o – Base Density – Oil: Liquid density of oil in kilograms per cubic meter at base pressure and temperature.

DENb,w – Base Density – Water: Liquid density of water in kilograms per cubic meter at base pressure and temperature.

DENobs – Observed Density: Liquid density in kilograms per cubic meter at observed pressure and temperature.

DENobs,o – Observed Density – Oil: Oil density in kilograms per cubic meter at observed pressure and temperature.

DENobs,w – Observed Density – Water: Water density in kilograms per cubic meter at observed pressure and temperature.

GSV – Gross Standard Volume: The volume at base conditions corrected also for the meter's performance (MF or CMF).

IV – Indicated Volume: The change in meter reading that occurs during a receipt or delivery.

KF – K-Factor: A term in pulses per unit volume determined during a factory or field proving. The number of pulses generated by a linear meter divided by the k-factor will determine the indicated volume.

MF – Meter Factor: A dimensionless term obtained by dividing the volume of the liquid passed through the prover corrected to standard conditions during proving by the indicated standard volume (ISVm) as registered by the meter.

NSV – Net Standard Volume: The gross standard volume corrected for shrinkage and nonmerchantable quantities such as sediment and water.

Composite Meter Factors

A CMF is a meter factor that includes corrections for the effects of any combination of temperature, pressure, or shrinkage.

A CMF may be used:

1) if anticipated changes in pressure and temperature parameters result in uncertainties within those stated in Chapter 1,
2) for test separators at oil batteries, and
3) for separators at gas wells.

Test separators typically use CMFs to apply temperature correction where an EFM system is not used. The CMF can also include correction for shrinkage. The operator must ensure that corrections included in CMFs are not being applied elsewhere, such as in a SCADA system or field data capture system.

Note that in separator applications where the hydrocarbon liquid is at its equilibrium vapour pressure, CPL is 1.0 and therefore is not required to be calculated as part of a CMF.

Calculation example for volumetric proving at an oil test separator:

$CMF_T = IV_P \times CTL_P / IV_M$

CMF_T = CMF that includes correction for the effect of temperature (CTL)

IV_P = Indicated prover volume

CTL_P = CTL calculated using prover temperature during run

IV_M = Indicated meter volume

If the indicated volume of the prover is recorded after degassing, the CMF will include correction for shrinkage (CMF_{TS}).

9.2.9.1.2. Orifice Meters

While not as common, orifice meters can be used for liquid measurement. For these applications, either of the following equations must be used.

API MPMS 14.3.1 (AGA3):

$$Q_b = \frac{Q_m}{p_b} = \frac{N_1 C_d E_v Y d^2 \sqrt{p_f \Delta P}}{p_b}$$

API MPMS 14.8 (Natural Gas Fluids Measurement – Liquefied Petroleum Gas Measurement):

$$Q_b = N_1 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{p_f}} (C_{tl} C_{pl})$$

Where:

N_1	Unit conversion factor (0.0000351241 when using SI units listed below)
C_d	Orifice plate coefficient of discharge
E_v	Velocity of approach factor
Y	Expansion factor
d	Orifice plate bore diameter calculated at flowing temperature (mm)
ΔP	Orifice differential pressure (kPa)
ρ_f	Density of the liquid at flowing conditions (kg/m^3)
ρ_b	Density of the liquid at base conditions (m^3/sec)
Q_b	Volume flow rate at base conditions (m^3/sec)
Q_m	Mass (kg)
C_{tl}	Compensation factor for the effect of temperature on liquid
C_{pl}	Compensation factor for the effect of pressure on liquid

For other nonlinear meters, refer to the applicable industry standard or manufacturer's procedures for determining base volumes.

9.2.9.1.3. Pressure and Temperature Compensation

Standards for Calculation

CTL and CPL must be calculated as per the current standards in Table 9.2-5 for the applicable density and temperature range. Applications using the superseded standards below that were in use prior to the implementation of these standards will require upgrading. Calculations for determining CTL or CPL not listed in Table 9.2-5 are not acceptable.

Table 9.2-5 Pressure and Temperature Compensation Standards*

Product and Density Range	Standard	Calculation input(s)	Calculation Output(s)	Comments
Crude oil, refined products, and lubricating oils 611.16-1163.85kg/m^3	API MPMS 11.1 May 2004	Observed density Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	Density @ 15°C CTL CPL VCF	Current
Hydrocarbon liquid 350-637kg/m^3	API MPMS 11.2.2M 1986	Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	CPL	Current

Product and Density Range	Standard	Calculation input(s)	Calculation Output(s)	Comments
NGL and LPG 210-740kg/m³	API MPMS 11.2.4 GPA TP-27 Table 53E September 2007	Observed density Observed temperature	Density @ 15°C	Current
NGL and LPG 351.7-687.8kg/m³	API MPMS 11.2.4 GPA TP-27 Table 54E September 2007	Density @ 15°C Flowing temperature	CTL	Current
Crude oil 610-1075kg/m³	API MPMS 11.1 (formerly API 2540) Table 53A 1980	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.1 2004
Crude oil 610-1075kg/m³	API MPMS 11.1 (formerly API 2540) Table 54A 1980	Generalized products 610-1075kg/m³	CTL	Superseded by API MPMS 11.1 2004
Generalized products 610-1075kg/m³	API MPMS 11.1 (formerly API 2540) Table 53B 1980	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.1 2004
Generalized products 610-1075kg/m³	API MPMS 11.1 (formerly API 2540) Table 54B 1980	Density @ 15°C Flowing temperature	CTL	Superseded by API MPMS 11.1 2004
Light hydrocarbon liquid 500-653kg/m³	ASTM-IP-API Petroleum measurement tables for light hydrocarbons Table 53 1986	Observed density Observed temperature	Density @ 15°C	Superseded by API MPMS 11.2.4/ GPA TP-27 September 2007
Light hydrocarbon liquid 500-653kg/m³	ASTM-IP-API Petroleum measurement tables for light hydrocarbons Table 54 1986	Density @ 15°C Flowing temperature	CTL	Superseded by API MPMS 11.2.4/ GPA TP-27 September 2007
Hydrocarbon liquid 638-1074kg/m³	API MPMS 11.2.1M 1984	Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	CPL	Superseded by API MPMS 11.1 2004
*Note: The printed API MPMS, Chapter 11.1, Tables 53, 53A, and 53B include correction for the thermal expansion or contraction of a glass hydrometer. Existing computer implementations of these tables may or may not include hydrometer correction.				

9.2.10. **Electronic Flow Measurement for Liquid Systems**

An EFM is any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a DCS, SCADA, or Programmable Logic Controller system (PLC), only the EFM portion has to meet the requirements in this section.

The following systems are not defined as an EFM:

1) any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation), and
2) a remote terminal unit (RTU) that transmits any data other than flow data and does not calculate flow.
3) Hardware and software requirements:
4) The EFM data storage capability must exceed the time period used for data transfer from the EFM.
5) The EFM must be provided with the capability to retain data in the event of a power failure (e.g., battery/facility backup, UPS, EPROM).
6) The system must have appropriate levels of access for security, with the highest level of access to the system restricted to authorized personnel.
7) The EFM must be set to alarm on out-of-range inputs, such as temperature, pressure, differential pressure (if applicable), flow, low power, or communication failures.
8) Any EFM configuration changes or forced inputs that affect measurement computations must be documented through either electronic audit trails or paper records.
9) The values calculated from forced data must be identified as such.

9.2.10.1. **Performance Evaluation**

If an EFM is used to calculate net liquid volumes, the permit holder must be able to verify that it is performing within the BCER target limits defined in this section.

A performance evaluation test must be completed within two weeks after the EFM is put into service and immediately after any change to the computer algorithms that affects the flow calculation on a per software version basis, and it must be documented for BCER audit upon request. It is recommended that a performance evaluation be conducted during a meter's initial maintenance (proving, calibration, internal inspection, etc.). For existing EFM systems, the permit holder should conduct its own performance evaluations to ensure that they are performing adequately. The BCER considers either one of the following methods acceptable for performance evaluation.

1) A performance evaluation test conducted on the system by inputting known values of flow parameters into the EFM to verify the volume calculation and other parameters. The test cases included in this section (Tables 9.2-6 to 9.2-9) are for liquid meters each with different flow conditions.

Test cases 1 to 5 for each liquid type are for density correction from flowing temperature to 15C. The hydrometer correction is used to compensate for the glass expansion when used to measure the density.

Test cases 6 to 10 for each liquid type are for volume correction using CPL and/or CTL factors to correct to base conditions. Other manufacturer's procedures can also be used to evaluate the EFM performance, provided that the volumes obtained from a performance evaluation test agree to within ±0.1% of those recorded on the sample test cases.

2) Evaluation of the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information must be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

The densities (test cases 1 to 5, 11 to 15) or volumes (test cases 6 to 10, 16 to 20) obtained from a performance evaluation test must agree to within ±0.1% of those recorded on the sample test cases. If the ±0.1% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem.

9.2.10.2. **Test Cases for Verification of Oil Flow Calculation Programs**

These test cases were calculated using the following standards.

Density @ 15°C / CTL / CPL / CTPL: API MPMS, Chapter 11.1: Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils (May 2004).

Hydrometer Correction: API MPMS, Chapter 9.3: Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method (November 2002).

9.2.10.3. Test Cases for Verification of NGL and LPG Flow Calculation Programs

These test cases were calculated using the following standards.

Density @ 15°C: API MPMS, Chapter 11.2.4 (GPA Technical Publication TP-27): Temperature Correction for the Volume of NGL and LPG, September 2007, Table 53E.
Hydrometer Correction: API MPMS, Chapter 9.3: Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method (November 2002).
CPL: API MPMS, Chapter 11.2.2M Compressibility Factors for Hydrocarbons, October 1986.CTL: API MPMS, Chapter 11.2.4 (GPA Technical Publication TP-27): Temperature Correction for the Volume of NGL and LPG, September 2007, Table 54E.

Table 9.2-6 Oil Density Correction Test Cases – Density Correction to 15°C

	Inputs		Outputs	
Test case	Oil density @ observed temp. (kg/m³)	Observed temp. (°C)	Oil density corrected to 15°C (kg/m³) with hydrometer correction	Oil density corrected to 15°C (kg/m³) without hydrometer correction
1	875.5	120.00	942.9	945.0
2	693.0	11.40	689.9	689.8
3	644.0	84.45	704.7	705.7
4	625.5	53.05	660.8	661.4
5	779.0	25.00	786.7	786.8

Table 9.2-7 Volume correction Test Case at Atmospheric Pressure- Volume Correction to 15 C and 0.0 Kpa (g)

	Inputs				Outputs				
Test case	Metered volume (m³)	Density (kg/m³) @ 15°C	Observed temp. (°C)	Observed pressure (kPag)	CTL	CPL	CTL corrected volume (m³)	CTL & CPL corrected volume (m³)	CTL & CPL corrected volume (m³) rounded*
6	60.0	903.5	40.5	700.0	0.98071	1.00050	58.842368	58.871812	58.9
7	15.0	779.0	3.9	400.0	1.01120	1.00034	15.167952	15.173133	15.2
8	100.0	1008.0	89.0	3700.0	0.95472	1.00255	95.472126	95.715578	95.7
9	250.0	875.5	5.0	200.0	1.00799	1.00013	251.998452	252.030396	252.0
10	150.0	640.0	75.0	1000.0	0.90802	1.00365	136.203308	136.700489	136.7

*The CPL and CTL shown are rounded to five decimal places, but they are not rounded prior to calculating the volumes. Only the final volume is rounded to one decimal place to meet reporting requirements. The corrected volumes are shown to six decimal places for verification purposes.

Table 9.2-8 Other Liquid Hydrocarbon Density Correction Test Cases- Density correction to 15 C

Test case	Inputs		Outputs	
	Liquid density @ observed temperature and base pressure (kg/m³)	Observed temperature (°C)	Liquid density corrected to 15°C (kg/m³) with hydrometer correction	Liquid density corrected to 15°C (kg/m³) without hydrometer correction
11	525.0	92.50	614.2	614.9
12	412.5	11.40	404.5	404.5
13	355.5	84.45	506.7	506.9
14	623.5	53.05	658.1	658.7
15	652.5	25.00	661.3	661.5

Table 9.2-9 Volume Correction Test Cases at Equilibrium Vapour Pressure- Volume Correction to 15 C and Equilibrium Vapour Pressure

Test case	Inputs					Outputs				
	Metered volume (m³)	Density (kg/m³) @ 15°C and EVP	Observed temp. (°C)	Observed pressure (kPag)	Equilibrium vapour pressure (kPa) @ observed temp.	CTL	CPL	CTL corrected volume (m³)	CTL & CPL corrected volume (m³)	CTL & CPL corrected volume (m³) rounded*
16	60.0	544.5	40.5	1645.0	738.0	0.93642	1.0054	56.184942	56.488356	56.5
17	15.0	402.0	3.9	1125.0	1125.0	1.05931	1.0000	15.889672	15.889672	15.9
18	100.0	632.0	55.0	348.0	213.0	0.93587	1.0004	93.586521	93.623473	93.6
19	250.0	512.5	5.0	1500.0	494.0	1.02732	1.0041	256.830532	257.880793	257.9
20	150.0	356.5	-14.5	4260.0	1650.0	1.20782	1.0224	181.173148	185.235683	185.2

*The CPL and CTL shown are rounded as per their respective standards. CPL is rounded to four decimal places and CTL to five decimal places. They are not rounded prior to calculating the volumes. Only the final volume is rounded to one decimal place to meet reporting requirements. The corrected volumes are shown to six decimal places for verification purposes.

9.2.11. **EFM Records**

For all metering equipment covered by this section, records must be kept as outlined in the following report types and made available for examination by the BCER. Operators are given flexibility in the formatting of these reports; it is not necessary to present the information exactly as outlined.

These records must be maintained for mechanical, electromechanical, or within the EFM. EFM systems may retain this information automatically. It is the responsibility of the operating company to ensure that the records are saved for the required time, a minimum of 72 months. It is advisable to save the records on a regular basis and when metering problems occur, so they are not lost when memory is full or when the EFM is shut off.

The reports must be recorded using electronic/magnetic (not necessarily within the EFM), printed, or handwritten media and retained for a minimum of 72 months. They must be available upon request by the BCER.

9.2.11.1. The Daily Report (Test Meters)

The following information must be recorded on a daily or per test basis for test meters only:

1) test meter and well identification.
2) test period accumulated flow.
3) hours on production or hours of flow (specify).

9.2.11.2. The Daily Report (All Other Hydrocarbon Liquid Meters)

The following information must be recorded on a daily basis:

1) meter identification.
2) daily accumulated flow.
3) hours on production or hours of flow (specify).
4) flow data audit trail—include at least one of the following:
    a. instantaneous values for flow rate, operating pressure (if applicable), and temperature taken at the same time each day.
    b. daily volume and average daily values for operating pressure (if applicable) and temperature.
    c. hourly accumulated flow rate and average hourly values for operating pressure (if applicable) and temperature.

9.2.11.3. The Event Log

When any parameter that affects the flow calculation is changed, such as meter factor, fluid densities, or transmitter range, a process is required to record that a change has been made. In an EFM system this may be accomplished using the event log within the EFM (if so equipped). These parameter changes can also be recorded manually on paper or electronic records.

The event log must include such items as below:

1) instrumentation range changes.
2) algorithm changes.
3) meter factor or k-factor changes.
4) orifice plate changes.
5) fixed fluid density changes.
6) other manual inputs.

The log must identify the person making the change and the date of the change.

9.2.11.4. The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time each alarm is cleared must be recorded. The alarm log includes such items as below:

1) master terminal unit failures.
2) remote terminal unit failures.
3) communication failures.
4) low-power warning.
5) high/low volumetric flow rate.
6) over ranging of end devices.

9.2.11.5. The Meter Report

The meter report is primarily required to confirm that the EFM is operating properly. A meter report is not required when using mechanical or electromechanical systems, where many of these values are fixed. For these mechanical or electromechanical meters, records are required to verify that the various factors used in the calculation are correct.

The meter report details the configuration of each meter and flow calculation information. It must include the required parameters to demonstrate that the net standard volume is being properly computed from the gross indicated volume. The type of EFM device will determine which of the following are required:

1) Instantaneous flow data.
    a. gross and net flow rate or gross and net volume calculated over a time period such that the correction factors are not changing.
    b. operating pressure.
    c. differential pressure (if applicable).
    d. flowing temperature.
    e. flowing density.
    f. sediment and water content if an on-line S&W monitor is used..
    g. meter pulse count.
    h. CTL, CPL, CTPL.

2) Current configuration information
   a. meter identification.
   b. date and time.
   c. pressure base.
   d. temperature base.
   e. flowing or base density if a fixed density is used.
   f. meter factor and/or k-factor.
   g. shrinkage factor (where applicable).

9.2.11.6. **Production Data Verification and Audit Trail**

The field data, records, and any calculations or estimations, including EFM, relating to BCER-required production data submitted to the Ministry must be kept for a minimum of 72 months and available for inspection upon request. The reported data verification and audit trails must be in accordance with the following:

1) Test records: any records and documentation produced in the production proration testing of wells that affect measured volumes.
2) Proving records: any records and documentation produced in the proving of meters and calibration of the prover and all peripheral devices (if the prover and peripheral devices are owned and operated by the permit holder).
3) S&W records: any records and documentation produced in the determination of relative oil/water percentages that affect volumes.
4) Delivery and receipt records: any records and documentation produced in the determination of delivery or receipt volumes.
5) Estimation records: any records and documentation related to the estimation of reported volumes, including estimation methodology, record of event, and approvals.
6) Tank gauging records: any records and documentation produced in the determination of reported volumes.
7) Volume loss records: any records and documentation for volumes lost due to incidents such as theft, spills, and fires.
8) EFM: any records and documentation (electronic, magnetic, or paper form) produced in the determination of metered volumes in accordance with the EFM requirements in section 9.2.11.

9.3. Conventional Oil Measurement

This section presents the base requirements and exceptions for conventional crude oil and emulsion measurements from wells and batteries that are used in determining volumes for reporting to Petrinex. The requirements for crude oil/emulsion volumes transported by truck are detailed in Chapter 10.

Conventional crude oil has the following characteristics:

1) it is a mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds,
2) it is recovered or is recoverable at a well from an underground reservoir,
3) it is liquid at the conditions under which its volume is metered or estimated, and
4) it must have a density of less than 920kg/m^3 at standard conditions.

9.3.1. General Requirements

Crude oil may be found in association with water in an emulsion. In such cases, the total liquid volume must be metered, and the relative volumes of oil and water in the emulsion must be determined by obtaining and analyzing a representative sample of the emulsion, by using a product analyzer, or by other means if applicable.

A permit holder must measure produced crude oil/emulsion volumes by tank gauging, weigh scale, or meter unless otherwise stated in this guideline. The BCER will consider an oil measurement system to be in compliance if the base requirements detailed below are met. The BCER may stipulate additional or alternative requirements for any specific situation based on a site-specific assessment and will inform licensees in writing of any additional or alternative requirements respecting their facilities.

9.3.2. General Measurement, Accounting, and Reporting Requirements for Battery / Facility Types

9.3.2.1. General Production Accounting Formula

Production = Total disposition + Closing inventory – Opening inventory – Total receipts

9.3.2.1.1. General

All wells in the battery/facility must be classified as oil wells.

Liquid production from an oil battery/facility must be metered as an oil, water, or oil/water emulsion volume. This measurement may be performed at the battery/facility site, a truck delivery/receipt point, or a pipeline delivery point. The meter factor obtained from meter proving must be applied to the meter volumes until another prove is conducted.

All wells in a multi-well oil battery/facility must be subject to the same type of measurement (measured or prorated). If there is a mixture of measured and prorated wells within the same battery/facility, the exception criteria in section 5.6 must be met or a BCER site-specific approval must be obtained.

Production from gas batteries/facilities or other oil batteries/facilities may not be connected to an oil proration battery/facility upstream of the oil proration battery/facility group measurement point(s) unless specific criteria are met (see section 5.6) or BCER approval is obtained.

Any oil well that produces fluids from any formation is considered on production and a facility code is required to report the production in Petrinex even for a "test."

9.3.2.1.2. Single-Well Oil Battery / Facility (Petrinex subtype 311)

Oil/emulsion must be separated from gas and continuously metered or utilize dedicated tank(s).

9.3.2.1.3. Multiwell Group Oil Battery / Facility (Petrinex subtype 321)

Each well must have its own separation and measurement equipment, similar to a single-well battery/facility.

All separation and measurement equipment for the wells in the battery/facility, including the tanks but excluding the wellheads, must share a common surface location.

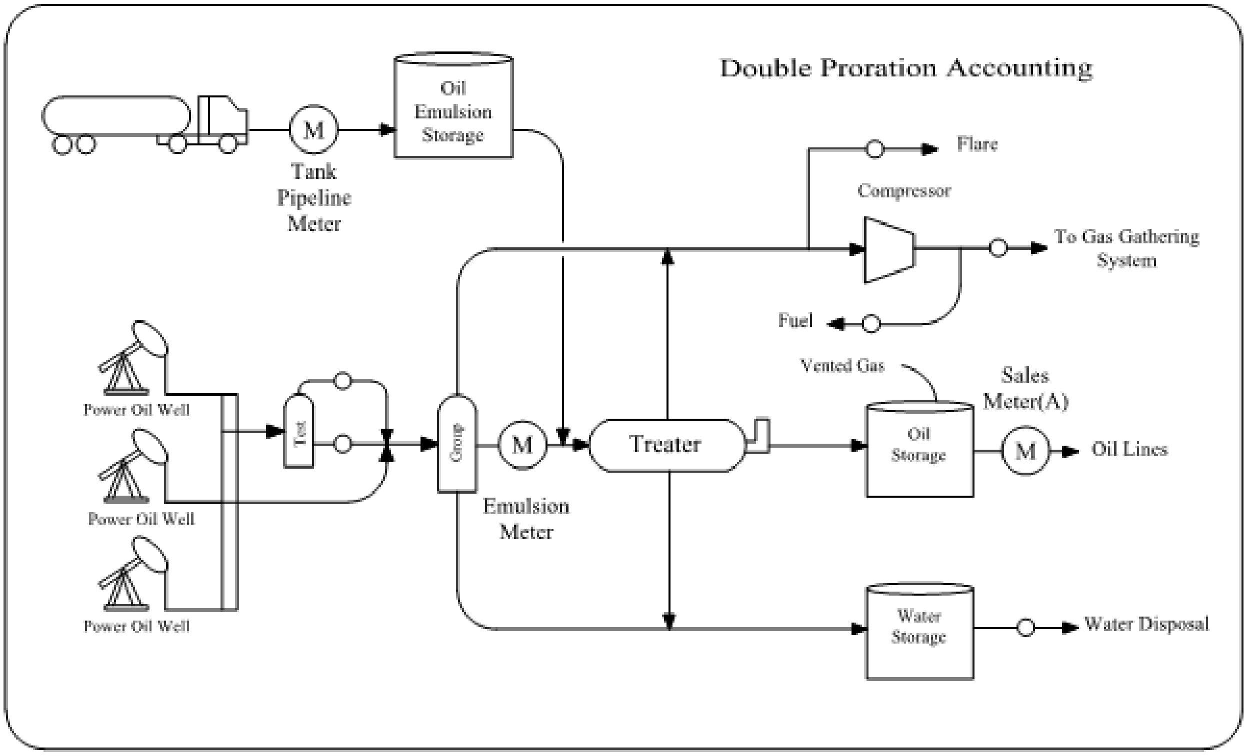
9.3.2.1.4. Proration Battery / Facility (Petrinex subtype 322)

All well production is commingled prior to the total battery/facility oil/emulsion being separated from the gas and metered. Individual monthly well oil production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

Double proration, whereby the proration oil battery/facility disposition volume(s) is prorated to group/receipt measurement points and then further prorated to the wells, is allowed without special approval subject to the following conditions:

1) All prorated oil/emulsion must be metered using measurement systems that meet delivery point requirements before commingling with other oil/emulsion receipts.
2) The group oil/emulsion meter in figure 9.3-1 must be proved to stock tank conditions or corrected to stock tank conditions using a flash liberation analysis.
3) All metered oil/emulsion receipts to the battery/facility and the metered oil/emulsion production must be prorated against the total oil and water disposition of the battery/facility.

Figure 9.3-1 Double Proration Accounting



Sales oil and water disposition volumes with inventory change must be prorated to the total truck/pipeline volumes metered and the total well emulsion volumes metered (first proration). The volumes used for all meters must be net oil volumes which do not include water. This proration using PF1 has to be done off-sheet and not reported in Petrinex.

Double Proration Example

Meter A = Oil Sales Meter
Meter B = Group Oil/Emulsion Meter
Meter C = Truck/Pipeline Meter

PF1 = [Meter (A) + INVCL – INVOP] / [Meter (B) + Meter (C)]

Prorated meter (B) volume = Meter (B) x PF1

Prorated individual truck-in and/or pipeline volumes = Meter (C) volumes for each load received x PF1

PF2 = Prorated meter (B) volume / Total estimated production volume

The prorated oil and water volume at the emulsion meter (B) is further prorated using PF2 (second proration) to the tested oil wells. The oil and water proration factors PF2 must then be reported in Petrinex.

9.3.3. Base Requirements for Oil Well Testing

9.3.3.1. Proration Well Testing Frequency

Every conventional crude oil well included in a proration oil battery/facility requires a minimum of two 22 hour tests to be conducted per month and be in accordance with Drilling and Production Regulation 58 - Production test of oil wells.

9.3.3.2. Well Test Considerations

If there is a change in operating conditions during a test, such as a power failure or a change in choke setting, the test must be rejected and a new test must be conducted.

If there is insufficient or lost test data, such as meter failure, the test must be rejected and a new test must be conducted.

If there is a significant change in oil, gas, or water for a test, the validity of the test should be questioned, and a retest should be considered.

Sufficient purge time must be allowed to ensure that liquids from the previous test are displaced by the new test well liquids.

The pressure difference between the test separator and the group line must not exceed 200kPa.

A well test may be stopped early for operational reasons and still be considered valid. Reasons for the short test must be documented and made available to the BCER upon request.

9.3.3.3. Common Flow Lines

For common flow lines, a well test must be conducted, with all other wells on the common flow line shut in following adequate purge time.

Combined (cascade) testing is allowed for common flow-lined wells, provided that the conditions in Section 9.3.4 are met. However, the combined test must be conducted first, and then the low gas producing well must be shut in to test the high gas producing well, allowing sufficient purging and stabilization time.

9.3.3.4. Field Header and Common Flow Line Purging

If a field header is located in the same building as the test separator, the test separator must be purged by allowing at least two liquid dumps to occur prior to starting the well test. The field header must clearly identify which well is tied to the header valves.

If a field header is not located in the same building as the test separator, sufficient purge time must be allowed to ensure that liquids from the previous test are replaced by the new test well liquids.

If two or more wells are tied into a common flow line, only one well must be produced during the well test, and the other well(s) must be shut in. Similar to a field header situation, sufficient purge time must be allowed to ensure that liquids from the previous production condition are replaced by the new test well liquids.

Sufficient purge time must be calculated as follows:

Purge time = Test line volume ÷ New test well liquid flow rate

Example: Calculate the minimum purge time required for the following test line:

Test line dimensions = 1500m length, 88.9mm OD pipe, 3.2mm wall thickness +

Previous well test flow rates = 5.5m^3 oil/d, 12.0m^3 water/d

Step 1

d = (88.9 – 3.2 x 2) ÷ 1000 = 0.0825 m

Test line volume = (3.142 x d^2 x length) ÷ 4

= (3.142 x (0.0825)^2 x 1500) ÷ 4

= 8.02m^3

Step 2

Purge time required = Test line volume (m^3) ÷ Well flow rate (m^3/h)

Well total liquid flow rate = (5.5m^3 + 12.0m^3) ÷ 24h = 0.729m^3/h

Purge time required = 8.02m^3 ÷ 0.729m^3/h = 11.0h

Therefore, the minimum purge time required is 11.0 hours.

9.3.4. **Combined (Cascade) Testing**

When a prorated oil well has such low gas production that it cannot properly operate test equipment, a permit holder may test two wells simultaneously—combined (cascade) test—through the same test separator. In such cases, the following procedure must be followed:

1) Establish oil, gas, and water production volumes for a high gas producing well by testing it individually through the test separator.
2) Conduct a test for both the high gas producing well and a low gas producing well together through the same test separator immediately after testing the high gas producing well, allowing time for stabilization. (The testing sequence may be reversed with the testing of the combined wells first.)
3) The operating condition of both wells must not be changed. If it is, a new set of tests is required.
4) Total test oil, gas, and water volumes determined for the combined (cascade) test minus the test oil, gas, and water volumes for the high gas producing well will be the test volumes for the low gas producing well (see example below).

5) Both wells should have similar S&W percentages. If any of the calculated oil, gas, or water volumes for the low gas producing well are negative, the tests are not valid and both tests must be repeated.

The use of combined (cascade) testing does not require special approval from the BCER.

Example:

Well A = High gas producing

Well B = Low gas producing

Table 9.3-1 Combined (Cascade) Testing

Test Results

Well	Test date	Oil (m^3)	Gas (e^3m^3)	Water (m^3)
Well A + B	July 4	80.0	20.0	20.0
Well A	July 5	50.0	19.0	12.0
Well B = (Well A + B – Well A)	**July 4**	**30.0**	**1.0**	**8.0**

9.3.5. **Oil Proration Battery / Facility Accounting and Reporting Requirements**

Prorated production is an accounting system or procedure in which the total battery/facility production is allocated to wells based on individual well tests. Production from multiple oil wells may be commingled before separation and continuous single-phase measurement of the components (see Figure 9.3-2). Individual well production must be tested in accordance with Drilling and Production Regulation 58 to determine the production rates that can be used to estimate the well's monthly production volume. The estimated monthly well production volume is corrected using a proration factor. In summary, the following must be performed (see section 9.3.5.1 for details):

1) test production volumes of gas (in e^3m^3) and oil and water (in m^3) rounded to two decimal places;

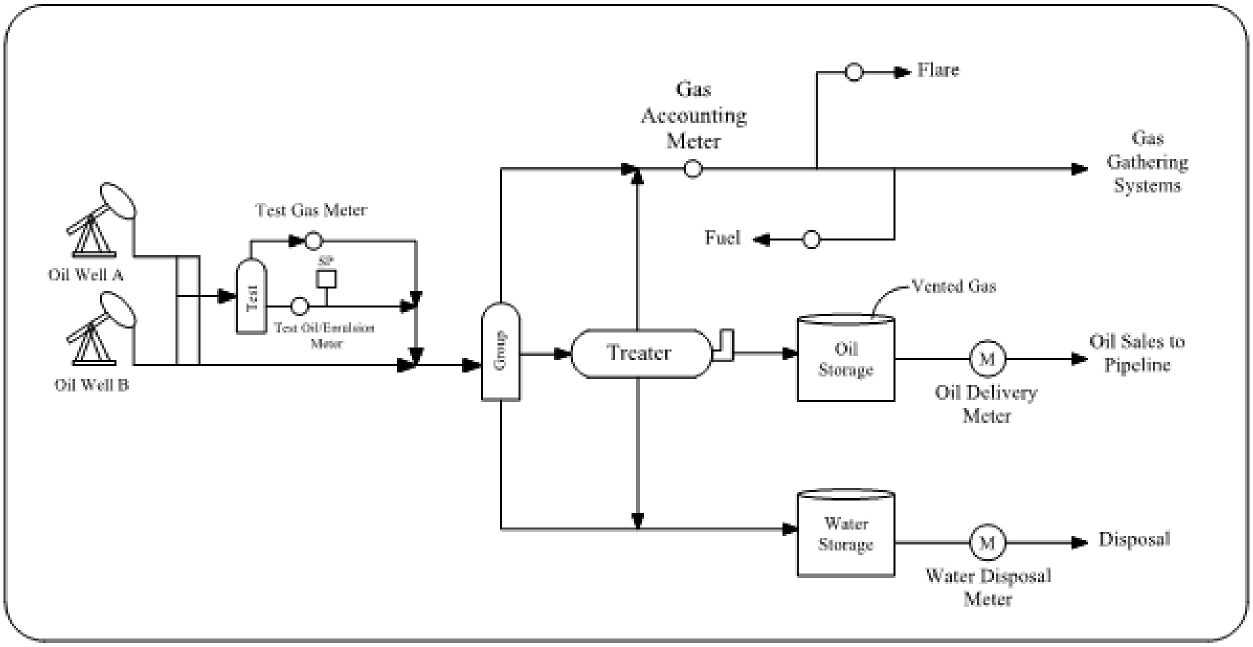
2) record test duration hours to two decimal places with the nearest quarter hour as the minimum resolution;

3) determine the hour production rate for each product from the well;

4) determine the estimated well production by multiplying the hour rate by the monthly hours of production; and

5) determine the actual (prorated) production volume by multiplying the estimated well production by the proration factor (the total actual battery/facility production volume divided by the total estimated battery/facility production volume).

Figure 9.3-2 Oil Proration Battery



All conventional oil wells under primary production and waterflood operations included in proration batteries are still required to have a minimum of two 22 hour well tests conducted each month.

Monitoring the performance of miscible floods and other enhanced oil recovery schemes usually requires testing criteria other than rate alone; therefore, testing requirements for miscible flood schemes are set out in each scheme approval provided by the BCER.

Many low-rate wells exhibit erratic production rates due to high water-oil ratios or gas-oil ratios, and oversized production lines and test separators can make accurate measurement difficult. Longer test duration can improve test accuracy for many of these wells. To allow permit holders the opportunity to conduct longer duration tests, wells that produce <6m^3/day are permitted to use up to an eight-day cycle chart drive for measurement of test gas production volumes.

9.3.5.1. **Proration Estimated Volume Calculation**

Calculate the estimated production of each well from the test data using the sample worksheet on Table 9.3-2.

1) Calculate the test rate/hour for crude oil, gas, and water:

   Rate per hour = Test production volume (including GIS volumes for gas) ÷ Test duration (hr)

   Enter the test rate/hour rounded to four decimal places.

2) Calculate the hours of production for each test rate during the reporting month. Include only the hours of prorated production:

   a. hours of production from the first day of the month to the start of the first test for the month—data from the last test conducted during the previous month must be used to estimate production until the first test for the month is conducted, and

   b. hours of production from the start of each test conducted during the month up to the start of the next test, or the end of the month, whichever is applicable.

   Enter the hours produced rounded to the nearest hour.

3) Calculate the estimated production of oil, gas, and water for the production hours applicable to each test rate:

   Estimated production = Test rate/hour x Hours produced

   Enter the estimated production of oil, gas, and water rounded to one decimal place.

4) Calculate the totals for each well:

   Add the hours produced that are applicable to each test rate and enter the total.

   Add the estimated production of oil, gas, and water, and enter the totals.

   Note that if a GOR is used to estimate the well gas production in accordance with section 4.4.6 then: Estimated well gas production = Estimated well oil production x GOR

Table 9.3-2 Proration Estimated Volume Calculation

UWI	100/01-01-101-01W7/00					Test duration[c]	Hourly test rate				Estimated production		
Vessel	Test date		Test oil	Test gas	Test water		Oil	Gas	Water	Prod	Oil	Gas	Water
	dd	mm	m^3	e^3m^3	m^3	hours	m^3/hr	e^3 m^3/hr	m^3/hr	hours	m^3	e^3m^3	m^3
Prior mo.	25	6	9.05	1.35	3.53	24.00	0.3771	0.0563	0.1471	96	36.2	5.4	14.1
	5	7	8.85	1.28	3.26	24.00	0.3668	0.0533	0.1358	168	62.0	9.0	22.8
	12	7	9.40	1.51	2.98	24.00	0.3917	0.0629	0.1242	216	84.6	13.6	26.8
	21	7	9.15	1.67	3.65	24.00	0.3813	0.0696	0.1521	264	100.7	18.4	40.2
									Totals	**744**	**283.5**	**46.4**	**103.9**
UWI	**100/02-01-101-01W7/00**					**Test duration[c]**	**Hourly test rate**				**Estimated production**		
Vessel	**Test date**		**Test oil**	**Test gas**	**Test water**		**Oil**	**Gas**	**Water**	**Prod**	**Oil**	**Gas**	**Water**
	dd	**mm**	**m^3**	**e^3m^3**	**m^3**	**hours**	**m^3/hr**	**e^3 m^3/hr**	**m^3/hr**	**hours**	**m^3**	**e^3m^3**	**m^3**
Prior mo.	28	6	5.05	0.95	4.15	24.00	0.2104	0.0396	0.1729	48	10.1	1.9	8.3
	[a]3	7	5.85	1.25	4.50	48.00	0.2406	0.0490	0.1792	336	80.8	16.5	60.2
	[a]4	7	5.70	1.10	4.10								
	17	7	6.01	1.15	5.00	24.00	0.2357	0.0451	0.1961	168	39.6	7.6	32.9
	24	7	5.40	0.99	4.10	24.00	0.2374	0.0435	0.1802	192	45.6	8.4	34.6
									Totals	**744**	**176.1**	**34.4**	**136.0**
UWI	**100/03-01-101-01W7/00**					**Test duration[c]**	**Hourly test rate**				**Estimated production**		
Vessel	**Test date**		**Test oil**	**Test gas**	**Test water**		**Oil**	**Gas**	**Water**	**Prod**	**Oil**	**Gas**	**Water**
	dd	**mm**	**m^3**	**e^3m^3**	**m^3**	**hours**	**m^3/hr**	**e^3 m^3/hr**	**m^3/hr**	**hours**	**m^3**	**e^3m^3**	**m^3**
Prior mo.	1[b]	7	1.80	1.10	2.20	24.00	0.0750	0.0458	0.0917	24	1.8	1.1	2.2
	2[b]	7	4.00	2.00	5.00	24.00	0.1667	0.0833	0.2083	120	20.0	10.0	25.0
	7	7	3.95	1.95	4.95	23.00	0.1717	0.0848	0.2152	288	49.4	24.4	62.0
	19	7	4.25	2.05	5.05	26.00	0.1635	0.0788	0.1942	216	35.3	17.0	41.9
	28	7	5.65	2.00	5.50	27.75	0.2036	0.0721	0.1982	96	19.5	6.9	19.0
									Totals	**744**	**126.0**	**59.4**	**150.1**

Note that test gas volumes must include gas-in-solution (GIS) volumes (see section 4.4.6 Gas in Solution (GIS) with Oil Volumes under Pressure).

[a] Tests on July 3rd and 4th were comparable and consecutive (i.e., there were no operational changes). Therefore, the results are combined and used as one 48-hour test.

[b] Tests on July 1st and 2nd were not comparable due to operational changes (e.g., choke/pump speed). Therefore, they are used as separate 24-hour tests.

[c] Test duration must be reported to the nearest quarter hour as the minimum resolution (record hours to two decimal places, e.g., 2hr and 45min are entered as 2.75hr).

9.3.5.2. **Calculate Proration Factors and Monthly Production**

1) Calculate the total estimated battery/facility production for oil, gas, and water:

   Total estimated battery/facility production = Sum of all the wells' total estimated production

2) Calculate the total actual battery/facility production and proration factors for oil, gas, and water:

   For oil and water,

   Total actual battery/facility production = Total monthly disposition + Closing inventory – Opening inventory – Total receipts

   For gas,

   Total actual battery/facility production = Total monthly disposition (sales, fuel, flare, vent) – Total receipts

   Proration factor = Total actual battery/facility production ÷ Total estimated battery/facility production

   The proration factors for oil, gas, and water must be rounded to five decimal places.

   Note that if a GOR is used to estimate the total battery/facility gas production volume in accordance with section 4.4.6

   Estimated battery/facility gas production = Actual battery/facility oil production x GOR

   Estimated battery/facility gas production = Actual battery/facility gas production

   Gas proration factor = 1.00000

3) Calculate each well's monthly prorated production volumes for oil, gas, and water:

   Monthly prorated oil volume = Well estimated oil production x Oil proration factor

   Monthly prorated gas volume = Well estimated gas production x Gas proration factor

   Monthly prorated water volume = Well estimated water production x Water proration factor

4) Check that total well production equals total actual battery/facility production for oil, gas, and water. If the volumes are not equal due to rounding, minor adjustments to the monthly volumes may be required.

   Sum of prorated well production = Total actual battery/facility production

9.3.6. Condensate Receipts at an Oil Battery / Facility

If condensate or other light hydrocarbon liquids are received by pipeline or truck at an oil battery/facility, the permit holder must choose from the applicable condensate reporting options in section 5.6.

9.4. Water Measurement

This section presents the requirements for measurement of water from oil and gas production, water source, water injection and disposal, waste processing and disposal.

All liquid water produced at wellhead or group separator conditions are considered production and must be reported to FIN.

9.4.1. Water Measurement and Accounting Requirements for Various Battery / Facility Types

9.4.1.1. Gas Facilities

Water determinations must follow the requirements outlined in section 6.3 for gas facilities.

9.4.1.2. Oil Facilities

The operator must separate the water from the oil and measure the water if the total water production at a well or battery/facility exceeds 50m^3 per month and the water cut is in excess of 0.5% of the total liquid production. The battery/facility water disposition must be metered if over the 50m^3 per month limit; the receiving battery/facility is responsible for measurement and reporting of the water disposition.

The two methods for determining oil/water production for oil wells are separated measurement and proration. The requirements for determining water production vary between these two methods, and there are also some variations within each method.

All measurement and testing requirements outlined in section 9.3 must be adhered to.

9.4.1.2.1. Multiwell Group Oil Battery / Facility

Total water production from a multi-well group oil battery/facility must be determined in the same way as from an oil SWB.

9.4.1.2.2. Multiwell Proration Oil Battery / Facility

Water production from a multi-well proration oil battery/facility is determined based on well testing and proration from the battery/facility disposition volumes plus inventory change at month end.

9.4.1.3. Water Source Production

Water source wells or other sources of water, such as rivers and lakes, must be continuously metered before commingling with water or fluids from another source.

If a source well is producing gas, the associated gas production must be separated and metered or estimated if <0.5e^{3}m^3/d and reported.

9.4.1.4. Water Injection and Disposal Battery / Facility

Water injected into injection or disposal wells must be continuously metered at each wellhead at the injection site and used for reporting to the Ministry. If there is more than one battery/facility sending water to an injection or disposal well/facility, each receipt must be metered before commingling.

When water is separated from the gas down hole and injected into another zone or formation without coming to surface, the water volume must be metered if it is >50m^3/month or estimated if it is <50m^3/month.

Skim oil recovered from these facilities should not exceed 1.0% of the total received volume based on a six-month rolling average basis. Operators may be contacted to explain the origin of the excessive skim oil.

9.4.1.4.1. BCER Site-Specific Requests

If the 1.0% skim oil limit is exceeded, the BCER inspector or auditor may direct in writing that the operator implement changes to improve the skim oil percentage, and these directions will become conditions of operation for that battery/facility. Examples of conditions are as follows:

1) Investigate where the oil originated from.
2) Install proportional sampling or water cut analyzer at the receipt point.
3) Inform the source operator to ship emulsion to a proper treatment facility.
4) Report the oil receipt at the injection facility from the source battery/facility.

9.4.1.5. **Waste Processing and Disposal Facility**

All products received at a waste processing battery/facility must be metered, sampled, analyzed, and reported as oil, water, and solids according to the approval conditions.

9.4.2. **WGR Testing Methodology**

Well testing requirements are as follows:

1) The criteria for a permit holder to utilize a WGR for a non-effluent well is the same as a group separator as outlined in section 6.2.1.
2) Effluent well WGRs must be determined as per section 6.2.1 .
3) New wells must have the required tests conducted within the first 30 days of production and annually thereafter, unless otherwise stated or exempted If the Permit holder can demonstrate that the WGR has not stabilized, such as load water has not been fully recovered, multiple tests may have to be conducted over the next few months to determine the stabilized production WGR.
4) Wells that could have operation or production characteristics changed because of such events as workovers or chemical stimulations must have a test conducted within 30 days.

10. Chapter 10- Trucked Liquid Measurement

10.1. Introduction

This section presents the requirements for trucked liquid measurement from oil and gas production facilities to another battery/facility or sales. Applicable liquids include oil, condensate, water, NGLs, propane and butane.

Trucked liquid measurement requirements at a Cross Border Measurement battery/facility must adhere to the requirements outlined in Chapter 7 - Cross Border Measurement.

10.2. General Requirements

Crude oil or condensate may be found in association with water in an emulsion. In such cases, the total liquid volume of the trucked load must be metered, and the relative volumes of water in the emulsion must be determined by obtaining and analyzing a representative sample of the emulsion or by using a product analyzer such as a water-cut monitor or a Coriolis meter's density measurement (where applicable).

A permit holder must accurately measure produced liquids/emulsion volumes by using tank gauging, a weigh scale, or a meter, unless otherwise stated in this guideline. The delivery point measurement requirements must be met for all trucked liquids unless the exception conditions in this section are met or site-specific approval from the BCER has been obtained.

The BCER will consider a truck liquid measurement system to be in compliance if the following base requirements are met. The BCER may stipulate additional or alternative requirements for any specific situation, based on a site-specific assessment.

All delivery point meters must be proved in accordance with section 2. LACT meters may use the proving procedure in API MPMS, chapter 4 "Proving Systems," instead of the section 2 procedure.

10.2.1. Reporting Requirements

Monthly oil, condensate, and water volumes for well(s) (production) and battery('s)/facility('s) (production, receipts, and dispositions) must be reported as the number of cubic meters rounded to the nearest tenth of a cubic meter (0.1m^3). Metered volumes must be corrected to 15°C and at the greater of 0kPag or equilibrium vapour pressure at 15°C. See section 9.2.11.6 for production data verification and audit trail requirements.

For delivery point measurement, hydrocarbon liquid volumes must be determined to 2 decimal places and rounded to 1 decimal place for monthly reporting. If there is more than one volume determination within the month at a reporting point, the volumes determined to 2 decimal places must be totalled prior to the total being rounded to 1 decimal place for reporting purposes.

10.2.2. **Temperature Correction Requirements**

All delivery point measurement of hydrocarbons and emulsions requires temperature correction to 15°C (see section 9.2.5 Temperature Measurement). See section 9.2.9.1.3 for temperature determination requirements. Composite meter factors are not acceptable for delivery point measurements.

The temperature correction factor (CTL) must be determined in accordance with the API MPMS, Chapter 11.1. LPG must follow the applicable GPA Technical Publication TP-27 or an equivalent applicable procedure accepted by an appropriate industry technical standards association.

10.2.3. **Pressure Correction Requirements**

The pressure correction factor (CPL) must be determined in accordance with API MPMS, Chapter 11, and is required only for LACT applications.

10.3. **General Trucked Liquid Measurement Requirements for Various Battery / Facility Types**

10.3.1. **Oil Batteries / Facilities, Gas Batteries/Facilities, Gas Gathering Systems & Gas Plants**

For trucked hydrocarbon/emulsion production into an oil battery/facility, gas battery/facility, gas gathering system or gas plant, delivery point measurement is required for the total liquid volume. If there is a mixture of trucked-in production and prorated production within the same battery/facility, the exception criteria in section 5.6 must be met or BCER site-specific approval must be obtained.

For condensate trucked into an oil battery/facility, delivery point measurement is required for the total liquid volume. The requirements in section 5.6.2 must be met.

For any oil battery/facility, the trucked-out liquid is metered at the delivery point (located at the receiving battery/facility), and the oil volume determined at the receiving battery/facility must be used as the delivering battery's/facility's oil disposition. Proper measurement must be set up at the receipt point only, except for load oil delivery from a battery/facility to well(s). In this case, delivery point measurement is required at the loading battery/facility. If there are emergencies or problems at the receipt point, the origin measurement may be used, but only as a temporary solution.

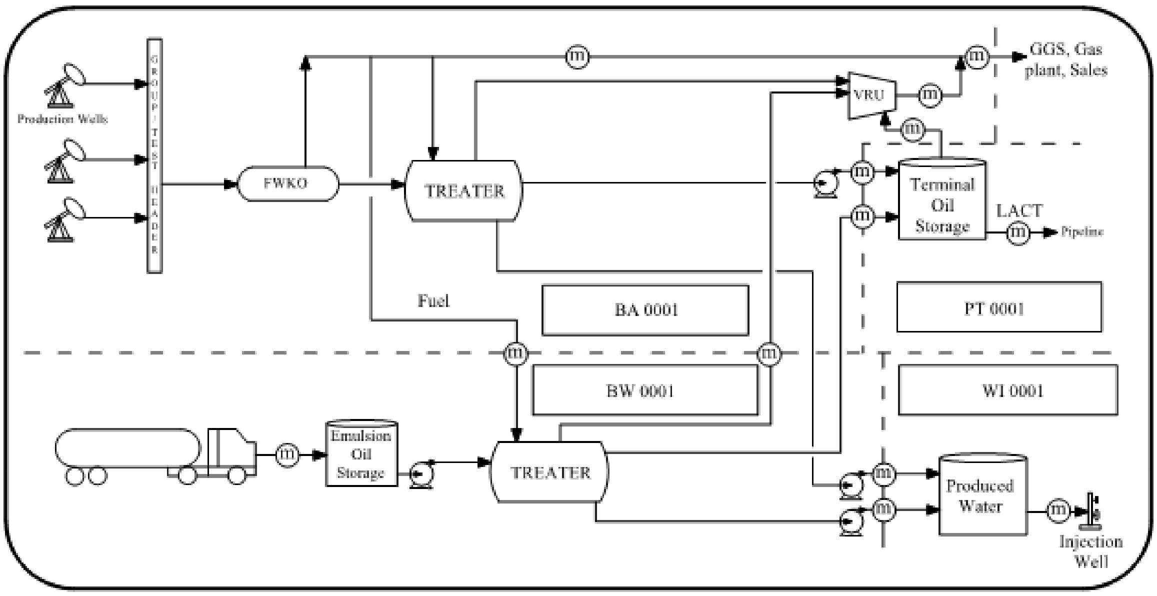
If clean oil from a battery (BT) is delivered into an oil pipeline via a LACT unit and that same BT also receives clean trucked oil, condensate, or diluent from other sources, a terminal (TM) Petrinex code must be obtained so that the clean trucked-in fluid is received at the TM instead of at the BT. The BT oil must also be measured with delivery point measurement before commingling with other fluids at the TM. The TM will then deliver the fluid to the pipeline via the LACT unit. If there is no delivery point measurement for the BT oil to the TM, measurement by difference rules apply.

Custom Treating, Oil Battery / Facility, and Terminal Delineation

A terminal is required when there is more than one source of clean oil going through a LACT meter into an oil pipeline. Any oil, water, and gas crossing a battery/facility boundary must be metered. If there is blending of hydrocarbon liquids of densities >40kg/m^3, such as butane blending with the oil before the LACT, the lighter hydrocarbon used for blending must be received and stored at the terminal and the oil production metered before the blending point.

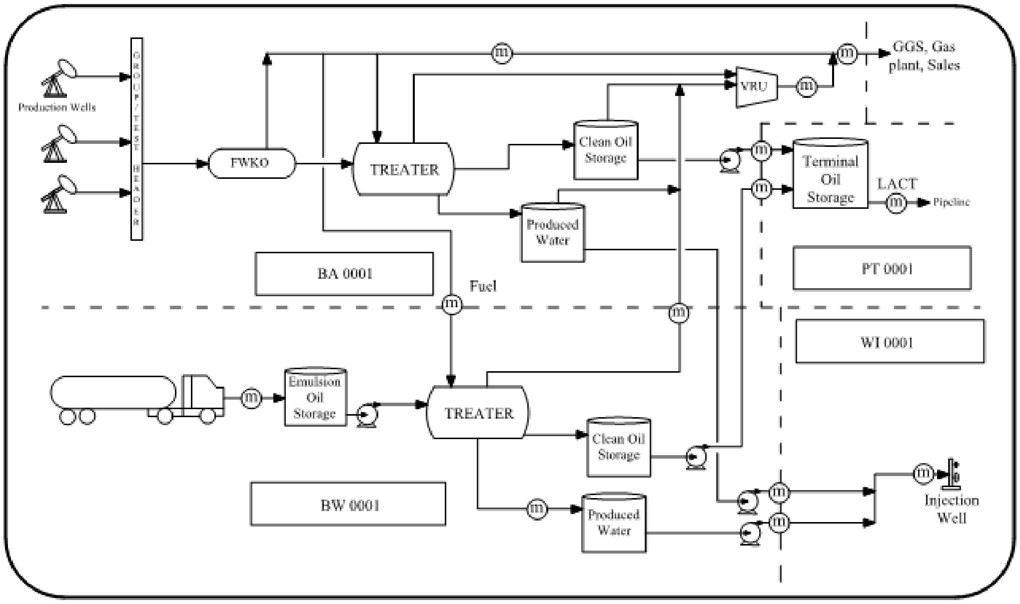
Scenario 1: Dedicated tankage for clean crude and produced water for both the crude proration battery/facility and the custom treating facility (See Figure 10.3-1).

Figure 10.3-1 Custom Treating, Oil Battery/Facility, and Terminal Schematic - Scenario 1



Scenario 2: Dedicated metering on treaters for water/oil and a shared tank for clean crude and produced water (See Figure 10.3-2).

Figure 10.3-2 Custom Treating, Oil Battery/Facility, and Terminal Schematic - Scenario 2



The main difference between the two scenarios is that Scenario 1 has dedicated tanks with metering off the tanks, whereas Scenario 2 has shared tanks but metering off each treater.

For both scenarios, the transfer of fuel from the proration battery/facility to the custom treating facility provides heat for the custom treater and pressure to help dump the treater to storage tanks. There is also a receipt meter for the gas coming back from the custom treater and terminal to the proration battery/facility.

10.3.2. **Custom Treating Facilities**

The measurement requirements are the same as for trucking into a conventional oil battery/facility above.

10.3.3. **Pipeline Terminals**

At the pipeline terminals that receive either pipelined and/or trucked clean oil, the receipt meter or weigh scale measurement is considered to be a custody transfer measurement. That is, there is no proration/allocation from the pipeline disposition volumes to the receipt (REC) volumes that are reported to Petrinex. Any measurement beyond this point is considered as downstream operations and not covered in this guideline.

However, if the downstream pipeline operator allocates to the shippers the imbalance (generally less than 1 per cent) on its pipeline system (according to the contractual requirements) and the allocated volumes are reported to Petrinex instead of the measured REC volumes, then the delivery point measurement requirement also applies to the measurement point(s) at the other end of the pipeline. This scenario also applies to section 10.3.4.

10.3.4. **Clean Oil Terminals**

Clean oil terminals are those that receive trucked and/or pipelined clean oil only; the receipt meter is considered as a delivery point. That is, there will be proration/allocation from the terminal LACT disposition volumes to the receipt volumes for that month.

10.3.4.1. **Exception**

Volumetric allocation of the monthly LACT volumes to the monthly truck receipt volume is not required at a clean oil terminal without BCER site-specific approvals if all of the following criteria are met:

1) The meter factor for each delivery point meter or the weigh scale accuracy verification must not deviate from the prior factor or verification by more than 0.5%.
2) Any deviation over 0.5% must be investigated and rectified, and allocation for the previous month(s) disposition volumes to the receipt volumes is required.
3) The monthly measurement difference between the receipts and dispositions after including allowances for blending shrinkage, if applicable, and the inventory changes at the clean oil terminal must be less than or equal to 0.5%.

The permit holder must revert to allocating monthly pipeline LACT volumes to the receipt volumes if any of the above criteria are not met.

10.3.5. **Gas Plants, Gas Batteries, and Gas Gathering Systems**

For gas systems receiving trucked liquid, the measurement requirements are the same as for trucking liquid into a conventional oil battery.

10.3.6. **Water Injection/Disposal Facilities**

For water trucked into an injection or disposal facility, delivery point measurement accuracy is not required. See Chapter 2 for battery/facility accuracy requirements.

10.3.7. **Waste Processing Facilities**

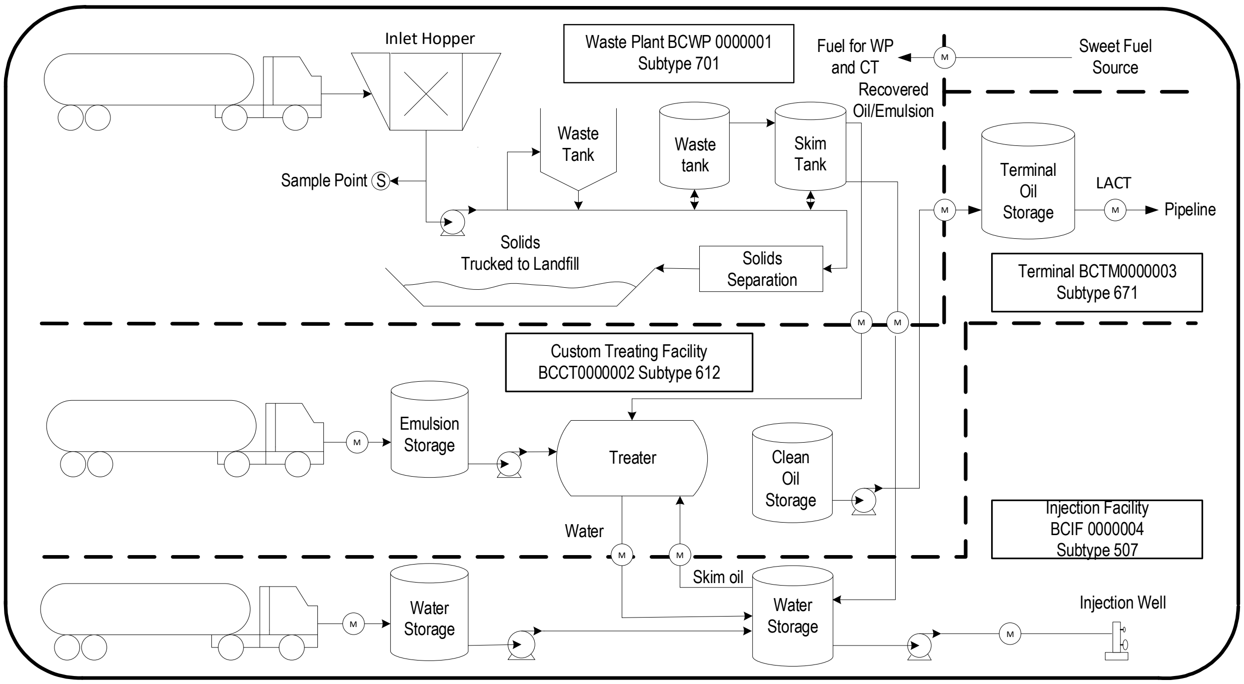
A waste processing facility handles volumes of waste generated in the upstream petroleum industry. However, many BCER-approved waste facilities have an integrated custom treating facility designated for processing oil/water emulsions extracted from the solids during waste processing. In addition, oil/water emulsions from other batteries are trucked in and metered independently from the waste oil/water emulsions, and both streams are processed through the same treating facilities. The total waste stream disposition to the custom treater (CT) must have emulsion volume and S&W determinations in order to properly allocate the clean oil and water volumes back to the other received emulsions. Therefore, delivery point measurement is required at the receipt point of non-waste truck unloading and at the total waste oil/emulsion delivery point to the custom treater for further processing, such as in a treater, where it is commingled with other oil/emulsion from other sources.

There are also injection/disposal facilities that receive other liquids, such as waste streams going into subsurface caverns for disposal. Waste liquids for disposal require measurement accuracy similar to disposal of produced water.

10.3.7.1. Integrated Waste Treatment Including Waste Plant (WP), Custom Treating (CT), Water Disposal (IF), and Terminal (TM) Delineation

Integrated oil and water processing and waste facilities are ones with various distinct processing and reporting entities. They are referred to as oilfield waste management facilities (OWMFs). See figure 10.3-3 below. Any fluids transferred between the different reporting facilities within the integrated site must be measured and reported. Report fuel gas receipt at the WP and fuel gas usage. No fuel gas transfer or fuel use reporting required at the CT in this case.

Figure 10.3-3 Integrated Waste Treatment Facility Delineation



10.4. Design and Installation of Measurement Systems

Delivery point measurement is required for most trucked fluids delivery/receipt except as mentioned above. The gross volume must be measured through a system consisting of inlet tank gauging, inlet meter, or weigh scale. Gauge boards must not be used for delivery point measurement.

Truck ticket estimates (i.e., volume estimates determined using the truck tank load indicator completed by the trucker or trucking company for bill of lading/transportation of dangerous goods purposes) are not considered as measurement for the purpose of well or battery/facility volume measurement. Therefore, truck ticket estimates must not be used for determining volumes unless the requirements in section 10.4.4 Load Fluids are met.

See section 9.2.2 for liquid measurement design and installation requirements.

10.4.1. **Meters**

Turbine meters are typically not suitable for viscous fluids and therefore are not recommended for unloading crude oil or stratified truck loads.

When metering devices for the purpose of measuring truck delivery/receipt volumes are installed, the following must also be installed:

1) sample point
2) air eliminator
3) proving taps

For some types of meters and applications, a strainer and a back pressure control system are required. See Figures in section 9.2.2 for examples of a typical liquid meter run installations acceptable by the BCER.

Additional requirements for clean oil and pipeline terminals:

1) For mechanical automatic temperature compensators without gravity selection (ATC) or with gravity selection (ATG):
   a. For new applications after date June 1, 2008, mechanical ATC and ATG must not be used. All existing ATC and ATG are grandfathered at their existing applications and must not be relocated or reused for other applications.
   b. The difference between actual density and compensation density must be less than 40kg/m3.
   c. Product temperature must be between –10°C and +40°C excluding LPGs.
   d. The compensation density (mechanically set density or user-entered density for electronic flow computers) must be a volume weighted average of the expected receipt volumes. When product temperatures exceed 40°C, it may be necessary to reduce the allowable density difference to maintain a 0.5% uncertainty.
   e. Temperature compensation devices must be designed for the actual range of operating temperatures observed. If product temperatures exceed 40°C, it may be necessary to reduce the allowable density difference to maintain a 0.5% uncertainty.

10.4.2. **Weigh Scales**

Weigh scales for the purpose of delivery point measurement must be verified in accordance with section 2.11. For sampling points and methods, see section 8.3. Systems employing weigh scales must also provide for determination of density of oil and water in accordance with one of the following:

1) API MPMS, Chapter 9: Density Determination Using Hydrometer,

2) precision laboratory method – ASTM method, or

3) on-line densitometer (Coriolis, nuclear device, etc.).

To maintain an uncertainty of 0.5% or less, the net weight of the payload must not be less than 40% of the gross vehicle weight and the net weight must not be less than 6500 kg. An exemption from this requirement is granted only during seasonal road ban periods when reduced truck loads are mandated by weight restrictions.

10.4.3. **Exceptions**

10.4.3.1. **Truck-Mounted Level Gauges and Truck-Mounted Meters**

Truck gauge level indicators and truck-mounted meters are considered to have met the requirement for low-accuracy measurement with an overall uncertainty of ±1% or less if the following criteria are met. These units can be used for trucked-in delivery point measurement to proration oil batteries if all of the following requirements are met:

1) the battery/facility receives not more than 100m^3 of trucked-in oil per day;

2) the maximum percentage of trucked-in oil to any battery/facility is 10% of the monthly total battery/facility oil production volume.

3) the gauges or meters are verified/proved annually and if not within ±1% accuracy they are repaired and recalibrated/reproved.

4) the product temperature is determined to within 1°C; and

5) the truck gauge levels or meters are initially set by calibrating to a master meter or provers with a demonstrated uncertainty of not more than 0.2%.

Additional criteria for truck-mounted level gauges:

1) the stated depth of liquid is within 12.7mm of a known gauge level marker if used;

2) the depth of liquid is determined while the tank trailer is level to within 150mm over its length; and

3) the minimum load on the trailer is more than 65% of full load.

10.4.3.2. **Truck Tickets and Lease Tank Gauging**

Truck ticket volumes uncorrected for temperature are not acceptable for delivery point measurement of trucked liquid. If the fluid transfers are between unitized or common equity facilities with common royalty, then the temperature correction estimates may be used. The truck ticket must be based on a low-accuracy measurement requirement with an overall uncertainty of ±1% or less of trucked liquid, such as lease tank gauging at the battery/facility sending the liquid production or truck-mounted meter, for determining inlet volumes at a proration battery/facility if certain situations exist. The S&W% and corrected opening and closing readings must be on the ticket or available on a summary sheet for BCER audit purposes. An individual truck load should be recorded on its own ticket.

The BCER may accept low-accuracy measurement with an overall uncertainty of ±1% or less for trucked liquid production at a proration battery/facility if:

1) trucked production is temporary, pending battery/facility consolidation within one year or less;
2) individual well oil volumes being trucked are less than 2.0m^3/day;
3) the crude oil volume receipt (net of water) is 5% or less of the total receiving battery/facility oil production; and
4) truck-mounted meters used for low-accuracy measurement with an overall uncertainty of ±1% or less are proved in accordance with the requirements in Chapter 2.

10.4.4. **Load Fluids**

Load fluids at a minimum must be measured using devices that meet the requirement for low-accuracy measurement an overall uncertainty of ±1% either at the source (loading) location or at the delivery point. Reporting of load fluid on Petrinex is limited to oil-based and/or water-based fluid(s) injected during preproduction well stimulation or postproduction activities. Only the load fluid product codes OIL, COND, or WATER can be reported. Well drilling fluids must not be reported on Petrinex as load fluids.

10.4.5. **Split Loads**

A split load is defined as existing when a truck takes on partial loads from more than one well or battery/facility in a single trip or when load oil is delivered to more than one receipt point or wells.

Permitted	Single-well oil battery/facility delivering to other facilities. Gas wells with the total condensate and water production < than 2.0 m3 per day. No restrictions for split loads for produced water only. Load oil for well servicing only; load up from a single source only.
Not Permitted	Multiwell batteries/facilities delivering to other facilities other than load oil: if the condensate/oil production > 2.0 m3/day/well. if the emulsion (condensate/oil and water) > 2.0 m3/d/well
Requirements	Densities must be “similar” (within 40kg/m^3). If they are not, blending tables are required to calculate shrinkage. The shrinkage volume must be prorated back to each battery/facility on a volumetric basis.

Measurement Volume from each well or battery/facility must be measured at the time of loading onto the truck (or offloading from the truck for load oil) by one of the methods below:

1) gauging the battery/facility lease tank.

2) gauging the truck tank (not allowed for density difference over 40kg/m^3 for any oils or emulsions); or

3) truck-mounted meter/gauge that meets low-accuracy measurement and is proved at least annually.

Calibrated gauge tables are required for methods (1) and (2) above.

Sampling Fluid from each single-well oil battery/facility must be sampled to determine the S&W and the oil/water volumes. The truck driver must collect the samples by taking at least three well-spaced grab samples during the loading period.

For load oil, the S&W must be determined at the loading source.

Records The truck tickets must show the individual load volumes, as well as the total volume at delivery (receipt) point, supported by opening and closing gauge or meter readings.

Accounting For battery/facility emulsions, the total load must be measured and sampled at the receiving location and prorated to each of the wells based on the measured loading volumes and S&W from each of the wells.

For load oil, the initial volume must be measured at the loading source and prorated to each delivery point based on the measured volume delivered to each well.

10.4.6. **Sampling and Analysis**

For trucked-in hydrocarbons and emulsions receipt/delivery, a truck thief sampler or a proportional sampler may be used to obtain a sample from the truck tank. In some cases spot (grab) samples may be used to obtain the sample from the off-load/load line. Automatic sampling methods are preferred; however, manual or tank sampling systems may also be allowed, as discussed below.

The frequency of sampling or readings must be sufficient to ensure that a representative sample of the entire truck volume is obtained. Consideration must be given to both conditioning the flow stream and locating a probe or sampler. Flow conditioning to ensure turbulent mixing can be achieved through velocity control, piping configurations, or introduction of a mixing element upstream of the sample point. A sample probe is required for truck delivery point sampling unless there is an in-line product analyzer, or the sampling is incorporated as part of the measurement system. A mid-pipe probe location should be used for accurate sampling.

The permit holder must choose the sampling methodology based on emulsion characteristics, stratification, and S&W consistency of each load to obtain a representative sample. API MPMS, Chapter 8.1, section 8, provides further information on manual sampling procedures.

10.4.7. **Automatic Sampling**

Automatic sampling is typically conducted through the use of proportional samplers. If automatic sampling procedures are used, a manual procedure should also be in place for use when the automatic system is out of service or for intermittent verification of the automatic system reading. For more information, API MPMS, Chapter 8.2, sections 7 to 15, provide further details on flow conditioning, probe location, and sampling frequency. Other requirements for automatic sampling are found in section 8.3.1.

10.4.8. **Manual Spot (Grab) Sampling**

Manual spot (grab) sampling may be acceptable in situations involving a tight emulsion with less than 0.5% S&W in the truck by taking three well-spaced grab samples during the unloading period. Grab samples are not acceptable when there is stratification of S&W within the truck.

The use of manual sampling techniques, such as truck tank thieving (full height or intermittent), may also be acceptable. However, in the presence of stratification, one unit of height at the bottom of the truck tank represents a significantly lesser volume than the same unit of height at the midpoint of the truck tank because of the shape of the tank. The resulting S&W from a full-height core thief therefore may not be representative of the entire load. Which then inhibit the use of grab samples.

Lease tank thieving is subject to similar stratification limitations (excluding the non-uniformity of the tank).These concerns can be reduced by locating any water-emulsion interface and obtaining bottom, middle, and top samples of the emulsion to determine the average water cut of the emulsion. However, lease tank thieving requires dedicated tankage for each load received or delivered to avoid mixing of product between deliveries.

Visual estimates or estimates based on changing off-load pump speeds must not be used for free water volume determination.

10.4.9. **S&W Determination**

The permit holder must select the most appropriate method for determining the S&W. See section S&W Determination and Appendix G – Manual Water-Cut (S&W) Procedures

10.4.10. **Density Determination**

Truck load sample density determination at 15°C must be conducted at least annually, or more frequently if there are changes in the hydrocarbon liquid and water production characteristics. Density of the load may be determined by one of the following methods:

1) Truck load samples may be collected from the receiving point and sent to an independent laboratory for analysis must determine absolute density of the hydrocarbon phase and the water phase (if required). The density found in this analysis must be applied to all hydrocarbon liquids coming from the specific battery/facility.

2) Truck load samples or samples from automatic samplers may be tested for density as outlined in section 9.2.7.

In applications where an automated measurement system with integrated software is not used, and the truck volumes have a S&W greater than 1%, density determination at 15°C of an emulsion sample is difficult. There are two different thermal corrections to be applied, one for the water and one for the hydrocarbon liquids.

The two options are:

1) The first must determine the sample density using a precision densitometer that has its measuring cell at 15°C. No further corrections are required.

2) The second must separately predetermine the density at 15°C of the water and the hydrocarbon liquids. When using this option, the emulsion density is calculated manually by applying the S&W cut to the density of each component. The calculation is

   Pemulsion = (PHCL x (100 - %S&W)) + (Pwater x %S&W)

   Where: Pemulsion is the calculated density of the emulsion at 15°C

   PHCL is the density of the hydrocarbon liquid portion at 15°C

   Pwater is the density of the water portion at 15°C

10.5. Volume Determination

10.5.1. Tank Gauging

Tank gauging procedures are detailed in section 9.2.8. The starting and closing levels measured are then converted to volume through the use of gauge tables (supplied by the tank manufacturer), which have been calculated using measurements of the tank. The difference between the closing and opening volumes is the measured volume. If the tank is used for delivery point measurement, the temperature and density of the tank contents must be taken in order to correct the indicated volume to standard conditions before determining the volume difference.

10.5.2. Weigh Scales

The procedure for determining the volume of liquid on a truck using a scale must weigh the truck before and after loading or unloading and determine the difference to obtain the net weight. The entire load must be weighed at a time—i.e., split weighing, whereby the truck is weighed after unloading a portion of its load to obtain the weight of the unloaded portion, is not permitted.

To determine the density of the load, an on-line densitometer may be used or a representative sample must be obtained and the density and temperature measured with a hydrometer and thermometer respectively. The observed density must be corrected to 15^{o}C.

The net weight determined during the weighing process divided by the sample density at 15°C results in the net volume of the load prior to deductions for S&W.

10.5.3. Meters

Metered volumes must be determined in accordance with Chapter 9.

11. Chapter 11- Acid Gas and Sulphur Measurement

11.1. Introduction

This section presents the base requirements and exceptions for acid gas and sulphur measurements at processing plants and injection facilities in the upstream oil and gas industry that are used in determining volumes for reporting to FIN for volumetric and carbon tax reporting purposes. The product of Acid Gas (ACGAS) must be reported as FLARED if it is actually flared (or incinerated) at a gas processing plant, or a liquefied natural gas facility.

The Activity of Shrinkage for the Product of ACGAS is valid, for instances where ACGAS is not actually being Flared (or incinerated). This Product/Activity combination can only be reported at gas processing plants and liquefied natural gas facilities.

The requirements for reporting flared/incinerated acid gas as FLARE/ACGAS become mandatory effective January 1, 2020; however, operators are strongly encouraged to adopt these new reporting changes prior to that date so that they can test their systems and be prepared for when this reporting becomes mandatory.

Note: ACGAS/FLARE is only permitted at facility subtypes that currently allow the reporting of ACGAS/SHR.

In a gas processing plant where sour gas is processed, most of the acidic portion of the gas must be removed from the gas stream (sweetening) in order to produce a saleable pipeline quality gas product. However, in the process of removing the acidic portion of the sour gas, acid gas, which consists mainly of H_2S and CO_2, is generated and must be disposed of in an environmentally and economically acceptable way, such as by elemental sulphur production, acid gas injection, or acid gas flaring.

11.2. General Requirements

The sour gas plant inlet and acid gas streams must be metered and reported in such a manner that meets the requirements set out in this chapter, those set out by the British Columbia Air Quality Requirements “Sulphur Recovery Criteria for Natural Gas Processing Plants” and those outlined in the BCER’s British Columbia Flaring and Venting Reduction Guideline.

The acid gas from the sweetening process is generally saturated with water vapour (wet). This water vapour portion must be subtracted from the saturated acid gas to obtain the dry volume without water vapour per section 11.3.

11.3. Acid Gas Measurement

The quantity of acid gas going to sulphur plants, to compression and injection, or to flaring is generally metered at a low pressure of 50 to 110kPag; therefore, metering must be appropriately sized and well maintained to achieve accurate measurement.

Acid gas is saturated with water vapour, which represents a significant portion of the total gas measured. The amount of water vapour varies significantly with the temperature of the reflux drum. Therefore, the acid gas meter must have continuous temperature correction (see section 4.4.1) to calculate the correct acid gas volume (see section 11.3.1). The gas density must also include the water content, and the meter coefficient must include a factor to exclude the water vapour content of the gas in the final volume computation for reporting purposes. The accuracy of the gas relative density factor and water content determination must be periodically verified to ensure that acid gas measurement uncertainty is within tolerance.

11.3.1. **Determining Acid Gas on a Dry Basis**

For ideal gases, the total vapour pressure of a system containing several components is the sum of the vapour pressure of the individual components at the temperature of the system.

The component's vapour pressure percentage of the total pressure of a system is equal to the volume percentage of that component in the system. The reflux drum is the vessel in which the acid gas separates from the sweetening solution. The amount of water vapour in the acid gas leaving the reflux drum is a function of the temperature and the absolute pressure in the reflux drum.

Calculating Acid Gas Flow Rate

The calculation method for the acid gas flow rate is as follows:[1]

Step 1: Determine the percentage of water vapour in the acid gas on the basis of the ratio of vapour pressure of water to total pressure in the reflux drum at the reflux drum temperature.

Step 2: Convert the acid gas composition from dry basis to a wet basis at reflux drum pressure and temperature, and determine the acid gas relative density and compressibility factor on a wet basis at meter pressure and temperature.

Step 3: Calculate the acid gas and water vapour flow rate corrected from actual flowing pressure and temperature to standard conditions of 101.325kPa(a) and 15°C.

Step 4: The volume calculated in step 3 contains water vapour in the percentage determined in step 1 and must be converted to dry basis volume for reporting purposes. A correction factor (CF) has to be applied to correct the acid gas flow from a wet to a dry basis.

CF = (100.00 – % H_2O in acid gas)/100

[1] Wichert, E., "Water content affects low pressure, acid-gas metering," Oil & Gas Journal, January 2, 2006, pp. 44–46.

Dry acid gas flow rate = CF x flow rate calculated in Step 3

The H_2S content of the acid gas is the dry basis acid gas flow times the % H_2S /100 in the acid gas on a dry basis.

Calculating Vapour Pressure of Water

The formula for determining the vapour pressure of water[2] is

$$\log P = A - B/(C + T)$$

where: P = water vapour pressure in mm of mercury
A = 8.10765
B = 1750.280
C = 235
T = temperature of acid gas in reflux drum (°C)

The direct formula for determining the vapour pressure of water in kPa(a) is thus

$$P_{H2O} = 0.13332 * 10^{(8.10765 - 1750.280/(235 + T))}$$

where: P_{H2O} = water vapour pressure in kPa(a) at T°C

$$\% \ H_2O \text{ in the acid gas} = 100\ \% * P_{H2O}/(P_{RD} + P_{atm})$$

where: P_{RD} = reflux drum pressure, kPag

P_{atm} = atmospheric pressure, kPa(a)

Converting Acid Gas Calculation from Dry to Wet Basis

An example acid gas conversion calculation from dry to wet basis with the meter installed upstream of the back-pressure regulator of the reflux drum is provided below:

A. Reflux drum data

Reflux drum temperature = 40°C
Reflux drum pressure = 70kPag
Atmospheric pressure = 95.0kPa(a)

[2] The vapour pressure of water at a certain temperature can also be obtained from the GPSA Engineering Data Book, SI Units version, 12th edition, 2004 or subsequent versions, Figures 24–36.

If the meter is installed upstream of the back-pressure regulator of the reflux drum, the upstream pressure and the temperature of the meter run may be used as the reflux drum pressure and temperature.

B. Acid gas components on a dry basis from acid gas analysis:

H_2S = 65%; CO_2 = 33.5%; C_1 = 1.2%; C_2 = 0.3%

C. Calculate the percentage of components, including water vapour, on a wet basis:

Percentage of water vapour =

$$\frac{100\% * \text{Vapour pressure of water at } 40°\text{C}}{\text{Reflux drum gauge pressure} + \text{atmospheric pressure}}$$

P_{H2O} $= 0.13332 \times 10^{(8.10765 - 1750.280/(235 + 40))}$
$= 7.377$ kPa(a)

(Vapour pressure of water at 40°C is 7.384kPa(a), from the Saturated Steam Table in the Thermodynamics section of the GPSA SI Engineering Data Book, Figures 24-36.)

Percentage of water vapour =

$$\frac{7.377}{(70 + 95) * 100\%} = 4.47\%$$

Enter into column 2 (see the following table) and normalize.

Table 11.3-1 Converting Acid Gas Calculations from Dry to Wet Basis

Comp.	Col. 1 Dry basis (%)	Col. 2 Wet basis (%)	Col. 3 Molar mass (kg/kmol)[1]	Col. 4 (Col.1*Col.3) / 100	Col. 5 Col.2*Col.3) / 100
H_2S	65.00	62.09	34.082	22.153	21.162
CO_2	33.50	32.00	44.010	14.743	14.083
C_1	1.20	1.15	16.042	0.193	0.184
C_2	0.30	0.29	30.069	0.090	0.087
H_2O	0.00	4.47	18.0153	0.000	0.805
Total	100.00	100.00		37.179	36.321

[1]Molar mass of air = 28.9586 kg/kmol (GPSA Engineering Data Book, 2004 or later editions, Figure 23-2, or GPA-2145).

From column 4, ideal gas RD, dry basis = 37.179/28.9586 = 1.284.

From column 5, RD wet basis = 36.321/28.9586 = 1.254 (this RD must be used in the flow calculation for acid gas volumes).

11.3.1.1. Difference Between the Acid Gas Volume on a Wet Basis and on a Dry Basis

An example calculation is presented to show the difference in the results of the acid gas flow rate and the sulphur content of acid gas using dry versus wet basis metering. The example data for the meter run and assumed conditions are as follows:

Orifice meter diameter: 154.051mm
Orifice plate diameter: 76.200mm
Meter upstream pressure: 70.00kPag
Differential pressure: 10.00kPa
Meter temperature: 40°C
Atmospheric pressure: 95.0kPa
Acid gas composition: per above table

Results with AGA #3 1992 or later method:

Flow rate, dry basis without accounting for moisture content
= 33.126e³m³/d
Sulphur content = 33.126 x 65/100 * 1.35592 = 29.20t/d
Flow rate, wet basis = 33.499e³m³/d, containing 4.47 vol % H_2O
Flow rate, wet basis converted to dry basis
= 33.499 * (100 – 4.47)/100
= 32.002e³m³/d dry acid gas equivalent

This volume, 32.0e³m³/d, must be reported as "Acid Gas" on the monthly volumetric submission.
An example for percentage difference in acid gas volume between dry and wet basis:

% difference in flow rate = (33.126 – 32.002) * 100 %/32.002 = 3.51%
Sulphur content = 32.002 * 65/100 * 1.35592 = 28.21 t/d
Difference in calculated sulphur balance between dry and wet basis metering
= 29.20 – 28.21 = 0.99t/d
Percentage difference = 0.99 x 100/28.21 = 3.51%

Thus, if the moisture content in the metering of the acid gas in this example were ignored (dry basis taken as wet basis), the reported acid gas flow and sulphur content in the acid gas leaving the reflux drum would be 3.51% higher than the correct value.

This method of estimating the water vapour content is valid when the gas is in contact with water in a low-pressure vessel, such as in the reflux drum. The method does not apply to low pressure gas, such as in a flare line, when the flared gas originates from a high-pressure vessel.

The table below summarizes the above figures and also provides the results that are obtained by the 1985 AGA # 3 Report method, using Wichert-Aziz (W-A) compressibility factors.

Table 11.3-2 Acid Gas Volume on a Wet Basis and on a Dry Basis

Item	AGA #3, post-1992		AGA #3, 1985, W-A Z factors[1]	
	Dry basis	Wet basis	Dry basis	Wet basis
Z factor at St'd P and T	0.992 848	0.991 999	0.993 037	0.992 788
Z factor at Meter P, T	0.991 002	0.990 030	0.991 007	0.990 674
Flow rate, e^3m^3/d	33.126	33.499	33.096	33.481
Corrected to dry gas	-	32.002	-	31.984
% difference	-	3.51	-	3.48
Sulphur flow, t/d	29.20	28.21	29.17	28.19
% difference, t/d		3.51		3.48

[1]Z factors by Wichert-Aziz method, including water content in wet gas.

11.3.1.1.1. Calculation Method of Water Content if Meter Located Downstream of Back- Pressure Valve of Reflux Drum

The water content in the acid gas is a function of the pressure and temperature of the reflux drum. If the acid gas meter is located downstream of the back-pressure regulator of the reflux drum, both the pressure and the temperature of the meter will be somewhat lower than the pressure and temperature of the reflux drum. Under these conditions, it is still necessary to determine the water vapour content of the acid gas stream at the reflux drum pressure and temperature, as shown above, to correctly calculate the acid gas flow rate.

The reflux drum pressure must be recorded for the correct calculation of the water vapour content of the acid gas. The reflux drum temperature should also be used to estimate the water content. However, since the flow data from the meter include the temperature at the meter run, the reflux drum temperature can be estimated on the basis of the meter temperature, as follows:

$T = T_m + 2.28 – 2.28 * P_2/(P_{RD} + P_{atm})$

Where P_2 = the downstream meter tap pressure, kPa(a)

T_m = temperature downstream of the orifice plate

Having estimated the temperature at the reflux drum from the temperature downstream of the orifice plate, the vapour pressure of the water can be calculated as above. The percentage of water vapour in the acid gas can then be determined using the reflux drum pressure, and the same procedure as outlined in the above example can be used to calculate the acid gas flow rate.

11.3.1.2. Effect of Compression and Cooling of Acid Gas

In the situation of acid gas compression and injection, the acid gas flow rate may in some instances be metered after one or more stages of compression and cooling (see section Acid Gas Injection/Disposal Facility). This will remove a sufficient amount of water so that the remaining water vapour in the compressed and cooled acid gas will have little effect on the acid gas metering. In such a situation, it is not necessary to include the effect of water vapour in the metering of the acid gas.

11.4. Sulphur Measurement and Pit Volume Determination

11.4.1. Sulphur Pit Volume/Tonnage Determination

When pit gauging is used to determine a liquid sulphur volume, the gauging procedures must be conducted in accordance with the following:

1) The operator must ensure that the gauge/strapping table used to convert the gauge level to a liquid volume is specific for the pit being gauged.
2) Pit gauging should be used for inventory determination only and must not be used for delivery point measurement.
3) All dip sticks and electronic level devices must have a minimum resolution of 6 mm.
4) It is acceptable to have one reading per determination.
5) The sulphur density at pit temperature is obtained from Figure 11.4-1 Liquid sulphur density vs. temperature.

The general formula for determining the produced sulphur tonnage is as follows:
Sulphur tonnage = Gauge reading x CF x Sulphur density
where: CF = Pit gauge/strapping table conversion factor

11.4.2. Sulphur Measurement

Sulphur sales/delivery point measurement using meters, must meet the requirements in section 9.2.5. These meters must be kept at a temperature so that the molten sulphur will not solidify when there is no flow.

For sulphur sales/delivery point measurement using a weigh scale, see section 2.11.

For daily sulphur production measurement using pit level gauging, two pits are required, one for production and the other for withdrawal using level measurement. The daily sulphur production tonnage should be adjusted by the total monthly disposition at the end of the month.

11.4.2.1. Exceptions

For daily sulphur production volume determination, if there is only one pit in place in an existing plant and sulphur is being withdrawn without measurement, the operator may use the measured acid gas volume on a dry basis, provided that there is a continuous acid gas sampling device, such as a gas chromatograph, to calculate the sulphur tonnage entering the sulphur plant. The daily sulphur production can then be calculated using the following formula:

Estimated daily sulphur production (t) = Daily acid gas inlet (t) – Daily incineration (t) – Daily flared (t) – Others if applicable (t).

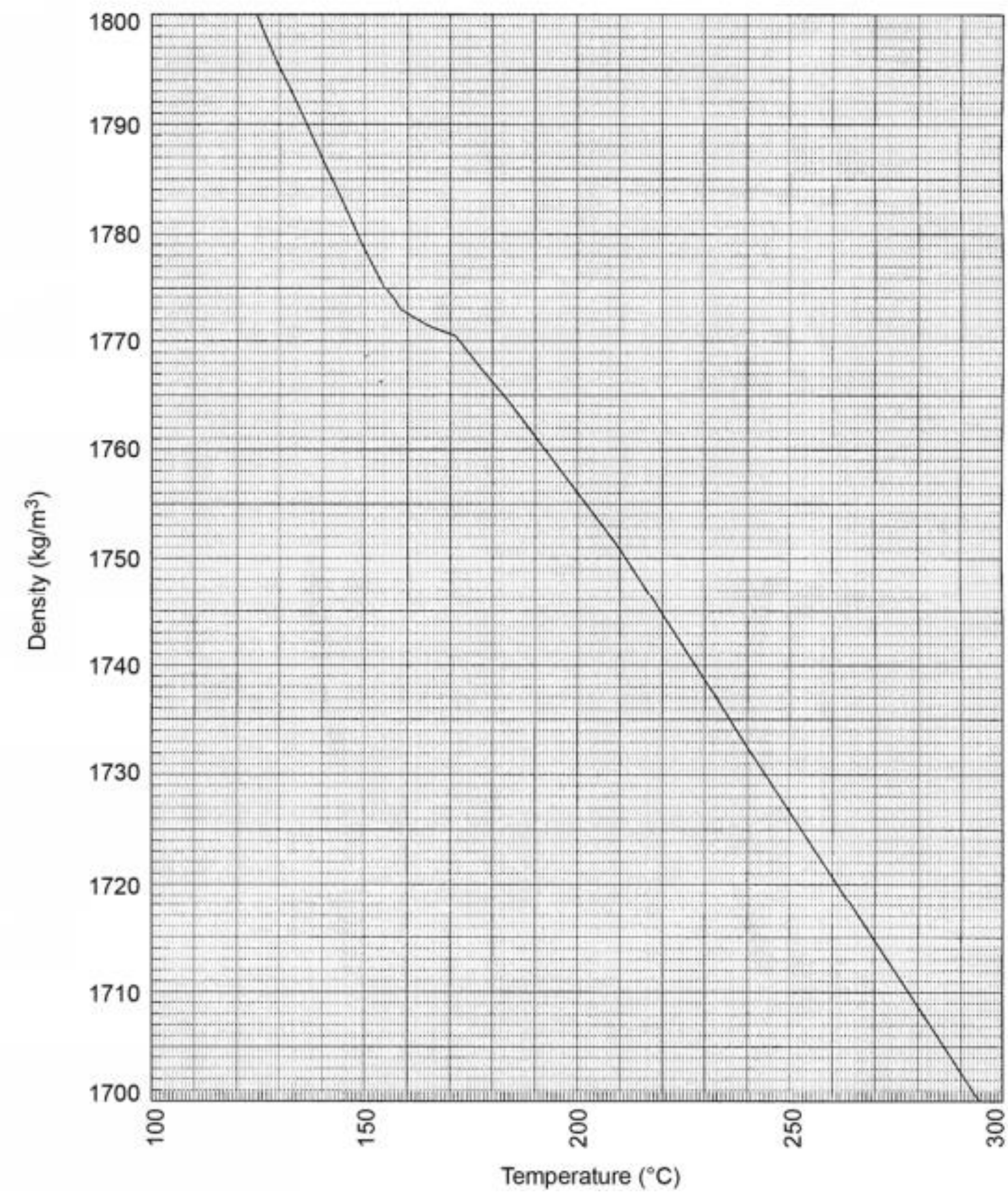
The estimated daily sulphur production tonnage must be adjusted by the total monthly disposition at the end of the month by calculating a proration factor and applying that to all estimated daily production tonnage:

Sulphur proration factor (S_{pf}) = Total monthly sulphur disposition tonnage (including inventory changes) ÷ Total estimated daily sulphur production tonnage

Actual daily sulphur production (t) = Estimated daily sulphur production (t) × S_{pf}

The "actual daily sulphur production" is the daily production tonnage to be reported on the BC-19 Report.

Figure 11.4-1 Liquid sulphur density vs. temperature



11.4.3. **Sulphur Balance Calculation for Sour Gas Processing Plants**

When sour gas is produced to a sour gas treating plant, it always enters the plant through a plant inlet separator. A liquid water phase is usually present with the sour gas, and in many instances a liquid hydrocarbon phase can also be produced into the separator with the gas and water. In such situations, all three phases will contain some H_2S in different proportions.

All of the H_2S entering the plant in the different fluids will also exit the plant by one means or another. The balance is an important part of checking to ensure that all streams are accounted for and reported. The BC-19 reports a monthly balance between the accounting of the mass of sulphur entering and leaving the plant for sour gas plants with an approved sulphur inlet rate greater than 1t/d. To achieve this objective, certain minimum measurements of concentrations and flow volumes must be made by the plant operator. This section provides the minimum requirements to achieve the desired goal.

If a monthly balance in cannot be achieved on a regular basis, the operator must implement appropriate measures to ensure that the required plant-wide balance is achieved. Appropriate measures include, but are not limited to,

1) improving the acid gas, inlet gas, flare, and sulphur measurement systems.
2) installing a continuous gas analyzer on the gas stream of the plant inlet separator and/or on the outlet gas stream of the reflux drum for acid gas flaring plants.
3) installing a proportional sampler on the gas stream of the plant inlet separator; and
4) improving the methodology for determining sulphur content in inlet condensate and water.

11.4.4. **Overview of Plant Inlet and Outlet Points for H2S**

Figure 11.4-2 illustrates the paths by which H_2S enters the sour gas plant and by which method it can exit from the plant.

The H_2S entering the plant in the gas, condensate, and water has to be accounted for on the BC-19 report in terms of tonnes of elemental sulphur. Since the flow volumes of the three types of fluid streams out of the inlet separator are required to be measured, it becomes a simple task to account for the amount of H_2S entering the plant by determining the H_2S concentration in each stream.

11.4.5. **Determining H2S Contents**

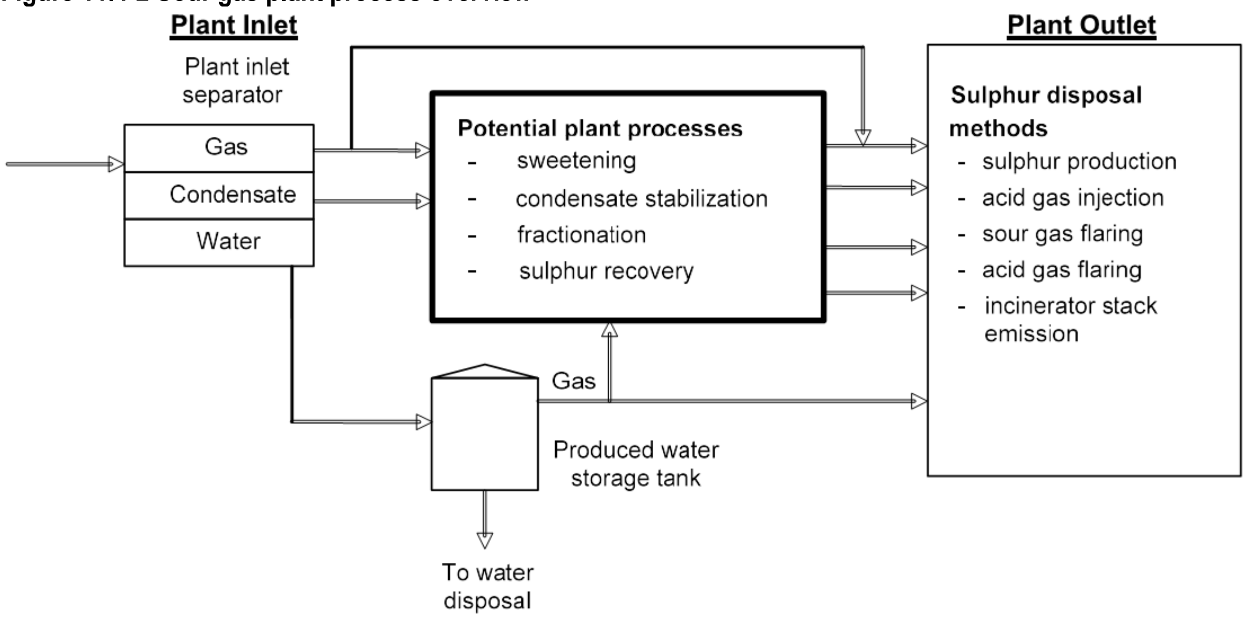
11.4.5.1. **Determining H2S in Sour Gas**

See: section 8.3 for the sampling requirements used in the determination of H_2S concentration in the inlet gas stream.

11.4.5.2. **Determining the Concentration of H2S in Condensate**

Condensate associated with sour gas will contain some H_2S. The physical relationship between the concentration of H_2S in the gas and in the condensate depends on the composition of the gas and the condensate and the pressure and temperature in the plant inlet separator. The concentration of the H_2S in the condensate is usually determined in a laboratory on condensate samples obtained from the inlet separator.

Figure 11.4-2 Sour gas plant process overview



As long as the gas and condensate entering a sour plant originate from a single pool, the H_2S concentration in the condensate will likely remain quite stable at the sampled conditions of pressure and temperature. Minor changes in pressure and temperature of the separator will only have a slight influence on the composition of the condensate. If major changes in pressure occur, such as due to installation of plant inlet compression and the resultant lowering of the inlet pressure, new samples must be taken and analyzed.

If the production to the plant occurs from two or more pools with different reservoir fluid compositions, the composition of the condensate will vary. In such cases, a vapour/liquid equilibrium correlation between the mole fraction of H_2S in the sour gas and the condensate can be used to estimate the mole fraction of H_2S in the condensate based on compositional analysis, computer process simulation, or stabilizer overhead volume and % H_2S to ensure acceptable accuracy for the BC-19 report balance.

11.4.5.3. **Determining Concentration of H2S in Inlet Separator Water**

The concentration of H_2S dissolved in the water that enters the plant inlet separator is a function of the separator pressure and temperature, as well as the concentration of H_2S in the sour separator gas. The amount of H_2S dissolved in the water can be predicted quite readily with correlations based on compositional analysis or computer process simulation.

Water can be metered ahead of the liquid level control valve on the water outlet line from the separator, or it can be gauged in a low-pressure produced water storage tank. The vapours from the tank are usually swept from the tank to flare with sweet gas. Some plants producing large amounts of sour water have installed a vapour recovery system, by which the tank vapours are conserved and treated in the processing plant.

If the total estimated sulphur content dissolved as H_2S in the sour water is less than 0.05t/d (50kg/d), the amount may be ignored in the balance determination.

It is recognized that a portion of the H_2S in the water of the plant inlet separator will remain in the water when the water is disposed of in a disposal well. This amount of H_2S is small and will depend on the water temperature in the produced water storage tank at atmospheric pressure, the amount of agitation in the water, and whether sweet gas is used for sweeping the vapours from the tank to flare. The small amount of H_2S remaining in the water is difficult to estimate and therefore need not be included in the disposal accounting.

11.4.6. **Calculation Procedure for Estimating the Plant Sulphur Inlet Mass per Day**

1) The following streams must be accurately metered:

   a. Sour gas out of the separator, Q, e^3m^3/d,

   b. Sour condensate out of the separator, converted to gas equivalent volume, e^3m^3/d, and

   c. Sour water out of the separator or into the storage tank, m^3/d, if required.

2) The sulphur content in the sour gas out of the separator can be calculated:

   Sulphur equivalent in sour gas, t/d = (Q, e^3m^3/d) (y) (1.35592)
   where: y is the mole fraction of H_2S.

3) The condensate must be sampled and analyzed semi-annually as a minimum frequency, in accordance with Chapter 8. When there are continuous gas analyzers and the H_2S content in the gas stream changes, the sulphur content in the condensate out of the separator can be calculated on the basis of the mole fraction of H_2S in the separator gas. The formula below should be used. Any alternative methods used must be supported by documentation that it is equivalent to the above method and made available to the BCER upon request.

   $x = y/K$

   where: x = mole fraction of H_2S in the separator condensate
   y = mole fraction of H_2S in the sour gas in the plant inlet separator
   $K = A + (B-A)\,(T/66)^{1.2}$
   $A = -0.7034\,(\mathrm{LOG}_{10}(P))^3 + 9.1962\,(\mathrm{LOG}_{10}(P))^2 - 39.58\,\mathrm{LOG}_{10}(P) + 56.695$
   $B = -3.9694\,(\mathrm{LOG}_{10}(P))^3 + 46.021(\mathrm{LOG}_{10}(P))^2 - 178.95\,\mathrm{LOG}_{10}(P) + 234.35$
   T = temperature of the sour gas in the plant inlet separator or metering temperature, ºC
   P = pressure of the plant inlet separator, kPa(a)

   Sulphur equivalent in condensate, t/d = (Gas equivalent of condensate, e^3m^3/d) (x) (1.35592)

The range of applicability of the above method for determining x, the mole fraction H_2S in condensate, is between 700 to 9000kPa(a) and 0 to 80°C.

4) The amount of H2S dissolved in the water, z (mole fraction), in the plant inlet separator can be estimated by the following formula:[3]

$$z = y/(4.53 – 7494.6/P + 758.4 (1.8 T + 32)/P + 4.65 y)$$

where all terms are as defined above.

Sulphur equivalent in water, t/d, = (1.31) (water production, m^3/d) (z) (1.35592)

The sum of the results of points 2, 3, and 4 for each sour gas inlet separator is the total sulphur inlet to the plant in t/d.

11.4.7. **Calculation Procedure for Estimating Plant Sulphur Outlet Mass per Day**

There are basically three different sulphur disposal schemes approved by the BCER:

1) sulphur recovery,
2) acid gas flaring, and
3) acid gas compression and injection.

Each of these schemes is treated separately as far as collecting the disposition data for the BC-19 report is concerned. The plant inlet data are collected identically for the above different sulphur disposal schemes.

Potential sulphur disposal methods from sour gas plants are

1) sulphur recovery,
2) sour gas flaring or incineration,
3) acid gas flaring or incineration,
4) sulphur plant incinerator stack emissions, and
5) sour gas flaring or incineration from the produced water storage tank (>0.05t/d).

The disposal of the sulphur by any of these methods must be accounted for. This requires measurement of flow rates and knowledge of concentrations of H_2S in the gas streams.

An important feature of the sulphur balance on the outlet side is the determination of the H_2S content of the acid gas out of the reflux drum. This gas stream is fully saturated with water vapour at the operating pressure and temperature of the reflux drum. Depending on what method is used in the determination of the H_2S content, the results could be on a dry basis or a wet basis. The operator must determine on which basis the analysis is determined.

[3] Froning, H. R. Jacoby, R. H., and Richards, W. L., "New K-Data Show Value of Water Wash," *Hydrocarbon and Petroleum Refiner*, April 1964, pp. 125–130.

The water content of the acid gas out of the reflux drum can be estimated by the procedure in section 11.3.1.1.1

Any H_2S determination and any complete analysis of the acid gas stream from the reflux drum presented on a dry basis must be normalized to a wet basis by the inclusion of the water vapour mole fraction. If the H_2S content in the acid gas is determined on a wet basis, the water vapour content is simply included as calculated above. In any case, the wet acid gas composition must be used in the metering calculations of the acid gas stream at low pressure. This stream is then converted to a dry basis for reporting purposes.

11.4.7.1. **Sulphur Recovery Plants**

The production of liquid sulphur must be determined by gauging the liquid sulphur level in sulphur production and storage pits or from weigh bills of shipments by truck or sulphur railroad tank cars, plus inventory changes in the pit.

Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flow rate is greater than $0.5e^3m^3/d$ on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter. A separate acid gas meter designed for the expected flow conditions and range must be used to measure acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume.

The emissions from the sulphur plant emission stack must be monitored for flow rate and SO_2 concentrations.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations. These emissions must be reported as flared gas when this gas is not recycled or directed to the incinerator. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur outlet of the plant but would still be a part of the sulphur inlet.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is ≥ 1 t/d or ±20% if the actual inlet is < 1 t/d. The acid gas sent to the sulphur plant must be reported as shrinkage and acid gas flaring at the plant must be reported as flare.

11.4.7.2. **Acid Gas Flaring Plants**

Plants approved for flaring of acid gas **must** meter the acid gas leaving the reflux drum of the sweetening process train. The meter calculation procedure must include the effect of the water vapour content in the acid gas at reflux drum pressure and temperature. Due to the effects of varying reflux drum pressure and temperature, the concentration of the H_2S content of the acid gas stream should be checked at least once per week by Tutweiler by a person trained in the use of the technique and the calculation procedure to determine the H_2S concentration in the acid gas. A gas chromatograph may also be used for this analysis. Plants slipping CO_2 into the sales gas or receiving sour gas from different pools having different H_2S concentrations in the sour inlet gas may need to determine the H_2S concentration in the acid gas more often. A file must be set up to provide a record of the H_2S analysis determinations for inspection by the BCER.

Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flow rate is greater than $0.5e^3m^3/d$ on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations and must also be reported as flared gas if >0.05t/d. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur out of the plant.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is ≥1t/d or ±20% if the actual inlet is <1t/d.

11.4.7.3. **Acid Gas Injection/Disposal Facility**

Facilities approved for injection of acid gas into downhole injection wells must meter the acid gas leaving the reflux drum of the sweetening process train or at some point in the process piping at the plant site. If the gas is metered before the first stage of compression (Scenario 1), the meter calculation procedure must include the effect of the water vapour content in the acid gas at the reflux drum pressure and temperature. The concentration of the H_2S content of the acid gas stream should be checked at least once per week by Tutweiler or gas chromatography by a person trained in the use of the technique and the calculation procedure to determine the H_2S concentration in the acid gas. Facilities slipping CO_2 into the sales gas or receiving sour gas from different pools having different H_2S concentrations in the sour inlet gas may need to determine the H_2S concentration in the acid gas more often than once per week. A file must be set up to provide a record of the Tutweiler determinations for inspection by the BCER.

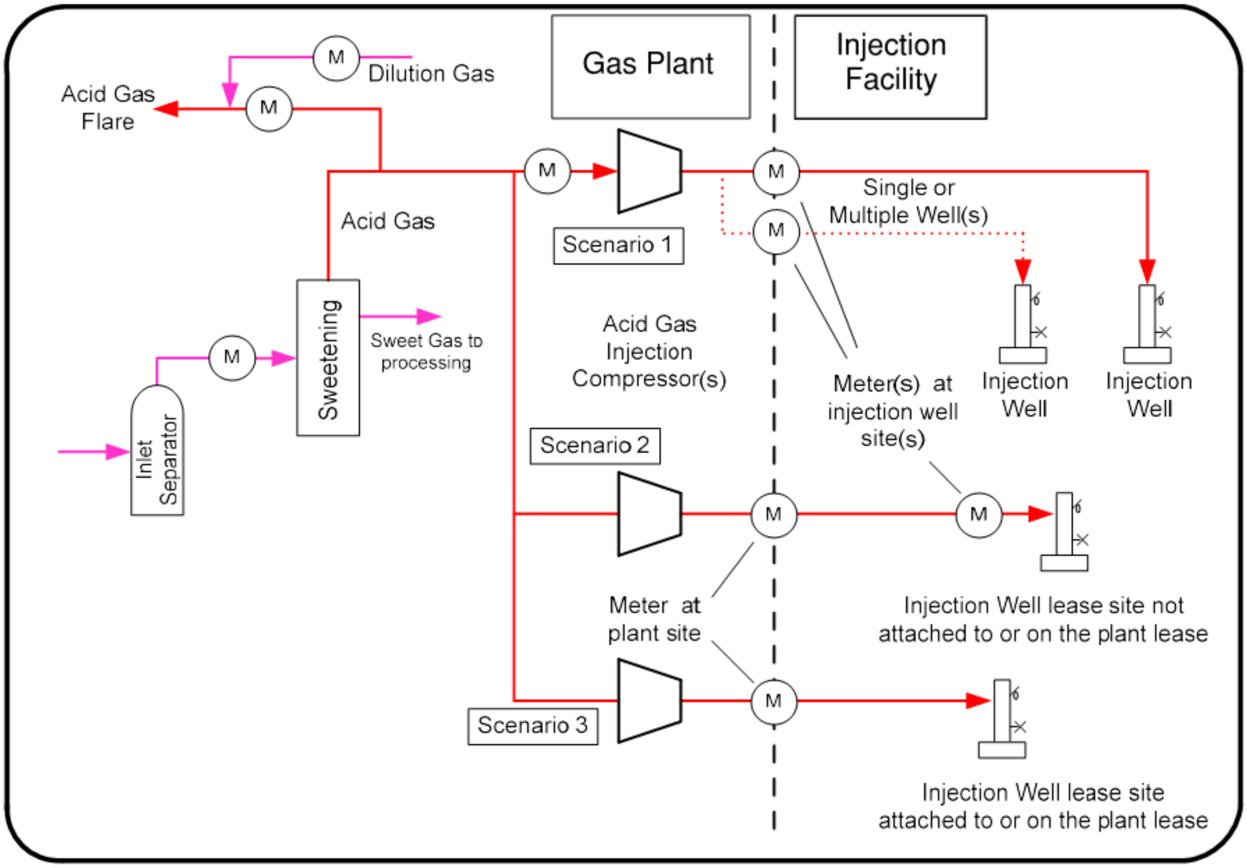
Once the acid gas is compressed, it must be metered before injection into each well. If there is more than one injection well, each well must have its own injection measurement at the well site. If sour water is injected together with the acid gas, they must be separately metered before commingling. See below, including Figure 11.4-3, for various scenarios.

Scenario 1 – Acid gas meter at plant/facility is before compression. Injection wellhead meter is required and can be used as the beginning of the gas injection facility/station. The injection well is on the same lease as the plant/facility.

Scenario 2 – Acid gas meter at plant/facility is after compression and the injection well lease site is not attached to or on the same plant/facility lease. This acid gas meter can be used as the beginning of the gas injection plant/facility; injection wellhead meter is required. Metering difference must be reported at the gas injection plant/facility.

Scenario 3 – Acid gas meter at plant/facility is after compression and the injection well lease site is attached to or on the same plant/facility lease. This acid gas meter can be used as the beginning of the gas injection station/facility; injection wellhead meter is not required.

Figure 11.4-3 Acid gas injection measurement scenarios



Meters designed for the expected flow conditions and range must be used to measure sweet and sour gas flared if the average flared gas flow rate is greater than $0.5e^3m^3/d$ on a yearly basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter. A separate acid gas meter designed for the expected flow conditions and range must be used to measure acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume.

The emissions from the vapours from the produced water storage tank are those that were estimated to be contained in the produced sour water in the plant inlet calculations and must also be reported as flared gas if >0.05t/d. If the vapours from the water storage tank are recovered through a vapour recovery unit and are injected into a sour plant process stream, they do not form a separate part of the sulphur out of the plant.

The sum of the sulphur contained in the above points must be the sulphur out of the plant. The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is ≥1t/d or ±20% if the actual inlet is <1t/d. The acid gas injected must be reported as a disposition to the injection facility, and acid gas flaring at the plant must be reported as flare.

11.5. **Production Data Verification and Audit Trail**

The field data, records, any calculations, or estimations, and EFM records relating to BCER required production data or volumes reported to FIN must be kept for inspection upon request. The records verification and audit trails must be in accordance with the following:

1) Proving/calibration records: any records and documentation produced in the proving/calibration of meters and calibration of the prover and all peripheral devices (if the prover and peripheral devices are owned and operated by the licensee)
2) Delivery and receipt records: any records and documentation produced in the determination of delivery or receipt volumes/tonnage.
3) Estimation records: any records and documentation related to the estimation of reported volume/tonnage, including estimation methodology, record of event, and approvals.
4) Pit gauging records: any records and documentation produced in the determination of reported volume/tonnage.
5) Volume/tonnage loss records: any records and documentation for volumes lost due to incidents such as spills and fires.
6) EFM: any records and documentation (electronic, magnetic, or paper form) produced in the determination of metered volume/tonnage in accordance with the EFM requirements in sections 4.4.9.2 for gas and 7.13.10 for liquids.

Appendix A – Gas Equivalent Factor (GEF) Determination

Gas Equivalent Factor Determination

Definition: Gas Equivalent Volume (GEV) is the volume of gas (e^3m^3) that would result from converting 1m^3 of liquid into a gas. This is generally used for condensate and other hydrocarbon liquids ($_{HCL}$). GEV_{HCL} = GSV_{HCL} x GEF where :

GSV_{HCL} = Gross Standard Volume
GEF = Gas Equivalent Factor
GEV_{HCL} = Gas Equivalent Volume

GEF Method of Calculation

The gas equivalent of a liquid may be calculated by one of three methods, depending on the type of analysis of the liquid (by volume, mole, or mass fractions) and the known properties of the liquid. The volume analysis method is most commonly used in industry.

Engineering Data
Certain constants used in the various methods of calculating the gas equivalent factor: Density of water = 999.102 kg/m^3 at 15°C, 1 mole (18 g) water vapour = 22.414L at 101.325kPa, and 0°C. Scale up by a factor of 1000 to be in kmols, m^3, and convert to Std. temperature, 1kmol = 22.414 m^3x (273.15 + 15) / 273.15 = 23.645m^3 at 101.325kPa and 15°C.

Appendix A Table 1 Example Liquid Analysis

Component	Liquid Volume%	Mole%	Mass%
N_2	0.06	0.19	0.08
CO_2	0.81	1.58	1.09
H_2S	0.00	0.00	0.00
C_1	8.28	16.17	4.05
C_2	11.17	14.62	6.87
C_3	12.75	15.33	10.56
IC_4	3.94	3.98	3.62
NC_4	8.91	9.35	8.49
IC_5	4.83	4.36	4.92
NC_5	5.40	4.93	5.56
C_6	7.65	6.14	8.35
C_7	8.80	6.78	10.54
C_8	8.27	5.89	10.32
C_9	5.70	3.68	7.26
C_{10}	3.63	2.22	4.80
C_{11}	2.25	1.31	3.05
C_{12}	7.55	3.47	10.44
Total	**100.00**	**100.00**	**100.00**

Appendix A Table 2

Properties at 15°C	Specific Gravity (SG)	API Gravity	Molecular Weight (kg/kmol)
Total Sample	0.613	99.3	64.0
C_{12}+	0.848	35.4	192.4

Appendix A Table 3

C_5 and C_7 + Properties	Mole fraction	Mass fraction	Liquid Volume fraction	Molecular Weight (kg/kmol)	SG $_{HCL}$	Std. Density $_{HCL}$ (kg/m^3)	API
C_5+	0.3878	0.6524	0.5408	107.7	0.740	739.33	59.7
C_7+	0.2335	0.4641	0.3620	127.2	0.786	785.29	48.5

Appendix A Table 4 Gas Equivalent Factor by Volume Fraction Calculation

Component	Volume Fraction Liquid Analysis (from lab)		Pseudo Factor e^3m^3 (gas)/ m^3 (liquid) at 101.325 kPa and 15°C		Pseudo Volume Fraction e^3m^3 (gas)/m^3 (liquid)
N_2	0.0006	x	0.680392	=	0.000408
CO_2	0.0081	x	0.441203	=	0.003573
H_2S	0.0000	x	0.554612	=	0.000000
C_1	0.0828	x	0.442167	=	0.036611
C_2	0.1117	x	0.281396	=	0.031432
C_3	0.1275	x	0.272130	=	0.034696
IC_4	0.0394	x	0.229015	=	0.009023
NC_4	0.0891	x	0.237680	=	0.021177
IC_5	0.0483	x	0.204853	=	0.009894
NC_5	0.0540	x	0.206668	=	0.011160
C_6	0.0765	x	0.182166	=	0.013936
C_{7+}	0.3620	x	0.145980	=	0.052845
Total	1.0000			**Total**	0.224755

Gas Equivalent Factor $_{HCL}$ = the sum of the Pseudo Volume Fractions **= 0.224755** e^3 m^3 (gas)/m^3 (liquid)
The Pseudo Factor and Pseudo Volume Fraction calculation example below uses the lab analysis for C_{7+} . The Density and Molecular constants used to derive the Component Pseudo Factor are from GPA 2145-16.

C_{7+} Std. Density = 785.29 kg/m^3
C_{7+} Molecular Weight = 127.2 kg/kmol
Pseudo Factor = [23.645 (m^3/kmol) x Std. Density C_{7+} (kg/m^3)] / [Molecular Weight (kg/kmol) x (1000m^3/e^3m^3)]
Pseudo Factor = [23.645 (m3/kmol) x 785.29 (kg/m^3)] / [127.2 (kg/kmol) x (1000m^3/e^3m^3)]
Pseudo Factor = 0.145980 e^3m^3 (gas) / m^3 (liquid)
Pseudo Volume Fraction = Volume Fraction Liquid Analysis x Pseudo Factor e^3m^3 (gas) / m^3(liquid)
Pseudo Volume Fraction = 0.3620 x 0.145980 e^3m^3(gas) / m^3(liquid) = **0.052845** e^3m^3 (gas) / m^3(liquid)

Appendix A Table 5 Gas Equivalent Factor by Mole Fraction Calculation

Component	Mole Fraction Liquid Analysis		Pseudo Factor m^3/kmol 101.325 kPa and 15°C		Pseudo Mole Fraction m^3 (liquid) / kmol
N_2	0.0019	x	0.034753	=	0.000066
CO_2	0.0158	x	0.053590	=	0.000847
H_2S	0.0000	x	0.042630	=	0.000000
C_1	0.1617	x	0.053475	=	0.008647
C_2	0.1462	x	0.084027	=	0.012285
C_3	0.1533	x	0.086888	=	0.013320
IC_4	0.0398	x	0.103250	=	0.004109
NC_4	0.0935	x	0.099482	=	0.009302
IC_5	0.0436	x	0.115420	=	0.005032
NC_5	0.0493	x	0.114410	=	0.005640
C_6	0.0614	x	0.129800	=	0.007970
C_7+	0.2335	x	**0.161980**	=	**0.037822**
Total	1.0000			**Total**	**0.105040**

Total Sample Gas Equivalent Volume

GEF = 23.645 m^3/ kmol / [Total Pseudo Mole Fraction (m^3/kmol) / 1000 (m^3 / e^3 m^3)]
GEF = 23.645 m^3/ kmol / **[0.105040** (m^3/kmol)] / 1000 (m^3 / e^3 m^3)]
GEF = **0.225105** $e^3 m^3$ (gas) / m^3 (liquid)

The Pseudo Factor calculation example below uses the lab analysis for C7+ . The Density and Molecular constants used to derive the Component Pseudo Factor are from GPA 2145-16.

Properties of C7 + sample at 15°C:

C_{7+} Std. Density = 785.29 kg/m^3
C_{7+} Molecular Weight = 127.2 kg/kmol

Pseudo Factor (m^3/kmol) = C_{7+} Molecular Weight / C_{7+} Std. Density
Pseudo Factor (m3/kmol) = 127.2 kg/kmol / 785.29 kg/m^3
Pseudo Factor (m3/kmol) = **0.161980** (factor in table)

Gas Equivalent Factor by Mass Fraction Calculation

Step 1. Calculate Pseudo Volume (L) = Mass Fraction / Liquid Density × 1000 L/m3
Step 2. Calculate Volume Fraction = Component Pseudo Volume / Total Pseudo Volume
Step 3. Calculate Component Pseudo GEF = Volume Fraction × (Pseudo Factor $e^3\ m^3$ (gas) / m^3 (Liquid)

Appendix A Table 6 Gas Equivalent Factor by Mass Fraction Calculation

					Step 1	Step 2				Step 3
Component	**Mass Fraction Liquid Analysis**		**Liquid Density (kg/m^3)**		**Pseudo Volume (L)**	**Volume Fraction**		**Pseudo Factor e^3m^3(gas) /m^3@ 101.325 kPa & 15 C**		**Pseudo GEF e^3m^3(gas) / m^3 (Liquid)**
N_2	0.0008	/	806.10	=	0.0010	0.0006	x	0.68040	=	0.0004
CO_2	0.0109	/	821.22	=	0.0133	0.0081	x	0.44120	=	0.0036
H_2S	0.0000	/	799.40	=			x	0.55460	=	
C_1	0.0405	/	300.00	=	0.1350	0.0822	x	0.44217	=	0.0363
C_2	0.0687	/	358.00	=	0.1919	0.1168	x	0.28151	=	0.0329
C_3	0.1056	/	507.67	=	0.2080	0.1266	x	0.27222	=	0.0345
IC_4	0.0362	/	563.07	=	0.0643	0.0391	x	0.22906	=	0.0090
NC_4	0.0849	/	584.14	=	0.1453	0.0885	x	0.23763	=	0.0210
IC_5	0.0492	/	624.54	=	0.0788	0.0480	x	0.20468	=	0.0098
NC_5	0.0556	/	631.05	=	0.0881	0.0536	x	0.20681	=	0.0111
C_6	0.0835	/	663.89	=	0.1258	0.0766	x	0.18216	=	0.0139
C_7+	0.4641	/	**785.29**	=	0.5910	0.3598	x	**0.14598**	=	0.0525
Total	**1.0000**				**1.6425**	**1.0000**		**Total**		**0.2251**

Gas Equivalent (GEF) = Total Pseudo $e^3\ m^3$ / m^3 = **0.2251** e^3m^3 (gas) / m^3 (liquid)

The Pseudo Factor and GEF calculation example below uses the lab analysis for C7+ . The Density and Molecular constants used to derive the Component Pseudo Factor are from GPA 2145-16.

C_{7+} Molecular Weight = 127.2 kg/kmol
C_{7+} Std. Density = 785.29 kg/m^3

Pseudo Factor = [23.645 (m^3/ kmol) x C7+ Std. Density] / [C_{7+} Molecular Weight x 1000 (m^3 / $e^3\ m^3$)]
Pseudo Factor = [23.645 (m^3/ kmol) x 785.29 kg/ m^3] / [127.2 kg/kmol x 1000 (m^3 / $e^3\ m^3$)]
Pseudo Factor = **0.14598** $\boldsymbol{e^3m^3}$ (gas) / m^3 (liquid)

Appendix B – Determining Fuel Gas Estimates

Treaters

The two methods below can be used to estimate fuel gas use for treaters and lease fuel reporting. They are only estimates and must be treated as such.

Method 1

This method uses the specific heats of oil and water to calculate the amount of fuel required to heat up one unit of oil-water mixture. Specific Heat of Oil = 150 BTU/bbl/°F = 1698.3 BTU/m^3/°C Specific Heat of Water = 350BTU/bbl/°F = 3962.8 BTU/m^3/°C

Temperature difference [dT (°C)] = Oil (water) Outlet Temperature – Emulsion Inlet Temperature

Assuming BTU content of gas = 1000 BTU/ft^3 = 35 494 BTU/m^3

Fuel consumption (m^3/month) = (Oil Volume per Month / (35494 / 1698.3) + Water Volume per Month / (35494 / 3962.8)) x (dT / Firetube Efficiency)

The treater firetube efficiency can be obtained from the manufacturer's specification.

Method 2

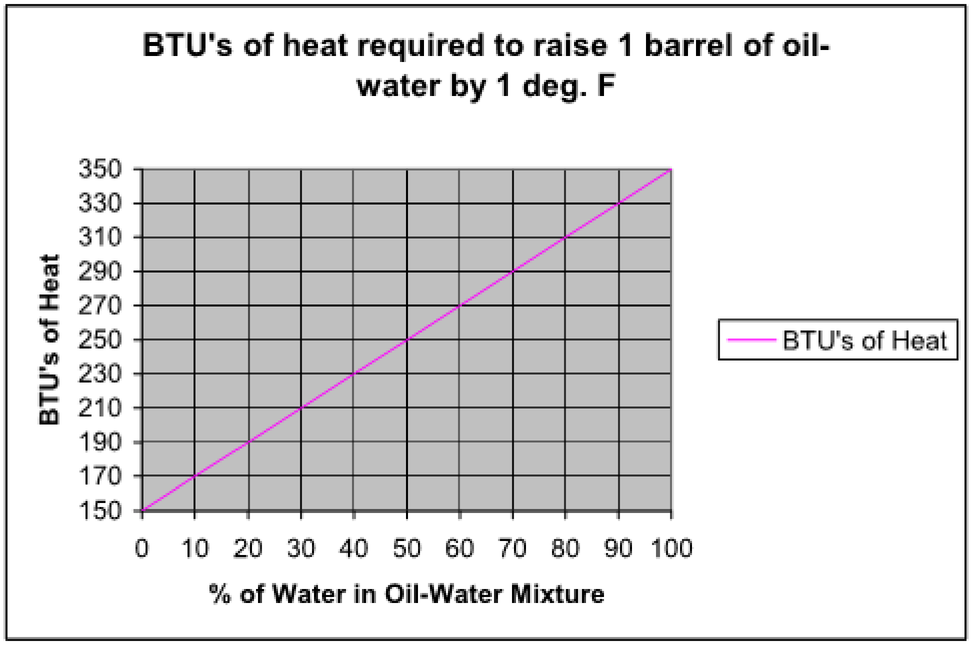
Use the graph below. This method uses the percentage of water in the oil-water mixture to look up on a graph the heat required to increase the temperature of the oil-water mixture and then calculate the amount of fuel required.

Heat Required (BTU) = Emulsion per Month (bbl) X dT (°F) X BTU of Heat (from graph)/bbl/°F

Fuel Consumption (m^3/month) = Heat Required (BTU) / [Firetube Efficiency X 1000 (BTU/ft^3)] X 0.02831685

Determining Fuel Gas Estimates

Appendix B Figure 1 BTUs of Heat Required



Compressors

Fuel gas usage data may be obtained from the manufacturer's specifications or from Figure 15-35 of the GPSA *Engineering Data Book* – 12th Edition.

Line Heaters

Similar to the calculation of fuel consumption for treaters, fuel consumption for line heaters can be determined by using the specific heat of the natural gas (gas analysis, published data, software), the density of natural gas (from gas analysis), efficiency factor (manufacturer's specifications), temperature change from inlet to outlet, and the volume of natural gas.

Manufacturer's specifications can also provide fuel gas usage based on design criteria.
Usage rates must to be considered in the calculations.

Reboilers, Chemical Pumps, TEGs, Catadyne Heaters, Etc.

Manufacturer's specifications can provide fuel gas usage. This will be based on design criteria and will need to include usage rates.

Alternative Calculations

The marketplace has available software packages that will perform volume calculations for line heaters, treaters, and compressors.
Alternative calculations that utilize generally accepted engineering procedures and principles may be sufficient.

Appendix A has been adapted from the AER Appendix E – E1 Method to Estimate Fuel Gas in Guide 46: *Production Audit Handbook*.

Appendix C – Effluent Well Testing Decision Tree Accounting Sample Calculations

Introduction to Volumetric Reporting for Effluent Metered Gas Production

Utilizing the applicable effluent well testing decision tree to apply an effluent well testing exemption requires changes to the volumetric reporting methodologies. This appendix presents the details around reporting of facilities and wells that make use of the effluent well testing exemption process. The following exemption scenarios are outlined in this appendix:

A. Reporting of production for wells utilizing a battery/facility-based testing exemption from annual well testing;

B. Reporting of production for individual wells that are utilizing a well based testing exemption for both tested and testing exempt wells; and

C. Reporting of production for a battery/facility containing a combination of different measurement schemes (mixed measurement). This would include non-testing exempt wells, testing exempt wells, and measured production all included within a common reporting battery/facility.

Operators must review section 6.5.3 of this document prior to implementing a reporting structure to determine which exemption, if any, pertains to your specific reporting battery/facility.

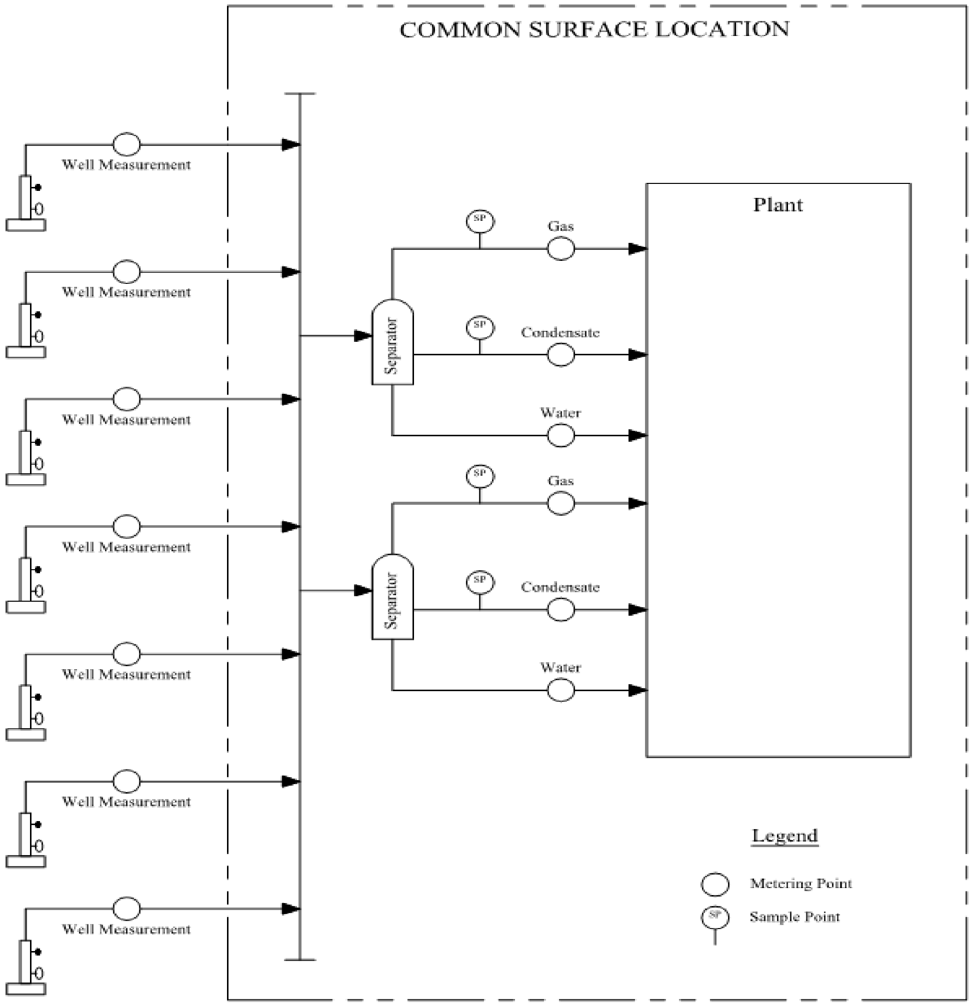
Definitions

CGR	Condensate to Gas Ratio - A ratio calculated by dividing the total condensate test volumes by the measured test gas volume. Referenced in m^3/e^3m^3.
ECF	Effluent Correction Factor – A factor determined from periodic tests conducted at each well whereby a test separator is connected downstream of the effluent meter and the volumes measured by the test separator are compared to the volume measured by the effluent meter. If condensate produced from a gas well is recombined with the gas stream or trucked to a linked gas plant for further processing, then the ECF = Well test gas volume + GEV of condensate/ Effluent gas measured during the test.
Electronic Flow Measurement (EFM)	Any flow measurement and related system that collects data and performs flow calculations electronically.
LGR	Liquid to Gas Ratio – A ratio calculated by dividing the total water and/or condensate test volumes by the measured test gas volume. Includes all free liquid. Referenced in m^3/e^3m^3.

"Measured" Gas Source	Production that is diverted through a separator and includes measurement of each phase (gas and liquid) production.
PA	Production Accounting.
WGR	Water to Gas Ratio – A ratio calculated by dividing the total water test volumes by the measured test gas volume. Referenced in m^3/e^3m^3. If condensate produced from a gas well is recombined with the gas stream or trucked to a linked gas plant for further processing, then the WGR= Well test water/ Well test gas volume + GEV of condensate.
GEF	A factor based on the composition of a hydrocarbon liquid mixture that is used to convert the same hydrocarbon liquid mixture to its equivalent gas volume. This factor is mixture dependent and not a constant for all mixtures. Referenced in e^3m^3/m^3.
GEV	The volume of gas (e^3m^3) that would result from converting $1m^3$ of liquid into a gas by applying a GEF to the liquid volume.

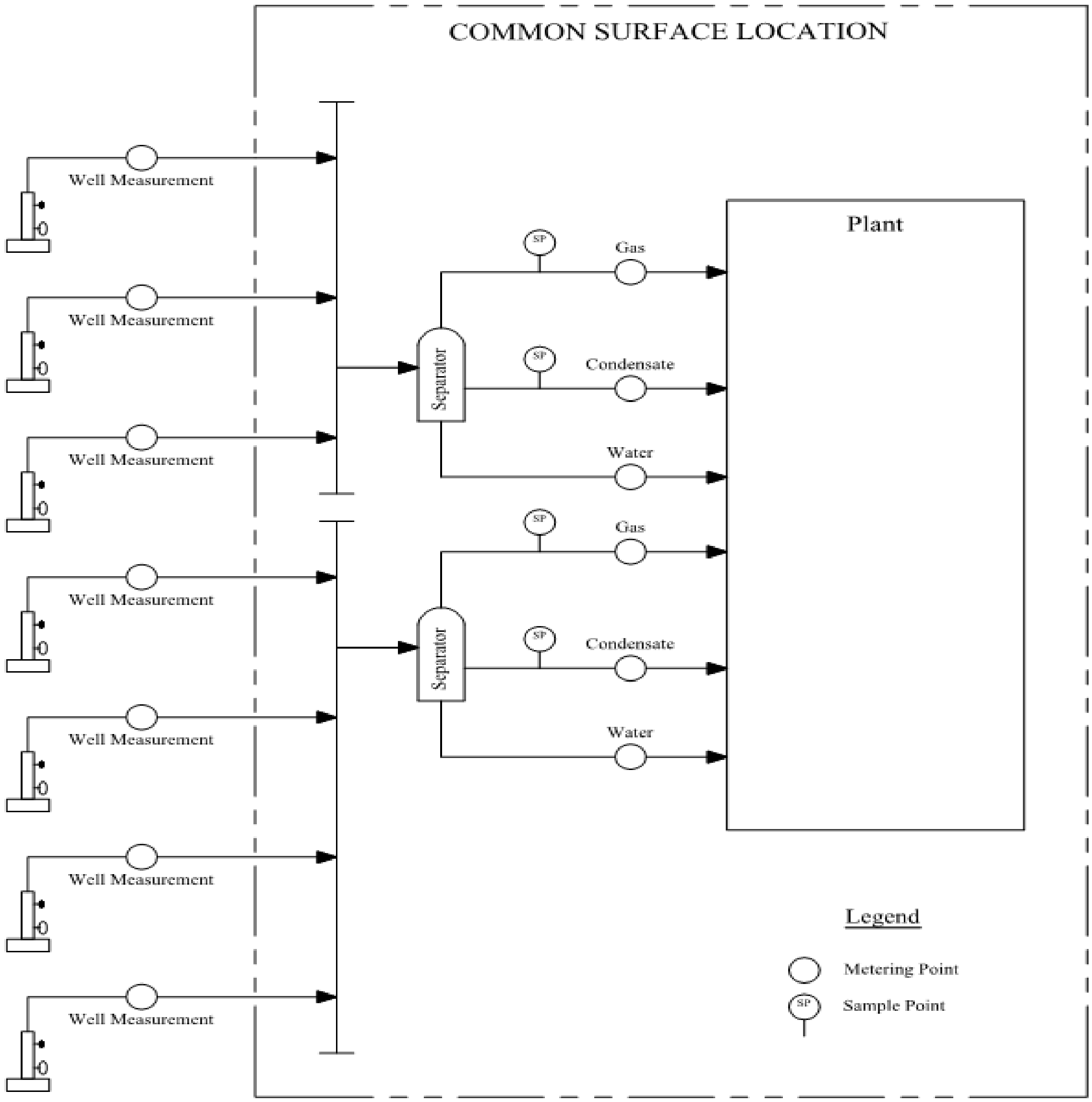
Multiple Inlet Separators into a Battery / Facility
In the event that multiple inlet separators are installed in parallel to one another at a Multi-Well Effluent Proration Battery/Facility, the inlet separator volumes must be summed together to determine the total battery/facility production. See Appendix C Figure 1 for example.

Appendix C- Figure 1 - Multiple Inlet Separators into a Battery / Facility



In the event that select wells deliver to a dedicated separator at a given battery/facility, the decision tree must be applied individually for each separator. Each Inlet will be considered a separate reporting entity. See Appendix C Figure 2 for example.

Appendix C - Figure-2 Individual Separator Decision Tree Requirements



Section A Battery / Facility Based Testing Exemption

Applicability

1) Applies when the initial assessment is performed on a reporting Multi-Well Effluent Proration Battery/Facility following the introduction of the battery/facility based effluent testing decision tree. Applies where a Multi-Well Effluent Proration Battery/Facility has qualified for a testing exemption based on the decision tree and an annual evaluation of this exemption remains valid.

Considerations

1) Multi-Well Effluent Proration Battery/Facility Based Testing Exemption for Wet Metered Wells may be applied if the battery's/facility's annual weighted average LGR is <$0.1500 m^3/e^3m^3$ and the battery/facility CGR is <$0.0500 m^3/e^3m^3$.

2) Wells qualifying for effluent measurement and are included within a Multi-Well Effluent Proration Battery/Facility based testing exemption can use ECFs of 1.00000 and a calculated battery/facility WGR and CGR if applicable (condensate volumes are tanked at the battery/facility) or;

3) If the battery/facility qualifies as a test exempt battery/facility the permit holder may, providing there is no objection from the working interest owners of any well producing to the battery, use the WGR, CGR, and ECF from each well's most recent test instead of using the battery calculated WGR, CGR, and ECF of 1.00000. If condensate is recombined at the battery/facility with the gas stream or trucked to a linked gas plant for further processing and the most recent ECF test is used, the ECF is calculated using: ECF = (well test gas volume + GEV of well test condensate) / effluent gas volume measured during the test.

Example Calculation

1) In the example calculation Multi-Well Effluent Proration Battery/Facility gas production will be determined at the group point and prorated to all wells within the reporting battery/facility based on an ECF of 1.00000 applied to all wells. The ECF from the most recent well test could also be used.

2) Multi-Well Effluent Proration Battery/Facility water production will be prorated back to each well based on a calculated battery/facility WGR which will be applied to all wells.

3) Condensate volumes will be prorated:

   a. If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are tanked and trucked or pipelined out for sale at the battery/facility, the condensate liquid volumes must be prorated back to the wells based upon a calculated battery/facility CGR which will be prorated to all the wells within the battery/facility.

4) If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are recombined back into the gas stream at the battery/facility, the GEV of the recombined condensate must be calculated and added to the measured group gas. The condensate volumes are not prorated back to the well.

5) Proration targets for effluent proration batteries must remain consistent with existing effluent proration battery/facility limits outlined in section 3.2.3.

Note: Any fuel, flare and/or vent gas extracted from the production line (i.e., well or compressor station) within the Multi-Well Effluent Proration Battery/Facility must be added to the battery/facility gas production volume.

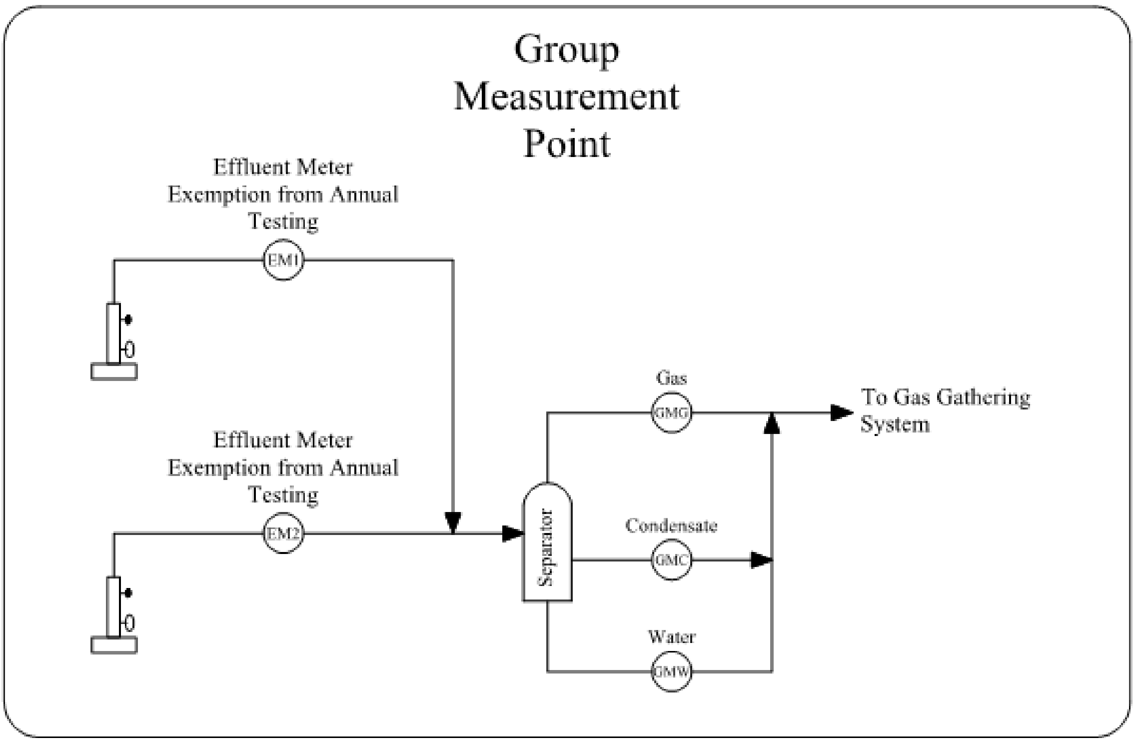
The following two examples utilize different accounting model practices:

Example 1. is for recombined hydrocarbon liquid production at a battery/facility and;

Example 2. is for tanked and trucked out hydrocarbon liquid production at the battery/facility.

Example 1. Calculation - Hydrocarbon Liquids Recombined at Battery/Facility

Appendix C- Figure 3- Group Measurement Point



Example 1: Typical Multi-Well Effluent Proration Battery/Facility configuration in which liquids are recombined and a battery/facility-based testing exemption for wet metered wells from annual testing is implemented.

Month End Hypothetical Accounting Information:

Meter ID in Appendix C, Figure 3	Meter Function in Appendix C, Figure 3	Volume Through Meter	Applied ECF	Applied CGR	Applied WGR
EM1	EM1 Effluent Meter -Exempt from Testing	10.00e³m³	1.000000	N/A as Battery/ Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/facility WGR. See below for example calculation.
EM2	EM2 Effluent Meter -Exempt from Testing	11.00e³m³	1.000000	N/A as Battery/ Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/facility WGR. See below for example calculation.
GMG	Group Separator Gas Meter	20.00e³m³			
GMC	Group Separator Condensate Meter	0.75m³			
GMW	Group Separator Water Meter	1.50m³			

Applicability

Criteria outlined in 6. Chapter 6- Determination of Production at Gas Wells must be adhered to.

Calculate Effluent Battery/Facility LGR:

Battery/Facility Water Volume **+** Battery/Facility Condensate Volume (m^3)	**/**	Battery/Facility Gas Volume (e^3m^3)	=	Battery/Facility LGR (m^3/e^3m^3)
GMW + GMC	/	GMG	=	
1.50 + 0.75	/	20.00	=	
2.25	/	20.00	=	0.11250

Calculate Battery/Facility CGR:

Battery/Facility Condensate Volume (m^3)	/	Battery/Facility Gas Volume (e^3m^3)	=	Battery/Facility CGR (m^3/e^3m^3)
GMC	/	GMG	=	
0.75	/	20.00	=	0.03750

Because the LGR is less than 0.1500m^3/e^3m^3 and the CGR is less than 0.0500m^3/e^3m^3, this Multi-Well Effluent Proration Battery/Facility qualifies for battery/facility based well testing exemption providing there is no objections from working interest participants or freehold royalty holders (if present).

Gas Calculations

The total reportable Multi-Well Effluent Proration Battery/Facility gas production is equal to the sum of the group metered gas production and the group metered condensate production converted to a gas equivalent (GEV). The gas equivalent factor (GEF) of 0.22478e^3m^3/m^3 is used within the calculation to convert the liquid condensate to a GEV below. This factor is only utilized as an example supplied from Appendix A. Each battery/facility must determine its own unique GEF representative of the condensate production present.

Calculate Battery/Facility Gas Production:

Measured Battery/Facility Gas (e^3m^3)	+	Measured Condensate Production (m^3) * GEF (e^3m^3/m^3)	=	Battery/Facility Gas Production (e^3m^3)
GMG	+	GMC * GEF	=	
20.00	+	0.75 * 0.22478	=	
20.00	+	0.169	=	20.17

Calculate Well's Estimated Gas Production:

Well #	Well's Monthly Effluent Metered Volume (e^3m^3)	*	Well's ECF	=	Well's Estimated Gas Production (e^3m^3)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
Total					21.00

Calculate Battery/Facility Gas Proration Factor:

Battery/Facility Actual Gas Production (e^3m^3)	/	Sum of Well's Estimated Gas Production (e^3m^3)	=	Battery/Facility Gas Proration Factor
See Battery/Facility Gas Production Above	/	See *Well's Estimated Gas Production* Above	=	
20.17	/	21.00	=	0.960476

The Multi-Well Effluent Proration Battery's/Facility's gas production is prorated back to the wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery's/facility's gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Battery/Facility Proration Factor	=	Prorated Battery/Facility Gas Production (e^3m^3)[1]
EM1	10.00	*	0.960476	=	9.60
EM2	11.00	*	0.960476	=	10.57
Total	21.00				20.17

[1]These are the monthly volumes to be utilized for reporting purposes.

Condensate Calculations

The Multi-Well Effluent Proration Battery's/Facility's condensate liquid volume is recombined back into the gas stream at the battery/facility and therefore reported as a gas equivalent volume. There is no proration of condensate liquid volumes back to the wells independent of the gas production.

Water Calculations

Calculate Battery/Facility Water Production:

In this example, water is measured and put back into the gas stream (note that no GEV applied). There is no water inventory, and it is assumed that there are no receipts for this example. Production will equal the 1.50m³ monthly metered volumes.

Calculate Battery/Facility WGR:

Battery/Facility Water Production (m^3)	/	Battery/Facility Gas Production (e^3m^3)	=	Battery/Facility (m^3/e^3m^3)
GMW	/	*See Battery/Facility Gas Production* Above	=	
1.50	/	20.17	=	0.07437

This calculated Multi-Well Effluent Proration Battery's/Facility's WGR will be input into the PA system for every well within the battery/facility as all wells are exempt from testing. The PA system will then calculate each well's estimated water production (well estimated gas production * well WGR).

Calculate Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Well's Estimated Water Production (m^3)
EM1	10.00	*	0.07437	=	0.74
EM2	11.00	*	0.07437	=	0.82
Total	21.00				1.56

Calculate Battery/Facility Water Proration Factor:

Battery/Facility Water Production (m^3)	/	Sum of Well's Estimated Water Production (m^3)	=	Battery/Facility Water Proration Factor
GMW	/	See *Well's Estimated Water Production* Above	=	
1.5	/	1.56	=	0.961538

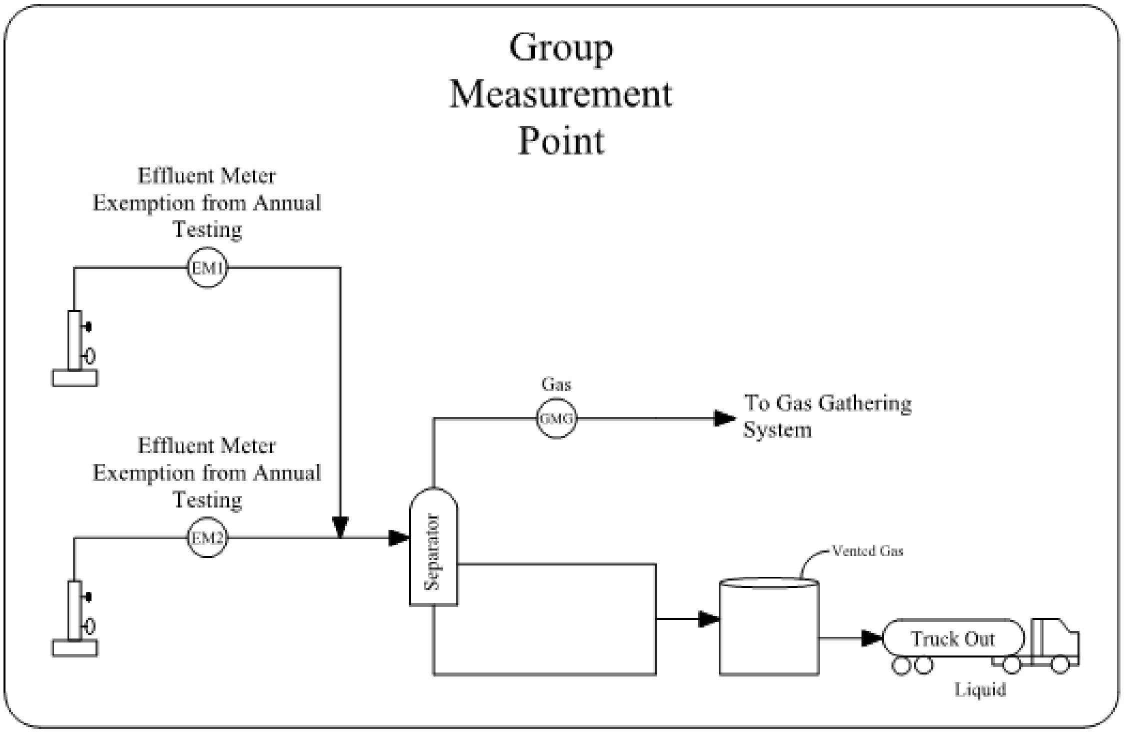
Calculate Individual Well's Prorated Water Production:

Well #	Well's Estimated Water Production (m^3)	*	Battery/Facility Water Proration Factor	=	Well's Prorated Water Production (m^3)[1]
EM1	0.74	*	0.961538	=	0.71
EM2	0.82	*	0.961538	=	0.79
Total	1.56				1.50

[1]These are the monthly volumes to be utilized for reporting purposes.

Example 2. Calculation - Hydrocarbon Liquids Tanked at Battery/Facility

Figure 4



Example 2. : Typical Multi-Well Effluent Proration Battery/Facility configuration in which Battery/Facility liquids are tanked and trucked out while implementing a battery/facility based testing exemption.

Month End Hypothetical Accounting Information:

Meter ID in Appendix C, Figure 4	Meter Function in Appendix C, Figure 4	Volume Through Meter	Applied ECF	Applied CGR	Applied WGR
EM1	EM1 Effluent Meter -Exempt from Testing	10.00e^3m^3	1.000000	Based upon calculated battery/facility CGR. See below for example calculation.	Based upon calculated battery/facility WGR. See below for example calculation.
EM2	EM2 Effluent Meter -Exempt from Testing	11.00e^3m^3	1.000000	Based upon calculated battery/facility CGR. See below for example calculation.	Based upon calculated battery/facility WGR. See below for example calculation.
GMG	Group Separator Gas Meter	18.00e^3m^3			
Vent	Vented Gas	2.00e^3m^3			
OI	Opening Inventory	10.00m^3			
OI%	Opening Inventory Water Cut %	66.67%			
CI	Closing Inventory	12.25m^3			
CI%	Closing Inventory Water Cut %	66.67%			
DelCond	For simplicity there are no trucked-out volumes.	0.00m^3			
DelWTR	For simplicity there are no trucked-out volumes.	0.00m^3			
RecCond	For simplicity there are no receipt volumes.	0.00m^3			
RecWTR	For simplicity there are no receipt volumes.	0.00m^3			

Applicability

Criteria outlined in Chapter 6 must be adhered to.

Calculate Effluent Battery/Facility LGR:

Liquid Production (m³)	/	Battery/Facility Gas Production (e³m³)	=	Effluent Battery/Facility LGR (m³/e³m³)
(Closing Liquid Inventory + Deliveries – Receipts – Opening Liquid Inventory)	/	Group Metered Gas + Vent	=	
(CI + DelCond + DelWTR – RecCond – RecWTR – OI)	/	GMG + Vent	=	
(12.25 + 0.00 + 0.00 – 0.00 – 0.00 – 10.00)	/	18.00 + 2.00	=	
2.25	/	20.00	=	0.11250

Calculate Battery/Facility Condensate Production:

Closing Inventory (m³)	+	Dispositions (m³)	-	Receipts (m³)	-	Opening Inventory (m³)	=	Battery/ Facility Condensate Production (m³)
CI * (1 - CI%)	+	DelCond	-	RecCond	-	OI * (1 - OI%)	=	
12.25 * (1 - 0.6667)	+	0.00	-	0.00	-	10.00 * (1 - 0.6667)	=	
4.08	+	0.00	-	0.00	-	3.33	=	0.75

Calculate Battery/Facility CGR:

Battery/Facility Condensate Production (m³)	/	Battery/Facility Gas Production (e³m³)	=	Battery/Facility CGR (m³/e³m³)
See Battery/Facility Condensate Production Above	/	GMG + Vent	=	
0.75	/	18.00 + 2.00	=	
0.75	/	20.00	=	0.03750

Because the LGR is less than 0.1500m³/e³m³ and the CGR is less than 0.0500m³/e³m³ this Multi-Well Effluent Proration Battery/Facility qualifies for a battery/facility based well testing exemption providing there is no objections from working interest participants or freehold royalty holders (if present).

Gas Calculations

The Multi-Well Effluent Proration Battery's/Facility's gas proration factor is calculated slightly different when condensate volumes are not recombined at the battery/facility. The total reportable battery/facility gas production is equal to the measured gas production and does NOT include the GEV of any condensate production. Therefore, the condensate production is not considered when determining the overall battery/facility gas proration factor.

Calculate Effluent Battery/Facility Gas Production:

Battery/Facility Gas Production (e³m³)	+	Battery/Facility Vented Gas (e³m³)	=	Battery/Facility Gas Production (e³m³)
GMG	+	Vent	=	
18.00	+	2.00	=	20.00

Calculate Well's Estimated Gas Production:

Well #	Well's Monthly Effluent Metered Volume (e^3m^3)	*	Well's ECF	=	Well's Estimated Gas Production (e^3m^3)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
Total					21.00

Calculate Battery/Facility Gas Proration Factor:

Battery/Facility Gas Production (e^3m^3)	/	Sum of Well's Estimated Gas Production (e^3m^3)	=	Battery/Facility Gas Proration Factor
See *Battery/Facility Gas Production* Above	/	See *Well's Estimated Gas Production* Above	=	
20.00	/	21.00	=	0.952381

The Multi-Well Effluent Proration Battery's/Facility's gas production is prorated back to the wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery's/facility's gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Battery/Facility Proration Factor	=	Prorated Battery/Facility Gas Production (e^3m^3)[1]
EM1	10.00	*	0.952381	=	9.52
EM2	11.00	*	0.952381	=	10.48
Total	21.00				20.00

[1]These are the monthly volumes to be utilized for reporting purposes.

<u>Condensate Calculations</u>

Where condensate volumes are delivered to a tank at the Multi-Well Effluent Proration Battery/Facility and trucked or pipelined for sale, the condensate liquid volumes will be prorated back to the wells based upon a battery/facility CGR.

Calculate Battery/Facility Condensate Production:

Closing Inventory (m³)	+	Disposition (m³)	-	Receipts (m³)	-	Opening Inventory (m³)	=	Battery/ Facility Condensate Production (m³)
CI * (1 - CI%)	+	DelCond	-	RecCond	-	OI * (1 - OI%)	=	
12.25 * (1 - 0.6667)	+	0.00	-	0.00	-	10.00 * (1 - 0.6667)	=	
4.08	+	0.00	-	0.00	-	3.33	=	0.75

The Multi-Well Effluent Proration Battery's/Facility's condensate production must be prorated back to the wells based on a battery/facility CGR applied to each well.

Calculate Battery/Facility CGR:

Battery/Facility Condensate Production (m³)	/	Battery/Facility Gas Production (e³m³)	=	Battery/Facility CGR (m³/e³m³)
See *Battery/Facility Condensate Production* Above	/	See *Battery/Facility Gas Production* Above	=	
0.75	/	20.00	=	0.03750

This calculated Multi-Well Effluent Proration Battery/Facility CGR will be input into the PA system for every well within the battery/facility that is exempt from testing. The PA system will calculate each well's theoretical condensate production (well theoretical gas production * well CGR).

Calculate Well's Estimated Condensate Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's CGR (m^3/e^3m^3)	=	Well's Estimated Condensate Production (m^3)
EM1	10.00	*	0.03750	=	0.38
EM2	11.00	*	0.03750	=	0.41
Total	21.00				0.79

Calculate Battery/Facility Condensate Proration Factor:

Battery/Facility Condensate Production (m^3)	/	Sum of Well's Estimated Condensate Production (m^3)	=	Battery/Facility Condensate Proration Factor
See *Battery/Facility Condensate Production* Above	/	See *Well's Estimated Condensate Production* Above	=	
0.75	/	0.79	=	0.949367

Calculate Individual Well's Prorated Condensate Production:

Well #	Well's Estimated Condensate Production (m^3)	*	Battery/Facility Condensate Proration Factor	*	Well's Prorated Condensate Production (m^3)[1]
EM1	0.38	*	0.949367	=	0.36
EM2	0.41	*	0.949367	=	0.39
Total	0.79				0.75

[1]These are the monthly volumes to be utilized for reporting purposes.

Water Calculations

Calculate Battery/Facility Water Production:

Closing Inventory (m^3)	+	Dispositions (m^3)	-	Receipts (m^3)	-	Opening Inventory (m^3)	=	Battery/ Facility Water Production (m^3)
CI * CI%	+	DelWTR	-	RecWTR	-	OI * OI%	=	
12.25 * (0.6667)	+	0.00	-	0.00	-	10.00 * (0.6667)	=	
8.17	+	0.00	-	0.00	-	6.67	=	1.50

Calculate Battery/Facility WGR:

Battery/Facility Water Production (m^3)	/	Battery/Facility Gas Production (e^3m^3)	=	Battery/Facility WGR (m^3/e^3m^3)
See *Battery/Facility Water Production* Above	/	See *Battery/Facility Gas Production* Above	=	
1.50	/	20.00	=	0.07500

This calculated Multi-Well Effluent Proration Battery's/Facility's WGR will be input into the PA system for every well within the battery/facility exempted from testing. The PA system will calculate each well's estimated water production (well estimated gas production * well WGR).

Calculate Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Well's Estimated Water Production (m^3)
EM1	10.00	*	0.07500	=	0.75
EM2	11.00	*	0.07500	=	0.83
Total	21.00				1.58

Calculate Battery/Facility Water Proration Factor:

Battery/Facility Water Production (m^3)	/	Sum of Well's Estimated Water Production (m^3)	=	Battery/Facility Water Proration Factor
See *Battery/Facility Water Production* Above	/	See *Well's Estimated Water Production* Above	=	
1.50	/	1.58	=	0.949367

Calculate Individual Well's Prorated Water Production:

Well #	Well's Estimated Water Production (m^3)	*	Battery/Facility Water Proration Factor	=	Well's Prorated Water Production (m^3)[1]
EM1	0.75	*	0.949367	=	0.71
EM2	0.83	*	0.949367	=	0.79
Total	1.58				1.50

[1]These are the monthly volumes to be utilized for reporting purposes.

Well Based Testing Exemption

There are four potential scenarios that could arise when implementing an individual wet metered well based exemption based on the specific delineation of the asset. These include:

1) Scenario 1 – Battery/Facility Includes Only Wells Exempt from Testing and a Battery/Facility Based Testing Exemption For Wet Metered Wells Cannot be Applied
2) Scenario 2 – Battery/Facility Includes Only Wells that Require Testing
3) Scenario 3 – Battery/Facility Includes both Wells Exempt from Testing (Scenario 1) and Wells Requiring Testing (Scenario 2)
4) Scenario 4 – Battery/Facility Containing Mixed Measurement Schemes

Note that the calculations below include examples for facilities that tank hydrocarbon liquid production and sample calculations where the hydrocarbon liquids are recombined and sent down the pipeline. Please see the sample calculations that pertain to your reporting scenario below.

Scenario 1 – Battery / Facility Includes Only Wells Exempt from Testing and a Battery / Facility Based Testing Exemption For Wet Metered Wells Cannot be Applied

Applicability

This section outlines the criteria where all individual wells may be exempt from testing even when the battery/facility based testing exemption criteria cannot be met as a result of the Well Testing Decision Tree – Well Based Testing Exemption. In this case, the respective calculations would be the same as the example provided in Section 'A' above: "Battery/Facility Based Testing Exemption."

Considerations:

1) Wells must qualify for testing exemption based on the Chapter 6 effluent well testing decision tree considerations.

2) Assuming all the wells within the Multi-Well Effluent Proration Battery/Facility are exempt from testing due to the criteria outlined in the Well Based Testing Exemption, battery/facility liquid production delivered to a tank at a battery/facility must be prorated back to all wells based upon a calculated battery/facility CGR and battery/facility WGR.

Method of Calculation

1) Multi-Well Effluent Proration Battery/Facility gas production will be determined at the group point and prorated to all wells within the reporting battery/facility and may be based on an ECF of 1.00000 applied to all wells. The Permit Holder may, providing there is no objection from the working interest owners of any well producing into the battery/facility, opt to use the ECF from the most recent test.

2) Multi-Well Effluent Proration Battery/Facility water production will be prorated back to each well based on a calculated battery/facility WGR which will be applied to all wells. The Permit Holder may, providing there is no objection from the working interest owners of any well producing into the battery/facility, opt to use the WGR from each wells most recent test rather than use the battery/facility calculated WGR.

3) Condensate volumes will be prorated based on one of the two following configurations: If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are recombined back into the gas stream at the battery/facility, the GEV of the recombined condensate must be calculated and added to the measured group gas.

   a. If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are tanked and trucked or pipelined out for sale at the battery/facility, the condensate liquid volumes must be prorated back to the wells based upon a calculated battery/facility CGR which will be prorated to all the wells within the battery/facility. The Permit holder may, providing there is no objection from the working interest owners of any wells producing into the battery/facility, opt to use the CGR from each wells most recent test rather than use the battery/facility calculated CGR.

4) Proration targets for effluent proration batteries / facilities must remain consistent with existing effluent proration battery/facility limits outlined in Chapter 3.

Note: Any fuel, flare and/or vent gas extracted from the production line (i.e., well or compressor station) within the Multi-Well Effluent Proration Battery/Facility must be added to the battery/facility gas production volume.

Scenario 2 – Battery/Facility Includes Only Wells that Require Testing

Applicability

This section covers the specific handling of individual wells that are not exempt from testing based on the decision tree and require effluent testing on an annual or bi-annual frequency.

Considerations

Applies to wells not meeting testing exemption criteria, and therefore testing of individual wells is deemed necessary to determine their respective WGR, ECF, and CGR if applicable (condensate volumes are tanked at the battery/facility).

Method of Calculation

1) The Multi-Well Effluent Proration Battery/Facility gas production will be determined at the group point and prorated to all wells that require annual or bi-annual testing based on the well's estimated gas production (monthly effluent metered volume multiplied by the calculated well's ECF).

2) Water production will be prorated to all wells that require annual or bi-annual testing based upon their individual WGR (derived from the respective well test) multiplied by the wells theoretical gas production.

3) Condensate volumes will be accounted for based on one of the two following configurations:

    a. If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are recombined back into the gas stream, the gas equivalent of the recombined liquids must be calculated and added to the measured group gas volume.

    b. If the Multi-Well Effluent Proration Battery's/Facility's condensate volumes are tanked and trucked out for sale at the battery/facility, the condensate liquid volumes must be prorated back to the wells that require annual or bi-annual testing based upon their individual CGR (derived from the well test) multiplied by the well's estimated gas production.

4) Proration targets for effluent proration batteries must remain consistent with existing effluent proration battery/facility limits outlined in Chapter 3.

Note: Any fuel, flare and/or vent gas extracted from the production line (i.e., well or compressor station) within the Multi-Well Effluent Proration Battery/Facility must be added to the battery/facility gas production volume.

Scenario 3 - Battery / Facility Includes both Wells Exempt from Testing (Scenario 1) and Wells Requiring Testing (Scenario 2)

For test exempt wells the operator may, at its discretion, providing there are no objections from working interest owners, use the WGR, CGR, and the ECF from each well's most recent test instead of using the battery/facility calculated WGR, CGR, and ECF of 1.00000. This is option is not included in the following examples.

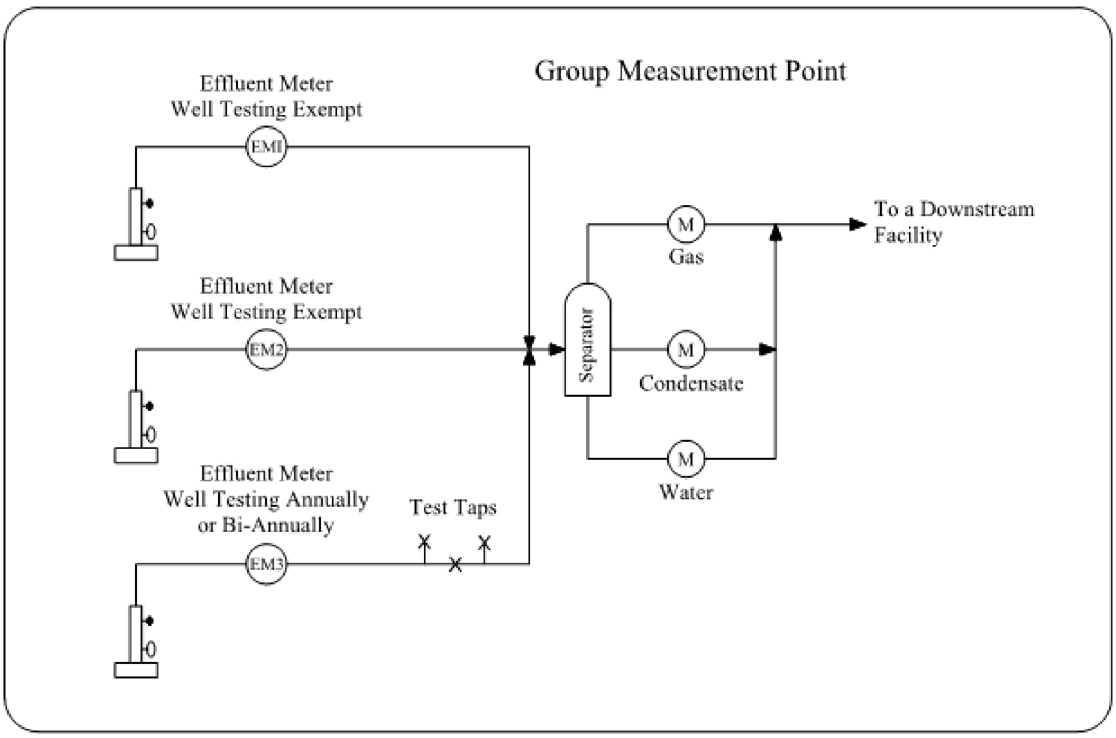
The following two examples must be utilized to model accounting practices around:

Example 1. is for recombined hydrocarbon liquid production at a battery/facility and;

Example 2. is for tanked and trucked out hydrocarbon liquid production at a battery/facility.

Example 1. Calculation - Hydrocarbon Liquids Recombined at Battery / Facility

Appendix C- Figure 5



Example 1: Typical Multi-Well Effluent Proration Battery/Facility configuration including one well that requires testing.

Month End Hypothetical Accounting Information:

Meter ID in Appendix C, Figure 5	Meter Function in Appendix C, Figure 5	Volume Through Effluent Meter	ECF based upon exemption or well test data	Applied CGR	WGR m^3/e^3m^3 based battery/ facility WGR or well test data
EM1	Well #1 Effluent Meter - Testing Exempt	$10.00e^3m^3$	1.000000	N/A as Battery / Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/ facility WGR. See below for example calculation.
EM2	Well #2 Effluent Meter - Testing Exempt	$11.00e^3m^3$	1.000000	N/A as Battery/Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/ facility WGR. See below for example calculation.
EM3	Well #3 Effluent Meter -Testing Required	$12.00e^3m^3$	0.930000	N/A as Battery/Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	0.28000
GMG	Group Separator Gas Meter	$31.00e^3m^3$			
GMC	Group Separator Condensate Meter	$1.00m^3$			
GMW	Group Separator Water Meter	$6.00m^3$			

Applicability

As the Multi-Well Effluent Proration Battery/Facility LGR is >0.1500m³/e³m³ a battery/facility testing exemption cannot be applied.

Calculate Effluent Battery/Facility LGR:

Battery/Facility Water Volume **+** Battery/Facility Condensate Volume (m³)	/	Battery/Facility Gas Volume (e³m³)	=	Battery/Facility LGR (m³/e³m³)
GMW + GMC	/	GMG	=	
6.0 + 1.00	/	31.00	=	
7.00	/	31.00	=	0.22581

Gas Calculations

The total reportable Multi-Well Effluent Proration Battery's/Facility's gas production is equal to the sum of the group measured gas production and the group measured condensate production converted to a gas equivalent (GEV). The gas equivalent factor (GEF) of 0.22478e³m³/m³ is used within the calculation to convert the liquid condensate to a GEV below, which is only utilized as an example supplied from Appendix A. Each battery/facility must determine its own unique GEF representative of the condensate production.

Calculate Effluent Battery/Facility Gas Production:

Measured Battery/Facility Gas (e³m³)	+	Measured Condensate Production (m³)* GEF (e³m³/m³)	=	Battery/Facility Gas Production (e³m³)
GMG	+	GMC * GEF	=	
31.00	+	1.00 * 0.22478	=	
31.00	+	0.22478	=	31.22

Calculate Well's Estimated Gas Production:

Well #	Well's Monthly Effluent Metered Volume (e³m³)	*	Well's ECF	=	Well's Estimated Gas Production (e³m³)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
EM3	12.00	*	0.930000	=	11.16
Total					32.16

Calculate Battery/Facility Gas Proration Factor:

Battery/Facility Gas Production (e³m³)	/	Sum of Well's Estimated Gas Production (e³m³)	=	Battery/Facility Gas Proration Factor
See *Battery/Facility Gas Production* Above	/	See *Well's Estimated Gas Production* Above	=	
31.22	/	32.16	=	0.970771

The Multi-Well Effluent Proration Battery's/Facility's gas production must be prorated back to the wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery/facility gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e³m³)	*	Battery/Facility Gas Proration Factor	=	Well's Prorated Gas Production (e³m³)[1]
EM1	10.00	*	0.970771	=	9.71
EM2	11.00	*	0.970771	=	10.68
EM3	11.16	*	0.970771	=	10.83
Total	32.16				31.22

[1]These are the monthly volumes to be utilized for reporting purposes.

Condensate Calculations

The Multi-Well Effluent Proration Battery's/Facility's condensate liquid volume is recombined back into the gas stream at the battery/facility and therefore reported as a gas equivalent volume. There is no proration of condensate liquid volumes back to the wells independent of the gas production.

Water Calculations

Calculate Effluent Battery/Facility Water Production:

The Multi-Well Effluent Proration Battery's/Facility's water is measured and put back into the gas stream. There is no water inventory for this example, and it is assumed that there are no water receipts. Production will be 6.00m³ for a monthly metered volume. Theoretical water volumes are first determined for the wells that require testing prior to determining water production for wells that are exempt from testing.

Calculate the Tested Well's Estimated Water Production:

Well's Estimated Gas Production (e^3m^3)	*	Tested Well's WGR (m^3/e^3m^3)	=	Tested Well's Estimated Water Production (m^3)
See *Well's Estimated Gas Production* Above	*	EM3 WGR	=	
11.16	*	0.28000	=	3.12

Calculate the Test Exempt Well's Estimated Water Production:

Group Metered Water Volume (m^3)	-	Tested Well's Estimated Water Volume (m^3)	=	Test Exempt Well's Estimated Water Production (m^3)
GMW	-	See *Tested Well's Estimated Water Production* Above	=	
6.00	-	3.12	=	2.88

Calculate the Test Exempt Well's Estimated Gas Production:

Group Metered Gas Volume (e^3m^3)	+	Group Metered Condensate Volume (m^3) * GEF (e^3m^3/m^3)	-	Tested Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's Estimated Gas Production (e^3m^3)
GMG	+	GMC * GEF	-	See *Well's Estimated Gas Production* Above	=	
31.00	+	1.00 * 0.22478	-	11.16	=	
31.00	+	0.22478	-	11.16	=	20.06

Calculate the Test Exempt Well's WGR:

Exempt Well's Estimated Water Production (m^3)	/	Exempt Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's WGR (m^3/e^3m^3)
See *Test Exempt Well's Estimated Water Production* Above	/	See *Test Exempt Well's Estimated Gas Production* Above	=	
2.88	/	20.06	=	0.14357

Calculate the Test Exempt Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Test Exempt Well's Estimated Water Production (m^3)
EM1	10.00	*	0.14357	=	1.44
EM2	11.00	*	0.14357	=	1.58
Total	22.00				3.02

Calculate the Effluent Battery's/Facility's Water Proration Factor:

Battery/Facility Water Production (m³)	/	Sum of Well's Estimated Water Production (m³)	=	Battery/Facility Water Proration Factor
GMW	/	See *Test Exempt Well's Estimated Water Production* Above + See *Tested Well's Estimated Water Production* Above	=	
6.00	/	3.02 + 3.12	=	
6.00	/	6.14	=	0.977199

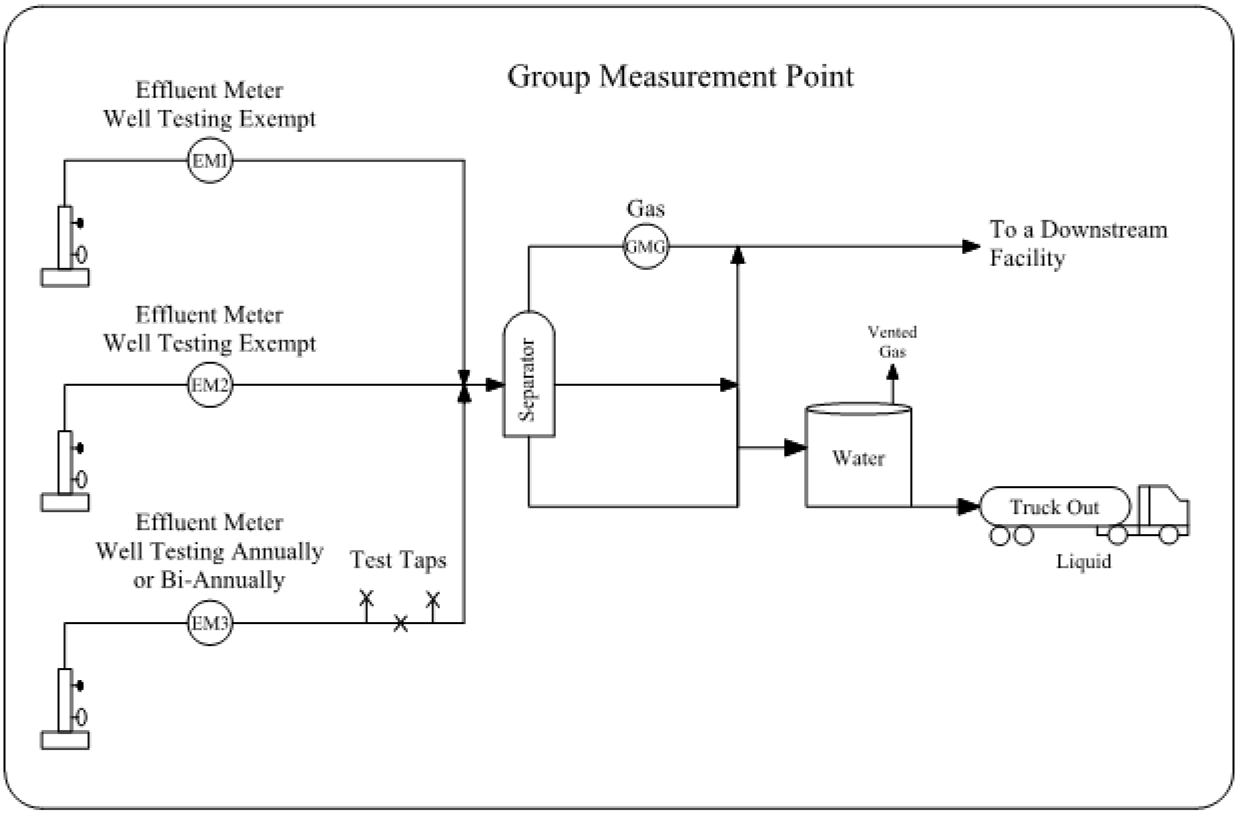
Calculate Individual Well's Water Production:

Well #	Well's Estimated Water Production (m³)	*	Water Proration Factor	=	Prorated Water Production (m³)[1]
EM1	1.44	*	0.977199	=	1.1
EM2	1.58	*	0.977199	=	1.54
EM3	3.12	*	0.977199	=	3.05
Total	6.14				6.00

[1]These are the monthly volumes to be utilized for reporting purposes.

Example 2. Calculation - Hydrocarbon Liquids Tanked at Battery/Facility

Appendix-4-Figure 6



Example 2. : Typical Multi-Well Effluent Proration Battery/Facility configuration where liquids are tanked and trucked out at the battery/facility. One of the three wells require annual or bi-annual testing.

Month End Hypothetical Accounting Information:

Meter ID in Fig. Appendix C, Figure 6	Meter Function in Appendix C, Figure 6	Volume Through Effluent Meter	ECF based upon exemption or well test data	CGR m^3/e^3m^3 based battery/ facility CGR or well test data	WGR m^3/e^3m^3 based battery/ facility WGR or well test data
EM1	Well #1 Effluent Meter - Testing Exempt	$10.00e^3m^3$	1.000000	Based upon calculated battery/ facility CGR. See below for example calculation.	Based upon calculated battery/ facility WGR. See below for example calculation.
EM2	Well #2 Effluent Meter - Testing Exempt	$11.00e^3m^3$	1.000000	Based upon calculated battery/ facility CGR. See below for example calculation.	Based upon calculated battery/facility WGR. See below for example calculation.
EM3	Well #3 Effluent Meter -Testing Required	$12.00e^3m^3$	0.930000	0.19000	0.28000
GMG	Group Separator Gas Meter	$29.00e^3m^3$			
Vent	Vented Gas	$2.00e^3m^3$			
OI	Opening Inventory	$10.00m^3$			
OI%	Opening Inventory Water Cut %	40.00%			
CI	Closing Inventory	$17.00\ m^3$			
CI%	Closing Inventory Water Cut %	40.00%			
DelCond	For simplicity there are no trucked-out volumes.	$0.00m^3$			
DelWTR	Trucked-out water volumes	$3.20m^3$			
RecCond	For simplicity there are no receipt volumes.	$0.00m^3$			
RecWTR	For simplicity there are no receipt volumes.	$0.00m^3$			

Applicability

The Proration Battery/Facility LGR is >0.1500m^3/e^3m^3, a battery/facility-based testing exemption cannot be applied

Calculate Effluent Battery/Facility LGR:

Closing Liquid Inventory + Liquid Deliveries – Liquid Receipts – Opening Liquid Inventory (m^3)	/	Battery/Facility Gas Volume (e^3m^3)	=	Effluent Battery/Facility LGR (m^3/e^3m^3)
CI + DelCond + DelWTR – RecCond - RecWTR – OI	/	GMG + Vent	=	
(17.00 + 0.00 + 3.20 – 0.00 – 0.00 – 10.00)	/	29.00 + 2.00	=	
10.20	/	31.00	=	0.32903

Gas Calculations

The Multi-Well Effluent Proration Battery's/Facility's gas proration factor is calculated slightly different when condensate volumes are not recombined back into the gas stream at the battery/facility. The total reportable effluent battery/facility gas production is equal to the group measured gas production and does NOT include the GEV of the condensate production as the condensate is not recombined back into the gas stream. Therefore, the condensate production is not considered in determining the overall gas proration factor.

Calculate Effluent Battery/Facility Gas Production:

Battery/Facility Gas Production (e^3m^3)	+	Battery/Facility Vented Gas (e^3m^3)	=	Battery/Facility Gas Production (e^3m^3)
GMG	+	Vent	=	
29.00	+	2.00	=	31.00

Calculate Well's Estimated Gas Production:

Well #	Well's Monthly Effluent Metered Volume (e^3m^3)	*	Well's ECF	=	Well's Estimated Gas Production (e^3m^3)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
EM3	12.00	*	0.930000	=	11.16
Total					32.16

Calculate Battery/Facility Gas Proration Factor:

Battery/Facility Gas Production (e^3m^3)	/	Sum of Well's Estimated Gas Production (e^3m^3)	=	Battery/Facility Gas Proration Factor
See *Battery/Facility Gas Production* Above	/	See *Well's Estimated Gas Production* Above	=	
31.00	/	32.16	=	0.963930

The Multi-Well Effluent Proration Battery's/Facility's gas production must be prorated back to the wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery/facility gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Battery/Facility Proration Factor	=	Prorated Battery/Facility Gas Production (e^3m^3)[1]
EM1	10.00	*	0.963930	=	9.64
EM2	11.00	*	0.963930	=	10.60
EM3	11.16	*	0.963930	=	10.76
Total	32.16				31.00

[1]These are the monthly volumes to be utilized for reporting purposes.

Condensate Calculations

Where condensate volumes are delivered to a tank at the battery/facility and trucked or pipelined for sale, the condensate liquid volumes must be prorated back to the wells based upon each well's unique CGR. Estimated condensate volumes are first determined for the wells that require testing prior to determining condensate production for wells that are exempt from testing.

Calculate Battery/Facility Condensate Production:

Closing Inventory (m^3)	+	Dispositions (m^3)	-	Receipts (m^3)	-	Opening Inventory(m^3)	=	Battery/Facility Condensate Production (m^3)
CI * (1- CI%)	+	DelCond	-	RecCond	-	OI * (1- OI%)	=	
17.00 * (1 - 0.40)	+	0.00	-	0.00	-	10.00 * (1- 0.40)	=	
10.20	+	0.00	-	0.00	-	6.00	=	4.20

The PA system will calculate each well's estimated condensate production (well estimated gas production * well CGR).

Calculate the Tested Well's Estimated Condensate Production:

Tested Well's CGR (m^3/e^3m^3)	*	Well's Estimated Gas Production (e^3m^3)	=	Tested Well's Estimated Condensate Production (m^3)
EM3 CGR	*	See *Well's Estimated Gas Production* Above	=	
0.19000	*	11.16	=	2.12

Calculate the Test Exempt Well's Estimated Condensate Production:

Battery/Facility Condensate Volume (m³)	-	Tested Well's Estimated Condensate Volume (m³)	=	Test Exempt Well's Estimated Condensate Production (m³)
See *Battery/Facility Condensate Production* Above	-	See *Tested Well's Estimated Condensate Production* Above	=	
4.20	-	2.12	=	2.08

Calculate the Test Exempt Well's Estimated Gas Production:

Battery/Facility Gas Volume (e³m³)	-	Tested Well's Estimated Gas Production (e³m³)	=	Test Exempt Well's Estimated Gas Production (e³m³)
See *Battery/Facility Gas Production* Above	-	See *Well's Estimated Gas Production* Above	=	
31.00	-	11.16	=	19.84

Calculate the Test Exempt Well's CGR:

Exempt Well's Estimated Condensate Production (m³)	/	Exempt Well's Estimated Gas Production (e³m³)	=	Test Exempt Well's CGR (m³/e³m³)
See *Test Exempt Well's Estimated Condensate Production* Above	/	See *Test Exempt Well's Estimated Gas Production* Above	=	
2.08	/	19.84	=	0.10484

Calculate the Test Exempt Well's Estimated Condensate Production:

Well #	Test Exempt Well's Estimated Gas Production (e^3m^3)	*	Well's CGR (m^3/e^3m^3)	=	Test Exempt Well's Estimated Condensate Production (m^3)
EM1	10.00	*	0.10484	=	1.05
EM2	11.00	*	0.10484	=	1.15
Total	22.00				2.20

Calculate the Effluent Battery's/Facility's Condensate Proration Factor:

Battery/Facility Condensate Production (m^3)	/	Sum of Well's Estimated Condensate Production (m^3)	=	Battery/Facility Condensate Proration Factor
See *Battery/Facility Condensate Production* Above	/	See *Test Exempt Well's Estimated Condensate Production* Above + See *Tested Well's Estimated Condensate Production* Above	=	
4.20	/	2.20 + 2.12	=	
4.20	/	4.32	=	0.972222

Calculate Individual Well's Condensate Production:

Well #	Well's Estimated Condensate Production (m^3)	*	Condensate Proration Factor	=	Prorated Condensate Production (m^3)[1]
EM1	1.05	*	0.972222	=	1.02
EM2	1.15	*	0.972222	=	1.12
EM3	2.12	*	0.972222	=	2.06
Total	4.32				4.20

[1]These are the monthly volumes to be utilized for reporting purposes.

Water Calculations

Calculate Effluent Battery/Facility Water Production:

Closing Inventory (m³)	+	Dispositions (m³)	-	Receipts (m³)	-	Opening Inventory(m³)	=	Battery/ Facility Water Production (m³)
CI * (CI%)	+	DelWTR	-	RecWTR	-	OI * (OI %)	=	
17.00 * (0.40)	+	3.20	-	0.00	-	10.00 * (0.40)	=	
6.80	+	3.20	-	0.00	-	4.00	=	6.00

The PA system will calculate each well's estimated water production (well estimated gas production * well WGR).

Calculate the Tested Well's Estimated Water Production:

Tested Well's WGR (m^3/e^3m^3)	*	Well's Estimated Gas Production (e^3m^3)	=	Tested Well's Estimated Water Production (m^3)
EM3 WGR	*	See *Well's Estimated Gas Production* Above	=	
0.28000	*	11.16	=	3.12

Calculate the Test Exempt Well's Estimated Water Production:

Battery/Facility Water Volume (m³)	-	Tested Well's Estimated Water Volume (m³)	=	Test Exempt Well's Estimated Water Production (m³)
See *Battery/Facility Water Production* Above	-	See *Tested Well's Estimated Water Production* Above	=	
6.00	-	3.12	=	2.88

Calculate the Test Exempt Well's Estimated Gas Production:

Group Gas Volume (e^3m^3)	-	Tested Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's Estimated Gas Production (e^3m^3)
See *Battery/Facility Gas Production* Above	-	See *Well's Estimated Gas Production* Above	=	
31.00	-	11.16	=	19.84

Calculate the Test Exempt Well's WGR:

Exempt Well's Estimated Water Production (m³)	/	Exempt Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's WGR (m^3/e^3m^3)
See *Test Exempt Well's Estimated Water Production* Above	/	See *Test Exempt Well's Estimated Gas Production* Above	=	
2.88	/	19.84	=	0.14516

Calculate the Test Exempt Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Test Exempt Well's Estimated Water Production (m^3)
EM1	10.00	*	0.14516	=	1.45
EM2	11.00	*	0.14516	=	1.60
Total	22.00				3.05

Calculate the Effluent Battery's/Facility's Water Proration Factor:

Battery/Facility Water Production (m^3)	/	Sum of Well's Estimated Water Production (m^3)	=	Effluent Battery/Facility Water Proration Factor
See *Battery/Facility Water Production* Above	/	See *Test Exempt Well's Estimated Water Production* Above + See *Tested Well's Estimated Water Production* Above	=	
6.00	/	3.05 + 3.12	=	
6.00	/	6.17	=	0.972447

Calculate Individual Well's Water Production:

Well #	Well's Estimated Water Production (m^3)	*	Water Proration Factor	=	Prorated Water Production (m^3)[1]
EM1	1.45	*	0.972447	=	1.41
EM2	1.60	*	0.972447	=	1.56
EM3	3.12	*	0.972447	=	3.03
Total	6.17				6.00

[1]These are the monthly volumes to be utilized for reporting purposes.

Scenario 4 - Battery/Facility Containing Mixed Measurement Schemes

Applicability

This section provides the detailed method of calculation and examples for reporting production from the following sources:

1) Effluent metered wells that are testing exempt based on the applicable Effluent Well Testing Decision Tree

2) Effluent metered wells that require testing to be conducted based on the Effluent Well Testing Decision Tree – Well Based Testing Exemption

3) Measured gas sources that produce to a common battery/facility in which effluent wells also deliver into.

Considerations

1) Applicable Measurement by Difference requirements outlined in section 5.6 must be adhered to as applicable.

2) Proration targets for effluent proration batteries must remain consistent with existing effluent proration battery/facility limits outlined in Chapter 3.

Note**:** Any fuel, flare and/or vent gas extracted from the production line (i.e., well or compressor station) within the Multi-Well Effluent Proration Battery/Facility must be added to the battery/facility gas production volume.

Method of Calculation

1) When a battery/facility receives measured gas production (production streams utilizing a separator, or gas with free liquids removed) into a Multi-Well Effluent Proration Battery/Facility, upstream of the effluent battery/facility group separator, operators must ensure that the measured gas source remains whole and is not subject to the battery's/facility's proration factors as outlined in section 5.6.

2) The PA system must calculate the total effluent battery/facility production by first subtracting off the measured production to derive the battery's/facility's gas production subject to a proration.

3) Should a battery/facility be recombining liquids for sale, then the operator must calculate the gas equivalent of the recombined hydrocarbon liquids and add the gas equivalent volume to the metered gas volume.

4) If the Multi-Well Effluent Proration Battery/Facility produces its hydrocarbon liquids to a tank the operator must report the condensate for the measured source as a receipt – not as a GEV of gas.

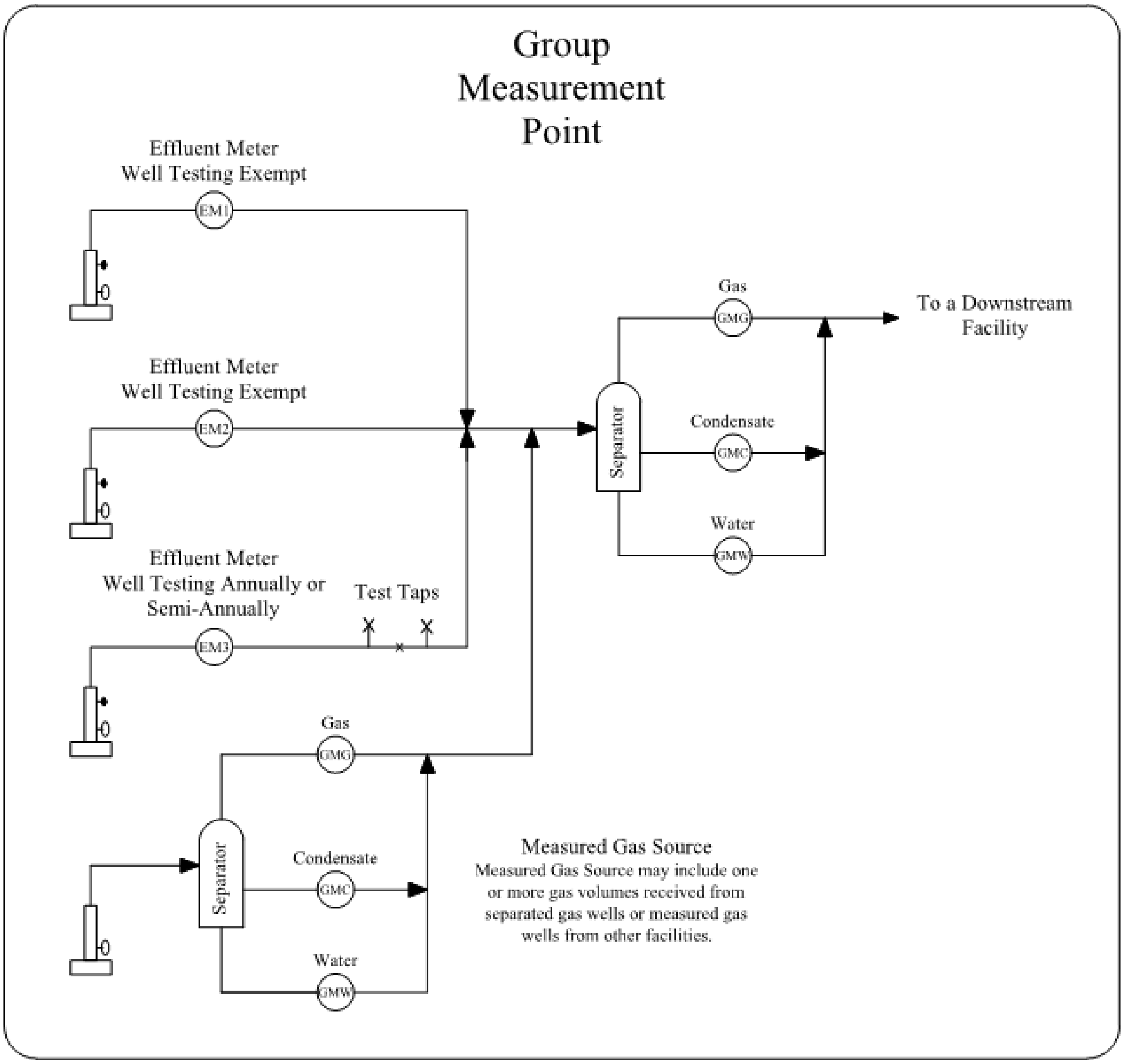
The following are two examples to be utilized to model accounting practices around:

Example 1. Recombined hydrocarbon liquid production at the Battery/Facility and;

Example 2. Tanked and trucked out hydrocarbon liquid production from the Battery/Facility.

Example 1. Calculations - Hydrocarbon Liquids Recombined at Battery/Facility

Appendix C Figure 7



Example 1.: Typical Multi-Well Effluent Proration Battery/Facility configuration that recombines liquid volumes. The reporting battery/facility contains multiple measurement schemes including: one measured well reported within the battery/facility, 2 wells that are exempt from testing, and one well that requires testing based on the Well Testing Decision Tree.

Month End Hypothetical Accounting Information:

above	Meter Function in Appendix C, Figure 7	Volume Through Meter	Applied ECF	Applied CGR	Applied WGR
EM1	Well #1 Effluent Meter -Exempt from Testing	$10.00e^3m^3$	1.000000	N/A as Battery/ Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/facility WGR. See below for example calculation.
EM2	Well #2 Effluent Meter -Exempt from Testing	$11.00e^3m^3$	1.000000	N/A as Battery/ Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	Based upon calculated battery/facility WGR. See below for example calculation.
EM3	Well #3 Effluent Meter -Testing Required	$12.00e^3m^3$	0.930000	N/A as Battery/ Facility Condensate is Recombined back into the gas stream and reported as a gas equivalent.	0.28000
M4G	Well #4 Gas Meter	$9.00e^3m^3$			
M4C	Well #4 Condensate Meter	$2.00m^3$			
M4W	Well #4 Water Meter	$5.00m^3$			
GMG	Group Separator Gas Meter	$40.00e^3m^3$			
GMC	Group Separator Condensate Meter	$3.00m^3$			
GMW	Group Separator Water Meter	$11.00m^3$			

Applicability

As the Multi-Well Effluent Proration Battery/Facility LGR is $>0.1500m^3/e^3m^3$ a battery/facility based well testing exemption cannot be applied. For the purposes of this example, 2 wells are exempt from testing based on the Well Testing Decision Tree.

Calculate Effluent Battery's/Facility's LGR:

Battery/Facility Water Volume + Battery/Facility Condensate Volume – Well #4 Water Meter – Well #4 Condensate Meter (m^3)	/	Battery/Facility Gas Volume – Well #4 Gas Meter (e^3m^3)	=	Effluent Battery/Facility LGR (m^3/e^3m^3)
(GMW + GMC – M4W – M4C)	/	GMG – M4G	=	
(11.00 + 3.00 – 5.00 – 2.00)	/	40.00 – 9.00	=	
7.00	/	31.00	=	0.22581

Gas Calculations

The total reportable Multi-Well Effluent Proration Battery's/Facility's gas production is equal to the sum of the group measured gas production and the group measured liquid condensate production converted to a GEV less the measured receipts. The GEF ($0.22478e^3m^3/m^3$) is used to convert the condensate to a GEV and is only utilized as an example value referenced from Appendix A. Each battery/facility must determine a unique GEF that is representative of their condensate production.

Calculate the Battery's/Facility's Gas Production:

Measured Battery/Facility Gas (e^3m^3)	+	Measured Condensate Production (m^3)* GEF (e^3m^3/m^3)	=	Battery/Facility Gas Production (e^3m^3)
GMG	+	GMC * GEF	=	
40.00	+	3.00 * 0.22478	=	
40.00	+	0.67434	=	40.67

Calculate the Measured Gas Wells Production

Measured Well's Gas (e^3m^3)	+	Measured Well's Condensate Production (m^3) * GEF(e^3m^3/m^3)	=	Measured Well's Gas Production (e^3m^3)
M4G	+	M4C * GEF	=	
9.00	+	2.00 * 0.22478	=	
9.00	+	0.44956	=	9.45

Calculate Effluent Well's Estimated Gas Production:

Well #	Well's Monthly Metered Volume (e³m³)	*	Well's ECF	=	Well's Estimated Gas Production (e³m³)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
EM3	12.00	*	0.930000	=	11.16
Total	33.00				32.16

Calculate Effluent Battery/Facility Gas Proration Factor:

Battery/Facility Gas Production Measured Gas Well's Gas Production (e³m³)	/	Sum of Well's Estimated Gas Production (e³m³)	=	Battery/Facility Gas Proration Factor
See *Battery/Facility Gas Production* Above – See *Measured Gas Well's Gas Production* Above	/	See *Well's Estimated Gas Production* Above	=	
40.67 – 9.45	/	32.16	=	
31.22	/	32.16	=	0.970771

The Multi-Well Effluent Proration Battery's/Facility's gas production is then to be prorated back to the effluent wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery/facility gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Battery/Facility Gas Proration Factor	=	Prorated Battery/Facility Gas Production (e^3m^3)[1]
EM1	10.00	*	0.970771	=	9.71
EM2	11.00	*	0.970771	=	10.68
EM3	11.16	*	0.970771	=	10.83
M4	9.45	*	N/A – Measured Receipt	=	9.45
Total	41.61				40.67

[1]These are the monthly volumes to be utilized for reporting purposes.

Condensate Calculations

The Multi-Well Effluent Proration Battery's/Facility's condensate liquid volume is recombined back into the gas stream at the battery/facility and therefore reported as a gas equivalent volume. There is no proration of condensate liquid volumes back to the wells independent of the gas production.

Water Calculations

The Multi-Well Effluent Proration Battery's/Facility's water production volume must be prorated back to the effluent wells based upon applicable WGR's. Measured water receipts must be deducted from the battery/facility water prior to the estimated water volumes being determined for the wells that require testing. Then a battery/facility is able to determine water production for wells that are exempt from testing.

Effluent Battery's/Facility's Water Production

GMW = 11.0m^3

Calculate the Tested Well's Estimated Water Production:

Tested Well's WGR (m³/e³m³)	*	Well's Estimated Gas Production (e³m³)	=	Tested Well's Estimated Water Production (m³)
EM3 WGR	*	EM3 * EM3 ECF	=	
0.28000	*	12.00 * 0.930000	=	
0.28000	*	11.16	=	3.12

Calculate the Test Exempt Well's Estimated Water Production:

Battery/Facility Water – Measured Well's Water Receipt (m³)	-	Tested Well's Estimated Water Production (m³)	=	Test Exempted Well's Estimated Water Production (m³)
GMW – M4W	-	See *Tested Well's Estimated Water Production* Above	=	
11.00 - 5.00	-	3.12	=	
6.00	-	3.12	=	2.88

Calculate the Test Exempt Well's Estimated Gas Production:

Battery/Facility Gas (e³m³)	-	Measured Gas Receipts (e³m³)	-	Tested Well's Estimated Gas Production (e³m³)	=	Test Exempted Well's Estimated Gas Production (e³m³)
GMG + (GMC * GEF)	-	M4G + (M4C * GEF)	-	EM3 * EM3 ECF	=	
40.00 + (3.00 * 0.22478)	-	9.00 + (2.00 * 0.22478)	-	12.00 * 0.930000	=	
40.67	-	9.45	-	11.16	=	20.06

Calculate the Test Exempt Well's WGR:

Exempt Well's Estimated Water Production (m^3)	/	Exempt Wells Estimated Gas Production (e^3m^3)	=	Test Exempt Wells WGR (m^3/e^3m^3)
See *Test Exempted Well's Estimated Water Production* Above	/	See *Test Exempted Well's Estimated Gas Production* Above	=	
2.88	/	20.06	=	0.14357

Calculate the Effluent Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Well's Estimated Water Production (m^3)
EM1	10.00	*	0.14357	=	1.44
EM2	11.00	*	0.14357	=	1.58
EM3	11.16	*	0.28000	=	3.12
Total	32.16				6.14

Calculate the Effluent Battery's/Facility's Water Proration Factor:

Battery/Facility Water to be Prorated (m^3)	/	Sum of Well's Estimated Water Production (m^3)	=	Effluent Battery/Facility Water Proration Factor
GMW – M4W	/	See *Well's Estimated Water Production* Above	=	
11.00 – 5.00	/	6.14	=	
6.00	/	6.14	=	0.977199

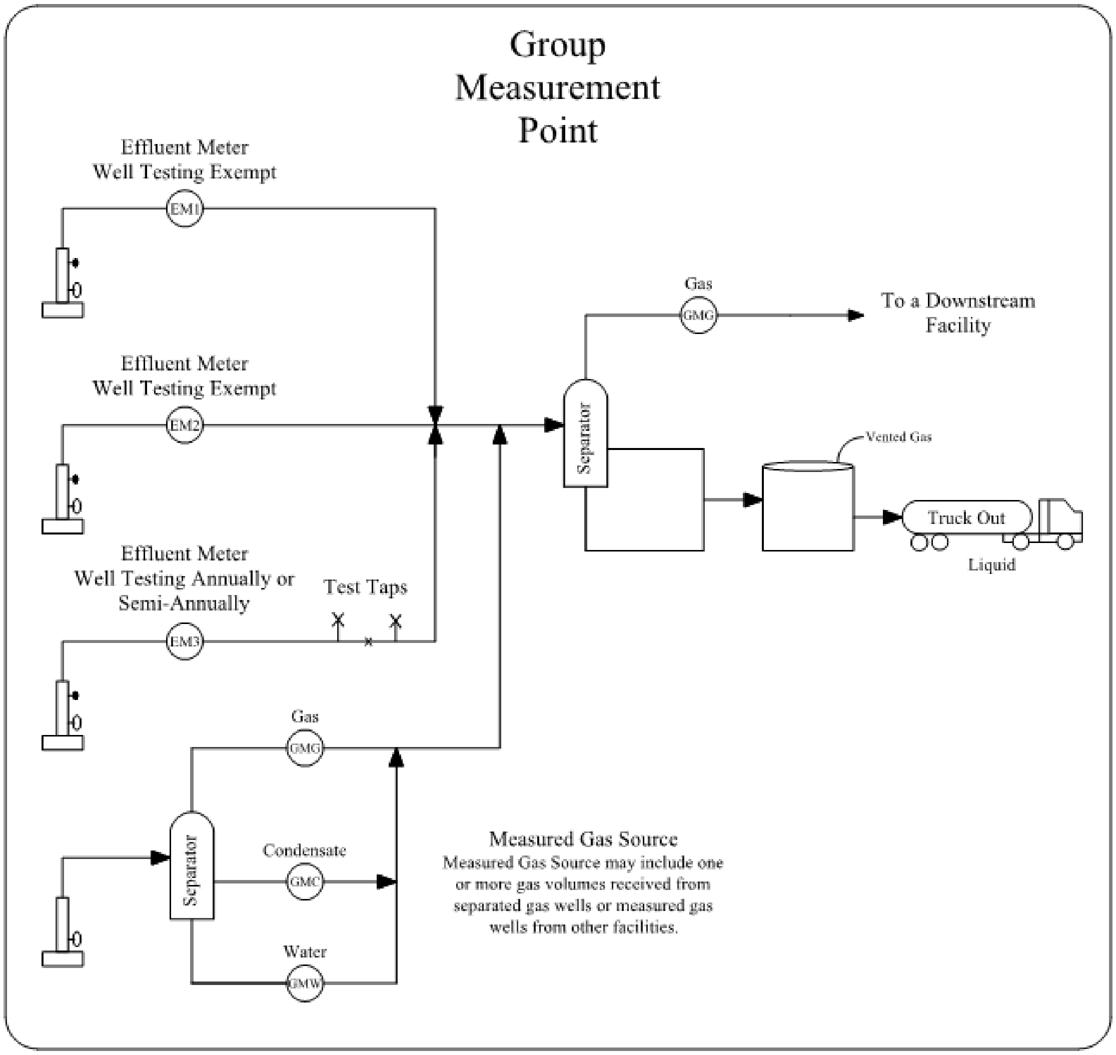
Calculate Individual Well's Water Production:

Well #	Well's Estimated Water Production (m^3)	*	Water Proration Factor	=	Prorated Water Production (m^3)[1]
EM1	1.44	*	0.977199	=	1.41
EM2	1.58	*	0.977199	=	1.54
EM3	3.12	*	0.977199	=	3.05
M4	5.00	*	N/A – Measured Receipt	=	5.00
Total	11.14				11.00

[1]These are the monthly volumes to be utilized for reporting purposes.

Example 2. Calculations - Hydrocarbon Liquids Tanked at Battery/Facility

Appendix C Figure 8



Example 2. : Typical Multi-Well Effluent Proration Battery/Facility configuration where liquids are tanked and trucked-out at the Facility. The reporting battery/facility contains multiple measurement schemes including: with a measured gas source tied in upstream of the effluent battery's/facility's group separator, 2 wells that are exempt from testing and one well that requires testing based on the Well Testing Decision Tree.

Month End Hypothetical Accounting Information:

Meter ID in Appendix C, Figure 9	Meter Function in Appendix C, Figure 9	Volume Through Meter	Applied ECF	Applied CGR	Applied WGR
EM1	Well # 1 Effluent Meter -Exempt from Testing	10.00e³m³	1.000000	Based upon calculated battery/facility CGR. See below for example calculation.	Based upon calculated battery/facility WGR. See below for example calculation.
EM2	Well # 2 Effluent Meter -Exempt from Testing	11.00e³m³	1.000000	Based upon calculated battery/facility CGR. See below for example calculation.	Based upon calculated battery/facility WGR. See below for example calculation.
EM3	Well # 3 Effluent Meter -Testing Required	12.00e³m³	0.930000	0.54000	0.28000
M4G	Well # 4 Gas Meter	9.00e³m³			
M4C	Well # 4 Condensate Meter	2.00m³			
M4W	Well # 4 Water Meter	2.00m³			
GMG	Group Separator Gas Meter	38.00e³m³			
VENT	Vented Gas	2.00e³m³			
OI	Opening Inventory	10.00m³			
OI%	Opening Inventory Water Cut %	30.00%			
CI	Closing Inventory	13.00m³			
CI%	Closing Inventory Water Cut %	30.00%			
DelCond	Trucked Out Condensate Volumes Measured at Delivery Point	7.70m³			
DelWTR	Trucked Out Water Volumes Determined at Delivery Point	5.30m³			
RecCond	For simplicity there are no receipt volumes.	0.00m³			

Meter ID in Appendix C, Figure 9	Meter Function in Appendix C, Figure 9	Volume Through Meter	Applied ECF	Applied CGR	Applied WGR
RecWTR	For simplicity there are no receipt volumes.	0.00m³			

Applicability

As the Multi-Well Effluent Proration Battery/Facility LGR is >0.1500m³/e³m³ and therefore a battery/facility well testing exemption cannot be applied. For the purposes of this example, 2 wells are exempt from testing based on the Well Testing Decision Tree.

Calculate Effluent Battery/Facility LGR:

Monthly Liquid Effluent Production (m³)	/	Effluent Battery/Facility Gas Volume (e³m³)	=	Effluent Battery/Facility LGR (m³/e³m³)
Closing Liquid Inventory + Liquid Deliveries – Liquid Receipts – Well #4 Condensate Meter – Well #4 Water Meter – Opening Liquid Inventory	/	Group meter + Tank Vent – Well #4 Gas Meter	=	
CI + DelCond + DelWTR – RecCond – RecWTR – M4C – M4W – OI	/	GMG + Vent – M4G	=	
13.00 + 7.70 + 5.30 – 0.00 – 0.00 – 2.00 – 2.00 - 10.00	/	38.0 + 2.0 – 9.0	=	
12.00	/	31.00	=	0.38710

Gas Calculations

The total reportable Multi-Well Effluent Proration Battery's/Facility's gas production is equal to the sum of the group measured gas plus vent gas off the condensate production tank.

Calculate the Battery's/Facility's Gas Production:

Battery/Facility Gas Production (e^3m^3)	+	Battery/Facility Vented Gas (e^3m^3)	=	Battery/Facility Gas Production (e^3m^3)
GMG	+	Vent	=	
38.00	+	2.00	=	40.00

Calculate the Measured Well's Monthly Metered Gas Volume:

Measured Well's Gas (e^3m^3)	+	Measured Well's Condensate Production (m^3)* GEF (e^3m^3/m^3)	=	Measured Well's Gas Production (e^3m^3)
M4G	+	M4C * GEF	=	
9.00	+	2.00 * 0.22478	=	
9.00	+	0.44956	=	9.45

Calculate Effluent Well's Estimated Gas Production:

Well #	Well's Monthly Metered Volume (e^3m^3)	*	Well's ECF	=	Well's Estimated Gas Production (e^3m^3)
EM1	10.00	*	1.000000	=	10.00
EM2	11.00	*	1.000000	=	11.00
EM3	12.00	*	0.930000	=	11.16
Total	32.00				32.16

Calculate Effluent Battery/Facility Gas Proration Factor:

Battery/Facility Gas Production - Measured Gas Well's Gas Production (e^3m^3)	/	Sum of Well's Estimated Gas Production (e^3m^3)	=	Battery/Facility Gas Proration Factor
See *Battery/Facility Gas Production* Above – See *Measured Well's Gas Production* Above	/	See *Well's Estimated Gas Production* Above	=	
40.00 – 9.45	/	32.16	=	
30.55	/	32.16	=	0.949938

The Multi-Well Effluent Proration Battery's/Facility's gas production must be prorated back to the effluent wells by multiplying each well's estimated gas production (well's monthly effluent metered volume * well's ECF) by the battery/facility gas proration factor.

Calculate Individual Well's Prorated Gas Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Battery/Facility Gas Proration Factor	=	Prorated Battery/Facility Gas Production (e^3m^3)[1]
EM1	10.00	*	0.949938	=	9.50
EM2	11.00	*	0.949938	=	10.45
EM3	11.16	*	0.949938	=	10.60
M4	9.45	*	N/A – Measured Receipt	=	9.45
Total	41.61				40.00

[1]These are the monthly volumes to be utilized for reporting purposes.

Condensate Calculations

Calculate Battery/Facility Condensate Production:

Closing Inventory (m³)	+	Dispositions (m³)	-	Receipts (m³)	-	Opening Inventory(m³)	=	Battery/ Facility Condensate Production (m³)
CI * (1- CI%)	+	DelCond	-	RecCond	-	OI * (1 - OI%)	=	
13.00 * (1 - 0.30)	+	7.70	-	0.00	-	10.0 * (1 - 0.30)	=	
9.10	+	7.70	-	0.00	-	7.00	=	9.80

Calculate Tested Well's Estimated Condensate Production:

Well #	Tested Well's Estimated Gas Production (e³m³)	*	Tested Well's CGR (m³/e³m³)	=	Tested Well's Estimated Condensate Production (m³)
EM3	EM3 * ECF	*	EM3 CGR	=	
EM3	12 * 0.930000	*	0.54000	=	
EM3	11.16	*	0.54000	=	6.03

The PA system will calculate each well's estimated condensate production (well estimated gas production * well CGR).

Calculate the Test Exempt Well's Estimated Condensate Production:

Battery/Facility Condensate Volume (m³)	-	Measured Well's Condensate Volume (m³)	-	Tested Well's Estimated Condensate Volume (m³)	=	Test Exempt Well's Estimated Condensate Production (m³)
See *Battery/Facility Condensate Production* Above	-	M4C	-	See *Tested Well's Estimated Condensate Production* Above	=	
9.80	-	2.00	-	6.03	=	1.77

Calculate the Test Exempt Well's Estimated Gas Production:

Battery/Facility Gas Volume (e^3m^3)	-	Measured Well's Gas Volume (e^3m^3)	-	Tested Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's Estimated Gas Production (e^3m^3)
GMG + Vent	-	M4G	-	EM3 * EM3 ECF	=	
38.00 + 2.00	-	9.00	-	12.00 * 0.930000	=	
40.00	-	9.00	-	11.16	=	19.84

Calculate the Test Exempt Well's CGR:

Test Exempt Well's Estimated Condensate Production (m^3)	/	Exempt Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's CGR (m^3/e^3m^3)
See *Test Exempt Well's Estimated Condensate Production* Above	/	See *Test Exempt Well's Estimated Gas Production* Above	=	
1.77	/	19.84	=	0.08921

Calculate the Test Exempt Well's Estimated Condensate Production:

Well #	Test Exempt Well's Estimated Gas Production (e^3m^3)	*	Well's CGR (m^3/e^3m^3)	=	Test Exempt Well's Estimated Condensate Production (m^3)
EM1	10.00	*	0.08921	=	0.89
EM2	11.00	*	0.08921	=	0.98
Total	22.00				1.87

Calculate the Effluent Battery's/Facility's Condensate Proration Factor:

Battery/Facility Condensate Production - Measured Well's Condensate Production (m³)	/	Sum of Well's Estimated Condensate Production (m³)	=	Effluent Battery/Facility Condensate Proration Factor
See *Battery/Facility Condensate Production* Above - See *Measured Well's Condensate Production* Above	/	See *Test Exempt Well's Estimated Condensate Production* Above + See *Tested Well's Estimated Condensate Production* Above	=	
9.80 – 2.00	/	1.87 + 6.03	=	
7.80	/	7.90	=	0.987342

Calculate Individual Well's Condensate Production:

Well #	Well's Estimated Condensate Production (m³)	*	Condensate Proration Factor	=	Prorated Condensate Production (m³)[1]
EM1	0.89	*	0.987342	=	0.88
EM2	0.98	*	0.987342	=	0.97
EM3	6.03	*	0.987342	=	5.95
M4C	2.00	*	N/A Measured Receipt	=	2.00
Total	9.90				9.80

[1]These are the monthly volumes to be utilized for reporting purposes.

<u>Water Calculations</u>

The Multi-Well Effluent Proration Battery's/Facility's water production volume must be prorated back to the effluent wells based upon applicable WGR's. Measured water receipts must be deducted from the battery/facility water prior to the estimated water volumes being determined for the effluent wells. Wells that require testing are required to have their estimated water determined prior to determining estimated water production for testing exempt wells.

Calculate Battery/Facility Water Production:

Closing Inventory (m^3)	+	Dispositions (m^3)	-	Receipts (m^3)	-	Opening Inventory (m^3)	=	Battery/ Facility Water Production (m^3)
CI * CI%	+	DelWTR	-	RecWTR	-	OI * OI %	=	
13.00 * 0.3	+	5.30	-	0.00	-	10.00 * 0.30	=	
3.90	+	5.30	-	0.00	-	3.00	=	6.20

Calculate the Tested Well's Estimated Water Production:

Tested Well's WGR (m^3/e^3m^3)	*	Well's Estimated Gas Production (e^3m^3)	=	Tested Well's Estimated Water Production (m^3)
EM3 WGR	*	EM3 * EM3 ECF	=	
0.28000	*	12.00 * 0.930000	=	
0.28000	*	11.16	=	3.12

Calculate the Test Exempt Well's Estimated Water Production:

Battery/Facility Water – Measured Well's Water Receipt (m^3)	-	Tested Well's Estimated Water Production (m^3)	=	Test Exempted Well's Estimated Water Production (m^3)
See *Battery/Facility Water Production* Above – M4W	-	See *Tested Well's Estimated Water Production* Above	=	
6.20 - 2.00	-	3.12	=	
4.20	-	3.12	=	1.08

Calculate the Test Exempt Well's Estimated Gas Production:

Battery/Facility Gas Volume (e^3m^3)	-	Measured Well's Gas Volume (e^3m^3)	-	Tested Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Well's Estimated Gas Production (e^3m^3)
GMG + Vent	-	M4G	-	EM3 * EM3 ECF	=	
38.00 + 2.00	-	9.00	-	12.00 * 0.930000	=	
40.00	-	9.00	-	11.16	=	19.84

Calculate the Test Exempt Well's WGR:

Test Exempt Wells Estimated Water Production (m^3)	/	Exempt Well's Estimated Gas Production (e^3m^3)	=	Test Exempt Wells WGR (m^3/e^3m^3)
See *Test Exempted Well's Estimated Water Production* Above	/	See *Test Exempt Well's Estimated Gas Production* Above	=	
1.08	/	19.84	=	0.05444

Calculate the Effluent Well's Estimated Water Production:

Well #	Well's Estimated Gas Production (e^3m^3)	*	Well's WGR (m^3/e^3m^3)	=	Well's Estimated Water Production (m^3)
EM1	10.00	*	0.05444	=	0.54
EM2	11.00	*	0.05444	=	0.60
EM3	11.16	*	0.28000	=	3.12
Total	32.16				4.26

Calculate the Effluent Battery's/Facility's Water Proration Factor:

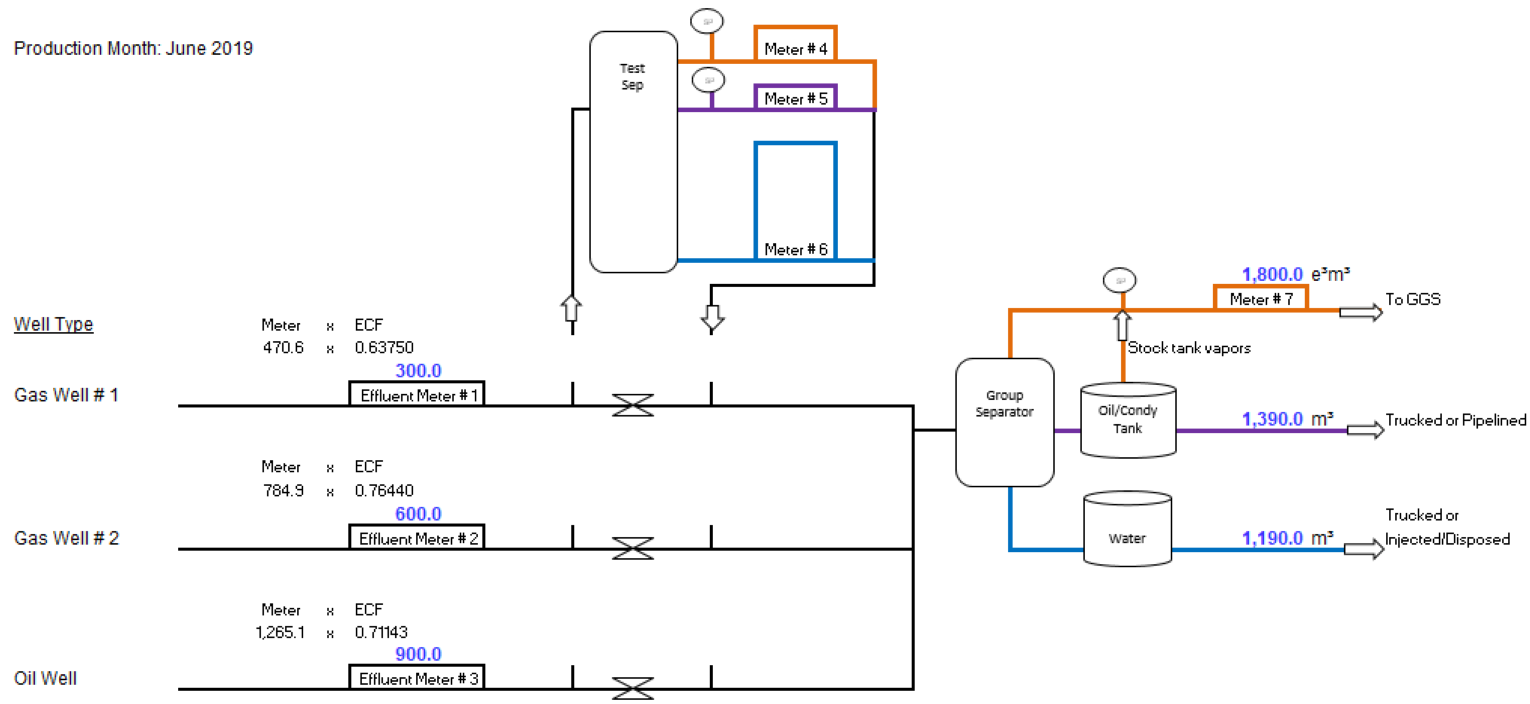
Battery/Facility Water to be Prorated (m³)	/	Sum of Wells Estimated Water Production (m³)	=	Effluent Battery/Facility Water Proration Factor
See *Battery/Facility Water Production* Above – M4W	/	See *Well's Estimated Water Production* Above	=	
6.20 – 2.00	/	4.26	=	
4.20	/	4.26	=	0.985915

Calculate Individual Well's Water Production:

Well #	Well's Estimated Water Production (m³)	*	Water Proration Factor	=	Prorated Water Production (m³)[1]
EM1	0.54	*	0. 985915	=	0.53
EM2	0.60	*	0. 985915	=	0.59
EM3	3.12	*	0. 985915	=	3.08
M4W	2.00	*	N/A – Measured Receipt	=	2.00
Total	6.26				6.20

[1]These are the monthly volumes to be utilized for reporting purposes.

Appendix D – Mixed Oil and Gas Scenario 2 Production Accounting Method



Oil/Condy Production	
Closing Inventory	30.0 m³
+ Trucked Dispositions	1,390.0 m³
- Opening Inventory	20.0 m³
= Oil/Condy Production	1,400.0 m³

Water Production	
Closing Inventory	20.0 m³
+ Trucked Dispositions	1,190.0 m³
- Opening Inventory	10.0 m³
= Water Production	1,200.0 m³

Table 1: Scenario 2 GIS Factor Multiplied by Well Test Estimated Oil/Condy Volume Test Data (12 hour tests)

Well	Test Date	Product	Meter	Test Volumes		Previous Gas Only ECF in Effluent Meter	Effluent Volume before with ECF removed (e^3m^3)	FLIB Shrinkage Factor	FLIB GIS Factor (e^3m^3/m^3)
Gas Well # 1	1/May/19	Effluent	Meter # 1	6.00	e^3m^3	0.85000	7.06		
		Dry Gas	Meter # 4	4.50	e^3m^3				
		Condy	Meter # 5	5.00	m^3			0.9205	0.03011
		Water	Meter # 6	3.00	m^3				
Gas Well # 2	2/May/19	Effluent	Meter # 2	10.00	e^3m^3	0.84000	11.90		
		Dry Gas	Meter # 4	9.10	e^3m^3				
		Condy	Meter # 5	9.00	m^3			0.9101	0.03451
		Water	Meter # 6	6.00	m^3				
Oil Well	3/May/19	Effluent	Meter # 3	14.00	e^3m^3	0.83000	16.87		
		Dry Gas	Meter # 4	12.00	e^3m^3				
		Oil	Meter # 5	8.00	m^3			0.9407	0.018576
		Water	Meter # 6	8.00	m^3				

Table 2: Scenario 2 Effluent Battery Calculations

	a.	b.	c.	d.	e.	f.	g.
Well	Measured Well Gas During Test (e^3m^3) (Meter # 4)	Measured Hydrocarbon Liquids During Test (m^3) (Meter # 5)	FLIB Shrinkage Factor	Measured Hydrocarbon Liquids During Test x FLIB Shrinkage Factor (m^3) **(b. x c.)**	FLIB GIS Factor (e^3m^3/m^3)	GIS: Shrunk Hydrocarbon Liquids x FLIB GIS (e^3m^3) **(d. x e.)**	Measured Well Gas During Test + GIS (e^3m^3) **(a. + f.)**
Gas Well # 1	4.50	5.00	0.9205	4.60	0.030110	0.14	4.64
Gas Well # 2	9.10	9.00	0.9101	8.19	0.034510	0.28	9.38
Oil Well	12.00	8.00	0.9407	7.53	0.018576	0.14	12.14

	h.	i.	j.	k.	l.	m.
Well	Effluent metered volume during test with prior ECF applied (e^3m^3)	Prior Gas Only ECF within Flow Computer, RTU or SCADA system.	Effluent metered volume during test with prior ECF applied divided by prior ECF. (e^3m^3) **(h. / i.)**	New Effluent Correction Factor **(g. / j.)**	Monthly Effluent Metered Volume before ECF Applied (e^3m^3) (SMD)	Monthly effluent metered Volume (after new ECF applied) (e^3m^3) **(k. x l.)**
Gas Well # 1	6.00	0.85000	7.06	0.6571	470.6	309.2
Gas Well # 2	10.00	0.84000	11.90	0.7881	784.9	618.6
Oil Well	14.00	0.83000	16.87	0.7197	1,265.1	910.5

Table 3: Scenario 2 Effluent Battery Prorated Oil/Condy Production @ Stock Tank Conditions

	n.	o.	p.	q.	r.
Well	Measured Well Gas During Test + GIS (e^3m^3) **(g.)**	Measured Hydrocarbon Liquids During Test x FLIB Shrinkage Factor (m^3) **(d.)**	Oil/Condy Gas Ratio (m^3/e^3m^3) **(o. / n.)**	Monthly effluent metered Volume (after new ECF applied) (e^3m^3) **(m.)**	Estimated Oil/Condy Production (m^3) **(p. x q.)**
Gas Well # 1	4.64	4.60	0.9922	309.2	306.8
Gas Well # 2	9.38	8.19	0.8729	618.6	540.0
Oil Well	12.14	7.53	0.6199	910.5	564.4

s.
Oil Condy production (m3)
1,400.0

Table 4: Scenario 2 Prorate Group Oil/Condy to Wells based upon Well Estimated Oil/Condy Production

	t.		u.	v.	
Well	Estimated Oil/Condy Production (m^3) **(r.)**		Oil/Condy Production (m^3) **(r.)**	Prorated Oil/Condy Production to Wells (m^3)	
Gas Well # 1	306.8	**t.1**		304.4	**v.1 = (t.1 / t.4) x u.**
Gas Well # 2	540.0	**t.2**		535.7	**v.2 = (t.2 / t.4) x u.**
Oil Well	564.4	**t.3**		559.9	**v.3 = (t.3 / t.4) x u.**
Total	1,411.3	**t.4**	1,400.0	1,400.0	

Proration Factor (Oil/Condy Prod) / (Total Estimated Oil/Condy Prod.)	0.99201	(Note: Should be between 0.9500 to 1.0500)

Table 5: Scenario 2 Effluent Battery Prorated Gas Production

	w.
Well	Gas Monthly Metered Effluent Volume x New ECF (e^3m^3) **(m.)**
Gas Well # 1	309.2
Gas Well # 2	618.6
Oil Well	910.5

x.
Group Separator Dry Metered Volume (e^3m^3) (Meter # 7)
1,800.0

Table 6: Scenario 2 Prorate Group Gas to Wells Based on Well Estimated Volumes

	y.		z.	aa.	
Well	Gas Monthly Metered Effluent Volume x New ECF (e^3m^3) **(w.)**		Total Group Separator Gas (e^3m^3) **(w.)**	Prorated Group Gas to Wells (e^3m^3)	
Gas Well # 1	309.2	**y.1**		302.8	**aa.1 = (y.1 / y.4) x z.**
Gas Well # 2	618.6	**y.2**		605.7	**aa.2 = (y.2 / y.4) x z.**
Oil Well	910.5	**y.3**		891.5	**aa.3 = (y.3 / y.4) x z.**
Total	1,838.4	**y.4**	1,800.0	1,800.0	

Proration Factor (Total Group Gas Prod.) / (Total Estimated Gas Prod.)	0.97913	(Note: Should be between 0.9500 - 1.0500)

Table 7: Scenario 2 Effluent Battery Prorated Water Production

	ab.	ac.	ad.	ae.	af.
Well	Measured Well Gas During Test + GIS (e^3m^3) **(g.)**	Test Water Prod. m^3 (Test Data Meter # 6)	Water Gas Ratio (m^3/e^3m^3) **(ac. / ab.)**	Gas Monthly Metered Effluent Volume x New ECF (e^3m^3) **(q.)**	Well Estimated Water Prod: Monthly Effluent Metered Volume After ECF Applied x WGR (m^3) **(ad. x ae.)**
Gas Well # 1	4.64	3.0	0.64675	309.2	200.0
Gas Well # 2	9.38	6.0	0.63948	618.6	395.6
Oil Well	12.14	8.0	0.65899	910.5	600.0

ag.
Water Production (m^3)
1,200.0

Table 8: Scenario 2 Prorate Group Water to Wells Based n Well's Estimated Water Production

	ah.		ai.	aj.	
Well	Well Estimated Water Production (m³) **(af.)**		Total Group Water Production (m³) **(ag.)**	Prorated Group Water to Wells (m³)	
Gas Well # 1	200.0	**ah.1**		200.7	**aj.1 = (ah.1 / ah.4) x ai.**
Gas Well # 2	395.6	**ah.2**		397.1	**aj.2 = (ah.2 / ah.4) x ai.**
Oil Well	600.0	**ah.3**		602.2	**aj.3 = (ah.3 / ah.4) x ai.**
Total	1,195.6	**ah.4**	1,200.0	1,200.0	

Proration Factor (Total Water Prod) / (Total Estimated Water Prod.)	1.0037	(Note: should be between 0.9500 to 1.0500)

Table 9: Scenario 2 Reporting Summary

		Production			
Battery Subtype	Well Type	Condensate (m³)	Oil (m³)	Gas (e³m³)	Water (m³)
	Gas Well # 1	304.4		302.8	200.7
	Gas Well # 2	535.7		605.7	397.1
362	Total	840.1		908.5	597.8
311	Oil Well		559.9	891.5	602.2
Total		840.1	559.9	1,800.0	1,200.0
S/B = 0.0		**0.0**		**0.0**	**0.0**

Note: Single oil well will report an oil, gas and water disposition to the effluent proration gas battery.

Table 10: Scenario 2 Petrinex Reporting

	Oil Battery Reporting - Gas		
	Gas Production	891.5	e³m³
	Solution Gas Disposition to the gas battery:	891.5	e³m³
	Oil Battery Reporting - Oil		
	Oil Volume Disposition to the Gas Battery	559.9	m³
	Oil Battery Reporting - Water		
	Water Volume Disposition to the Gas Battery	602.2	m³

	Gas Battery Reporting - Gas		
	Gas Battery Gas Production	908.5	e³m³
	Gas Receipts:		
	Oil Well (Single Well Battery)	891.5	e³m³
	Gas Battery Dispositions the GS - Gas		
	Total Battery Gas Disposition to the GS	1,800.0	e³m³
	Gas Battery Reporting - Oil Receipts		
	Oil Wells Liquid Volume	559.9	m³
	Gas Battery dispositions of Oil to the GS	559.9	m³
	Gas Battery Reporting - Condy/Oil		
	Closing Inventory	30.0	m³
+	Trucked out	1,390.0	m³
-	Receipts from Oil Battery	559.9	m³
-	Opening Inventory	20.0	m³
=	Gas Battery Condy Production	840.1	m³
	Gas Battery Reporting - Water		
	Closing Inventory	20.0	m³
+	Trucked out	1,190.0	m³
-	Receipts from Oil Battery	602.2	m³
-	Opening Inventory	10.0	m³
=	Gas Battery Water Production	597.8	m³

Appendix E – Gas Equivalent Volume Determination

Liquid Analysis Example

Component	Volume Fractions	Mole Fractions	Mass Fractions
N_2	0.0006	0.0019	0.0008
CO_2	0.0081	0.0158	0.0109
H_2S	0	0	0
C1	0.0828	0.1617	0.0405
C2	0.1117	0.1462	0.0687
C3	0.1275	0.1533	0.1056
IC4	0.0394	0.0398	0.0362
NC4	0.0891	0.0935	0.0849
IC5	0.0483	0.0436	0.0492
NC5	0.0540	0.0493	0.0556
C6	0.0765	0.0614	0.0835
C7	0.0880	0.0678	0.1054
C8	0.0827	0.0589	0.1032
C9	0.0570	0.0368	0.0726
C10	0.0363	0.0222	0.0480
C11	0.0225	0.0131	0.0305
C12+	0.0755	0.0347	0.1044
TOTAL	1.0000	1.0000	1.0000

Properties of C5+ & C7+ portion of sample

	Mol. Fractions	Wt. Fractions	Liq. Vol. Fractions	Mol. Wt. (kg/kmol)	Absolute Density (AD) (kg/m^3)
C5+	0.3878	0.6524	0.5408	107.7	739.33
C7+	0.2335	0.4641	0.3620	127.2	785.29

Appendix F – Calculated Compositional Analysis Examples

Calculated Well Stream Compositional Analysis Example

Step 1: Collect volumetric and compositional data for both gas and liquid phases.

Gas	
Gas Volume (e^3m^3)	10000.0
Composition	Mole %
N_2	1.00
CO_2	2.00
H_2S	2.40
C1	80.00
C2	8.00
C3	3.00
IC4	1.00
NC4	1.50
IC5	0.20
NC5	0.50
C6	0.30
C7+	0.10
	100.00

Liquid	
Liquid Volume (m^3)	200.0
Composition	Mole %
N_2	0.00
CO_2	1.00
H_2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

Step 2: Convert the condensate liquid volume to GEV.

A) Convert liquid volume to equivalent gas volume using the condensate gas equivalent factor.

Equation 1: GEV = Volume of condensate (m^3) x GEF (m^3 gas per m^3 liquid)

GEV = 200 (m^3) x 220.12 (m^3 gas per m^3 liquid) ÷ 1000 (e^3m^3/m^3) = 44.024e^3m^3

If the gas equivalent factor is not included with the condensate analysis report, it can be calculated.

Equation 2: GEF = Absolute Density of Condensate (kg/m^3 @ 15°C) / Molecular weight of the condensate (grams/mole)

B) Convert the compositional fractions to equivalent gas volumes on a component basis.

Equation 3: Component gas volume (e^3m^3) = [Component mole percent] x [GEV]

Example: n-pentane equivalent volume
Volume of condensate = 200m^3
Gas Equivalent Factor = 220.12
Equivalent n-pentane (NC5) gas volume = [11.0%] x [44.024e^3m^3] = 4843m^3

Liquid	
Liquid Volume (m^3)	200.0
Composition	Mole %
N_2	0.00
CO_2	1.00
H_2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

A

B

Liquid	
Gas Equivalent Volume (e^3m^3)	44.024
Composition	e^3m^3 gas
N_2	0.00
CO_2	0.44
H_2S	0.88
C1	1.32
C2	1.76
C3	3.08
IC4	4.40
NC4	6.60
IC5	3.08
NC5	4.84
C6	4.40
C7+	13.21
	44.02

Step 3:

Add the gas volumes and liquid gas equivalent volumes and normalize to mole fraction 1 or 100%

Gas	
Gas Volume (e^3m^3)	10000.0
Composition	e^3m^3 gas
N_2	100.0
CO_2	200.0
H_2S	240.0
C1	8000.0
C2	800.0
C3	300.0
IC4	100.0
NC4	150.0
IC5	20.0
NC5	50.0
C6	30.0
C7+	10.0
	10000.0

+

Liquid	
Gas Equivalent Volume (e^3m^3)	44.0
Composition	e^3m^3 gas
N_2	0.00
CO_2	0.44
H_2S	0.88
C1	1.32
C2	1.76
C3	3.08
IC4	4.40
NC4	6.60
IC5	3.08
NC5	4.84
C6	4.40
C7+	13.21
	44.0

=

Recombined Volume	
Gas Equivalent Volume (e^3m^3)	10044.0
Composition	e^3m^3 gas
N_2	100.0
CO_2	200.4
H_2S	240.9
C1	8001.3
C2	801.8
C3	303.1
IC4	104.4
NC4	156.6
IC5	23.1
NC5	54.8
C6	34.4
C7+	23.2
	10044.0

Recombined Composition	
Gas Equivalent Volume (e^3m^3)	10044.0
Composition	Mole %
N_2	1.00
CO_2	2.00
H_2S	2.40
C1	79.66
C2	7.98
C3	3.02
IC4	1.04
NC4	1.56
IC5	0.23
NC5	0.55
C6	0.34
C7+	0.23
	100.00

Calculated Group Compositional Analysis Example

Step 1:
Collect volumetric and compositional data for both gas and liquid phases for all streams. The information is required for all wells.

Step 2:
Mathematically recombine the fluid based on volumetric and compositional data collected in Step 1 for each stream.

Step 3:
Add the recombined fluid volumes on a component basis and normalize to 100%.

Stream 1: Gas

Gas Volume (e^3m^3)	10000
Composition	Mole %
N_2	1.14
CO_2	0.16
C1	85.31
C2	6.44
C3	3.77
IC4	0.63
NC4	1.32
IC5	0.33
NC5	0.41
C6	0.26
C7+	0.23
	100.00

Liquid

Gas Equivalent Volume (e^3m^3)	800
Composition	Mole %
N_2	0.12
CO_2	0.08
C1	22.02
C2	6.14
C3	8.56
IC4	2.62
NC4	7.11
IC5	3.66
NC5	5.73
C6	9.73
C7+	34.23
	100.00

Recombined Fluid

Gas Equivalent Volume (e^3m^3)	10800
Composition	Mole %
N_2	1.06
CO_2	0.15
C1	80.62
C2	6.42
C3	4.12
IC4	0.78
NC4	1.75
IC5	0.58
NC5	0.80
C6	0.96
C7+	2.75
	100.00

Stream 2: Gas

Gas Volume (e^3m^3)	15000
Composition	Mole %
N_2	1.00
CO_2	2.00
H_2S	2.40
C1	80.00
C2	8.00
C3	3.00
IC4	1.00
NC4	1.50
IC5	0.20
NC5	0.50
C6	0.30
C7+	0.10
	100.00

Liquid

Gas Equivalent Volume (e^3m^3)	200
Composition	Mole %
N_2	0.00
CO_2	1.00
H_2S	2.00
C1	3.00
C2	4.00
C3	7.00
IC4	10.00
NC4	15.00
IC5	7.00
NC5	11.00
C6	10.00
C7+	30.00
	100.00

Recombined Fluid

Gas Equivalent Volume (e^3m^3)	15200
Composition	Mole %
N_2	0.99
CO_2	1.99
H_2S	2.39
C1	78.99
C2	7.95
C3	3.05
IC4	1.12
NC4	1.68
IC5	0.29
NC5	0.64
C6	0.43
C7+	0.49
	100.00

Total Recombined Fluid

Gas Equivalent Volume (e^3m^3)	36000
Composition	Mole %
N_2	0.76
CO_2	1.44
H_2S	1.01
C1	82.37
C2	6.95
C3	2.94
IC4	0.79
NC4	1.37
IC5	0.32
NC5	0.54
C6	0.47
C7+	1.04
	100.00

Stream 3: Gas

Gas Volume (e^3m^3)	10000
Composition	Mole %
N_2	0.10
CO_2	2.00
H_2S	0.00
C1	89.40
C2	6.00
C3	1.50
IC4	0.30
NC4	0.50
IC5	0.08
NC5	0.10
C6	0.01
C7+	0.01
	100.00

Liquid

Gas Equivalent Volume (e^3m^3)	0
Composition	Mole %
N_2	0.00
CO_2	0.00
H_2S	0.00
C1	0.00
C2	0.00
C3	0.00
IC4	0.00
NC4	0.00
IC5	0.00
NC5	0.00
C6	0.00
C7+	0.00
	0.00

Recombined Fluid

Gas Equivalent Volume (e^3m^3)	10000
Composition	Mole %
N_2	0.10
CO_2	2.00
H_2S	0.00
C1	89.40
C2	6.00
C3	1.50
IC4	0.30
NC4	0.50
IC5	0.08
NC5	0.10
C6	0.01
C7+	0.01
	100.00

Calculated Single Compositional Analysis (from Two Samples)

Step 1: Collect spot samples and record the metered volumes associated with each sample.

Step 2: Calculate individual component volumes by multiplying the individual component mole fractions or percentage values by the associated metered volumes.

Example: Gas Sample #1, Calculation of methane volume
Total Volume = 10000e³m³
Methane = 80.00mole%
Methane Volume = 10000.0e³m³ x 0.8000 = 8000.0e³m³

Step 3: Normalization: Individual component volumes are summed. The individual component volumes are then divided into the total to create a normalized (calculated) compositional value.

Example: Ethane (C2), Calculation of Mole%
Gas Sample #1, C2 volume: 800e³m³
Gas Sample #2, C2 volume: 560e³m³
Combined, C2 volume: 1360e³m³
Total gas volume: 18000e³m³
Calculated C2 concentration = 1360.0e³m³ / 18000e³m³ = 7.56mole%

Gas Sample #1		
Gas Volume (e³m³) = 10000.0		
Composition	Mole%	e³m³ gas
N_2	1.00	100.0
CO_2	2.00	200.0
H_2S	2.40	240.0
C1	80.00	8000.0
C2	8.00	800.0
C3	3.00	300.0
IC4	1.00	100.0
NC4	1.50	150.0
IC5	0.20	20.0
NC5	0.50	50.0
C6	0.30	30.0
C7+	0.10	10.0
	100.00	10000.0

\+

Gas Sample #2		
Gas Volume (e³m³) = 8000.0		
Composition	Mole%	e³m³ gas
N_2	0.60	48.0
CO_2	2.00	160.0
H_2S	1.50	120.0
C1	83.00	6640.0
C2	7.00	560.0
C3	2.50	200.0
IC4	1.00	80.0
NC4	1.40	112.0
IC5	0.18	14.4
NC5	0.45	36.0
C6	0.28	22.4
C7+	0.09	7.2
	100.00	8000.0

=

Calculated Single Compositional Analysis		
Gas Volume (e³m³) = 18000.0		
Composition	Calculated Mole%	e³m³ gas
N_2	0.82	148.0
CO_2	2.00	360.0
H_2S	2.00	360.0
C1	81.33	14640.0
C2	7.56	1360.0
C3	2.78	500.0
IC4	1.00	180.0
NC4	1.46	262.0
IC5	0.19	34.4
NC5	0.48	86.0
C6	0.29	52.4
C7+	0.10	17.2
	100.00	18000.0

Appendix G – Manual Water-Cut (S&W) Procedures

Water-cut procedures are divided into three categories and described on the following pages. Different procedures are specified for the three categories to improve accuracy and consistency of the S&W determinations. The use of "mason jars" with measuring tape attached is not acceptable for determining S&W. S&W percentage must be recorded to a minimum of one decimal place.

More detail on S&W determination is in API MPMS, Chapter 10.4: Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure). The BCER will consider any procedure that meets API MPMS, 10.4 standards to be in compliance with this directive. It is the responsibility of the licensee/operator to show that its procedure meets the above API standard.

Category 1—for 0 to 10% S&W

Obtain a representative sample of liquid.

Shake the sample container vigorously to mix it before pouring into the centrifuge tubes.

1) Fill each of two tubes with exactly 100 parts (50ml) of the sample. This step needs to be done first to eliminate any risk of blending shrinkage and to ensure exactly 100 parts of sample is being obtained.
2) Fill each tube with the solvent solution (premixed solvent and demulsifier) to the 200-part mark (100ml).
3) Stopper each tube tightly and invert 10 times.
4) Loosen the stoppers and immerse the tubes in a preheater. Heat the contents to 60°C ±3°C.
5) Stopper each tube tightly and invert 10 times.
6) Place the tubes in the centrifuge machine in a balanced condition and spin for 5 minutes.
7) Immediately after the centrifuge comes to rest, use a thermometer to verify that the sample temperature is within 9°C of the test temperature.

   If sample temperature is within 9°C, go to step 8. If sample temperature is not within 9°C, go back to step 4, raise the temperature, and repeat steps 5, 6, and 7.
8) Read and record the volume of water and sediment at the bottom of each tube.
9) Reheat the tubes to the initial spin temperature and return them, without agitation, to the centrifuge machine. Spin for an additional 5 minutes. Repeat the procedure until two consecutive, consistent readings are obtained.

10) For the test to be considered valid, a clear interface must be observed between the oil layer and the separated water. No emulsion should be present immediately above the oil/water interface. A test comprises TWO TUBES of the SAME SAMPLE. Compare the readings of the two tubes. If the difference is greater than one subdivision on the centrifuge tube, the test is invalid and should be repeated.

11) Calculation and reporting:

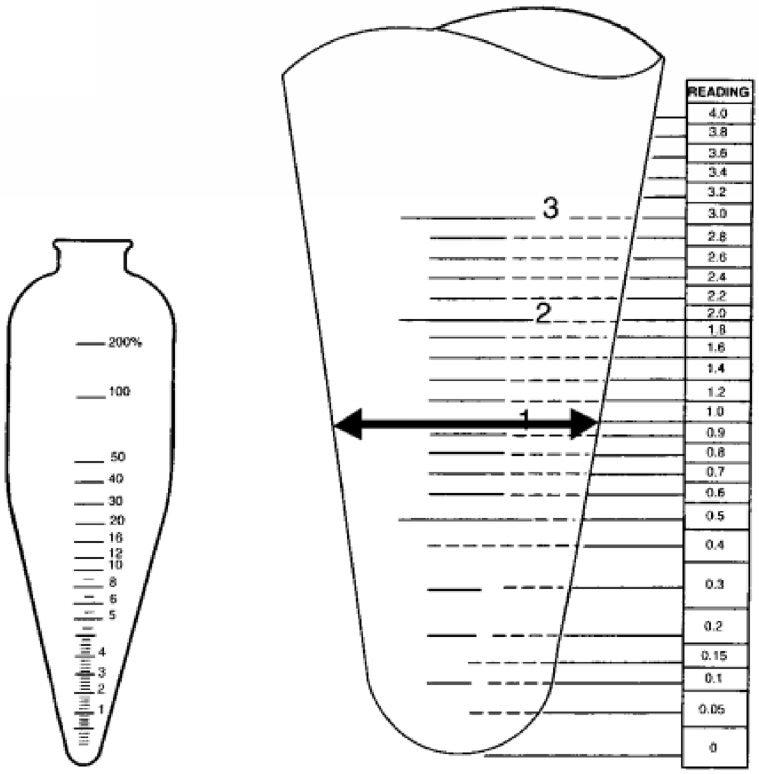
For 200ml tubes: the percentage of water and sediment is the average, to three decimal places, of the values read directly from the two tubes.

For 100ml tubes: read and record the volume of water and sediment in each tube. Add the readings together and report the sum as the percentage of water and sediment.

Example 1 (see Appendix G Figure 1)

100ml centrifuge tubes	**200ml centrifuge tubes**
If reading from each tube is the same:	
Reading from each tube = 0.50ml	Reading from each tube = 1.00ml
Water cut = (0.50 + 0.50) ÷ 100 = 1.0%	Water cut = 1.00 ÷ 100 = 1.0%
If reading from each tube is not the same:	
Reading from 1st run of each tube = 0.50, 0.60ml	Reading from 1st run of each tube = 1.00, 1.05ml
Reading from 2nd run of each tube = 0.50, 0.55ml	Reading from 2nd run of each tube = 1.00, 1.10ml
Water cut = (0.50 + 0.60 + 0.50 + 0.55) ÷ 2 ÷ 100 = 1.1%	Water cut = (1.00 + 1.05 + 1.00 + 1.10) ÷ 4 ÷ 100 = 1.0%

Appendix G Figure 1



Category 2—for 10 to 80% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible.

Read and record the total volume, the volume of free water, and the volume of oil/emulsion in the graduated cylinder. Calculate the free water percentage as follows:
Percentage of free water = (Volume of free water ÷ Total volume) x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of free water =

Volume of free water ÷ (Total volume – Volume of solvent/demulsifier) x 100%

Draw 100ml from the oil/emulsion portion in the graduated cylinder and fill each of two 100ml centrifuge tubes to exactly the 50ml mark. Add solvent to bring the level in the tubes to exactly the 100ml mark. The procedures previously outlined for samples with 0 to 10% water cut must be followed, with the exception that the water-cut readings from both tubes must be added together, even if they are not the same.

Note that if 200ml tubes must be used, a larger initial sample will be required, and if the water-cut readings from both tubes are not the same, the average of both tubes must be used as the resultant water cut of the oil/emulsion portion.

From the spinning results, calculate the percentage of water remaining in the oil/emulsion portion as follows:

Percentage of water remaining =

Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion ÷ Total volume

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of water remaining =

(Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion) ÷ (Total volume – Volume of solvent/demulsifier)

Calculate the total water-cut percentage as follows:

Total water-cut % = % free water + % water remaining

Example 2 (see Appendix G Figure 2)

1000ml graduated cylinder

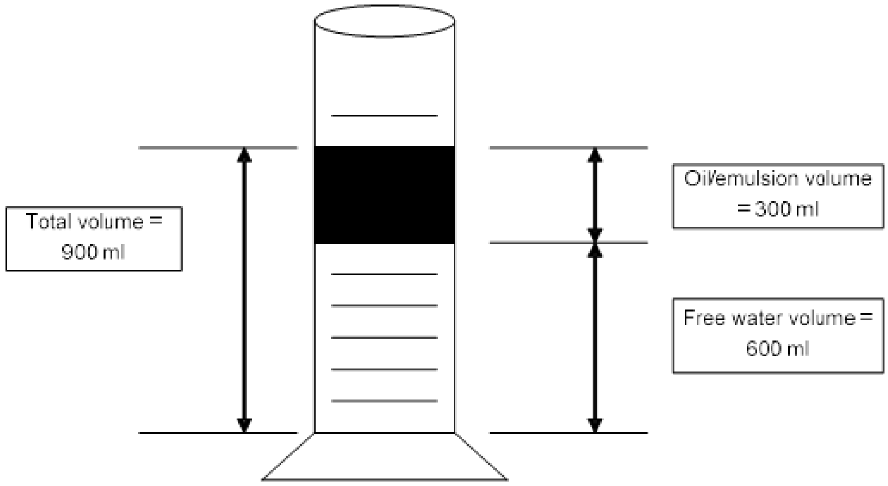
% of free water = 600ml ÷ 900ml x 100% = 66.7%

% of water remaining = 300ml x 10%* ÷ 900ml = 3.3%

Total water-cut % = 66.7% + 3.3%= 70.0%

* Water cut of oil portion determined by spinning samples

Appendix G Figure 2 Water-cut% from 10 to 80%



Category 3—for 80 to 100% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible. A narrow-necked graduated cylinder should be used to improve accuracy in sample measurement when the water cut is above 90% (see Appendix G Figure 3).

Read and record the total volume and the volume of free water in the graduated cylinder. If no solvent or demulsifier has been added to the sample, calculate the water-cut percentage as follows:

Water-cut % = Volume of free water ÷ Total volume x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Water-cut % = Volume of free water ÷ (Total volume - Volume of solvent/demulsifier) x 100%

The water content of the oil/emulsion portion in the graduated cylinder does not have to be determined, due to the limited amount of the oil/emulsion portion of the sample available at these high-water contents. However, if there is enough oil/emulsion volume, the licensee may choose to use the same procedure as that described for the 10 to 80% S&W, with the option to centrifuge only one sample.

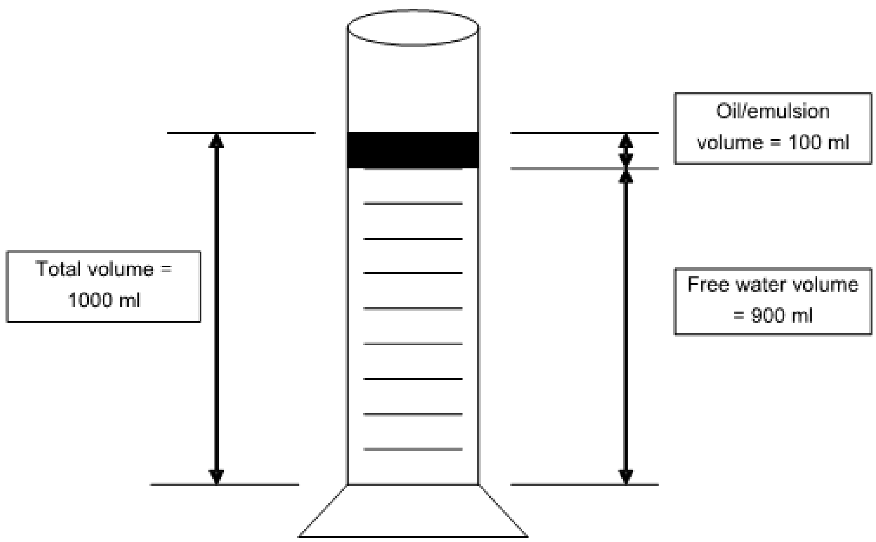
Example 3 (see Appendix G Figure 3)

1000ml graduated cylinder

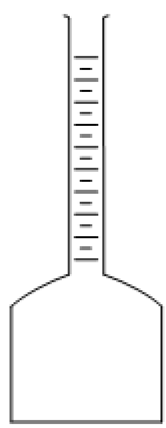
Water-cut % = 900ml ÷ 1000ml x 100%

= 90.0%

Appendix G Figure 3 Water-cut% over 80%



Appendix G Figure 4 Narrow-necked graduated cylinder



Appendix H – PETRINEX Facility Types and Subtypes

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Battery (BT)	311	Crude Oil Single-well Battery	A production facility for a single oil well
Battery (BT)	321	Crude Oil Multi-well Group Battery	A production facility consisting of two or more flow-lined oil wells having individual separation and measuring equipment but with all equipment sharing a common surface location.
Battery (BT)	322	Crude Oil Multi-well Proration Battery	A production facility consisting of two or more flow-lined oil wells having common separation and measuring equipment. Total production is prorated to each well based on individual well tests. Individual well production tests can occur at the central site or at remote satellite facilities.
Battery (BT)	351	Gas Single Well Battery	A production facility for a single gas well where production is measured at the wellhead. Production is delivered directly and is not combined with production from other wells prior to delivery to a gas gathering system or other disposition.
Battery (BT)	361	Gas Multi-well Group Battery	A production reporting entity consisting of two or more gas wells where production components are separated and measured at each wellhead. Production from all wells in the group is combined after measurement and then delivered to a gas gathering system or other disposition.
Battery (BT)	362	Gas Multi-well Effluent Measurement Battery	A production reporting entity consisting of two or more gas wells where estimated production from gas wells in the battery is determined by the continuous measurement of multiphase fluid from each well (effluent measurement). Commingled production is separated and measured then prorated back to wells based on the estimated production.
Battery (BT)	364	Gas Multi-well Proration Battery (Issued by BCER Only)	A production facility and reporting entity consisting of two or more gas wells where production from the wells in the battery is commingled before measurement. Battery (group) production must be prorated to the individual wells based on test data. This battery configuration must be approved by the BCER Operations Group before commencing operation.

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Battery (BT)	365	Gas Multi-well Group Battery (Issued by BCER Only)	A production reporting entity consisting of two or more gas wells where production components are separated and measured at each wellhead. Production from all wells in the group is combined after measurement and then delivered to a gas gathering system or other disposition. When a licence is not required according to BCER guidance, this facility subtype will be issued by BCER only.
Battery (BT)	371	Gas Test Battery	A production facility for gas well testing gas production prior to commencement of regular production. Wells with a gas test status can only report for a maximum of 3 months. Gas tests that occur after 3 months require a well status change to the new start date of the test well status. Multiple wells can be linked to a Facility ID with this status as long as the well's status is Gas Test.
Battery (BT)	381	Drilling & Completing	A Facility ID issued to an operator to facilitate the reporting of one or more drilling wells that recover product during swabbing or drill stem tests prior to the completion of a well. Wells must have a drilling & completing status and can only report for a maximum of 3 months. Drilling & completing means the well is still drilling and has not completed or reached total depth. A new Facility ID is required for each well after completion.
Battery (BT)	393	Mixed Oil & Gas	A legacy production facility that reports both gas and oil volumes at the same reporting facility. This facility must be set up by the BCER.
Battery (BT)	395	Water Hub	Water storage sites, or pits, constructed at and to be used at facility sites, for reclaimed, blended, or produced water (including frac flow back water).
Battery (BT)	902	Water Source Battery	A facility type set up to link BCER permitted source water wells. Permitted wells may produce either freshwater (non-saline above base of fish scales) or saline (deep formation water below base of fish scales).
Compressor Station (CS)	601	Compressor Station	No supplemental description.
Custom Treater (CT)	611	Custom Treating Facility	A facility that has a system or arrangement of tanks and other surface equipment receiving oil/water emulsion exclusively by truck for separation prior to delivery to market or other disposition. A facility licence is required.

Facility Type	Facility Subtype	**Facility Subtype Title**	Facility Subtype Description
Gas Gathering System (GS)	621	Gas Gathering System	A facility consisting of gas lines used to move products from one facility to another. The facility may also include compressors and/or line heaters. A gas gathering system can also have equipment such as separators and dehydrators that are located on the system but not associated with any well sites.
Gas Plant (GP)	401	Gas Plant Sweet	Gas Processing/Fractionation facility receiving gas that is less than 0.01M/KM H2S. (Note - BCER classifies sweet as containing no H2S)
Gas Plant (GP)	402	Gas Plant Acid Gas Flaring <1T/D Sulphur	Gas Processing/Fractionation facility/Acid gas flaring receiving gas that is greater than 0.01M/KM H2S & less than 1T/D sulphur.
Gas Plant (GP)	403	Gas Plant Acid Gas Flaring >1T/D Sulphur	Gas Processing/Fractionation facility/Acid gas flaring receiving gas that is greater than 1T/D sulphur.
Gas Plant (GP)	404	Gas Plant Acid Gas Injection	Gas Processing/Fractionation facility/Acid gas injection receiving gas that is greater than 0.01 & less than 1T/D sulphur.
Gas Plant (GP)	405	Gas Plant Sulphur Recovery	Gas processing facility with sulphur recovery.
Gas Plant (GP)	406	Gas Plant Mainline Straddle	Mainline straddle plants are usually located near the border of the province. Residue gas is delivered to a transporter pipeline, and then to a mainline straddle plant for processing (a second extraction of liquids, primarily ethane) before it leaves the province.
Gas Plant (GP)	407	Gas Plant Fractionation	Gas processing plant where spec product such as propane or butane is produced.
Gas Plant (GP)	408	Gas Plant Field Straddle	Field straddle plants are usually located near the producing area gathering system. Residue gas is delivered to multiple pipelines and then to a field straddle plant for processing (a second extraction of liquids, primarily ethane) before it leaves the province.
Injection Facility (IF)	501	Enhanced Recovery Scheme	An injection facility consisting of a system or arrangement of surface equipment associated with the injection of any substance through one or more wells for the purpose of hydrocarbon recovery. Enhanced recovery involves the improvement of hydrocarbon recovery through the injection of fluid into a hydrocarbon reservoir to maintain reservoir energy pressure and displace hydrocarbons to production wells and/or alter the reservoir fluids so that hydrocarbon flow and recovery are improved.
Injection Facility (IF)	502	Concurrent Production/Cycling Scheme	Concurrent production is defined as the production of an oil accumulation and its associated gas cap at the same time.

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Injection Facility (IF)	503	Disposal	Disposal refers to the injection of fluids for purposes other than enhanced recovery or gas storage. This scheme is required for the gathering, storage and disposal of water produced in conjunction with oil and gas and disposal of any fluid or other substance to an underground formation through wells based on the type of injection fluid. A facility licence is required.
Injection Facility (IF)	504	Acid Gas Disposal	Acid gas disposal has become a cost effective means to dispose of uneconomic quantities of H2S and CO2 into underground formations. The formation types that are typically considered suitable for disposal are depleted hydrocarbon-bearing zones or unusable water-bearing zones. The disposal of these waste byproducts can reduce public concern from sour gas production and flaring.
Injection Facility (IF)	505	Underground Gas Storage	Underground storage is used where products are stored in an underground formation or cavern until a market for the product is available. Products are received from other facilities and injected into the wells associated with the storage facility.
LNG Plant (LN)	451	LNG Plant	A facility that processes natural gas and produces liquefied natural gas. This includes large scale LNG export facilities and smaller scale regional LNG facilities
Meter Station (MS)	631	Field Receipt Meter Station	This subtype of meter station handles field Receipts from producing facilities, the linked pipeline receives the gas from the MS. The linked PL operator (MS Operator) will report the MS DISP to the linked PL and Petrinex will auto populate the REC at the linked PL When the auto populate flag is set to No the CSO must report the MS REC from the producing (field/upstream) facility(s) Petrinex will auto populate the DISP at the producing facility(s). When the auto populate flag is set to Yes Petrinex will auto populate the REC at the MS from the producing facility (auto flow through) and the DISP at the producing facility. Gas DISP to this type of MS is a Royalty Trigger and requires an SAF/OAF to be submitted for Crown Royalty purposes.

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Meter Station (MS)	632	Interconnect Receipt Meter Station	This subtype of meter station handles gas leaving the pipeline it is linked to. The linked PL operator (MS Operator) will report the MS REC from the linked PL and Petrinex will auto populate the DISP from the linked PL. When the auto populate flag set is set to No the CSO must report the MS DISP to the facility(s) other than the linked PL Petrinex will auto populate the REC at the other facility(s). When the auto populate flag is set to Yes Petrinex will auto populate the DISP to the other facility (auto flow through) and the REC at the other facility. Gas REC from this type of MS is not a Royalty Trigger and does not require an SAF/OAF for Crown Royalty purposes.
Meter Station (MS)	633	Interconnect Disposition Meter Station	This subtype of meter station handles gas leaving the pipeline it is linked to. When the auto populate flag set is set to No the linked PL operator (MS Operator) will report the MS REC from the linked PL and Petrinex will auto populate the DISP from the linked PL. The CSO must report the MS DISP to the facility(s) other than the linked PL Petrinex will auto populate the REC at the other facility(s). When the auto populate flag is set to Yes the CSO reports the DISP to the other facility(s) Petrinex will auto populate the REC at the other facility(s) and will also auto populate the MS REC from the linked PL and the DISP at the linked PL to the MS. Gas REC from this type of MS is not a Royalty Trigger and does not require an SAF/OAF for Crown Royalty purposes.
Meter Station (MS)	634	Interconnect Non-Reconciled Meter Station	This subtype of meter station is used when gas is leaving or entering the Pipeline it is linked to and the gas is from or to a non-reporting entity (e.g., non-Petrinex jurisdiction). The facility on the other side of the MS (not the linked PL) is not reporting in Petrinex. For example, Gas from or gas to the Yukon Territories. It should always be 100% out of balance. Only the linked PL can be reported in the from/to field at this type of MS. CSO is not permitted. Gas REC or DISP to/from this type of MS is not a Royalty Trigger and does not require an SAF/OAF for Crown Royalty purposes
Meter Station (MS)	635	Petrinex Summary Non-Reporting Meter Station	This subtype of meter station is not used for volumetric reporting in Petrinex.
Meter Station (MS)	636	Non- Reporting Meter Station	This subtype of meter station is not used for volumetric reporting in Petrinex.

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Meter Station (MS)	637	NEB Regulated Field Receipt Meter Station	This subtype of meter station handles field Receipts from producing facilities. When the MS is reporting in Petrinex the same rules as a 631 subtype apply. When the MS is not reporting in Petrinex the other facility(s) operator(s) report the GAS DISP to the MS when reporting their facility(s). The GAS DISP to this type of MS is a Royalty Trigger and requires an SAF/OAF to be submitted for Crown Royalty purposes.
Meter Station (MS)	638	NEB Regulated Interconnect Receipt Meter Station	This subtype of meter station handles gas leaving the pipeline it is linked to. When the MS is reporting in Petrinex the same rules as a 632 subtype apply. When the MS is not reporting in Petrinex the other facility(s) operator(s) report the GAS REC from the MS when reporting their facility(s). The GAS REC from this type of MS is not a Royalty Trigger and does not require an SAF/OAF to be submitted for Crown Royalty purposes.
Meter Station (MS)	639	NEB Interconnect Disposition Meter Station	This subtype of meter station handles gas leaving the pipeline it is linked to. When the MS is reporting in Petrinex the same rules as a 633 subtype apply. When the MS is not reporting in Petrinex the other facility(s) operator(s) report the GAS REC from the MS when reporting their facility(s). The GAS REC from this type of MS is not a Royalty Trigger and does not require an SAF/OAF to be submitted for Crown Royalty purposes.
Meter Station (MS)	640	Interconnect PL to PL Disposition Meter Station	This subtype of meter station handles gas received from the pipeline it is linked to and disposes gas to another PL. At this type of meterstation the auto populate flag is always set to Yes. The auto-populate facility will always be a PL different than the linked PL. CSO is not permitted. The linked PL operator (MS Operator) reports the MS DISP to the linked PL Petrinex will auto populate the REC at the linked PL it will also auto populate the REC at the MS from the other PL (auto flow through) and the DISP at the other PL.
Pipeline (PL)	204	Gas Transporter	A facility type that consists of a network of interconnected gas pipelines that move gas within and out of the province of British Columbia.
Pipeline (PL)	206	Gas Distributor	A facility type that engages in the selling of gas to ultimate customers through distribution pipelines (distribution systems). It covers the receipts, distribution, imports, and exports by end user delivery and customer sectors.
Pipeline (PL)	207	Oil Pipeline	A facility type that consists of a network of interconnected pipelines that moves oil and liquid products within and out of the province of British Columbia.

Facility Type	Facility Subtype	Facility Subtype Title	Facility Subtype Description
Pipeline (PL)	208	NGL Pipeline	A facility type that consists of a network of interconnected pipelines that moves NGLs within and out of the province of British Columbia. Sometimes NGLs are referred to as LPGs.
Pipeline (PL)	209	NEB Regulated Pipeline	A facility type regulated by NEB consisting of a network of interconnected pipelines that move oil, liquid, and gas products within and out of the province of British Columbia.
Refinery (RF)	651	Refinery	A hydrocarbon distillation facility.
Terminal (TM)	671	Tank Farm Loading & Unloading Terminal	A system or arrangement of tanks or other surface equipment associated with the operation of a pipeline and is licensed as part of the pipeline that may include measurement equipment and line heaters but does not include separation equipment or storage vessels at a battery approved under the oil and gas conservation act.
Terminal (TM)	672	NEB Regulated Terminal	A facility type regulated by NEB used to receive liquids from trucks or pipelines for further disposition.
Terminal (TM)	673	Third Party Tank Farm Loading & Unloading Terminal	A system or arrangement of tanks or other surface equipment receiving liquids by truck for the purpose of delivering liquids into or removing oil from a pipeline. The facility is operated independently from the pipeline and requires a BCER facility licence.
Terminal (TM)	675	Railcar Loading & Unloading Terminal	*A system or arrangement of tanks or other surface equipment associated with the operation of a rail line.*
Terminal (TM)	676	NGL Hub Terminal	*A facility where produced hydrocarbons and/or produced water is delivered by truck, rail, or pipeline, from or to the facility, and typically includes fluid storage tanks and/or pumping equipment Gas Processing Plants can also deliver to this facility type. This type is a reporting facility and includes all previously identified Pipeline Terminal facilities in BC.*
Waste Location (WL)	904	Waste Location	A reporting entity used in waste plant reporting related to waste generated or waste received at non-regulated locations. This subtype is not required to report on Petrinex

Facility Type	Facility Subtype	**Facility Subtype Title**	**Facility Subtype Description**
Waste Plant (WP)	701	Surface Waste Facility	Waste processing processes applies any method, technique, or process that is designed to change the physical, chemical, or biological character or composition of a substance. Defined as surface equipment designed for the purpose of collecting and treating oilfield waste material from any gas, oil, oilfield, or oil sands operation. Other waste processing facilities include those designed to collect oilfield waste and apply methods or techniques to reduce volumes, alter chemical characteristics, and/or remove dangerous components prior to final disposal. Waste processing facilities accepting waste generated within the upstream petroleum industry only require approval from the BCER. Facilities that accept a combination of upstream and downstream waste or industrial waste may require approval from the MOE and BCER.
Water Source (WS)	901	Water Source	The source of fresh (non-saline) water can either come from a shallow-drilled source well without a BCER well permit number, river, lake, or other surface locations. In all cases, the location/source of water is reflected by specific geographic location and requires a water licence under the Water Sustainability Act.

Appendix I – Documents Replaced by this BCER Manual

The following documents have been replaced by this BCER Manual:

1) FMG 04-01 Fuel Gas Tap Locations, Measurement and Reporting Requirements (Revised 2004/10).
2) FMG 03-03 Gas Meter Calibrations.
3) Information Bulletin - 2010-36

Appendix J – References

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