Measurement Requirements for Oil and Gas Operations

Directive PNG017

December 2019

Revision 3.0

Governing Legislation:

Act:	*The Oil and Gas Conservation Act*
Regulation:	*The Oil and Gas Conservation Regulations, 2012*
Order:	349/19

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Record of Change

Version	Date	Description
1.0	May 13, 2015	Approved Initial Draft
1.1	June 22, 2015	Updated Paper Battery requirements in section 12.2.1.2 and corrected several references-draft
1.2	November 17, 2015	Updated version to coincide with AER revisions and adoption of MARP in Saskatchewan-draft
2.0	April 1, 2016	Approved Initial Version (authorized by Minister's Order 47-16)
2.1	August 1, 2017	See What's New Section for changes and all changes are highlighted in red
3.0	December, 2019	See What's New Section for changes

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Introduction

Purpose

Directive PNG017: Measurement Requirements for Oil and Gas Operations (Directive PNG017) consolidates, clarifies, and updates the regulatory requirements with respect to measurement points used for accounting and reporting purposes, as well as those measurement points required for upstream petroleum facilities and some downstream pipeline operations under existing regulations. The term measurement as used in this document means measurement, accounting, and reporting. While measurement is the determination of a volume, accounting and reporting are integral components of measurement in that after a fluid volume is measured, mathematical procedures (accounting) may have to be employed to arrive at the desired volume to be reported.

Interpretation

Directive PNG017 includes measurement and reporting requirements that are applicable to oil and gas operations located in Saskatchewan only, but highlight known differences with the Directive PNG017 equivalents in Alberta and British Columbia, with the intention that it will ultimately form the basis of a comprehensive and harmonized regulatory document for all three jurisdictions. As a result, the term Regulator is referenced throughout the document which refers to the Saskatchewan Ministry of Energy and Resources (ER) in Saskatchewan, Alberta Energy Regulator (AER) in Alberta and the British Columbia Oil and Gas Commission (BCOGC). The majority of the measurement and reporting requirements in Directive PNG017 are identical in all three jurisdictions. *In situ*ations where requirements differ between the three jurisdictions, the requirement that is applicable in each jurisdiction is listed separately in a box, as shown below. Wells and facilities operated in Saskatchewan must comply with the requirement specified in the SK box. The Alberta and British Columbia information is provided for informational purposes only and subject to change without notice.

Province	Measurement and Reporting Requirement
SK	Requirement applicable to oil and gas operations in Saskatchewan
AB	Requirement applicable to oil and gas operations in Alberta
BC	Requirement applicable to oil and gas operations in British Columbia

Note that if there is no comment for any particular province that it does not mean that there are no applicable regulations.

What's New in This Edition

Section 1.1: Clarifies the requirement that all operators must ensure their measurement equipment is in good working order.

Section 1.6.3.5: New requirements related to *The Oil and Gas Emission Management Regulations* (OGEMR). Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 1.6.3.6: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 1.6.3.8: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 1.7.3: Clarifies requirements for produced water/stream at thermal *in situ* facilities. Also clarifies requirements for brine disposal wells at the request of potash companies.

Section 3.1: Adds reference to the reporting directives and guidelines in each province (e.g. calculation allocation and proration factors).

Section 3.1.1.1: Clarifies requirements relating to facility subtypes and proration factors.

Section 3.1.1.2: Clarifies requirements relating to facility subtypes and allocation factors.

Section 4.1: Clarifies reference to the Directives for reporting volumetrics.

Section 4.2: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added. As well, a new guideline for venting gas and fugitive emissions estimation methods, *Guideline PNG035: Estimating Venting and Fugitive Emissions* has been created. This guideline has no new requirements.

Section 4.2.1: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and add new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 4.2.2: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 4.2.8: Clarifies that gas must be measured and reported at various Petrinex facility sub-types.

Section 4.3.6: Section title changed from "Production Data Verification and Audit Trail and Volumetric Data Amendments" to "Data Verification, Audit Trail and Volumetric Data Amendments". Clarifies that data verification and audit trail is required for all data, not just production data.

Section 4.3.6.1: New requirements related to OGEMR. Clarifies current measurement and reporting requirements for fuel, flare and vent and adds new definitions of fuel, flare and vent starting January 1, 2020. Also, grandfathering clauses for fuel, flare and vent measurement requirements have been added.

Section 6.3.3: Section title changed from "Production Data Verification and Audit Trail" to "Data Verification and Audit Trail." Clarifies that data verification and audit trail is required for all data, not just production data.

Section 6.3.4: Clarifies the section header to reflect what the section relates to. This section does not apply in Saskatchewan.

Section 8: Amended to reflect that section 83 of *The Oil and Gas Conservation Regulations, 2012* (OGCR) was rescinded and replaced with section 93.1. Also clarifies that both facility and well analyses must be submitted to ER.

Section 8.4: Clarifies this section heading to reflect that this section only refers to gas and condensate sampling and analysis requirements and there is another section for oil sampling and analysis requirements. Also clarifies that this section refers to wells and facilities and gas and condensate sampling and analysis requirements. As well, clarifies that ER requires the analysis to be submitted once conducted.

Section 8.5.1: To reduce the red tape requirements for operators, establishes that ER will no longer require operators to conduct an analysis on new oil wells.

Section 8.5.1.1: Due to the elimination of the requirement to conduct an oil analysis this section is no longer required and has been eliminated.

Section 11.4.6.2: Adds requirement that acid gas flaring is no longer to be reported as shrinkage and is now reportable as FLARE of ACID GAS as of January 1, 2020.

Section 12.2.2: Clarifies that gas volumes over a specified volume must be metered instead of estimated.

Section 12.2.2.1: Removes the requirement for an analysis to be taken to assess whether or not the gas is from associated gas or cap gas.

Section 12.3.2: Clarifies that all flared and vented gas must be measured and reported using sound engineering practices.

Section 14.7.3: Adds requirement that gauge boards must be verified yearly as per API MPMS Chapter 2. Gauge boards still do not have to be calibrated.

Section 15.2.9: Clarifies the brine measurement and reporting requirements in Saskatchewan. These requirements were always in place but were previously in different locations throughout the Directive. For ease of use the requirements have been moved to one section of the Directive.

Glossary: First, provides new definitions for flare gas, fuel gas, fugitive emissions, gas in solution, makeup gas, and vent gas. Second, revises the definition of a well to match the OGCR.

Glossary: adds water definition to clarify the water types within the Directive.

Intent of this Directive

This Directive 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 determined volumes and what they are;
4. what data must be kept for audit purposes; and
5. what resultant volumes must be reported to the Regulator.

The licensee must comply with all requirements set out in this Directive.

In this Directive, the term "must" indicates a requirement that must be followed. In some situations, a requirement may be subject to exemptions if specific conditions are met.

The term "should" indicates a recommendation that will not be subject to enforcement. However, the Regulator may direct the licensee in writing to implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities.

The Directive does not include instructions on how the volumes must be reported to the Regulator which are included in other Regulator documents, such as Saskatchewan's *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting* (formerly known as Directive R01) - Petrinex, but it does include some information on requirements regarding facility subtype, status, and code in accordance with those documents.

If requirements in previously issued Regulator documents (interim directives, informational letters, guides, etc.) conflict with the requirements in this Directive, the requirements in this Directive replace the prior requirements. Over time, it is intended that all relevant superseded requirements will be rescinded.

Definitions

Many terms used in this Directive are defined in the Glossary (Appendix 2). However, many critically important definitions are also included within applicable sections.

Enforcement

SK	This Directive replaces and supersedes a number of Saskatchewan Regulatory documents, as identified in Appendix 1. This Directive currently has Regulatory authority in Saskatchewan effective April 1, 2016. Regulatory enforcement of the new requirements, including audits and inspections, that are intended to ensure compliance with the new oil and gas measurement requirements and will be applied in accordance with the implementation schedule outlined below. Enforcement actions will be applied according to Section 13.6 of *Directive PNG076: Enhanced Production Audit Program*. As a result of the implementation of Directive PNG017, ER will be rescinding all Measurement Exemptions approved in Saskatchewan before April 1, 2016. Industry must make continuous progress with respect to compliance for measurement and reporting by April 1, 2020, and ER may require operators to demonstrate their progress throughout the implementation schedule. Operators must meet the following implementation schedule: a. Requirements must be 25 per cent implemented by April 1, 2017. b. Requirements must be 50 per cent implemented by April 1, 2018. c. Requirements must be 75 per cent implemented by April 1, 2019. d. Requirements must be 100 per cent implemented by April 1, 2020. All operators are expected to be fully compliant with the Saskatchewan Regulatory requirements prior to the implementation of Directive PNG017. Any facilities licensed after April 1, 2016 must be designed and operated in full compliance with Directive PNG017. For facilities licensed prior to April 1, 2016, operators are expected to comply with the 4-year implementation schedule.

	The operator may apply for a site specific measurement exemption through the IRIS generic application process if all the necessary documentation associated with an application is submitted and there is significant evidence to support the exemption (refer to Section 5 of Directive PNG017).
AB	The AER enforcement process is specified in *Directive 019: Compliance Assurance*. Noncompliance events are listed in the Risk Assessed Noncompliance section of *Directive 019* under the Technical Operations Group, Production Operations Section, for *Directive 017* and *Directive 007* requirements.
BC	The BCOGC enforcement process is specified in the Compliance & Enforcement Manual http://www.bcogc.ca/node/6096/download

1 Standards of Accuracy

1.1 Introduction

With regard to accuracy, it is assumed an exact or true value exists for any variable that is valid for the conditions existing at the moment the result is determined. Determining the true value without doubt cannot be done, due to the limitations of measuring equipment and procedures and the possibility of human error. Typically, the closer one wants to approach the true value, the more expense and effort has to be expended.

Measurement in an oil and gas industry context, the principal measurement technologies and procedures are:

a. Meters for determining flow volumes.

b. Calculated volumes using a proration formula based on test volumes.

c. Estimates of volumes based on production facility and product characteristics.

d. Scales for samples and vehicles.

e. Gauge boards for tanks.

f. Gauges for temperature and pressure.

The Regulator has established standards of accuracy for gas and liquid measurement that take into account potential impacts to royalty, equity, reservoir engineering, declining production rates, aging equipment, environment, public safety, accuracy and completeness. These standards have evolved, but originated from a 1972 Alberta Board hearing decision that determined a need for pool production accuracy standards of 2.0% for oil, 3.0% for gas, and 5.0% for water. The current standards are stated as maximum uncertainty of monthly volume and/or single point measurement uncertainty. The uncertainties are to be applied as “plus/minus” e.g., ±5.0%. Measurement at delivery/sales points must meet the highest accuracy standards because volumes determined at these points can 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.

The specific standards of accuracy are listed in Section 1.7. Operators must ensure their measurement equipment is in good working order. If an inspection of a measurement device or of procedure reveals unsatisfactory conditions that significantly reduces measurement accuracy, the Regulator will direct the licensee to implement changes to improve measurement accuracy, and this direction will become a condition of operation for the facility or facilities.

1.2 Applicability and Use of Uncertainties

The Regulator used the uncertainty levels contained in this section to develop many of the requirements for equipment and/or procedures relating to measurement, accounting, and reporting for various aspects of oil and gas production and processing operations, which are explained in detail in other sections. If those requirements are being met and consideration has been made regarding the potential impacts to royalty, equity, reservoir engineering, environment, public safety, accuracy and completeness, the Regulator considers a licensee to be in compliance without the need to demonstrate compliance with the applicable uncertainty requirements contained in this section.

In some scenarios a licensee may deviate from the minimum requirements for equipment and/or procedures that are stated in this Directive. Refer to Section 5: Site-specific Deviation from Base Requirements.

1.3 Maximum Uncertainty of Monthly Volume

The Regulator 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 to which a maximum uncertainty of 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 for the other wells in the battery to arrive at the total estimated monthly oil production for the battery.
3. The total actual monthly oil production for the battery is determined based on measured deliveries out of the battery and inventory change.
4. A proration factor is determined by dividing the actual battery production by the estimated battery 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 single-phase 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 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, 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 calibration, sample gathering and analysis, variable operating conditions, etc. These uncertainties are for single-phase specific volume determination points of specific fluids (oil, 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 the latest edition of the International Standard Organization *(ISO) Standard 5168: Measurement of Fluid Flow—Estimation of Uncertainty of a Flow-rate Measurement.*

1.6.1 Example Calculation

Determination of single point measurement uncertainty for well oil at a proration battery using root sum square methodology:

Individual uncertainties from historical research:

For oil/emulsion measurement:

Oil meter uncertainty = 0.5% (typical manufacturer's specification)

Meter proving uncertainty = 1.5%

Sediment 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 gas measurement;

Primary element – gas meter uncertainty = 1.0%

Secondary element – (pulse counter or transducer, etc.) uncertainty = 0.5%

Secondary element calibration uncertainty = 0.5%

Tertiary element – (flow calculation, Electronic Flow Measurement (EFM), etc.) uncertainty = 0.2%

Gas sampling and analysis uncertainty = 1.5%

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

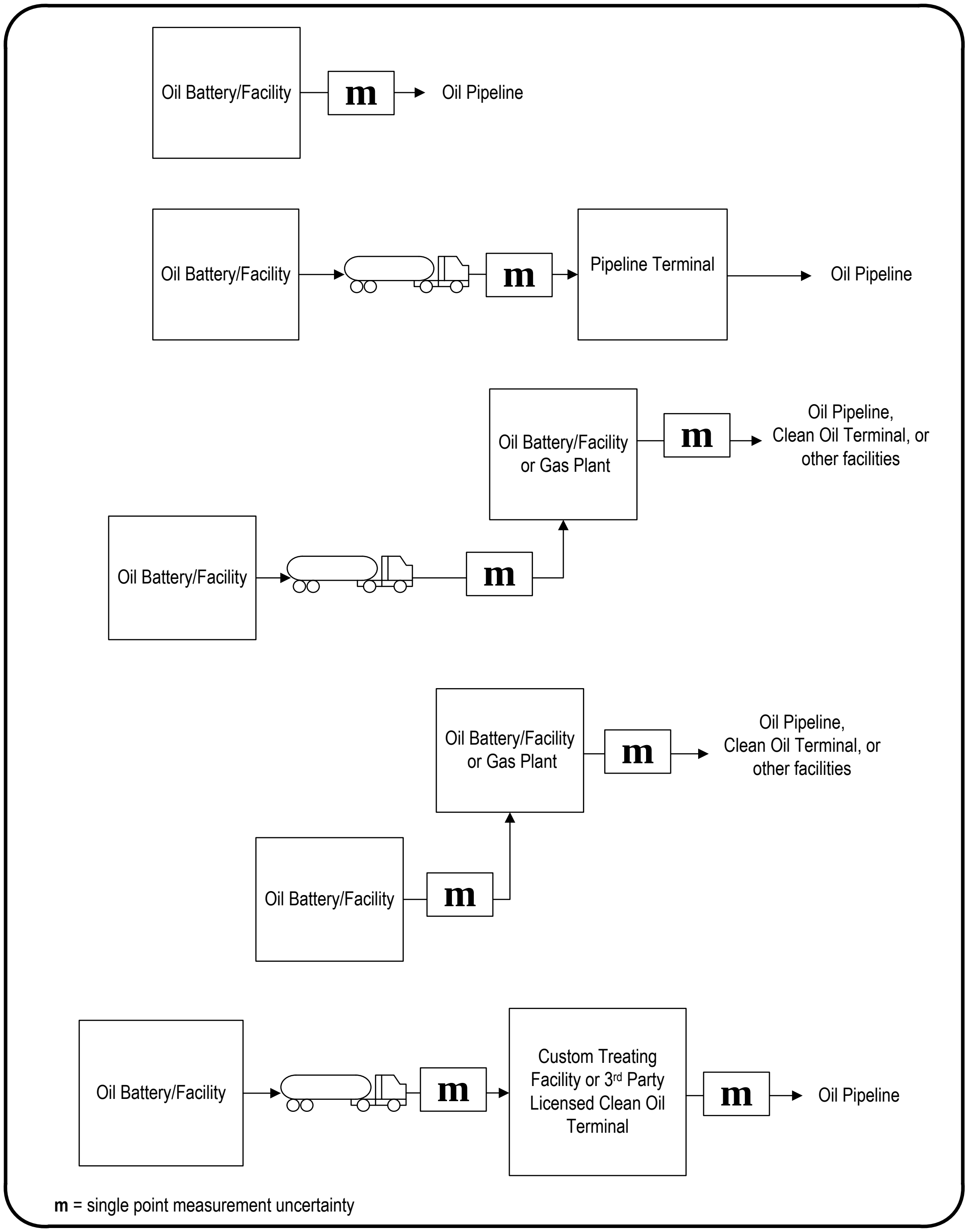
= 1.95% (rounded to 2.0%)

1.6.2 Oil Systems

1.6.2.1 Oil Systems - Total Battery/Facility Oil

Delivery point measurement, including single-well batteries.

Figure 1.1. Total battery/facility oil - delivery point measurement



Maximum uncertainty of monthly volume = N/A

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

Single point measurement uncertainty:

Delivery point measures > 100 m^3/d = 0.5%

Delivery point measures ≤ 100 m^3/d = 1.0%

The royalty trigger point for oil is at the wellhead. Thus, delivery point measurements are required at the following locations:

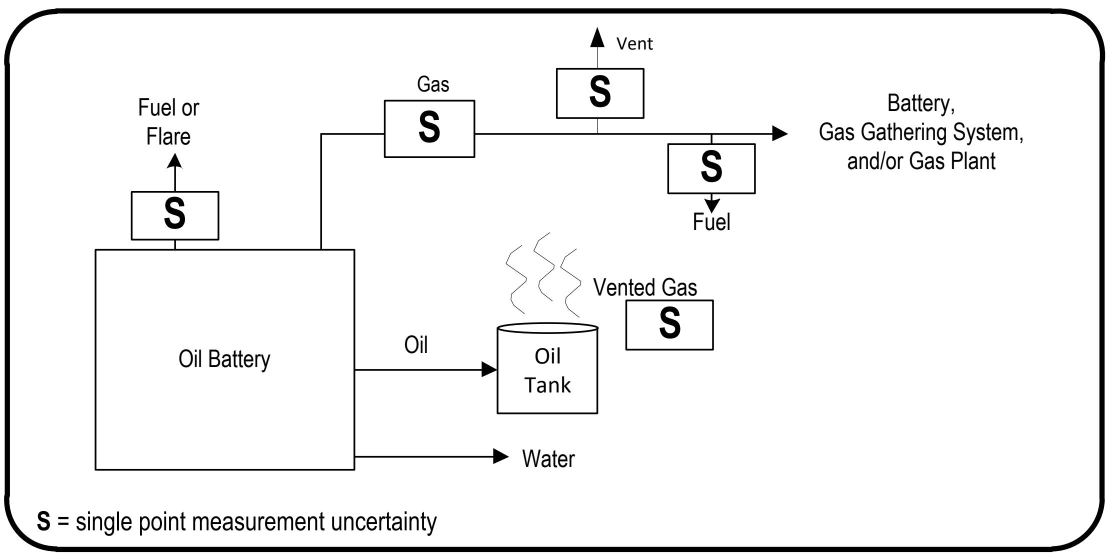
1. Facility dispositions
2. Trucked-in receipts
3. Pipeline receipts
4. Railcar receipts
5. Sales
6. LACT

Excluded: Test points and group points if they are not used for accounting or inventory.

1.6.2.2 Oil Systems - Total Battery Gas

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

Figure 1.2



Single point measurement uncertainty:

> $16.9\ 10^3m^3/d = 3.0\%$

> $0.50\ 10^3m^3/d$ but $\leq 16.9\ 10^3m^3/d = 3.0\%$

$\leq 0.50\ 10^3m^3/d = 10.0\%$

Maximum uncertainty of monthly volume (**M**)

> $16.9\ 10^3m^3/d = 5.0\%$

> $0.50\ 10^3m^3/d$ but $\leq 16.9\ 10^3m^3/d = 10.0\%$

$\leq 0.50\ 10^3m^3/d = 20.0\%$

Note that **M** is dependent upon combined deliveries, fuel, and vented gas measurement.

The maximum uncertainty of total monthly battery gas volumes allows for reduced emphasis on accuracy as gas production rate declines. For gas rates up to 0.50 $10^3 m^3/d$, the gas volumes may be determined by using estimates. Therefore, the maximum uncertainty of monthly volume is set at 20.0%. If gas rates exceed 0.50 $10^3 m^3/d$, the gas must be metered. However, a component of the total monthly gas volume may include estimates for low volumes of fuel, 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.

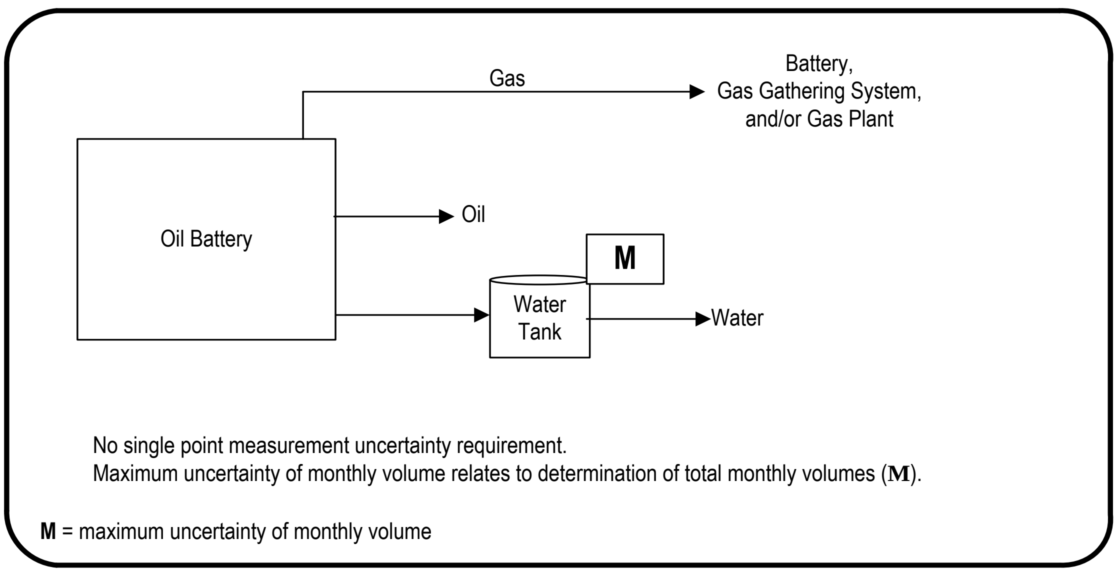
The equipment and/or procedures used to determine the metered gas volumes when metering is required must be capable of meeting a 3.0% single point measurement uncertainty. Due to the difficulty associated with metering very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes where rates do not exceed 0.50 $10^3 m^3/d$ are expected to be capable of meeting a 10.0% single point measurement uncertainty.

These uncertainties do not apply to gas produced in association with heavy oil with a density of 920 kg/m^3 or greater at 15°C.

1.6.2.3 Oil Systems - Total Battery Water

Includes single-well batteries.

Figure 1.3



Maximum uncertainty of monthly volume:

> 50 m^3/month = 5.0%

≤ 50 m^3/month = 20.0%

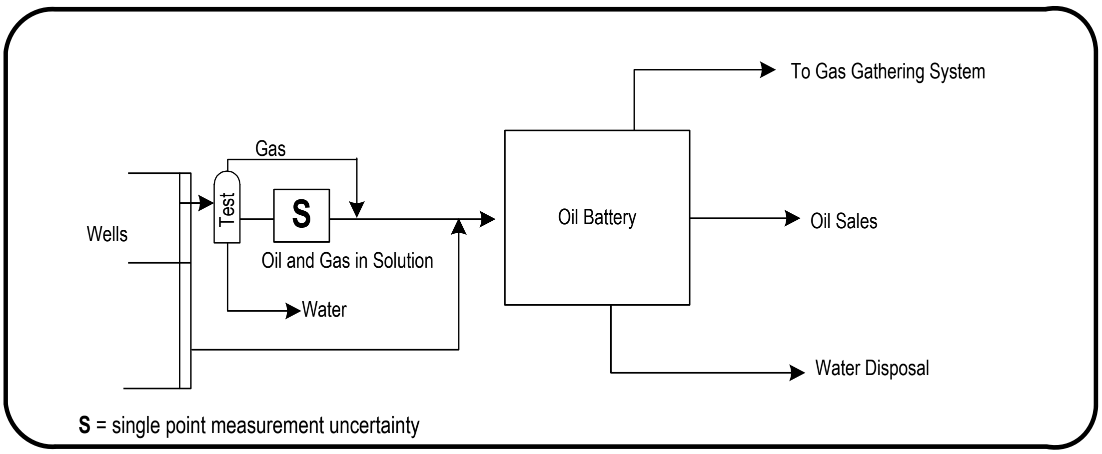
Single point measurement uncertainty = N/A

Total battery water may be determined by metering or estimation, depending on production rates, so no basic requirement has been set for single point measurement uncertainty.

Total battery water production volumes not exceeding 50 m^3/month may be determined by estimation. Therefore, the maximum uncertainty of monthly volume is set at 20.0%. If the total battery water production volumes exceed 50 m^3/month, the water must be separated from the oil and measured. Therefore, the maximum uncertainty of monthly volume is set at 5.0%.

1.6.2.4 Oil Systems - Well Oil - Proration Battery

Figure 1.4



Single point measurement uncertainty:

All classes = 2.0%

Maximum uncertainty of monthly volume:

Class 1 (high) > 30 m^3/d = 5.0%

Class 2 (medium) > 6 m^3/d but ≤ 30 m^3/d = 10.0%

Class 3 (low) > 2 m^3/d but ≤ 6 m^3/d = 20.0%

Class 4 (stripper) ≤ 2 m^3/d = 40.0%

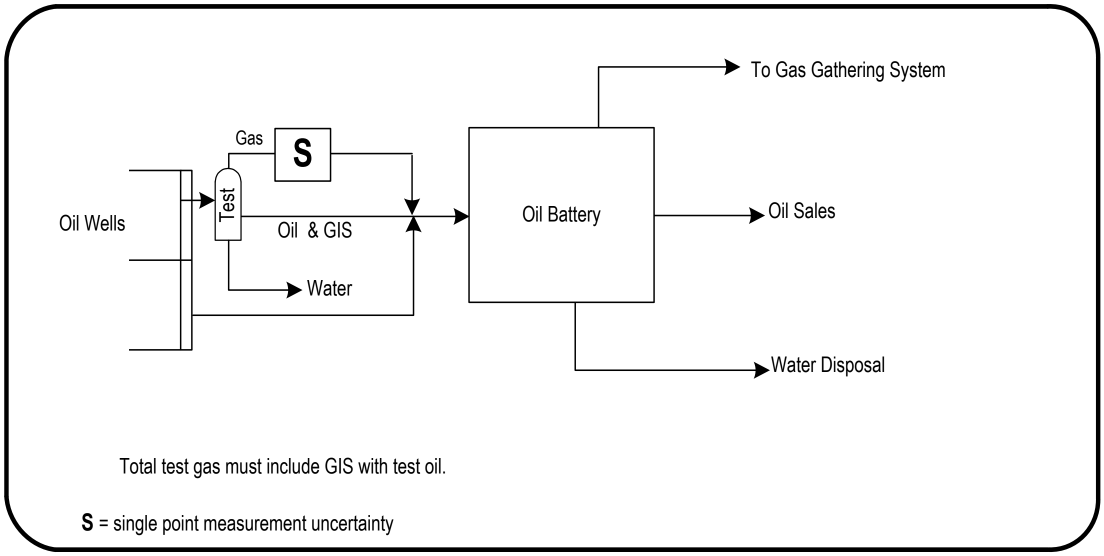
Maximum uncertainty is dependent upon oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly well oil production volumes for light and medium density oil wells in proration batteries 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. Lower rate wells are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly oil production volume will be accurate.

1.6.2.5 Oil Systems - Well Gas - Proration Battery

Also referred to as associated gas, as it is the gas produced in association with oil production at oil wells.

Figure 1.5



Single point measurement uncertainty:

> 16.9 $10^3m^3/d$ = 3.0%

> 0.50 $10^3m^3/d$ but ≤ 16.9 $10^3m^3/d$ = 3.0%

≤ 0.50 $10^3m^3/d$ = 10.0%

Maximum uncertainty of monthly volume:

> 16.9 $10^3m^3/d$ = 5.0%

> 0.50 $10^3m^3/d$ but ≤ 16.9 $10^3m^3/d$ = 10.0%

≤ 0.50 $10^3m^3/d$ = 20.0%

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

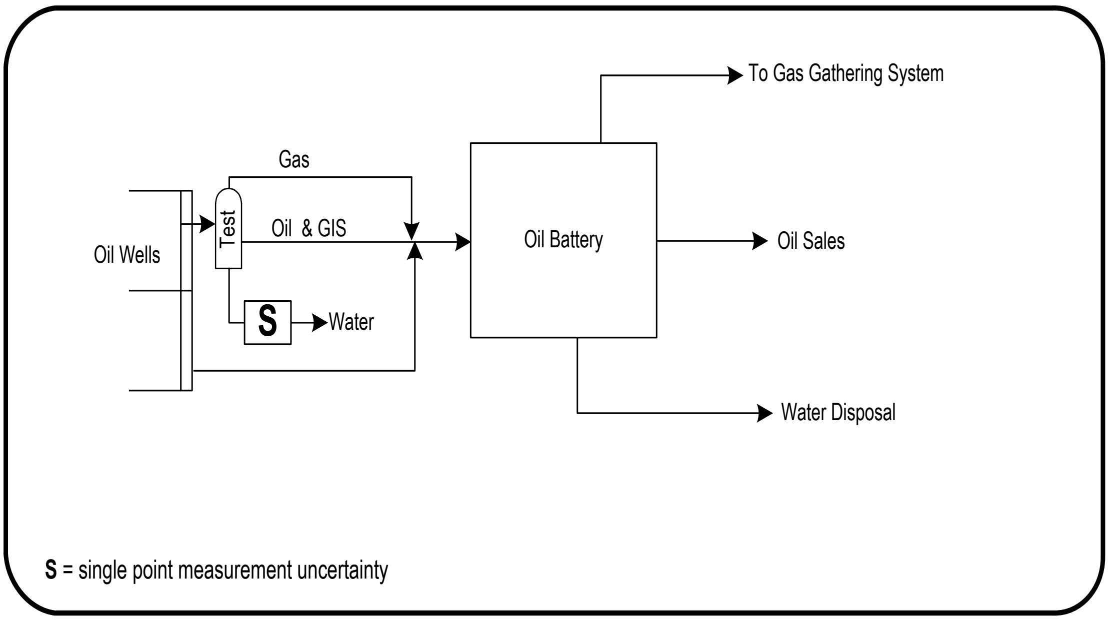
The maximum uncertainty of monthly oil well gas volumes has been developed to allow for reduced emphasis on accuracy as gas production rates decline. Rather than being determined by continuous metering, monthly oil well gas production volumes are estimated from well tests and corrected by the use of proration factors to result in actual volumes. Low gas production rates are typically associated with wells that are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly gas production volume will be accurate.

For gas rates up to 0.50 $10^3m^3/d$, the well test gas volume may be determined by using estimates. Therefore, the maximum uncertainty of monthly volume is set at 20.0%. If gas rates exceed 0.50 $10^3m^3/d$, the test gas must be metered. However, a component of a well's total test gas volume may include estimates for gas in solution dissolved in the test oil volume, 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 5.0% 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 3.0% single point measurement uncertainty. Due to 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 0.50 $10^3m^3/d$ are expected to be capable of meeting a 10.0% single point measurement uncertainty.

1.6.2.6 Oil Systems - Well Water - Proration Battery

Figure 1.6



Single point measurement uncertainty = 10.0%

Maximum uncertainty of monthly volume = N/A

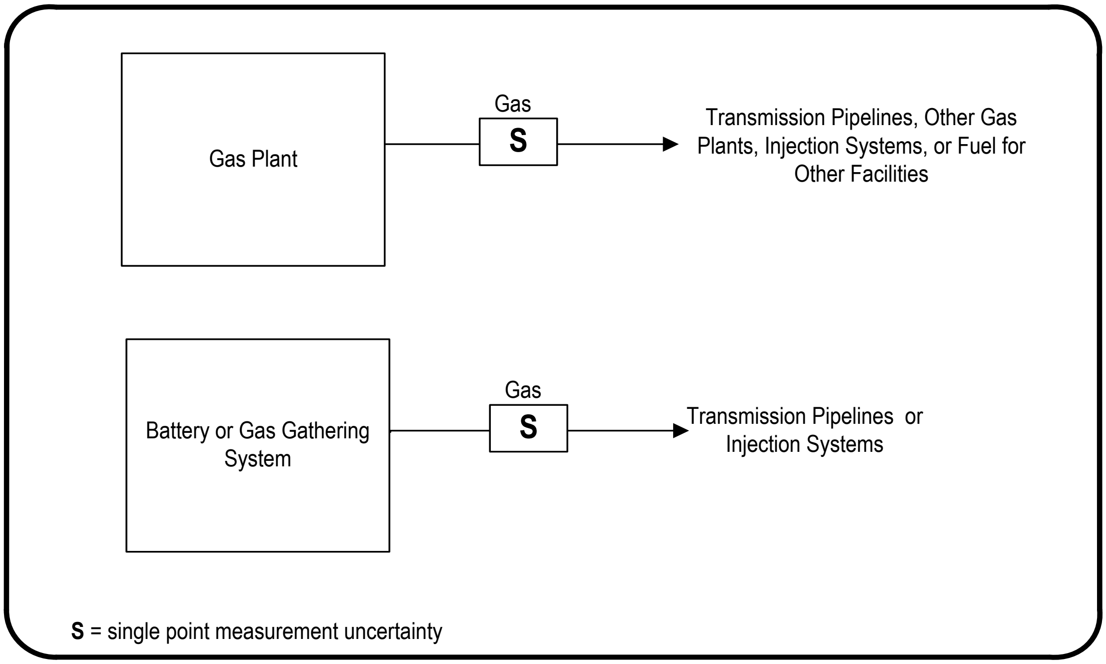
The uncertainty of the monthly volume will vary, depending upon the method used to determine test water rates and the frequency of well tests.

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 scenarios estimates may be used to determine water rates. Therefore, the single point measurement uncertainty is set at 10.0%.

1.6.3 Gas Systems

1.6.3.1 Gas Systems - Gas Deliveries – Sales Gas

Figure 1.7



Single point measurement uncertainty = 2.0%

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.

SK	Since the delivery point is often a custody transfer point, a stringent expectation is set for the single point measurement uncertainty.
AB	The delivery point or royalty trigger point for gas is generally for clean processed gas disposition (DISP) at the plant gate or for raw gas that is sent to another facility for FUEL usage only. The measurement at this point determines the gas volumes upon which royalties will be based. Therefore, a stringent expectation is set for the single point measurement uncertainty.
BC	Gas deliveries in this context will typically be clean, processed sales gas that is delivered out of a gas plant or gas 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.

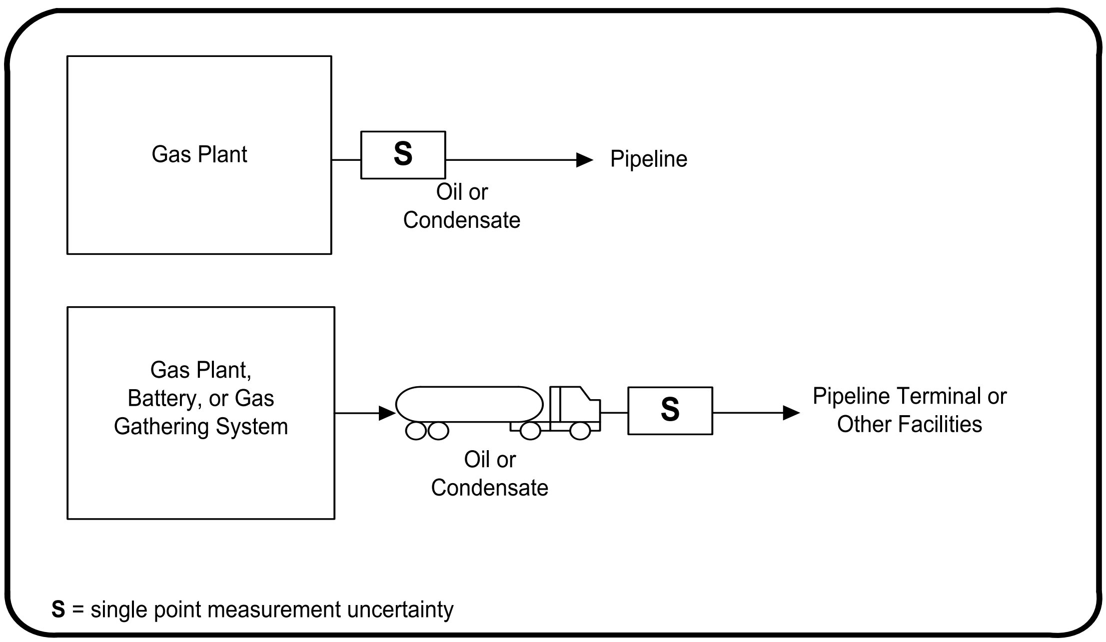
In some scenarios, this type of gas may be delivered to other plants for further processing or to injection facilities. Thus delivery point measurements are required at the following locations:

1. Gas plant dispositions
2. Sales to downstream
3. Purchase from downstream facilities
4. Cross-border and cross-jurisdiction
5. Gas delivered from one upstream facility to another that is not tied to the same system for FUEL, such as from a gas battery to an oil battery
6. Condensate disposition to an oil facility or for sales

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

1.6.3.2 Gas Systems - Hydrocarbon Liquid Deliveries

Figure 1.8



Single point measurement uncertainty:

Delivery point measures > 100 m^3/d = 0.5%

Delivery point measures ≤ 100 m^3/d = 1.0%

Maximum uncertainty of monthly volume = N/A

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

The term delivery point measurement for hydrocarbon liquids refers to the point at which the hydrocarbon liquid production from a battery or facility is measured. Where clean hydrocarbon liquids are delivered directly into a pipeline system via a Lease Automatic Custody Transfer Unit (LACT) measurement or trucked to a pipeline terminal, it can also be referred to as the custody transfer point. The delivery point terminology is from the perspective of the producing battery or facility, but the receiving facility (pipeline, terminal, custom treating facility, other battery, 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.

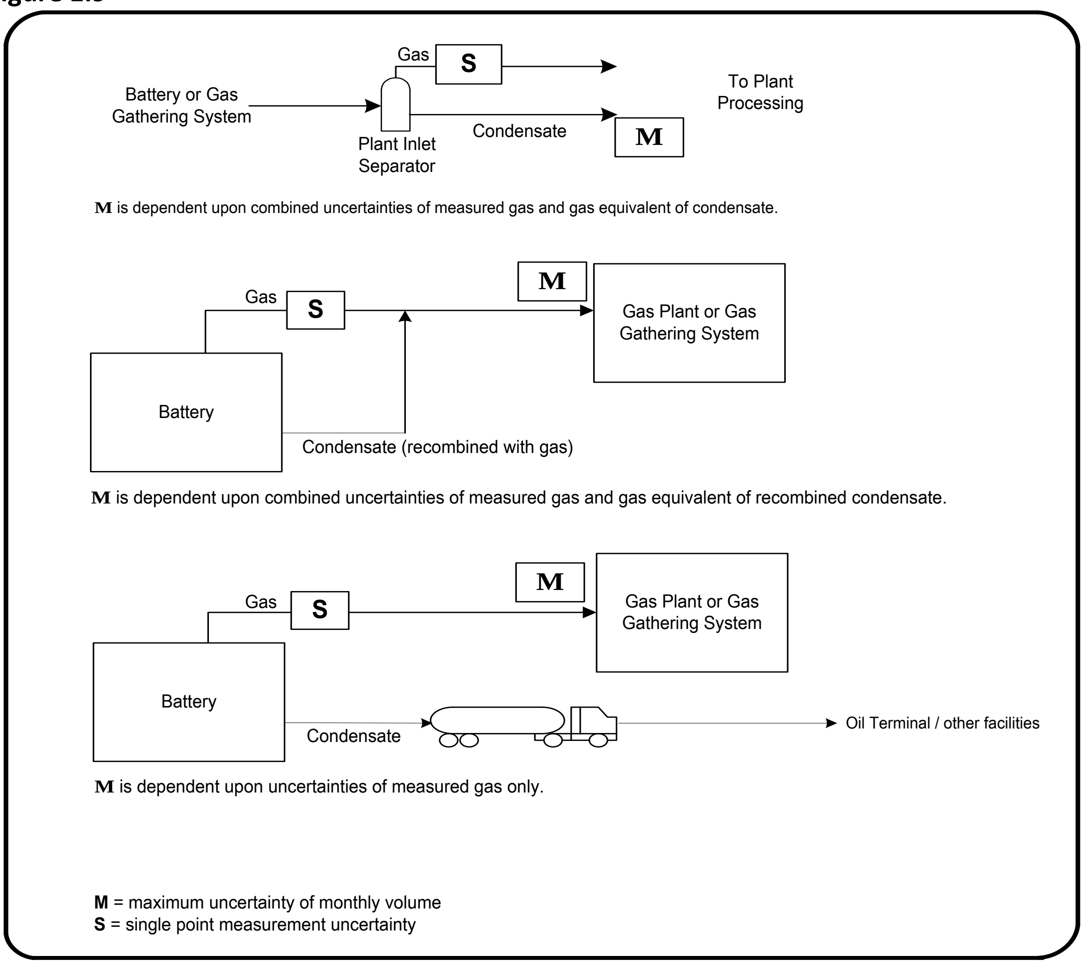
Hydrocarbon liquids delivered out of a gas system at the well, battery, or plant inlet levels are typically condensate, and in some scenarios they may be considered to be oil. The hydrocarbon liquids delivered out of a gas plant may be pentanes, butane, propane, ethane, or a mixture of various components.

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 ≤ 100 m^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.

1.6.3.3 Gas Systems - Plant Inlet or Total Battery / Group Gas

Figure 1.9



Maximum uncertainty of monthly volume = 5.0%

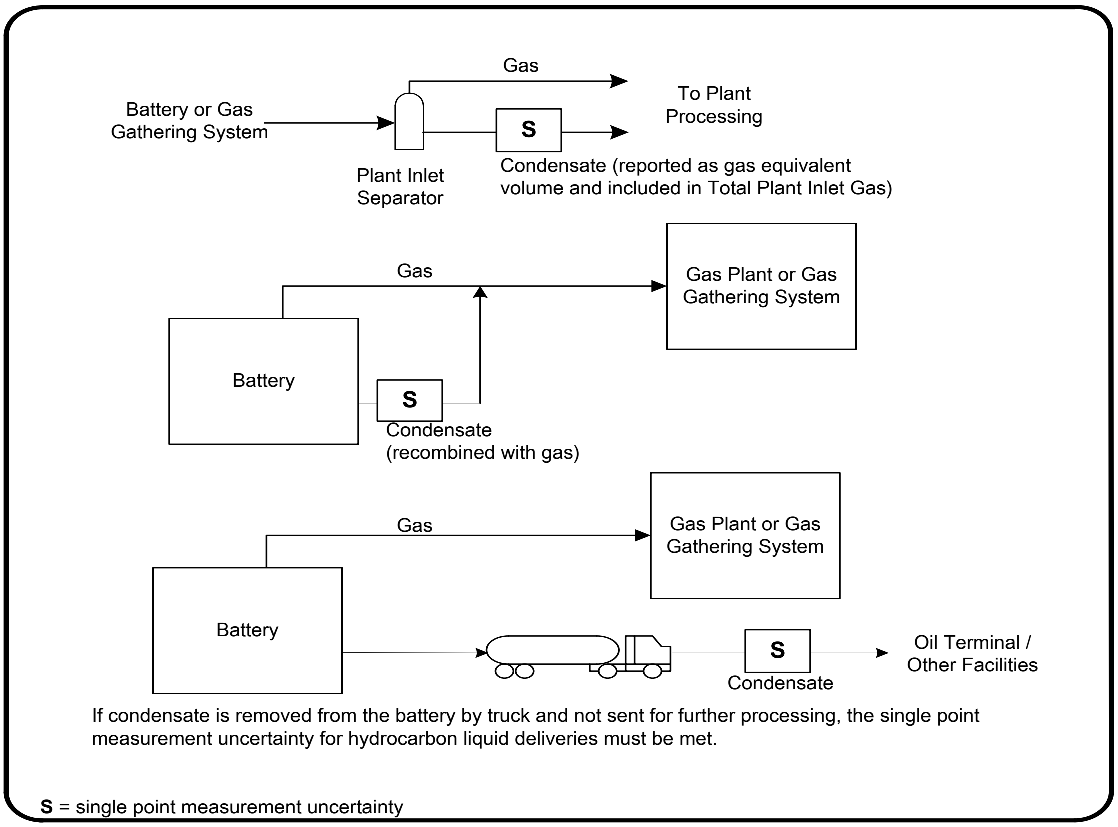
Single point measurement uncertainty = 3.0%

Plant inlet gas or total battery/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 5.0% to allow for the uncertainties associated with measuring gas under these conditions.

The equipment and/or procedures used to determine the measured gas volumes must be capable of meeting a 3.0% single point measurement uncertainty.

1.6.3.4 Gas Systems - Plant Inlet or Total Battery / Group Condensate - Recombined

Figure 1.10



Single point measurement uncertainty = 2.0%

Maximum uncertainty of monthly volume = N/A

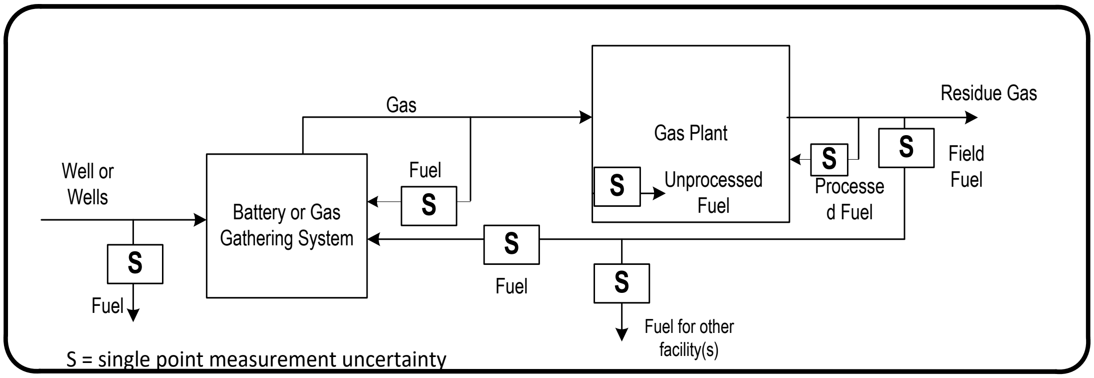
The condensate volume is included in the total gas volume for reporting purposes and is therefore covered by the maximum uncertainty of monthly volume for the plant inlet or total battery/group gas.

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/group condensate upstream of the plant inlet is separated and measured 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 scenario, the condensate single point measurement uncertainty is set at 2.0% for the liquid volume determination.

Note that if plant inlet or total battery/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 stated in Section 1.6.3.2.

1.6.3.5 Gas Systems - Fuel Gas

Figure 1.11



Single point measurement uncertainty:

> 0.50 $10^3m^3/d$ = 3.0%

≤ 0.50 $10^3m^3/d$ = 10.0%

Maximum uncertainty of monthly volume:

> 0.50 $10^3m^3/d$ = 5.0%

≤ 0.50 $10^3m^3/d$ = 20.0%

Note that maximum uncertainty is dependent upon combined uncertainties of various fuel sources at each reporting facility.

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 facilities, if the annual average fuel gas rate is 0.50 $10^3m^3/d$ 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 0.50 $10^3m^3/d$ on any site, 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 0.50 $10^3m^3/d$, the maximum uncertainty of the monthly volume is set at 5.0% to allow for the uncertainties associated with measuring gas under those conditions. See Section 4.2 for more detail.

Gas used for pneumatic devices must be reported as fuel gas.

Effective January 1, 2020, gas used for pneumatic devices that is vented or flared must be reported as vented or flared, respectively.

For facilities licensed prior to January 1, 2020 or for non-licensed facilities built before January 1, 2020, the volume of gas emitted by pneumatic devices may be estimated and then subtracted from the metered fuel gas volume in the case where the metered fuel gas provides the pneumatic gas supply.

For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include gas emitted by pneumatic devices.

Pilot, purge, sweep, blanket and makeup gas consumption must be reported as fuel gas.

Effective January 1, 2020, gas used for pilot, purge, sweep, blanket and makeup gas must be reported as flared.

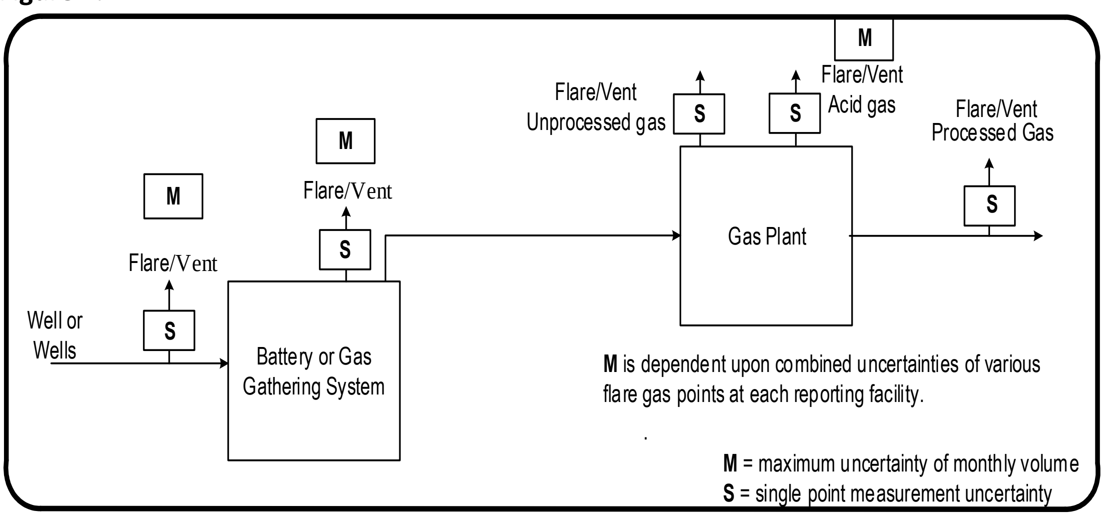
For facilities licensed prior to January 1, 2020 or for non-licensed facilities built before January 1, 2020, the volume of gas used as pilot, purge, sweep, blanket, and makeup gas may be estimated and then subtracted from metered fuel gas in the case where metered fuel gas also provides the pilot, purge, sweep, blanket, and makeup gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.50 $10^3m^3/d$ that may be estimated for flare gas.

For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pilot, purge, sweep, blanket, and makeup gas supply.

The equipment and/or procedures used to determine the measured gas volumes if metering is required must be capable of meeting a 3.0% single point measurement uncertainty. Due to 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 0.50 $10^3m^3/d$ are expected to be capable of meeting a 10.0% single point measurement uncertainty.

1.6.3.6 Gas Systems - Flare and Vent Gas

Figure 1.12



Maximum uncertainty of monthly volume = 20.0%

Single point measurement uncertainty = 5.0%

Flare gas may be clean processed gas or it may be unprocessed gas, depending on the point in the system from which gas is being flared. Continuous and intermittent flared and vent volumes at all oil or gas production or processing facilities, including thermal *in situ* facilities but excluding non-thermal heavy oil and bitumen facilities, where annual average total flared and vented volumes per facility exceed 0.5 10^3m^3/d excluding pilot, purge, or dilution gas must be metered.

Pilot, purge, sweep, blanket and makeup gas consumption must be reported as fuel gas.

Effective January 1, 2020, gas used for pilot, purge, sweep, blanket and makeup gas must be reported as flared. For facilities licensed prior to January 1, 2020 or for non-licensed facilities built before January 1, 2020, the volume of gas used as pilot, purge, sweep, blanket, and makeup gas may be estimated and then subtracted from metered fuel gas in the case where metered fuel gas also provides the pilot, purge, sweep and blanket gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.5 10^3m^3/d that may be estimated for flare gas.

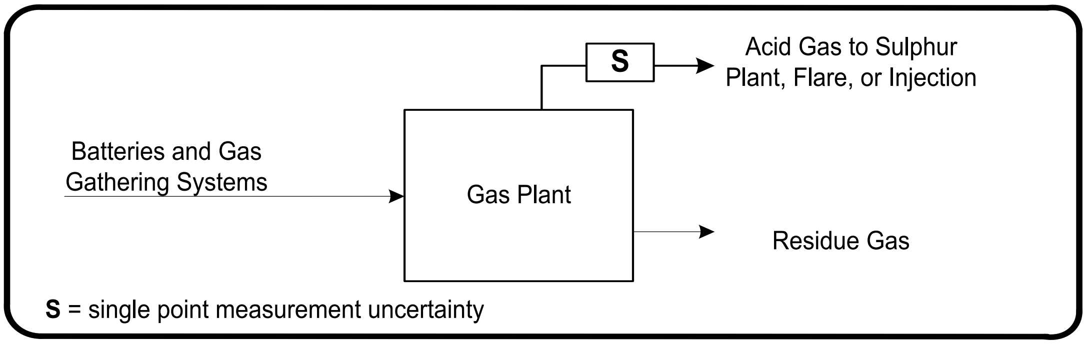
For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pilot, purge, sweep, blanket, and makeup gas supply.

Effective January 1, 2020, uncombusted gas released to the atmosphere, including fugitive emissions, must be reported as vent gas using the methodologies in *Guideline PNG035: Estimating Venting and Fugitive Emissions*. When a fugitive emission is discovered the operator must estimate and report the amount of gas released from the time of discovery until the fugitive emission is eliminated. If, at a facility, all gas that is received or produced is vented including casing gas, then no fugitive emissions need to be reported. All documentation relating to the fuel, flare and vent including fugitive emission must be kept for ER to review.

Sites requiring flare or vent gas metering may estimate up to 0.50 10^3m^3/day. Any continuous and intermittent flare and vent volumes at non-thermal heavy crude oil or bitumen facilities exceeding 2.0 10^3m^3/day must be metered. Sites requiring flare or vent gas metering may estimate up to 2.0 10^3m^3/day. Flare lines usually operate in a shut-in condition and may be required to accommodate partial or full volumes of gas production during flaring conditions. In some scenarios if flaring is infrequent and no measurement equipment is in place, flare volumes must be estimated such as flaring at SW Saskatchewan or SE Alberta gas wells in a proration battery where there is no on-site measurement equipment. Therefore, the maximum uncertainty of the monthly volume is set at 20.0%, to allow for the erratic conditions associated with flare measurement.

1.6.3.7 Gas Systems - Acid Gas

Figure 1.13



Single point measurement uncertainty = 10.0% for low pressure acid gas before compression, and = 3.0% after compression.

Maximum uncertainty of monthly volume = N/A

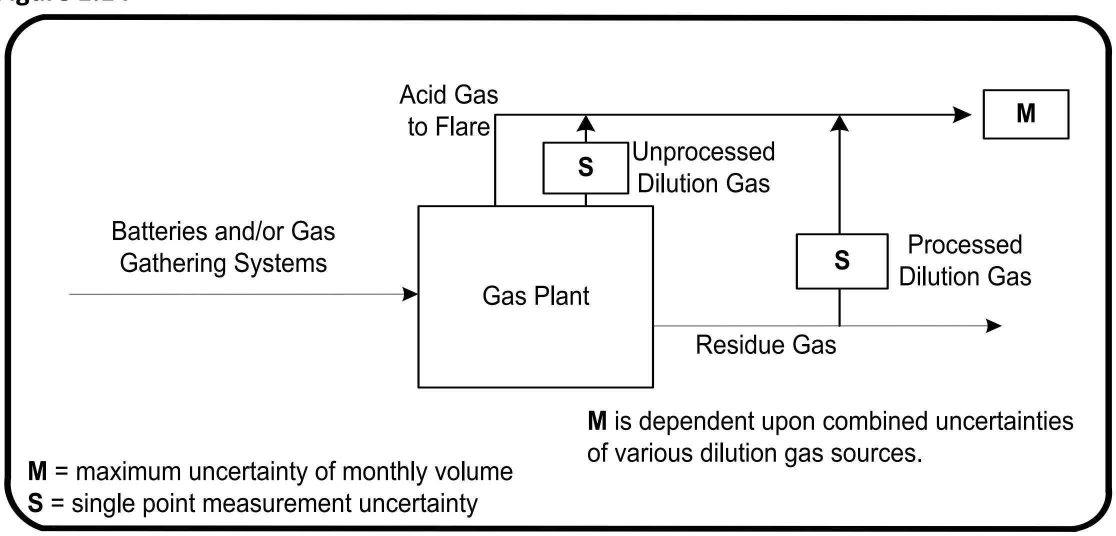
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Acid gas usually contains a great deal of water vapour and has other conditions associated with it, such as very low pressure that affects measurement accuracy. Therefore, the single point measurement uncertainty is set at 10.0%.

See Section 11.4.6.3 for details.

1.6.3.8 Gas Systems - Dilution Gas

Figure 1.14



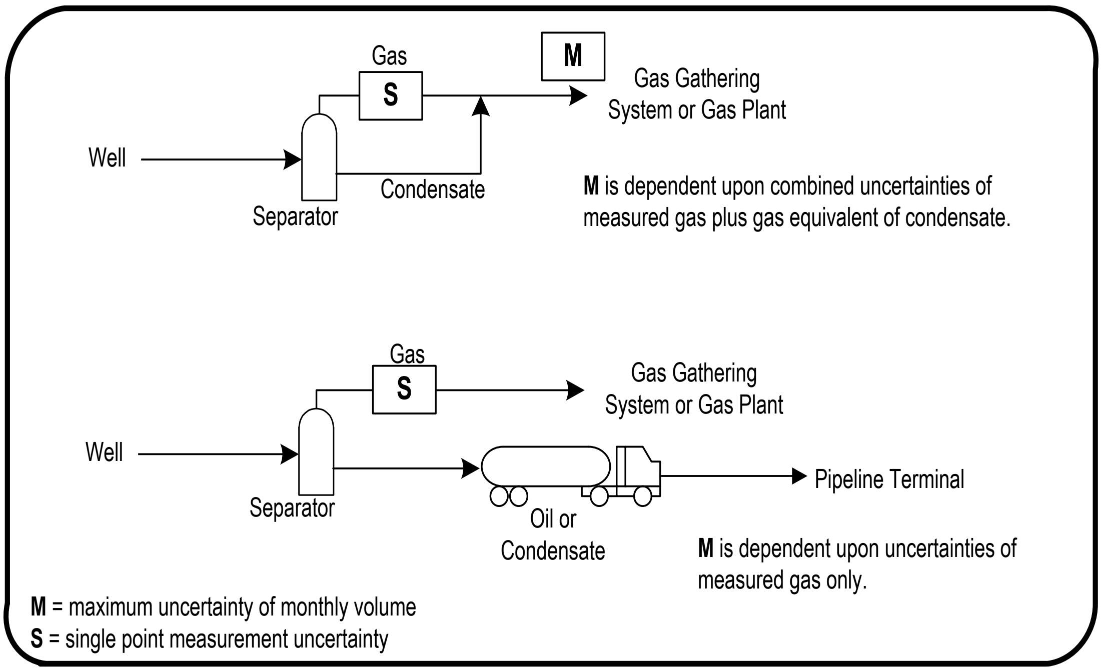
Single point measurement uncertainty = 3.0%

Maximum uncertainty of monthly volume = 5.0%

Dilution gas is gas used to provide adequate heating value for incineration or flaring acid gas. Since it must be measured, it is subject to the same uncertainties as stated in Section 1.6.3.5 for fuel gas that must be determined by measurement.

1.6.3.9 Gas Systems – Well with Gas - Separation

Figure 1.15



Single point measurement uncertainty = 3.0%

Maximum uncertainty of monthly volume:

> 16.9 $10^3m^3/d$ = 5.0%

≤ 16.9 $10^3m^3/d$ = 10.0%

If production components from gas wells are separated and continuously measured, 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 measured well gas volumes must be capable of meeting a 3.0% single point measurement uncertainty.

1.6.3.10 Gas Systems - Well Gas - Proration Battery

Figure 1.16. Well gas (effluent measurement battery)

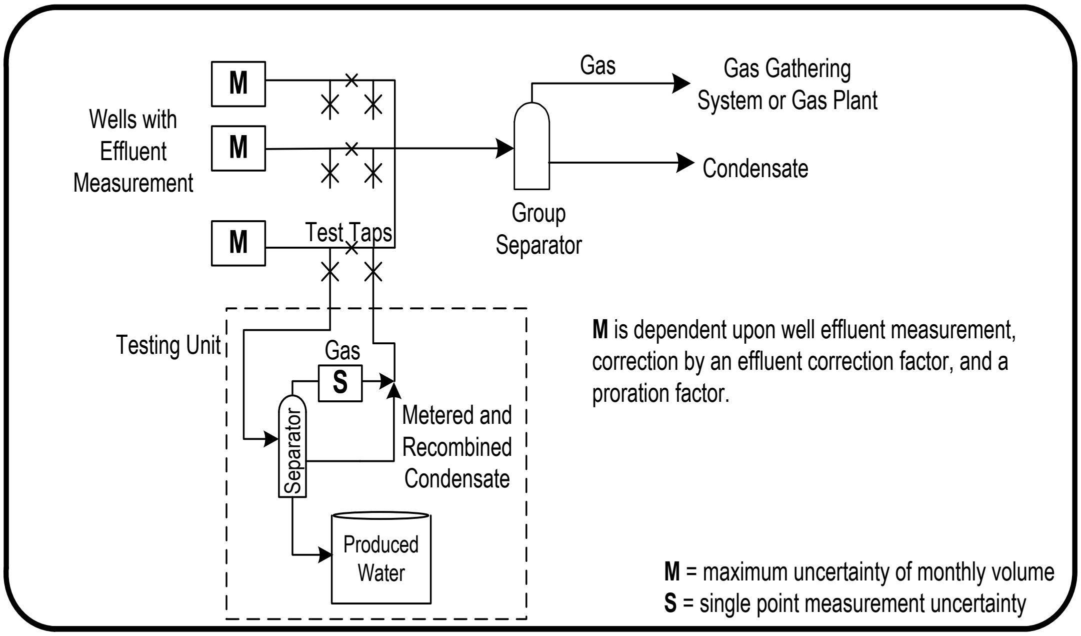
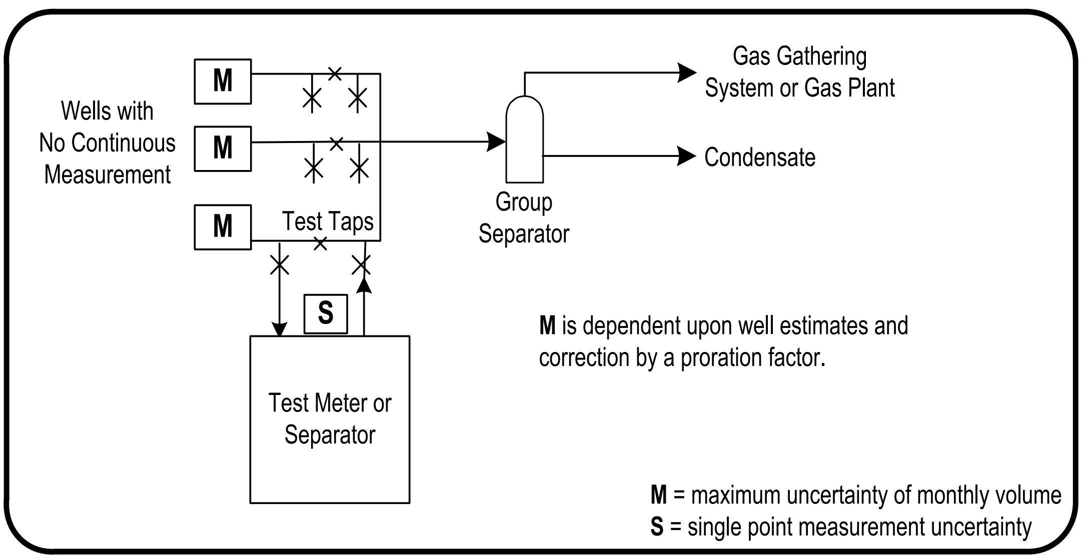


Figure 1.17. Effluent Measurement Battery (SW Saskatchewan, SE Alberta or other approved proration battery)



Single point measurement uncertainty = 3.0%

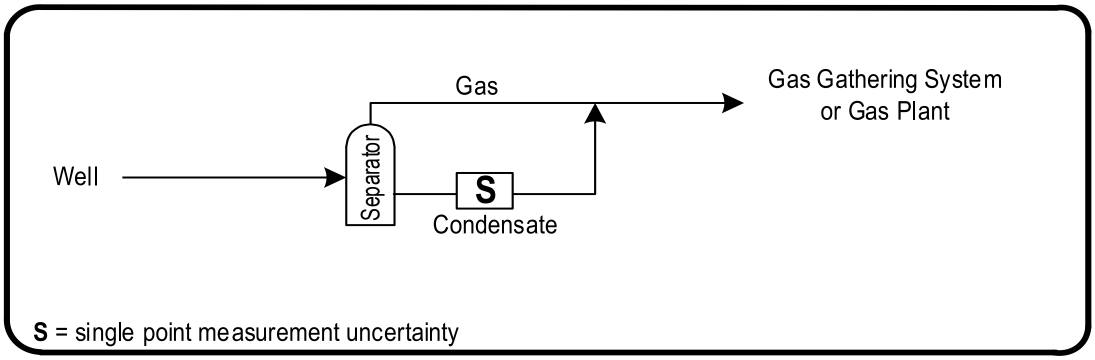
Maximum uncertainty of monthly volume = 15.0%

If production components from gas wells are not separated and continuously measured, the gas wells are subject to a proration accounting system. There are two types of gas proration batteries. Effluent 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. Dry gas wells approved to operate without continuous measurement have the production estimated based on periodic tests, and the actual production is prorated based on the measurement of group volumes at a central location. For both types of proration batteries, the maximum uncertainty of the monthly well gas volume is set at 15.0% to allow for the inaccuracies associated with these types of measurement systems.

The equipment and/or procedures used to determine the measured 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 3.0% single point measurement uncertainty.

1.6.3.11 Gas Systems - Well Condensate - Recombined

Figure 1.18



Single point measurement uncertainty = 2.0%

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.

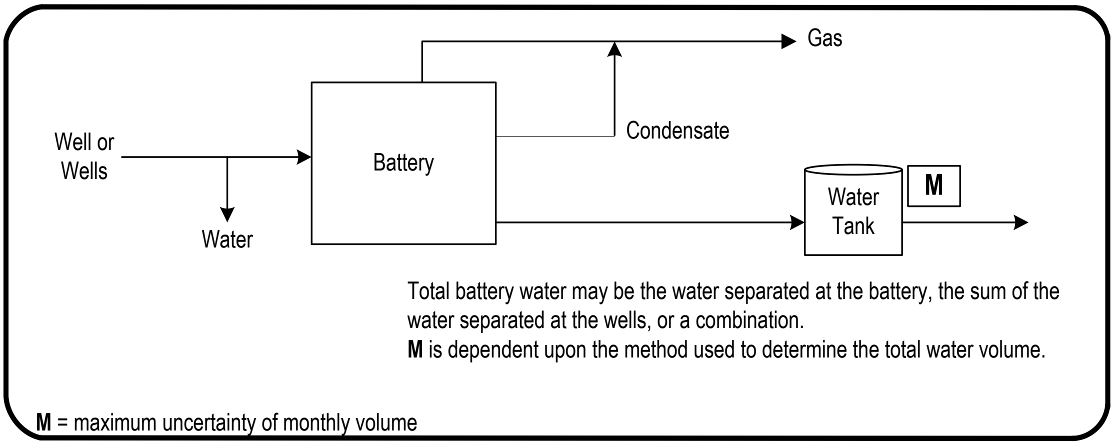
If condensate produced by a gas well is separated and measured at the wellhead prior to being recombined with the gas production, the condensate is mathematically converted to a gas equivalent volume and added to the well gas production volume. In this scenario, the condensate single point measurement uncertainty is set at 2.0% 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 scenario 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 2.0%. 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 scenario, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries stated in Section 1.6.3.2.

1.6.3.12 Gas Systems - Total Battery Water

Figure 1.19



Single point measurement uncertainty = N/A

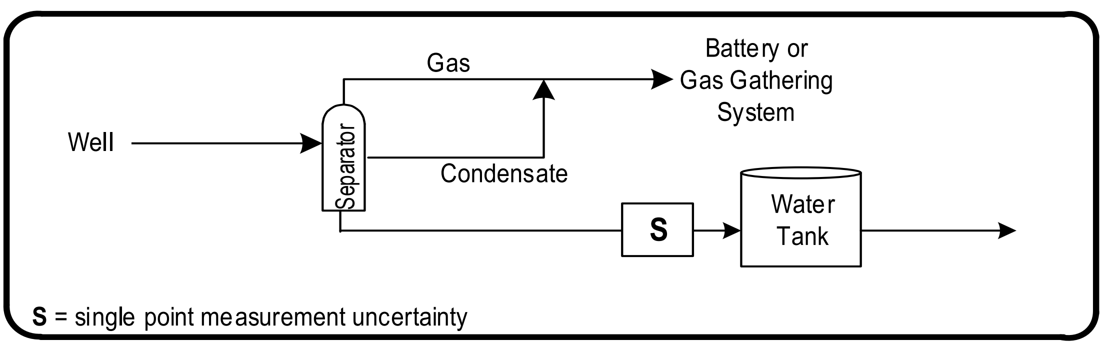
Maximum uncertainty of monthly volume = 5.0%

Total battery water may be determined by an individual group measurement, by totaling individual well measurements, or by totaling individual well estimates, so no basic requirement for measurement uncertainty has been set.

Total battery water in a gas system may be collected at a central location where it can be measured prior to disposal, or it may be a summation of individual well estimates or measurements of water collected at multiple locations and disposed from those sites. The 5.0% maximum uncertainty of monthly volume allows for some leeway in volume determination.

1.6.3.13 Gas Systems - Well Water

Figure 1.20



Single point measurement uncertainty = 10.0%

Maximum uncertainty of monthly volume = N/A

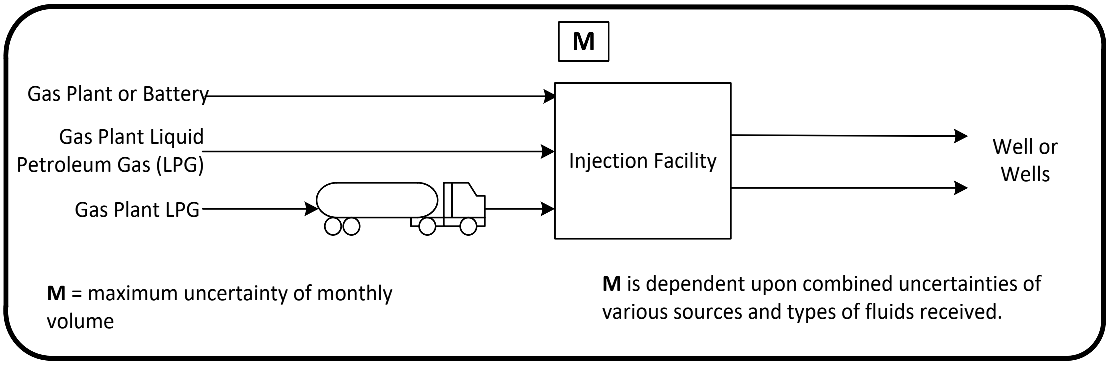
The uncertainty of the monthly volume will vary, depending upon whether produced volumes are subject to individual well measurement, estimation, or proration.

Water production at gas wells may be determined by measurement after separation, or if separators are not used, it may be determined by using water-gas ratios determined from engineering calculations or semiannual tests. To allow for the various methods used to determine production volumes, the single point measurement uncertainty is set at 10.0%.

1.6.4 Injection/Disposal Systems

1.6.4.1 Injection/Disposal Systems - Total Gas

Figure 1.21



Maximum uncertainty of monthly volume = 5.0%

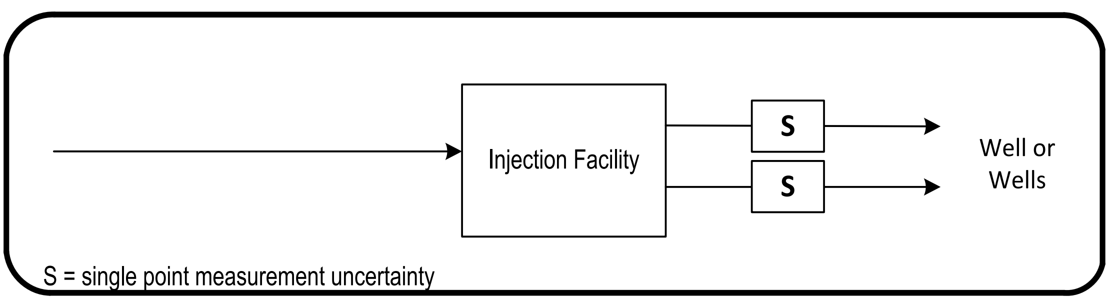
Single point measurement uncertainty = N/A

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 scenarios 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 5.0% to allow for the uncertainties associated with measuring gas under those conditions.

1.6.4.2 Injection/Disposal Systems - Well Gas

Figure 1.22



Single point measurement uncertainty = 3.0%

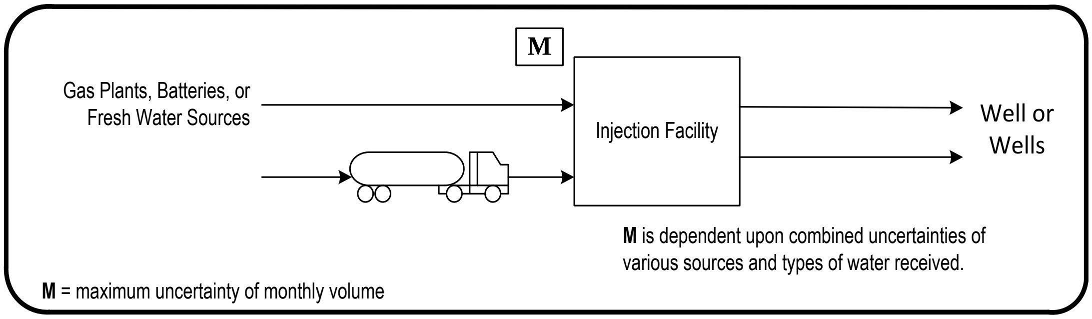
Maximum uncertainty of monthly volume = N/A

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 measured at the injection site 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 3.0% single point measurement uncertainty.

1.6.4.3 Injection/Disposal Systems - Total Water

Figure 1.23



Maximum uncertainty of monthly volume = 5.0%

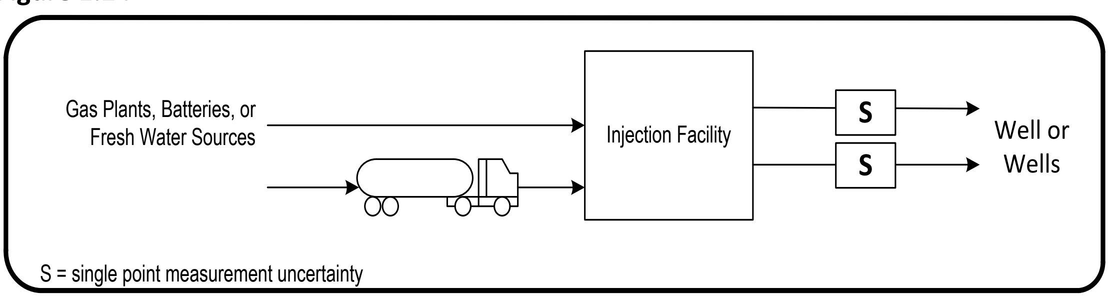
Single point measurement uncertainty = N/A

To be equivalent to the requirements for Oil Systems - Total Battery Water (Section 1.6.2.3) and Gas Systems - Total Battery Water (Section 1.6.3.12).

Water used in injection/disposal systems may be produced water from oil or gas batteries, fresh water from water source wells, or waste water. To be equivalent to the requirements for total oil and gas battery water, the expectation for the maximum uncertainty of monthly volume is set at 5.0%.

1.6.4.4 Injection/Disposal Systems - Well Water / Steam

Figure 1.24



Single point measurement uncertainty = 5.0%

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/steam injected/disposed into each well must be measured at the injection site. The single point measurement uncertainty is set at 5.0%. For water and steam production at a thermal *in situ* facility, the single point measurement uncertainty is set at 2.0%, see Sections 12.3.3 and 12.3.4 for details.

1.7 Standards of Accuracy—Summary

1.7.1 Oil Systems – excluding heavy oil

		Flow Rate	Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total battery oil (delivery point measurement)	Delivery point measures > 100 m^3/d	N/A	0.5
		Delivery point measures ≤ 100 m^3/d	N/A	1.0
(ii)	Total battery gas (includes produced gas that is vented, flared, or used as fuel)	> 16.9 $10^3m^3/d$	5.0	3.0
		> 0.50 $10^3m^3/d$ but ≤ 16.9 $10^3m^3/d$	10.0	3.0
		≤ 0.50 $10^3m^3/d$	20.0	10.0
(iii)	Total battery water	> 50 m^3/month	5.0	N/A
		≤ 50 m^3/month	20.0	N/A
(iv)	Well oil (proration battery)	Class 1 (high), > 30 m^3/d	5.0	2.0
		Class 2 (medium), > 6 m^3/d but ≤ 30 m^3/d	10.0	2.0
		Class 3 (low), > 2 m^3/d but ≤ 6 m^3/d	20.0	2.0
		Class 4 (stripper), ≤ 2 m^3/d	40.0	2.0

		Flow Rate	Maximum uncertainty of monthly volume	Single point measurement uncertainty
(v)	Well gas (proration battery)	> 16.9 $10^3 m^3/d$	5.0	3.0
		> 0.50 $10^3 m^3/d$ but ≤ 16.9 $10^3 m^3/d$	10.0	3.0
		≤ 0.50 $10^3 m^3/d$	20.0	10.0
(vi)	Well water		N/A	10.0

1.7.2 Gas Systems

		Flow Rate	Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas deliveries (sales gas)		N/A	2.0%
(ii)	Hydrocarbon liquid deliveries	Delivery point measures ≤ 100 m^3/d	N/A	0.5%
		Delivery point measures > 100 m^3/d	N/A	1.0%
(iii)	Plant inlet or total battery/group gas		5.0%	3.0%
(iv)	Plant inlet or total battery/group condensate (recombined)		N/A	2.0%
(v)	Fuel gas	> 0.50 $10^3 m^3/d$	5.0%	3.0%
		≤ 0.50 $10^3 m^3/d$	20.0%	10.0%

		Flow Rate	Maximum uncertainty of monthly volume	Single point measurement uncertainty
(vi)	Flare and vent gas		20.0%	5.0%
(vii)	Acid gas before compression		N/A	10.0%
	Acid gas after compression		N/A	3.0%
(viii)	Dilution gas		5.0%	3.0%
(ix)	Well gas (well site separation)	> 16.9 $10^3 m^3/d$	5.0%	3.0%
		≤ 16.9 $10^3 m^3/d$	10.0%	3.0%
(x)	Well gas (proration battery)		15.0%	3.0%
(xi)	Well condensate (recombined)		N/A	2.0%
(xii)	Total battery water		5.0%	N/A
(xiii)	Well water		N/A	10.0%

1.7.3 Injection/Disposal Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total gas	5.0%	N/A
(ii)	Well gas	N/A	3.0%
(iii)	Total water	5.0%	N/A
(iv)	Well water/steam	N/A	5.0%
	Produced water/steam at thermal *in situ* facilities	N/A	2.0%
(v)	Brine disposal well, see Section 15.2.9	N/A	5.0%

1.7.4 Heavy Oil - excluding Thermal In Situ Operations (from Section 12)

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas	N/A	3.0%
(ii)	Liquid products received into a cleaning plant, excluding the effect of S&W and density determination	N/A	1.0%
(iii)	Sales oil delivery point from a treatment facility	N/A	0.5%
(iv)	Test emulsion meter, excluding the effect of S&W determination	N/A	2.0%

1.7.5 Thermal In Situ Operations (from Section 12)

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas production or injection	N/A	3.0%
(ii)	Emulsion testing using grouped well metering when the subsurface drainage area has coalesced excluding the effects S&W determination		5.0%
(iii)	Emulsion test using metering for individual wells - excluding the effects S&W determination	N/A	2.0%
(iv)	Clean oil/bitumen sales	N/A	0.5%
(v)	Wellhead steam injection (CWE)	N/A	5.0%,
(vi)	All other steam measurement, including steam leaving a steam plant (CWE)	N/A	2.0%
(vii)	Liquid solvent injection	N/A	2.0%
(viii)	Fresh, brackish, or produced water delivered to or from an injection facility	N/A	2.0%
(ix)	Boiler feed water, boiler blowdown	N/A	2.0%
(iix)	Water disposal	N/A	2.0%

1.8 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 are visual tools showing the current physical layout of the facility. Schematics should be regularly reviewed and used by groups such as operations, engineering, and production accounting to ensure a common understanding. For the purpose of this Directive, process flow diagrams (PFD), piping and instrumentation diagrams, and process and instrumentation diagrams (P&ID) are not considered measurement schematics.

1.8.1 Measurement Schematics Requirements

The operator of record, the company who reports the monthly production to the Regulator generally via Petrinex, is responsible for creating, confirming, and revising any measurement schematics. The well licensee and physical operator shall provide all assistance they can. The schematics must be used by operations and production accounting to ensure that the reported volumes are in compliance with the Regulator's reporting and licensing requirements. How the required information is shown on a measurement schematic is up to the operator of record to decide as long as the measurement 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 18 months.

The measurement schematic must include the following:

1. Facility name, facility licensee name, and operator name if different
2. Legal Survey Location of surface facility and Unique Well Identifier (UWI), including downhole location, if different
3. Facility boundaries between each reporting facility with associated Petrinex codes and facility subtypes. For larger facilities, an optional field flow diagram may be used to show facility delineation. See Appendix 8 for an example.
4. Flow lines with flow direction that move fluids in and out of the facility(s) and those that connect the essential process equipment within the facility, including recycle lines and bypasses to measurement equipment. Identify if oil is tied into a gas system.
5. Flow split or diversion points (headers) with their Legal Survey Location if they are not on a well or facility lease site.
6. Process equipment that change the state or composition of the fluid(s) within the facility, such as separators, treaters, dehydrators, compressors, sweetening and refrigeration units, etc.
7. Measurement points and storage tanks or vessels that are used for estimating, accounting, or reporting purposes, including:
    a. Type of instrumentation (charts, EFM, or readouts)
    b. Type of meter(s) if applicable
    c. Testing or proving taps required by the Regulator
8. Fuel, flare, or vent take-off points – default to estimated if meter not shown.
9. Energy source (gas, propane, electricity) used for equipment if not metered or estimated as part of total site fuel.
10. Permanent flare points
11. Fresh water sources, such as lakes and rivers

UWIs and Legal Survey Locations are to be in a delimited format, such as 100/16-06-056-02W5/02 and 16-06-056-02W5, respectively.

Multiple facilities can be depicted 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:

Wells

1. A list of all producing, water source, injection/disposal, and shut-in wells.
2. Reporting event for wells with downhole commingled stratigraphic units or zones.
3. Identify mechanical lift, such as plunger lift, pump jack, etc.

SK	Default to ACTIVE if not shown.
AB	Default to FLOW if not shown.
BC	Default to Active if not shown

4. Suspended wells are optional, if shown, identify them as suspended.
5. Except for:
   a. Heavy Oil/Crude Bitumen Administrative Grouping (subtype 343) and Heavy Crude Oil Paper Battery (subtype 313): The well list is not required to be on the schematic but must state how many wells are in the battery and must be available upon request by the Regulator.
   b. Gas Multiwell Proration SW Saskatchewan and SE Alberta Batteries (subtypes 363 and 366): The well list is not required to be on the schematic but must state how many wells there are on each branch coming into the battery location and must be available upon request by the Regulator.
   c. Gas Test Battery (subtype 371) and Drilling and Completing Battery (subtype 381): No measurement schematic is required until the well is tied to a production battery and starts producing.

Process Equipment

1. Normally closed valves that can change production flow.
2. Identify if compressors are electric or gas drive. If they are gas drive, then the HP or KW rating is required unless fuel gas is measured as part of total fuel within a facility. Some cross-border facilities may be required to measure fuel for some compressors individually.
3. 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.
4. Pressure safety valves (PSV) are not required.

Measurement Points

1. Identify non-accounting meters if shown.
2. Originating facility ID or UWI/Legal Survey Locations for truck-in receipt points is not required.

Storage Tanks and Vessels

1. 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
2. Identify if the tank or vessel is underground or default to aboveground.
3. Identify optional non-reporting chemical storage or pop tanks if shown.
4. Identify if the tank or vessel is tied into a vapour recovery system (VRU) or flare system with the default being too vented.

SK	**A Measurement, Accounting and Reporting Plan (MARP) for Thermal In Situ Projects** For enhanced oil recovery projects requiring a MARP, the measurement schematic must include these additional items: 1. blowdown lines 2. ponds – volume and fluid type 3. meter ID and sample point ID 4. tank gauge 5. pumps 6. secondary measurement points
AB	**Measurement, Accounting, and Reporting Plan (MARP) for Thermal In Situ Oil Sands Schemes** For enhanced oil recovery schemes requiring a MARP, the measurement schematic must include these additional items: 1. blowdown lines 2. ponds – volume and fluid type 3. meter ID and sample point ID 4. tank gauge 5. pumps 6. secondary measurement points
BC	No Thermal *In Situ* Oil Sand Schemes in BC at this time.

1.8.2 Measurement Schematic Updates

Changes affecting reporting must be redlined on the measurement schematic at the field level when they occur and communicated to the production accountant at a date set by the operator of record to facilitate accurate reporting before the Petrinex submission deadline.

1. Physical changes, such as wells, piping, or equipment additions or removal, require a measurement schematic update.
2. Temporary changes within the same reporting period do not require a measurement 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 measurement schematic but must be available on request.

1.8.3 Implementation

SK	Operators must have measurement schematics for all the applicable facilities outlined in Directive PNG017 by April 1, 2018.
AB	Fully Implemented.
BC	Fully Implemented

No grandfathering for active facilities.

A facility that is reactivated must have an up-to-date measurement schematic within three months of reactivation or after the implementation period.

1.8.4 Measurement Schematic Availability

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

1. Facility licensee of the subject facility
2. The company that performs the volumetric reporting for the facility and the well licensee of wells within a reporting facility
3. The company that performs the product and residue gas allocations up to the allocation point(s)
4. Saskatchewan, Alberta and British Columbia Regulators or other cross-border Regulatory bodies
5. Operator of receipt/disposition points—all reporting measurement points for the facility only

1.9 Facility Delineation Requirements

Delineation of lease sites and geographic areas into reporting facilities is based on the measurement, accounting, and reporting rules described in:

SK	This Directive and *Directive PNG032 – Volumetric, Valuation and Infrastructure Reporting* (formerly known as *Directive R01*).
AB	AER's *Directive 017: Measurement Requirements for Oil and Gas Operations* and *Directive 007: Volumetric and Infrastructure Requirements*.
BC	BCOGC Measurement Guideline for Upstream Oil and Gas Operations Manual does not have a specific section for Facility Delineation Requirements. If further information is required contact OGCPipelines.Facilities@bcogc.ca.

Facility delineation requires accurate information on process flows and measurement points in the field, as well as a sound understanding of the Regulator facility definitions and facility subtypes outlined in the aforementioned directives.

Multiple measurement points and Regulatory flexibility can result in more than one way of delineating some facilities. However, the following general guidelines can be used.

1. All gas and liquid received into and delivered from a facility must be continuously or batch measured in a single phase.
2. Wells and the associated equipment are only linked to and reported under batteries (BT), injection facilities (IF), or water source facilities (WT).
   a. Gas wells are linked to and reported under gas batteries.
   b. Crude oil wells and bitumen wells are linked to and reported under crude oil batteries.
   c. Disposal wells are linked to and reported under disposal facilities.
   d. Injection wells are linked and reported under injection facilities.
   e. Source water wells:

SK	are linked to and reported under water source facilities (WT).
AB	may be linked to either a battery or, more commonly, the injection facility. If there is gas production, then linking to a subtype 902 battery will facilitate gas volumetric reporting.
BC	may be linked to either a battery, processing battery, injection station, or water hub facility. If there is gas production, then linking to a battery will facilitate gas volumetric reporting.

3. Measured and prorated wells must not be linked to the same battery and must be reported under separate reporting codes.

2 Calibration and Proving

Metering devices all require various types of maintenance to ensure operating conditions meet the uncertainty requirements outlined in Section 1 – Standard of Accuracy. This Section presents the base requirements and exemptions for maintaining metering devices.

The calibration and proving requirements stipulated in this Directive are applicable to measurement devices used to determine volumes for Regulator-required accounting and reporting purposes. These requirements are not applicable to measurement devices used only for a licensee's internal accounting purposes. The requirements are considered minimums, and a licensee may choose to apply more stringent requirements.

If a licensee wishes to deviate from these requirements or exemptions other than applying more stringent requirements, see Section 5: Site-Specific Deviation from Base Requirements to determine if the deviation requires submission of an application to and approval by the Regulator.

2.1 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 is, the more frequently it must be calibrated or proved. Example: For an annual frequency, if the last calibration was performed in May 2006, the operator has to perform another calibration by the end of June 2007 (end of the calendar quarter).

2.1.1 Frequency Exemptions

1. If the use or operation of a measurement device requiring monthly, bimonthly or quarterly calibration/proving is suspended for at least seven consecutive days, the scheduled calibration/proving may be delayed by the number of days the device was not in service. Documentation of the amount of time the device was not in service must be kept and made available to the Regulator on request. If this exemption is being applied, the licensee must attach a tag to the meter indicating that this exemption is in effect and the next scheduled calibration/proving date. This exemption is not applicable to measurement devices subject to calibration/proving frequencies that are semiannual 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, the countdown to the next required bench proving does not start until the meter is returned to service. The licensee must attach a tag to the meter indicating the installation date, but leaving the original proving tag intact.
3. The Regulator may request that calibration/proving of a meter be done at any time or may shorten or extend the due date for scheduled calibration/proving, depending on the specific circumstances at a measurement point.

2.2 Accuracy of Provers and Calibration Instruments

Provers and other instruments used for calibration of measurement devices must be tested for accuracy prior to first being used or immediately following any repairs (prior to being put back into service) or alterations being conducted on them, and periodically, in accordance with the following:

1. Portable provers must be calibrated every two years using measurement standards that are traceable to the standards listed in Section 2.2.1.
2. Stationary provers must be calibrated every four years using measurement standards that are traceable to the standards listed in Section 2.2.1.
3. Calibration instruments, such as manometers, thermometers, pressure gauges, deadweight testers, electronic testers, etc., must be tested for accuracy every two years against instruments having accuracy traceable to the standards listed in Section 2.2.1.
4. Master meters must be proved quarterly using a calibrated prover. The fluid used to prove the master meter must have properties 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.
5. 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.

2.2.1 Provers and Calibration Procedure Standards

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. The calibration and proving procedures must be in accordance with the following standards:

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 recommended procedures, or
4. Other applicable procedures accepted by an appropriate industry technical standards association.

Records of the foregoing accuracy tests must be kept for a minimum of three years following the expiry of the applicable test and provided to the Regulator on request.

2.3 Gas Meters

2.3.1 Gas Meter Calibration 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, such as differential pressure, static pressure and 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.

Calibration of gas meter elements requires the instrumentation to be subjected to various actual pressures, temperatures, and other values that are concurrently subjected to the calibration equipment. If the meter element or end device do not indicate the same value as the calibration equipment, adjustments must be made to the meter element and/or end device.

Some meter equipment technologies may require alternative equipment and procedures for calibration, which is acceptable provided that 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.

Orifice meters are commonly used to measure gas volumes. Gas orifice meters themselves (the meter run and orifice plate-holding device) do not require calibration/proving. However, the associated meter elements and the end devices to which they are connected must be calibrated, as described in Section 2.3.5.

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 calibrated 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.

2.3.2 Gas Meter Calibration Frequency

The frequency of meter element calibration and end devices must be:

1. Within the first calendar month of operation of a new meter
2. By the end of the calendar month following installation, after service or repairs have been made to the meter
3. Semiannually thereafter if the meter is used in a gas plant or for sales/delivery point, see Section 1.7.2 for details
4. Annually for all other meters

See Section 2.3.4 for the exemptions that extend calibration frequency.

2.3.3 Gas Meter Internal Inspection

A key contributor to meter accuracy is the condition of the internal components of the gas meter. Examples of internal components are orifice plates, vortex shedder bars, and turbine rotors. The procedure to inspect internal components is:

1. The internal component must be removed from service,
2. It must be inspected,
3. It must be replaced or repaired if found to be damaged, and
4. It can then be placed back in service.

This procedure must be in accordance with the following:

1. The required frequency for inspection of the gas meter primary element is semiannually for gas plant accounting meters and sales/delivery point meters and annually for all other gas meters.
2. Whenever possible, the inspection should be done at the same time as the calibration of the meter elements and end device, but to accommodate operational constraints the inspection may be conducted at any time, provided that the frequency requirement is met.

3. Inspections must be done in accordance with procedures specified by the API, the American Gas Association (AGA), other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.
4. 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.
5. A detailed record of the inspection documenting the condition of the internal components found and any repairs or changes made to the internal components must be kept for at least one year and provided to the Regulator on request.

2.3.4 Gas Meter Calibration and Proving Exemptions

1. If the "as found" calibration check of the gas meter confirms that the accuracy of all readings or outputs are within ±0.25% of full scale, with the exception of ±1°C for the temperature element, no adjustment of the instrumentation is required.
2. If meter elements and end devices have been found to not require adjustment for three consecutive calibrations, as indicated in item 1 above, the minimum time between routine calibrations may be doubled. A tag must be attached to the meter indicating that this exemption is being applied and the date of the next scheduled calibration. The records of the calibrations that qualify the meter for this exemption must be kept for at least one year and made available to the Regulator on request.
3. 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 calibration 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 calibration of both sets of equipment is required. A tag must be attached to the meter indicating that this exemption is being applied and the date of the next scheduled calibration. The records of the monthly comparisons and any calibrations that are done must be kept for at least one year and made available to the Regulator on request.
4. 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 2.3.1. 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 scenario 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. A detailed report indicating the details of the proving operation must be either left with the meter or readily available for inspection by the Regulator. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

5. For meters used in effluent 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 effluent correction factor (ECF) – water gas ratio (WGR) testing, see Section 7.4.
6. If the internal components of gas meters have been 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.
7. 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, provided that shutting down and depressuring the gas meter run to remove and inspect the internal components would be very disruptive to operations, require excessive flaring, or cause a safety concern, and:
    a. Previous internal component inspections have proven to be satisfactory; or
    b. The meter run is installed in a flow stream where the risk of internal component damage is low, e.g., sales gas, fuel gas; or
    c. The measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that internal component damage will be detected in a timely manner.
8. In the scenario of an orifice meter, if the orifice plate is mounted in a quick-change (senior) orifice meter assembly and when attempting to conduct 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 depressured 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, provided that:
    a. shutting down and depressuring the gas meter run to remove the orifice plate would be very disruptive to operations, require excessive flaring; or
    b. the orifice meter assembly is scheduled for repairs to be conducted the next time the gas meter run is shut down to eliminate the cause of the leak and allow future scheduled orifice plate inspections to be conducted; and one of the following must be true:
        i. Previous orifice plate inspections have proven to be satisfactory;
        ii. 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.; or
        iii. The measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that orifice plate damage will be detected in a timely manner.
9. Internal metering diagnostics may be used to determine if the structural integrity of the primary 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 recommended by the manufacturer. The operator must maintain documentation on the diagnostic

capability of the measurement system and make it available to the Regulator on request. An initial baseline diagnostic profile must be performed and documented during the commissioning process.

10. Single phase in-line proving of the gas meter may be used to determine if the primary 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.

Should the primary element inspections be deferred in accordance with any of the foregoing exemptions, the licensee must be able to demonstrate to the Regulator, on request, that the situation meets the conditions identified. If these exemptions are being used, it must be clearly indicated on a tag or label attached to the meter or end device. Evidence in battery or facility logs that the internal component inspection has been scheduled for the next shutdown must be available for inspection by the Regulator. For the purposes of these exemptions, 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 appears that it will allow sufficient time to conduct internal component inspection operations, the licensee should conduct those inspections prior to the conclusion of this unscheduled shutdown.

2.3.5 Orifice Meters with Chart Recorder Calibrations

The procedure for orifice meter chart recorder (meter element and end device) calibration must be in accordance with the following:

1. Pen arc, linkage, pressure stops, and spacing must be inspected and if necessary be adjusted.
2. 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.
3. The static pressure element must be calibrated at:
    a. zero;
    b. 50% of full span; and
    c. full span.
4. If a temperature element is in place, the temperature element must be calibrated at three temperatures:
    a. operating temperature;
    b. one colder temperature; and
    c. one warmer temperature.
5. If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points:
    a. operating temperature; and
    b. one other temperature.

    If the thermometer is found not to read within ±1°C it must be replaced.

6. If a thermometer or other temperature measuring device is not left in place and is transported by an operator 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 verification must be readily available for inspection by the Regulator for a period of one year.
7. Subsequent to the meter calibration, a tag or label must be attached to the meter or end device that identifies the meter serial number, orifice plate size and the date of the calibration.
8. 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 Regulator. If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.

2.3.6 EFM Meter Calibrations

For gas meters using digital (smart) transmitters connected to a remote terminal unit (RTU) or electronic flow measurement (EFM) at non-delivery measurement points, the transmitter may be verified or calibrated every five years in accordance with the following conditions:

1. The digital transmitter must be of one of the following types:
    a. A transmitter with a digital signal that is converted to an analog signal between 4 and 20 milliamperes, which is then sent to an RTU or EFM system
    b. A transmitter with a digital signal of one to five volts that is sent directly to an RTU or EFM system
    c. A digital transmitter connected to an RTU or EFM via other digital communication protocols, including Foundation Field Bus, Modbus, Profibus, Bristol Standard Asynchronous Protocol (BSAP), etc.

    This exemption applies only to digital transmitters as described above and does not apply to analog transmitters. Analog transmitters must be calibrated annually or to the frequency allowed by other exemption(s) in Section 2.3.4

2. For existing digital transmitters, if the last verification or calibration results do not necessitate further calibration in accordance with item #1 in Section 2.3.4 (i.e., the accuracy of all outputs were within ±0.25 per cent of full scale), then the next verification or calibration may be in five years.

3. New or newly installed digital transmitters must be verified or calibrated at the time of installation and then must be verified or calibrated after one year of operation. If the first-year verification or calibration results do not necessitate further calibration in accordance with item #1 in Section 2.3.4 (i.e., the accuracy of all outputs were within ±0.25 per cent of full scale) then the next verification or calibration may be in five years. If calibration is required after the first year of operation, then the transmitter must be verified or calibrated in the subsequent year.

4. If calibration is required during any fifth year verification or calibration, then the transmitter must be verified or calibrated in the subsequent year. Transmitters must be installed, set up, and verified or calibrated 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. Note that for new or newly installed digital transmitters, the differential pressure transmitter must be zero verified and adjusted at static operating pressure during the first-year verification or calibration. If the verification or calibration confirms that the zero reading is within ±0.25 per cent, then the differential pressure zero does not need to be verified again for the remainder of the five-year term.

5. If the static operating pressure changes by more than ±1750 kPa during the five years with no verification or calibration, then the differential pressure must be zero verified and adjusted at the new static operating pressure within the first month of the pressure change.

6. When verifying or calibrating the analog output signal transmitter, it is the analog output to the RTU or EFM system that must be compared to the reference value. Do not decouple the digital transmitter from the analog output to assess only the digital signal.

7. The output signal from the transmitter must match the received value at the RTU/EFM system.

8. A tag must be attached to the transmitter indicating that this exception is being applied and the date of the next scheduled calibration. The records of the calibrations that qualify the meter for this exception must be kept for at least five years and made available to the Regulator on request.

The procedure for calibration of an EFM system must be in accordance with the following:

1. For digital transmitters, as defined above, in Section 2.5.4 (1), the differential pressure element must be calibrated at:
    a. zero;
    b. 50% of calibrated full span; and
    c. calibrated full span.
2. For analog transmitters, the differential pressure element must be calibrated at:
    a. zero;
    b. 50% of full span (ascending);
    c. full span (ascending); and
    d. either 80% and 20% or 75% and 25% of full span (descending).
3. A zero check of the differential under normal operating pressure must be done before and after the calibration.
4. The static pressure element must be calibrated at:

   a. zero;
   b. 50% of full span; and
   c. full span

5. If a temperature element is in place, the temperature probe must be verified at two temperatures:
   a. the normal operating temperature; and
   b. one colder temperature or one warmer temperature.

   The temperature probe must calibrated or replaced if found not to be within ±1°C. Additionally, if an EFM system is used, the temperature probe and transmitter must be verified as a single unit, not decoupled and verified separately, and the indicated value of the transmitter that is sent to the EFM should be compared to the reference value.

6. Subsequent to the meter calibration, a tag or label must be attached to the meter or end device that identifies the meter serial number, orifice plate size and the date of the calibration.
7. A detailed report indicating the tests conducted on the meter or end device 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 Regulator. If the detailed report is left with the meter or end device, the foregoing requirement relating to the tag or label is considered to be met.
8. If data from the meter or end device 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.

2.4 Liquid Meters

Oil and other liquid production and disposition volumes except gas well condensate under certain conditions, see Section 2.6, must always be reported as liquid volumes at 15°C and either equilibrium vapour pressure or 101.325 kilopascals (kPa) absolute pressure.

2.4.1 Liquid Meter Proving

The frequency and methodology for calibrating the meter element are the same as in Section 2.3.

Meters used to measure hydrocarbons, water, and emulsions are subject to the following general proving requirements. However, there are additional specific requirements depending on the fluid types, as detailed in Sections 2.4 through 2.8.

1. The design and operation of the entire meter system must meet or exceed the meter manufacturer’s specifications.
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 recommended operating range.

3. The meter must be installed upstream of a snap acting control/dump valve, if present.
4. The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter. Tank-type volumetric or gravimetric provers must be connected downstream of the meter and downstream of a snap acting control/dump valve, but other provers, such as ball provers, pipe provers, or master meters, may be connected either upstream provided there is no gas breakout or downstream of the meter before a snap acting control/dump valve. The location of the proving taps will dictate the proving method(s) that can be used.
5. A new hydrocarbon meter must be proved within the first calendar month of operation or immediately following any repairs being conducted on the meter or any changes to the meter installation. Note that the resultant meter factor must be applied back to the volumes measured after the commencement of operation, repair, or change. A new water meter must be proved within the first 3 months of operation or immediately following any repairs being conducted on the meter or any changes to the meter installation and no retroactive application of meter factor is required.
6. The meters must be proved according to the frequency in Table 2.1.

Table 2.1. Meter proving frequency requirements and proving methods

		Proving method					
Application	**Meter type**	**Pipe/ compact/ small volume prover**	**Master meter**	**Volumetric vessel/tank prover**	**Bench proving**	**Calibrate transmitter**	**Proving frequency**
Live oil/condensate (meter at well/battery or test meter)	PD/turbine	A[1]	A	A	A[2]	N/A	Annual[7]
	Vortex/Coriolis	A[3]	A[3]	A[3]	A[2, 3]	N/A	Annual[7]
	Differential producer	N/A	N/A	N/A	N/A	A	Annual
Live oil/condensate (gas plant inlet separator or cross border)	PD/turbine	A[3]	A	A	A[2]	N/A	Semi-annual
	Vortex/Coriolis	A[3]	A[3]	A[3]	A[2, 3]	N/A	Semi-annual
	Differential producer	N/A	N/A	N/A	N/A	A	Semi-annual
Dead oil, stable HVP liquids, or delivery points[4]	PD/turbine	A	A	A[5]	N/A	N/A	Monthly[6]
	Coriolis/ ultrasonic	A	A	A[5]	N/A	N/A	Monthly[6]
Water	PD/turbine	A	A	A	A[2]	N/A	Annual[7]

Application	Meter type	Proving method					Proving frequenc y
		Pipe/ compact/ small volume prover	Master meter	Volumetric vessel/tank prover	Bench proving	Calibrate transmitter	
	Vortex/Cori olis/ magnetic/ ultrasonic	A[3]	A[3]	A[3]	A[2, 3]	NA	Annual[7]
	Differential producer	N/A	N/A	N/A	N/A	A	Annual

1 A = acceptable method: N/A = not applicable.
2 See Sections 2.5.1, 2.6.2, and 2.8 for bench proving information.
3 For meter proving exemptions, see Section 2.4.2.
4 A delivery point may be emulsion, crude oil, crude bitumen, condensate, LPGs, ethane, or NGLs.
5 For live oil/condensate delivery point only.
6 If flow is less than 100 m^3/day, quarterly proving is acceptable. For other exemptions, see Section 2.4.2.
7 If flow ≤ 2.0 m3/day, biennial proving is acceptable

7. The meter must be proved in line at normal operating conditions unless otherwise exempt by the Regulator.
8. 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.
9. Each proving run must consist of a representative volume of the normally metered fluid being directed into the prover or through the master meter.
10. 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.
11. An acceptable initial proving, also referred to as the first proving of a new or repaired meter, and all subsequent proving must consist of the number of consecutive runs, each with a meter factor (MF) within the average of all applicable runs, as specified in Table 2.2. The resultant meter factor will be the average of all the applicable run meter factors. Proving procedures using more than the specified number of runs are allowed, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.

Table 2.2. Proving requirements for hydrocarbons, water, and emulsions

Hydrocarbon meter type	Initial prove: number of required consecutive runs	Subsequent prove: number of required consecutive runs		Maximum MF deviation allowed from average of all applicable runs (%)
		As found MF ≤ ± 0.5% of previous	As found MF > ± 0.5% of previous	
Live oil – field proving (see 2.5)	4	1	4	1.5
Live oil – shop proving (see 2.5)	4	4	4	0.5
Dead oil, condensate at equilibrium, high vapour pressure liquids (see 2.5 & 2.6.1)	3	1	3	0.25
Live condensate – field proving (see 2.6.2)	4	1	4	2

Hydrocarbon meter type	Initial prove: number of required consecutive runs	Subsequent prove: number of required consecutive runs		Maximum MF deviation allowed from average of all applicable runs (%)
		As found MF ≤ ± 0.5% of previous	As found MF > ± 0.5% of previous	
Live condensate – shop proving (see 2.6.2)	4	4	4	0.5
Water– field proving (see 2.8)	4	1	4	1.5
Water– shop proving (see 2.8)	4	4	4	1.5

12. Whenever possible, the inspection of internal components should be done at the same time as the meter end device calibration, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.
13. 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 Regulator. If the detailed report is left with the meter, the requirement stated in point #14 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.
14. Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the type of prover or master meter used, and the average meter factor. 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 result in corrected volumes.
15. LACT meters may use the proving procedure in API-MPMS, Chapter 4: Proving Systems, instead of the procedure in Section 2.4.

2.4.2 Liquid Meter Proving Exemptions

1. If a meter used to measure fluids at flowline conditions is a type that uses no internal moving parts, e.g., orifice meter, vortex meter, cone meter, Coriolis meter or ultrasonic meter, it does not require proving, provided that all of the following conditions are met:
    a. The flow through the meter must be continuous (not intermittent) or the meter must qualify for bench proving or be a Coriolis-type meter with sufficient structural integrity as determined by internal diagnostics (see point b) and maintained within the rates specified by the meter manufacturer as providing accurate measurement. This exemption does not apply to master meter proving (see Section 2.2 for requirement). If there is a dump valve as part of the Coriolis or bench-proved measurement system, the dump valve must be checked for leaks at the same inspection or proving frequency set out in Table 2.1.

b. The design and operation of the entire meter system must be in accordance with the meter manufacturer's specifications.

c. The meter element/end device(s) must be calibrated at the frequencies specified in Section 2.3, using procedures specified in Section 2.3, by the API MPMS, the AGA, the device manufacturer, or other applicable industry-accepted procedures, whichever are most appropriate and applicable.

d. The internal components of the primary element must be removed from service at the same frequency as indicated in Table 2.1, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by the API, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate. Internal metering diagnostics may be used to determine if the structural integrity of the primary 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 recommended by the manufacturer. An initial baseline diagnostic profile must be performed and documented during the commissioning process. The operator must maintain documentation on the diagnostic capability of the measurement system and make that available to the Regulator on request.

e. If a meter is to be proved just like one with internal moving parts, no internal inspection is required.

f. Whenever possible, the inspection of internal components should be done at the same time as the meter end device calibration, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.

g. A tag or label must be attached to the meter (or end device) that identifies the primary device serial number and the date of the calibration.

h. A tag or label must be attached to the meter (or end device) that identifies the primary device serial number, the date of the internal components inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).

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 Regulator. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

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

2. If the volume of fluid measured by a delivery point or LACT meter does not exceed 100 m^3/d, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter measures ≤ 100 m^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 > 100 m^3/d.

3. For delivery point or LACT meters, if the meter factor has been found to be within 0.5 per cent of the previous factor for the average of the previous factor for three consecutive months, 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 to not be within 0.5% of the previous factor.

4. For delivery point meters that measure trucked-in oil, emulsion, and condensate and that have no moving internal parts (e.g., Coriolis meter, ultrasonic meter, orifice meter, vortex meter, cone meter), the meter may be proved semiannually if the current meter factor is within 0.5 per cent of the average of the previous three monthly factors. The tag attached to the meter must clearly indicate that the meter has been found to have consistent meter factors and is on a semiannual proving frequency. The required proving frequency will revert back to monthly whenever the meter factor determined during a proving is not within 0.5 percent of the average of the previous three factors. The meter must requalify for the exemption before the proving frequency can again be extended to semiannual. The meter must be proved following repairs to the meter changes to the metering installation.

5. If a meter that required internal inspection is used to measure liquid hydrocarbons and no meter bypass is installed, it is acceptable to defer a scheduled internal component inspection until the next time the liquid meter run is shut down, provided that shutting down and depressuring the meter run to remove and inspect the internal components would be very disruptive to operations or present a safety concern and:

    a. previous internal component inspections have proven to be satisfactory; or

    b. the meter run is installed in a flow stream where the risk of internal component damage is low, for example. processed or filtered liquids; or

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

2.5 Oil Meters

Live oil and dead oil require distinctly different proving procedures:

1. Live oil - Live oil meters are typically those used to measure volumes of oil or oil/water emulsion produced through test separators, but they also include meters used to measure well or group oil or oil/water emulsions that are delivered to other batteries or facilities by pipeline prior to the pressure being reduced to atmospheric. If oil production is measured 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 upon pressure reduction.

2. Dead oil - Dead oil meters are typically those used for delivery point measurement of clean oil that has been degassed to atmospheric pressure. These meters may be found measuring oil being pumped from a battery into a pipeline or measuring oil being pumped from a truck into a pipeline terminal, battery, or other facility. No consideration for gas in solution is required when proving meters used to measure dead oil.

2.5.1 Additional Proving Requirements for Live Oil Meters

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

Additional proving requirements for live oil are as follows:

1. If the proving procedure includes degassing the prover to physically reduce the pressure of the hydrocarbons to atmospheric pressure:
    a. The prover must be a tank-type volumetric or gravimetric prover;
    b. Each proving run must consist of a representative volume of hydrocarbons or hydrocarbons/water emulsion being directed through the meter and into the prover and the liquid volume then being 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; and
    c. 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.
2. If the proving procedure uses a shrinkage factor, rather than degassing, to adjust the prover volume to atmospheric conditions:
    a. A shrinkage factor representative of the fluid passing through the meter must be determined and used to adjust the meter volumes to atmospheric conditions.
        i. 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; and
        ii. The shrinkage factor must be based upon analysis of a sample of the metered fluid taken at normal operating conditions (see Section 14.3);
    b. Whenever the operating conditions at the meter experience a change that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based upon analysis of a sample of the metered fluid taken at the new operating conditions. Consideration must be given to proving the meter at the new operating conditions to determine if the meter factor has been affected; and

c. 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.

3. When proving a test oil meter, a well that is representative of the battery'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 with production characteristics that vary significantly from the average, consider determining specific meter factors to be used for each of those wells.

4. In the scenario 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.

5. In the scenario of a live oil delivery point meter, the meter factor must not include a correction factor for temperature. The meter must either be temperature compensated or a fluid temperature must be taken daily and the metered volume must be corrected to 15°C. This requirement does not apply to meter technologies that do not require correction for temperature.

2.5.1.1 Oil Meter Exemptions

1. *In situ*ations where individual well production rates are so low that proving a test oil meter in accordance with the requirements listed in Section 2.5.1 would require more than one hour for an individual proving run, it is acceptable to modify the proving procedures. The following modifications, in order of the Regulator's 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 those 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.

   The detailed proving report must clearly indicate if any of the aforementioned modifications was used to prove the meter.

2. A live oil meter may be removed from service and proved in a meter shop:

SK	a. If the meter is used to measure test volumes of non-heavy oil or emulsion and the average rate of flow of oil in the emulsion streams of all the wells tested through the meter is ≤ 2 m^3/d and no well exceeds 4 m^3/d of oil production in the emulsion stream; or b. If the meter is used to measure test volumes of heavy oil or emulsion (density ≥ 920 kg/m^3)

AB	a. If the meter is used to measure test volumes of non-heavy oil or emulsion, the average rate of flow of oil/emulsion of all the wells tested through the meter is ≤ 2 m^3/d and no well exceeds 4 m^3/d of oil/emulsion production; or b. If the meter is used to measure test volumes of heavy oil/emulsion (≥ 920 kg/m^3)
BC	See *Measurement Guidelines*

3. Shop proving is to be conducted in accordance with the following in addition to the general procedure in Section 2.4 where applicable:
   a. The meter installation must be inspected as follows, and corrective action must be taken when required:
      i. The flow rate through the meter must be observed to verify that it is within the manufacturer's recommended operating ranges; and
      ii. The dump valve must not be leaking with no flow registered between dumps.
   b. 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; and
      ii. Corrections for the temperature and pressure of the proving fluid must be made, where applicable.

   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, the shrinkage factor must be determined to correct for the effect of the gas in solution and provide that factor to the meter calibration shop so it may be built into the meter factor.

2.6 Condensate Meters

Condensate is subject to two different sets of measurement, accounting, and reporting rules. If condensate volumes are measured and delivered at equilibrium vapour pressure, the volume must be determined and reported as a liquid volume at 15°C and equilibrium vapour pressure. If condensate volumes are measured and delivered at flowline conditions, the volume must be determined at flowline pressure and corrected to 15°C, but the volume is reported as a gas equivalent volume at base conditions (101.325 kPa absolute and 15°C).

2.6.1 Proving Condensate Meters at Equilibrium Conditions

Meters that measure condensate 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 exemptions applicable to meters used for dead oil measurement (see Sections 2.4 and 2.5).

2.6.2 Proving Condensate Meters at Flowline Conditions

When a meter that requires proving is used to measure condensate at flowline conditions, it must be subjected to the proving requirements in Section 2.4.

2.6.2.1 Condensate Meter at Flowline Conditions Proving Exemptions

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

1. If the meter is used to measure condensate production on a continuous or intermittent basis, the rate of flow through the meter must be ≤ 2 m^3/d or it must be ≤ 3 m^3/d with the gas equivalent volume of the daily condensate volume being ≤ 3.0% of the daily gas volume related to the condensate production. 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.
2. The meter installation must be inspected as follows, and corrective action must be taken where required:
   a. The flow rate through the meter must be observed to verify that it is within the manufacturer’s recommended operating ranges; and
   b. The dump valve must not be leaking with no flow registered between dumps.

2.7 Other Liquid Hydrocarbon Meters

Meters used to measure other high vapour pressure liquid hydrocarbons, such as propane, butane, pentanes plus, gas liquid/liquid petroleum gas (NGL/LPG), etc., are subject to the same proving requirements and exemptions set out in Sections 2.4 and 2.6.1.

2.8 Water Meters

If a meter is used to measure water production, injection, or disposal or injection of other water-based fluids, in addition to the requirements in Section 2.4:

1. The meter must be installed and proved within the first three months of operation. Note that the meter factor may be assumed to be 1.0000 until the first proving is conducted.
2. 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.

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. 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 average 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, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.

Following the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the average meter factor. 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 result in corrected volumes.

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 Regulator. 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 recommended by the manufacturer.

Following the calibration, a tag or label must be attached to the product analyzer that identifies the analyzer serial number and the date of the calibration. 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 Regulator. 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 Calibration

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 adhere to at least one of following list of procedure standards, as available and applicable:

1. The device manufacturer’s recommended procedures;
2. Procedures described in the API Manual of Petroleum Measurement Standards; or
3. Other applicable procedures accepted by an appropriate industry technical standards association.

A record of the calibration must be made available to the Regulator on request.

2.10.2 Delivery Point Measurement Calibration

If automatic tank gauge devices are used to indicate fluid levels in tanks for delivery point measurement of oil or oil/water 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 list of procedure standards, as available and applicable:

1. The device manufacturer’s recommended procedures;

2. Procedures described in the API Manual of Petroleum Measurement Standards; or
3. Other applicable procedures accepted by an appropriate industry technical standards association.

A record of the calibration must be made available to the Regulator on request.

2.10.2.1 Delivery Point Calibration Frequency Exemption

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 from monthly 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 exemption must be kept and made available to the Regulator on request. The calibration frequency will revert back to monthly whenever the accuracy is found to not be within 0.5% of full scale.

2.11 Manual Tank Gauges for Oil Measurement

Tank gauging refers to determining levels in a tank and using those levels to calculate a volume increase or decrease in the tank. The level may be determined by using an automatic tank gauge device or by manually determining the level with a gauge tape. In either scenario, the volume of the tank relative to its height at any given point must be determined. This is referred to as the tank calibration, or tank strapping, and results in the creation of a tank gauge table.

2.11.1 Inventory Measurement Calibration

If tank gauging is used only for monthly inventory measurement, specific tank calibration procedures are not required. It is acceptable to use gauge tables provided by the tank manufacturer or, if those are unavailable, generic gauge tables applicable to the tank size/type being used.

2.11.2 Delivery Point Measurement Calibration

If tank gauging is used for delivery point measurement of oil or oil/water emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, the specific tanks being used must be calibrated on site within the first month of operation and any time the tank is damaged or altered. The calibration must result in the creation of a gauge table for each tank, which must then be used in conjunction with tank gauge readings to determine volumes. Calibration procedures must be in accordance with applicable methods stipulated in the API *Manual of Petroleum Measurement Standards*.

A record of the calibration must be made available to the Regulator on request.

2.12 Weigh Scales

Weigh scales used to measure oil/water emulsion and clean oil receipts at batteries, custom treating plants, 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; and
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:

1. Zero check: Determine if the scale reads zero with no weight on the scale;
2. Add a 10 kg standard weight: Determine if the scale reads 10 kg;
3. Remove the 10 kg standard weight: Determine if the scale returns to zero;
4. Add a test load consisting of 10 000 kg of standard weights or, alternatively, durable object(s) of known weight (minimum 5000 kg): Determine if the scale reads the correct weight of the test load (acceptable error is ±0.2% of the test load);
5. Add a loaded truck, typical of the loads routinely handled by the scale: Note the total weight of the test load and truck;
6. 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); and
7. Remove the truck: Determine if the scale returns to zero with no weight on the scale.

If as a result of the aforementioned 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.

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 Regulator on request. This record must include the following information:

1. Make, model, serial number, and capacity of the weigh scale and any associated equipment;
2. Date of the accuracy test;
3. Details of the tests performed and the results noted; and
4. Details regarding any alterations or calibration performed on the weigh scale.

2.12.1.1 Weigh Scale Test Frequency Exemptions

1. If the volume of fluid measured by a weigh scale does not exceed 100 m^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 ≤ 100 m^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 100 m^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.

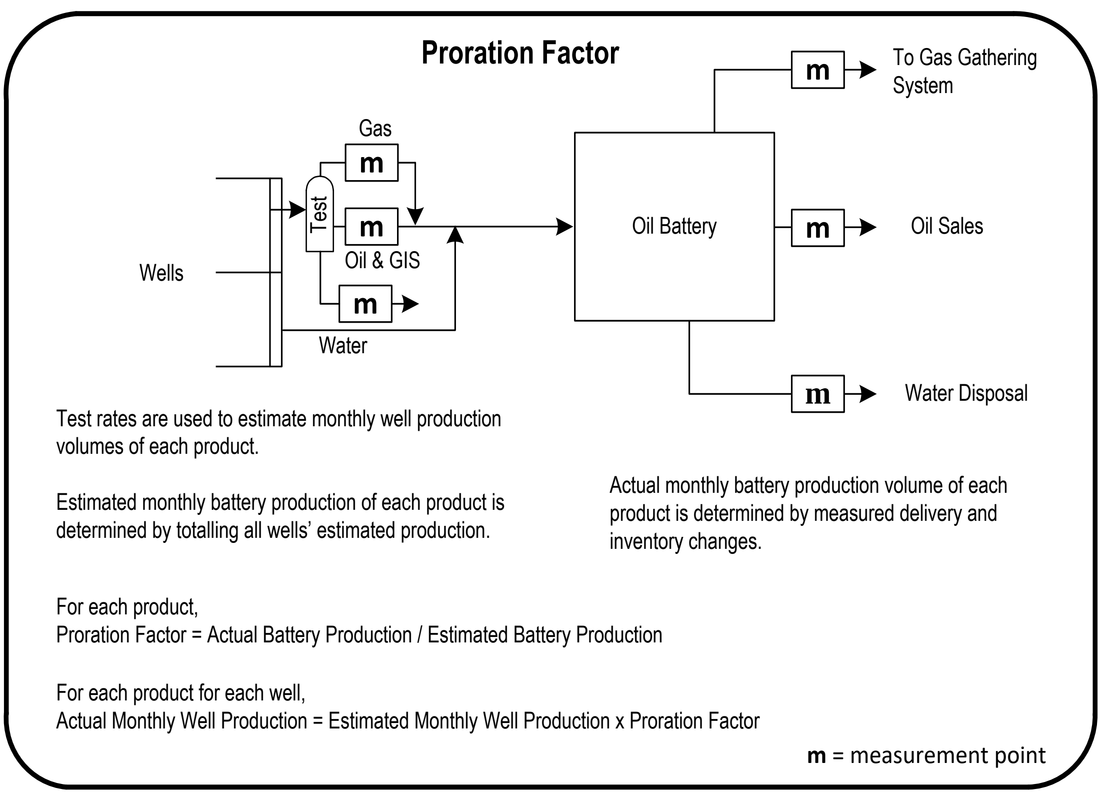
3 Proration Factors, Allocation Factors, and Metering Difference

3.1 Proration Factors and Allocation Factors

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

In the scenario of an oil proration battery (Figure 3.1), the oil, gas, and water produced by individual wells are not continuously measured. 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 is totaled to arrive at the battery's total monthly estimated production. The total actual oil, gas, and water production volumes for the battery are determined, 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 subject to proration.

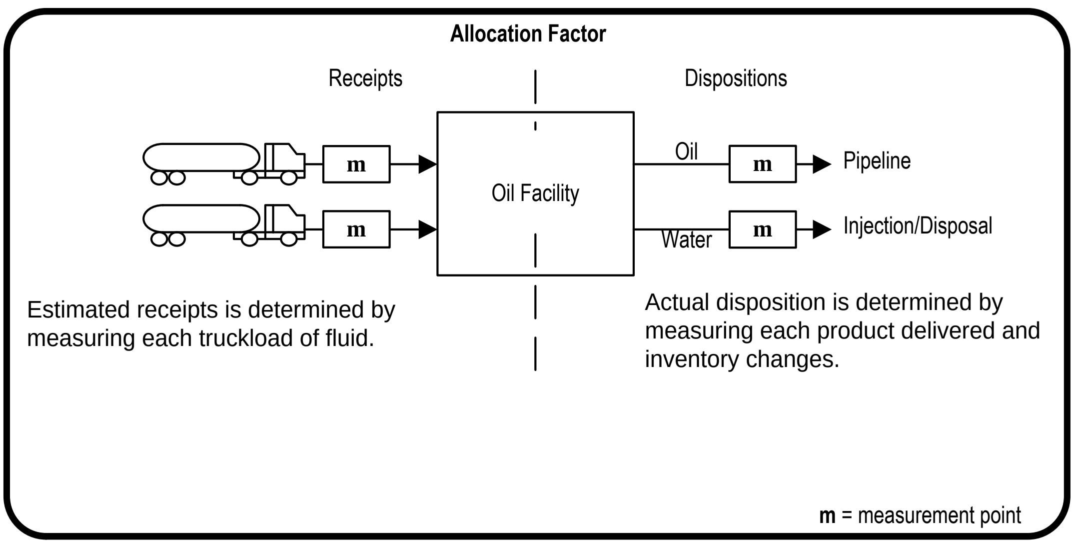
Figure 3.1. Proration Factor



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 oil terminals (Figure 3.2). The name of the factor has been chosen to reflect the differences between batteries that receive fluids from wells through flow lines where proration factors are used and facilities that receive fluids from batteries 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 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.

SK	Examples of how to calculate and report the proration and allocation factors can be found in *Directive PNG032* and Section 6 of Directive PNG017.
AB	Examples of how to calculate and report the proration and allocation factors can be found in Manual 011.
BC	Examples of how to calculate and report the proration and allocation factors can be found in BC OGC Directives.

Figure 3.2



The allocation factors discussed in this section 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 Regulator Standards of Accuracy (Section 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 the acceptable factor ranges, or targets, for different products may be different due to the products being subjected to different levels of uncertainty. For example, the acceptable factor ranges for oil and water in a non-heavy oil proration battery 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 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 bias errors.

3.1.1 Acceptable Ranges for Proration and Allocation 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. The Regulator requires proration factors and allocation factors to be monitored by operators and used as a warning flag to identify when the measurement system at a facility is experiencing problems that require investigation.

The Regulator deems the ranges of proration factors and allocation factors indicated in this section to be acceptable ranges. When a factor is found to exceed these limits, the licensee is required to investigate the cause of the factor being outside the acceptable range and document the results of the investigation and the actions taken to correct the situation. Action required by the operator regarding the investigations into the cause of the proration or allocation factor being outside the acceptable range may include, but is not limited to:

1. Verifying S&W measurement practices.
2. Verifying related fluid measurement system performance.
3. Proving or calibration of measurement equipment.
4. Inspecting the primary element for meters with no internal moving parts.

The Regulator acknowledges that at some facilities, physical limitations or the economics applicable to a particular situation may prohibit the resolution of situations where factors are consistently in excess of the acceptable ranges indicated in this section. In this scenario, the licensee must document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the Regulator, but must be available to the Regulator on request for audit.

If the cause of a factor being outside these acceptable ranges is determined and the error can be quantified, the Regulator requires the reported volumetric 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, amendments are not required to be submitted.

3.1.1.1 Proration Factors

Table 3.1

Facility	Oil	Gas	Water
Oil battery not producing heavy oil (Petrinex subtype in AB and SK: 322)	0.95000 – 1.05000	0.90000 – 1.10000	0.90000 – 1.10000
Oil battery producing heavy oil – primary production and waterflood operations (Petrinex subtypes in AB: 342 and 322 for heavy oil outside the oil sands areas and Petrinex subtypes in SK: 322 and 327)	0.85000 – 1.15000	no stated expectation due to generally low production volumes	0.85000 – 1.15000
Oil battery– thermal recovery operations (Petrinex subtypes in AB: 344 and 345 and Petrinex subtypes in SK: 344)	0.85000 – 1.15000	no stated expectation due to the nature of thermal production	0.85000 – 1.15000
Gas battery – SW Saskatchewan and SE Alberta (Petrinex subtypes in AB: 363 and 366 and Petrinex subtypes in SK: 363)		0.80000 – 1.20000	
Gas battery – outside SW Saskatchewan and outside SE Alberta (Petrinex subtypes in AB: 364 and 367 and Petrinex subtypes in SK: 364)		0.90000 – 1.10000	0.90000 – 1.10000
Gas battery – effluent measurement (Petrinex subtype in AB and SK: 362)		0.90000 – 1.10000	0.90000 – 1.10000

3.1.1.2 Allocation Factors

Table 3.2

Facility	Oil	Gas	Water
Custom Treating facilities (Petrinex subtypes in SK & AB: 611 and 612)	0.95000 – 1.05000		0.90000 – 1.10000
Terminals (Petrinex subtypes 671, 672, 673, 674 and 675)	0.95000 – 1.05000		

3.1.1.3 Target Range Proration Factor Exemption

SK	The Regulator acknowledges that at some multiwell oil proration batteries where all wells in the battery produce ≤ 2 m^3/d of oil or the majority of the wells in the battery produce ≤2 m^3/d of oil and no well produces > 6 m^3/d of oil (based on average rates determined semiannually) may be prohibited in the resolution of situations where proration factors are consistently in excess of the acceptable ranges indicated in Table 3.1. In this scenario, the licensee must document the reason(s) that prohibit further actions from being taken. This information does not have to be routinely submitted to the Regulator, but must be available to the Regulator on request for audit. Licensees with low volume oil producing wells are still required to determine proration factors as per Section 6 and submit the proration factors monthly to Petrinex.
AB	An exemption to the foregoing procedure is allowed for conventional oil proration batteries if, based on average rates determined semiannually, • all wells in the battery produce ≤ 2 m3/d of oil, or • the majority of the wells in the battery produce ≤ 2 m3/d of oil and no well produces > 6 m3/d of oil. In this case, the licensee 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 result.
BC	An exemption to the foregoing procedure is allowed for conventional oil proration batteries if, based on average rates determined semiannually, • all wells in the battery produce ≤ 2 m3/d of oil, or • the majority of the wells in the battery produce ≤ 2 m3/d of oil and no well produces > 6 m3/d of oil. In this case the licensee 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 result.

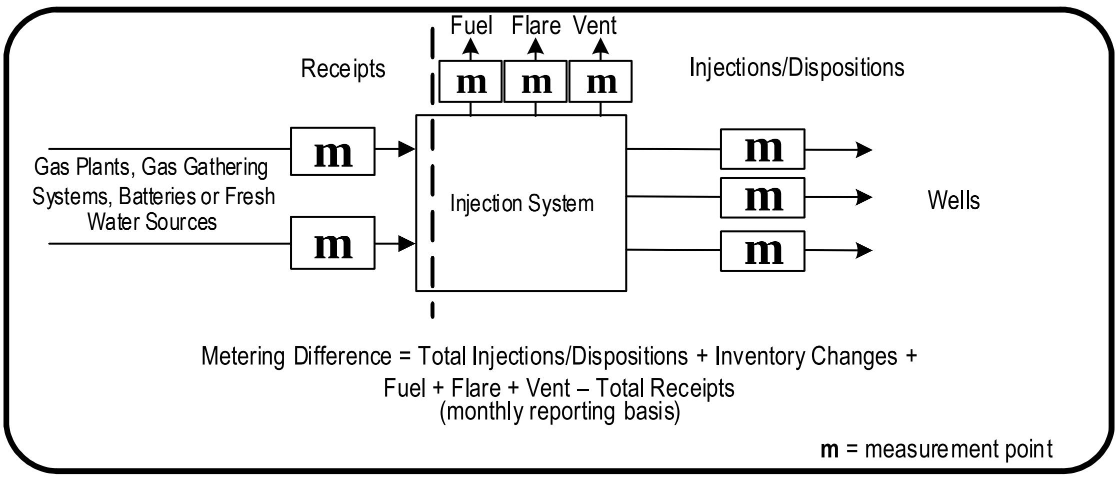
3.2 Metering Difference for Fluids other than Oil

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

Metering difference may be used as follows:

Injection/disposal facilities (Figure 3.3) - Receipts into these facilities are typically measured prior to being split up and delivered to individual wells, where each well's volume is metered prior to injection/disposal.

Figure 3.3

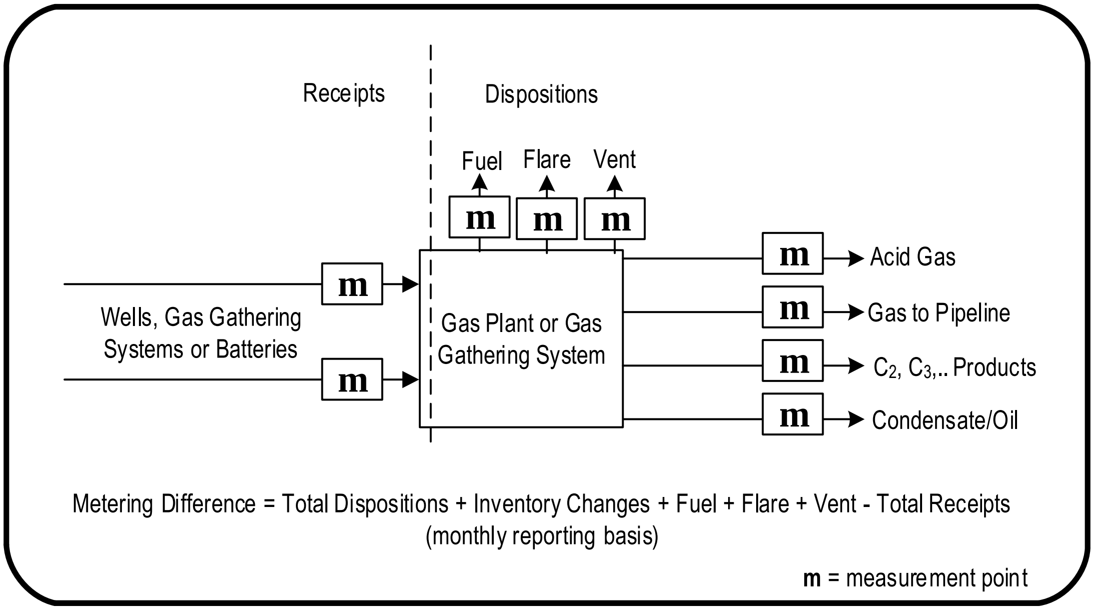


Batteries - Receipts into these facilities including production from wells and receipts from other facilities, are typically measured and the resultant product is measured prior to delivery to another facility. Proration factors continue to apply at proration batteries to reconcile estimated and actual production volumes.

Gathering systems (Figure 3.4) - Receipts into these facilities are typically measured prior to being subjected to some sort of limited processing, which may include liquids removal and compression, and the resultant product(s) is measured prior to delivery to a sales point or to a gas plant for further processing.

Gas plants (Figure 3.4) - Receipts into these facilities are typically measured prior to being processed into salable products, and those products are measured prior to delivery to a sales point.

Figure 3.4



3.2.1 Acceptable Metering Difference Range

If measurement and accounting procedures meet applicable requirements, metering differences up to ±5.0% of the total inlet/receipt volume are deemed to be acceptable. The Regulator requires the metering difference to be monitored by licensees and used as a warning flag to identify when the measurement system at a facility is experiencing problems that require investigation.

When a metering difference is found to be equal to or greater than 5.0%, the licensee is required to investigate the cause of the unacceptable metering difference and document the results of the investigation and the actions taken to correct the situation. The Regulator acknowledges that in some 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 range indicated. In such scenarios, the licensee must document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the Regulator, but must be available to the Regulator on request for audit.

If the cause of an unacceptable metering difference is determined and the error can be quantified, the Regulator requires the incorrectly reported production data to be amended, thereby bringing the metering difference back into an acceptable range. 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, amendments are not required to be submitted.

4 Gas Measurement

This section presents the base requirements and exemptions for gas measurement from any source in the upstream and midstream oil and gas industry that are used for determining volumes for reporting to the Regulator.

4.1 General Requirements

All gas production and injection must be continuously and accurately measured with a measurement device or determined by engineering estimation unless:

1. exemption conditions described in this section are met; or
2. site-specific Regulator approval has been obtained

A gas measurement system may deviate from these base requirements if:

1. the conditions in Section 4.3.8 are met; or
2. the deviation is provided for in Section 1: Standards of Accuracy.

Monthly gas volumes must be reported in units of 10^3m^3 and rounded to 1 decimal place as per:

SK	*Directive PNG032: Volumetric, Valuation and Infrastructure Reporting in Petrinex*
AB	*Directive 007: Volumetric and Infrastructure Requirements*
BC	See BC OGC Directives.

Standard or base conditions for use in calculating and reporting gas volumes are 101.325 kPa absolute and 15°C.

Metering equipment must be kept in good operating condition.

4.2 Gas Measurement and Accounting Requirements for Various Facility Subtypes

This section outlines specific requirements for various facility subtypes. General measurement requirements, including meter design, operation, and maintenance requirements are detailed in other sections.

SK	As of January 1, 2020, Operators must report FUEL, FLARE and VENT volumes based on the definitions listed in the current version of Directive PNG017 Appendix 2. Effective January 1, 2020, uncombusted gas released to the atmosphere, including fugitive emissions, must be reported as vent gas using the methodologies in *Guideline PNG035: Estimating Venting and Fugitive Emissions*. When a fugitive emission is discovered the operator must estimate and report the amount of gas released from the time of discovery until the fugitive emission is eliminated. If, at a facility, all gas that is received or produced is vented including casing gas, then no fugitive emissions need to be reported. All documentation relating to the fuel, flare and vent including fugitive emission must be kept for ER to review.
AB	See *Directive 017: Measurement Requirements for Oil and Gas Operations*
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

4.2.1 Oil Batteries

1. All wells linked to the battery for reporting purposes must be classified as oil wells.
2. Subject to Section 5.5 exemption criteria, all wells in a multiwell battery must be subject to the same type of measurement.
3. Production from gas batteries or other oil batteries may not be connected to an oil proration battery upstream of the oil battery group gas measurement point unless specific criteria are met and/or Regulator approval of an application is obtained. See Section 5: Site-specific Deviation from Base Requirements, Measurement by Difference.
4. Any oil facility such as well sites, batteries, compressors and oil satellites operators may estimate fuel gas use volumes for sites with an annual average fuel gas use of 0.50 $10^3m^3/d$ or less.

SK	This requirement to meter the fuel gas exceeding 0.50 $10^3m^3/d$ applies. The 0.50 $10^3m^3/d$ measurement limit for fuel gas also applies to flare and vent gas volumes, excluding heavy crude oil. At sites where fuel gas metering is required, up to 0.50 $10^3m^3/d$ may be estimated.
AB	For any site that was constructed after May 7, 2007, and was designed for annual average fuel gas use exceeding 0.50 $10^3m^3/d$ or for any site where annual average fuel gas use exceeds 0.50 $10^3m^3/d$, the fuel gas must be metered. At sites where fuel gas metering is required, up to 0.50 $10^3m^3/d$ may be estimated.
BC	It is expected that the operator will meter the whole volume consumed rather than just a specific stream for which the 0.50 $10^3m^3/d$ threshold has been exceeded. If there are multiple reporting facilities on the same site, the fuel use has to be separately measured and reported to each individual battery/facility.

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 the working interest ownership is not common or there are royalty trigger measurement points across the facilities, then any fuel gas volumes greater than 0.50 $10^3m^3/d$ crossing a reporting facility boundaries must be metered.

5. For sites with:

SK	Annual average flare/vent gas rates of ≤ 0.50 $10^3m^3/d$, the flare/vent may be estimated. For sites with an annual average flare/vent rate of > 0.50 $10^3m^3/d$, the flare/vent gas must be metered (see Figure 1.11). Sites requiring flare/vent gas metering may estimate up to 0.5 $10^3m^3/d$. These flare/vent thresholds do not apply to heavy oil batteries. See Section 12.2.2 for heavy oil flaring and venting measurement requirements.
AB	Annual average flare rates of ≤0.50 $10^3m^3/d$, the flare gas volume may be estimated. For sites with an annual average flare rate of > 0.50 $10^3m^3/d$, the flare gas must be metered (see Figure 1.11). Sites requiring flare gas metering may estimate up to 0.50 $10^3m^3/d$. This flare threshold does not

	apply to heavy oil and crude bitumen batteries. See Section 12.2.2 for heavy oil and bitumen flaring and venting requirements. Directive 060 specifies vent gas limits for sites. It also includes testing requirements for compressor seal vent gas, and vent gas may be estimated unless forbidden by other requirements.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

6. Gas used for pneumatic devices must be reported as fuel gas.

SK	Effective January 1, 2020, gas used for pneumatic devices that is vented or flared must be reported as vented or flared respectively. For facilities that are licensed prior to January 1, 2020 or for non-licensed facilities that are built before January 1, 2020, the volume of gas emitted by pneumatic devices may be estimated and then subtracted from the metered fuel gas volume in the case where the metered fuel gas provides the pneumatic gas supply. For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pneumatic gas supply.
AB	Effective January 1, 2020, gas used for pneumatic devices is vented or flared must be reported as vented or flared respectively. For facilities with first production before January 1, 2020, the volume of gas emitted by pneumatic devices may be estimated and then subtracted from the metered fuel gas volume in the case where the metered fuel gas provides the pneumatic gas supply.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

7. Pilot, purge, sweep, blanket and makeup gas consumption must be reported as fuel gas.

SK	Effective January 1, 2020, gas used for pilot, purge, sweep, blanket and makeup gas must be reported as flared. For facilities that are licensed prior to January 1, 2020 or for non-licensed facilities that are built before January 1, 2020, the volume of gas used as pilot, purge, sweep, blanket and makeup gas may be estimated and then subtracted from metered fuel gas in the case where metered fuel gas also provides the pilot, purge and makeup gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.50 $10^3m^3/d$ that may be estimated for flare gas. For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pilot, purge, sweep, blanket, and makeup gas supply. All vented or flared volumes for non-heavy oil facilities can be estimated up to 0.50 $10^3m^3/d$ or for heavy oil facilities up to 2.0 $10^3m^3/d$.

AB	Effective January 1, 2020, gas used for pilot, purge, sweep, blanket, and makeup gas must be reported as flared. For facilities with first production before January 1, 2022, the volume of gas used as pilot, purge, sweep, blanket, and makeup gas may be estimated and then subtracted from metered fuel gas in the case where metered fuel gas also provides the pilot, purge, sweep, blanket, and makeup gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.50 10^3 m^3/d that may be estimated for flare gas.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

4.2.1.1 Single-well Battery (Petrinex facility subtypes: 311 and 325 in SK and 311 and 331 in AB)

1. Gas must be separated from oil, emulsion or water, when present, and metered or estimated separately from the liquid volumes as a single phase.

4.2.1.2 Multiwell Group Battery (Petrinex facility subtypes: 321 and 326 in SK and 321 and 341 in AB)

1. Each well must have its gas separated from oil or emulsion and metered or estimated as a single phase, similar to a single-well battery.
2. All separation and measurement equipment for the wells in the battery, including the tanks but excluding the wellheads, must share a common surface location.

4.2.1.3 Proration Battery (Petrinex facility subtypes: 322 and 327, in SK and 322, 342, 344, and 345 in AB)

1. All well production is commingled prior to the total battery gas being separated from oil or emulsion and metered or estimated as a single phase.

4.2.1.4 Individual monthly well gas production is estimated based on well tests and corrected to the actual monthly volume through the use of a proration factor. Crude Oil Multiwell Swab Battery (Petrinex facility subtypes: 314 and 316 in SK only)

SK	Monthly gas production from individual crude oil swab wells must be metered or estimated (where appropriate) and reported.
AB	Crude Oil Multiwell Swab Batteries are not authorized in Alberta.
BC	Not Applicable

4.2.2 Gas Batteries

1. All wells linked to the battery for reporting purposes must be classified as gas wells.
2. Gas wells may produce condensate or oil.
3. A mixture of measured and prorated wells (mixed measurement) within the same battery may be permitted if:
    a. Regulator exemption criteria specified in Section 5: Site-specific Deviation from Base Requirements under Measurement by Difference are met, or;

   b. Regulator site-specific approval has been obtained, and the measured well(s) have been unlinked from the multiwell proration battery and linked to a separate battery facility to deliver gas into the proration battery.

4. Well(s) with no phase-separated measurement, including effluent wells, are not allowed to be linked to a Gas Multiwell Group Battery (facility subtype 361).
5. All gas and recombined liquids wells linked to a Gas Multiwell Battery (either facility subtypes 361, 362, 363, 364) must be connected by pipeline to a common point.
6. Gas production from oil wells or batteries or from other gas wells or batteries must not be connected to a gas proration battery upstream of the gas proration battery group measurement point unless Regulator exemption criteria in Section 5: Site-specific Deviation from Base Requirements under Measurement by Difference are met or Regulator site-specific approval is obtained.
7. Well status on Petrinex:

SK	Since gas royalties are based solely on monthly production volumes, GAS PUMP and GAS FLOW are not used. Only GAS ACTIVE well fluid mode type is used.
AB	Gas wells that are designed to operate on an on/off cycle basis using plunger lifts, on/off controllers, manual on/off, etc., or pump jacks must report well fluid mode type on Petrinex as GAS PUMP instead of GAS FLOW.
BC	Petrinex is under development

8. Any gas facility such as well sites, gas plants, batteries, or compressors, operators may estimate fuel gas use volumes for sites with an annual average fuel gas use of 0.50 $10^3 m^3/d$ or less.

SK	This requirement to meter the fuel gas exceeding 0.5 $10^3 m^3/d$ applies at sites where fuel gas metering is required, up to 0.5 $10^3 m^3/d$ may be estimated.
AB	For any site that was constructed after May 7, 2007, and was designed for annual average fuel gas use exceeding 0.5 $10^3 m^3/d$ or for any site where annual average fuel gas use exceeds 0.5 $10^3 m^3/d$, the fuel gas must be metered. At sites where fuel gas metering is required, up to 0.5 $10^3 m^3/d$ may be estimated.
BC	BC OGC Measurement Guideline for Upstream Oil and Gas Operations. This requirement to measure the fuel gas exceeding 0.5 $10^3 m^3/d$ applies from June 1 2013 and onwards. BC OGC Flaring and Venting Reduction Guideline Section 11.1- Metering Requirements and Guideline - any fuel gas added to acid gas to meet minimum heating value requirements or ground level ambient air concentrations where the annual average flow rate exceeds 0.5 $10^3 m^3/d$.

   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 the working interest ownership is not common or there are royalty trigger measurement points across the facilities, then any fuel gas volumes greater than 0.5 $10^3 m^3/d$ crossing a reporting facility boundaries must be metered.

9. For sites with:

SK	annual average flare/vent rates of ≤ 0.50 $10^3m^3/d$, the flare/vent gas volume may be estimated. For sites with an annual average flare/vent rate of > 0.5 $10^3m^3/d$, the flare/vent gas must be metered (see Figure 1.12). Sites requiring flare/vent gas metering may estimate up to 0.5 $10^3m^3/d$.
AB	annual average flare/vent rates of ≤0.50 $10^3m^3/d$, the flare/vent gas volume may be estimated. For sites with an annual average flare rate of > 0.50 $10^3m^3/d$, the flare gas must be metered (see Figure 1.11). Sites requiring flare/vent gas metering may estimate up to 0.50 103m3/d. These flare/vent threshold does not apply to heavy oil and crude bitumen batteries. See Section 12.2.2 for heavy oil and bitumen flaring and venting requirements.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

10. Gas used for pneumatic devices must be reported as fuel gas.

SK	Effective January 1, 2020, gas used for pneumatic devices that is vented or flared must be reported as vented or flared respectively. For facilities that are licensed prior to January 1, 2020 or for non-licensed facility that are built before January 1, 2020, the volumes of gas emitted by pneumatic devices may be estimated and then subtracted from the metered fuel gas volume in the case where the metered fuel gas provides the pneumatic gas supply. For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pneumatic gas supply.
AB	Effective January 1, 2020, gas used for pneumatic devices that is vented or flared must be reported as vented or flared respectively. For facilities with first production before January 1, 2022, the volume of gas emitted by pneumatic devices may be estimated and then subtracted from the metered fuel gas volume in the case where the metered fuel gas provides the pneumatic gas supply.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

11. Pilot, purge, sweep, blanket, and makeup gas consumption must be reported as fuel gas.

SK	Effective January 1, 2020, gas used for pilot, purge, sweep, blanket, and makeup gas must be reported as flared. For facilities that are licensed prior to January 1, 2020 or for non-licensed facility that are built before January 1, 2020, the volume of gas used as pilot, purge, sweep, blanket, and makeup gas may be estimated and then

	subtracted from metered fuel gas also provides the pilot, purge, sweep, blanket, and makeup gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.50 10^3m^3/d that may be estimated for flare gas. For facilities licensed after January 1, 2020 or for non-licensed facilities built after January 1, 2020, the facility must be built so that the metered fuel gas does not include pilot, purge, sweep, blanket, and makeup gas supply. All vented or flared volumes for non-heavy oil facilities can be estimated up to 0.50 10^3m^3/d or for heavy oil facilities up to 2.0 10^3m^3/d.
AB	Effective January 1, 2020, gas used for pilot, purge, sweep, blanket, and makeup gas must be reported as flared. For facilities with first production before January 1, 2022, the volume of gas used as pilot, purge, sweep, blanket, and makeup gas may be estimated and then subtracted from metered fuel gas in the case where metered fuel gas also provides the pilot, purge, sweep, blanket, and makeup gas supply. The volume that is subtracted from fuel gas does not contribute to the allowance of 0.50 103 m3/d that may be estimated for flare gas.
BC	See Measurement Guideline for Upstream Oil and Gas Operations

4.2.2.1 Single-well Battery (Petrinex subtype: 351)

1. Gas must be separated from water and condensate or oil (if applicable) and continuously measured as a single phase.
2. Condensate produced must be reported as a liquid if it is disposed directly from the battery without further processing. For wells that produce ≤ 2.0 m^3/d of total liquid (i.e., condensate and water) and that direct condensate and water production to lease tanks or to a single emulsion tank, operators may use the disposition equals production reporting methodology for reporting condensate and water production. This reporting methodology eliminates the requirement to report monthly condensate and water tank inventories. If operators choose to use this reporting method,
    a. They must account for existing tank inventories of condensate and water with the initial reporting and
    b. If the well status is changed to suspended after implementation, the condensate and water tank inventories must be deposed of (i.e., tank emptied) in the reporting month that the well status is changed.

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

    Refer to Section 12.2.1.1 for a further explanation of the disposition equals production reporting method.

3. Condensate that is recombined with the gas production after separation and measurement must be converted to a gas equivalent volume and added to the measured single-phase gas volume for reporting purposes.
4. Condensate that is trucked from the battery to a gas plant for further processing:

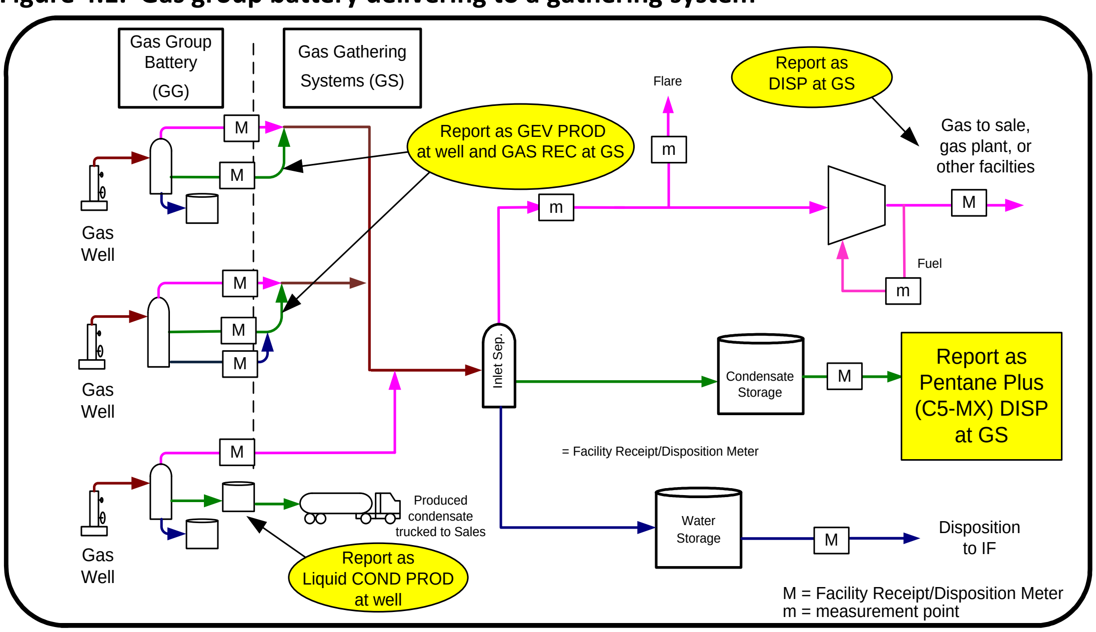
SK	Must be reported as a liquid condensate volume.
AB	Must be converted to a gas equivalent volume and added to the measured single-phase gas volume for reporting purposes.
BC	Must be converted to a gas equivalent volume and added to the measured single-phase gas volume for reporting purposes.

5. Oil produced in conjunction with the gas must be reported as oil at base 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 4.3.8.5.

4.2.2.2 Multiwell Group Battery (Petrinex facility subtypes: 361 in SK and 361 and 365 in AB)

1. Each well must have its own separation and measurement equipment, similar to a single-well battery.
2. The wells in the group battery may all be identical with regard to the handling of condensate and water, or there may be a mixture of handling methods. The rules for reporting condensate as a gas equivalent or as a liquid are the same as those for single-well gas batteries (see Figure 4.1). The rules for using the disposition equals production reporting methodology for condensate and water are the same as those for single-well gas batteries. See Section 4.2.2.1.
3. The volumes measured at each well separator must be used to report the production, PROD, volume on Petrinex. There must not be any proration from any downstream measurement point.

Figure 4.1. Gas group battery delivering to a gathering system



There is no group measurement point requirement for fluids from the gas group wells, but the wells must deliver to a common facility, normally a gas gathering system, with the metering difference reported at the gas gathering system. Hydrocarbon liquids and/or water may be tanked and disposed of by truck and reported as liquid DISP. Recombined hydrocarbon liquids reported as gas equivalent volume and water reported as liquid water must be sent to the same common facility as the gas. Multiple gas groups can deliver to the same gas gathering system.

If the gas gathering system further disposes of the fluids, similar to Figure 4.1, each fluid type (gas, hydrocarbon liquids, water) disposition must be measured and reported. The gas gathering system will also report a metering difference.

See Appendix 9 for schematics of the following scenarios of grouped wells:

Scenario 1 – 1 operator with 1 reporting entity (1 gas group)

Scenario 2 – 1 to 4 operators/equity partners with 4 reporting entities (4 single-well batteries) with licensed compressor facility on one well

Scenario 3 – 1 or 2 operators with 2 reporting entities (1 single-well batteries and 1 gas group)

Scenario 4 – 1 or 2 operators with 2 reporting entities (gas groups)

Scenario 5 – 1 or 2 operators with 2 reporting entities (gas groups) with licensed compressor on one well

4.2.2.3 Multiwell Effluent Measurement Battery (Petrinex facility subtype: 362)

1. The definition of and the requirements for this facility subtype 362 is found in Section 7.4.
2. Where delivery point measurement is required at the group measurement point, the combined (group) production of all wells in the effluent measurement battery must have three-phase separation and be measured as single-phase components. Where delivery point measurement is not required at the group measurement point, the group production may be measured using “two phase separation with three phase measurement”. This means that a two phase separator with an online product analyzer on the liquid leg of the separator may be used provided that:
    a. The measurement system design meets the requirements of Section 14, Figure 14.1
    b. The condensate and water is recombined and delivered to a gas gathering system or gas plant for further processing.
3. The resulting total actual battery gas volume (including gas equivalent volume [GEV] of condensate) and total actual battery water volume must be prorated back to the wells to determine each well’s actual gas and water production.
    a. 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.
    b. If liquid condensate is trucked to a gas plant for further processing the condensate:

SK	Must be reported as a liquid condensate volume.
AB	Must be reported as a gas equivalent volume (GEV).
BC	Must be reported as a gas equivalent volume (GEV).

4.2.2.4 Multiwell Proration Battery (Petrinex facility subtypes: 363 and 364 in SK and 363, 364, 366, and 367 in AB)

The definition of and the requirements for facility subtypes 363, 364, 366, and 367 are found in Section 7. See Section 7 for requirements.

4.2.3 Gas Gathering System (Petrinex facility subtypes: 621 and 622)

A reporting entity consisting of pipelines that move products (primarily gas) from one facility to another. The facility may also include compressor stations, line heaters, and dehydration equipment located on the system but not associated with any battery, injection facility, gas plant, or other facilities. Inlet measurement usually consists of the battery or facility group measurement point.

Outlet measurement usually consists of the gas plant inlet measurement.

See Section 15.2.1.6 for water reporting requirements.

4.2.4 Gas Plant (Petrinex facility subtypes: 401, 402, 403, 404, 405, 406)

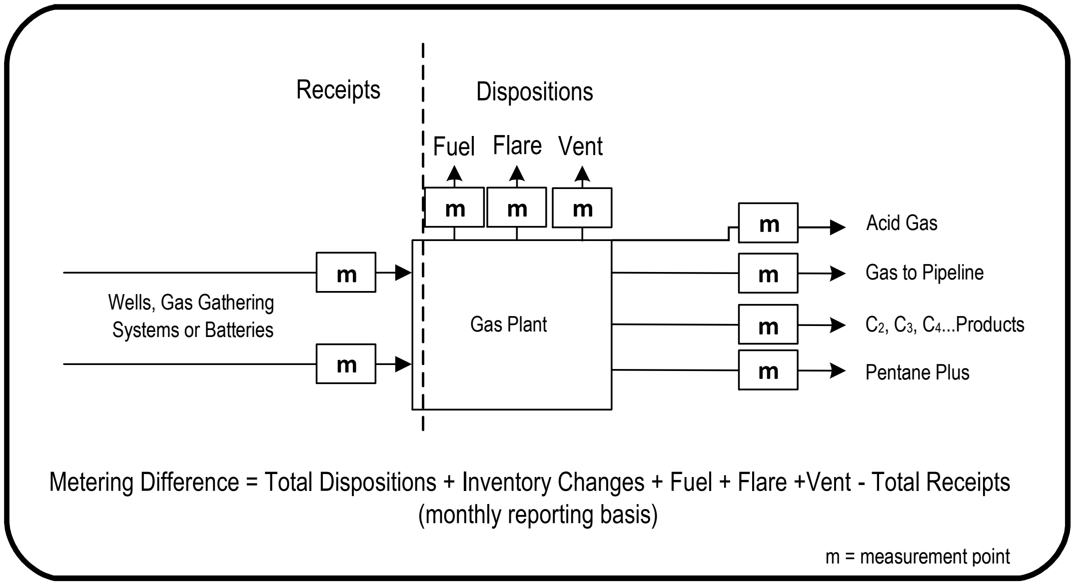
For gas plant facility subtypes definitions see

SK	*Directive PNG032: Volumetric, Valuation, and Infrastructure Reporting in Petrinex* (formerly known as Directive R01)
AB	Directive 011:
BC	Petrinex is under development

A system or arrangement of equipment used for receiving, measuring, and processing raw gas. Processing refers to the extraction of inert components, natural gas liquids, and water from the raw inlet gas through the use of dehydration, regenerative sweetening, and hydrocarbon liquids recovery processes. Does not include arrangement of equipment or facilities that recover less than 2.0 m^3/d of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, Jewel Thompson, or desiccant). Does not include an arrangement of equipment or facilities that remove small amounts of sulphur (<0.1 tonnes per day [t/d]) through the use of non-regenerative scavenging chemicals and dessicants.

Each plant inlet stream must have inlet separation and continuous measurement, used to report volume on Petrinex, for all liquids and gas before commingling with other streams and must be for the plant receipt from upstream facilities and for plant balance, unless all streams entering a gas plant are on the same gas gathering system and are dry (the absence of free liquids). In this case, the gas plant inlet measurement may consist of the gas gathering system outlet measurement or battery group measurement. Measurement of all gas dispositions out of the gas plant, such as sales, lease fuel for other facilities, flare and vent gas, acid gas disposition, and any volumes used at the gas plant, is required unless otherwise exempt by the Regulator. Monthly liquid inventory change must be accounted for and reported to Petrinex. (See Figure 4.4.)

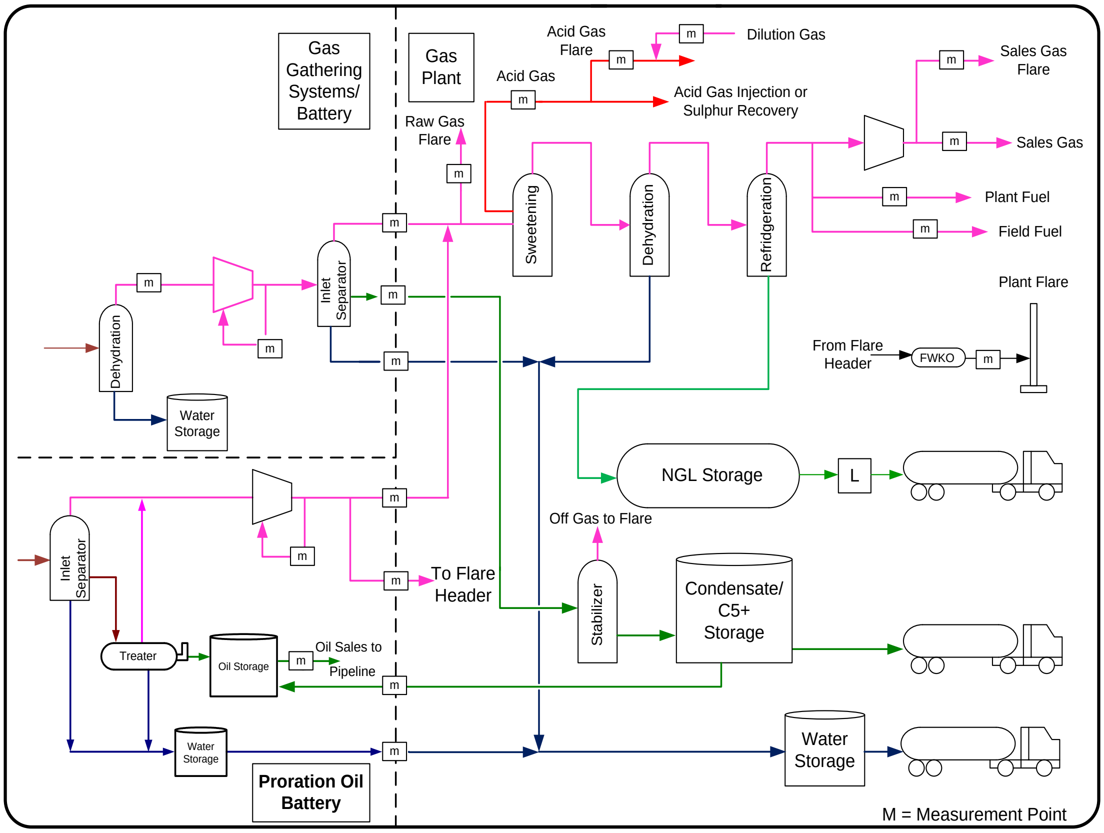
Figure 4.4. Typical gas plant measurement and reporting points



Except for thermal *in situ* schemes, facilities that use either regenerative sweetening processes or hydrocarbon liquid recovery processes must be reported as gas plants if they produce > 2.0 m^3/d of hydrocarbon liquid.

Delineation for an Oil Battery Delivering to or Receiving from a Gas Plant on Same Site

Figure 4.5. Oil battery delivering to or receiving from a gas plant



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

Gas plant condensate, C_{5+}, and/or NGL sent to an oil battery must be measured and reported as disposition to the oil battery.

SK	This is not a royalty trigger point but still requires delivery point measurement.
AB	This is a royalty trigger point requiring delivery point measurement.
BC	This is a royalty trigger point requiring delivery point measurement.

4.2.5 Gas Fractionation Plant (Petrinex facility subtype: 407)

In addition to the requirements in Section 4.2.4, condensate delivered to a gas fractionation plant must be measured and reported as a liquid receipt in cubic metres.

4.2.6 Injection or Disposal Facility (Petrinex facility subtypes: 501, 503, 504, 505, 506, 507, 510, 511, 512, 514, 516, 517, 518, 519 in SK and 501, 502, 503, 504, 505, 506, 507, 508, and 509 in AB)

Gas must be continuously metered as a single phase. For acid gas injection requirements, see Section 11 - Acid Gas and Sulphur Measurement. For stream injection see Section 12 – Heavy Oil Measurement (Section 12.3).

4.2.7 Meter Station (Petrinex facility subtypes: 631, 632, 633, 634, 640 in SK and 631, 632, 633, 634, 637, 638, 639, and 640 in AB)

Where gas meters are used to determine wellhead production, allocation pipeline disposition the provisions of this section applies. Gas must be continuously metered as a single phase.

4.2.8 Other Facilities (Petrinex facility subtypes: 204, 207, 208, 210, 211, 212, 213, 214, 371, 381, 671, 673, 674, 675, 676, 701, 702, 703, 904, 905, 906, 907 in SK and 204, 206, 207, 208, 209, 371, 381, 601, 611, 612, 651, 671, 672, 673, 675, 701, 702, 801, 901, 902, 903 in AB)

If gas is present, these facilities are required to measure and report the gas. Gas must be measured as a single phase.

4.3 Base Requirements for Gas Measurement

4.3.1 Design and Installation of Gas Measurement Devices

The design and installation of measurement equipment must be in accordance with the following:

4.3.1.1 General Design and Installation Requirements

Gas must be pressure and temperature corrected and reported to base conditions of 101.325 kPa and 15°C. Therefore, pressure and temperature measurement devices must be installed in accordance with Section 4.3.3 and 4.3.4.

In some cases, such as the meters listed below, manufacture's recommended installation is allowed. In these cases, the Operator must provide documentation to the Regulator (if requested) that shows that the meter and the installation meets the uncertainty requirements stipulated in Section 1.

4.3.1.2 Orifice Meters

If an orifice meter is used to measure gas, it must be designed and installed according to the applicable AGA Report #3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids (AGA3) listed in Table 4.1.

Table 4.1. Orifice meter design requirement (see detailed explanation in this section)

Meter run date of manufacture	Applicable AGA3 (API MPMS 14.3, Part 2) version
Before February 2003	AGA3 1991 or earlier meter run with upstream and/or downstream ID marking – may be reused or relocated for its designed application except to replace a meter where AGA3 2000 spec is required. Non-AGA meter run or run not marked with upstream or downstream ID – grandfathered for the existing volumetric throughput application, if relocated, it must be refurbished

	to AGA3 (1985) or later specification but cannot be used for sales/delivery point measurement.
After January 2003 (except for sales/delivery point meters measuring sales specification processed gas)	February 1991 or April 2000, or later
All sales/delivery point meters measuring sales specification processed gas manufactured after January 2003	April 2000 or later

When a meter such as a gas plant outlet meter is used to check sales/delivery point measurement and is not normally used to report volumes to the Regulator, it does not require AGA3 April 2000 specification. However, Operators are advised that when another gas source ties in to the sales pipeline between the check meter and the sales/delivery point meter, the check meter could become a sales or delivery point meter, and be subject to the requirements of that type of meter as illustrated in Figures 4.6 and 4.7.

Figure 4.6

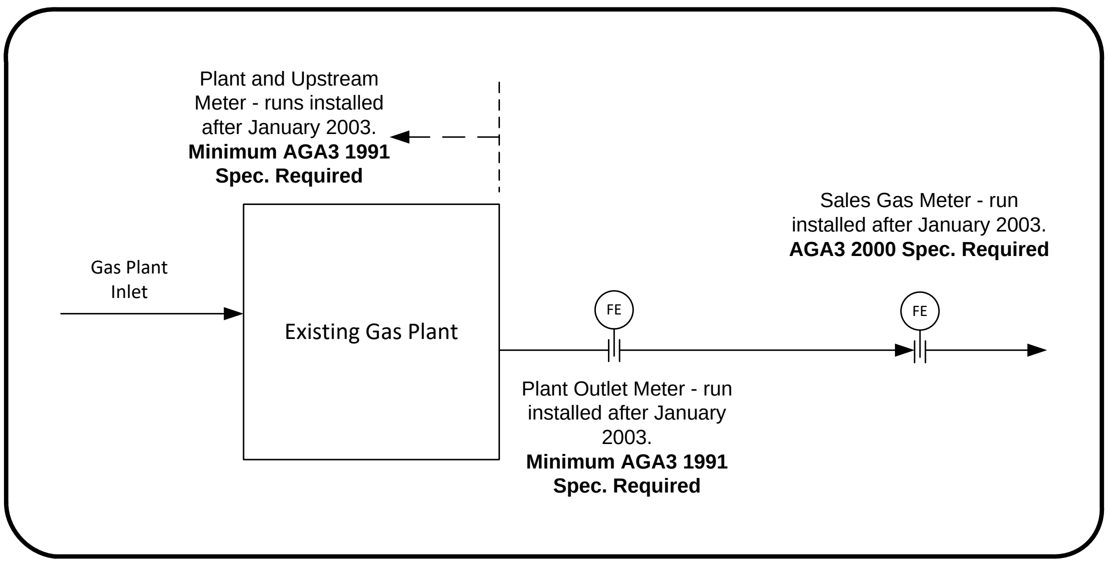
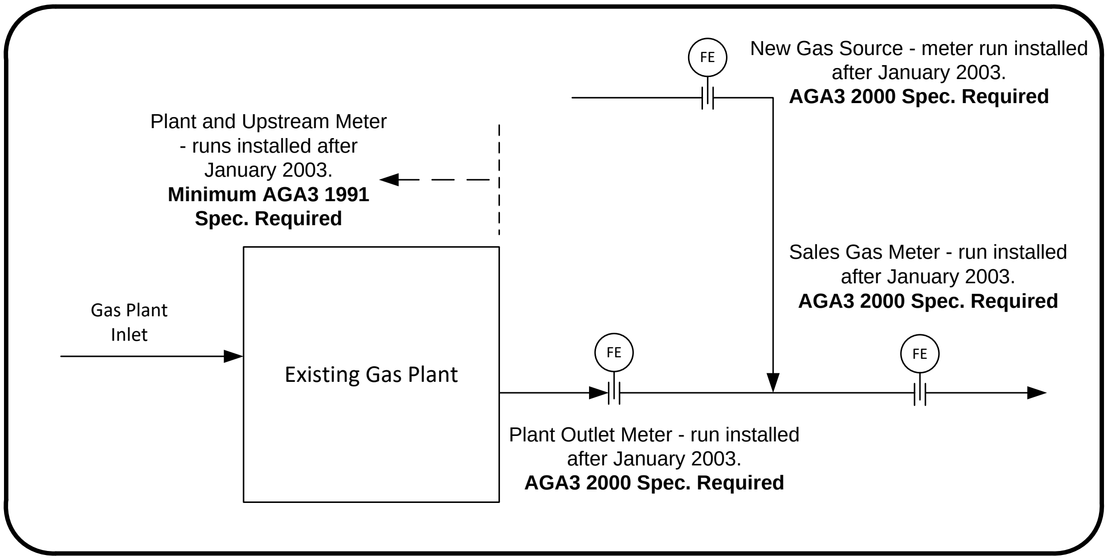


Figure 4.7



A permanently marked plate with the following information must be attached to each meter run and 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 (ID) of the meter run at 25.4 mm upstream of the orifice plate in millimetres to one decimal place (or to three decimal places if indicated in inches).

e. AGA3 version/year (for new runs only after January 31, 2005) and/or AGA3 configuration for runs installed after January 2003 and not using the April 2000 specification.

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 6 mm 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.

Temperature measurement must be installed according to the applicable AGA3 specifications and the temperature must be determined in accordance with 4.3.3.

4.3.1.3 Turbine and Vortex Meters

Turbine or vortex meters, used to measure gas 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) or the manufacturer's recommendation and must meet uncertainty requirements.

Temperature measurement is to be installed according to AGA7, i.e., between one and five pipe diameter downstream of the meter or the meter manufacturer's recommendation and the temperature as per Section 4.3.3.

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

4.3.1.4 Rotary Meters

Rotary metering systems must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.3: Rotary Type Gas Displacement Meters or the manufacturer's recommendation and must meet the uncertainty requirements.

4.3.1.5 Diaphragm Meters

Diaphragm meters must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.1: Diaphragm Type Gas Displacement Meters (up to 500 cubic feet/hour capacity), or ANSI B109.2: Diaphragm Type Gas Displacement Meters (over 500 cubic feet/hour capacity), and/or the manufacturer's recommendation and must meet the uncertainty requirements.

4.3.1.6 Venturi or Flow Nozzle Meters

Venturi or flow nozzle type of meters must be installed according to the provisions of the 1991 or later edition of the 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), other recognized International Standards or the meter manufacturer's recommendation and must meet the uncertainty requirements.

4.3.1.7 Ultrasonic Meters

Ultrasonic meters must be designed and installed according to the provisions of the 1998 or later editions of AGA Report No. 9: Measurement of Gas by Multipath Ultrasonic Meters (AGA9), applicable standard of an appropriate industry technical standards association or the meter manufacturer's recommendation and must meet the uncertainty requirements.

4.3.1.8 Coriolis Meters

Coriolis mass meters must be designed and installed according to the provisions of the latest edition of AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter, applicable standard of an appropriate industry technical standards association or the meter manufacturer's recommendation and must meet the uncertainty requirements.

Operators have two options for correcting to gas volumes at base conditions. Both of these options require an accurate gas composition determined in accordance with Section 8 of this Directive.

1. The first option is to measure the mass of the gas. The Operator can correct to base conditions by dividing the mass by the density at base conditions to get volume at base conditions.
2. The second option is to have the meter determine volume at flowing conditions, and correct the volume to base conditions. In most cases the Coriolis meter will not provide an accurate flowing density, so it is required that the pressure and temperature be accurately measured to determine volume at flowing conditions, then the volume can be corrected to base conditions.

4.3.1.9 Thermal Mass Meters

Thermal Mass meters must be designed and installed to applicable standard of an appropriate industry technical standards association or meter manufacturer's recommendation and must meet the uncertainty requirements. Thermal Mass meters should only be used if:

a. The composition does not change; or

b. The effect of composition change on the volume is within the uncertainty requirements for that applicable; or

c. The composition can be determined and recorded for flow calculation.

These meters are not recommended for use at gas plant flare stacks unless the above criteria can be met.

4.3.1.10 Other Meters

If meters other than those listed, for example cones or wedge meters, et cetera are used to measure gas, they must be installed according to applicable standard of an appropriate industry technical standards association, accepted standards or the meter manufacturer's recommendation and must meet the uncertainty requirements.

4.3.1.11 Electronic Flow Measurement Systems (EFM)

See Section 4.3.7.

4.3.2 Sensing Line Installation for Differential meters

This section applies to differential meters such as orifice, cone or venturi meters. Note that there are exemptions from these requirements detailed in the next section.

1. Accounting 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 deliver point, group point, and sales point measurement.
2. Sharing of metering taps by multiple differential pressure devices is not allowed. A separate set of taps and valve manifolds must be used for each device.
3. Equipment and sensing lines must be suitably winterized to prevent them from freezing.
4. Sensing lines must be self-draining towards the sensing taps to prevent liquid from being trapped in the line if they do not meet the exemption criteria for changes in sensing line diameter specified in Section 4.3.1.3.
5. Sensing lines should not exceed 1 m in length and should have a slope of 25.4mm per 300mm from the transmitter to the changer.

4.3.2.1 Exemptions from Requirements for Sensing Line Installation for Differential meters

SK	Grandfathering of existing differential pressure-sensing tap valves for installation before this Directive comes into force is granted without application unless any of the following situations exist:
AB	Grandfathering of existing differential pressure-sensing tap valves for installation before May 7, 2007 is granted without application unless any of the following situations exist:
BC	No Grandfathering of existing differential pressure-sensing lines for installations before June 1, 2013.

1. The metering device is being upgraded, refurbished, and commissioned within a new application or relocated;
2. The metering device does not meet the single point uncertainty limit, as detailed in Section 1: Standards of Accuracy;
3. 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
4. The metering point is at a delivery point, group point, sales point, or custody transfer point.

Grandfathering of changes in sensing line diameter from the sensing tap to the manifold, such as drip pots, installed before implementation of this Directive, is granted without application unless:

1. The metering device does not meet the single point uncertainty limit, as detailed in Section 1: Standards of Accuracy;
2. 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;
3. The metering point is at a delivery point, group point, sales point, or custody transfer point; or
4. The fuel measurement point has a clean, dry fuel source at a facility, such as a gas plant.

SK	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 within one year of when this Directive comes into force.
AB	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 within one year of February 2, 2009.
BC	Grandfather is not applicable.

4.3.3 Temperature

For all meters the flowing gas temperature must be measured and recorded according to Table 4.2.

Table 4.2. Temperature reading frequency table for gas measurement

Minimum temperature reading frequency	Criteria or events
Continuous	Sales/delivery points and/or EFM devices
Daily	> 16.9 $10^3m^3/d$
Weekly	≤ 16.9 $10^3m^3/d$
Daily	a. Production (proration) volume testing, or b. Nonroutine or emergency flaring and venting

Note that 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. Using the surface temperature of the piping or use a thermowell location where there is normally no flow is not acceptable. A meter equipped with a temperature compensation device is considered to have continuous temperature measurement.

4.3.4 Pressure

For all meters, pressure measurement must be located such that applicable standard of an appropriate industry technical standards association is met, and the pressure reading reflects that pressure at the meter. Where the pressure at the meter may drop below atmospheric pressure, absolute pressure measurement is required.

4.3.5 Volume Calculations

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

1. If an orifice meter is used to measure gas, the licensee 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.
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 recommended calculation procedures.
4. If a Coriolis mass meter is used to measure gas, volumes must be calculated from the measured mass flow and the base density derived from a representative gas sample analysis, including corrections for compressibility because 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 in the previous points, such as v-cones or wedge meters, are used to measure gas, volumes must be calculated according to

the applicable standard of an appropriate industry technical standards association or the meter manufacturer's recommendation.

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 Section 8.3. The following are the general requirements:
   a. The gas equivalent volume (GEV) is to 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 C_5 and/or heavier components in the sample can be grouped as C_{5+}, C_{6+}, C_{7+} 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.
7. For existing in-service orifice meter runs that are installed before February 2003 and are not designed to the AGA3 2000 or earlier specifications at the time of manufacture or not marked with upstream or downstream ID, nominal pipe ID can be used for flow calculations.

4.3.5.1 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. Compressibility factor of 1.0 can be applied when the pressure is below 700 kPag.

The AGA8[1] (1992 or later) 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 licensee 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

The Regulator will also accept the use of methods other than those listed. 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 Regulator 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 method.

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[1] See Section 4.6: References for complete bibliographical details for these citations.

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 super compressibility factor at a minimum of once every five minutes, whenever the gas composition is updated, and whenever the average pressure or temperature changes by more than ±0.5 per cent from the previous average 5-minute value used for calculation.

4.3.5.2 Physical Properties of Natural Gas Components

The Regulator adopts the physical properties contained in the most recent edition of the Gas Processors Suppliers Association (GPSA) *SI Engineering Data Book*[1] or the Gas Processors Association (GPA) *2145*[1] publication, whichever is the most current. The licensee should ensure that it is using the up-to-date list when buying a new measurement equipment. For standards, such as AGA8, that have imbedded physical constants different in value from those in GPA 2145 or GPSA *SI Engineering Data Book*[1], changes to such standards are not required unless they are made by the standard association.

4.3.6 Data Verification, Audit Trail and Volumetric Data Amendments

4.3.6.1 General

The field data, records, and any calculations or estimations, including EFM calculation or estimations, relating to Regulator-required production data submitted to Petrinex must be supplied upon request by ER. 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 4.3.1 Operations for more detail on orifice chart recorders). If EFM is used, the required data must be collected and retained according to Section 4.4.
3. Test records are any documentation produced in the testing or operation of metering equipment that affects measured volumes. This includes the record containing volume verification and calibration measurements for all secondary and tertiary elements.
4. When a gas metering error is discovered, the licensee of the facility must immediately correct the cause of the error and submit amended monthly production reports to Petrinex to correct all affected gas volumes.
5. All flared and vented gas:

SK	Must be reported as described in *Directive PNG032 – Volumetric, Valuation and Infrastructure Reporting*. Incinerated gas must be reported as FLARE gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as shrinkage, not as flared.

	Effective January 1, 2020, the requirement to report as FLARE gas does apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as activity of FLARE and product type of ACID GAS.
AB	Must be reported as described in AER *Directive 007: Volumetric and Infrastructure Requirements* and Manual 011. Incinerated gas must be reported as “flared” gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as shrinkage, not as flared. Effective January 1, 2020, this required to report as “flared” gas does apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as flared acid gas.
BC	Must be reported as described in the most recent version of *BC Oil and Gas Commission Flaring and Venting Reduction Guideline*

6. When the fuel usage, flaring, or venting location is within a gas gathering system but is not at a licensed entity:
    a. it must be reported as an activity associated with the closest licensed facility (e.g., compressor) within the gas gathering system; or
    b. if there is no applicable licensed facility within the gas gathering system, it must be reported as an activity associated with the gas gathering system itself.
7. Licensees must not prorate or allocate flared and vented volumes that occur at a facility to other upstream facilities and/or well locations.
8. Dilution gas, purge gas, or gas used to maintain a minimum heating value of the flared or incinerated gas must be reported as fuel. The reported total flare volume must exclude any of these fuel volumes. Effective January 1, 2020, dilution gas, purge gas, or gas used to maintain a minimum heating value of the flared or incinerated gas is to be reported as FLARE. The reported total flare volume must include all of these gas volumes.
9. Production hours for gas wells designed to operate on an on/off cycle basis, such as intermittent timers, pump-off controls, plunger lifts, manual on/off, or pump jacks, 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 are to 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 that are not part of a repeated cycle and emergency shutdown (ESDs) are considered down time. The operation personnel are required to make a decision based on the operating environment if the wells are not shut in but may or may not have production.
10. Gas used for instrumentation, pumps, purging, and heating must be reported as fuel use on a per-site basis, even if it is vented afterwards. If a site has an annual average fuel use of 0.50 10^3m^3/d or less, operator may estimate fuel use volumes.

SK	For sites where annual average fuel gas use exceeds 0.50 $10^3m^3/d$, the fuel gas must be metered (see Figure 1.11). Effective January 1, 2020 gas used for instrumentation, pumps, and purging that is vented or flared must be reported as vent gas or flare gas, respectively, on a per-site basis.
AB	For any site that was constructed after May 7, 2007, and was designed for annual average fuel gas use exceeding 0.5 $10^3m^3/d$ or for any site where annual average fuel gas use exceeds 0.5 $10^3m^3/d$, the fuel gas must be metered (see Figure 1.11). At sites where fuel gas metering is required, up to 0.5 $10^3m^3/d$ may be estimated. Effective January 1, 2020 gas used for instrumentation, pumps, and purging that is vented or flared must be reported as vent gas or flare gas, respectively, on a per-site basis.
BC	BC OGC Flaring and Venting Reduction Guideline: Gas that is used for pilot, purge or blanket gas must be reported as either flared or vented. Process gas used to operate instrumentation or as power gas to drive chemical pumps must be included as vented gas. This does not include fuel gas added to flare or incinerator streams in order to meet minimum heating value requirements.

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 the working interest ownership is not common or there are royalty trigger measurement points across the facilities, then any fuel gas volumes crossing reporting facility boundaries must be metered. The only exception is for integrated oilfield waste management facilities (OWMF) with WP, CT, and IF facilities on the same site, in which case fuel REC is to be reported at the WP and total OWMF fuel use at the same facility.

11. For sites with annual average flare or vent rates of ≤ 0.5 $10^3m^3/d$, the flare or vent gas volume may be determined by using estimates. For any site with an annual average flare or vent rate of > 0.5 $10^3m^3/d$, the flare or vent gas must be metered (See Figure 1.11). Sites requiring flare or vent gas metering may estimate up to 0.5 $10^3m^3/d$. These flare or vent thresholds do not apply to heavy oil batteries. See Section 12.2.2 for heavy oil flaring and venting measurement requirements.

4.3.6.2 Gas Lift Systems for Both Oil and Gas Wells

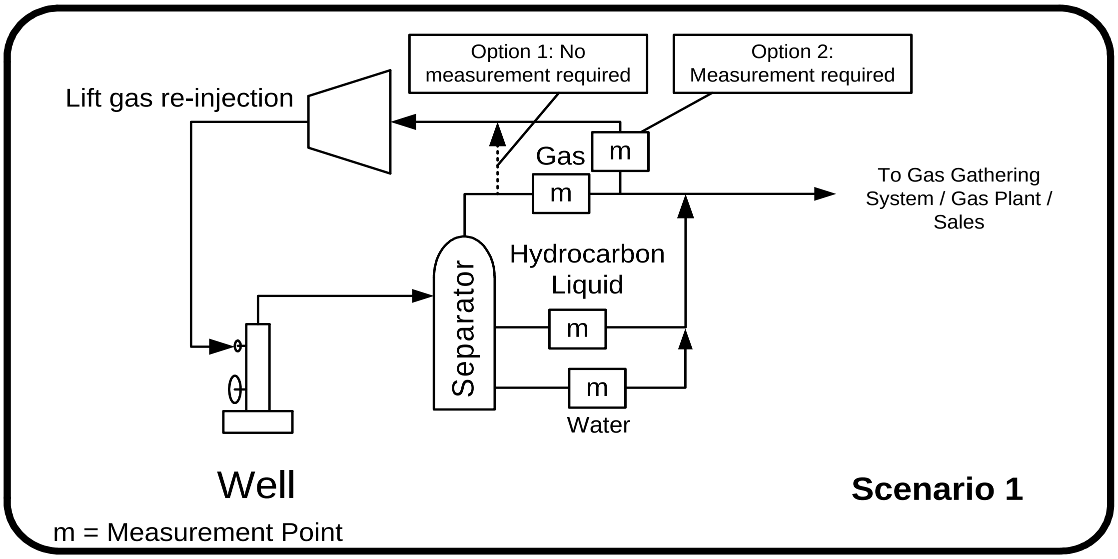
There are four gas source scenarios, and each one may be subject to different measurement, reporting, and sampling and analysis requirements when gas is injected into the wellbore to assist in lifting the liquids to the surface.

SK	GAS LIFT is not used for reporting.
AB	The *Directive 007* requirement is to update/change the well to GAS LIFT status for oil wells that use gas lift and to “GAS PUMP” status.
BC	*BC Oil and Gas Commission Flaring and Venting Reduction Guideline* Section 11 Measurement and Reporting

Scenario 1

There is no external gas source for the lift gas used given the raw gas is being separated and recirculated continuously at the well with compressor(s). Regular sampling and analysis frequency for the well type applies (see Section 8.4).

Figure 4.8. 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 measured production volume and the measured lift gas volume.

Scenario 2

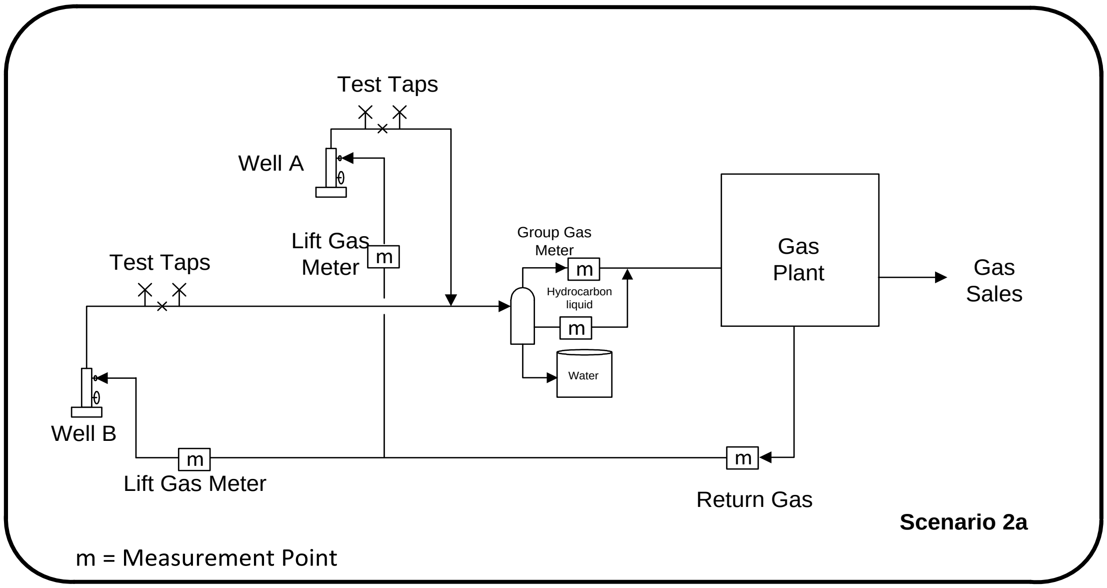
This scenario applies to the lift gas received back from a downstream gas plant/facility that is classified as return gas (no royalty implications).

Measurement is required at the battery level for any gas coming back from the gas plant/facility after sweetening/processing and reported as REC, but such measurement is not delivery point measurement. Part of this return gas could be used for fuel at the well. The lift gas injected into the wellbore must be measured and regular sampling and analysis frequency for the well type applies (see Section 8.4).

There are two possibilities under Scenario 2 (see Figures 4.9 and 4.10).

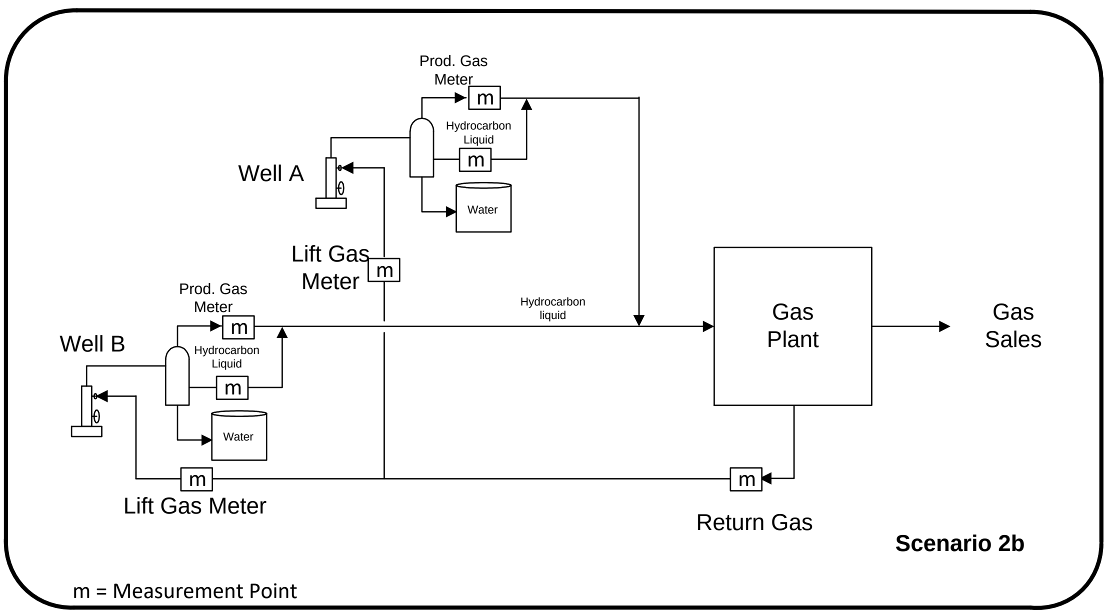
For proration tested wells, the gas lift volume during the test period must be netted off the total test gas production volume to determine the estimated gas production volume for each well.

Figure 4.9. Lift gas using return gas from plant – Scenario 2a



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

Figure 4.10. Lift gas using return gas from plant – Scenario 2b



Scenario 3 (Does not exist in Saskatchewan)

This scenario applies to lift gas that comes from external sources with royalty implications.

Any gas coming from a non-royalty paid gas source must be measured and reported at the battery/facility level as PURREC and as PURDISP at the sending facility. The well measurement and reporting requirement is the same as Scenario 2 and the gas sampling and analysis frequency for this type of gas lift well is semiannual.

Scenario 4

This scenario applies to lift gas that comes from royalty exempt sources.

SK	The measurement and reporting requirement is the same as Scenario 2.
AB	The measurement and reporting requirement is the same as Scenario 2 with the additional requirement that prior approval must be obtained from Alberta Energy to use the royalty-paid stream ID# WG999999 for the SAF/OAF submission to identify royalty-exempt gas that is to be used as gas lift.
BC	The lift gas comes from royalty exempted sources, such as TCPL or ATCO Gas

The gas sampling and analysis frequency for this type of gas lift well is semiannual.

4.3.6.3 Volumetric Data Amendments

SK	Section 4.3.6.3 does not apply in Saskatchewan.
AB	A number of operational, measurement, and production accounting scenarios may occur that can create errors in volumetric reporting in Petrinex. The errors may need to be corrected and amended volumes reported in Petrinex. The scenarios that require volumetric amendments are described as follows: 1. A gas metering error is discovered at a well or facility. In this case, the licensee of the facility must immediately correct the cause of the error and submit amended monthly production reports to Petrinex 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 $10^3m^3/d$, 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 m^3/month must be corrected and retroactive volumetric amendments made in Petrinex.
BC	This section does not apply in British Columbia.

4.3.7 Chart Operations

The chart drive for a circular chart recorder used to measure gas well gas production or group oil battery gas production must not be more than 8 days per cycle unless the exemption criteria specified in Section 5: Site-Specific Deviation from Base Requirements are met or regulator site-specific approval is obtained. A 24-hour chart drive is required for test gas measured associated with Class 1 and 2 proration oil wells. An 8-day chart drive may be used for test gas measurement associated with Class 3 and 4 proration oil wells. See

Section 6.5 Proration Well Testing for more detail on classes of wells. If the mode of operation causes painting on the chart of because of cycling or on/off flows, a 24-hour chart is required for any gas measurement point for EFM must be used.

The Operator must ensure that:

1. The meter location is properly identified on the chart.
2. The chart is correctly dated.
3. The on and off chart times are recorded on the chart to the nearest quarter hour if not actual.
4. The correct orifice plate and line size are recorded on the chart.
5. The time to the nearest quarter hour of any orifice plate change is indicated on the chart, along with the new orifice plate size.
6. It is noted on the charts if the differential, pressure, or temperature range of the recorder has been changed or if they are different from the ranges printed on the chart
7. The flowing gas temperature is recorded on the chart in accordance with Table 4.2.
8. Proper chart reading instructions are provided when the pen fails to record because of sensing line freezing, clock stoppage, pens out of ink, overlapping traces, or other reasons. Example instructions include:
    a. drawing in the estimated traces,
    b. requesting to read as average flow for the missing period, or
    c. providing an estimate of the differential and static pressure.
9. Any data or traces that require correction must not be covered over or obscured by any means

The Operator 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 whenever possible.
5. Static pen recordings are at 20% or more within the chart range whenever possible.
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 at the root mean square (RMS) of the band or in a sine wave motion alternating between the top and bottom of the painted area.

7. The pen trace colours conform to the industry-accepted practice (RED for differential, BLUE for static, and GREEN for temperature). However, any colour may be used, provided the colour used is documented.

4.3.7.1 Regulator Site-Specific Requests

If an inspection of a measurement device or of procedures reveals unsatisfactory conditions that significantly reduce measurement accuracy, the Regulator will direct that the licensee implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities. Examples of unsatisfactory conditions applicable to orifice chart recorders are as follows:

1. Thick pen traces that will cause excessive error when reading the traces.
2. Painting traces.
3. Differential or static pens recording too low on the chart—in scenarios where it is unavoidable because of low flow rate, high shut-in pressure, and equipment or operating pressure range limitations.

4.3.7.2 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 as per the specified calibration frequency 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.

4.3.7.3 Digital Chart Reading Technology

Some chart reading technology uses 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 digital technologies to read charts does not require prior approval of the Regulator, but the licensee 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 12 months, 18 months for gas production associated with heavy oil or crude bitumen, or alternatively the licensee 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 Saskatchewan and Alberta Regulators accept the electronic submission for audits, other jurisdiction 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 accounting 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.

4. If there are any changes or additions to those requirements and recommendations specific to chart scanning, 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 changing 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 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 Regulator inspection/audit purposes, the licensee 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 of the operator, the vendor must demonstrate the accuracy of the scanning and integration technology 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 Regulator 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 Regulator's known values.

4.3.8 Exemptions from Base Requirements

4.3.8.1 Gas in Solution with Oil Volumes under Pressure

In some scenarios, a gas volume must be determined, such as where the gas is dissolved in an oil volume under pressure, and there is no opportunity to measure the gas volume prior to it being commingled with other gas volumes. In that scenario, 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, 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 is to 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 GIS factors are required for wells in the battery that produce from different formations and where other test separators operate at different pressure and/or temperature conditions. Licensees should also consider determining seasonal GIS factors where ambient temperature differences may significantly affect the factors or when operating conditions change significantly.

The 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 measured. This volume divided by the stock tank volume of oil determined at the test separator provides a 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 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 (0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop) may be used as the GIS factor for non-heavy oil production until a more accurate, specific GIS factor is determined. It 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 2 m^3/d or if all battery 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.

4.3.8.2 Gas Produced from Gas Wells and Non-Heavy Oil Wells

For gas streams associated with the producing of non-heavy oil wells or gas wells up to 0.5 10^3m^3 per day of the annual average gas rate may be determined through estimation. No specific approval is required, but the operator must keep the estimation/testing documentation for Regulator audit. Examples of the gas streams that may be estimated up to 0.5 10^3m^3/d include well test gas, battery group gas, single-well battery gas, fuel gas used on a per site basis, and oil/condensate tank vented gas. A gas stream that must be measured regardless of daily volume is dilution gas added to an acid gas stream to ensure complete combustion due to 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 4.3.8.5. 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 upon 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. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors. Updated factors may be determined by one of the applicable tests/procedures described in Section 4.3.8.5.

4.3.8.3 Exemption for Gas Produced from Gas Wells and Non-Heavy Oil Wells

Crude oil multiwell proration batteries (Petrinex facility subtype 322) may use a monthly-calculated; battery-level GOR (monthly battery gas production ÷ monthly battery oil production) to calculate individual well gas production in accordance with the following conditions:

1. All wells using the battery-level GOR must produce ≤ 0.5 10^3m^3/d of gas
2. Any well producing > 0.5 10^3m^3/d of gas is not eligible to use the battery-level GOR, and well gas production must be determined using test rates obtained during proration testing
3. Monthly gas and oil volumes from wells not eligible to use the battery-level GOR must be subtracted from the total battery gas and oil volumes before calculating the battery-level GOR. For gas, the volume to be subtracted would be the total estimated gas determined from proration testing for all the ineligible wells; for oil, the volume would be the total prorated oil production for all the ineligible wells.
4. New wells added to the battery must produce ≤ 0.5 10^3m^3/d of gas for a minimum of six months before being eligible to use the battery-level GOR.

5. If there is no common ownership of all wells in the battery, written notification has been given to all working interest participants, with no resulting objections.
6. If there is no common Crown or Freehold royalty and only Freehold royalties are involved in all wells in the battery, 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 licensee must apply to the Regulator for approval if any Freehold royalty owner objects.

4.3.8.4 Gas Produced in Association with Heavy Oil Production

See Section 12.2.2 for details.

4.3.8.5 Methods for Determining Factors/Rates Used in Estimating Gas Volumes

If gas volumes are estimated using a 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 is to be divided by the oil volume to determine the 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 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 GOR factor will 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 GOR based on the compositional analysis.
4. Other methods listed under the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used

If gas volumes are estimated using an hourly rate:

1. A meter may be used to measure the gas stream for a minimum of one hour. The gas volume measured during this test may be used to determine the hourly rate that will be used to estimate gas volumes.
2. If applicable, such as for fuel gas volumes, the hourly rate may be determined based on the equipment manufacturer's stated gas consumption rates and the actual operating conditions.

Example Calculations for Estimating Gas Volumes Using GOR and GIS Factors

Determination of Total Produced Gas for a Single-Well Oil Battery

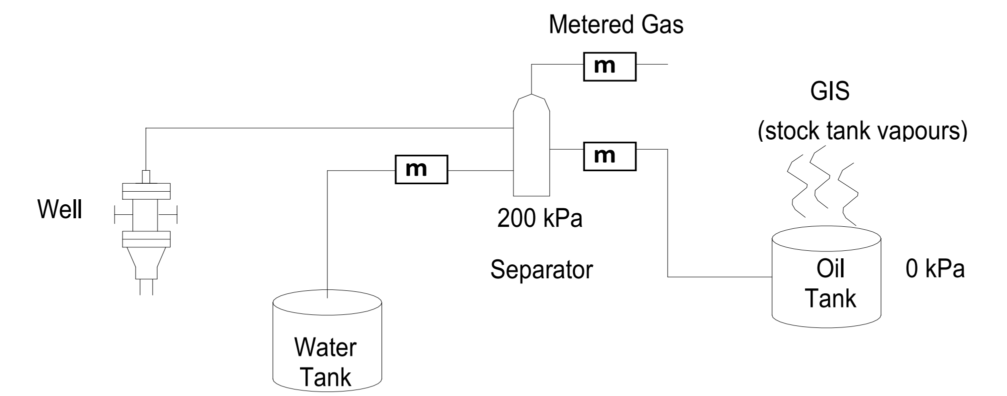
Figure 4.11 depicts a single-well battery where a three-phase separator is used to separate oil, gas, and water production from a well. The oil in the separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the GIS within the oil will be released. The gas leaving the separator in this example is metered, while the GIS released at the tank is estimated using a

GOR factor. Total gas production from the well is determined by adding the metered gas and the GIS released at the oil storage tank.

If a single-well battery 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 GOR factor.

Figure 4.11. Single-well oil battery example



Sample Calculation: Total Gas Volume at a Single-Well Battery (Figure 4.11)

Monthly well data (hypothetical) given for this example:

Gas meter volume = 96.3 $10^3 m^3$ (from chart readings)

Oil meter volume = 643.3 m^3 (from meter or tank gauging)

Pressure drop = 200 kPa

GIS factor = 6.37 m^3 gas/m^3 oil or 0.03185 m^3 gas/m^3 oil/kPa pressure drop (determined using a method other than the rule of thumb)

Step 1: Calculate GIS volume:

$6.37\ m^3/m^3 \times 643.3\ m^3 = 4097.8\ m^3 = 4.10\ 10^3 m^3$

or

$0.03185\ m^3/m^3/kPa \times 643.3\ m^3 \times 200\ kPa = 4097.8\ m^3 = 4.10\ 10^3\ m^3$

Step 2: Calculate the total battery gas production for the month:

$96.3\ 10^3 m^3 + 4.1\ 10^3\ m^3 = 100.4\ 10^3 m^3$

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Total Produced Gas for an Oil Proration Battery

Figure 4.12 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site.

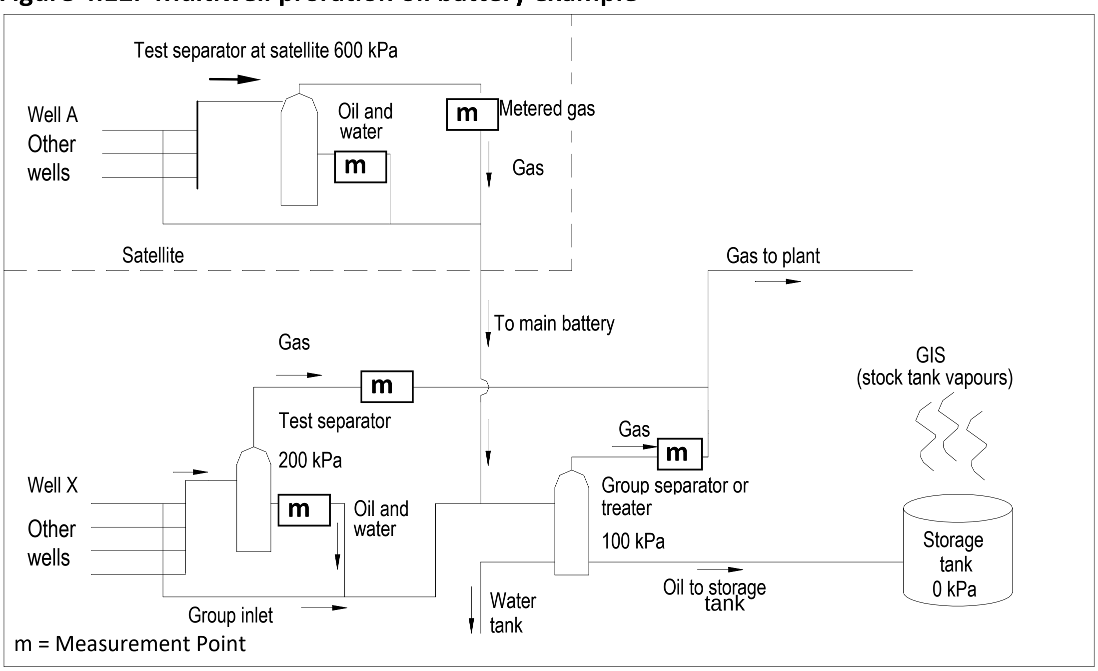
In this example, the oil, gas, and water leaving the test separator at the satellite are recombined with the satellite group production and directed to the group separation and measurement equipment at the main battery site. The oil and water leaving the test separator at the main battery site are recombined with the battery 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 GIS with the oil will be released.

The total gas production at the battery will be the sum of all the measured test gas at the battery site, the measured group gas at the battery, and the GIS released at the oil storage tank.

Trucked oil volumes received at the battery must not be included with the total battery oil volume when determining the GIS released at the oil storage tank.

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

Figure 4.12. Multiwell proration oil battery example



Sample Calculation: Total Gas Production at the Oil Proration Battery (Figure 4.12)

Monthly battery data (hypothetical) given for this example:

Oil production at the proration battery = 745.0 m^3 for the month (from meter and/or tank gauging)

Total test gas measured at the battery site = 30.0 10^3m^3 (from chart readings)

Measured group gas production = 67.4 $10^3 m^3$ (from chart readings)

Pressure drop from the group vessel to oil storage tank = 100 kPa

GIS factor = 3.99 m^3 gas /m^3 oil or 0.0399 m^3/m^3/kPa (determined using a method other than the rule of thumb)

Step 1: Calculate the GIS volume:

3.99 m^3/m^3 x 745.0 m^3 = 2972.6 m^3 = 2.97 $10^3 m^3$

or

0.0399 m^3/m^3/kPa x 745 m^3 x 100 kPa = 2972.6 m^3 = 2.97 10^3 m^3

Step 2: Calculate the total produced gas volume for the battery:

67.4 10^3 m^3 + 30.0 10^3 m^3 + 2.97 10^3 m^3 = 100.4 10^3 m^3

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Individual Well Test Gas for an Oil Proration Battery

Figure 4.12 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site. In either scenario, the oil leaving the test separator is under pressure and will 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 will be the sum of the gas measured as it leaves the test separator and the GIS that will evolve from the test oil volume after leaving the test separator. In the example, the test separators at the battery and satellite operate at significantly different pressures, and the oil leaving the test separator at the satellite will contain more GIS than the oil leaving the test separator at the battery.

Sample Calculation: Test Gas Production for Wells in the Satellite (Figure 4.5)

Satellite test data (hypothetical) given for this example for well A:

Metered test oil = 7.22 m^3 (from oil meter)

Metered test gas = 1.27 10^3 m^3 (from chart readings)

GIS factor = 25.62 m^3 gas/m^3 oil or 0.0427 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 600 kPa to group pressure at 100 kPa 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:

0.0427 m^3/m^3/kPa x 7.22 m^3 x 600 kPa = 185.0 m^3 = 0.19 $10^3 m^3$

or

25.62 m^3/m^3 x 7.22 m^3 = 185.0 m^3 = 0.19 $10^3 m^3$

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

1.27 $10^3 m^3$ + 0.19 $10^3 m^3$ = 1.46 $10^3 m^3$

Note that test gas volumes must be determined to two decimal places (in $10^3 m^3$).

Sample Calculation: Test Gas Production for Wells in the Battery (Figure 4.5)

Battery test data (hypothetical) given for this example for well X:

Metered test oil = 3.85 m^3 (from oil meter)

Metered test gas = 2.33 10^3m^3 (from chart readings)

GIS factor = 7.90 m^3 gas/m^3 oil or 0.0395 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 200 kPa to group pressure at 100 kPa 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:

0.0395 m^3/m^3/kPa x 3.85 m^3 x 200 kPa = 30.4 m^3 = 0.03 10^3m^3

or

7.90 m^3/m^3 x 3.85 m^3 = 30.4 m^3 = 0.03 10^3m^3

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

2.33 10^3m^3 + 0.03 10^3m^3 = 2.36 10^3m^3

Note that test gas volumes must be determined to two decimal places (in 10^3m^3).

4.4 Electronic Flow Measurement (EFM) for Gas

An EFM system 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 EFM portion has to meet the requirements in this section. All EFM systems previously approved by AER under *Guide 34* may continue as approved.

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.

4.4.1 Acceptable Base Requirements for EFM

If an EFM is used to calculate volumes for Regulator accounting purpose, the licensee must be able to verify that it is performing within the Regulator allowed deviation limits defined in this section.

When any parameter that affects the flow calculation is changed, such as orifice plate size, meter factor, fluid analysis, or transmitter range, a signoff procedure or an event log must be set up to ensure that the change is made in the EFM system. All data and reports must be retained for a minimum of 12 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 backup, UPS, EPROM.
3. System access must 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.

4.4.2 EFM Performance Evaluation Test

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 on a per software version basis. The evaluation must be documented for Regulator audit purposes on request. For existing EFM systems, the Regulator encourages licensees to conduct their own performance evaluations. A performance evaluation must be conducted and submitted for Regulator audit on request. The Regulator 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, coefficient factors, and other parameters. The first seven test cases included in this section 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' recommended equations can also be used to evaluate the EFM performance. The seven AGA3 test cases could also be used to evaluate any compressibility or super compressibility factors used in other flow calculations using the same gas composition, pressure, and temperature in the calculation as inputs.
2. Evaluate the EFM calculation accuracy with a flow calculation checking program that performs within the allowed deviation limits for all the factors and parameters listed in the test cases. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to 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 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 Regulator accounting and reporting purposes unless Regulator approval is obtained.

The volumetric flow rate (Q) obtained from a performance evaluation test must agree to within ±0.25% of those recorded on the sample test cases or other flow calculation checking programs. If the ±0.25% limit is exceeded, the EFM must be subjected to a detailed review of the 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%.

Test Cases 1 to 7 for Verification of Orifice Meter Gas Flow Calculation Programs

The Regulator has developed test cases to verify that the EFM system correctly calculates gas flow rates from orifice meters. The seven test cases were calculated on the following basis:

1. They are for flange taps only.
2. The atmospheric pressure is assumed to be 93.08 kPa(a) (13.5 psia).
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 and 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, as recommended by the AGA3 (1990), Part 1, Section 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 (101.325 kPa[abs] and 15°C) are used in the calculated temperature base factor (F_{tb}) and pressure base factor (F_{pb}).

Test Case 8 for Verification of AGA7 Gas Flow Calculation Programs

The Regulator has developed a test case to verify that the EFM system correctly calculates gas flow rates using the AGA7 equations. The test case was calculated on the following basis:

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.

Table 4.3. Allowable deviation limits for the AGA3 (1985) equation

AGA3 (1985) factors	Allowed deviation limit from test cases
Y, F_a, F_r, and F_{tf}	±0.01%
F_b	±0.1%
F_{gr}, F_{pv}	±0.2%
Q	±0.25% or ±0.15% without the above factors

Table 4.4. Allowable deviation limits for the AGA3 (1990) equation

AGA3 (1990) factors	Allowed deviation limit from test cases
Y_1, and E_v	±0.01%
C_d and Z_b	±0.1%
Z_f	±0.2%
Q	±0.25% or ±0.15% without the above factors

Table 4.5. Allowable deviation limits for the AGA7 equation

AGA7 factors	Allowed deviation limit from test cases
F_{pm} (flowing pressure) and F_{tm} (flowing temperature)	±0.1%
S (compressibility)	±0.2%
Q	±0.25% or ±0.15% without the above factors

TEST CASE 1 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0184	iC_4	-	0.0081
CO_2	-	0.0000	nC_4	-	0.0190
H_2S	-	0.0260	iC_5	-	0.0038
C_1	-	0.7068	nC_5	-	0.0043
C_2	-	0.1414	C_6	-	0.0026
C_3	-	0.0674	C_7	-	0.0022

Ideal gas relative density - 0.7792

Meter Data (flange taps)

Meter run	I.D.	-	52.370 mm (2.0618 inches)
Orifice	I.D.	-	9.525 mm (0.375 inches)

Flow Data (24 hr)

Static pressure	-	2818.09 kPa(a) (408.73 psia)
Differential pressure	-	10.2000 kPa (40.9897 inches H_2O)
Flowing temperature	-	57.0°C (134.600°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	28.4286	28.4286
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
F_{tb}	0.9981	0.9981
F_{gr}	1.1308	1.1308
F_a	1.0012	1.0012
F_r	1.0006	1.0006
F_{pb}	1.0023	1.0023
F_{tf}	0.9351	0.9351
F_{pv}	1.0360	1.0361
C'	31.175	31.179
Q	2.7422	2.7475 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.5990	0.5990
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
E_v	1.0005	1.0005
Z_b	0.9959	0.9959
Z_f	0.9280	0.9277
Q	2.7478	2.7531 10^3 m^3/24 hr

TEST CASE 2 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0156	iC_4	-	0.0044
CO_2	-	0.0216	nC_4	-	0.0075
H_2S	-	0.1166	iC_5	-	0.0028
C_1	-	0.7334	nC_5	-	0.0024
C_2	-	0.0697	C_6	-	0.0017
C_3	-	0.0228	C_7	-	0.0015

Ideal gas relative density - 0.7456

Meter Data (flange taps)

Meter run I.D. - 102.26 mm (4.026 inches)
Orifice I.D. - 47.625 mm (1.875 inches)

Flow Data (24 hr)

Static pressure - 9100.94 kPa(a) (1319.98 psia)
Differential pressure - 11.0000 kPa (44.2046 inches H_2O)
Flowing temperature - 50.0°C (122.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	733.697	733.697	
Y_1	0.9996	0.9996	
Y_2	N/A	1.0002	
F_{tb}	0.9981	0.9981	
F_{gr}	1.1564	1.1564	
F_a	1.0010	1.0010	
F_r	1.0002	1.0002	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9452	0.9452	
F_{pv}	1.1072	1.1073	
C'	888.905	889.000	
Q	145.93	146.03	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6019	0.6019	
Y_1	0.9996	0.9996	
Y_2	N/A	1.0003	
E_v	1.0244	1.0244	
Z_b	0.9967	0.9967	
Z_f	0.8098	0.8097	
Q	146.08	146.18	10^3 m^3/24 hr

TEST CASE 3 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0500	iC_4	-	0.0000
CO_2	-	0.1000	nC_4	-	0.0000
H_2S	-	0.2000	iC_5	-	0.0000
C_1	-	0.6000	nC_5	-	0.0000
C_2	-	0.0500	C_6	-	0.0000
C_3	-	0.0000	C_7	-	0.0000

Ideal gas relative density - 0.8199

Meter Data (flange taps)

Meter run	I.D.	-	590.55 mm (23.250 inches)
Orifice	I.D.	-	304.80 mm (12.000 inches)

Flow Data (24 hr)

Static pressure	-	10342.14 kPa(a) (1500.00 psia)
Differential pressure	-	22.1600 kPa (89.0522 inches H_2O)
Flowing temperature	-	60.0°C (140.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	30429.66	30429.66	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
F_{tb}	0.9981	0.9981	
F_{gr}	1.1028	1.1028	
F_a	1.0013	1.0013	
F_r	1.0001	1.0001	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9309	0.9309	
F_{pv}	1.1076	1.1078	
C'	34636.6	34643.21	
Q	8603.19	8614.04	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6029	0.6029	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
E_v	1.0375	1.0375	
Z_b	0.9968	0.9968	
Z_f	0.8216	0.8213	
Q	8564.77	8575.48	10^3 m^3/24 hr

TEST CASE 4 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0029	iC_4	-	0.0000
CO_2	-	0.0258	nC_4	-	0.0000
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.9709	nC_5	-	0.0000
C_2	-	0.0003	C_6	-	0.0000
C_3	-	0.0001	C_7	-	0.0000

Ideal gas relative density - 0.5803

Meter Data (flange taps)

Meter run	I.D.	-	146.36 mm (5.7622 inches)
Orifice	I.D.	-	88.900 mm (3.500 inches)

Flow Data (24 hr)

Static pressure	-	9839.99 kPa(a) (1427.17 psia)
Differential pressure	-	6.6130 kPa (26.575 inches H_2O)
Flowing temperature	-	22.35°C (72.23°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	2694.965	2694.97	
Y_1	0.9998	0.9998	
Y_2	N/A	1.0001	
F_{tb}	0.9981	0.9981	
F_{gr}	1.3116	1.3116	
F_a	1.0001	1.0001	
F_r	1.0002	1.0002	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9884	0.9884	
F_{pv}	1.0843	1.0843	
C'	3790.16	3790.31	
Q	501.64	501.82	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6047	0.6047	
Y_1	0.9998	0.9998	
Y_2	N/A	1.0001	
E_v	1.0759	1.0759	
Z_b	0.9980	0.9980	
Z_f	0.8425	0.8425	
Q	503.44	503.63	10^3 m^3/24 hr

TEST CASE 5 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0235	iC_4	-	0.0088
CO_2	-	0.0082	nC_4	-	0.0169
H_2S	-	0.0021	iC_5	-	0.0035
C_1	-	0.7358	nC_5	-	0.0031
C_2	-	0.1296	C_6	-	0.0014
C_3	-	0.0664	C_7	-	0.0007

Ideal gas relative density - 0.7555

Meter Data (flange taps)

Meter run I.D. - 154.05 mm (6.0650 inches)
Orifice I.D. - 95.250 mm (3.750 inches)

Flow Data (24 hr)

Static pressure - 2499.9 kPa(a) (362.58 psia)
Differential pressure - 75.000 kPa (301.395 inches H_2O)
Flowing temperature - 34.0°C (93.2°F)

Gas Volume Result

AGA3 (1985)

Factors	**U/S Tap**	**D/S Tap**	
F_b	3111.24	3111.24	
Y_1	0.9894	0.9897	
Y_2	N/A	1.0044	
F_{tb}	0.9981	0.9981	
F_{gr}	1.1485	1.1485	
F_a	1.0005	1.0005	
F_r	1.0001	1.0001	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9695	0.9695	
F_{pv}	1.0382	1.0394	
C'	3561.90	3567.34	
Q	800.22	813.37	10^3 m^3/24 hr

AGA3 (1990)

Factors	**U/S Tap**	**D/S Tap**	
C_d	0.6042	0.6041	
Y_1	0.9894	0.9897	
Y_2	N/A	1.0044	
E_v	1.0822	1.0822	
Z_b	0.9962	0.9962	
Z_f	0.9240	0.9217	
Q	799.83	813.00	10^3 m^3/24 hr

TEST CASE 6 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0268	iC_4	-	0.0123
CO_2	-	0.0030	nC_4	-	0.0274
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.6668	nC_5	-	0.0000
C_2	-	0.1434	C_6	-	0.0180
C_3	-	0.1023	C_7	-	0.0000

Ideal gas relative density - 0.8377

Meter Data (flange taps)

Meter run	I.D.	-	52.500 mm (2.0669 inches)
Orifice	I.D.	-	19.050 mm (0.750 inches)

Flow Data (24 hr)

Static pressure	-	2506.33 kPa(a) (363.50 psia)
Differential pressure	-	17.0500 kPa (68.5171 inches H_2O)
Flowing temperature	-	7.2°C (44.96°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	115.138	115.138
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
F_{tb}	0.9981	0.9981
F_{gr}	1.0902	1.0902
F_a	0.9996	0.9996
F_r	1.0003	1.0003
F_{pb}	1.0023	1.0023
F_{tf}	1.0148	1.0148
F_{pv}	1.0708	1.0714
C'	136.15	136.22
Q	14.602	14.660 $10^3\ m^3/24$ hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6005	0.6005
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
E_v	1.0088	1.0088
Z_b	0.9951	0.9951
Z_f	0.8588	0.8578
Q	14.687	14.746 $10^3\ m^3/24$ hr

TEST CASE 7 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0070	iC_4	-	0.0062
CO_2	-	0.0400	nC_4	-	0.0090
H_2S	-	0.0000	iC_5	-	0.0052
C_1	-	0.8720	nC_5	-	0.0016
C_2	-	0.0340	C_6	-	0.0000
C_3	-	0.0250	C_7	-	0.0000

Ideal gas relative density - 0.6714

Meter Data (flange taps)

Meter run	I.D.	-	52.500 mm (2.0669 inches)
Orifice	I.D.	-	12.70 mm (0.50 inches)

Flow Data (24 hr)

Static pressure	-	299.92 kPa(a) (43.50 psia)
Differential pressure	-	6.3455 kPa (25.5 inches H_2O)
Flowing temperature	-	1.67°C (35°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	50.523	50.523	
Y_1	0.9933	0.9935	
Y_2	N/A	1.0039	
F_{tb}	0.9981	0.9981	
F_{gr}	1.2190	1.2190	
F_a	0.9994	0.9994	
F_r	1.0018	1.0018	
F_{pb}	1.0023	1.0023	
F_{tf}	1.0250	1.0250	
F_{pv}	1.0035	1.0036	
C'	63.013	63.029	
Q	1.4263	1.4416	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6006	0.6006	
Y_1	0.9933	0.9934	
Y_2	N/A	1.0039	
E_v	1.0017	1.0017	
Z_b	0.9973	0.9973	
Z_f	0.9905	0.9903	
Q	1.4335	1.4489	10^3 m^3/24 hr

TEST CASE 8 (for AGA7 Flow Calculations)

Gas Analysis

N_2	-	0.0268	iC_4	-	0.0123
CO_2	-	0.0030	nC_4	-	0.0274
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.6668	nC_5	-	0.0000
C_2	-	0.1434	C_6	-	0.0180
C_3	-	0.1023	C_7	-	0.0000

Flow Data (24 hr)

Uncorrected volume - 128.0 10^3m^3
Static pressure - 2506.33 kPa(a) (363.50 psia)
Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result

AGA7 (Volumetric Flow)

Factors

F_{pm}	24.6784
F_{pb}	1.0023
F_{tm}	1.0298
F_{tb}	0.9981

Using AGA8 compressibility equations,

S	1.1588
Q	3770.9 10^3 m^3/24 hr

Using RK compressibility equations,

S	1.1467
Q	3731.6 10^3 m^3/24 hr

4.5 Measurement Reports for EFM Systems

The required information on each report must be stored using electronic media (not necessarily on the EFM) or printed media and can exist individually on different formats or reports and generated on demand for audit, as follows:

1. Daily for daily report required data
2. Monthly for monthly report required data
3. Event and alarm logs at regular intervals before information is overwritten
4. Meter reports generated on request for audit

4.5.1 Daily Report

The daily report must include:

1. Meter identification
2. Daily accumulated flow, with indicating flags for estimated flows made by the system or by the operation personnel and alarms that have occurred for over-ranging of end devices
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, differential pressure (if applicable), static pressure, and temperature taken at the same time each day, or
    b. Average daily values for differential pressure (if applicable), static pressure, and temperature, or
    c. Hourly accumulated flow rate and average hourly values for differential pressure (if applicable), static pressure, and temperature

Existing EFM systems that do not have any of the audit trail capabilities specified in Section 4.5, and cannot develop the capability due to system limitations, should be evaluated for upgrading, especially when new production is tied into the facilities. The Regulator may request upgrades, where audit/inspection results indicate they are warranted.

4.5.2 Monthly Report

This report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

1. Monthly cumulative flow
2. Flags indicating any change made to flow volumes
3. Total hours on production or hours of flow (specify)

4.5.3 Meter Report

The meter 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 and be produced on demand:

1. Instantaneous Flow Data, including:
    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 component (if live)
    h. Optional: instantaneous (AGA3) factors (see the orifice meter test cases in Section 4.4.2 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
    c. Contract hour
    d. Atmospheric pressure
    e. Pressure base (unless fixed)
    f. Temperature base (unless fixed)
    g. Meter tube reference inside diameter
    h. Orifice plate reference bore size
    i. Static pressure tap location
    j. Orifice plate material
    k. Meter tube material
    l. Calibrated static pressure range
    m. Calibrated differential pressure range
    n. Calibrated temperature range
    o. High/low differential cutoff
    p. Relative density (if not live)
    q. Compressibility (if not live)
    r. Gas components (if not live)

s. Meter factor and/or K-Factor

t. Effluent correction factor

4.5.4 Event Log

This log is used to note and record exceptions and changes to the flow parameter, configuration, programming, and database affecting flow calculations, such as, but not limited to:

1. Orifice size change
2. Transmitter range change
3. Date of gas/liquid analysis update
4. Algorithm changes
5. Meter factor, K-Factor, or effluent correction factor changes
6. Other manual inputs

4.5.5 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 of clearing of each alarm must be recorded. 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

4.6 References

American Gas Association Transmission Measurement Committee Report No. 8 (AGA8), November 1992. *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases*.

Dranchuk, P.M., and Abou-Kassam, J.H., "Calculation of Z Factors for Natural Gases Using Equations of State," *The Journal of Canadian Petroleum Technology*, Vol. 14, No. 3, July-September 1975, pp. 34-36.

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Hall, K.R., and Yarborough, L., "A New Equation of State for Z Factor Calculations," *The Oil and Gas Journal*, June 18, 1973, pp. 82-92.

Pitzer, K.S., Lippman, D.Z., Curl, R.F., Huggins, C.M., and Petersen, D.E., "The Volumetric and Thermodynamic Properties of Fluids II. Compressibility Factor, Vapour Pressure and Entropy of Vapourization," *Journal of the American Chemical Society*, Vol. 77, No. 13, July 1955.

Redlich, O., and Kwong, J.N.S., "On the Thermodynamics of Solutions. V. An Equation of State. Fugacities of Gaseous Solutions," *Chemical Review* 44, 1949, pp. 233-244.

Wichert, E., and Aziz, K., "Calculate Z's for Sour Gases," *Hydrocarbon Processing*, Vol. 51, May 1972, pp. 119-122.

Yarborough, L., and Hall, K.R., "How to Solve Equation of State for Z-Factors," *The Oil and Gas Journal*, February 18, 1974, pp. 86-88

5 Site-specific Deviation from Base Requirements

Section 1: Standards of Accuracy states that a licensee may deviate from the Regulator'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 licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties.

This section describes situations where a licensee may deviate from the minimum requirements without Regulator approval, provided that specific criteria are met. Licensees may also apply for approval to deviate from the minimum requirements if the specific criteria are not met; this section indicates what information must be included in such an application. If these exemptions or approvals are in use, Regulator inspectors and auditors will review the licensee's records for demonstrated compliance with the criteria specified in this section or in the applicable approval.

Approvals will remain in place indefinitely, including after transfer of the facility to another licensee, provided that conditions specified in the approval are met. If a Regulator audit or inspection finds that approval conditions are not being met, the approval may be revoked and the licensee may be required to meet applicable base requirements immediately, or other appropriate requirements may be specified.

5.1 Site-specific Exemptions

Deviation from base measurement, accounting, and reporting requirements is allowed without submission of an application to the Regulator, provided that all the qualifying criteria listed under the subsequent Exemption sections are met.

Qualifying Criteria – These criteria detailed in the subsequent sections must be met to qualify for the exemption. If the qualifying criteria have been met and the exemption is implemented, it may remain in place indefinitely, as long as it does not meet any of the revocation clauses and no physical additions to the facility are made, e.g., new wells or stratigraphic units or zones. If additions or changes are made to the facility, the qualifying criteria must be met for all the wells or stratigraphic units or zones added to the facility for the exemption to remain in place.

Documentation Requirement –To support the qualifying criteria, as long as the exemption applies, the licensee or operator must retain all the data and documentation and the last three testing records (if applicable). The Regulator may revoke an exemption when the licensee fails to produce the supporting data or documentation during an audit or inspection. The licensee will have thirty days to meet the applicable base requirements or at the Regulator's discretion, the licensee can negotiate a plan to comply with the exemption requirements within an approved timeframe.

5.2 Site-specific Approval Applications

SK	The operator may apply for a site specific measurement exemption through the IRIS generic application process, if all the necessary documentation associated with an application is submitted and there is significant evidence to support the exemption, refer to Section 5 of Directive PNG017.

	(see http://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/measurement-requirements/apply-for-a-measurement-exemption)
AB	For Measurement Deviations under Directive 17 applications are sent to Directive017Applications@aer.ca
BC	Site-Specific Applications under the BC OGC Measurement Guideline for Upstream Oil and Gas Operations are sent to OGCPipelines.Facilities@bcogc.ca

If the exemption criteria cannot be met or if a specific situation is not covered in this section, the licensee may be allowed to deviate from base measurement, accounting, and reporting requirements upon approval of an application submitted to the Regulator.

If a licensee anticipates that proposed changes to the facility may not meet the approval conditions, the licensee may reconfigure the 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 appropriate sections that follow.

1. Well and/or facility list, including:
    a. Battery code and locations
    b. Well locations - unique well identifier
    c. Licence number(s)
    d. EOR project code where applicable
    e. Respective pool or stratigraphic unit or zone designations and unique identifier for each stratigraphic unit or zone
    f. Indication as to unit or non-unit operation, if applicable
    g. Mineral ownership type (i.e. Crown/Freehold)
    h. Crown royalty status (e.g. new/old, etc.)
    i. Ownership and royalty equity issues, if any
    j. Latest six months' gas, oil/condensate, and water flow rates (or expected flow rates for new wells)
    k. 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
    l. Facility plot plan for the existing system and the proposed new gas or oil source(s), if applicable
2. Justifications for deviation from measurement requirements, e.g., economics, minimal impact on measurement accuracy.

5.3 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 chart cycle is greater than eight days;
2. The single-well oil battery orifice gas meter chart cycle is greater than 24 hours; or
3. The Class 3 and 4 oil well test orifice gas meter chart cycle is greater than eight days.

Mixing of wells with EFM systems and wells using extended cycle paper charts within the same battery is allowed without approval from the Regulator.

Group, sales, or delivery point meters and Class 1 and 2 oil well test gas meters do not qualify for exemption from chart cycle requirements, and approvals for extension of the chart cycle for those meters will not normally be granted.

5.3.1 Exemptions

Orifice meter gas chart cycles may be extended without Regulator site-specific approval if all the qualifying criteria in Section 5.3.1.1 are met and an application is not required.

5.3.1.1 Qualifying Criteria

Qualifying criteria that must be met includes the following:

1. For a gas multiwell battery, all wells in the battery are gas wells. A single-well battery does not qualify for this exemption on its own; the entire group battery or gas gathering system must be considered.
2. For an oil battery, all wells in the battery are oil wells, and each well is linked to either an oil single-well battery or to an oil multiwell group battery, 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:
    a. have common working interest ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;
    b. are producing from Crown mineral leases or are producing Freehold owned minerals (i.e. there is no mixture of Crown and Freehold minerals), and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received.
5. The monthly average volumetric gas flow rate for each well is ≤ 16.9 $10^3m^3/d$ including the gas equivalent of condensate for gas multiwell battery measurement.
6. The differential pen records at ≥ 33% within the chart range, and the static pressure pen should record at ≥ 20% within the chart range. 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 and there is no visible separation between the up and down traces for a period of time.

7. Temperature must be recorded at a minimum of once per week and if that is not possible, then continuous temperature measurement (temperature pen) is required.
8. The wells that are within the same battery as the extended chart cycle wells and are designed for and/or operate on on/off flows, e.g., plunger lifts, pump-off controls, intermittent timers, must be measured using EFM. In addition, an extended chart cycle with EFM is allowed.

Exception: wells producing gas at a rate ≤ 3.0 10^3m^3/d do not have to meet qualifying criteria 6 to 8 to qualify for extended chart cycles; however, all other criteria must be met.

5.3.1.2 Revocation of Exemptions

If any of the following scenarios exists or occurs, the exemption is revoked:

1. Gas from an oil battery is delivered to a gas battery.
2. There is mixed measurement within the battery other than with EFM.
3. The oil well is not linked to either an oil single-well battery or to an oil multiwell group battery where each well has its own separation and measurement equipment.
4. The working interest participants for any well flowing to the battery have changed and a new working interest participant objects to the exemption.
5. Any well within the battery has exceeded the 16.9 10^3m^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 measurement battery or one or more of the existing wells has been modified to operate on on/off flows but EFM is not used.

Base measurement requirements must be reinstated if the exemption is revoked due to any of the scenarios stated in Section 5.3.1.2.

5.3.2 Applications

The following information must be submitted with an application to extend orifice meter gas chart cycles if the criteria in Section 5.3.1.1 are not met:

1. All of the information listed in Section 5.2.
2. If there is no common ownership or no common Crown or Freehold royalty, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold mineral owners and working interest participants, with no resulting objection received.
3. A discussion of the impact on measurement accuracy of intermingling base chart cycles and extended chart cycles in a common battery and how it may relate to concerns about working interest equity and/or royalty considerations.

4. A minimum of two current, consecutive, representative gas charts. Additionally, the licensee 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.

5.3.3 Considerations for Site-specific Approval

1. Differential and static pressures are stable, with essentially uninterrupted flow:
    a. On/off flow as designed, including plunger lifts, pump-off controls, intermittent timers, etc., that cause painting or spiking, do 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% within the chart range and the static pressure pen should record at ≥ 20% within the chart range.
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 must provide its assessment/opinion, but the Regulator 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.

5.4 Gas Proration outside SW Saskatchewan and SE Alberta Shallow Gas Stratigraphic Units or Zones or Area

For wells outside the boundary of and/or producing from stratigraphic units or zones other than those approved for the SW Saskatchewan and SE Alberta Shallow Gas Stratigraphic Units or Zones or Area (see Section 0), it may be acceptable to use a proration system for gas well production instead of having measurement for every well. If a proration system is implemented, all wells in the battery must be subject to the proration system.

5.4.1 Exemptions

Gas wells may be produced without individual well measurement and be connected to a proration battery without Regulator site-specific approval if all the qualifying criteria in Section 5.4.1.1 are met and no application is required.

5.4.1.1 Qualifying Criteria

1. All wells are classified as gas wells.
2. All freehold owners are notified without consideration of the commonality of their interest.
3. All wells flowing to the battery:

   a. have common ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;
   b. have common Crown or Freehold royalty, and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received

4. The licensee has discussed and addressed reservoir engineering issues with its own reservoir engineering staff or external knowledgeable personnel to ensure minimal reservoir engineering concerns and has documented the results for audit.
5. Total liquid production at each well in the battery is ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.
6. The maximum average daily well gas flow rate of all wells in the battery is ≤ 10.0 10^3 m^3/d including gas equivalent volume of condensate, with the highest daily well flow rate ≤ 16.9 10^3m^3 including gas equivalent volume of condensate and except as allowed below in item 9. If an existing battery with measured gas well production is being converted to a proration battery, qualifying flow rates must be based on the monthly average flow rates recorded during the six consecutive months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.
7. Periodic well tests are conducted under normal operating conditions to determine hourly flow rates that will be used to estimate monthly well production based on monthly well operating hours. The well tests are conducted for a minimum of 12 hours, and all gas, condensate, and water volumes are separated and measured during the test. For gas wells with minimal water production of ≤ 0.01 m^3 water/10^3 m^3 gas and no condensate or oil, the testing duration must be sufficient to clearly establish stabilized flow rates and single-phase testing is allowed.
8. Following the commencement of production at the proration battery, all wells are tested within the first month, then again within six months, and then annually after that. New wells added to the battery at some future date must be tested within the first month of production, then again within six months, and then annually after that.
9. For new wells tying into a gas proration battery and that will be producing more than 16.9 10^3m^3/d but that are expected to drop below 16.9 10^3m^3/d within six months, every well must be tested monthly for the first six months with a separator or until the production rate has stabilized and annually thereafter. If the gas production rate for any of the wells is more than 16.9 10^3m^3/d after six months of production or the liquid production rate is higher than 2 m^3/d, a separator must be installed to continuously separate and measure the well production, and the measurement-by-difference rules in Section 5.5 apply in this scenario.
10.

SK	This qualifying criteria does not apply in Saskatchewan
AB	For coalbed methane (CBM) wells and wells producing from above the base of groundwater protection each with water production ≤ 0.01 m^3 water/10^3m^3 gas and no condensate, if at any time more than 30.0 m^3/month of net water production is realized at the group measurement point, the operator must investigate the source of the water production by retesting and using at least a two-phase separator at the suspected gas well(s) within 30 days and then prorate the water production accordingly.
BC	Not Applicable

11. The flow rates established from the well tests are used to determine estimated monthly well production from the date of the test until the date of the next test, except that the test conducted during the first month of production is also used to estimate the wells' production for the producing days prior to the test. The total measured group gas and liquid production are prorated to the wells, based on each well's estimated production, to determine the actual well production.

5.4.1.2 Revocation of Exemptions

If any of the following scenarios exists or occurs, the exemption is revoked:

1. An oil well is added to the battery, or one or more of the existing gas wells has been reclassified as an oil well.
2. The maximum average daily flow rate of all wells in the battery for any month exceeded 10.0 10^3m^3/d, or the highest single well flow rate exceeded 16.9 10^3m^3/d except as allowed in Section 5.4.1.1, item 9.
3. Total liquid volume exceeded 2 m^3/d during a 24 hour test period or prorated to 24 hours if the test period is not 24 hours.
4. A new well has been added to the proration battery with a daily flow rate over 16.9 10^3m^3 except as allowed in Section 5.4.1.1 item 9 or whose additional volume will cause the average daily well gas flow rate of all wells in the battery to exceed 10.0 10^3m^3/d.
5. Wells within the proration battery or new wells added to the battery were not tested as required.
6. The gas proration methodology in item 11 under Qualifying Criteria in Section 5.4.1.1 was not followed.

Base measurement requirements must be reinstated if the exemption is revoked due to any of the scenarios listed above.

5.4.2 Applications

The following information must be submitted with an application to use a proration system, instead of individual gas well measurement, to determine gas well production if the criteria in Section 5.4.1.1 are not met:

1. All of the information listed in Section 5.2;

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 gas proration as it relates to reservoir engineering data needs - discussion of this matter by the licensee with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application;
3. A clear explanation and flow diagram of proposed well and group measurement devices and locations, the proposed accounting and reporting procedures, and the proposed method and frequency of testing;
4. If there is no common ownership or no common Crown or Freehold royalty, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold mineral owners and working interest participants, with no resulting objection received.

5.4.3 Considerations for Site-specific Approval

1. All wells must be classified as gas wells.
2. There are minimal equity, royalty, and reservoir engineering concerns.
3. All wells should have similar flow rates.
4. Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?
5. Total liquid production at each well in the battery should be ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

5.5 Measurement by Difference

Measurement by difference (MbD) is defined as any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes. It results in the unmeasured volume absorbing all the measurement error associated with the measured volumes. In the scenario of a proration battery, either 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. MbD is not allowed for multiwell group batteries, single-well batteries, or sales points unless special approval is obtained from the Regulator.

5.5.1 Gas Measurement by Difference

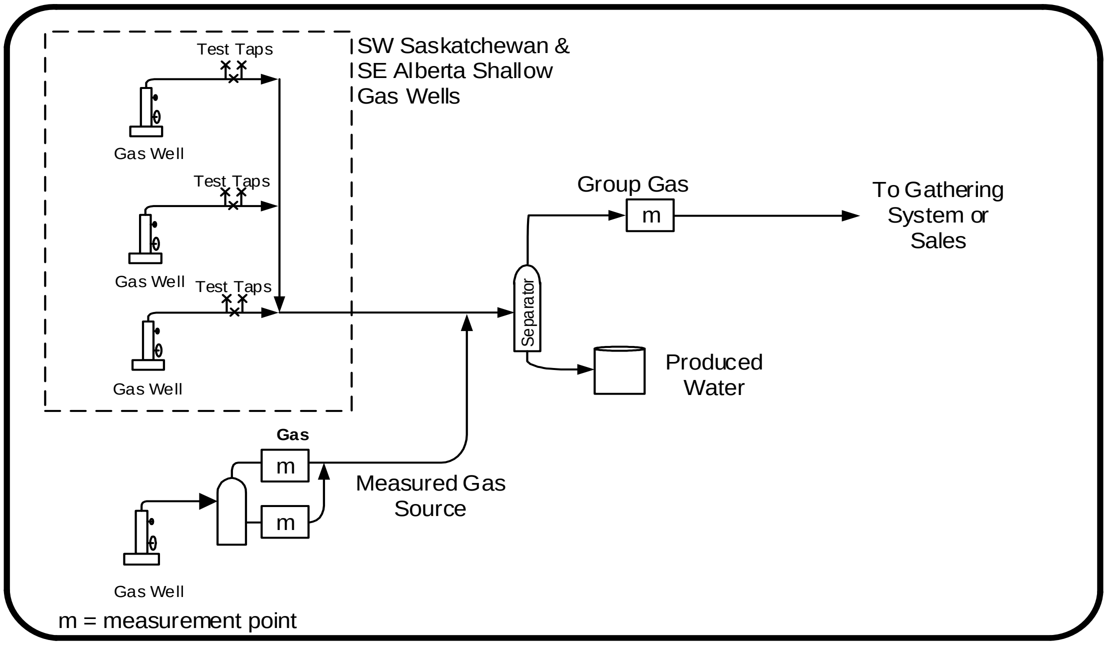
For proration batteries, MbD can include, but is not limited to, the following scenarios.

Note: All schematics are examples only; systems may be configured differently.

Scenario 1

Measured gas source(s) other than from the designated SW Saskatchewan or SE Alberta Shallow Gas Stratigraphic Units or Zones or Area delivering into a Gas Multiwell Proration SW Saskatchewan or SE Alberta Battery (Figure 5.1):

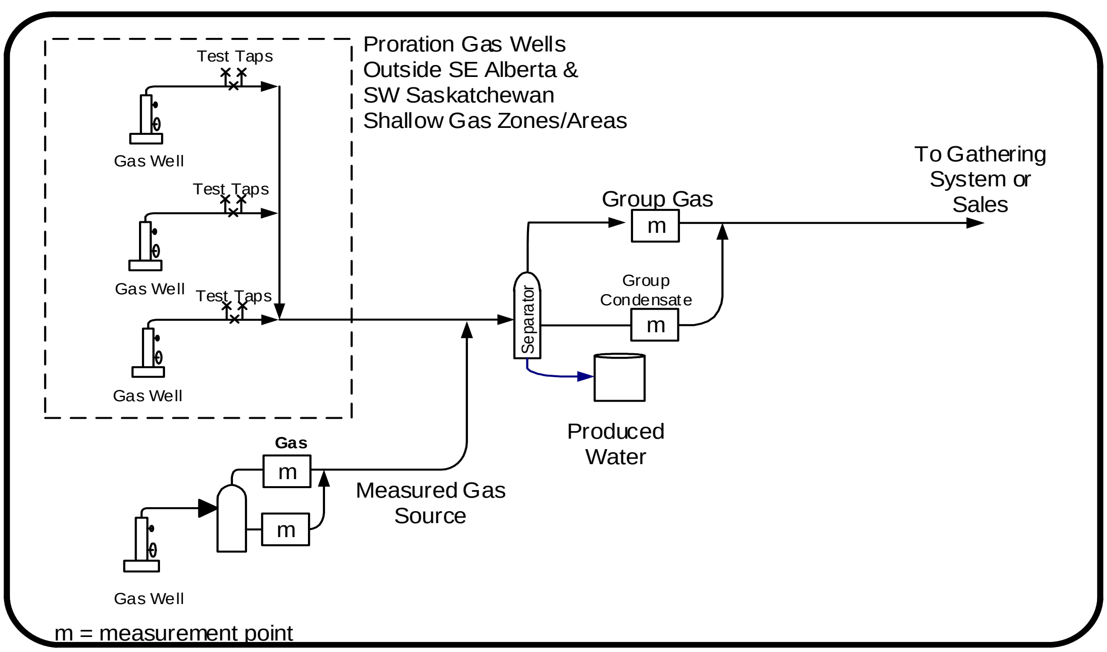
Figure 5.1



Scenario 2

Measured gas source(s) delivering into a Gas Multiwell Proration Outside SW Saskatchewan or SE Alberta Battery (Figure 5.2):

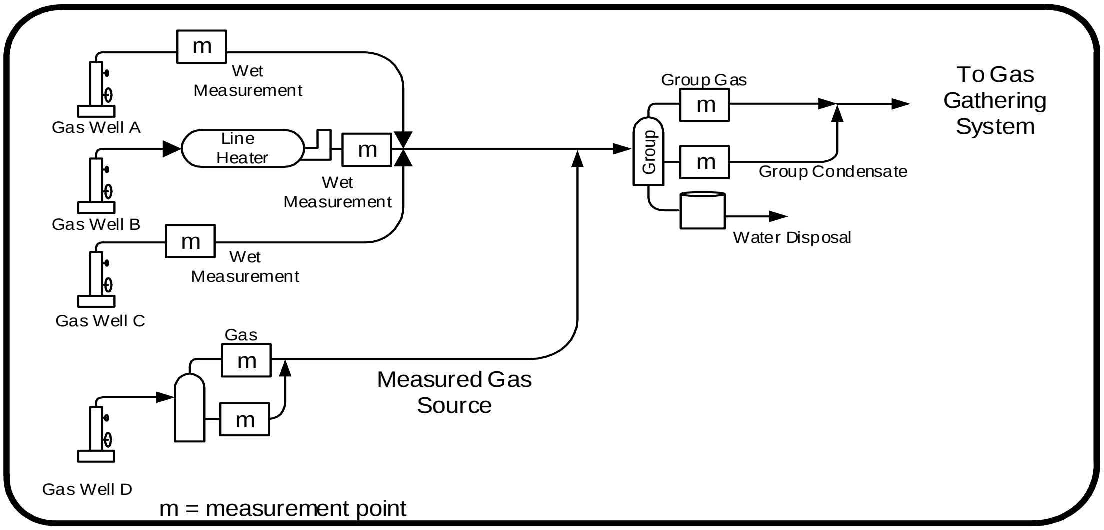
Figure 5.2



Scenario 3

Measured gas source(s) delivering into a gas multiwell effluent measurement battery with battery condensate separated, metered and recombined with battery gas (Figure 5.3):

Figure 5.3



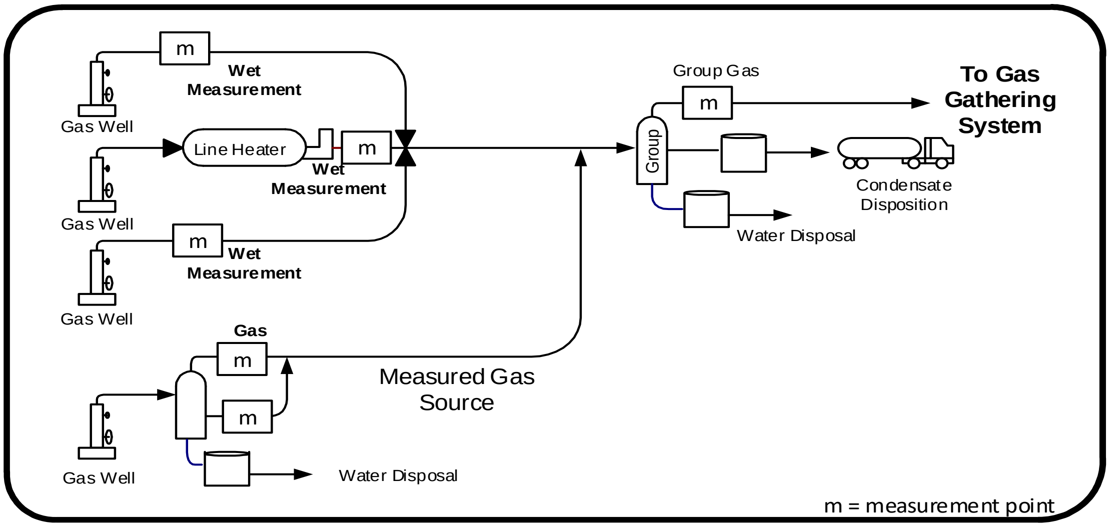
Scenario 4

Measured gas source(s) delivering into a gas multiwell effluent measurement battery with battery condensate separated and sent to a tank for disposition to sales. (Figure 5.4): Note that this scenario can also occur at gas multiwell proration batteries outside SW Saskatchewan or SE Alberta.

In this scenario, the condensate from the measured gas source may be reported as a liquid condensate disposition to the effluent battery, rather than being included in the measured gas volume. If this reporting option is used, the following conditions must be adhered to:

1. MbD ratios and qualifying criteria for both gas and oil (condensate) are applicable at the effluent battery (see Section 5.5.3).
2. The condensate meter at the measured gas source must meet delivery point measurement requirements and be proven to base 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 disposition minus the measured gas source condensate receipt plus change in inventory.

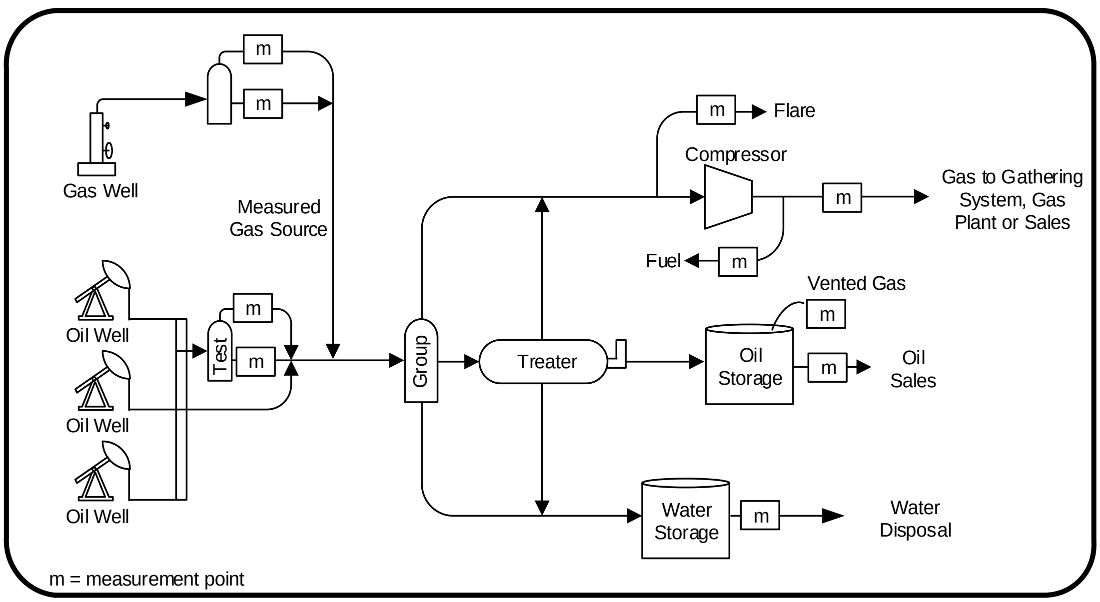
Figure 5.4



Scenario 5

Measured gas source(s) delivering into an oil multiwell proration battery (Figure 5.5):

Figure 5.5

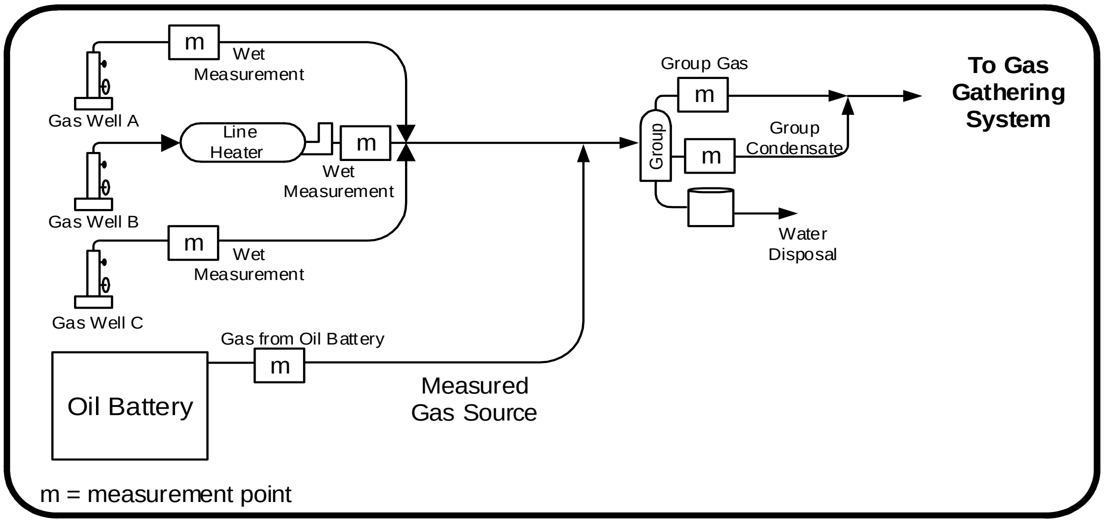


For the measured gas source(s), the applicable condensate metering and reporting option described in Table 5.6 in Section 5.5.5 must be used.

Scenario 6

Measured oil facility delivering gas into a gas proration battery (Figure 5.6):

Figure 5.6



5.5.1.1 Measured Gas Source into Gas Proration Battery

If any measured gas source will be tied into a gas proration battery:

1. The gas and liquids from all tied-in gas sources must be separately and continuously metered. If the R ratio in Table 5.1 cannot be met, the operator may consider the tied-in measured gas wells as continuous or 31-day test and include them as part of the gas proration battery. However, these wells must be tagged as continuous test.
2. The monthly gas volume, including the 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 battery monthly gas production volume.
3. Table 5.1 indicates when gas measurement by difference may be acceptable by exemption and when submission of an application may be required.

Table 5.1

Prorated gas flow rate (excluding all measured gas source)	R*	Application Required
≤ 0.5 $10^3 m^3/d$	< 1.00	No
> 0.5 $10^3 m^3/d$	≤ 0.35	No
> 0.5 $10^3 m^3/d$	> 0.35 and ≤ 0.75	No**
> 0.5 $10^3 m^3/d$	> 0.75	Yes

* 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).

** Must meet additional qualifying criteria, see Section 5.3.1.2

5.5.1.2 Measured Gas Source into Oil Proration Battery

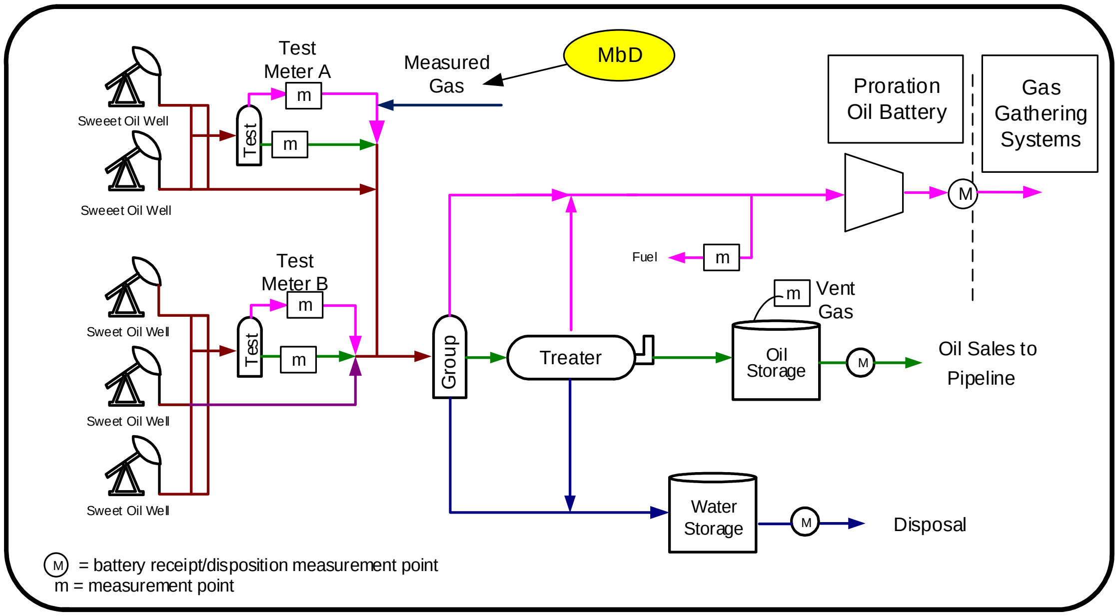
If any measured gas source is tied in to an oil battery:

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 of the 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 oil battery gas disposition volume to determine the monthly battery gas production volume. See Table 5.6 for reporting options.
3. If condensate is received from a tied-in measured gas source, the portion of the monthly condensate volume that will remain in a liquid state at the oil battery must be subtracted from the battery total monthly oil battery disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil production volume. See Table 5.6 for reporting options.

Scenario 1

Figure 5.7. Measured gas coming into oil battery with measurement by difference



Facility delineation in Figure 5.7 is determined by where the measured gas enters the oil battery relative to where the oil battery gas is measured.

To calculate actual battery gas production:

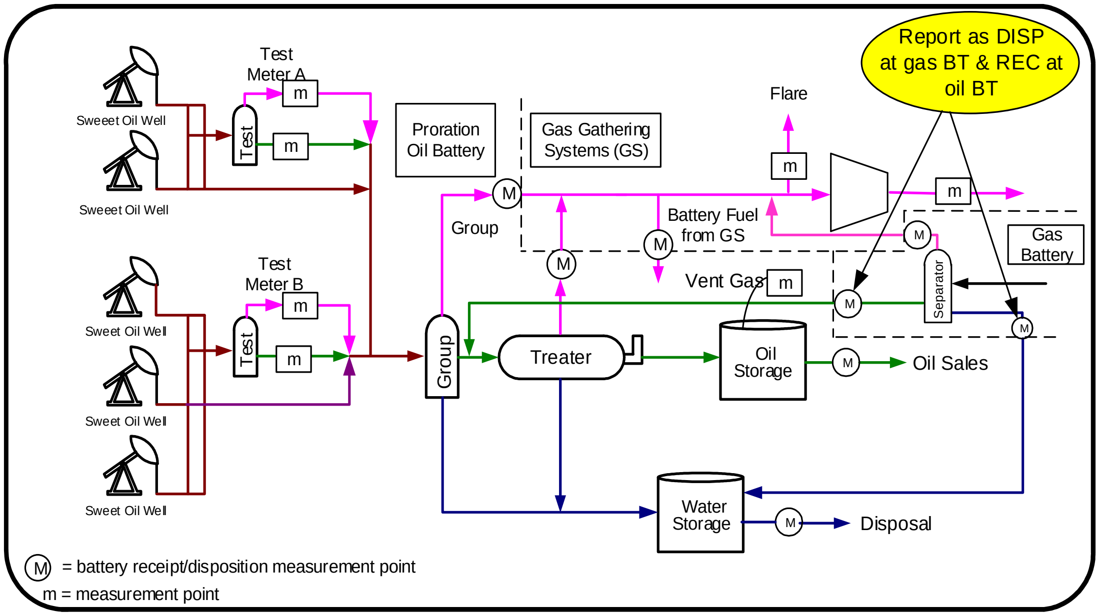
Total battery gas disposition to the gas gathering system is the metered volume after compression. The battery gas production is calculated by subtracting the measured gas receipt volumes from the sum total of the battery disposition to the gas gathering system fuel, flare, and vent. The resultant battery gas production volume is then prorated to the flowlined oil wells. The amount of measured gas that can be delivered into the oil battery is limited by the measurement by difference (MbD) percentage in Section 5.5.

To calculate battery oil production:

If the measured gas streams have condensate, see Section 5.5.1, Table 5.6 and Section 14.3 on how to calculate and report blending shrinkage, flashing shrinkage, disposition, and receipt.

Scenario 2

Figure 5.8. Measured gas battery delivering hydrocarbon liquids and water to an oil battery



To calculate actual oil battery gas production:

The sum total of the group separator and treater gas is prorated back to flowlined oil wells. The gas metered off 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 measurement by difference restriction, but oil measurement by difference still applies to the measured condensate delivered to the oil battery.

Condensate Receipt into Oil Battery:

Condensate measured at the gas battery separator may be reported as a liquid disposition, a GEV disposition, or a combination of both (depending on the composition and volume) from the gas facility into the oil battery. See Section 5.5.1.1, Table 5.1 and Section 5.5.1.2, Table 5.2 and Section 14.3 on exemptions and how to calculate and report blending shrinkage, flashing shrinkage, disposition, and receipt.

4. Table 5.2 indicates when gas measurement by difference may be acceptable by exemption and when submission of an application may be required.

Table 5.2

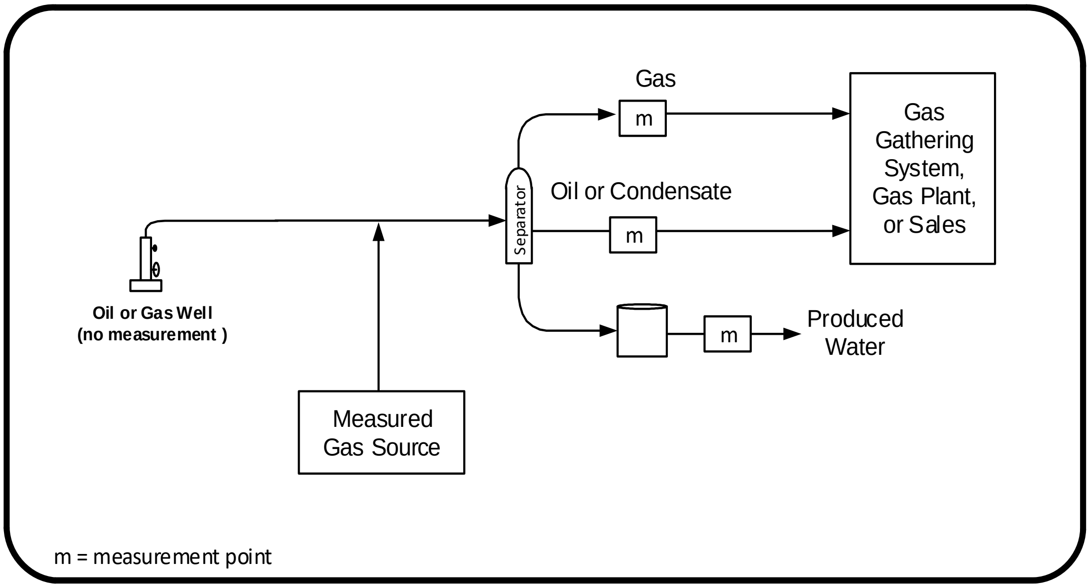
Prorated gas flow rate (excluding all measured gas source)	R*	Application Required
≤ 0.5 $10^3 m^3/d$	< 1.00	No
> 0.5 $10^3 m^3/d$	≤ 0.35	No
> 0.5 $10^3 m^3/d$	> 0.35 and ≤ 0.75	No**
> 0.5 $10^3 m^3/d$	> 0.75	Yes

* 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).
** Must meet additional qualifying criteria, see Section 5.5.3.1.2.

5.5.1.3 Measured Gas Source into Single-Well Battery

Where a measured gas source will be tied into a single-well battery, as shown in Figure 5.9, this situation does not qualify for an exemption, and an application must be submitted to and approved by the Regulator prior to implementation.

Figure 5.9



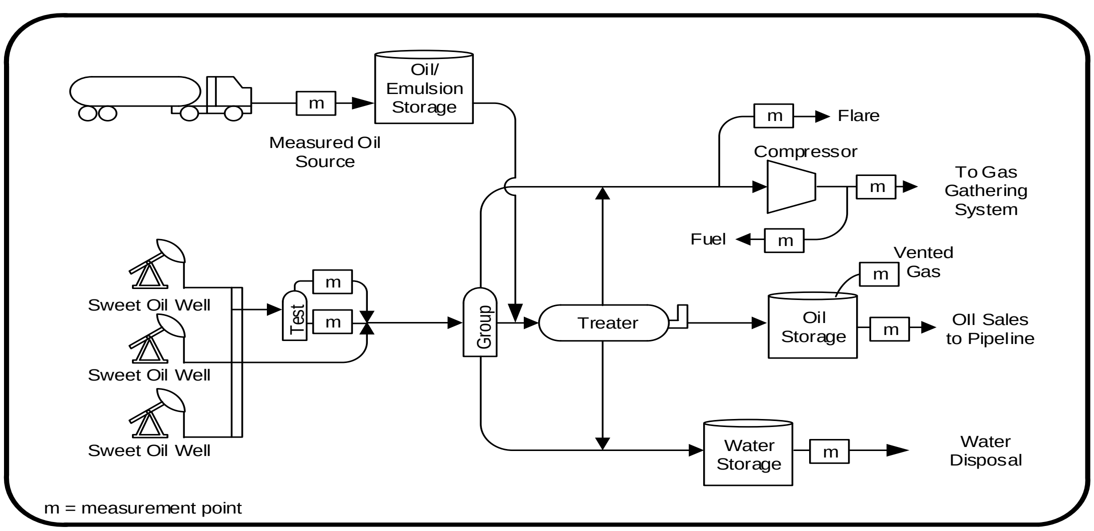
5.5.2 Oil Measurement by Difference

For oil streams, measurement by difference can include but is not limited to the following scenarios.

Scenario 1

Measured oil and/or oil-water emulsion from a battery delivering into an oil proration battery by truck (Figure 5.10):

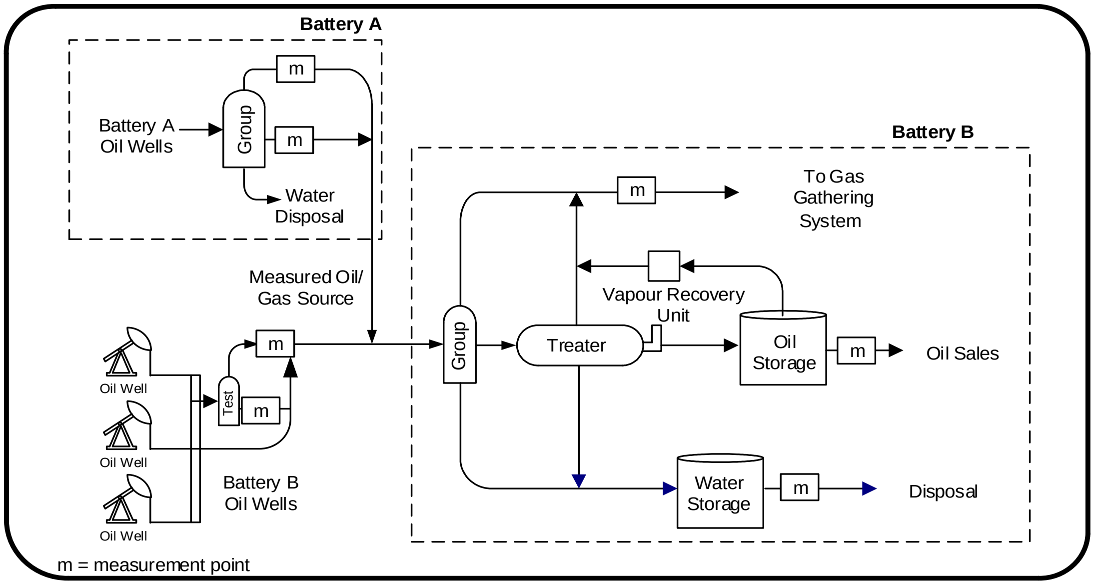
Figure 5.10



Scenario 2

Measured oil and/or oil-water emulsion (and gas if applicable) under pressure from a battery delivering into an oil proration battery by pipeline (Figure 5.11):

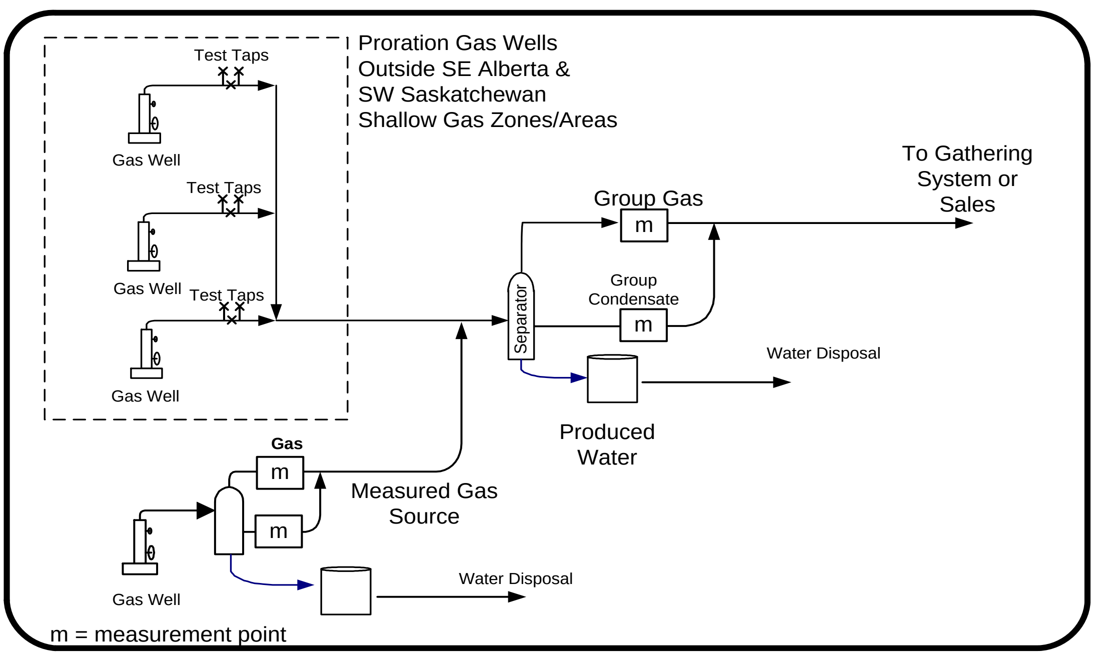
Figure 5.11



Scenario 3

Measured oil and/or emulsion from a measured gas source delivering into a gas proration battery or gas plant (Figure 5.12): For specific measurement and reporting information, see Section 5.5.3.1.1 #8.

Figure 5.12



5.5.2.1 Measured Oil and/or Oil-Water Emulsion Source into Oil Battery

If any measured oil and/or oil-water emulsion source will be delivered to a battery including trucked-in volumes:

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 scenario of oil-water emulsions, the measurement uncertainty requirements apply to total volume determination only.
2. Measured oil volumes must be determined and reported at base conditions.
3. The liquids received from the measured oil and/or oil-water emulsion source(s) must be subtracted from the total monthly battery 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. Table 5.3 indicates when oil measurement by difference is acceptable by exemption and when submission of an application is required.

Table 5.3

Measured oil delivery/receipt volume	R*	Application Required
≤ 1000 m^3/month	Not applicable	No
> 1000 m^3/month	≤ 0.25	No
> 1000 m^3/month	0.25 < R ≤ 1.00	No**
> 1000 m^3/month	> 1.00	Yes

* Total measured oil delivery/receipt volume divided by the monthly battery oil production

** Must meet additional qualifying criteria, see Section 5.5.3.2.1

5. Consideration should be given to incorporating pipeline measured oil and/or oil-water emulsion source(s) delivered by pipeline as a satellite of the battery if the battery is an oil proration battery and including it in the battery's proration system. In that scenario, measurement by difference would be avoided. A pipelined single oil well or oil wells in a multiwell group may also be considered as continuous or 31-day test and included as part of the oil proration battery. However, wells must be tagged as continuous test.

5.5.3 Exemptions

Measurement by difference is allowed without Regulator site-specific approval if all of the applicable criteria in this section are met.

If the measurement by difference will involve existing production, initial qualifying flow rates must be based on average calendar daily flow rates (monthly flow rate divided by number of production hours in the month multiplied by 24) recorded during the six months prior to implementation of the measurement by difference. 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.

5.5.3.1 Exemptions for All Measured Gas Streams

For measured gas source(s) from either gas or oil batteries tied into a gas proration battery or an oil battery.

5.5.3.1.1 Qualifying Criteria

1. Volumetric criteria for measured gas tying into a proration battery

Table 5.4

Prorated gas flow rate (excluding all measured gas source)	R*
≤ 0.5 $10^3m^3/d$	< 1.00
> 0.5 $10^3m^3/d$	≤ 0.35
> 0.5 $10^3m^3/d$	0.35 < R ≤ 0.75**

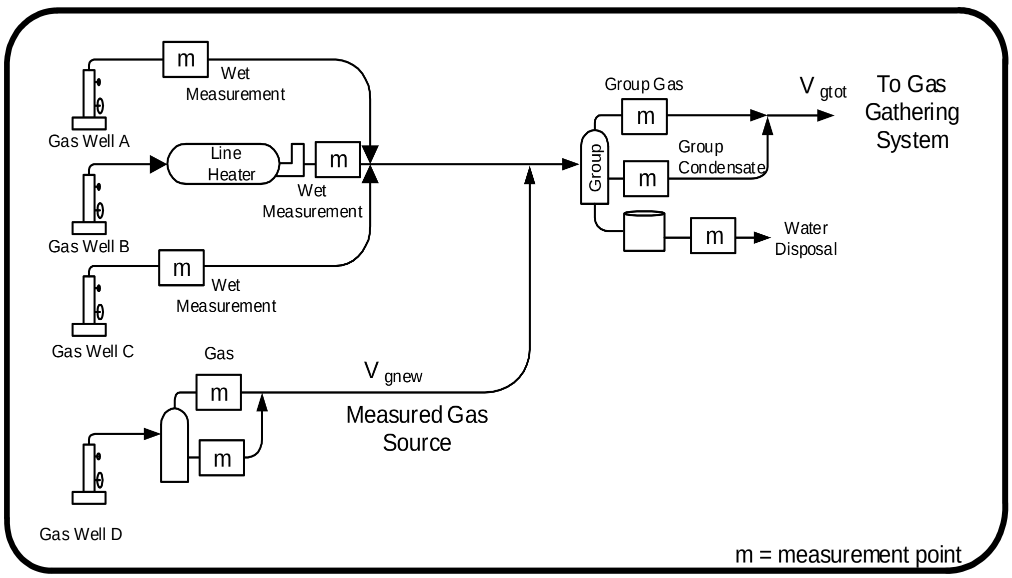
*R: Ratio of volume of all tied-in measured gas (including GEV of condensate where applicable) to the total gas disposition volume from the receiving battery (including fuel, flare and vent volumes).

** Additional l qualifying criteria apply, see Section 5.5.3.1.2

.

Example:

Figure 5.13



For the gas battery in Figure 5.13,

V_{gtot} = 100 $10^3m^3/d$ (total of measured gas and GEV of condensate delivered out of the battery, including volumes received from Gas Well D)

V_{gnew} = 30 $10^3m^3/d$ (total of measured gas and GEV of condensate delivered to the battery from Gas Well D)

Prorated gas flow rate = $V_{gtot} - V_{gnew}$ = 100 – 30 = 70 $10^3m^3/d$

R = 30/100 = 0.3

Since the prorated flow rate is above 0.5 $10^3m^3/d$ and R is below 0.35 for the Gas Well D tie-in, it is within the acceptable exemption range.

2. All proration wells flowing to the battery:

a. have common working interest ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;

b. have common Crown or Freehold royalty, and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received.

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 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 source(s) produces condensate and is connected by pipeline to an oil battery, the applicable condensate metering and delivery/reporting options described in Table 5.6 in Section 5.5.5 must be used.
6. In the scenario of an oil battery or a gas proration battery, the monthly gas volume, including the 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 the GEV of condensate, where appropriate, to determine the monthly battery gas production volume.
7. In the scenario 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 and/or emulsion from a tied-in measured gas source may be delivered to a gas proration battery, or gas plant in accordance with the following:

   a. The oil or 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 emulsion disposition must be reported as a liquid oil volume and kept whole, as it is reported through the gathering system and gas plant.

   d. Blending shrinkage requirements in Section 14.3.2 must be adhered to.

   e. The oil and gas MbD exception qualifying criteria set out in Section 5.5.3 must be adhered to.

5.5.3.1.2 Additional 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%.

2. EFM must be installed on both the gas and condensate meters at the measured gas source meter(s) and the proration battery group separator.
3. Gas proration factor targets, as set out in Table 3.1 must be maintained.
4. Potential reservoir engineering/management concerns have been considered and determined to be acceptable.

5.5.3.1.3 Revocation of Exemptions: R ≤ 0.35

If any of the qualifying criteria specified in Section 5.5.3.1.1 is not adhered to, then an exemption is revoked.

Base measurement requirements must be reinstated if an exemption is revoked.

5.5.3.1.4 Revocation of Exemptions: 0.35 < R ≤ 0.75

If any of the qualifying criteria in Section 5.5.3.1.1 or the additional qualifying criteria in Section 5.5.3.1.2 is not adhered to, then an exemption is revoked.

However, if the gas proration factor at the proration battery exceeds the proration factor targets as set out in Section 3.1.1, then the operator must take steps to bring the proration factor back within range within two months after the initial violation month. If the gas proration factor cannot be restored to within the target range within two months, the exemption 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 an exemption is revoked.

5.5.3.2 Exemption for Measured Oil Receipts Received by Truck or Pipeline at an Oil Proration Battery

5.5.3.2.1 Qualifying Criteria

1. Volumetric Criteria for Measured Oil Delivered by Truck or Pipeline to an Oil Proration Battery:

Table 5.5. Measured Oil Delivered by Truck or Pipeline to an Oil Proration Battery

Measured oil delivery/receipt volume	R*
≤ 1000 m^3/month	Not applicable
> 1000 m^3/month	≤ 0.25
> 1000 m^3/month	0.25 < R ≤ 1.00**

* Total measured oil delivery/receipt volume divided by the monthly battery oil production

** Additional qualifying criteria apply, see Section 5.5.3.2.2

2. The monthly battery oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery 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):

a. have common working interest ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;

b. have common Crown or Freehold royalty, and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received.

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 exemption criteria for gas measurement by difference must also be met.

5.5.3.2.2 Additional Qualifying Criteria: 0.25 < R ≤ 1.00

1. Delivery point measurement must be installed at the proration battery to meter the measured oil receipts (trucked in or pipelined) and the delivery point measurement uncertainty is ≤ 0.5%, irrespective of the daily volume of the metered receipts.
2. Oil (and gas if applicable) proration factor targets, as set out in Table 3.1 must be maintained.
3. Proving requirements and frequency for the delivery point measurement devices must be adhered to.
4. Blending requirements in Section 14.3.2 must be adhered to.
5. Potential reservoir engineering/management risks have been considered and determined to be acceptable.

5.5.3.2.3 Revocation of Exemptions: R ≤ 0.25

If any of the qualifying criteria specified in Section 5.5.3.2.1 are not adhered to then an exemption is revoked. Base measurement requirements must be reinstated if an exemption is revoked.

If an exemption is revoked, the operator must:

1. Deliver all oil receipts over 1000 m^3/month elsewhere;
2. Set up another treater train with separate receipt measurement, tankage, and disposition measurement to process the trucked in or pipelined receipts prior to commingling with the battery production; or
3. Obtain Regulator site specific special approval to continue.

5.5.3.2.4 Revocation of Exemptions: 0.25 < R ≤ 1.00

If any of the qualifying criteria in Section 5.5.3.2.1 or the additional qualifying criteria in Section 5.5.3.2.2 are not adhered to, then an exemption is revoked.

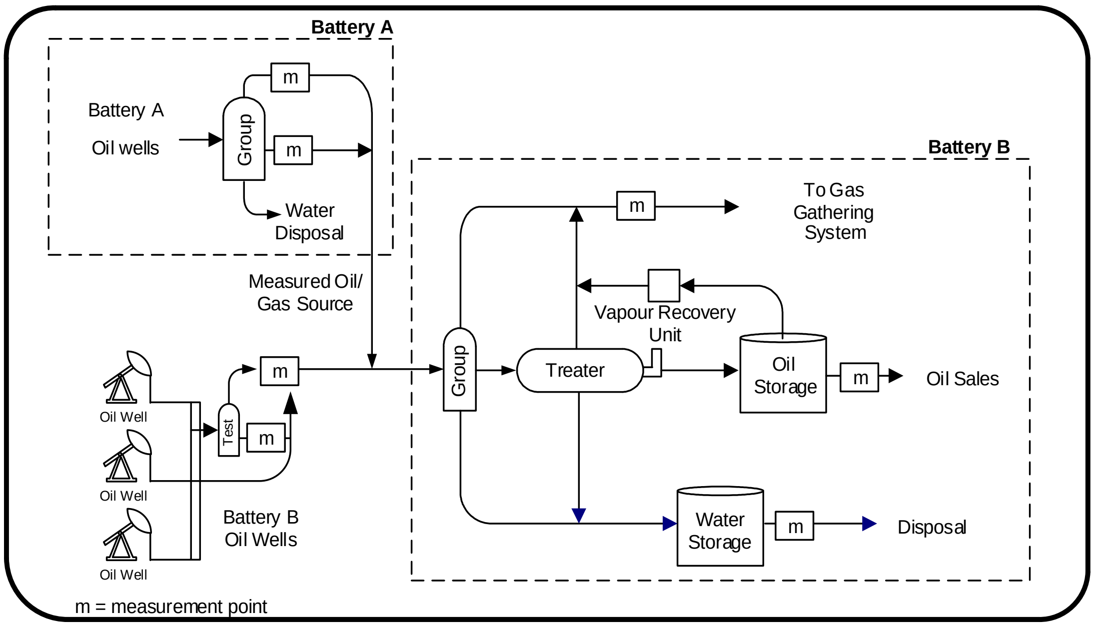
However, if the oil (and gas if applicable) proration factor(s) at the proration battery exceeds the proration factor targets as set out in Table 3.1, then the operator must take steps to bring the proration factors back within range within two months after the initial violation month. If the proration factors cannot be restored to within the target range within two months, the exemption 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 an exemption is revoked.

If an exemption is revoked the operator must:

1. Deliver all oil receipts over 1000 m^3/month elsewhere;
2. Set up a treater train with separate receipt measurement, tankage, and disposition measurement to process the trucked in or pipelined receipts prior to commingling with the battery production; or
3. Obtain Regulator site specific approval to continue.

Figure 5.14. Oil System Example



Note that with the addition of Battery A production, if the measurement by difference meets all the qualifying criteria and the total oil delivery volume at Battery B is over 100 m^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 B.

For this example (Figure 5.14), given the following data:

Battery A oil production volume = 20.0 m^3/d

Battery B oil production volume = 90.0 m^3/d before tying in Battery A

Battery A gas production volume = 15.0 10^3m^3/d

Battery B gas production volume = 20.0 10^3m^3/d before tying in Battery A

Step 1: Calculate the monthly measured oil volume from Battery A delivered to the proration battery (Battery B) and the percentage of the prorated oil production:

Monthly measured oil production volume from Battery A = 20.0 m^3/d x 30 days = 600 m^3

Battery A oil volume as a percentage of Battery B oil production volume = 20 m^3/d / 90.0 m^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 A monthly measured oil volume is below 1000 m^3/month, the oil volumetric criteria are met. The gas R ratio is also below 0.75 so an application is not required in this case, provided all prequalifying criteria are met.

5.5.4 Applications

The following information must be submitted with an application to add measured gas or oil/emulsion sources to a prorated battery if the applicable qualifying criteria and additional qualifying criteria in Section 5.5.3.2.2 are not met:

1. All of the information listed in Section 5.2;
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 is no common ownership or no common Crown or Freehold royalty, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold mineral owners and working interest participants, with no resulting objection received.

5.5.5 Considerations for Site-specific Approval

1. There are minimal equity, royalty, and reservoir engineering concerns.
2. Economic considerations, including an assessment of whether implementation of a proration system would reduce costs enough to significantly extend operations, and an assessment of the other options that have been considered.
3. The gas and liquids from the tied-in measured source(s) must be separately and continuously measured.
4. If the tied-in measured gas source(s) produces condensate and it is connected by pipeline to an oil battery, the licensee must choose the applicable condensate delivery/reporting options from Table 5.6:

Table 5.6. Options for condensate (diluent) delivery to an oil battery

Condensate received at oil battery (from all measured gas sources)	Condensate reporting options
≤ 2.0 m^3/day and ≤ 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 and send the sample to a lab for a liquid analysis (to C_{30+}). 3. Multiply the monthly metered condensate volume by the liquid volume fraction from the analysis to derive the component volumes. 4. Report the C_{6+} (Hexane plus) as a liquid condensate disposition from the measured gas source to the oil battery. 5. Most of the light ends (H_2 to NC_5) will flash out of the liquid condensate at the oil battery treater. Add the light ends (H_2 to NC_5) 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 m^3/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 C_{30+}) and 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.

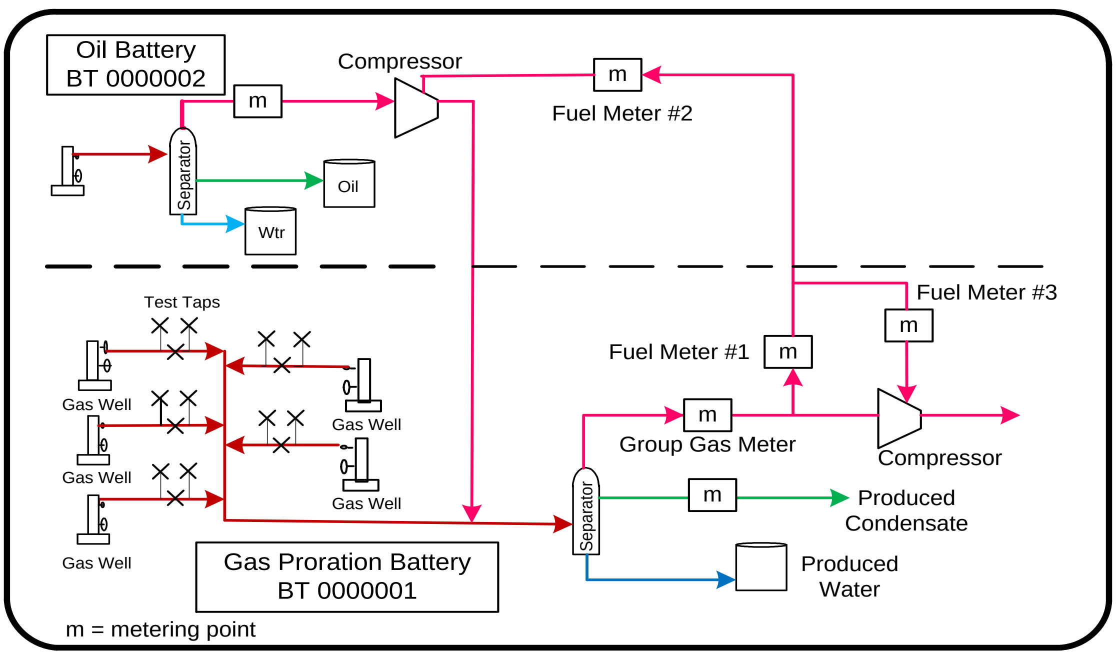
In the scenario of an oil battery or a gas proration battery, the monthly gas volume including GEV of condensate where appropriate received from a tied-in measured gas source and any other receipts must be subtracted from the total monthly battery gas volume including GEV of condensate where appropriate to determine the monthly battery gas production volume.

In the scenario of an oil battery, the monthly liquid condensate, oil, 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 oil and/or water production volume.

5.5.6 Fuel Gas Measurement by Difference

Section 4.3.3.1 (12) 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 $10^3m^3/d$. 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 5.15). Three acceptable fuel gas MbD scenarios are described below.

Figure 5.15



1. Site fuel gas at BT 0000001 is measured at fuel meter #1. The volume of fuel gas sent to BT 0000002 is ≤ 0.5 $10^3m^3/d$, and the volume of fuel gas consumed at the compressor at BT 0000001 is > 0.5 $10^3m^3/d$. In this case, fuel gas MbD is acceptable for the reported fuel gas BT 0000001, and the reported fuel gas at BT 0000001 will equal fuel meter #1 minus fuel meter #2. If the fuel gas sent to BT 0000002 is > 0.5 $10^3m^3/d$ and the fuel gas consumed at the compressor at BT 0000001 is ≤ 0.5 $10^3m^3/d$ then fuel gas MbD is acceptable for the reported fuel gas at BT 0000002, and the reported fuel gas at BT 0000002 will equal fuel meter #1 minus fuel meter #3.

2. Site fuel gas at BT 0000001 is metered at fuel meter #1. The volume of fuel gas sent to BT 0000002 is > 0.5 10^3m^3/d, and the volume of fuel gas consumed at the compressor at BT 0000001 is > 0.5 10^3m^3/d. In this case, MbD is acceptable for the fuel gas used at either BT 0000001 or BT 0000002; depending on which site is expected to have the higher reported fuel gas volume. If the fuel gas volume at BT 0000002 will be less than the fuel gas volume at BT 0000001, then fuel gas MbD is acceptable for BT 0000001, and the reported fuel gas at BT 0000001 will equal fuel meter #1 minus fuel meter #2. If the fuel gas volume at BT 0000002 will be less than the fuel gas volume at BT 0000001, then fuel gas MbD is acceptable for BT 0000002, and the reported fuel gas at BT 0000002 will equal fuel meter #1 minus fuel meter #3.

3. Site fuel gas at BT 0000001 is measured at fuel meter #1. The monthly volume of fuel gas sent to BT 0000002 is < 0.5 10^3m^3/d, and the monthly volume of fuel gas consumed at the compressor at BT 0000001 is < 0.5 10^3m^3/d. In this case, reported fuel gas volumes for BT 0000001 and BT 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 BT 0000001 = fuel meter #1 × BT 0000001 estimated fuel ÷ (BT 0000001 estimated fuel + BT 0000002 estimated fuel). Battery fuel gas estimates should be based on sound engineering estimates.

5.6 Surface Commingling of Multiple Gas Stratigraphic Units or Zones or Wells

If gas wells have been completed in multiple stratigraphic units or zones and those stratigraphic units or 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 stratigraphic unit or zone or each well usually has to be measured separately prior to commingling. Where applicable, such stratigraphic units or zones or wells may be commingled at surface prior to the combined production being measured, if the qualifying criteria in Section 5.6.1.1 are met or upon Regulator approval of an application. Proportionate monthly production volumes must still be determined and reported for each stratigraphic unit or zone or well, in accordance with the applicable criteria and considerations described in Sections 5.6.1.1 and 5.6.3.

The following criteria and considerations do not apply to wells that qualify for the Gas Multiwell Proration SW Saskatchewan and SE Alberta Battery procedures if specific stratigraphic units or zones are approved (without application) for commingling in the wellbore.

Commingling of stratigraphic units or zones in the wellbore require approval from the Regulator.

5.6.1 Exemptions

Surface commingling of two gas stratigraphic units or zones in a gas well or separate gas wells on the same surface location prior to measurement is allowed without Regulator site-specific approval if all the qualifying criteria in Section 5.6.1.1 are met and no application is required.

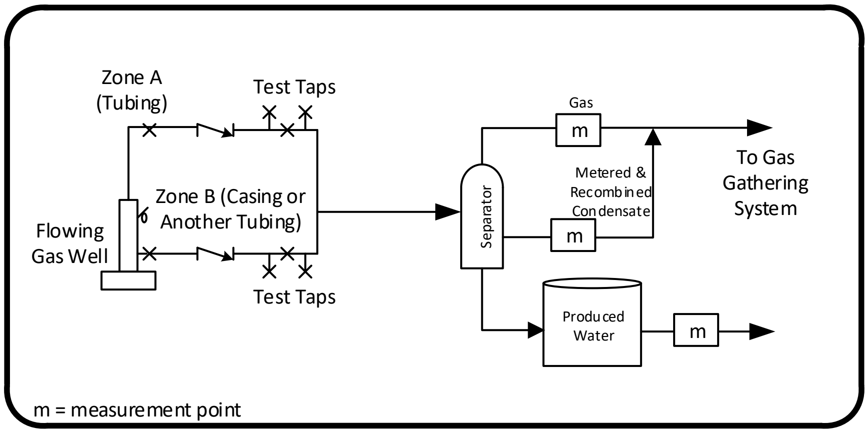
5.6.1.1 Qualifying Criteria

1. Both stratigraphic units or zones or wells:
    a. have common working interest ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;
    b. have common Crown or Freehold royalty, and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received.
2. Monthly average of total liquid production from both stratigraphic units or zones is ≤ 2 m^3/d.
3. The combined daily flow rate of both stratigraphic units or zones or wells is ≤ 16.9 $10^3 m^3$, including GEV of condensate (if recombined). If the stratigraphic units or zones or 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. If new stratigraphic units or zones/wells are to 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 stratigraphic zone/well is ≥ 75% of the shut-in wellhead pressure of the higher-pressure stratigraphic unit or zone.
5. The combined production from both stratigraphic units or zones/wells is measured continuously. Separation before measurement is required for both phases.
6. Check valves are installed on each flow line upstream of the commingling point.
7. Testing requirements:
    a. Each stratigraphic unit or zone or well must be tested once per month for the first six months after commingling, then annually thereafter, and/or immediately following any significant change to the producing conditions of either stratigraphic unit or zone or well.
    b. The tests must be conducted for 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 stratigraphic units or zones or 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 stratigraphic units or zones or wells must be done consecutively with stabilization periods.
    e. Any of the three test methods may be used. Methods (i) and (ii) are preferred given the testing is conducted under normal flowing conditions is performed without shutting in stratigraphic units or zones or wells, so that minimal stabilization time is required.

i. 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 stratigraphic unit or zone or well individually (Figure 5.16).

Test Method (i)

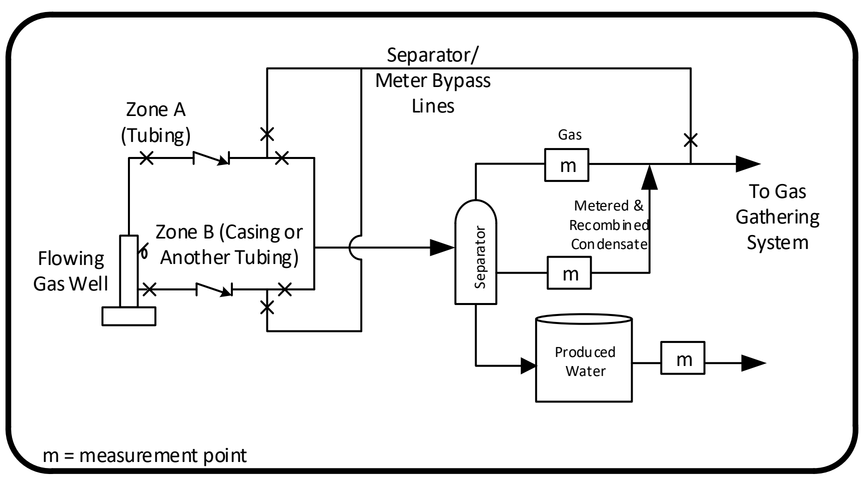
Figure 5.16



ii. Install permanent bypasses or taps to hook up temporary bypasses downstream of the check valve so that one stratigraphic unit or zone or well will be bypassing the existing separation and metering equipment while the other stratigraphic unit or zone or well is tested using the existing equipment. Note that the production from the bypassed stratigraphic unit or zone or well must be estimated based on the production test rates (Figure 5.17).

Test Method (ii)

Figure 5.17



iii. Shut in one producing stratigraphic unit or zone at a time and use the existing separation and measurement equipment to test each stratigraphic unit or zone or well individually after stabilization.

8. The production rates determined for each stratigraphic unit or zone or well by the periodic tests must be used to estimate the monthly production for each stratigraphic unit or zone or well from the date they are conducted until the date the next test is conducted. The monthly measured combined production must be prorated to each stratigraphic unit or zone or well based on the estimates, and those prorated volumes must be reported as the monthly production for each stratigraphic unit or zone or well.

5.6.1.2 Revocation of Exemptions

If any of the following scenarios exists or occurs, the exemption is revoked:

1. The combined production from both stratigraphic unit or zones or wells was not measured 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 Qualifying Criteria in Section 5.6.1.1 were not followed.
4. The gas proration methodology in item 8 under Qualifying Criteria in Section 5.6.1.1 was not followed.

Base measurement requirements must be reinstated if the exemption is revoked due to any of these scenarios.

5.6.2 Applications

The following information must be submitted with an application to commingle production at surface prior to measurement from multiple stratigraphic units or zones in a gas well or multiple wells on the same surface location if the qualifying criteria in Section 5.6.1.1 are not met:

1. All of the information listed in Section 5.2;
2. Shut-in and proposed operating pressures at the wellhead for all stratigraphic units or zones or wells;
3. Operating pressure for the gathering system at the well's measurement point;
4. Proposed testing procedures to determine the individual stratigraphic unit or zone or well production rates;
5. Proposed accounting procedures for prorating total volumes to the individual stratigraphic units or zones or wells; and
6. All wells flowing to the battery:
    a. have common working interest ownership, and where there is no common ownership, written notification has been provided to all working interest participants and no objections have been received;
    b. have common Crown or Freehold royalty, and where the wells are producing Freehold minerals and the Freehold ownership is not common, written notification has been provided to all Freehold owners and no objections have been received.

5.6.3 Considerations for Site-specific Approval

1. Generally, there is ≤ 2 m^3/day of total liquid production from all stratigraphic units or zones or wells.
2. All stratigraphic units or zones or wells must be classified as gas stratigraphic units or zones or wells.
3. There are minimal equity, royalty, and reservoir engineering concerns.
4. The combined production of all stratigraphic units or zones or wells must be continuously measured. If there are gas and liquid components, they must be separately measured.
5. Check valves must be in place on the flow line upstream of the commingling point.
6. Testing requirements:
   a. Each stratigraphic unit or zone or 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 stratigraphic unit or zone or 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 stratigraphic units or zones or 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 stratigraphic units or zones or wells must be done consecutively, with stabilization periods.
   e. Any of the three test methods described in the exemptions in Section 5.6.1.1 may be used, with the consideration that more than two stratigraphic units or zones or wells may be involved. Methods (i) and (ii) are preferred, because the testing is conducted under normal flowing conditions without shutting in stratigraphic units or zones or wells, so that minimal stabilization time is required. The Regulator may specify test procedures if specific circumstances warrant them.
7. The production rates determined for each stratigraphic unit or zone or well by the periodic tests must be used to estimate the monthly production for each stratigraphic unit or zone or well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each stratigraphic unit or zone or well based on the estimates, and those prorated volumes must be reported as the monthly production for each stratigraphic unit or zone or well.

6 Non-Heavy Oil Measurement

This section presents the base requirements and exemptions for non-heavy crude oil and emulsion measurements from wells and batteries in the upstream oil and gas industry that are used in determining volumes for reporting to Petrinex. The requirements for crude oil/emulsion volumes transported by truck are detailed in Section 10.

Non-heavy 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 measured or estimated, and
4. It has a density of less than 920 kg/m^3 at base conditions.

6.1 General Requirements

Crude oil may be found in association with water in an emulsion. In such scenarios, the total liquid volume must be measured, 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. Applications for which estimation of water content is appropriate e.g., inventory, are covered in more detail later in this section.

A licensee must measure produced crude oil/emulsion volumes by tank gauging, weigh scale, or meter unless otherwise stated in this Directive. The Regulator will consider an oil measurement system to be in compliance if the base requirements detailed in Section 6.2 are met. The Regulator 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.

6.2 General Measurement, Accounting, and Reporting Requirements for Various Battery Types

6.2.1 General Accounting Formula

Production = Total disposition + Closing inventory – Opening inventory – Total receipts

6.2.2 Oil Batteries

All wells in the battery must be oil wells.

Liquid production from an oil battery must be measured as an oil, water, or oil/water emulsion volume. This measurement may be performed at the battery 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 multiwell oil battery 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, the exemption criteria in Sections 5.5 must be met or a Regulator site-specific approval must be obtained.

Production from gas batteries or other oil batteries cannot be connected to an oil proration battery upstream of the oil proration battery group measurement point(s) unless specific criteria are met or Regulator site-specific approval is obtained as per Sections 5.5. For oil delivered to a gas system, see Section 6.2.3.

Any oil well that produces fluids from any stratigraphic unit is considered on production and a battery code is required to report the production on Petrinex even for a test.

SK	See *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting*. (formerly known as Directive R01)
AB	See *Manual 011: How to Submit Volumetric Data to the AER,* Appendix 8 for load fluid reporting.
BC	Not Applicable

6.2.2.1 Single-well Battery (Petrinex facility subtypes: 311 in SK and 311 and 331 in AB)

Oil/emulsion must be separated from gas and measured.

6.2.2.2 Multiwell Group Battery (Petrinex facility subtypes: 321 in SK and 321 and 341 in AB)

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

All separation and measurement equipment for the wells in the battery, including the tanks but excluding the wellheads, must share a common surface location.

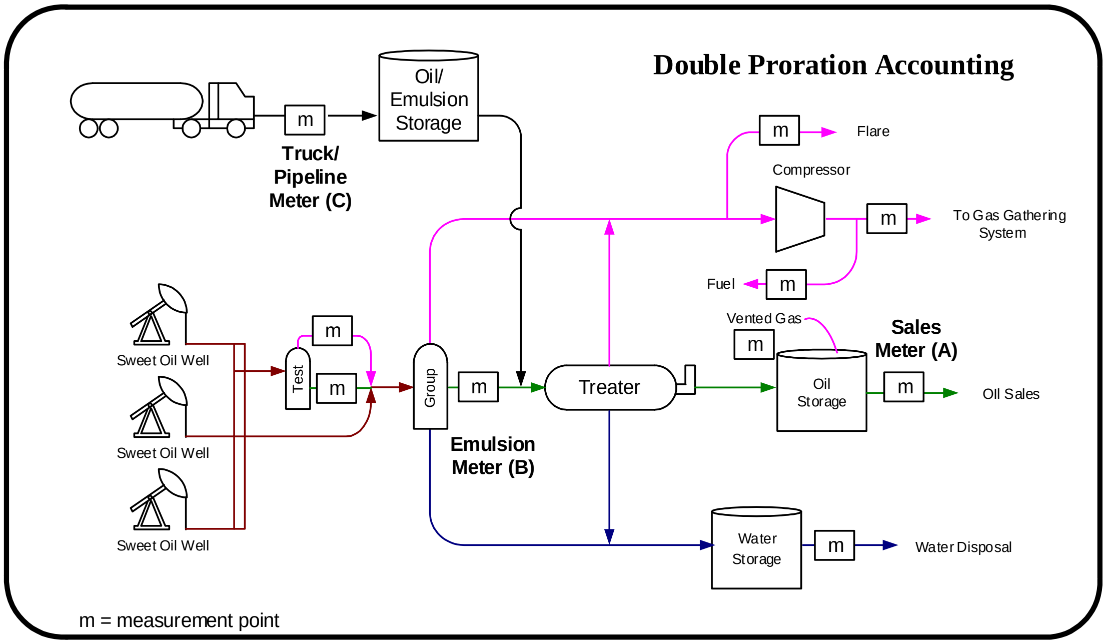
6.2.2.3 Proration Battery (Petrinex facility subtypes: 322 in SK and 322 and 342 in AB)

All well production is commingled prior to the total battery oil/emulsion being separated from the gas and measured. 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 disposition volume(s) is prorated to group/receipt measurement points and then further prorated to the wells (see Figure 6.1), is allowed without special approval subject to the following conditions:

1. All prorated oil/emulsion must be measured using measurement systems that meet delivery point requirements before commingling with other oil/emulsion receipts.
2. All measured oil/emulsion receipts to the battery and the measured oil/emulsion production must be prorated against the total oil and water disposition of the battery.

Figure 6.1



Sales oil and water disposition volumes with inventory change must be prorated to the total truck/pipeline volumes measured and the total well emulsion volumes measured (first proration). This proration using PF1 has to be done off-sheet and not reported on Petrinex.

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 on Petrinex.

6.2.3 Gas Batteries Producing Oil

All wells in the battery must be gas wells.

Oil production, receipt, disposition, and inventory volumes must be reported as liquid oil. Oil volumes must not be converted to a gas equivalent volume (GEV) and must not be added to the gas volumes. If oil is recombined with the gas and delivered to a gas plant through a gas gathering system, the oil volume as determined at the battery must be reported as a receipt of OIL by the gas plant. The gas plant must report the oil disposition as appropriate.

6.2.3.1 Single-well Battery (Petrinex facility subtype: 351)

Oil/emulsion must be separated from gas and measured.

6.2.3.2 Multiwell Group Battery (Petrinex facility subtypes: 361 in SK and 361 and 365 in AB)

Each well must have its own separation and measurement equipment, similar to a single-well battery and its gas production must be connected by pipeline to a common location for further processing.

6.3 Base Requirements for Oil Measurement

6.3.1 System Design and Installation of Measurement Devices

The system design and installation of oil/emulsion measurement devices must be in accordance with Sections 14.2, 14.3, and 14.7.

EMF systems must be designed and installed according to the requirements in Section 6.8. 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 14.9.2.

6.3.2 Volumetric Calculations

Crude oil volume measurements must be determined to a minimum of two decimal places and rounded to one decimal place for monthly reporting. Where there is more than one volume determination within the month at a reporting point, the volumes determined to two decimal places must be totaled prior to the total being rounded to one decimal place for reporting purposes.

6.3.2.1 Temperature Correction Requirements

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 metres at a base temperature of 15°C and rounded to the nearest tenth of a cubic metre (0.1 m^3). Battery or facility opening and closing inventory volumes for monthly reporting must be rounded to the nearest 0.1 m^3 but do not require correction to 15°C. The temperature correction (**C**orrection for the effect of **T**emperature on **L**iquids [CTL]) factor must be determined in accordance with API MPMS, Chapter 11.1.

In a proration battery, 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.

See Section 14.4 for more details.

6.3.2.2 Pressure Correction Requirements

Correction to a 0.0 kPa gauge (atmospheric pressure) must be performed for continuous flow crude oil pipeline measurement where custody transfer measurement is performed. See Section 14.5 for more details.

6.3.2.3 Shrinkage Factor

See Section 14.3 for details.

6.3.2.4 General Volume Calculations

See Section 14.9 for details.

6.3.3 Data Verification and Audit Trail

The field data, records, and any calculations or estimations, including EFM calculations and estimations, relating to Regulator-required data submitted to Petrinex must be kept for inspection upon request by ER. 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 licensee.
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 either electronic, magnetic, or paper form produced in the determination of measured volumes in accordance with the EFM requirements in Section 6.8.

Records of the foregoing must be provided to the Regulator upon request.

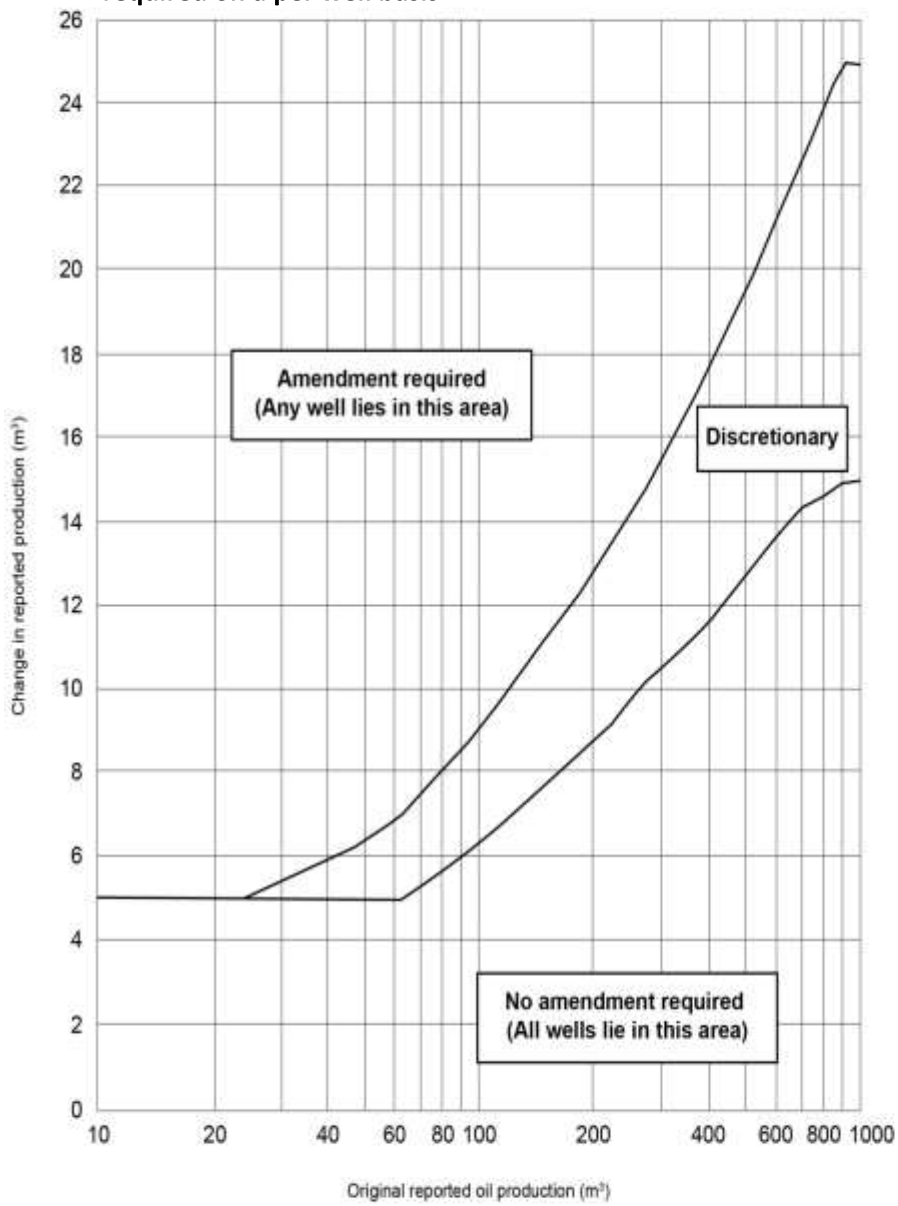
6.3.4 Amendment Requirements for Reported Information in Petrinex

SK	Section 6.3.4 does not apply in Saskatchewan.
AB	Monthly volumetric data amendments are required if significant and correctable reporting errors are identified, and they must be completed in accordance with the

requirements in *Directive 007* and *Manual 011*. The following criteria may be used to determine amendment requirements for most cases:

- For multiwell batteries, any error that results in a change in the total battery production must be corrected regardless of the magnitude of the change since the error will affect the production for all the wells in the battery.
- Any errors that results in a change in the reported oil production at a well in excess of a predetermined volume may warrant an amendment. The graph in Figure 6.2 illustrates the volumetric error criteria that must be used to determine when volumetric amendments are required.

Figure 6.2: Criteria for determining when volumetric amendments are required on a per well basis



BC	Not Applicable

6.4 Field Operations

6.4.1 Production Hours

Physical well shut-ins and emergency shutdowns (ESDs) are considered downtime. Other occurrences resulting in downtime include wax or hydrates plugging lines and some other failures. If the well has no oil production but still has gas production, it is considered to be on production. The operations personnel have to make a determination based on the operating environment in other situations when the wells are not physically shut in but may not have oil and gas production.

Oil wells are considered on production even when the wells are not pumping or flowing *in situ*ations where:

1. The wells are operating on an on/off cycle basis, such as intermittent timers, pump-off controls, and plunger lifts;
2. The wells are operating normally and as designed on repeated cycles; and
3. Part of the operation involves shutdown of pump equipment and/or periodic shut-in of the wells as part of the repeated cycle.

6.4.2 Fluid Sampling Requirements for S&W Determination (and Density)

See Section 14.6 for density determination details.

6.4.3 S&W Analysis

Conduct water-cut sampling and analysis for each test.

See Section 14.8 for S&W determination details and Appendix 3 for water-cut procedures.

6.4.4 Proration Well Testing

Proration testing requirements for non-heavy crude oil wells are detailed in Table 6.1.

Table 6.1. Proration testing requirements for non-heavy crude oil wells

Class[a]		Oil rate (m^3/d)	Minimum test frequency	Minimum time between tests[b] (days)	Minimum test duration[c] (hours)
No.	Name				
1	High	> 30	3 per month[d]	5	12
2	Medium	> 6 but ≤ 30	2 per month[e]	10	22
3	Low	> 2 but ≤ 6	1 per month	15	22
4	Stripper	≤ 2	1 every quarter	45	22

[a] Classification for each well must be determined at least semi-annually based on the average daily oil rate since the last assessment. If a well experiences operational changes that cause a change in the oil rate that could affect the classification, the operator must immediately change the classification. The average daily oil rate must be based on producing days (not calendar days).

[b] Minimum separation time between tests if minimum number of tests are conducted - the time between tests may be reduced if more than the minimum number of tests are conducted.

[c] Licensees should conduct longer duration tests for wells exhibiting erratic rates to obtain more representative test data.

[d] For Class 1 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to two per month if the well is shut in for at least 10 days within the month and to one per month if the well is shut in for at least 20 days within the month.

[e] For Class 2 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to one per month if the well is shut in for at least 15 days within the month.

6.4.4.1 Well Test Considerations

If there is a change in operating conditions during a test, such as due to 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 due to 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 200 kPa.

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 Regulator upon request.

6.4.4.2 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 flowlined wells, provided that the conditions in Section 6.7 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.

6.4.4.3 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:

$$\text{Purge time} = \text{test line volume} \div \text{new test well liquid flow rate}$$

Example: Calculate the minimum purge time required for the following test line:

Test line dimensions = 1500 m length, 88.9 mm OD pipe, 3.2 mm wall thickness

Previous well test flow rates = 5.5 m^3 oil/d, 12.0 m^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

= 8.02 m^3

Step 2

Purge time required = Test line volume (m^3) ÷ Well flow rate (m^3/hr)

Well total liquid flow rate = (5.5 m^3 + 12.0 m^3) ÷ 24 hr

= 0.729 m^3/hr

Purge time required = 8.02 m^3 ÷ 0.729 m^3/hr

= 11.0 hr

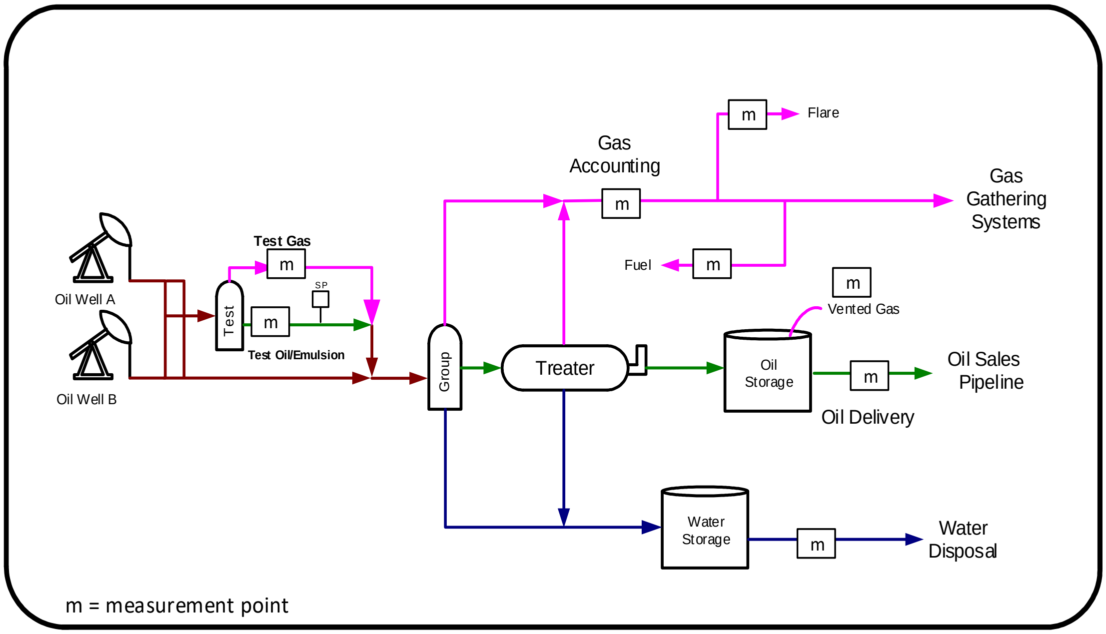
Therefore, the minimum purge time required is 11.0 hours.

6.5 Oil Proration Battery Accounting and Reporting Requirements

Prorated production is an accounting system or procedure in which the total battery 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 6.3). Individual well production must be tested in accordance with Table 6.1 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 6.5.1 for details):

1. Test production volumes of gas (in 10^3m^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.
5. Determine the actual prorated production volume by multiplying the estimated well production by the proration factor (the total actual battery production volume divided by the total estimated battery production volume).

Figure 6.3. Proration testing battery



The minimum test frequency and duration requirements (see Table 6.1) apply to all non-heavy oil wells under primary production and waterflood operations included in proration batteries.

Monitoring the performance of miscible floods and other enhanced oil recovery schemes usually requires testing criteria other than rate alone and therefore testing requirements for miscible flood schemes are set out in each scheme approval.

Licensees must monitor the classification for wells producing to a battery and meet the required testing frequency and duration for each well (see Table 6.1) unless otherwise approved by the Regulator.

Many low-rate and stripper 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 licensees the opportunity to conduct longer duration tests, class 3 and 4 wells are allowed to use up to an eight-day cycle chart drive for measurement of test gas production volumes.

The use of automatic well testing equipment and procedures with EFM provides licensees the opportunity to conduct tests of shorter durations than specified in Table 6.1. The automation computer can monitor the test and use statistical calculation methods to ensure that a representative rate is obtained prior to terminating the test. This practice is acceptable when:

1. the accumulated oil test volume is polled at a frequency of at least once per hour;
2. the criteria for stabilization ensures that the uncertainty for the monthly well oil volume does not exceed half of the maximum uncertainty of monthly volume stipulated in Section 1, Standards of Accuracy; and
3. the computer program is properly documented and available to the Regulator upon request.

The test-to-test method, whereby data from a test are used to estimate production until the next test is conducted, must be used to estimate the production volume from each oil well based on the test rate and the total production hours. This production estimation method and the proration methodology are outlined in Sections 6.5.1 and 6.5.2. A licensee may use its own worksheet format, provided that the required data are retained and available to the Regulator upon request.

6.5.1 Proration Estimated Volume Calculation

Calculate the estimated production of each well from the test data using the sample worksheet below (Table 6.2).

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 per 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 will 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 per 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 4.3.8:

   Estimated well gas production = estimated well oil production x GOR

Table 6.2

UID	WI 100060100101W400					Test duration[c]	Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water		Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	**dd**	**mm**	**m^3**	**10^3m^3**	**m^3**	**hours**	**m^3/hr**	**$10^3m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**10^3m^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	0.3688	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**

UID	WI 100080100101W400					Test duration[c]	Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water		Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	**dd**	**mm**	**m^3**	**10^3m^3**	**m^3**	**hours**	**m^3/hr**	**$10^3m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**10^3m^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
	3[a]	7	5.85	1.25	4.50	48.00	0.2406	0.0490	0.1792	336	80.8	16.5	60.2
	4[a]	7	5.70	1.10	4.10								
	17	7	6.01	1.15	5.00	25.50	0.2357	0.0451	0.1961	168	39.6	7.6	32.9
	24	7	5.40	0.99	4.10	22.75	0.2374	0.0435	0.1802	192	45.6	8.4	34.6
									Totals	**744**	**176.1**	**34.4**	**136.0**

UID	WI 100160100101W400					Testduration[c]	Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water		Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	**dd**	**mm**	**m^3**	**10^3m^3**	**m^3**	**hours**	**m^3/hr**	**$10^3m^3/hr$**	**m^3/hr**	**hours**	**m^3**	**10^3m^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 4.3.8).

[a] Tests on July 3 and 4 were comparable and consecutive, e.g., there were no operational changes. Therefore, the results are combined and used as one 48-hour test.

[b] Tests on July 1 and 2 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., 2 hr. and 45 min are entered as 2.75 hr.

6.5.2 Calculate Proration Factors and Monthly Production

1. Calculate the total estimated battery production for oil, gas, and water:

   Total estimated battery production = sum of all the wells' total estimated production

2. Calculate the total actual battery production and proration factors for oil, gas, and water:

   For oil and water,

   Total actual battery production = total monthly disposition + closing inventory – opening inventory – total receipts

   For gas,

   Total actual battery production = total monthly disposition (including fuel, flare, vent) – total receipts

   Proration factor = total actual battery production ÷ total estimated battery production

   The proration factors for oil, gas, and water must be rounded to five decimal places.

   If a GOR is used to estimate the total battery gas production volume in accordance with Section 4.3.8:

   Estimated battery gas production = actual battery oil production x GOR

   Estimated battery gas production = actual battery 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 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 production

6.6 Condensate Receipts at an Oil Battery

If condensate that could be flashed into the gas phase is received by pipeline at an oil battery, the licensee must choose from the applicable condensate reporting options in Section 5.5.

The volume of condensate received from an external source that will be reported as a GEV, that volume must be subtracted from the total monthly battery gas disposition volume to determine the monthly battery gas production volume.

When condensate is received by truck at an oil battery 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 unflashed condensate must be reported as a liquid condensate receipt.

Note that this may also be applicable to other light hydrocarbons delivered into an oil battery.

6.7 Combined (Cascade) Testing

When a prorated oil well has such low gas production that it cannot properly operate test equipment, a licensee may test two wells simultaneously - combined (cascade) test - through the same test separator. In such scenarios, 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.
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 Regulator.

Example

Well A = High gas producing

Well B = Low gas producing

Table 6.3 Test Results

Well	**Test date**	**Oil (m^3)**	**Gas (10^3 m^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**

6.8 Electronic Flow Measurement for Oil Systems

See Section 14.10 for details.

6.9 Reporting Requirements and Scenarios for Wells Producing Oil

The following scenarios are the required reporting scenarios for both oil wells and gas wells producing oil. See Section 13 for condensate scenarios.

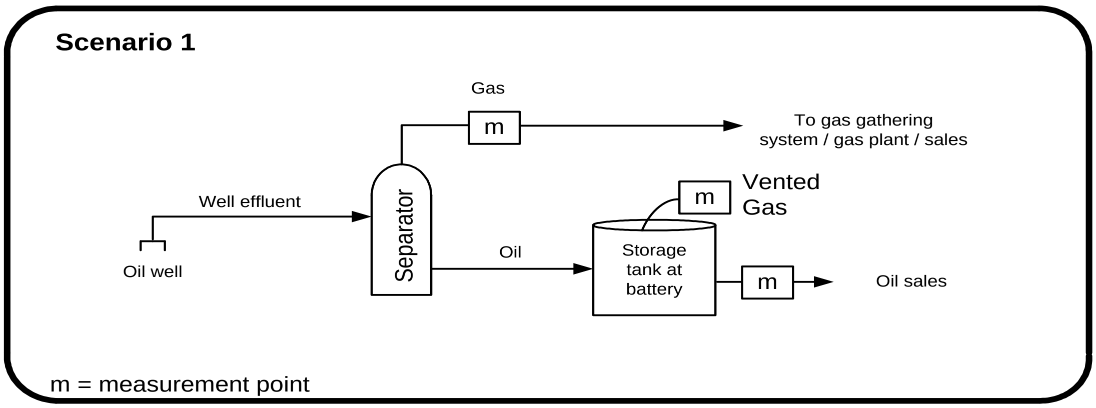
6.9.1 Oil Wells

Scenario 1

Oil separated from well effluent and sold from battery facilities.

Report as OIL PROD and OIL DISP at the battery in Petrinex.

Figure 6.4. Scenario 1

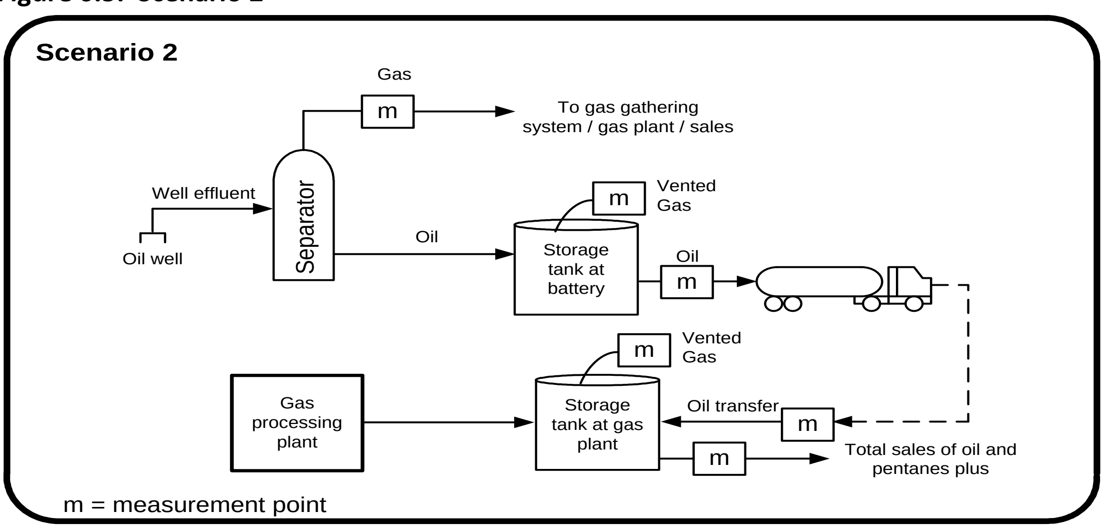


Scenario 2

Oil separated from well effluent, measured, and trucked to a tank at the gas plant.

Report as OIL PROD and OIL DISP at battery and OIL REC at the gas plant in Petrinex.

Figure 6.5. Scenario 2



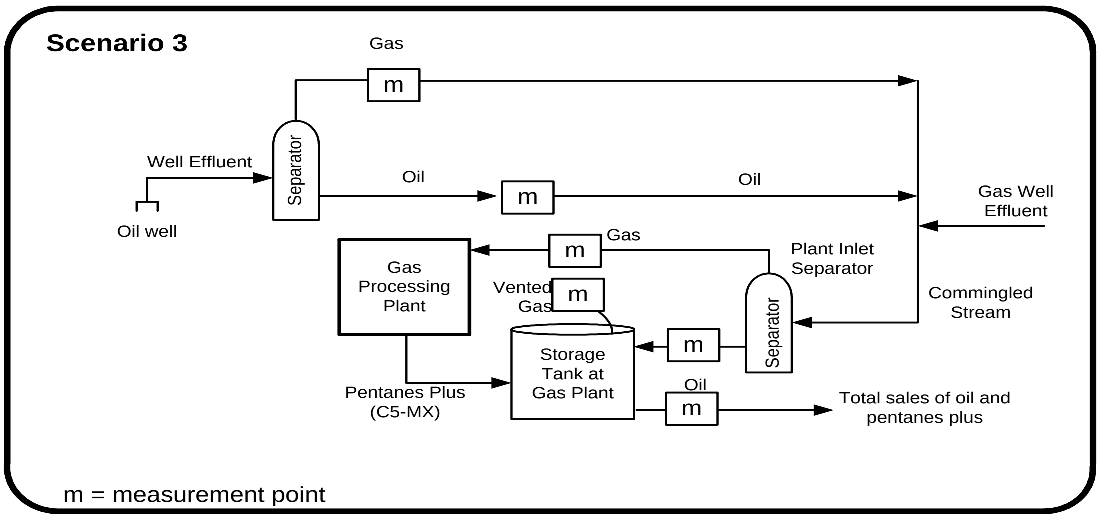
Scenario 3

Oil separated from well effluent, measured, commingled with gas, and sent to a gas plant.

Report as OIL PROD and OIL DISP at battery and OIL REC at the gas plant in Petrinex. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus products.

Note: The total plant inlet volumes reported would normally include the gas equivalent of the inlet condensate, but in this scenario, the inlet condensate volumes used to calculate the total plant inlet must be the net of the oil production that has been transferred to the plant. The reported plant inlet volumes and the pentanes plus production will be the measured volumes less this transferred oil production.

Figure 6.6. Scenario 3

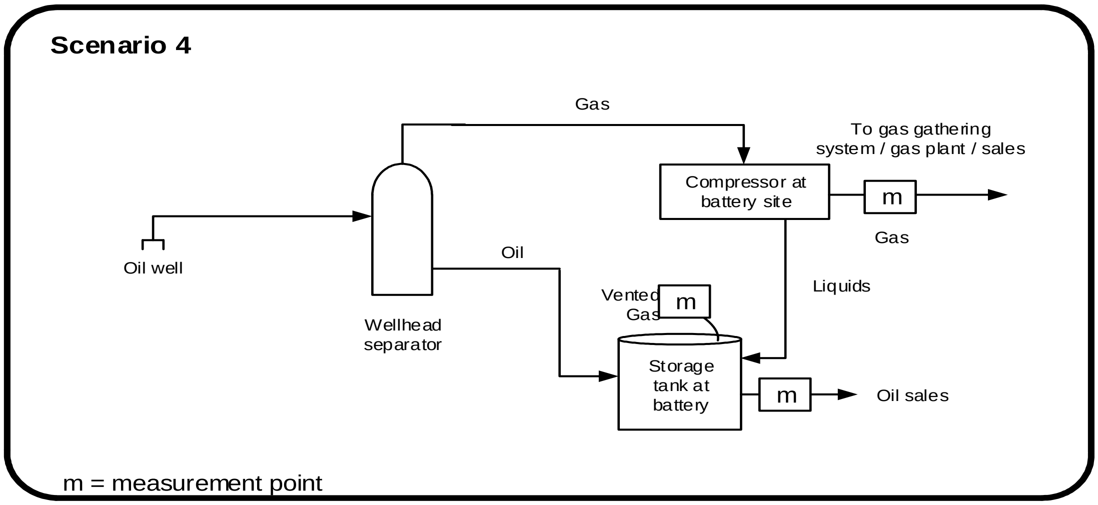


Scenario 4

Oil separated from well effluent at battery, gas compressed as part of normal battery operations, and additional liquids recovered as a result of compression and commingled with battery oil production.

Report total fluid as OIL PROD and prorate to wells in the battery and total OIL DISP in Petrinex.

Figure 6.7. Scenario 4

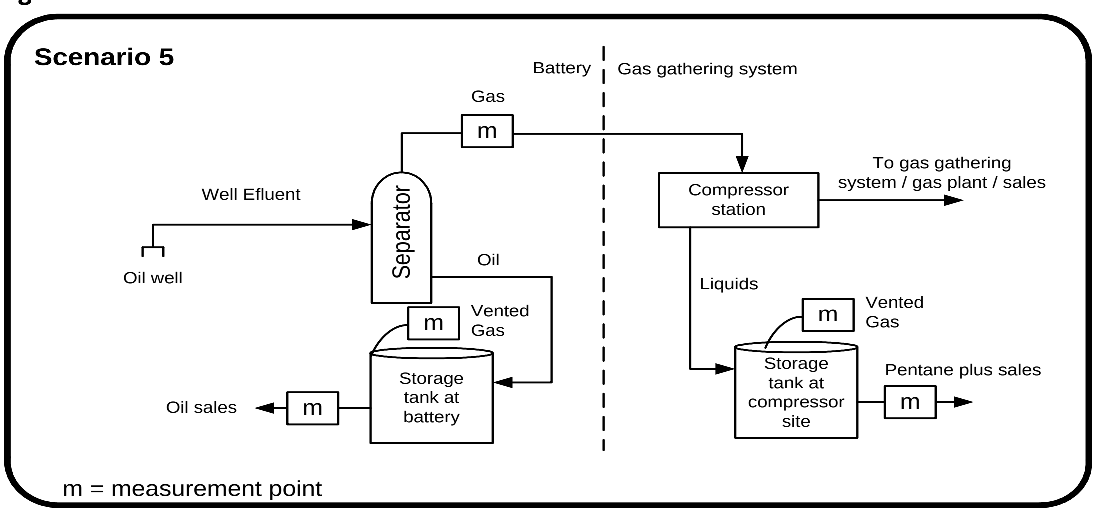


Scenario 5

Oil separated from well effluent at battery, gas compressed not as part of normal battery operations, and additional liquids recovered as a result of compression.

Report total OIL PROD and total OIL DISP at the battery in Petrinex. Hydrocarbon liquids recovered as a result of compression will be reported as pentanes plus (C5-MX) at the gathering system in Petrinex.

Figure 6.8 Scenario 5



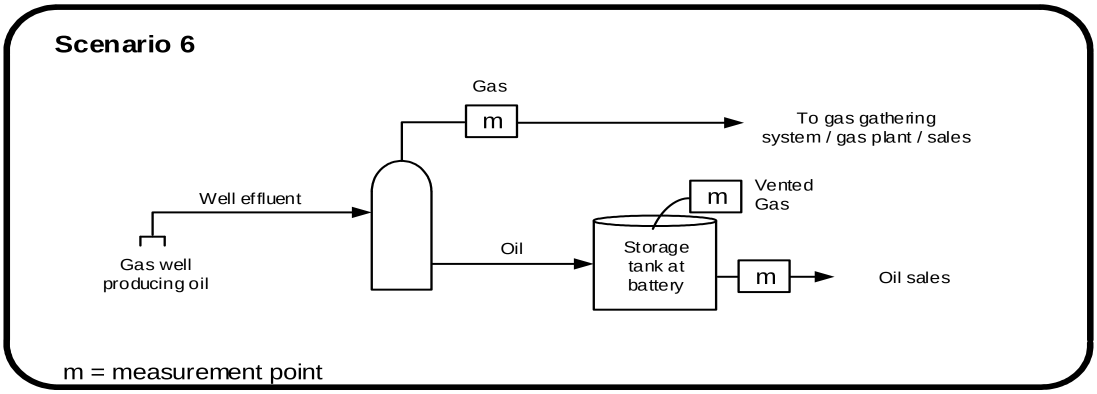
6.9.2 Gas Well Producing Oil

Scenario 6

Oil separated from well effluent, measured, and sold from battery.

Report as OIL PROD and OIL DISP at the battery in Petrinex.

Figure 6.9. Scenario 6



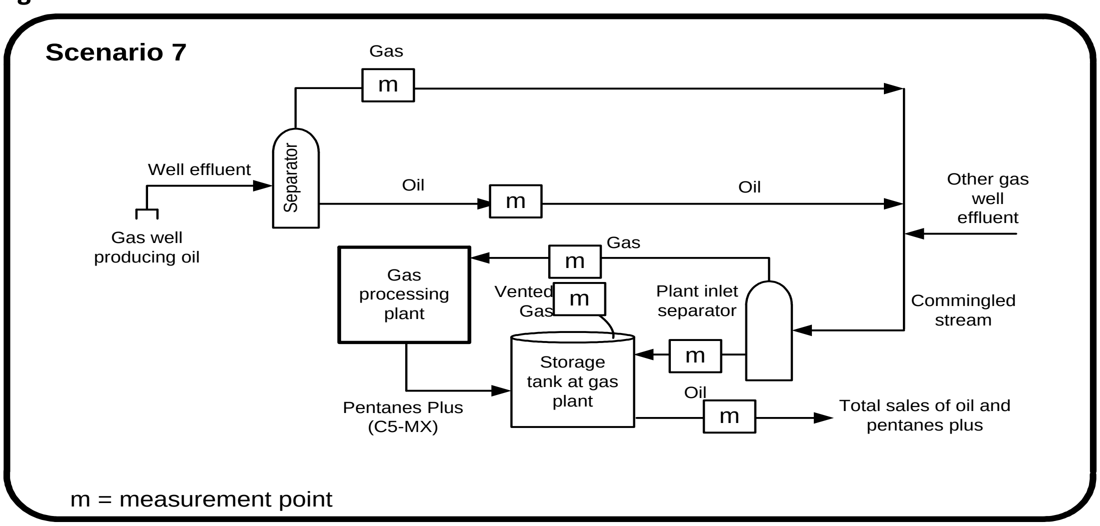
Scenario 7

Oil separated from well effluent, measured, commingled with gas, and sent to a gas plant.

Report as OIL PROD and OIL DISP at battery and OIL REC at the gas plant in Petrinex. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus (C5-MX) products.

Note: The total plant inlet volumes reported would normally include the gas equivalent of the inlet condensate, but in this scenario, the inlet condensate volumes used to calculate the total plant inlet must be the net of the oil production that has been transferred to the plant. The reported plant inlet volumes and the pentanes plus production will be the measured volumes less this transferred oil production.

Figure 6.10. Scenario 7

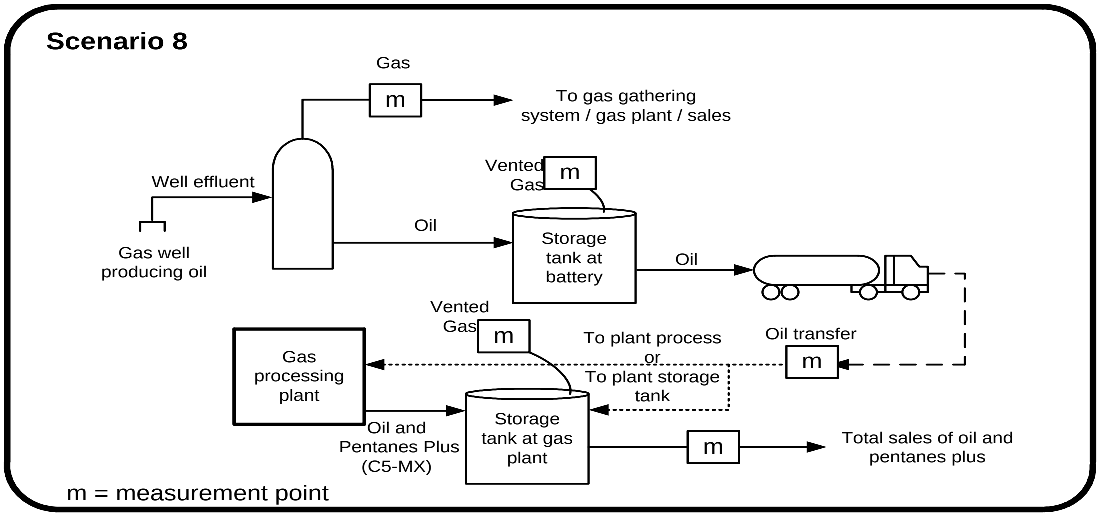


Scenario 8

Oil separated from well effluent, measured, and trucked to a gas plant process or a storage tank at the gas plant.

Report as OIL PROD and OIL DISP at battery and OIL REC at the gas plant in Petrinex. Shipments reported at the gas plant will be the total combined sales of this transferred oil and the plant pentanes plus (C5-MX) products.

Figure 6.11. Scenario 8



7 Gas Proration Batteries

This section presents the requirements and exemptions relating to measurement, accounting, and reporting for gas proration batteries.

Gas well operators have the option of not measuring the gas and/or separated liquids for each well. If the gas and liquids are not separated and measured, they can be prorated. Operators that decide to install prorated systems in accordance with the provisions of this section are accepting higher uncertainty at the wellhead, offset by lower capital and operating costs.

Prorated wells are tested periodically to determine the typical flow rate. The gas and liquids from a number of wells are measured at a group meter, and the volume at the group meter is prorated back to the individual wells based on the most recent test and the hours on stream.

The measurement uncertainty assigned to individual wells within gas proration batteries is greater than for wells where the gas is separated and measured. For this reason, operators should understand the impact of this type of measurement when dealing with partners and third parties.

Prorated wells can be tied in to the same system as measured wells but under separate battery codes. In these scenarios, the measured wells are kept whole, and the difference between the proration battery disposition and the measured well volume is prorated to all the proration wells. This is referred to as measurement by difference (see Section 5.5), since the measured volume is subtracted from the group measurement before proration. Measurement by difference increases the uncertainty of the prorated well volume estimate.

7.1 General Requirements

The three types of gas proration batteries include:

1. Gas multiwell proration SW Saskatchewan and SE Alberta batteries (Petrinex facility subtype 363),
2. Gas multiwell proration outside SW Saskatchewan and SE Alberta batteries (Petrinex facility subtype 364), and
3. Gas multiwell effluent measurement batteries (Petrinex facility subtype 362).

All wells in a gas proration battery must be gas wells and must be connected by flow line to a common group separation and measurement point.

All 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 to determine the actual well production volumes for reporting purposes. All wells must be tested annually unless otherwise stated in Section 7.

All volumetric calculations must be in $10^3 m^3$, to the required decimal places listed in Table 7.1.

Table 7.1. Required decimal places for volumetric calculations in prorated gas batteries

Type of calculations	Number of decimals to be calculated to	Number of decimals to be rounded to
Production and estimated production	2	1
Well test gas, GEV of test condensate, test condensate, or test water	3	2
WGR, condensate-gas ratio (CGR), and oil-gas ratio (OGR)	5	4
Proration factors, ECF	6	5

Test taps must be installed at all proration gas wells. The required test tap locations are illustrated in Figure 7.8 for Petrinex subtypes 362, 363 and 364.

See Section 8 for sampling and analysis of gas, condensate, and water.

7.1.1 Group Measurement

Where delivery point measurement is required, the combined (group) production of all wells in the proration battery must have three-phase separation and be measured as single-phase components. 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 online product analyzer on the liquid leg of the separator may be used provided that:

1. The measurement system design meets the requirements of Section 14
2. The condensate and water is recombined and delivered to a gas gathering system or gas plant for further processing

If liquid condensate is trucked out of the group separation and measurement point to a gas plant for further processing:

SK	The condensate must be reported as a liquid condensate volume from the battery.
AB	The condensate must be reported as a gas equivalent volume from the battery.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Gas wells in any one of the three types of proration batteries must not be commingled with measured gas sources or gas from another proration battery prior to group measurement, or with gas wells in a different type of gas proration battery, upstream of their respective group measurement points. Variances from this requirement may be allowed if the Exemption criteria in Sections 5.5 and 5.5.1 are met or if site-specific approval has been obtained from the Regulator prior to implementation.

7.1.2 Stabilized Flow and Representative Flow

Wells that use artificial lift systems are characteristically never in stabilized flow and thus must be tested for a minimum duration that runs over multiple flow cycles to accurately determine a representative volume of gas, condensate, or water. These representative production volumes are then extrapolated to accurately reflect the wells' production over an extended period of time.

7.2 Gas Multiwell Proration SW Saskatchewan and SE Alberta Batteries (Petrinex facility subtype: 363)

Gas wells in this type of battery do not require dedicated continuous measurement for each well or special approvals from the Regulator.

Production rates determined during a well test must be used in the estimation/proration calculations within 30 days of the test until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells, based on each well's estimated monthly gas production. Estimated well gas production is based on hourly production rates, determined by periodic well tests and monthly producing hours.

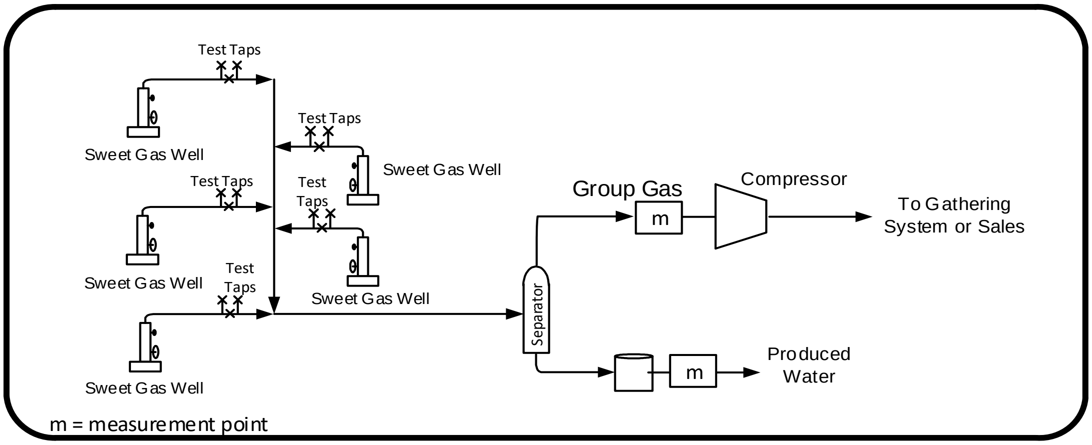
Gas wells that produce from shallow gas stratigraphic units or zones in SW Saskatchewan or SE Alberta may be included in these types of batteries.

SK	The stratigraphic units or zones include coals and shales from the base of the Glacial Drift to the base of the Upper Cretaceous. The production from two or more of these stratigraphic units or zones without segregation in the wellbore requires prior approval from the Regulator for commingled production.
AB	The stratigraphic units or zones include coals and shales from the top of the Edmonton Group to the base of the Colorado Group. The production from two or more of these stratigraphic units or zones without segregation in the wellbore requires prior approval from the Regulator for commingled production, which has been granted in a portion of SE Alberta in Order No. MU 7490, or adherence to the self-declared commingled production requirements described in *Directive 065: Resources Applications for Oil and Gas Reservoirs*.
BC	Not Applicable

7.2.1 Group Measurement

Group measured production is generally determined through individually measured product streams. A minimum of two-phase group measurement is required because the battery water production must be reported at the battery level. This group measurement point is located generally at the battery site where a compressor is present (see Figure 7.1).

Figure 7.1. Typical Gas Multiwell Proration SW Saskatchewan or SE Alberta Battery



7.2.2 Size of a Gas Multiwell Proration SW Saskatchewan or SE Alberta Battery

There is no limit on the number of flowlined wells that may be in a Gas Multiwell Proration SW Saskatchewan or SE Alberta Battery. However, licensees are encouraged to consider the logistics of the battery's operation in determining the size of these batteries, with the key factors being:

1. The ability to conduct representative well tests at the minimum frequency specified in Table 7.2; and
2. The configuration and operating pressures of the battery and flow lines such that all wells can readily flow.

This approach will generally result in the main pipeline system laterals being used to establish a group measurement point.

7.2.3 Testing Requirements

Gas production rate tests must be conducted for each well in the battery in accordance with the following requirements:

1. The test must be of sufficient duration to clearly establish a stabilized flow rate. Stabilized flow indicates a point at which flowing parameters of gas, condensate, or water are producing under normal operating conditions and represent production levels equal to the well's normal average flow rate. Stabilized flow can only be achieved when all testing equipment associated in determining an actual volume has reached equilibrium, i.e., liquid levels in test separator, pressure and temperature stabilization to normal operating conditions.
2. The test must be representative of the well's capability under normal operating conditions. Representative flow can be used when stabilized flow is not achievable, such as for wells with artificial lift systems and wells with slugging characteristics. The test volumes of gas, condensate, or water must be representative of the well's production capability under normal operating conditions.

   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, condensate, or water. These representative production volumes are then extrapolated to accurately reflect the wells' production over an extended period of time.

3. Testing programs and procedures must ensure that all wells are treated equitably within their respective batteries. These types of wells are typically tested by directing flow from the well through a test meter. However, a test separator system may also be used.

4. New wells must be tested within the first 30 days of production, then again within 12 months, and thereafter according to Table 7.2.

If these requirements cannot be satisfied, the operator must either reconfigure the system, e.g., redirect some wells to another battery/group measurement point, or test each of the individual wells within the battery once per month.

Table 7.2. Testing frequency for SW Saskatchewan and SE Alberta shallow gas wells

Minimum rate	Maximum rate	Number of tests	Frequency*
	≤ 0.5 $10^3m^3/d$	1	Triennial
> 0.5 $10^3m^3/d$	≤ 5.0 $10^3m^3/d$	1	Biennial
> 5.0 $10^3m^3/d$		1	Annual

*See Appendix 2 for frequency definition.

7.2.4 Production Accounting and Reporting Procedures

7.2.4.1 Water Reporting Requirements

The reporting of water production for the qualified wells in Gas Multiwell Proration SW Saskatchewan and SE Alberta Batteries is not required. However, all water receipts and disposition must be reported at the battery level. An ABMC receipt code for Alberta and an SKMC receipt code for Saskatchewan must be used to balance the disposition at the battery level on Petrinex. If the water is trucked to non-Petrinex reporting facilities without a reporting code or evaporated on site, it must be reported using an ABMC or SKMC disposition code respectively.

7.2.4.2 Gas Production Volume Calculations

Monthly gas production volumes are to be calculated as follows:

1. Calculate well gas test rate:

   Well gas test rate (10^3m^3/hour) = Well test gas volume (10^3m^3) ÷ Well test duration (hours)

2. Calculate estimated monthly well gas volume:

   Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3. Calculate total estimated gas production for the battery:

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

4. Calculate proration factor for gas:

   Gas proration factor =Total battery measured monthly gas volume ÷ Total battery estimated monthly gas volume

5. Calculate actual monthly (prorated) well gas production:

Actual monthly well gas production = Gas proration factor x Estimated monthly well gas volume

7.3 Gas Multiwell Proration Outside SW Saskatchewan and SE Alberta Batteries (Petrinex facility subtype 364)

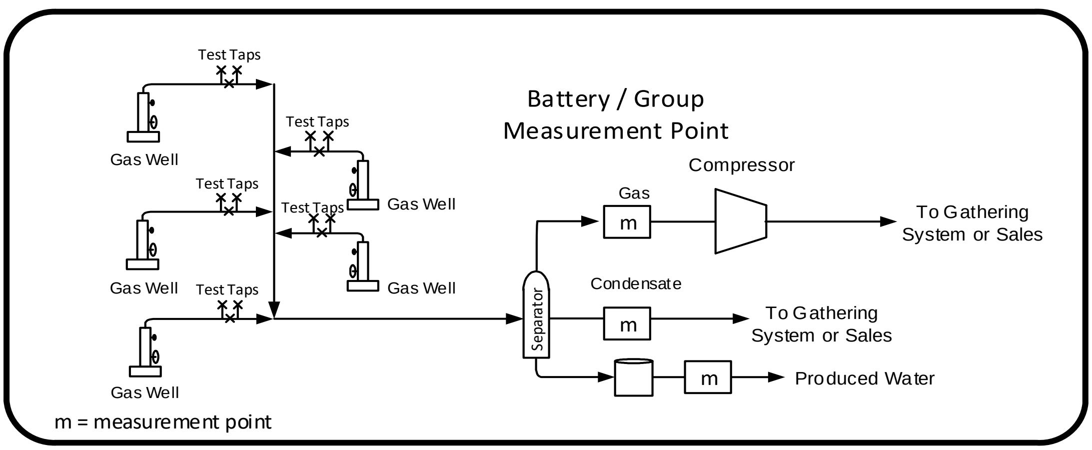
Gas wells in this type of battery do not require dedicated continuous measurement for each well. Production rates, WGRs, and/or CGRs determined during a well test must be used within 30 days in the estimation/proration calculations until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells based on each well's estimated monthly gas production. Estimated well gas production is based on hourly production rates, determined by periodic well tests and monthly producing hours.

Total battery condensate production must be measured if present. If it is delivered for sale from the battery, it must be prorated back to the individual wells based on each well's CGR from the production tests. The sales condensate must be reported as a liquid disposition on Petrinex. Then the estimated gas production volume at each well will not include the GEV of the condensate. If the condensate is recombined with the gas for further processing at a gas plant, the condensate must be reported as a GEV and added to the measured gas production volume and reported on Petrinex.

Total battery water production must be measured and prorated back to the individual wells based on each well's estimated monthly water production. Estimated well water production is based on a WGR, determined by well tests multiplied by the estimated monthly well gas production (see Figure 7.2).

Figure 7.2. Typical Gas Multiwell Proration Outside SW Saskatchewan and SE Alberta Battery



If total water production at each well in the battery is less than or equal to 0.50 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion, water production may be prorated to all wells in the battery based on the estimated gas production at each well. If a group of new wells not previously on production is to be configured as a proration battery, the qualifying flow rates must be based on production tests conducted under the normal operating conditions of the proration battery.

There is no geographical or zonal limitation for this type of proration battery. The Exemption criteria in Section 5.4 must be met or Regulator site-specific approval must be obtained prior to the proration battery implementation either at the initial design and installation stage or at a later stage of production when the production rate decreases to a point that continuous measurement is not economical.

Gas wells producing oil rather than condensate must not be tied into a Gas Multiwell Proration Outside SW Saskatchewan or SE Alberta battery unless the well oil and gas production volumes are separated and measured prior to commingling with the other wells in the battery and either the Exemption criteria in Sections 5.5 and 5.5.1 are met or site-specific approval has been obtained from the Regulator prior to implementation. However, if a gas well classified as producing condensate in a gas multiwell proration outside SW Saskatchewan or SE Alberta battery is reclassified by the Regulator as producing oil, the well may remain in the battery provided that the well is equipped with a separator and there is continuous measurement of the gas, oil, and water or, alternatively, the measurement, accounting, reporting procedures specified in Section 7.3.2.1 are followed.

7.3.1 Well Testing Requirements

Well testing is typically performed by directing well production through a three-phase portable test separator configured with dedicated meters for gas, condensate, and water. Test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be measured during typical well test durations. Other options that provide equivalent liquid volume determination accuracy may also be considered. For example, if 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, may be acceptable (see Figures 7.3 and 7.4).

Figure 7.3. Typical testing unit for Gas Multiwell Proration Outside SW Saskatchewan and SE Alberta Battery

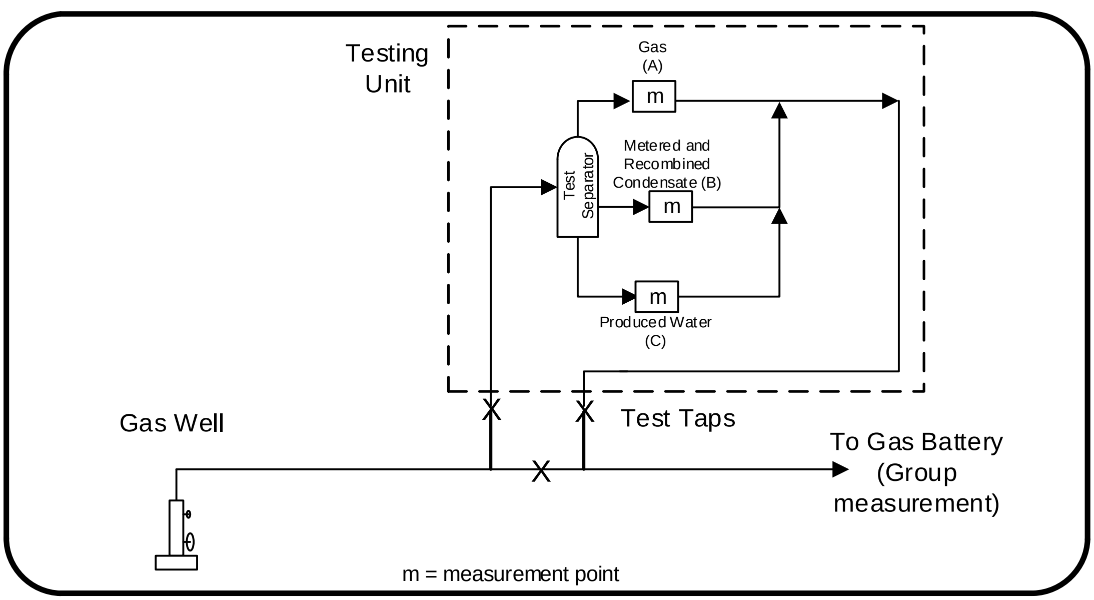
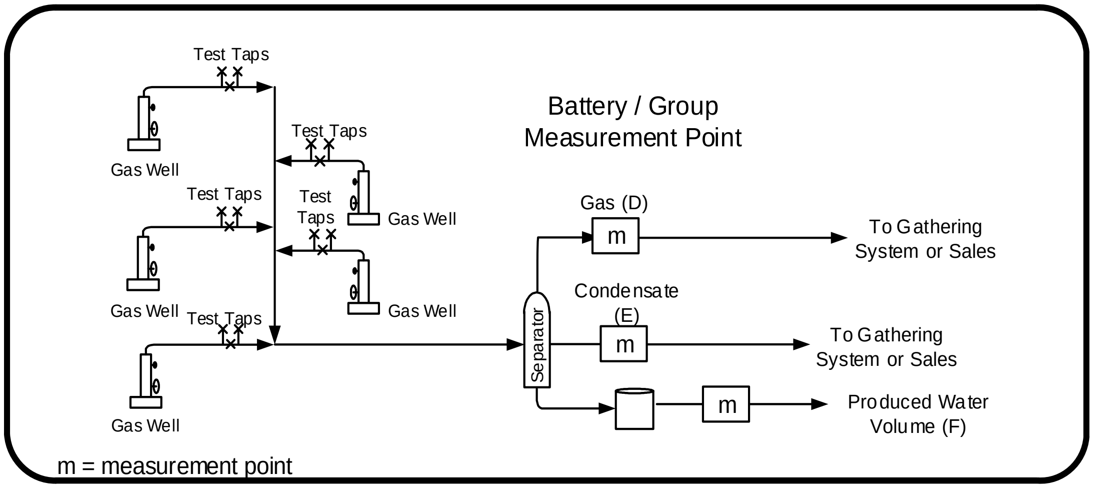


Figure 7.4. Typical Gas Multiwell Proration Outside SW Saskatchewan and SE Alberta battery



Test frequency may be extended with Regulator approval.

Unless alternative test procedures have been specified in a Regulator approval, the test must be conducted with measurement of all phases as follows:

1. The test must begin only after a liquid level stabilization period.
2. The test duration must be a minimum of 12 hours.
3. After the commencement of production at the proration battery, all wells must be tested within the first month, and thereafter annually. New wells added to the battery at some future date must be tested within the first month of production, then again within six months, and thereafter annually.
4. Consistent testing procedures must be used for consecutive tests to identify if a change in a well's flow characteristics has occurred.
5. These wells are typically tested by directing flow from the well through a test separator. If the initial testing with a separator shows a liquid-gas ratio (LGR) of less than 0.01 m^3 liquid/10^3m^3 gas, other testing methodology, such as a smaller separator or a single test meter without separation, could be used for the next test. If the total liquid volumes at group measurement point exceed a ratio of 0.05 m^3 liquid/10^3m^3 gas in any month, a test separator must be used to test all the wells within the battery for the next round of testing to determine where the liquid originated.
6. The gas, condensate, and water volumes must be measured.
7. The condensate must be sampled during every test and subjected to a compositional analysis, which is to be used to determine the gas equivalent factor (GEF). The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator. The water must be removed from the condensate before conducting the analysis.
8. The GEF must be used to convert the liquid condensate volume determined during the test to a GEV, which will be added to the measured test gas volume to determine the total test gas volume if:

SK	the condensate is not delivered for sale at the group measurement point or trucked for further processing, see Section 7.3.2.
AB	the condensate is not delivered for sale at the group measurement point, see Section 7.3.2.
BC	See Measurement Guideline Upstream Oil and Gas Operations

9. The WGR, CGR, and OGR (if applicable) must be determined by dividing the test water, condensate, and oil volume respectively by the total test gas volume.
10. For orifice meters, the test gas meter must use 24-hour charts for a test period of 72 hours or less, unless electronic flow measurement is used; for testing periods longer than 72 hours, seven-day charts may be used, provided that good, readable pen traces are maintained, see Section 4.3.7.

7.3.1.1 Exemption from Gas Multiwell Proration Outside SW and SE Alberta Batteries

SK	1. New and existing wells producing from shallow gas zones/stratigraphic units in SW Saskatchewan may be tested in accordance with the testing requirements set out in Section 7.2.3. 2. Existing shallow gas wells in batteries located outside the SW Saskatchewan shallow gas zones/stratigraphic unit with a LGR ≤ 0.01 m^3 liquid / $10^3 m^3$ gas may be tested in accordance with the testing requirements set out in Section 7.2.3. The stratigraphic units or zones include coals and shales from the base of the Glacial Drift to the base of the Upper Cretaceous. The production from two or more of these stratigraphic units or zones without segregation in the wellbore requires prior approval from the Regulator for commingled production.
AB	1. New and existing wells producing from shallow gas zones in SE Alberta—may be tested in accordance with the testing requirements set out in Section 7.2.3. 2. Existing wells in batteries located outside the SE Alberta shallow gas zones with a LGR ≤ 0.01 m^3 liquid / $10^3 m^3$ gas may be tested in accordance with the testing requirements set out in Section 7.2.3. The stratigraphic units or zones include coals and shales from the top of the Edmonton Group to the base of the Colorado Group. The production from two or more of these stratigraphic units or zones without segregation in the wellbore requires prior approval from the Regulator for commingled production, which has been granted in a portion of SE Alberta in Order No. MU 7490, or adherence to the self-declared commingled production requirements described in *Directive 065: Resources Applications for Oil and Gas Reservoirs*.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

7.3.2 Production Volume Calculations

Monthly production volumes are to be calculated as follows:

Units: All gas volumes and GEV are to be in 10^3m^3 and liquid volumes in m^3.

1. Calculate well gas test rate, see Figure 7.3:

   Well gas test rate (10^3m^3/hour) = (Well test gas volume [A] + GEV of well test condensate [B]) ÷ Well test hours

   Note: Do not include GEV of [B] if condensate is:

SK	delivered for sale at the group measurement point or trucked for further processing.
AB	delivered for sale at the group measurement point.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

2. Calculate estimated monthly well gas volume:

   Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3. Calculate total estimated gas production for the battery:

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

4. Calculate the well WGR, see Figure 7.3:

   WGR = Well test water volume (C) ÷ (Well test gas volume [A] + GEV of well test condensate [B])

   Note: Do not include GEV of [B] if condensate is:

SK	delivered for sale at the group measurement point or trucked for further processing.
AB	delivered for sale at the group measurement point.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

5. Calculate estimated water production for each well:

   Estimated monthly well water volume = Estimated monthly well gas volume x WGR

6. Calculate total estimated water production for the battery:

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

   If the condensate is:

SK	delivered for sale at the group measurement point or trucked for further processing,
AB	delivered for sale at the group measurement point,
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

calculate the next two items; otherwise go directly to item 9.

7. Calculate the well CGR, see Figure 7.3:

   CGR = Well test condensate volume (B) ÷ Well test gas volume (A)

8. Calculate estimated condensate production for each well:

   Estimated monthly well condensate volume = Estimated monthly well gas volume x CGR

9. Calculate total estimated condensate production for the battery:

   Total battery estimated monthly condensate volume = Sum of all estimated monthly well condensate volumes

10. Calculate proration factors for gas, condensate

SK	If delivered for sale at the group measurement point or trucked for further processing,
AB	If delivered for sale at the group measurement point,
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

and water, see Figure 7.4:

   Gas Proration Factor (GPF) = (Total battery measured monthly gas volume [D] + GEV of total battery condensate [E]) ÷ Total battery estimated monthly gas volume

Note: Do not include GEV of [E] if condensate is:

SK	delivered for sale at the group measurement point or trucked for further processing.
AB	delivered for sale at the group measurement point.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

   Water Proration Factor (WPF) = Total battery actual monthly water volume (F) ÷ Total battery estimated monthly water volume

   Condensate Proration Factor (CPF) = Total battery measured monthly condensate volume [E] ÷ Total battery estimated monthly condensate volume

11. Calculate actual monthly (prorated) well production:

   Actual monthly well gas production = Estimated monthly well gas volume x Gas Proration Factor

   Actual monthly well water production = Estimated monthly well water volume x Water Proration Factor

   Actual monthly well condensate production = Estimated monthly well condensate volume x Condensate Proration Factor

7.3.3 Exemption for Gas Wells Producing Oil

SK	If the hydrocarbon liquid that a gas well produces changes from condensate to oil, based on its density, the well may remain in a Gas Multiwell Proration Outside SW Saskatchewan Battery, provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or,

	alternatively, the measurement, accounting, and reporting procedures specified below are followed, (see Figure 7.5).
AB	If a gas well classified as producing condensate in a gas multiwell proration outside SE Alberta battery is reclassified by the Regulator as a gas well producing oil, the well may remain in the battery provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or, alternatively, the measurement, accounting, and reporting procedures specified below are followed, (see Figure 7.5).
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Annual Gas Rate–WGR tests must be conducted on the well. An oil-gas ratio (OGR) must also be determined during this test. The WGR, estimated water production, water proration factor, and actual water production are determined in the same manner, see Section 7.3.2.

Units: All gas volumes and GEV are to be in 10^3m^3 and liquid volumes in m^3.

1. Calculate well gas test rate, see Figure 7.6:

   Well gas test rate = Well test gas volume (A) ÷ Well test hours

2. Calculate estimated monthly well gas volume:

   Estimated monthly well gas volume = Well gas test rate x Monthly total hours of well production

3. Calculate the OGR, see Figure 7.6:

   OGR = Well test oil volume (B) ÷ Well test gas volume (A)

4. Calculate actual well oil production:

   Actual monthly well oil production = Estimated monthly well gas volume x OGR

5. Calculate actual total oil production:

   Actual monthly total battery oil production = Sum of all actual monthly well oil volumes

6. At the group measurement point, subtract the oil production volume (item 5) from the total liquid hydrocarbon volume to determine the total battery condensate production.

SK	The GEV of the total battery condensate volume, if not delivered for sale or trucked for further processing, must be added to the measured group gas volume to determine the total battery gas volume, see Figure 7.5:
AB	The GEV of the total battery condensate volume, if not delivered for sale, must be added to the measured group gas volume to determine the total battery gas volume, see Figure 7.5:
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

   Total battery condensate volume = Battery total liquid hydrocarbon volume (E) –Actual monthly total battery oil production

7. Calculate total estimated gas production for the battery:

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

8. Calculate proration factor for gas, see Figure 7.5:

Gas Proration Factor (GPF) = (Total battery measured monthly gas volume [D] + GEV of total battery condensate volume [item 6]) ÷Total battery estimated monthly gas volume

9. Calculate actual monthly (prorated) well gas production:

Actual monthly well gas production = Estimated monthly well gas volume x Gas Proration Factor

Figure 7.5. Typical Gas Multiwell Proration Outside SW Saskatchewan or SE Alberta battery

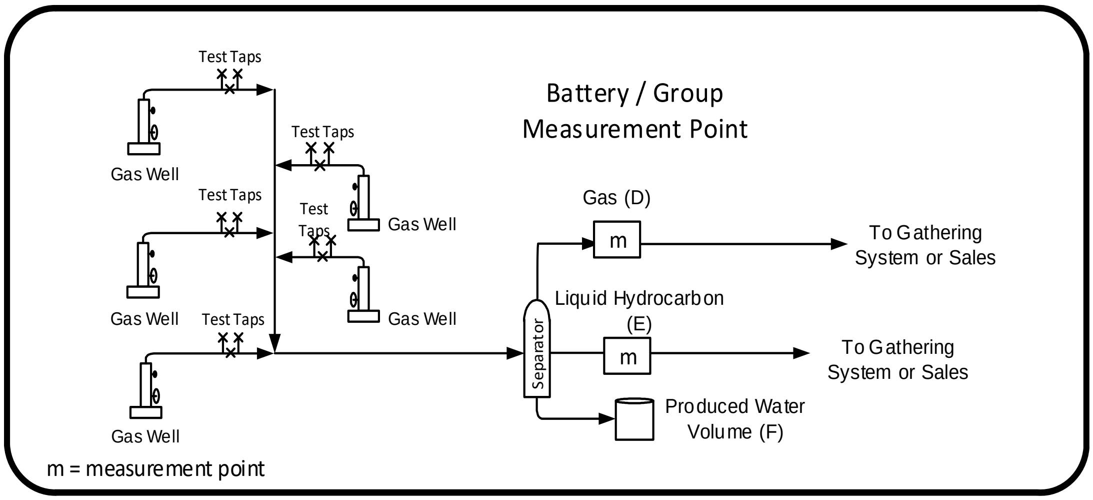
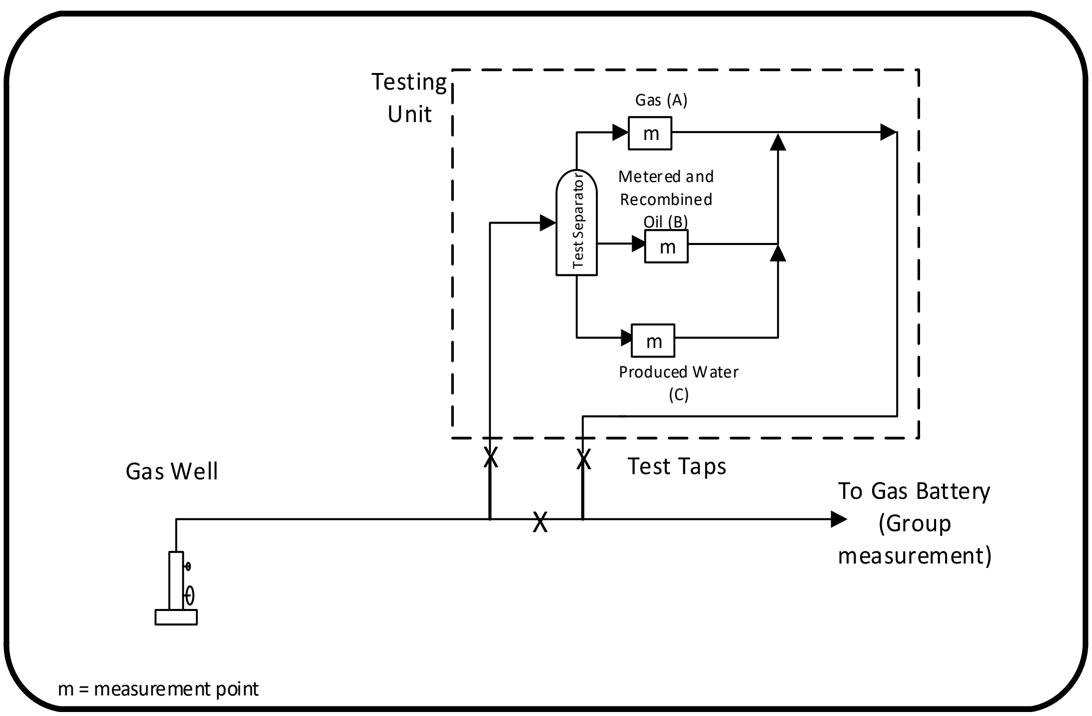


Figure 7.6. Typical Testing Setup

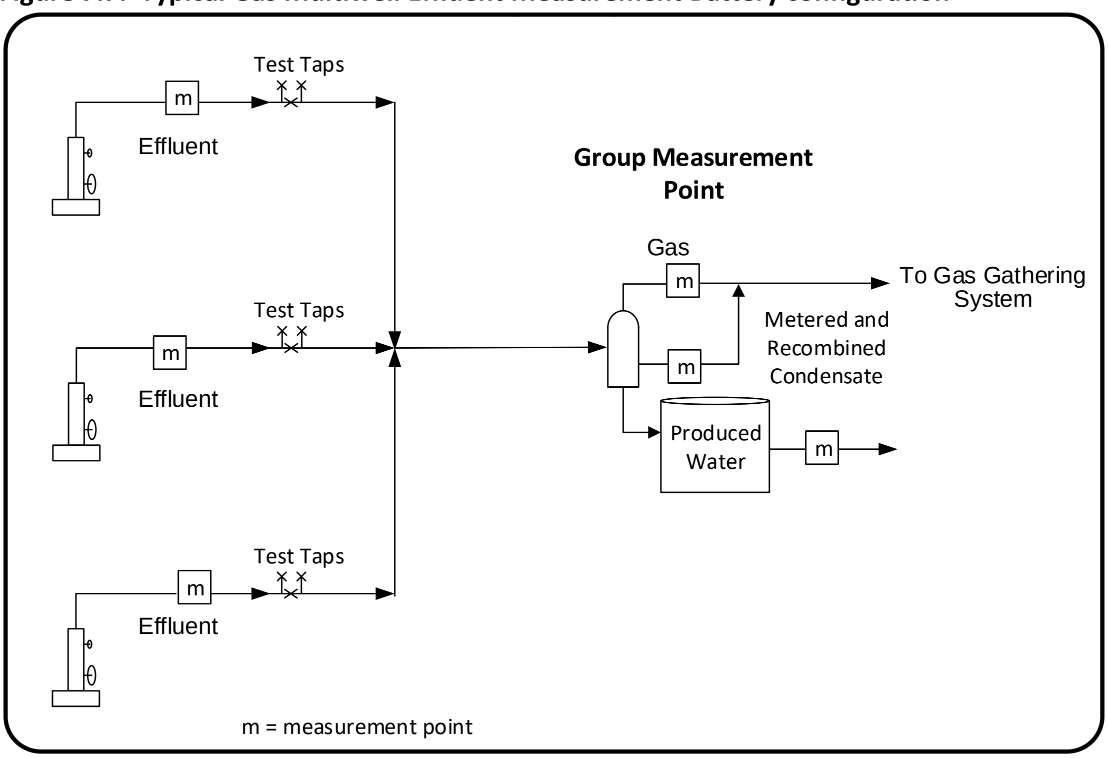


SK	Report the calculated monthly oil production volume as oil produced from the well. Prorate monthly condensate production, if delivered for sale or trucked for further processing, and water production as in the normal proration battery in Section 7.3.2.
AB	Report the calculated monthly oil production volume as oil produced from the well. Prorate monthly condensate production, if delivered for sale, and water production as in the normal proration battery in Section 7.3.2.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

7.4 Gas Multiwell Effluent Measurement Batteries (Petrinex subtype 362)

Gas wells in this type of proration battery have dedicated effluent measurement, whereby total multiphase well fluid passes through a single meter, see Figure 7.7. This type of measurement must be subjected to testing regardless of the type of effluent meter used. For a new completion or recompletion of another stratigraphic unit or zone in an existing well, effluent measurement is not allowed at a certain LGR level, see Section 7.4.1.1 for details.

Figure 7.7. Typical Gas Multiwell Effluent Measurement Battery configuration

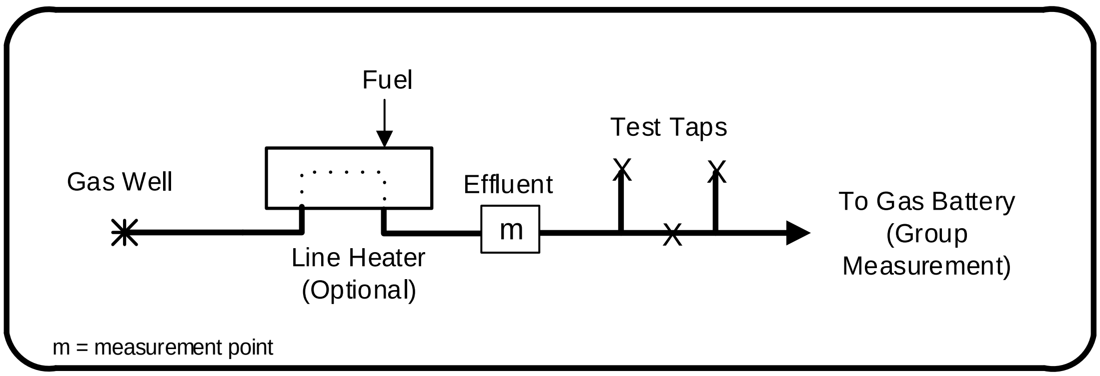


Production rates, WGR, CGR, and ECF determined during a well test must be used in the estimation/proration calculations within 60 days of the test until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells, based on each well's estimated monthly gas production. Estimated well gas production is based on the total volume measured by the effluent meter multiplied by an ECF, see Figure 7.8. The uncertainty of measurement will increase with higher liquid rates, especially under liquid slugging conditions.

Figure 7.8 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. For well testing purposes, test taps must be located downstream of this meter within the same pipe run. The line heater, fuel gas tap, and other equipment, if present, must be upstream of the meter or downstream of the test taps to ensure that the test meter is subjected to the same condition as the effluent meter. After measurement, production from the well is commingled with other flowlined effluent gas wells in the battery and sent to a group (battery) location, where single-phase (group) measurements of hydrocarbon liquids, gas, and water must be conducted downstream of separation.

Figure 7.8. Typical gas well effluent metering configuration



For most wells, the required minimum well testing frequency is annual unless the criteria in Section 7.4.1.1 are met. Total battery water production must be measured and prorated back to the individual wells, based on each well's estimated monthly water production. Estimated well water production is based on a WGR, determined by periodic well tests multiplied by the estimated monthly well gas production.

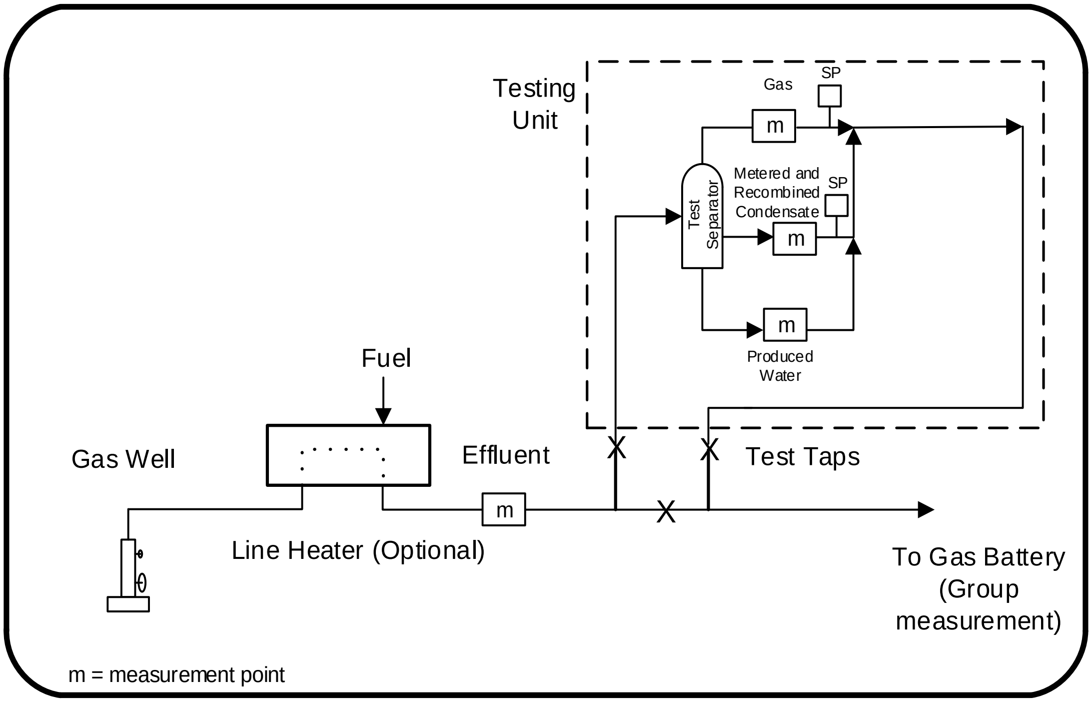
SK	Gas wells that produce oil, rather than condensate, must not be tied into a Gas Multiwell Effluent Measurement Battery, unless the well oil and gas production volumes are separated and measured prior to commingling with the effluent wells and either the Exemption criteria in Sections 5.5 and 5.5.1 are met or site-specific approval has been obtained from the Regulator prior to implementation. If the hydrocarbon liquid that a gas well produces changes from condensate to oil, based on its density, see Section 7.4.3.
AB	Gas wells that are classified as producing oil, rather than condensate, must not be tied into a Gas Multiwell Effluent Measurement Battery, unless the well oil and gas production volumes are separated and measured prior to commingling with the effluent wells and either the Exemption criteria in Sections 5.5 and 5.5.1 are met or site-specific approval has been obtained from the Regulator prior to implementation. If a gas well classified as producing condensate in a multiwell effluent measurement battery is reclassified by the Regulator as producing oil, see Section 7.4.3 .
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

7.4.1 Well Testing

Well testing is typically performed by directing well production downstream of the effluent meter and within the same pipe run through a three-phase portable test separator configured with dedicated meters for gas, condensate, and water, see Figure 7.9. Test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be measured during typical well test durations. Other options that provide equivalent liquid volume determination accuracy may also be considered. For example, if 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, may be acceptable. The test must be conducted as follows:

1. The test must begin only after a liquid level stabilization period within the test separator.
2. The test duration must be a minimum of 12 hours.
3. All new wells must be tested within the first 30 days of initial production.
4. Consistent testing procedures must be used for consecutive tests to identify if a change in a well's flow characteristics has occurred.
5. The gas, condensate, and water volumes must be measured.
6. The condensate must be sampled during every test and subjected to a compositional analysis, which is to be used to determine the GEF. The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator. The water must be removed from the condensate before conducting the analysis.
7. The GEF must be used to convert the liquid condensate volume determined during the test to a GEV, which will be added to the measured test gas volume to determine the total test gas volume if the condensate is not delivered for sale at the group measurement point. The ECF can then be determined based on whether the condensate is recombined with the gas, see Section 7.4.2.
8. The WGR must be determined by dividing the test water volume by the sum of the measured test gas volume and the gas equivalent of the measured test condensate volume if the condensate is not delivered for sale at the group measurement point, see Section 7.4.2.
9. For orifice meters, the effluent meter and the test gas meter must use 24-hour charts for a test period of 24 hours or less, unless electronic flow measurement (EFM) is used; for testing periods longer than 24 hours, seven-day charts may be used, provided that good, readable pen traces are maintained, see Section 4.3.4.

Figure 7.9. Typical effluent well measurement configuration with test unit

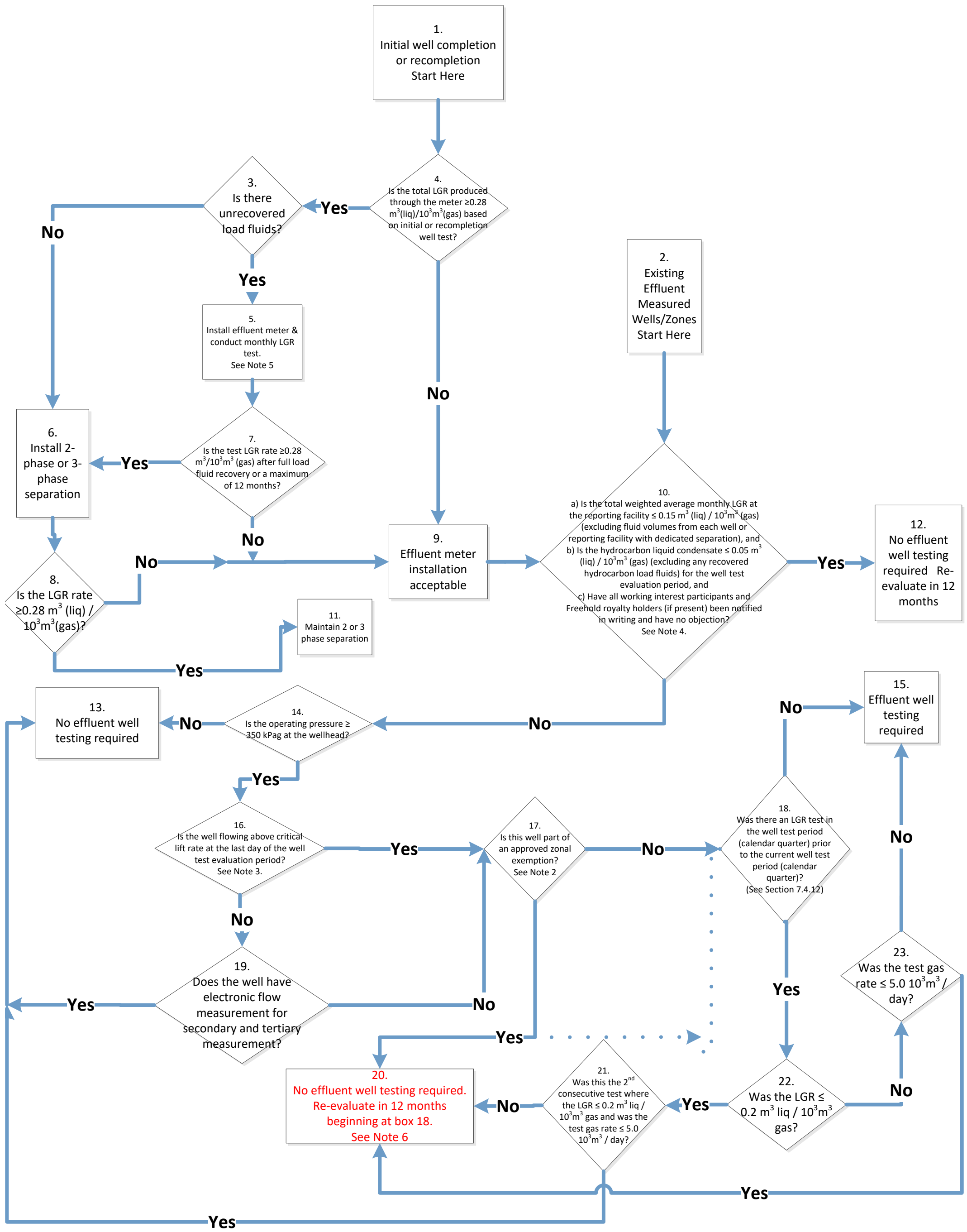


7.4.1.1 Effluent Well Measurement and Testing Decision Tree

The type of measurement and testing frequency for effluent measured wells must follow the decision tree process in Figure 7.10.

Note that the starting point for initial well completion or recompletion is different than for existing effluent measured stratigraphic units or zones or wells.

Figure 7.10. Effluent well measurement and testing decision tree. (Text boxes are numbered from left to right.)



Note 1: Where all wells in a facility are above critical lift and in a deemed exempt stratigraphic unit or zone, if the LGR is greater than 0.2 m^3 (liq) / 10^3m^3 (gas) at the respective facility inlet to which the wells flow, the stratigraphic unit or zone is not exempt and the Note 1 path is to be followed.

Note 2: Regulator stratigraphic unit or zonal measurement exemptions are by special approvals only.

Note 3: The Turner Correlation[2] is used to approximate critical lift. The calculation below produces a value in million standard cubic feet (mmscf) per day. Use a factor of 28.3168 $10^3 m^3$/mmscf to convert to metric units. Although there have been further refinements to the Turner Correlation calculation, the formulas below will be applied to determine critical lift as it relates to the well measurement and testing decision tree. These simplified formulas assume a fixed-gas gravity (G) of 0.6 and fixed-gas temperature (T) of 120ºF.

$$v_g(Water) = \frac{5.62(67 - kP)^{0.25}}{(kP)^{0.50}}$$

$$v_g(Condensate) = \frac{4.02(45 - kP)^{0.25}}{(kP)^{0.50}}$$

$$k = \frac{2.693G}{ZT}$$

$$q_g = \frac{3.06 P v_g A}{ZT}$$

G = gas gravity
P = Pressure (absolute) - lb force / square inch
T = Temperature (absolute) – degrees Rankine
v_g = Minimum gas velocity required to lift liquids – ft / second
Z = Compressibility factor
A = Cross sectional area of flow – square feet
q_g = Flow rate – mmscf / day

The following represents a sample Turner Correlation calculation:

Evaluation period: November–October

SCADA daily average tubing pressure, October: 684.6 kPa

Turner Correlation formula: assumes G = 0.6
T = 48.9ºC (120ºF)
Z = 0.9

Variable	Value	Units	Calculation
G	0.6		
Z	0.9		
T	580	Rankin	[(48.9 x 1.8) + 32] + 460
k	0.003095		(2.693 x 0.6) ÷ (0.9 x 580)
P	114	PSIA	(684.6 kPa ÷ 6.89475) + (101.325 kPa ÷ 6.89475)
A	0.0217	Ft^2	[3.1415 x (1.995 inches ÷ 12)^2] ÷ 4 *(tubing size = 2 3/8 inches)*
q_g	0.392	mmscf/d	
q_g	11.10	$10^3 m^3$/d	0.392 mmscf x 28.3168 $10^3 m^3$/mmscf

If both condensate and water are present, use the Turner Correlation for water to evaluate system behavior. The Turner Correlation uses the cross-sectional area of the flow path when calculating liquid lift rates. For example, if the flow path is through the tubing, the minimum gas rate to lift water and condensate is calculated using the inside diameter (ID) of the tubing. When the tubing depth is higher in the wellbore than the midpoint of perforations, the midpoint elevation between the highest and lowest perforations in the casing in a vertical well, the Turner Correlation does not consider the rate required to lift liquids between the midpoint of perforations and the end of the tubing. Ultimately, the liquid lift rate calculations are based on the tubing's ID or the area of the annulus and not on the casing's ID unless flow is up the casing only. Midpoint of perforations is the midpoint

[2] **Turner, R. G., Hubbard, M. G., and Dukler, A. E., 1969,** ***Analysis and Prediction of Minimum Flow Rate for the*** *Continuous Removal of Liquids from Gas Wells*, *JPT* 21(11): 1475–1482.

elevation between the highest and lowest perforations in the casing. The Midpoint of Perforations elevation is used in the Turner Correlation that plays a role in the well testing decision tree found in Section 7.4.1.1. **Note 4:** Average Monthly LGR/CGR Calculation

Follow Figure 7.10 to determine if a facility exemption is appropriate for specific wells that flow to the reporting facility based on the total liquid/condensate volumes versus the total gas volume measured at the group measurement point for the reporting month. Production volumes include not only volumes measured at a group measurement point, but all fluid production volumes used for reporting purposes. This requires accounting for all fluid volumes that are received into or delivered out of the reporting facility for that reporting month.

LGR = [Total group measured liquids (condensate + water) + (Disposition + Inventory change before group measurement) – Liquid received] ÷ [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

CGR = [Total group measured condensate + (Disposition + Inventory change before group measurement) – Condensate received] ÷ [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

Note 5: An initial well test must be conducted within 30 days of production and monthly thereafter. The WGR, CGR, and ECF factors from the last test must be used to calculate estimated production until the next test is conducted. Once full fluid recovery is achieved or the 12 month period is passed, whichever comes first, the well must be evaluated according to the decision tree process based on the last well test.

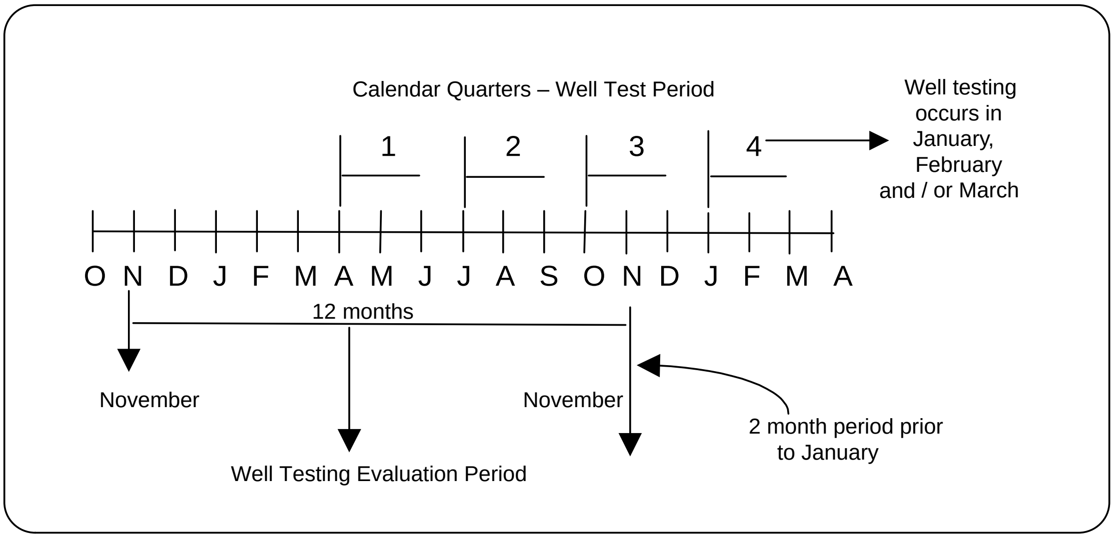
Note 6: Wells that require biennial testing must use the ECF, CGR, WGR, and sample analysis from the most current ECF test until the next ECF test results and sample analysis are available.

7.4.1.2 Well Test Evaluation

The well testing evaluation period is based on a cycle of 12 consecutive months that all of the wells in a reporting facility will identically follow. The well test evaluation period must end two months before the planned calendar quarter in which the required well testing will be conducted for a reporting facility. Once the evaluation period is chosen, it will remain fixed for a reporting facility. Well testing, when required according to Figure 7.10, must occur once in the fixed calendar quarter. Figure 7.11 provides an illustrated example.

Well and reporting facility data are gathered for the 12-month period identified. The wells and/or the reporting facility would be analyzed within the context of the well measurement and testing decision tree. 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 operations. The illustrated example shown in Figure 7.11 typically fits a well testing system in which winter road access is available.

Figure 7.11. Well test evaluation example



For the purposes of evaluating text box 10 of the well measurement and testing decision tree in Figure 7.10, the reporting facility and the affected wells such as wells without well separation will be on the same well testing evaluation period. However, a reporting facility has operating characteristics such that a reporting facility well testing exemption in text box 10 is not possible, the well testing evaluation period can become unique to a well. This means that for a well that requires testing according to the well measurement and testing decision tree, the well maintains a fixed well testing evaluation period, but the well testing evaluation period may not be the same for all of the wells in a reporting facility. If a facility is of such a size that it would take more than one calendar quarter to test all of the wells, an operator can choose the calendar quarter in which a well test is to occur which in turn determines the Well Testing Evaluation Period. Once the well testing period of a calendar quarter is chosen, the operator must test once in the fixed calendar quarter period.

The pressure data, as recorded by the well measurement equipment, will be the monthly average for the last month of the well test evaluation period. If no tubing or casing pressure records are continuously recorded, then the upstream static pressure data from the well's flow meter may 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.

7.4.1.3 Record Keeping

The following lists the minimum records required related to well testing and/or the well measurement and testing decision tree where it is applicable:

General Information:

1. Producer
2. Reporting facility – name and surface location
3. Petrinex reporting code
4. Well – name
5. Well – unique well identifier (UWI)
6. Production formation – name and/or stratigraphic unit or zone code

Well Test Information:

7. Current well testing date
8. Last well test date
9. Effluent well meter run – internal diameter (mm)
10. Meter run orifice size (mm) (if applicable)
11. Test tap location (relative to effluent meter)
12. Test tap connection – diameter (mm)
13. Last gas sample date
14. Last condensate sample date
15. Test gas average rate (10^3 m^3/day)
16. Test condensate average rate (m^3/day)
17. Test water average rate (m^3/day)
18. Current WGR ($m^3/10^3m^3$)
19. Current CGR ($m^3/10^3m^3$)
20. Current LGR ($m^3/10^3m^3$)
21. Last WGR ($m^3/10^3m^3$)
22. Last CGR ($m^3/10^3m^3$)
23. Last LGR ($m^3/10^3m^3$)
24. ECF – last value calculated
25. ECF – current value calculated

Decision Tree Information

26. Wellhead tubing internal diameter (mm)
27. Wellhead casing internal diameter (mm)
28. Wellhead tubing pressure (KPa)
29. Wellhead casing pressure (KPa)
30. Effluent meter monthly average D/P for evaluation period (kPa) – listed by month (optional)
31. Effluent meter monthly average static pressure for evaluation period (KPa) – listed by month
32. Effluent meter monthly average temperature for evaluation period (ºC) – listed by month (optional)
33. Evaluation period average reporting facility LGR
34. Evaluation period average reporting facility CGR
35. Artificial lift method, i.e., cycling, plunger control
36. Well chart or EFM – model and make

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 facility LGR calculations
    a. Meter tag
    b. Meter location
    c. Meter volume
    d. Meter units (10^3m^3, etc.)
43. Well flow volume prior to recompletion (optional)
44. Well recompletion flow volume (optional)

7.4.1.4 Revocation of Exemption Allowed by Decision Tree

A testing exemption for an effluent gas well may be revoked if certain criteria are not met. Baseline well testing must be conducted if a testing exemption is revoked for any of the following reasons:

1. Noncompliance

   Potential areas of noncompliance include:
    a. Incorrect exemption calculations,
    b. Inadequate record keeping,
    c. Source data for exemption calculations cannot be validated, and
    d. Incorrect application/implementation of the well measurement and testing decision tree.
2. A working interest participant or Freehold mineral owner for any flowing well to the reporting facility objects to the exemption.

Additionally, if the Regulator has a concern with the activities, operations, production data, or reporting associated with well testing, on notice in writing, the Regulator can partially or fully revoke well testing exemptions and impose, modify, or substitute well testing conditions for any period of time. The Regulator will advise the operator in writing as to the reason for the revocation, provide a reasonable time period for the operator to meet the conditions set by the Regulator, and provide an opportunity for the operator to comment.

7.4.2 Production Volume Calculations

Monthly production volumes are to be calculated as follows (see Figure 7.12).

Units: All gas volumes and GEV are to be in 10^3m^3 and liquid volumes in m^3.

7.4.2.1 Testing-Exempt Battery

For a battery that is exempt from testing, the volumetric calculation is to be based on the following:

ECF = 1.00000

WGR = Battery-based water-gas ratio

LGR = Battery-based liquid-gas ratio

CGR = Battery-based condensate-gas ratio

If battery condensate volumes are recombined back into the gas stream, the gas equivalent of the recombined liquids will be calculated and added to the measured group gas volume to obtain the total battery gas volume. Condensate liquid volumes will not be prorated to the wells.

SK	If battery condensate volumes are tanked and trucked out for sale or for further processing, the condensate liquid volumes will be prorated back to the wells in the battery based on the calculated battery CGR.
AB	If battery condensate volumes are tanked and trucked out for sale (AB), the condensate liquid volumes will be prorated back to the wells in the battery based on the calculated battery CGR.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Well water production may be determined by either:

1. Calculating the battery water proration factor and then multiplying the well's estimated water production by the battery's water proration factor or
2. Multiplying the wells' percentage of the total estimated gas production by the monthly measured battery water volume. In this case report a battery water proration factor of 1.00000
3. Exception: The operator may, providing there is no objection from the working interest owners of any well producing into the battery, use the WGR, CGR and ECF from each well's most recent ECF test instead of using the battery-calculated WGR, CGR and ECF of 1.00000. This option may be used as long as the battery qualifies as a test-exempt battery.

7.4.2.2 Testing - Exempt Wells

For a battering with both exempt and nonexempt wells, the volumetric calculation must be based on the following:

ECF = 1.00000 for exempt wells

For the wells that require testing, water production will be prorated to each well based on the well's individual WGR derived from the well tests multiplied by its estimated gas production. For those wells that are test exempt, a battery WGR will be established and applied to all the test-exempt wells after netting off the estimated water production of the tested wells.

If battery condensate volumes are recombined back into the gas stream, the gas equivalent of the recombined liquids will be calculated and added to the measured group gas volume recombined volume and recombined analysis. Condensate liquid volumes will not be prorated to the wells.

Exception: For test-exempt wells, the operator may, at its discretion, use the WGR, CGR, and ECF from each well's most recent ECF test instead of using the battery-calculated WGR, CGR, and ECF of 1.00000.

SK	If battery condensate volumes are tanked and trucked out for sale or for further processing, the tested wells' estimated condensate production will be calculated based on each well's CGR derived from the well tests multiplied by the well's estimated gas production. For those wells that are test exempt, a battery CGR will be established and applied to all the test-exempt wells after netting off the estimated condensate production of the tested wells.
AB	If battery condensate volumes are tanked and trucked out for sale, the tested wells' estimated condensate production will be calculated based on each well's CGR derived from the well tests multiplied by the well's estimated gas production. For those wells that are test exempt, a battery CGR will be established and applied to all the test-exempt wells after netting off the estimated condensate production of the tested wells.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

7.4.2.3 Nonexempt Wells

If there are no exempt wells in the battery and condensate is delivered for sale at the group measurement point, go directly to item 8. Otherwise, follow items 1 to 7.

1. Calculate the ECF:

   ECF = (Well test gas volume [B] + GEV of well test condensate [C]) ÷ Effluent gas volume measured during test (A)

2. Calculate estimated gas production for each well:

   Estimated monthly well gas volume = Monthly well effluent volume x ECF

3. Calculate the WGR:

   WGR = Well test water volume (D) ÷ (Well test gas volume [B] + GEV of well test condensate [C])

4. Calculate estimated water production for each well:

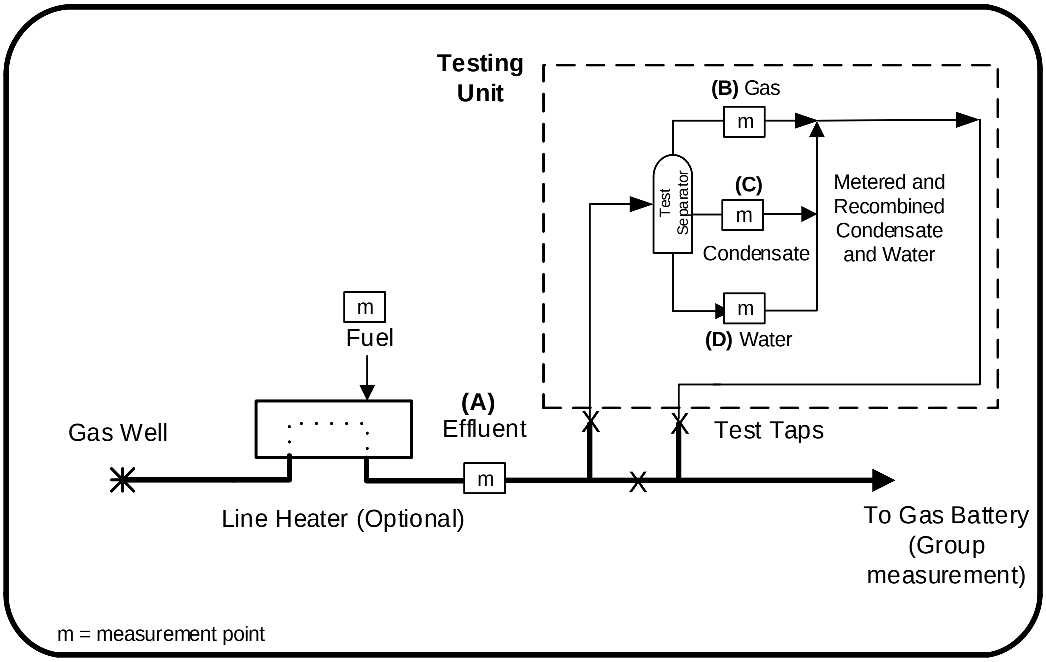
   Estimated monthly well water volume = Estimated monthly well gas volume x WGR

5. Calculate total battery estimated volumes (gas and water):

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

Figure 7.12. Effluent well meter testing configuration with condensate production



6. Calculate proration factors for gas and water:

   Gas Proration Factor = (Total battery measured monthly gas volume + GEV of total battery condensate) ÷ Total battery estimated monthly gas volume

   Water Proration Factor = Total battery actual monthly water volume ÷ Total battery estimated monthly water volume

7. Calculate actual monthly (prorated) well production:

   Actual monthly well gas production = Estimated monthly well gas volume x Gas Proration Factor

   Actual monthly well water production = Estimated monthly well water volume x Water Proration Factor

For the battery with condensate delivered for sale at the group measurement point:

8. Calculate the ECF:

   ECF = Well test gas volume (B) ÷ Effluent gas volume measured during test (A)

9. Calculate the well CGR:

   CGR = Well test condensate volume (C) ÷ Well test gas volume (B)

10. Calculate the WGR:

    WGR = Well test water volume (D) ÷ Well test gas volume (B)

11. Calculate estimated gas, condensate, and water production for each well:

    Estimated monthly well gas volume = Monthly well effluent volume x ECF

    Estimated monthly well condensate volume = Estimated monthly well gas volume x Condensate Gas Ratio

    Estimated monthly well water volume = Estimated monthly well gas volume x Water Gas Ratio

12. Calculate total estimated gas, condensate, and water production for the battery:

    Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

Total battery estimated monthly condensate volume = Sum of all estimated monthly well condensate volumes

Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

13. Calculate total battery monthly gas, condensate, and water production:

    Total battery monthly gas volume = Total gas disposition + Flare + Vent + Fuel (take off before sales meter)

    Total battery monthly condensate volume = Total condensate disposition + inventory change

    Total battery monthly water volume = Total water disposition + inventory change

14. Calculate proration factors for gas, condensate, and water:

    Gas Proration Factor (GPF) = Total battery monthly gas volume ÷ Total battery estimated monthly gas volume

    Condensate Proration Factor (CPF) = Total battery monthly condensate volume ÷ Total battery estimated monthly condensate volume

    Water Proration Factor (WPF) = Total battery monthly water volume ÷ Total battery estimated monthly water volume

15. Calculate actual monthly (prorated) well production:

    Actual monthly well gas production = Estimated monthly well gas volume x Gas Proration Factor

    Actual monthly well condensate production = Estimated monthly well condensate volume x Condensate Proration Factor

    Actual monthly well water production = Estimated monthly well water volume x Water Proration Factor

7.4.3 Sampling and Analysis Requirements

7.4.3.1 Testing Exempted Batteries

For testing exempted 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
    a. There is common ownership in all 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. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the Regulator for approval.

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.

7.4.3.2 Testing Exempted Wells

For test-exempt wells in batteries that have tested and test-exempt wells, 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
    a. There is common ownership in all 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.

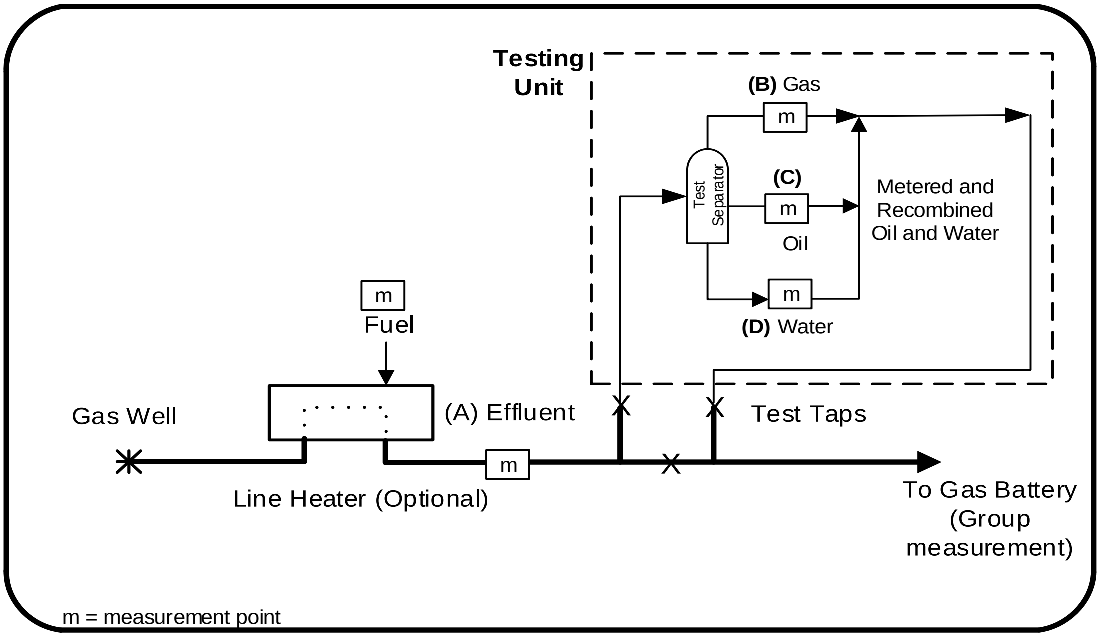
Regardless of which of the above approaches is used, the operator may, at its discretion, test and sample any test-exempt well and use the well sample and analysis to calculate well volume.

7.4.4 Exemption for Gas Wells Producing Oil in Effluent Measurement Battery

SK	If the hydrocarbon liquid that a gas well produces changes from condensate to oil, based on its density, the well may remain in a Gas Multiwell Effluent Measurement Battery, provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or, alternatively, the effluent meter is left in place and the measurement, accounting, and reporting procedures specified below are followed, (see Figure 7.13).
AB	If an existing gas well classified as producing condensate in a multiwell effluent measurement battery is reclassified by the Regulator as a gas well producing oil, the well may remain in the multiwell effluent measurement battery provided that the well is equipped with a separator and there is continuous measurement of the gas and liquid components or, alternatively, the effluent meter is left in place and the measurement, accounting, and reporting procedures specified are followed, see Figure 7.13.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Annual ECF-WGR tests must be conducted on the well. These types of wells do not qualify for the test frequency exemptions or reductions described in Section 7.4. An OGR, to be used for the well oil production calculation, must also be determined during this test. The WGR, estimated water production, water proration factor, and actual water production are determined in the same manner as indicated in Section 7.4.2.

Figure 7.13. Effluent well meter testing configuration with oil production



1. Calculate the ECF:

   ECF = Well test gas volume (B) ÷ Effluent gas volume measured during test (A)

2. Calculate estimated gas production for the well:

   Estimated monthly well gas volume = Monthly well effluent volume x ECF

3. Calculate the OGR:

   OGR = Well test oil volume (C) ÷ Well test gas volume (B)

4. Calculate actual well oil production:

   Actual monthly well oil volume = Estimated monthly well gas production x OGR

5. Calculate the total monthly battery condensate volume:

   Total battery condensate volume = Total battery liquid hydrocarbon volume – Total monthly oil volume

6. Report the calculated monthly oil production volume as oil produced from the well. Prorate monthly gas and water production as in Section 7.4.2.

7.5 Well Effluent Measurement in the Duvernay and Montney Stratigraphic Units

Section 7.5 only applies to Alberta since Saskatchewan does not have Duvernay and Montney Stratigraphic units. Unconventional resource development plays such as the Duvernay and Montney formations in the northwestern part of Alberta present unique operational and measurement challenges, including the following:

1. Hydrocarbon liquid densities of oil wells (oil) and gas wells (condensate/oil) are very similar, which can result in a mix of oil well and gas well classifications on a common development pad. This makes it difficult for operators to design production and measurement systems until the wells are drilled, tested, and classified.
2. Initial well operating pressures and production rates are high and decline rapidly, e.g., initial pressures up to 60 MPa (8700 psi) and initial production rates of 60

10^3m^3 /d of gas. This adds significant costs to separator construction and makes it difficult to properly size separation equipment for the entire life cycle of the wells.

3. Gas well LGRs are very high (up to approximately 1.12 m^3 liquid /10^3m^3 gas [200 bbl/MMcf])

The equipment design, project development delay, and cost challenges presented by high-pressure, high-LGR unconventional oil and gas plays present an opportunity to implement a measurement, production accounting, and volumetric reporting system that is applicable to both oil wells and gas wells drilled into a common formation (either the Duvernay or Montney) and that delivers acceptable measurement performance.

The following discussion describes the qualifying criteria and the 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 into Petrinex according to existing reporting requirements. Gas wells report production to a gas multiwell effluent measurement battery (subtype 362), and oil wells report production to a crude oil battery (subtype 311 or 321). Oil wells report gas and oil volumes and gas wells report gas and condensate/oil volumes, depending on the well's volumetric gas well liquid (VGWL) classification.

7.5.1 Qualifying Criteria for Well Effluent Measurement in the Duvernay and Montney Stratigraphic Units

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 only the Duvernay formation, or all wells are drilled and completed in only the Montney formation. Surface commingling of Duvernay and Montney wells within the same measurement system is not allowed.
2. Gas well LGRs may exceed 0.28 m^3 liquid / 10^3m^3 gas with no upper LGR restriction, and the effluent measurement system may consist of only gas wells. Specifically, gas wells with LGRs > 0.28 m^3 liquid / 10^3m^3 gas may be effluent measured.
3. 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 licensee must apply to the Regulator for approval.

7.5.2 Measurement Systems requirements for Well Effluent Measurement in the Duvernay and Montney Stratigraphic Units

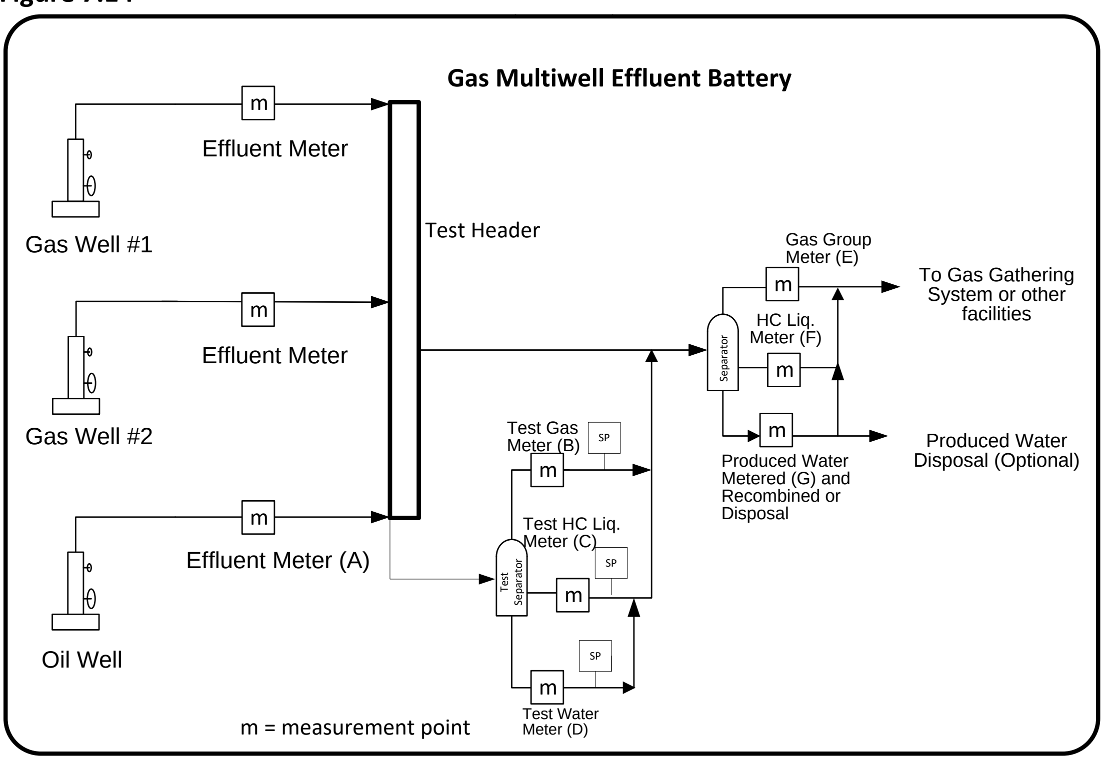
1. The two effluent measurement operational scenarios described in Sections 7.5.3 and 7.5.4 must adhere to the following common requirements:

2. Well and facility developments must include test separation (permanent or portable) and test measurement systems to meet Section 7 effluent well testing requirements.
3. Sample point installation must comply with Section 8 sampling requirements.
4. All wells must calculate monthly estimated condensate/oil volumes using the most recent CGR/OGR, as determined through ECF testing.
5. 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.
6. Well ECF tests must be conducted monthly, at minimum, until stabilized flow from the well is realized. Stabilized flow means that the individual ECFs obtained from the three most recent ECF tests do not vary by more than ±5.0 per cent of the average of the three most recent ECFs. After stabilized flow is realized, ECF tests must be conducted semiannually, at minimum.
7. Battery gas and condensate/oil proration factors must fall within the range of 0.9500 to 1.05000. If the proration factors fall outside this range, ECF tests must be conducted more frequently in order to bring the proration factors back within the required range. This requirement is in addition to the ECF test frequency described above i.e. ECF tests may have to be conducted more frequently than described above.
8. Each well must be sampled during each ECF test, and the group separator must be sampled monthly to analyze gas and hydrocarbon liquids.
9. The hydrocarbon liquid sample obtained from each well during each ECF test must undergo a multistage flash liberation analysis (FLIB) or computer flash simulation to obtain the shrinkage factor and gas-in-solution factor.
    a. The derived shrinkage factor will be applied to the hydrocarbon liquid test volumes.
    b. The gas in solution factor will, when multiplied by the test oil/condensate volume, yield the amount of gas that will flash out of oil/condensate as it is processed through the battery (multistage flash).
    c. The derived flash gas volume will be added to the metered test gas volume to determine the total test gas used in the proration.
10. 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.
11. Gas well production/disposition must be reported as a facility subtype 362: Gas Multiwell Effluent Measurement battery.
12. Oil well production/disposition to the 362: Gas Multiwell Effluent Measurement battery must be reported as subtype 311: Crude Oil Single-Well Battery or subtype 321: Crude Oil Multiwell Group Battery.
13. Through the Enhanced Production Audit Program on Petrinex, operators must notify the Regulator of the facility reporting codes of the batteries using the mixed oil well / gas well effluent measurement system.

14. Annually, operators must prepare and submit to the Regulator a measurement performance report for each mixed oil well / gas well effluent measurement system that has been implemented. Additionally, operators must meet with the Regulator measurement specialist annually to review the performance reports. The reports must contain the following data and discussion items:
    a. A list of the wells and facilities included in the measurement system.
    b. For each well, a chronological listing of ECF test and sample dates and the test results (test duration, test gas volume, test hydrocarbon liquid volume, test water volume, effluent metered volume, ECF, CGR, WGR, per cent change of ECF from last test). The operator must provide detailed individual ECF test data (source test measurement data) to the Regulator upon request.
    c. For each measurement system, a chronological listing of monthly production volumes for each reporting facility and the gas, hydrocarbon liquid, and water proration factors
    d. A general discussion of the performance of the measurement system, highlighting operational and measurement challenges, mitigate measures taken if proration factors trended outside the required tolerances, best practices implemented, lessons learned, etc.
    e. Additional development plans for the upcoming year
15. All other requirements in this Directive remain in effect

7.5.3 Operational Scenario 1 – Hydrocarbon Liquids are Recombined into the Gathering System

Figure 7.14



Scenario 1 (see Figure 7.14) production measurement and well volume are determined as follows:

1. Production from the gas wells and oil well is 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 or to another facility such as a gas plant.
3. Using standard ECF proration accounting procedures, individual well volumes of gas and condensate/oil (gas wells), gas and oil (oil wells), and water are determined.
4. The oil well and gas well hydrocarbon liquid volumes are calculated for each component using the sample analysis obtained during ECF testing. The oil well's oil and gas volumes are then subtracted from the group measured gas and hydrocarbon liquid volumes to derive the effluent battery condensate/oil volume. The oil well's water production volume is also subtracted from the battery's measured water volume.
5. The oil well production is reported to an oil battery facility subtype 311 or 321 (stock tank liquid volume). The gas battery's liquid condensate is converted to a gas equivalent and added to the group separator gas volume. This is reported as a gas disposition from gas multiwell effluent measurement battery facility subtype 362.

7.5.3.1 Additional Measurement System Requirements – Hydrocarbon Liquids are Recombined into the Gathering System

In addition to the requirements set out in Section 7.5.2, Operational Scenario 1 must also adhere to the following 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 and well test separator condensate/oil leg must use a Coriolis mass meter and a water-cut analyzer.
3. Gas and hydrocarbon liquid sample analysis for individual wells must be used to calculate the well gas and hydrocarbon liquid GEV.
4. The group gas and hydrocarbon liquid sample analysis must be used to calculate the group gas and hydrocarbon liquid GEV.
5. The hydrocarbon liquid meters at the test and group separators must be proved to separator operating conditions.

7.5.3.2 Production Accounting and Reporting Procedures – Hydrocarbon Liquids are Recombined into the Gathering System

Do the following after testing each well:

1. Calculate the ECF:

   ECF = Well test gas volume / Effluent gas volume measured during test

2. Calculate estimated monthly well gas volume:

   Estimated monthly well gas volume = Monthly well effluent volume × ECF

3. Obtain shrinkage factor (SF) and flash factor (GIS) for oil wells and gas equivalent factor (GEF) for gas wells from the hydrocarbon liquid sample taken during the test
4. Calculate the WGR

   WGR = Well test water volume / (Well test gas volume)

5. Calculate estimated water production for each well:

   Estimated monthly well water volume = Estimated monthly well gas volume × WGR

Do the following after testing gas wells:

1. Calculate the CGR or OGR:

   CGR or OGR = Well test condensate or oil volume / Well test gas volume

2. Calculate estimated well condensate or oil production:

   Estimated monthly well condensate or oil volume = Estimated monthly well gas production × CGR or OGR

Do the following after testing oil wells:

1. Calculate the OGR:

   OGR = Well test oil volume / Well test gas volume

2. Calculate estimated well oil production:

   Estimated monthly well oil volume = Estimated monthly well gas production × OGR

Do the following for all wells:

1. Calculate battery estimated volumes

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

   Total battery estimated monthly hydrocarbon liquid volume = Sum of all estimated monthly well hydrocarbon liquid volumes

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

2. Calculate proration factors for gas, hydrocarbon liquids, and water:

   Gas proration factor = Total battery actual monthly gas volume / Total battery estimated monthly gas volume

   Hydrocarbon liquid proration factor = Total battery actual monthly hydrocarbon liquid volume / Total battery estimated monthly HC liquid volume

   Water proration factor = Total battery actual monthly water volume / Total battery estimated monthly water volume

3. Calculate monthly well production:

   Prorated monthly well gas production = Estimated monthly well gas volume × gas proration factor

   Prorated monthly well hydrocarbon liquid production = Estimated monthly well hydrocarbon liquid volume × hydrocarbon liquid proration factor

Actual prorated monthly well water production = Estimated monthly well water volume × water proration factor

Do the following for oil wells:

1. Calculate the well actual oil and gas production volumes after applying shrinkage and flash factors (see 3 above):

   Actual monthly oil production = Prorated monthly well oil production × (1 − SF)

   Flash gas volume = Actual monthly well oil production × GIS

   Actual monthly gas production = Prorated monthly oil well gas production + Flash gas volume

Do the following for gas wells:

1. Calculate GEV of prorated monthly well condensate production:

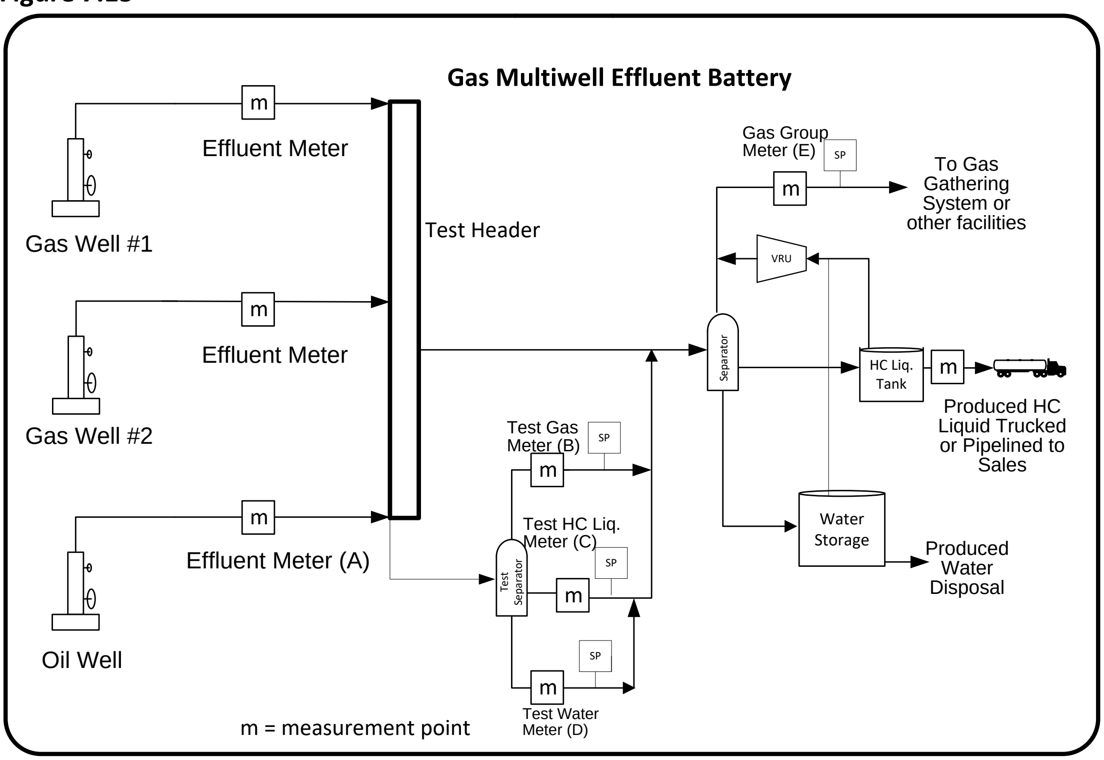
   GEV of condensate = Prorated monthly well condensate production × GEF

2. Calculate actual monthly gas well volume:

   Actual monthly gas well volume = Prorated monthly gas production + GEV of condensate

7.5.4 Operational Scenario 2 – Hydrocarbon Liquids are Delivered to Sales at the Battery

Figure 7.15



Scenario 2 (see Figure 7.15) production measurement and well volume are 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 (note that hydrocarbon liquids and water are measured at the receiving facility).
2. The hydrocarbon liquids and water are individually tanked and disposed to sales (hydrocarbon liquids) or disposal/injection (water). The gas is delivered to a gas gathering system or another facility such as a gas plant.
3. Standard ECF proration accounting procedures are used to determine individual well volumes of gas and condensate/oil (gas wells), gas and oil (oil wells), and water.
4. Oil, gas, and water volumes from oil wells are then subtracted from the group measured gas, hydrocarbon liquid, and water volumes.
5. Oil production is reported to an oil battery facility subtype 311 or 321 for oil wells. For gas wells, the condensate/oil is reported as a liquid volume disposition from a gas effluent measurement battery facility subtype 362.

7.5.4.1 Additional Measurement System Requirements – Hydrocarbon Liquids are Delivered to Sales at the Battery

In addition to the requirements set out in Section 7.5.2, Operational Scenario 2 must also adhere to the following requirements:

1. The battery 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 condensate/oil leg of the separator must use a Coriolis mass meter and a water-cut analyzer.
3. Gas and hydrocarbon liquid sample analyses from individual wells must be used to calculate the well gas and hydrocarbon liquid GEV.
4. The group gas sample analysis must be used to calculate the group GEV.
5. The hydrocarbon liquid meter at the test separator must be proved to stock tank conditions.
6. 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 processed to ensure vapour management complies with Directive 060, Section 8.1(4) for atmospheric storage tanks vented to atmosphere or flared.

7.5.4.2 Production Accounting and Reporting Procedures – Hydrocarbon Liquids are delivered to Sales at the Battery

Do the following after testing each well:

1. Calculate the ECF:

ECF = Well test gas volume / Effluent gas volume measured during test

2. Calculate estimated gas production:

   Estimated monthly well gas volume = Monthly well effluent volume × ECF

3. Obtain GIS for wells from the hydrocarbon liquid sample taken during test
4. Calculate the WGR

   WGR = Well test water volume / (Well test gas volume)

5. Calculate estimated water production for each well:

   Estimated monthly well water volume = Estimated monthly well gas volume × WGR

Do the following after testing gas wells:

1. Calculate the CGR or OGR:

   CGR or OGR = Well test condensate or oil volume / Well test gas volume

2. Calculate estimated well condensate or oil and gas production:

   Estimated monthly well condensate or oil volume = Estimated monthly well gas production × CGR or OGR

   Estimated monthly well flashed gas volume = Estimated monthly well condensate or oil volume × GIS

   Total estimated monthly well gas volume = Estimated monthly well gas volume + Estimated monthly well flashed gas volume

Do the following after testing oil wells:

1. Calculate the OGR:

   OGR = Well test oil volume / Well test gas volume

2. Calculate estimated well oil and gas production:

   Estimated monthly well oil volume = Estimated monthly well gas production × OGR

   Estimated monthly well flashed gas volume = Estimated monthly well oil volume × GIS

   Total estimated monthly well gas volume = Estimated monthly well gas volume + Estimated monthly flashed gas volume

Do the following for all wells:

1. Calculate total battery estimated volumes

   Total battery estimated monthly gas volume = Sum of all estimated monthly well gas volumes

   Total battery estimated monthly hydrocarbon liquid volume = Sum of all estimated monthly well hydrocarbon liquid (oil and condensate) volumes

   Total battery estimated monthly water volume = Sum of all estimated monthly well water volumes

2. Calculate proration factors for gas and hydrocarbon liquid:

Gas proration factor = Total battery actual monthly gas volume / Total battery estimated monthly gas volume

Hydrocarbon liquid proration factor = Total battery actual monthly hydrocarbon liquid volume / Total battery estimated monthly hydrocarbon liquid volume

Water proration factor = Total battery actual monthly water volume / Total battery estimated monthly water volume

3. Calculate monthly well production:

Actual prorated monthly well gas production = Estimated monthly well gas volume × gas proration factor

Actual prorated monthly well hydrocarbon liquid production = Estimated monthly well hydrocarbon liquid volume × hydrocarbon liquid proration factor

Actual prorated monthly well water production = Estimated monthly well water volume × water proration factor

The volumes and proration factors above will be reported on Petrinex under the gas battery for gas wells and the oil battery for oil wells.

8 Gas and Liquid Sampling and Analysis

This section outlines the gas and related liquid sampling and analysis requirements for the various categories of production measurement. These requirements add to the requirements in:

SK	Section 93.1 of *The Oil and Conservation Regulations, 2012*, which continue to apply.
AB	Sections 11.070 and 11.080 of *The Oil and Gas Conservation Regulations, 2012*, which continue to apply.
BC	*The Oil and Gas Activities Act*

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. The Regulator may also consider applications for further requirement alterations or eliminations if the licensee can demonstrate that measurement accuracy would either not be reduced or not impact royalty, equity, environment, public safety or reservoir engineering concerns.

SK	In Saskatchewan, all sampling and analysis reports for both facilities and wells must be submitted to ER as per the specifications listed in *Directive PNG013: Well Data Submission Requirements*
AB	Upon Regulator Request
BC	Upon Regulator Request

8.1 General

Gas and liquid analyses are required for the determination of gas volumes, conversion of liquid volumes to gas equivalent, and product allocation. The sampling and analysis requirements identified in Section 8 pertain only to those areas that affect the calculations and reporting required by the Regulator.

These requirements apply solely to the measurement of hydrocarbon fluids and are not intended to supersede the business requirements that licensees are required to meet regarding product allocations.

If oil is produced from gas wells, as defined by the Regulator, the oil must be reported as liquid oil production and not as a gas equivalent volume (GEV). Therefore, compositional analysis of the oil is not required for that purpose. The oil produced may be combined with the gas and delivered to a gas plant or other facilities for further processing, or the oil could be separated from the gas at the well equipment and directed to tankage, and then for further treatment or sale.

Gas density and composition are integral components of gas volume calculations and plant product allocation calculations. 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.

SK	If liquid condensate produced from gas wells is recombined with the gas well production, 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 this reason, the condensate sampling requirements must mirror the gas sampling requirements. If liquid condensate is separated at a well, battery, or gas gathering system and delivered from that point for sale or other disposition, or trucked for 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.
AB	If liquid condensate produced from gas wells is 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 this reason, the condensate sampling requirements must mirror the gas sampling requirements. If liquid condensate is separated at a well, battery, or gas gathering system 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.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Sampling and analysis frequencies and updating requirements for the various production types are summarized in Section 8.4. Further details are provided in the sections that follow. These sampling frequencies are the base requirements for gas and related liquid measurement.

Sampling and analysis of oil/emulsion streams at oil and gas wells and batteries are performed to determine the relative oil and water content of the streams. Oil/emulsion sampling and analysis are discussed in Section 6.4.

8.2 Sampling and Analysis Requirements

Except where noted in this Directive, the gas sampling equipment and methodology must follow the requirements set out in API MPMS 14.1 of June 2001, Gas Processors Association (GPA) 2166-05, or other equivalent industry standards.

Except where noted in this Directive, the condensate sampling equipment and methodology must follow the requirements set out in GPA 2174-93, the evacuated cylinder method cited in GPA 2166-05, or in other equivalent industry standards.

Samples and analysis 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 Section 1, Standards of Accuracy are fulfilled. When the uncertainty requirements cannot be met, licensees must consider more frequent sampling, calculated analyses in Section 8.3.2, 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 through 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 such as sales, fuel, flare, and injection gases meet the uncertainty guidelines in Section 1, Standards of Accuracy, the licensee may use a single gas analysis for all meters on the common stream.

8.2.1 Sampling Procedures

1. Sample points must be located to provide representative samples.
2. Sample probes must not be located within the minimum upstream straight lengths of the meter.
3. Access from grade or platform must be provided for the sample point.
4. If sample transfer tubing is to be used, its length must be minimized.
5. The sample transfer tubing must be oriented to minimize the potential to trap liquids in gas samples and water in condensate samples.
6. A means must be provided to safely purge sample transfer tubing between the sample point and the connection point of the sample cylinder.
7. Sample containers must be clean and meet the pressure, temperature, and materials requirements of the intended service and have the required Regulatory approvals as necessary.
8. The procedures used for sampling, transportation, handling, storage, and analysis must ensure that atmospheric contamination does not occur.

All samples must be analyzed using a gas chromatograph or equivalent to determine the components to a minimum of C_{7+} composition except for sales or delivery points where C_{6+} 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 percentage of 100, and the relative density must be determined to a minimum of three decimal points.

8.2.2 Sample Point and Probes

The sample point location and probe installation requirements that follow apply to all Regulator measurement points.

SK	With the exception of sales/delivery point measurement, current sample point locations and installations existing prior to when this Directive comes into force, do not have to be upgraded to meet the sample probe requirements but must meet the sample point requirements.
AB	With the exception of sales/delivery (royalty trigger) point measurement, current sample point locations and installations existing prior to December 5, 2007, do not have to be upgraded to meet the sample probe requirements but must meet the sample point requirements.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

A sample probe must be installed according to the requirements in this section when an installation is relocated or reused for another well or facility.

8.2.2.1 Requirements for Gas Sampling

1. For sampling applications where the gas is at or near its hydrocarbon dew point, a sample probe must be used. This requirement applies to any separator application where hydrocarbon liquids are present.
2. For gas applications where the gas is not near its hydrocarbon dew point, the licensee may use a sample probe.
3. The preferred location for gas sample points is the top of horizontal lines.
4. An optional location for gas sample probes is the side of vertical lines with the probe tip sloping 45° downward.
5. Sample probes must be located at least five pipe diameters downstream of any piping disturbances, such as bends, elbows, headers, and tees.
6. 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 five pipe diameters downstream of an orifice plate.
7. Sample points may be located downstream of ultrasonic meters that experience minimum pressure drop through the meter unless a flow conditioner is used and the gas is at or near its hydrocarbon dew point, in which case the sample point must be upstream of the flow conditioner.
8. 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.

9. Sample points used to sample blends of two gas streams must have provision for mixing, such as an upstream static mixer, with due consideration to potential phase changes brought about by a pressure drop associated with the mixing device.
10. Orifice meter impulse lines or transmitter manifolds lines must not be used for taking samples.
11. Level gauge connections must not be used for taking samples.

8.2.2.2 Requirements for Condensate Sampling

1. With the exception of two-phase separators, a sample probe is recommended.
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 preferred location for condensate sample points is the side of horizontal lines.
4. An optional location for liquid sample points is the side of vertical lines with the probe tip sloping 45° downward.
5. The location of the sample point must be such that phase changes due to changes in pressure and/or temperature are minimized. Specifically, sample points must not be located where vapour breakout is likely such as downstream of pressure-reducing components, orifice plates, flow conditioners, turbine, PD or Coriolis mass meters, control valves, and Regulators or where the stream temperature has increased.
6. For separator applications, the sample point must 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 must be located between the pump discharge and the meter.
7. Orifice meter impulse lines or transmitter manifolds lines must not be used for taking samples.
8. Level gauge connections must not be used for taking samples.

8.2.3 H_2S Sampling and Analysis

This section relates to obtaining high pressure samples. Special considerations, such as extra sample(s) or purging, should be taken when obtaining low pressure samples at a boot separator configuration, treater, stabilizer, or at an acid gas facility.

Hydrogen sulphide (H_2S) is a reactive molecule that presents challenges for sampling and analysis of gas mixtures containing it. H_2S is easily lost during sampling and analysis, resulting in underreporting of H_2S concentrations. Factors that affect representative sampling and analysis accuracy through H_2S loss are:

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
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
3. Minimizing the time between sampling and analysis

Typical construction materials 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 5000 ppm when moisture is present.

The choice of analytical technique also affects the amount of H_2S reported. Instrument-oriented techniques, such as gas chromatography, are typically more precise than chemistry-oriented techniques, such as Tutweiler titrations or stain tubes. However, such instrument-oriented techniques are often impractical for individual well site applications.

Therefore, consideration should be given to analysis technique limitations and sample degradation as they relate to the specific reporting requirements in determining the best approach.

See Table 8.1 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 analysis techniques 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 must be used. Unexpectedly large variances between lab and field H_2S values must be investigated.

Table 8.1. H_2S analysis technique comparison

Analysis technique	Lower detection limit	Advantages	Limitations
Online GC	500 ppm	Real-time, accuracy Minimal elapsed time	Capital cost, ongoing maintenance
Laboratory GC	500 ppm	Precision, accuracy	Potential degradation during transport that varies with H_2S concentration
Tutweiler GPA C-1	1500 ppm	On site	Titration apparatus, reagent quality, variability in operator technique, including visual endpoint detection, computations, mercaptan interference
Stain Tubes GPA 2377	1 ppm	On site	Poor precision (±25%) Matrix effects as described in manufacturer's specifications

Analysis by gas chromatography is the preferred method at higher H_2S concentrations.

For H_2S concentrations between 1500 and 5000 ppm, it is recommended that both stain tube and Tutweiler values be obtained if online GC is not used.

If high accuracy of low-level, below 1500 ppm, H_2S concentration is required, consideration should be given to using a low-level sulphur-specific detector, such as a GC sulphur chemiluminescence detector. Sulphur Chemilumine Scene Detectors is a category of sulphur selective detectors that achieve a low detection limit of H_2S and other sulphur compounds, such as mercaptans, sulphides, and disulphides. These detectors are used in measurement of H_2S in natural gas streams. The use of containers that minimize degradation and the time elapsed between sampling and analysis is also recommended in these situations.

Refer to Appendix 4 for more detail on the analytical methods used in the industry for determining H_2S concentrations in gas samples.

8.2.4 Compositional Analysis of Natural Gas

The two recommended 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 molecular weight and density description of the C_{7+} fraction 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 C_{7+} components, 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 C_{7+} 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 C_{7+} components can be grouped together into a single sharp chromatograph 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 C_{7+} fraction. Inherently, if the composition of the C_{7+} fraction is unknown, some agreed-upon physical properties must be applied for calculation purposes. The GC C_{7+} calibration is also affected, which increases the uncertainty of the C_{7+} measurement and heating value computation.

If detailed information on C_{7+} physical properties is not available, default values can be applied, as in Table 8.2.

Table 8.2. Recommended default values for C_{7+} properties*

Component Names	Molecular mass grams per mole	Liquid density kg/m^3 at 15°C	Heating value MJ/m^3
C_{7+}, Heptanes plus	95.00	735.0	195

* C_{7+} is a pseudo-compound. The values in most scenarios have been found to adequately represent the heavier fraction of natural gas samples.

8.3 Gas Equivalent Factor Determination from Condensate

Gas Equivalent Factor (GEF) is the volume of gas, $10^3 m^3$ at base conditions that would result from converting 1.0 m^3 of liquid into 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 Regulator.

The GEF of a liquid may be calculated by any one of three methods described in Appendix 5, depending upon the type of component analysis conducted on the liquid such as volume, mole, or mass fractions and the known properties of the liquid.

8.3.1 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 5 present the different methodologies used to calculate the GEF. All physical properties are based on GPA Standard 2145-03 (2003 or later) published data.

1 kmol = 23.645 m^3 @ 101.325 kPa and 15°C.

8.3.2 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 in this section:

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 effluent 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 recommended options for sampling these streams are on-line gas chromatographs or proportional sampling systems. However, if the recommended 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 scenarios, 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 follow.

8.3.2.1 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 scenarios, 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.

Subject to the exemption criteria described in the following paragraph, the gas and liquid flow rates used must be from the same day that the gas and liquid samples were obtained.

Flow rates from the day of sampling must be used in determining recombined compositions, with the following exemptions:

1. When the daily liquid-to-gas ratio is constant, volumes from an extended period such as multiday or up to monthly may be used.
2. If some of the liquid stream is not recombined in a month such as scenarios where it is dropped to a tank, the composition flow volume of the liquids not recombined must be deducted from the initial recombined composition. This is typically performed by recalculating the recombined composition with new flow rates, typically the flow rates for the month.

See the example in Appendix 6.

8.3.2.2 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 such as inlets, compressors and 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 should 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 measured. 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.

See the example in Appendix 6.

8.3.2.3 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, such as 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.

See the example in Appendix 6.

8.4 Gas and Condensate Sampling and Analysis Requirements

SK	For facilities and wells, Table 8.3 outlines the frequency for updated analysis required for gas and condensate streams. The sampling and analysis of condensate, if applicable, must be performed at the same time as the gas sampling. Configuration examples are shown in Figures 8.1 through 8.17. In each scenario, other similar configurations may also apply. Gas and condensate samples and analysis must be conducted on all new wells and new measurement points as per *Directive PNG013: Well Data Submission Requirements*. 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 measurement points excluding wellhead gas analysis, substitute compositions must 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 of the producing well, and there are often contaminants such as nitrogen or frac fluid in test samples. For non-well meters, the substitute composition should be a reasonably close replica as to the expected composition. 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 20 10^3m^3/month, retroactive volumetric adjustments must be calculated using the initial gas composition. By April 1, 2020, gas and condensate samples and analysis must be conducted for all existing wells and measurement points unless one has already been conducted and submitted, or an automatic exemption is applied as per Section 8. For the time period prior to April 1, 2020, a substitute composition may be used for gas measurement and gas equivalent of liquid calculations. In Saskatchewan, sampling and analysis reports must be submitted to ER as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.* If an analysis has already been completed it must be submitted to ER before April 1, 2020 as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.*
AB	Table 8.3 gives the analysis update frequency for gas and condensate streams. The sampling and analysis of condensate, if applicable, must be performed at the same time as the gas sampling. The configurations shown in Figures 8.1 through 8.17 are examples. In each scenario, other similar configurations may also apply. 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 must 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 such as nitrogen or frac fluid in test samples. 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 20 10^3m^3/month, retroactive volumetric adjustments must be calculated using the initial gas composition. See Section 4.3.3.3 for information regarding volumetric data amendments in Petrinex resulting from errors caused by using substitute gas and condensate analyses.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Table 8.3. Sampling and analysis frequencies for various types of facilities

	Type of facility		Gas rate $10^3m^3/d$	Sample and analysis type	Sampling point	Frequency
Gas wells/ batteries/ facilities	SW Saskatchewan and SE Alberta shallow gas stratigraphic units or zones or areas or coalbed methane (CBM) well with minimal water (facility subtype 363) See Section 8.4.1		N/A	Gas only	Group meter	Biennially
	Gas proration outside SW Saskatchewan and SE Alberta shallow gas stratigraphic units or zones or areas or effluent measurement battery (facility subtypes 362 and 364) See Sections 8.4.2 & 8.4.3		N/A	Gas/condensate	Test meters	At time of testing
					Group meter	Annually
	Multiwell group battery or single-well battery including CBM well/battery with no condensate or oil (facility subtypes 361 and 351) See Section 8.4.4		N/A	Gas only	All meters	Annual first year, then Biennially
	Multiwell group battery or single-well battery with condensate or oil (facility subtypes 361 and 351) See Section 8.4.5		> 16.9	Gas/condensate	Per meter	Annually
			≤ 16.9	Gas/condensate	Per meter	Biennially
	Gas storage schemes, injection (facility subtypes 504, 505, 517, and 519) and withdrawal phase (facility subtypes 351, 361, 362, 363, 364) See Section 8.4.6			Gas	Per injection/ production meter	First month, then semi-annually
	Gas cycling schemes See Section 8.4.7	Injection		Gas/condensate	Per injection meter	Per approval or source requirement (if not in approval)
		Production			Per production meter	Per approval or semi-annually (if not in approval)
	Gas sales/delivery (all facility subtypes apply) See Section 8.4.8			Gas only	Per meter	Annually
	Gas plants (facility subtypes: 401-407 and 411) See Section 8.4.9.1			Gas/condensate	Per accounting meter	Semiannually
	Gas gathering systems (facility subtypes 611 and 612) See Section 8.4.9.2		> 16.9	Gas/condensate	Per inlet meter	Annually
			≤ 16.9	Gas/condensate	Per inlet meter	Biennially
Non-heavy oil wells/ batteries	Single-well/ multiwell group battery (facility subtypes: 311 and 321) See Section 8.4.10	Flared		Gas only	Per meter	Initial
		Conserved	> 16.9	Gas only	Per meter	Annually
			≤ 16.9	Gas only	Per meter	Biennially

	Type of facility		Gas rate $10^3m^3/d$	Sample and analysis type	Sampling point	Frequency
	Multiwell proration Battery (facility subtype: 322) for injection phase (facility subtypes: 501, 503, 506, and 510) See Section 8.4.11	Primary production and water flood See Section 8.4.11	> 16.9	Gas only	Per test/group meter per pool	Annually
			≤ 16.9	Gas only	Per test/group meter per pool	Biennially
		Miscible/immiscible flood See Section 8.4.12	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)
Heavy oil[1] batteries See Section 8.4.13	Single-well/ multiwell group battery (facility subtypes: 325 and 326)		≤ 2.0	Gas only	Per well	Initial
			> 2.0	Gas only	Per meter	Biennially
	Multiwell proration battery (facility subtypes: 327 and 344)		≤ 2.0	Gas only	Per meter/ Per pool	Initial
			> 2.0	Gas only	Per test/group meter	Biennially
Water source well/battery	Single-well/ multiwell battery (facility subtypes: 906 and 907)			Gas only (if present)	Per well	Initial

1. Heavy oil is crude oil with a density ≥ 920 kg/m^3 at 15 ^oC

Licensees 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, such as joint venture and allocation agreements, more frequently than required by this Directive, the licensee must use those data to update volumetric calculations.

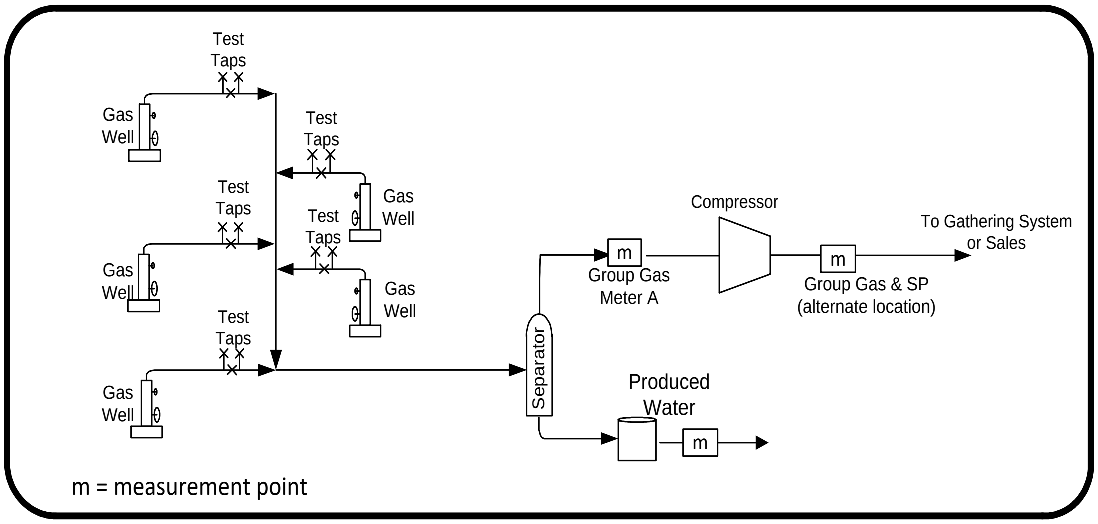
8.4.1 Gas Multiwell Proration SW Saskatchewan and SE Alberta Batteries with Minimal Water (Petrinex facility subtypes: 363 in SK and 363 and 366 in AB including CBM)

SK	Shallow gas wells are those that produce from shallow gas stratigraphic units or zones, including coals and shales from the bottom of the Glacial Drift to the bottom of the Upper Cretaceous. The production from two or more of these stratigraphic units or zones without segregation in the wellbore requires either prior approval from the Regulator for commingled production.
AB	Shallow gas wells are those that produce from shallow gas stratigraphic units or zones, including coals and shales from the top of the Edmonton Group to the base of the Colorado Group. The production from two or more of these zones without segregation in the wellbore requires either prior approval from the Regulator for

	commingled production, which has been granted in a portion of SE Alberta in Order No. MU 7490 or adherence to the self-declared commingled production requirements described in *Directive 065*.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

In the configuration of Figure 8.1 of shallow gas wells or CBM wells with water production not more than 0.01 m^3/ $10^3 m^3$ gas, analyses must be updated biennially at group gas meter A. No sampling and analysis are required at the test meter or well. Density and component analysis data from the group meter sample point may be used for test meter calculations.

Figure 8.1. Typical shallow gas wells or CBM well configuration



For shallow gas wells and CBM wells that have been fractured or stimulated using a gaseous medium (e.g., N_2 or CO_2), gas sampling and analysis frequency must be in accordance with the following:

1. An initial sample and analysis must be obtained within the first month the well is put on production to establish the initial N_2 or CO_2 concentration and other component composition.
2. Where there is adequate analog sample and analysis data that is representative of how concentrations of N_2 or CO_2 will decline from month to month in the produced gas, the monthly analog sample and analysis data may be used to calculate well volumes in the second to fifth months.
    a. The analog data set must contain monthly sample and analysis data showing how N_2 or CO_2 concentrations decline month over month for up to 12 months and from at least six wells within an eight km radius of the subject well. The analog data set must be a volume-weighted average composition.
3. After being on production for six months, a second sample and analysis must be obtained to confirm that the well gas N_2 or CO_2 concentration is declining as predicted by the analog data set. The sample and analysis must be used to re-

establish the well gas composition with the analog data set. The monthly analog sample and analysis data may be used to calculate well volumes from the seventh to twelfth months.

4. After being on production for one year, the sample and analysis from the group separator may be used to determine the well gas volumes.

5. If analog sample and analysis data does not exist as described above, then the well must be sampled bimonthly until the well gas composition has stabilized; the sample and analysis obtained at the group meter may then be used to determine well gas volumes. Composition stabilization means that the mole fraction of N_2 or CO_2 in the total sample analysis is ≤ 0.05 or ≤ 0.02, respectively.

For CBM wells that have been fractured or stimulated using a gaseous medium, gas samples must be taken monthly until the composition stabilizes and then biennially or as otherwise required by the exemptions in this directive.

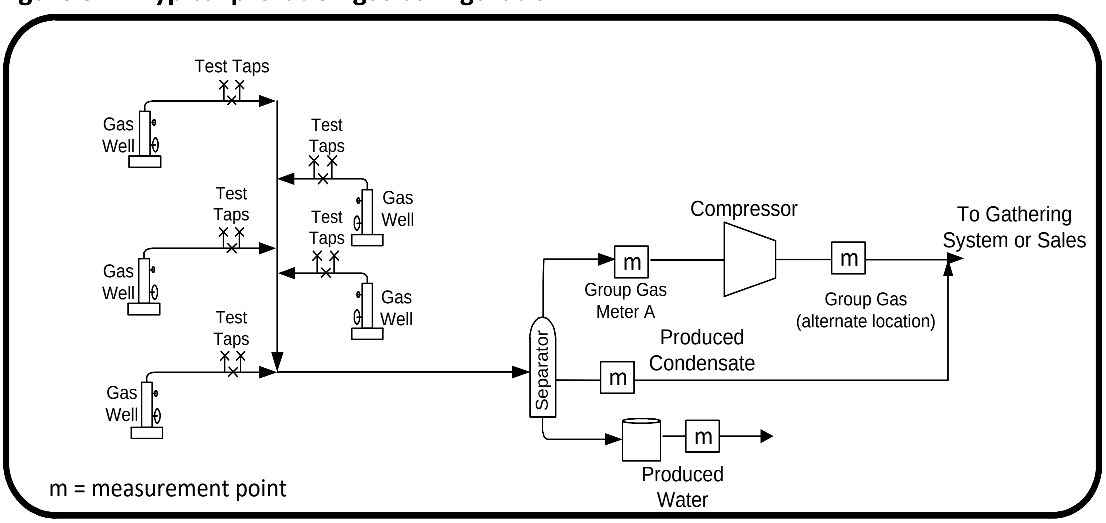
If these stratigraphic units or zones are commingled with gas from other outside stratigraphic units or zones, sampling must be done on a per pool or stratigraphic unit or zone basis for CBM or per commingled pool(s) basis from a representative well within the pool(s) biennially.

For exemptions on sampling for these pools or stratigraphic units or zones, see Section 8.4.2.

8.4.2 Gas Multiwell Proration Outside SW Saskatchewan and SE Alberta Batteries (Petrinex facility subtypes: 364 in SK and 364 and 367 in AB)

In the configuration in Figure 8.2, gas density and composition must be updated annually at group gas meter A and at each well during a test. If condensate at the group measurement point is recombined and delivered to a gas plant, the condensate GEF must be updated annually.

Figure 8.2. Typical proration gas configuration



8.4.2.1 Exemptions for Sampling Frequency

1. A licensee is not required to update the analyses where three consecutive gas relative density (RD) determinations conducted at the specified determination

frequency or, alternatively, no more frequently than once per year are all within ±1.0% of the average of the three RD's as shown in Example 8.1. In this situation, there is no need for an application to be submitted to the Regulator. Records and data in support of this exemption must be retained by the licensee and made available to the Regulator upon request. Notwithstanding this exemption, the licensee 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 RD's.

2. The gas and condensate analyses determined at the group measurement points may be used for the test meters, provided that all wells are from the same pool.

3. For wells producing from multiple pools into a group measurement point, average individual gas and (where applicable) condensate analyses may be used in volume calculations for all the wells in each individual pool (or commingled pool) producing to a test meter provided the following qualifying criteria are met.

    a. All wells flowing to the group measurement point have common ownership. If there is not common ownership, written notification has been given to all working interest participants, with no resulting objection received.

    b. All wells flowing to the group measurement point have common Crown or Freehold royalty. 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 licensee must apply to the Regulator for approval if any Freehold royalty owners objects.

        i. In each subsequent year, gas and condensate analyses must be obtained from at least four wells in each pool (or commingled pool) or at least 25 per cent of the wells in each pool (or commingled pool), whichever is greater. This new data will be used to recalculate average gas and condensate relative densities and provided that the newly sampled well gas and condensate relative densities variance remains within the 2 per cent limit of the average, the exemption will remain in effect (see example 8.2). If the well gas and condensate relative densities variance exceeds the 2 per cent limit, this exemption is revoked. The revocation of the exemption remains in place until sampling and analysis of all wells in the pool re-establishes the required RD variance.

        ii. If the pool (or commingled pool) has four or fewer wells flowing to the group measurement point, then, in each subsequent year, gas and condensate analyses must be obtained from one well from each pool (or commingled pool). If the newly sampled well gas and condensate relative densities variance remains within 2 per cent of the previous years' relative densities, the exemption remains in effect. If the well gas and condensate relative densities variance exceeds the 2 per cent limit, this exemption is revoked. The revocation of the exemption remains in place until sampling and analysis of all wells in the pool re-establishes the required RD variance.

c. New wells that have been fractured or stimulated with a gaseous medium are not eligible for this exemption until their gas and condensate RDs are within the 2 per cent variance of the calculated pool average gas and condensate RD.

Example 8.1. Meter A RD Differences

Sample date	RD	RD Difference from average
June 03, 2000	0.583	- 0.29%
June 09, 2001	0.586	+ 0.22%
June 06, 2002	0.585	+ 0.05%
Average	0.5847	

In this example, meter A would be exempt from the requirement for future updates as the three consecutive RD's are within ±1.0% of the average of the three RD's.

8.4.3 Multiwell Effluent Measurement Battery (Petrinex facility subtype: 362)

In the configuration in Figure 8.4, gas analyses, condensate composition, and GEF must be updated at the time of testing each effluent well and annually at the group gas and condensate meters as shown in Figure 8.3. The gas analysis to be used for volumetric calculation at the effluent meter is as follows:

Option 1: Use the separated gas analysis from the ECF-WGR test; or

Option 2: Use the recombination of the gas analysis and the condensate analysis from the ECF-WGR test.

Note: All wells within the effluent battery must use the same analysis option.

8.4.3.1 Exemptions for Analyses at Group Gas and Condensate Metering Points

1. A licensee is not required to update analyses at the group gas and condensate metering points if:

   a. Three consecutive gas RD determinations conducted at the specified determination frequency or no more frequently than once per year are all within ±1.0% of the average of the three RD's as shown in Example 8.1; and

   b. The daily average liquid condensate volume is less than or equal to 2.0 m^3/d for all reporting months for 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.

   In these situations, there is no need for an application to be submitted to the Regulator. Records and data in support of these exemptions must be retained by the licensee and made available to the Regulator upon request. Notwithstanding these exemptions, the licensee 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 RD's, and the licensee must update the condensate analyses if the liquid condensate volume or GEV percentage increases beyond the qualifying limits.

2. A licensee is not required to update the well gas and condensate analyses if three consecutive calculated recombined relative density (RD) determinations conducted at the specified determination frequency or, alternatively, no more frequently than once per year are all within ±1.0% of the average of the three RDs (see Example 8.1). Specifically, the RDs would be those of the gas plus gas equivalent of the recombined liquid condensate. After the well has fallen below the critical lift velocity as determined using the Turner Correlation calculation described in Section 7.4.1.1 a new gas and condensate analysis must be obtained.

   In this situation, there is no need for an application to be submitted to the Regulator. Records and data in support of this exemption must be retained by the licensee and made available to the Regulator upon request. Notwithstanding this exemption, the licensee 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 recombined RDs.

Figure 8.3. Typical multiwell effluent measurement battery

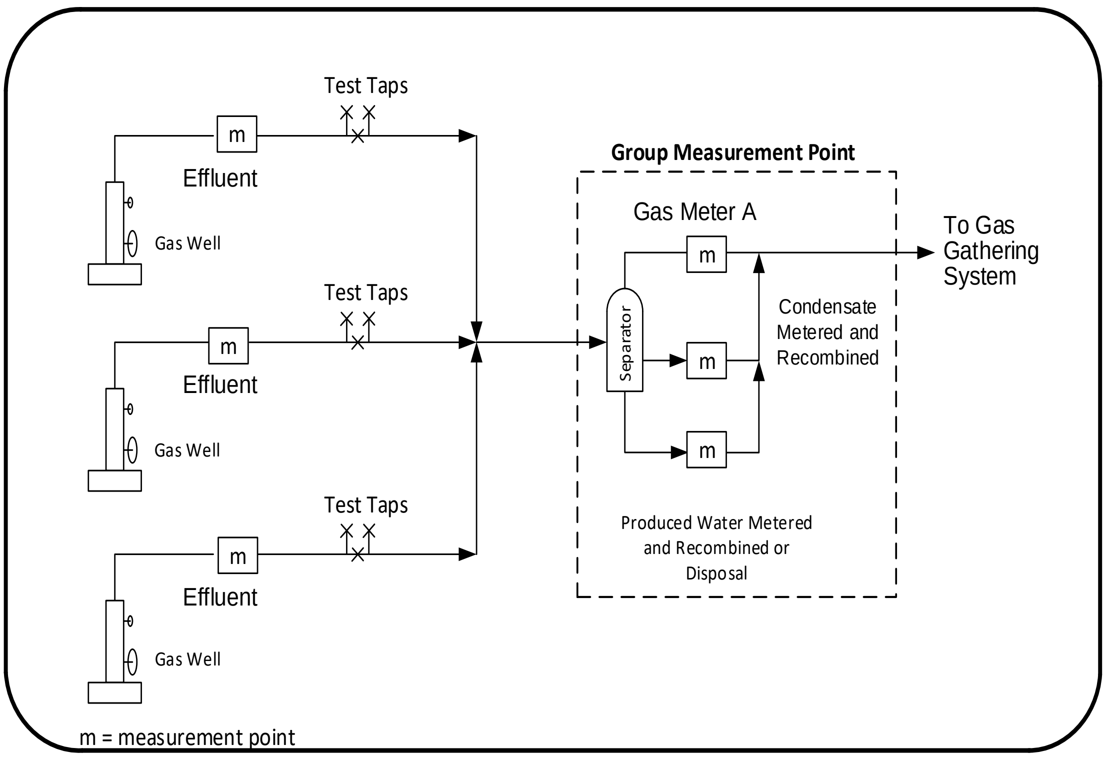
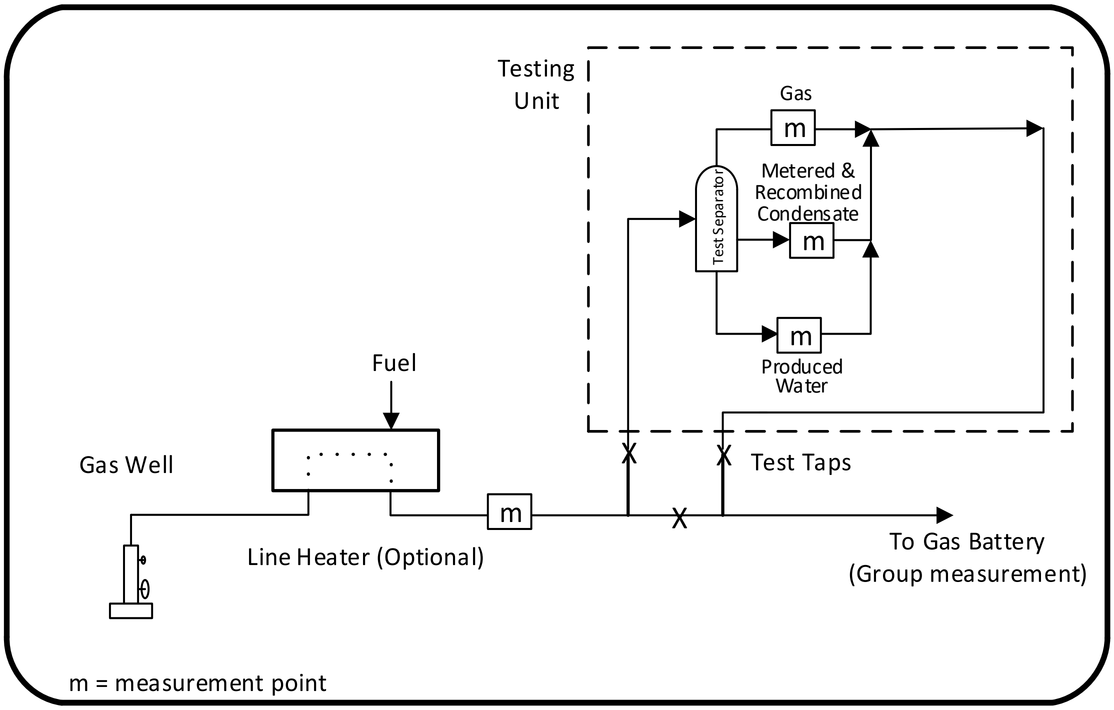


Figure 8.4. Typical effluent well testing configuration



8.4.4 Gas Single Well Battery (Petrinex facility subtype: 351) or Gas Multiwell Group Battery (Petrinex facility subtype: 361) and Shallow Gas Well or CBM Well without Condensate or Oil

For the configuration in Figure 8.5, the gas analysis must be updated within the first year and then biennially at each well meter shown as gas meter A.

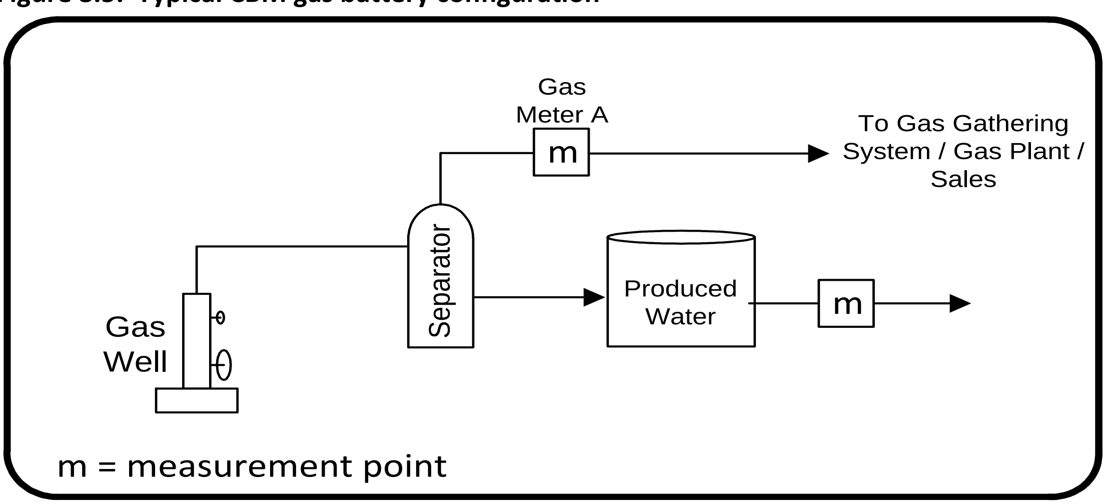
SK	Shallow gas wells are those that produce from the shallow gas stratigraphic units and include coals and shales from the bottom of the Glacial Drift and the bottom of the Upper Cretaceous. The production from two or more of these stratigraphic units without segregation in the wellbore requires prior approval from the Regulator.
AB	Shallow gas wells are those that produce from shallow gas zones and include coals and shales from the top of the Edmonton Group to the base of the Colorado Group. The production from two or more of these zones without segregation in the wellbore requires either prior approval from the AER for commingled production, which has been granted in a portion of SE Alberta in Order No. MU 7490, or adherence to the self-declared commingled production requirements described in *Directive 065: Resources Applications for Oil and Gas Reservoirs*.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

For shallow gas wells and CBM wells that have been fractured or stimulated using a gaseous medium (e.g., N_2 or CO_2), frequency of gas sampling and analysis must be in accordance with the following:

1. An initial sample and analysis must be obtained in the first month the well is put on production to establish the initial N_2 or CO_2 concentration and other component composition.
2. Where there is adequate analog sample and analysis data that is representative of how concentrations of N_2 or CO_2 will decline from month to month in the produced gas, the monthly analog sample and analysis data may be used to calculate well volumes from the second to fifth months.
   a. The analog data set must contain monthly sample and analysis data showing how N_2 or CO_2 concentrations decline month over month for up to 12 months and from at least six wells within an eight km radius of the subject well. The analog data set must be a volume-weighted average composition.
3. After being on production for six months, a second sample and analysis must be obtained to confirm that the well gas N_2 or CO_2 concentration is declining as predicted by the analog data set. The sample and analysis must be used to re-establish the well gas composition with the analog data set. In the seventh month and for the duration of the well life cycle, the analog sample and analysis data may be used to determine the well gas volumes.
4. If analog sample and analysis data does not exist as described above, then the well must be sampled bimonthly until the well gas composition has stabilized; after that, no further sampling of the well is required. Composition stabilization means that the mole fraction of N_2 or CO_2 in the total sample analysis is ≤ 0.05 or ≤ 0.02, respectively.

For shallow gas wells and coalbed methane wells that have not been fractured or stimulated using a gaseous medium, only a single gas sample and analysis is required through the entire producing life cycle of the well. The operator may determine the timing of the gas sampling, but it must be obtained within the first year of the well being placed on production. A representative sample analysis from an analog well or a calculated average gas composition based on the sample analyses of several analog wells may be used for gas volume determination until the actual well gas sample and analysis are obtained.

Figure 8.5. Typical CBM gas battery configuration



8.4.4.1 Exemptions for Analysis Frequency

1. A licensee is not required to update the analyses if three consecutive gas analyses conducted at the specified determination frequency or, alternatively, no more frequently than once per year are all within ±1.0% of the average RD of the three analyses as shown in Example 8.1. In this situation, there is no need for an application to be submitted to the Regulator. Records and data in support of this exemption must be retained by the licensee and made available to the Regulator upon request. Notwithstanding this exemption, the licensee must update the gas analyses when changes are made to producing conditions that could affect the gas analysis by more than ±1.0% of the average RD of the three qualifying analysis.
2. A representative analysis for all wells producing to a common gathering system or facility from a common pool can be used if the RD of all common-pool wells are within 2.0% of the average analysis of those wells. Gas analyses must initially be obtained for all the common-pool wells to arrive at the average analysis. Subsequent analyses can be made on 25% or at least four wells from the pool (whichever is greater) at the frequency stated in this Directive, provided that the RD variance remains within the 2.0% limit of these wells as shown in Example 8.2. Should the variance exceed this limit, this exemption is revoked and biennial analyses must be determined for each measurement point.

Example 8.2. Pool RD Differences

Consider an 8-well pool producing gas under this configuration:

Well Id	RD	RD Difference from average
11-14	0.602	-0.99%
10-16	0.610	+0.33%
10-21	0.602	-0.99%
9-27	0.616	+1.32%
11-30	0.608	0.00%
6-31	0.616	+1.32%
11-32	0.606	-0.33%
11-16	0.604	-0.66%
Average	0.608	

In this scenario, it is acceptable to use the analyses from the well with the RD closest to the average, Well Id 11-30, for all well meters, as all RDs are within ±2.0% of the average of all well RDs. The analysis must then be updated biennially for at least four wells from the pool. This exemption will remain in place, provided that all four well RD’s continue to be within ±2.0% of the average of all the updated RD’s. When this criterion is not met, analyses must revert to biennial updates for all wells.

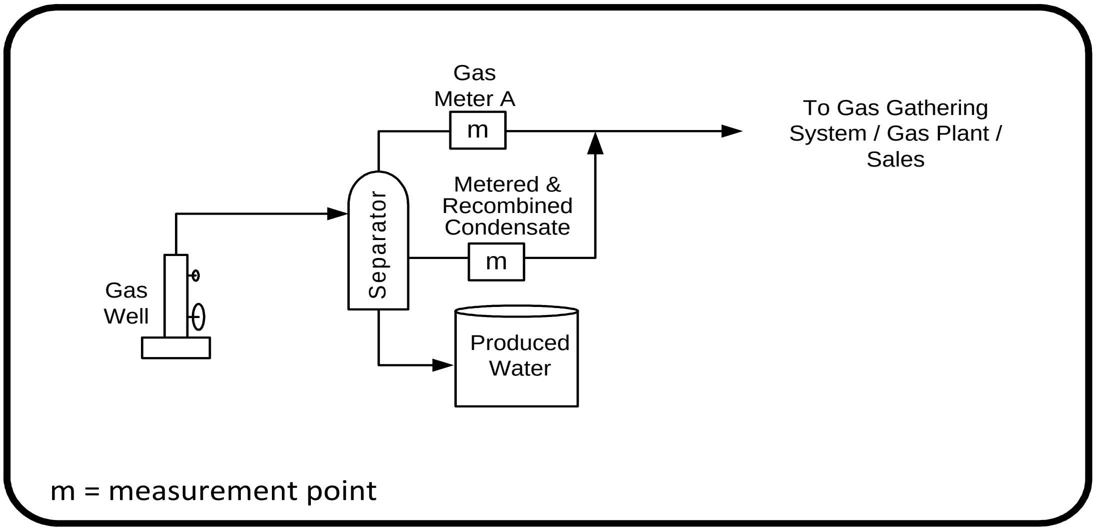
A permanent exemption on a pool basis would be available where the updated average RD meets the criterion of Exemption 1. Where practical, the Regulator expects the same wells to be used to arrive at the average RD used in pursuit of this exemption.

8.4.5 Gas Single Well Battery (Petrinex facility subtype: 351) or Gas Multiwell Group Battery

(Petrinex facility subtype: 361) with Condensate or Oil

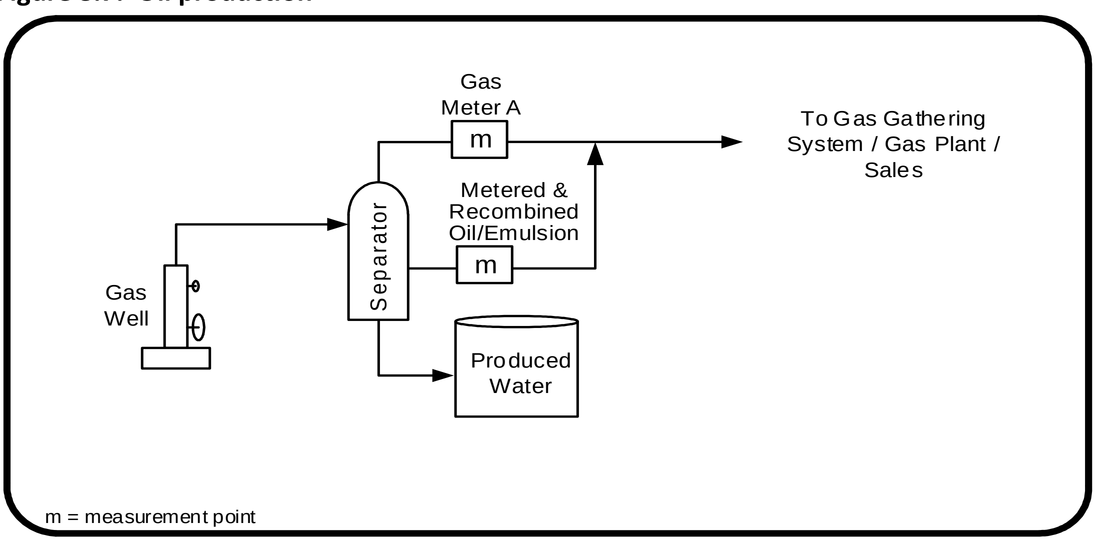
For gas wells producing condensate in Figure 8.6, the frequency of sampling and analysis for gas and condensate depends upon the gas flow rate through gas meter A plus the GEV of condensate. If the flow rate exceeds 16.9 $10^3m^3/d$, the frequency is annual. If the flow rate is less than or equal to 16.9 $10^3m^3/d$, the frequency is biennial. The flow rate value is a monthly average.

Figure 8.6. Condensate production



For gas wells producing oil in Figure 8.7, the sampling and analysis of oil/emulsion streams to determine relative oil and water content must conform to the requirements in Sections 6.4.3 and 14.8. The gas sampling frequency is the same as for a gas well producing condensate, except that the total gas flow rate does not include GEV of oil/emulsion.

Figure 8.7. Oil production



8.4.5.1 Exemptions for Gas Batteries with Condensate

1. For gas wells producing condensate, a licensee is not required to update the gas and condensate (if applicable) analyses at the metering points if:

a. Three consecutive gas RD determinations conducted at the specified determination frequency or no more frequently than once per year are all within ±1.0% of the average of the three RDs as shown in Example 8.1; and

b. Daily average liquid condensate volume is less than or equal to 2.0 m^3/d for all reporting months for 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.

In these situations, there is no need for an application to be submitted to the Regulator. Records and data in support of these exemptions must be retained by the licensee and made available to the Regulator upon request. Notwithstanding these exemptions, the licensee 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 licensee must update the condensate analyses if the liquid condensate volume or GEV percentage increases beyond the qualifying limits.

2. A representative analysis for all wells producing to a common gathering system or facility from a common pool may be used if the RD's of all common-pool wells are within 2% of the average RD of those wells. Gas analyses must initially be obtained for all the common-pool wells to arrive at the average RD. Subsequent analyses may be made on 25% or at least four wells from the pool, whichever is greater, at the frequency stated in this Directive, provided that the RD variance remains within the 2% limit of these wells as shown in Example 8.2. Should the variance exceed this limit, this exemption is revoked and biennial analyses must be determined for each measurement point.

8.4.6 Underground Gas Storage (Petrinex facility subtype: 505)

For the gas storage configuration shown in Figure 8.8, there are two phases to consider:

1. Storage Injection Phase

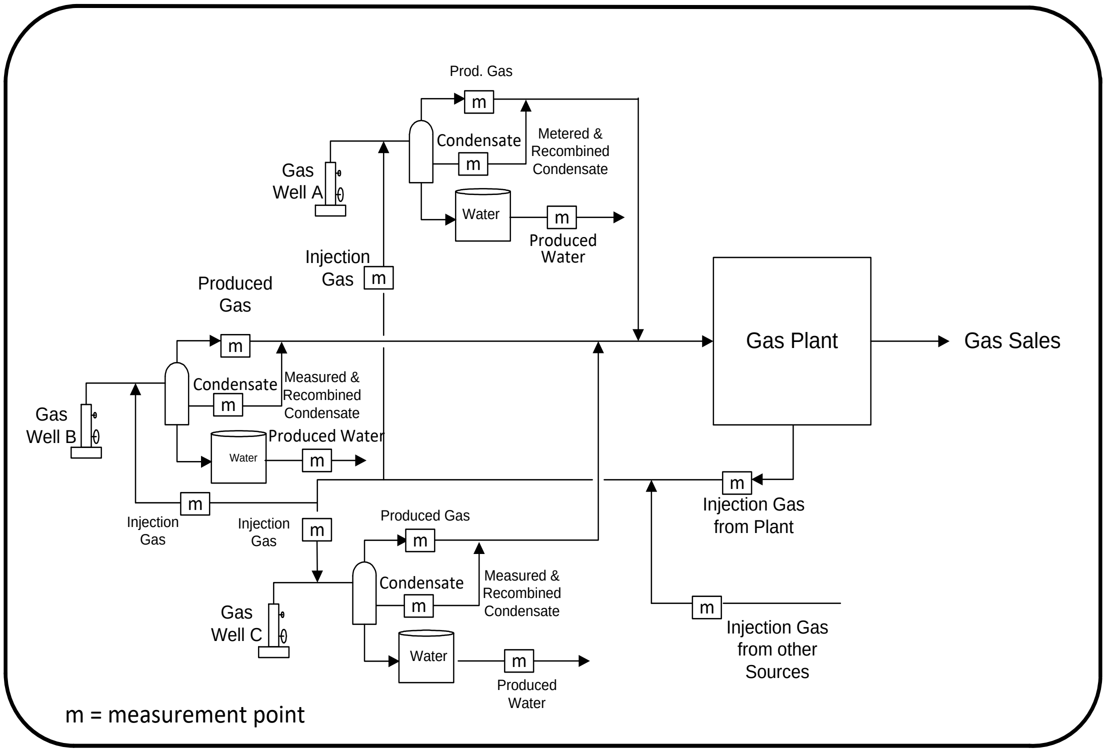
   If the injection gas only comes from a single source, an annual common stream sample analysis may be used for all injection meters, and no individual well injection analyses are required.

   If there are multiple injection gas sources, sample analysis is required at each source stream and at each well injection measurement point. In this scenario, the minimum analysis frequency for injection meters are semiannual, however, a continuous proportional sampler or a gas chromatograph should be installed to provide more accurate compositions for gas volume calculations.

2. Storage Recovery Phase

   During each recovery phase, analyses must be updated at each gas well's production meters within the first month and semiannually thereafter if necessary.

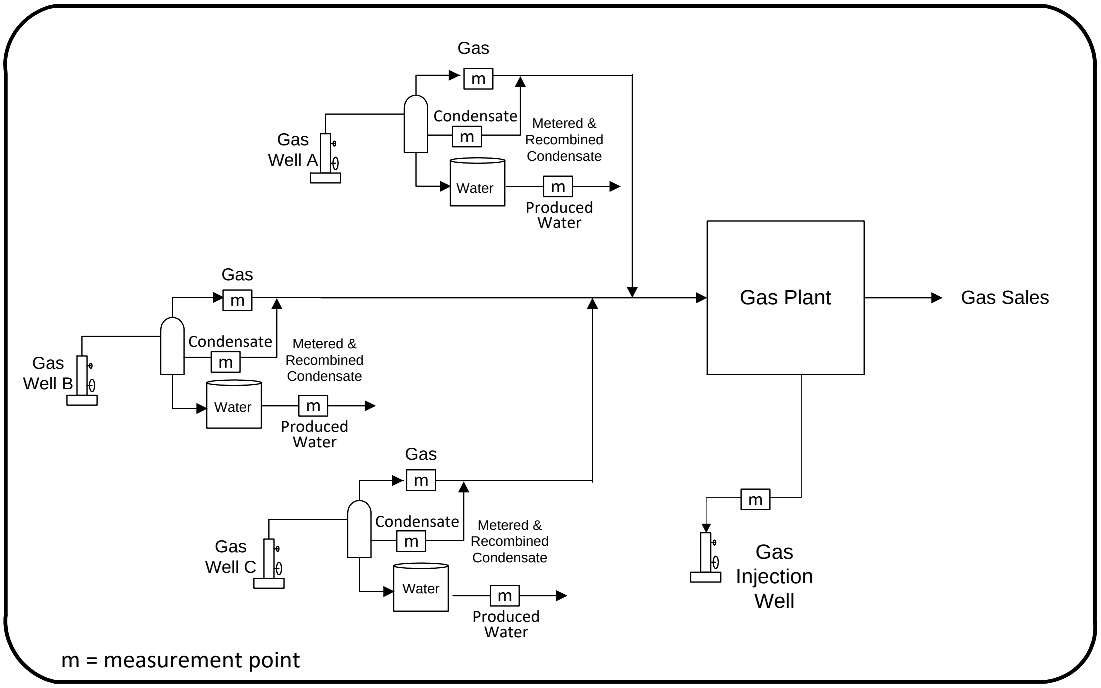
Figure 8.8. Underground Gas Storage



8.4.7 Gas Cycling Scheme (Petrinex facility subtype: 502)

In the gas cycling scheme configuration shown in Figure 8.9, analyses must be updated at each well meter, A, B, and C, 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 such as semiannually for gas plant gas.

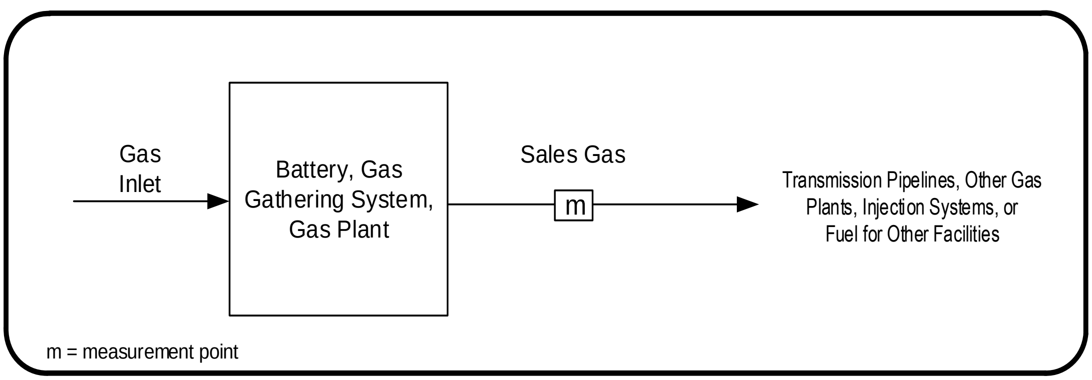
Figure 8.9. Gas Cycling Scheme



8.4.8 Gas Sales/Delivery

In the gas sales/delivery configuration shown in Figure 8.10, gas sales/delivery in this context will typically be clean, processed sales gas that is delivered out of a gas plant or a facility into a transmission pipeline. In some scenarios, this type of gas may be delivered to other plants for further processing or fuel or to injection facilities.

Figure 8.10. Gas Sales/Delivery



If a meter is used to determine the sales gas/delivery point volume from a battery, 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.

8.4.9 Gas Plants (Petrinex facility subtypes: 401 to 407) and Gas Gathering Systems (Petrinex facility subtypes: 621 in SK and 621 and 622 in AB)

In the configuration shown in Figure 8.11, 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. 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, or for heavy oil gas production. For gas sales measurement point sampling frequency, see Section 8.4.8.

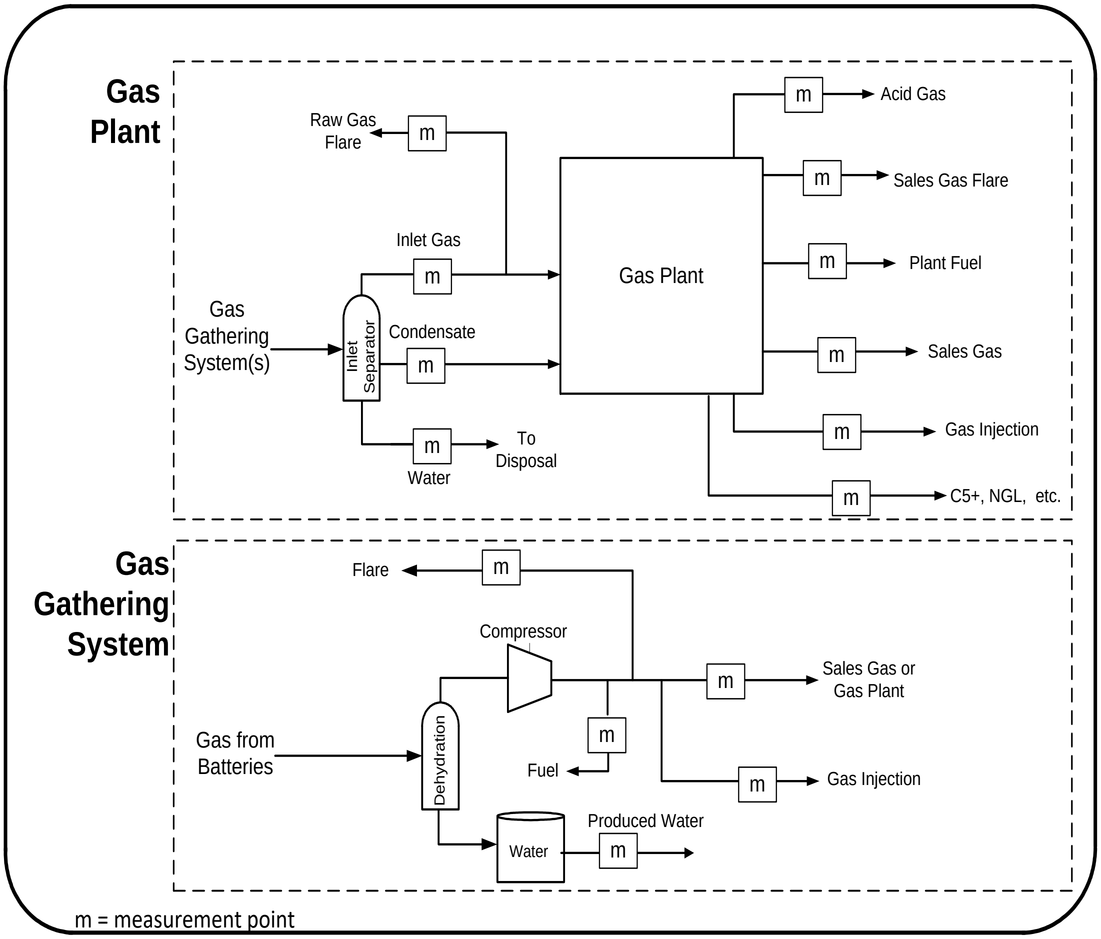
8.4.9.1 Gas Plant

The minimum frequency for updating analyses at all accounting meters within a gas plant is semiannual. Inlet condensate is reported as a GEV, so analyses are required. High-vapour pressure liquids, such as C_5-SP and other NGLs, are to be reported as liquid volumes on Petrinex, which will then perform the GEV calculation automatically using standard factors for plant balancing.

8.4.9.2 Gas Gathering System

The minimum frequency for updating analyses at all accounting meters within a gas gathering system is annual for all flow rates that exceed 16.9 $10^3m^3/d$. If the flow rate is less than or equal to 16.9 $10^3m^3/d$, 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 gas gathering system without further processing, it is reported as a liquid volume, but analyses for GEV calculation purposes are required for reporting on Petrinex.

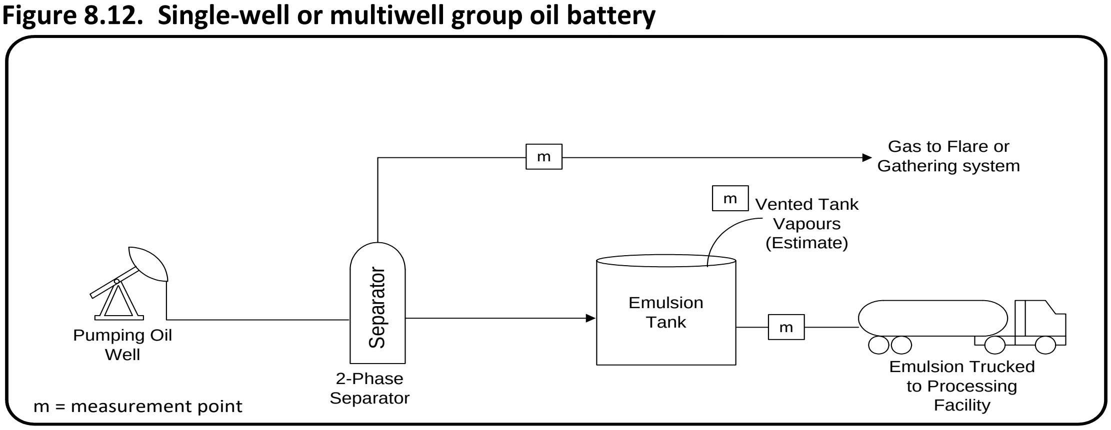
Figure 8.11. Gas Plants and Gas Gathering Systems sample point



8.4.10 Crude Oil Single Well Battery (Petrinex facility subtypes: 311) and Crude Oil Multiwell Group Battery (Petrinex subtype: 321)

In the configuration shown in Figure 8.12, if all associated 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 $10^3 m^3/d$, the frequency is annual. If the average flow rate is less than or equal to 16.9 $10^3 m^3/d$, the frequency is biennial.

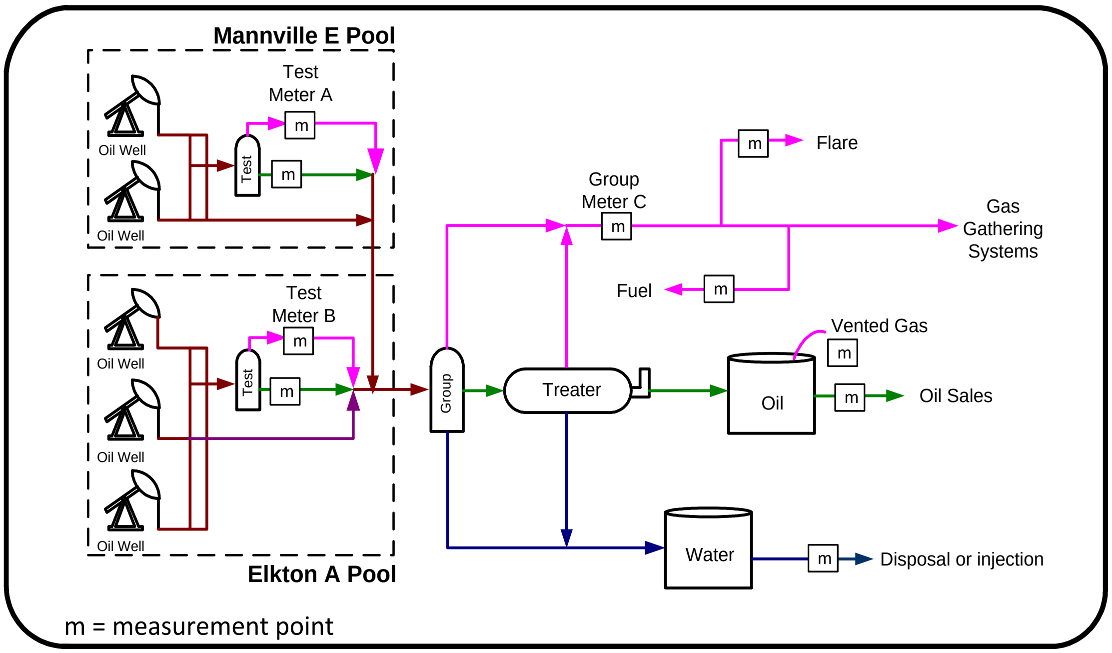
Figure 8.12. Single-well or multiwell group oil battery



8.4.11 Crude Oil Multiwell Proration Battery (Petrinex facility subtype: 322)

In the configuration shown in Figure 8.13, the gas analyses must be updated at the test meters A and B biennially for maximum test gas rates up to 16.9 $10^3m^3/d$ or annually if the maximum test gas rates exceed 16.9 $10^3m^3/d$.

Figure 8.13. 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 $10^3m^3/d$ or biennially if the total rate through the meter is less than or equal to 16.9 $10^3m^3/d$ based on the monthly average flow rate.

Example 8.3. Minimum Gas Analysis Frequency

Consider a five-well proration battery with two wells producing from the Mannville E Pool and three wells producing from the Elkton A Pool. Battery gas production is gathered and conserved.

Pool	Well	Satellite meter	Test gas rate $10^3m^3/d$
Mannville E	10-14	Meter A	4.2
Mannville E	10-16	Meter A	6.8
Elkton A	10-21	Meter B	18.0
Elkton A	9-27	Meter B	12.0
Elkton A	10-30	Meter B	6.5
Total rate for Meter C =			47.5

A gas analysis must be established for the Mannville E Pool, as a minimum using either the 10-14 or 10-16 well, and updated biennially at meter A, as the maximum rate through meter A for the Mannville E pool wells is less than 16.9 $10^3m^3/d$.

A gas analysis must be determined for the Elkton A Pool at meter B, as a minimum using any one of the three wells, and updated annually, as the maximum rate through meter B for the Elkton A pool wells is greater than 16.9 $10^3m^3/d$.

The gas analysis at meter C must be updated annually, as the flow rate through the meter exceeds 16.9 $10^3m^3/d$.

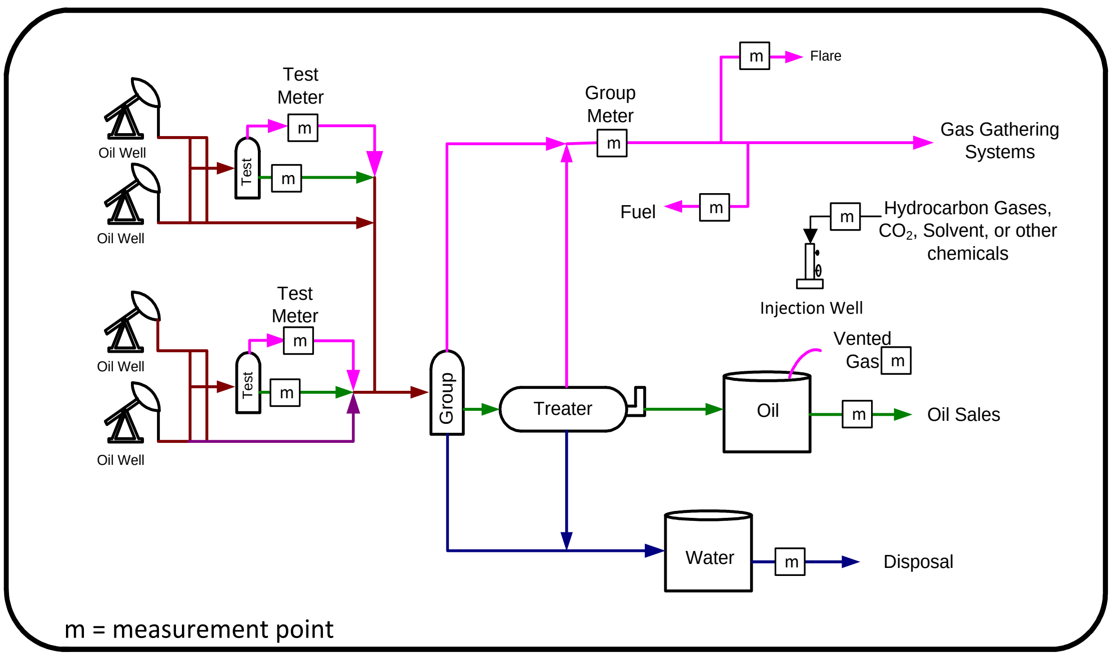
8.4.11.1 Exemption for Gas Analysis Frequency

If the total battery gas, net of lease fuel, is flared, an initial pool gas analysis must be determined at meters A and B. 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 from multiple pools. If the gas directed through meter C originates from a single pool, no updates are required subsequent to the initial analysis. However, this exemption is revoked as soon as the gas is conserved, and gas analyses must be performed according to the frequencies specified in this section.

8.4.12 Miscible/Immiscible Flood

In the configuration shown in Figure 8.14, 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 meter(s) must have analyses updated monthly.

Figure 8.14. Typical Miscible/Immiscible Flood



8.4.13 Crude Oil Batteries Producing Heavy Oil (Petrinex facility subtypes: 313, 325, 326, and 327 in SK and 311, 321, 322, 343, and 344 in AB)

SK	Heavy oil production at a single-well as shown in Figure 8.15 or multiwell group battery as shown in Figure 8.16 typically involves directing all production to a

	tank without using a separator or gas meter. In such scenarios, gas production may be estimated using a GOR. If a meter is used to measure gas for the purposes of conducting GOR tests or continuous gas production measurement, an initial gas analysis is required. An analysis from a comparable well producing from the same pool may be used if a meter will be used to measure gas to determine GOR. Note: If no initial gas analysis was completed than at least one gas analysis must be completed before April 1, 2020. An analysis from a comparable well producing from the same pool may be used if a meter will be used to measure gas to determine GOR. In Saskatchewan, all sampling and analysis reports must be uploaded within 30 days of the analysis being completed as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.* If an analysis has already been completed it must be uploaded before April 1, 2020 as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.*
AB	Heavy oil production at a single-well as shown in Figure 8.15 or multiwell group battery as shown in Figure 8.16 typically involves directing all production to a tank without using a separator or gas meter. In such scenarios, gas production may be estimated using a GOR. If a meter is used to measure gas for the purposes of conducting GOR tests or continuous gas production measurement, an initial gas analysis is required. An analysis from a comparable well producing from the same pool may be used if a meter will be used to measure gas to determine GOR.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Figure 8.15. Single well battery producing heavy oil

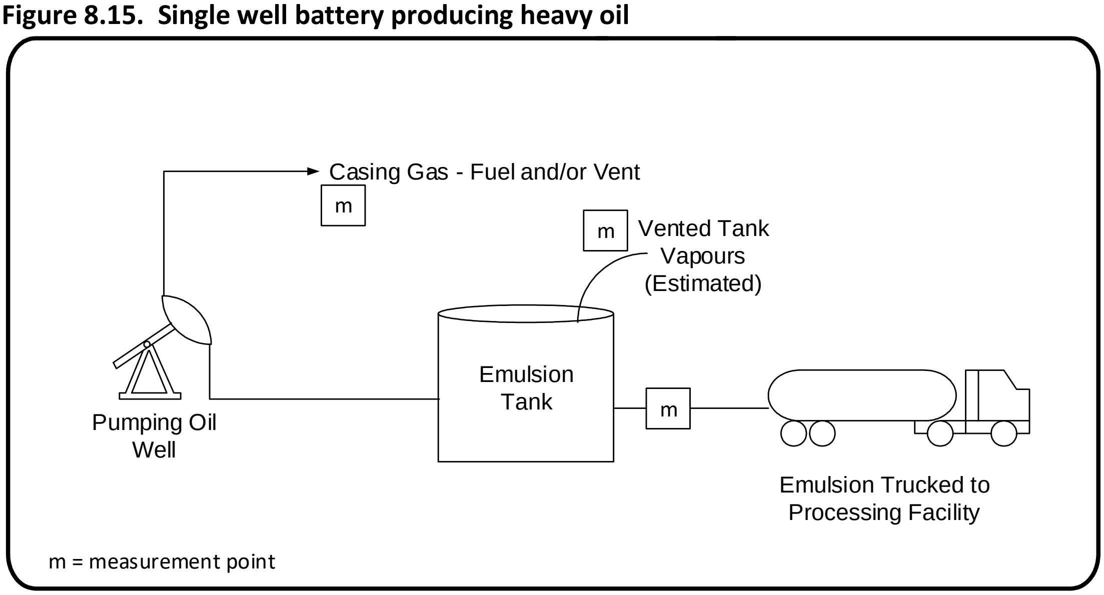
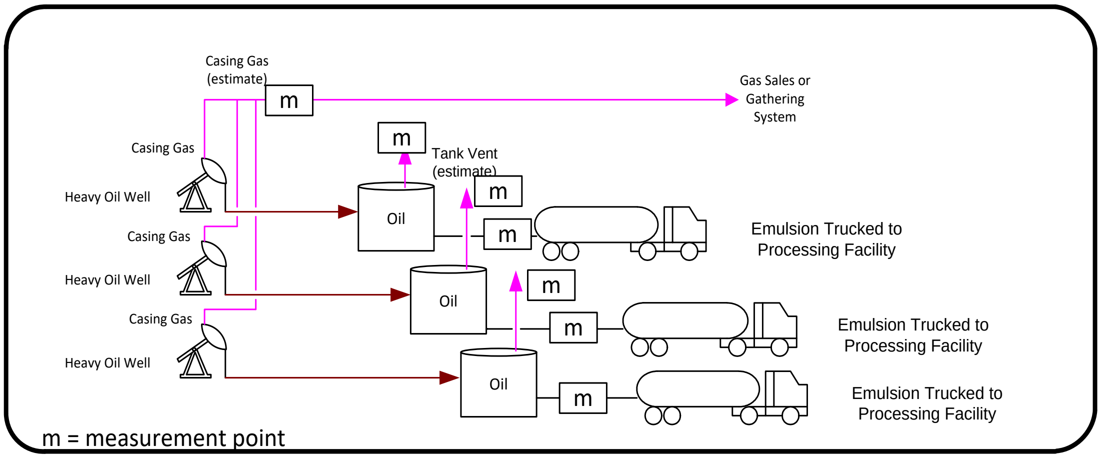


Figure 8.16. Multiwell group battery producing heavy oil



If a GOR is determined by methods other than using gas measurement, an initial gas analysis is not required.

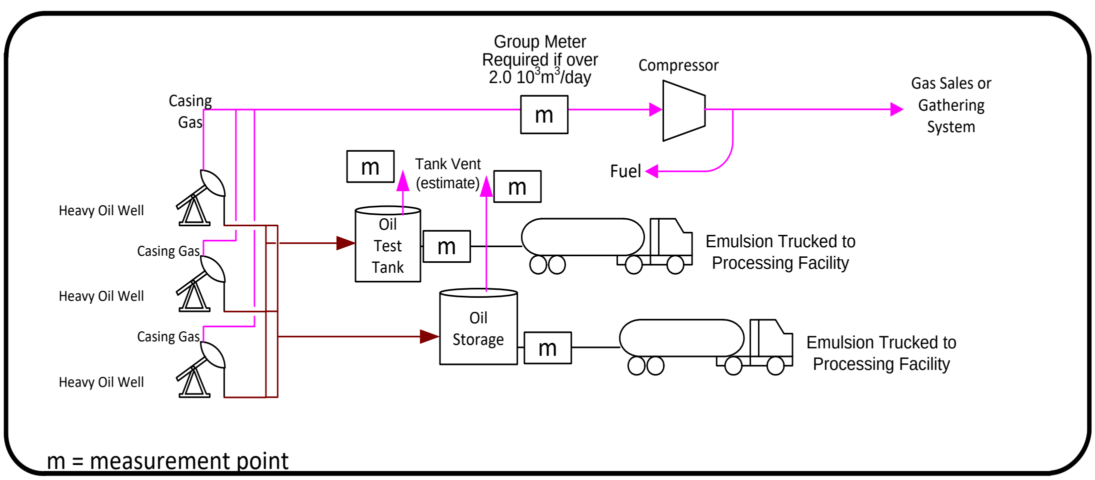
If a meter is used to measure gas on a continuous basis, biennial analysis updates are required.

Heavy oil production at multiwell proration batteries as shown in Figure 8.17 may involve directing all production to tanks without using separators or gas meters, but if combined gas volumes meet the economic requirements in:

SK	*Directive S-10 - Saskatchewan Upstream Petroleum Industry Associated Gas Conservation*
AB	*Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting*
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

then the gas must be gathered and conserved.

Figure 8.17. Multiwell proration battery producing heavy oil



If a meter is used to measure gas for the purposes of conducting GOR tests, an initial gas analysis is required. If a GOR is determined by methods other than using gas measurement, an initial gas analysis is not required.

If a meter is used to measure gas on a continuous basis, biennial analysis updates are required.

8.5 Oil Sampling and Analysis Requirements

Sampling and analysis must be in accordance with Sections 6, 8, 10, 14 or other equivalent method approved by an appropriate industry standards association.

8.5.1 Oil Analysis Requirements for Wells and Facilities

SK	In Saskatchewan, an oil analysis may be conducted on oil wells and facilities. As per *The Oil and Gas Conservation Regulations, 2012* Section 93.1, the Minister may require an oil sample and analysis to be conducted. All oil sampling and analysis conducted must be submitted to ER as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.* If an oil analysis has already been completed, it must be submitted to ER before April 1, 2020 as per the specifications listed in *Directive PNG013: Well Data Submission Requirements.*
AB	Upon Regulator request
BC	Upon Regulator request

9 Cross-Border Measurement

This section presents the measurement requirements for all upstream and midstream oil and gas products crossing a provincial or territorial border.

9.1 General Requirements

For those facilities receiving and/or delivering products and waste to another jurisdiction either by trucking, rail or pipeline, including pipelines under the National Energy Board (NEB) jurisdiction, each jurisdictional products and waste streams must be isolated and measured prior to commingling. The delivery point measurement standards for each jurisdictional authority must be followed, unless site-specific approval from the Regulator and the other jurisdictional authority(ies) has been obtained. All streams must be isolated and metered or estimated according to requirements in this Directive. This can include production, gathering systems, and all fuel, flare, and vent volumes. If the measurement or other equipment requirement for delivery point measurement of hydrocarbon and related fluids from any jurisdiction is different from the Regulator requirements, the higher requirements, such as frequency and accuracy, between the jurisdictions must be followed.

Non-royalty exempt fuel gas usage at cross-border oil and gas processing facility must be separately determined and measured if it is over 0.5 $10^3 m^3$/d for each jurisdiction. If the usage is for production from both jurisdictions, no separate fuel gas metering is required if site-specific approval is obtained from both jurisdictions involved. For example, a compressor used only for gas coming from another jurisdiction into Alberta or Saskatchewan must be metered separately at the cross-border facility and the fuel gas use for other equipment processing commingled production or the entire facility must be measured with another meter.

9.2 Cross-Border Sampling Requirements

Except where otherwise noted, the gas and liquid sampling equipment and methodology must follow the requirements set out in Section 8: Gas and Liquid Sampling and Analysis.

Spot or grab samples are acceptable for obtaining gas and liquid analyses, provided the uncertainty requirements in Section 1 of this Directive are fulfilled.

When the uncertainty requirements cannot be met, consider:

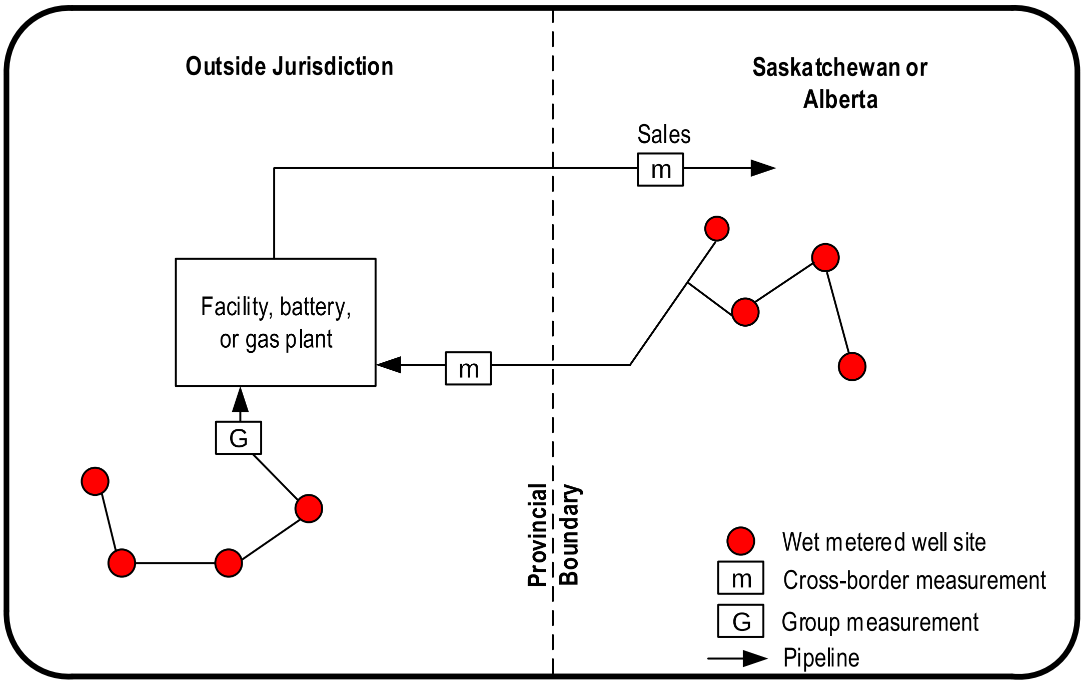
1. More frequent spot sampling for calculated analysis;
2. The use of proportional samplers; or
3. The use of gas chromatographs or other continuous analyzers.

9.3 Cross-Border Measurement Points

Figures 9.1 through 9.9 are some of the scenarios to determine if a specific circumstance is considered cross border. Each scenario applies as well if the flow is in the opposite direction. There must be only one cross-border measurement point for each pipeline crossing the provincial boundary unless site-specific approval is obtained from both jurisdictions involved.

The cross-border measurement point can be on either side of the jurisdictional border before commingling with any fluids from another jurisdiction. Measurement-by-difference rules apply in all situations where there is measured production going into a proration battery.

Figure 9.1. Effluent gas measured wells to an out-of-province location (non-common pool)



For cross-border common pools producing from one or more jurisdictions, if the surface facility is located in one jurisdiction and the well production as defined by the bottom hole location is in another jurisdiction, delivery point measurement of the production is required (see Figure 9.2). The production from this well must be reported as delivered to the other jurisdiction where the surface facility is located.

Figure 9.2. Gas gathering system of effluent gas measured well with measured well downhole location in another jurisdiction

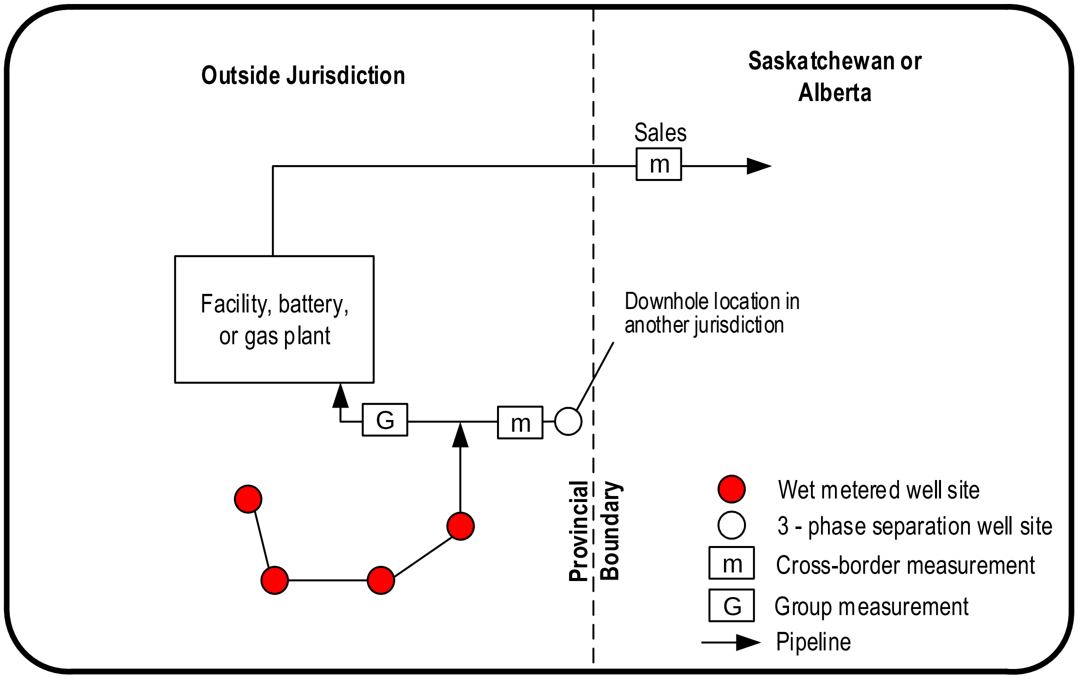


Figure 9.3. Multiple jurisdictional crossing

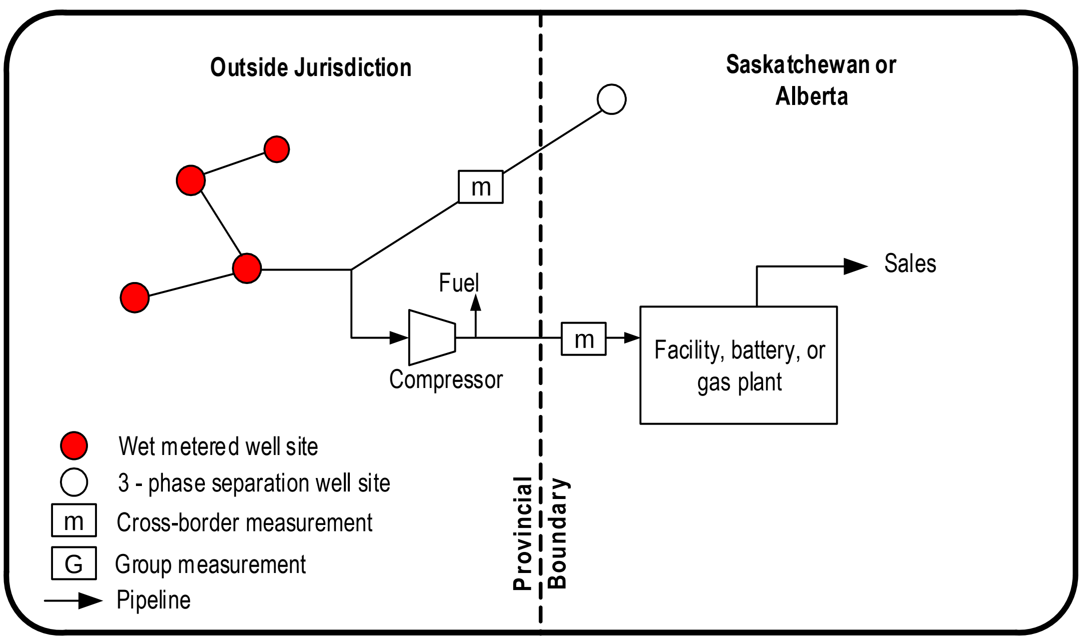


Figure 9.4. Measured gas source from an out-of-province location

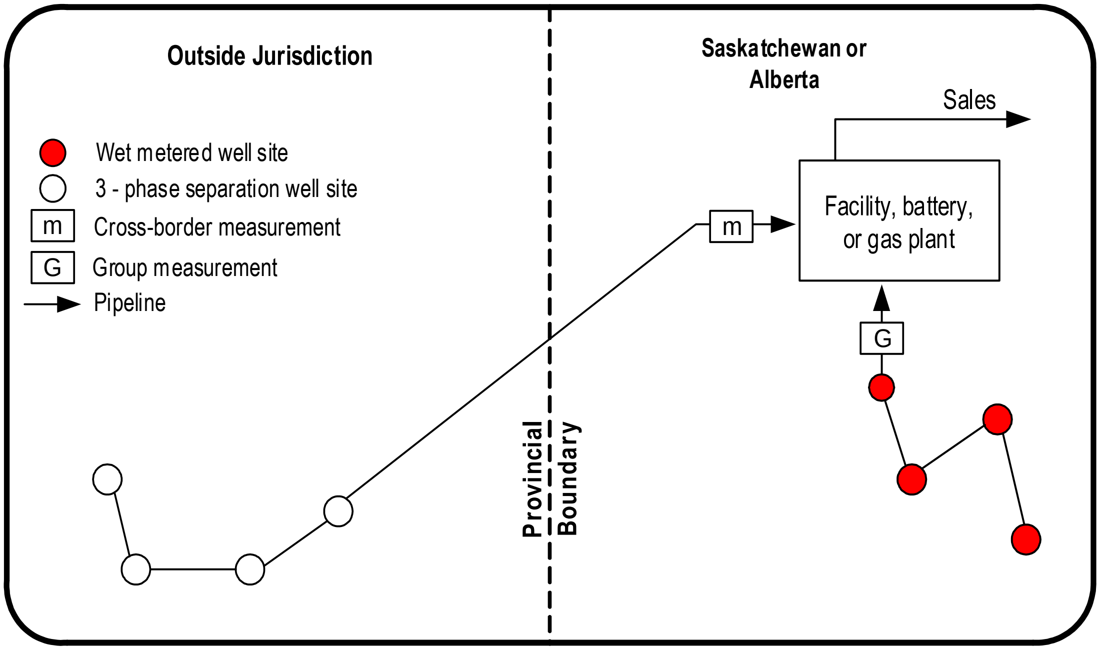


Figure 9.5. Sales gas source from an out-of-province location

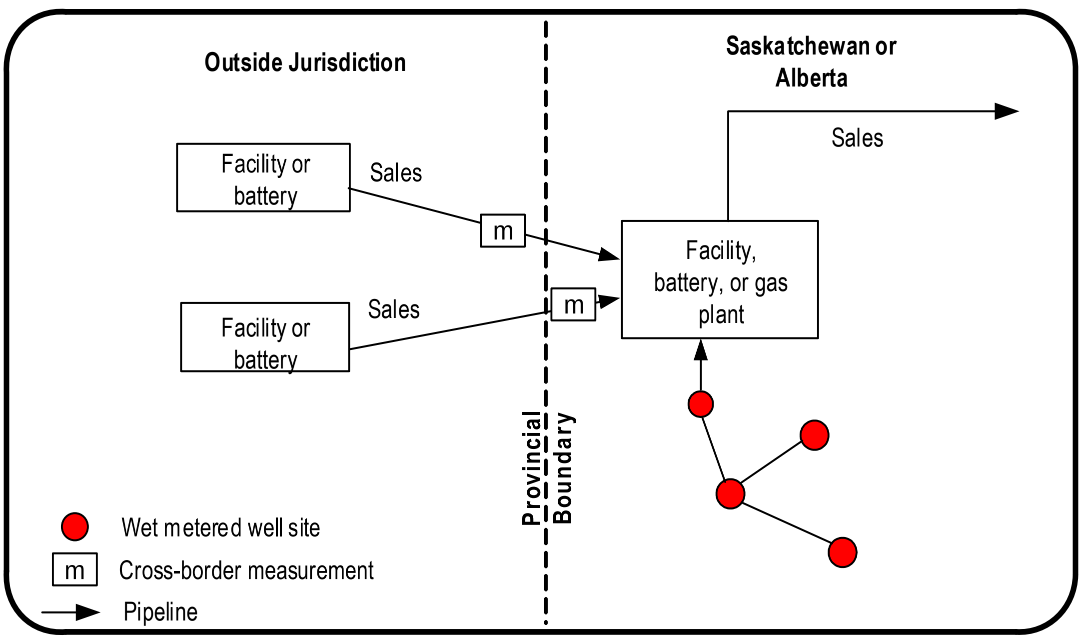
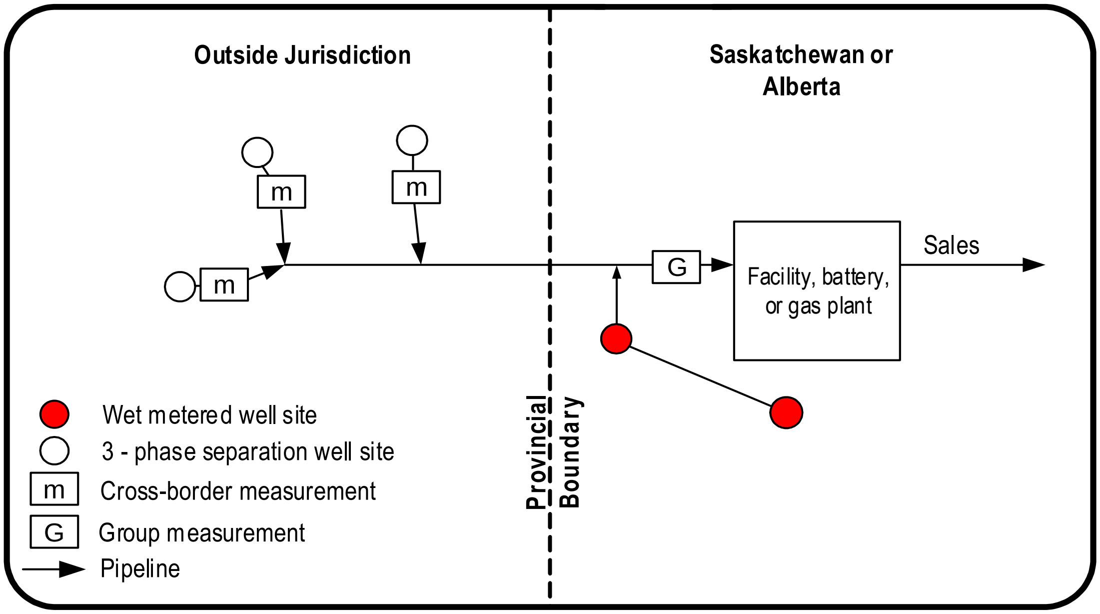


Figure 9.6. Measured sources from an out-of-province location



For Figure 9.6, the three-phase separation wells can be designed to delivery point measurement requirements without another cross-border measurement point.

Measurement-by-difference rules applies in Figures 9.1, 9.2, 9.4, 9.5, and 9.6 unless the effluent metered wells have a group measurement point prior to commingling with the measured gas source(s).

Figure 9.7. Sales oil or gas source from an out-of-province location

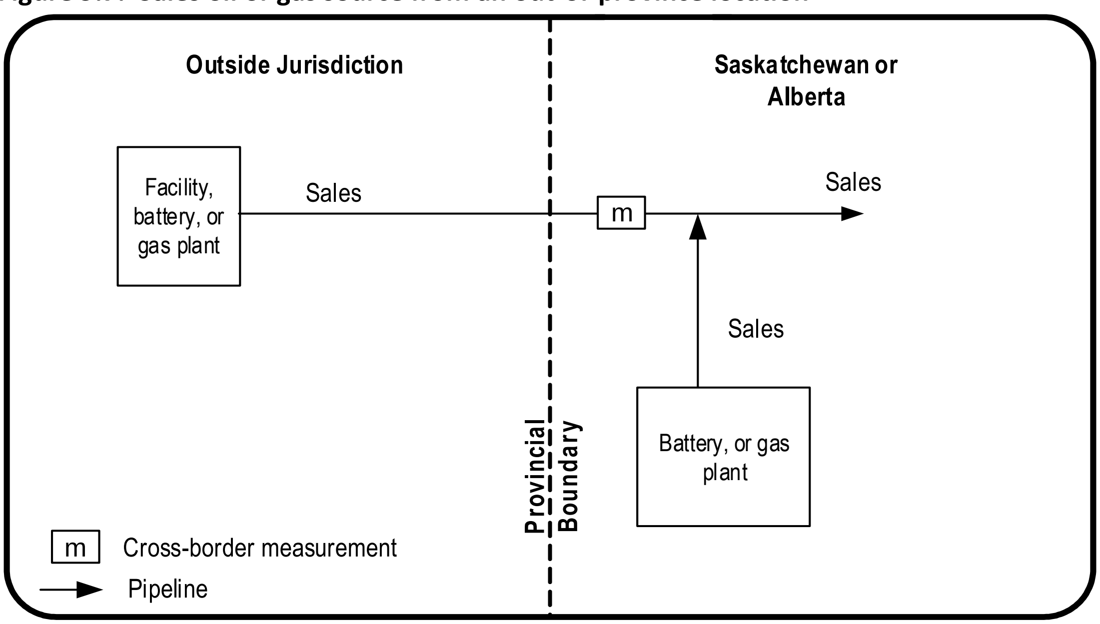


Figure 9.8. Sales oil or gas source from an out-of-province location

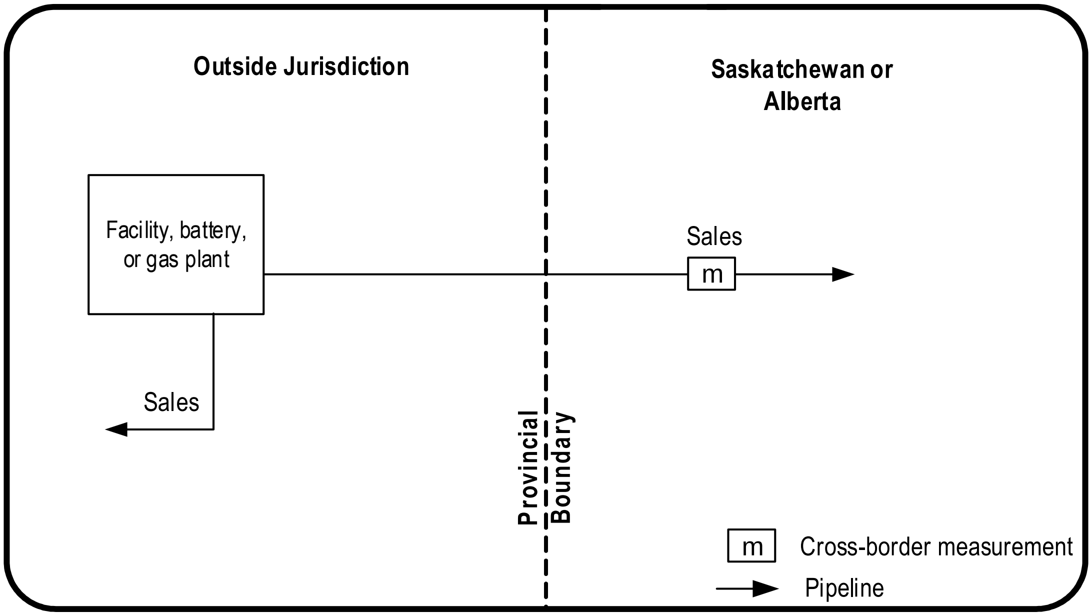
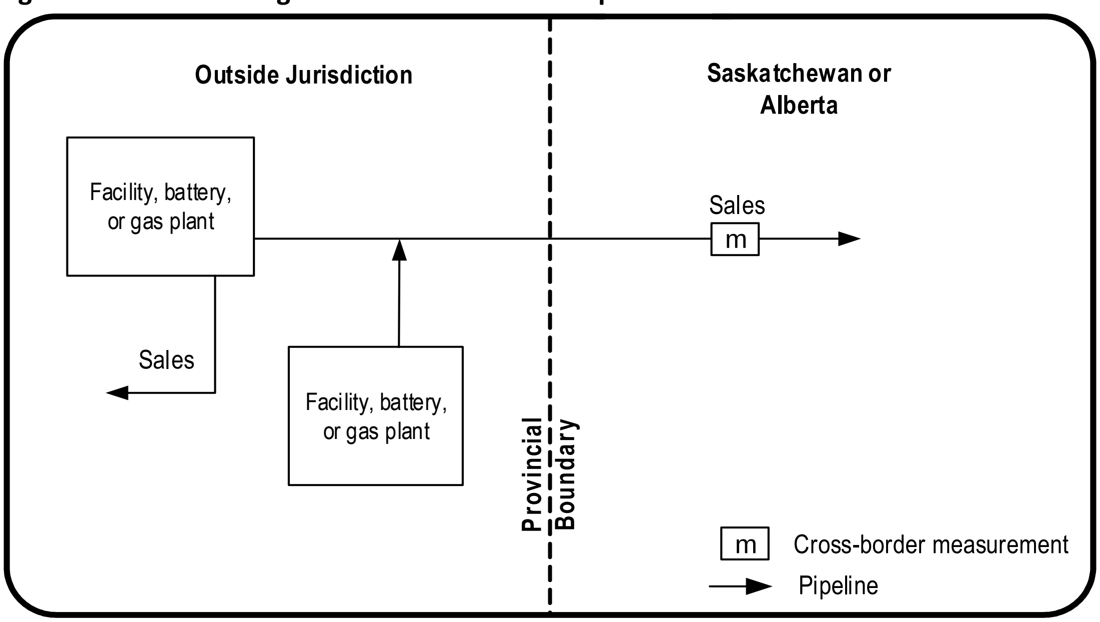


Figure 9.9. Sales oil or gas source from an out-of-province location



10 Trucked Liquid Measurement

This section presents the requirements for trucked liquid measurement from oil and gas production facilities to another facility or sales. Applicable liquids include crude oil, condensate, water and NGLs.

10.1 General Requirements

Crude oil or condensate may be found in association with water in an emulsion. In such scenarios, the total liquid volume of the trucked load must be measured, and the relative volumes of oil and 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 licensee must accurately measure produced liquids/emulsion volumes by using tank gauging, a weigh scale, or a meter, unless otherwise stated in this Directive. The delivery point measurement requirements must be met for all trucked liquids unless the exemption conditions in this section are met or site-specific approval from the Regulator has been obtained as per Section 5.

The Regulator will consider a truck liquid measurement system to be in compliance if the base requirements outlined in Sections 10.1.1, 10.1.2 and 10.1.3 are met. The Regulator 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.

10.1.1 Reporting Requirements

Monthly oil, condensate, and water volumes for well and battery, for example, production, receipts, and dispositions, must be reported as the number of cubic metres rounded to the nearest tenth of a cubic metre (0.1 m^3). Measured volumes must be corrected to 15°C and at the greater of 0 kPaG or equilibrium vapour pressure at 15°C. See Section 6.3.3 for production data verification and audit trail requirements.

For delivery point measurement, hydrocarbon liquid volume must be determined to two decimal places and rounded to one decimal place for monthly reporting. If there is more than one volume determination within the month at a reporting point, the volumes determined to two decimal places must be totaled prior to the total being rounded to one decimal place for reporting purposes.

10.1.2 Temperature Correction Requirements

All delivery point measurement of hydrocarbons and emulsions requires temperature correction to 15°C, see Section 6.3.2.1. See Section 14.4 for temperature determination requirements. Composite meter factors are not acceptable for delivery point measurements.

The correction for the effect of temperature on liquids (CTL) factor 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 standard association.

10.1.3 Pressure Correction Requirements

The correction for the effect of pressure on liquids (CPL) factor must be determined in accordance with API MPMS, Chapter 11, and is required only for LACT applications.

10.2 General Trucked Liquid Measurement, Accounting, and Reporting Requirements for Various Facility Types

10.2.1 Oil Batteries that Produce Non-Heavy Oil

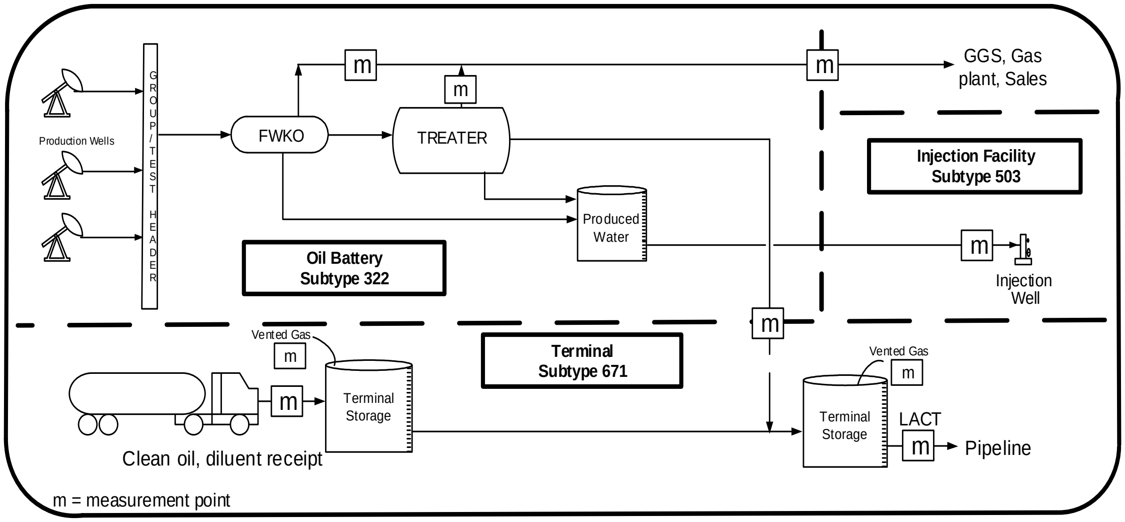
For trucked oil/emulsion production into an oil battery, delivery point measurement is required for the total liquid volume. If there is a mixture of trucked-in production and prorated production within the same battery, the exemption criteria in Section 5.5.2 must be met or Regulator site-specific approval must be obtained.

For condensate trucked into an oil battery, delivery point measurement is required for the total liquid volume. The requirements in Section 6.6 must be met.

For any oil battery, the trucked-out liquid is measured at the delivery point located at the receiving facility, and the oil volume determined at the receiving facility must be used as the delivering battery's oil disposition. Proper measurement must be set up at the receipt point only, except for load oil delivery from a facility to well(s). In this scenario, delivery point measurement is required at the loading facility. If there are emergencies at the receipt point, the origin measurement may be used, but only as a temporary solution.

If clean oil from a battery 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 with delivery point measurement, a terminal Petrinex code must be obtained so that the clean trucked-in fluid is received at the terminal instead of at the battery. The battery oil must also be measured with delivery point measurement before commingling with other fluids at the terminal. The terminal will then deliver the fluid to the pipeline via the LACT unit. If there is no delivery point measurement for the battery oil to the terminal, measurement by difference rules apply, see Sections 5.5 and Figure 10.1.

Figure 10.1. Oil battery and terminal schematic

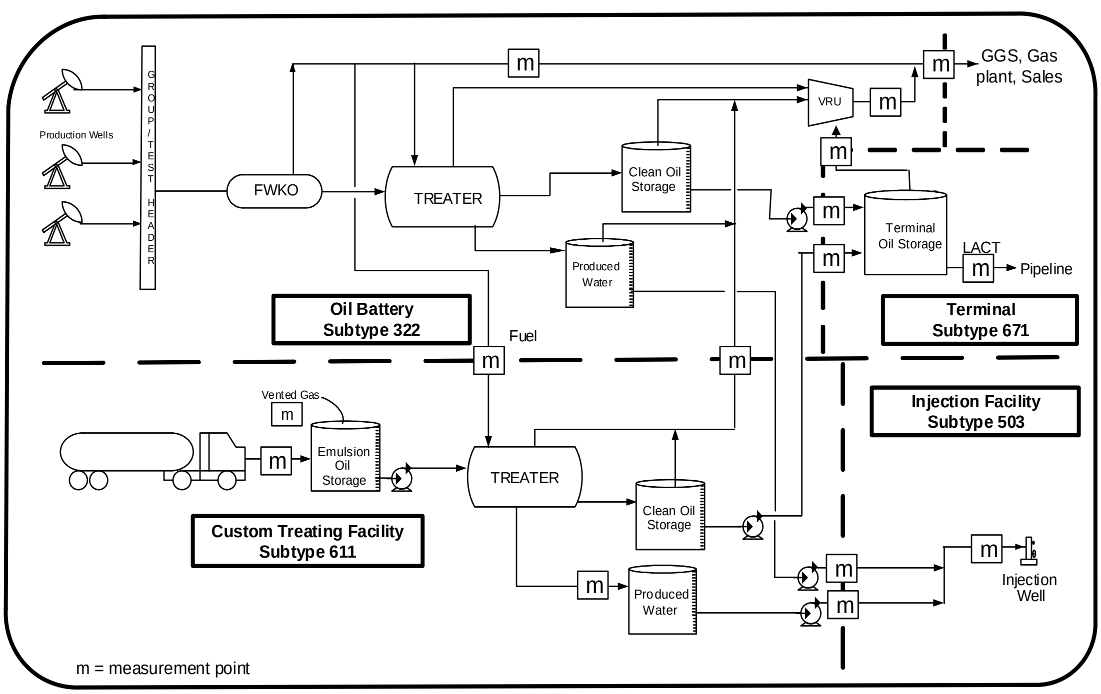


10.2.1.1 Custom Treating, Oil Battery, and Terminal Delineation

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 facility boundary must be measured. If there is blending of hydrocarbon liquids of densities that differ by > 40 kg/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 measured before the blending point.

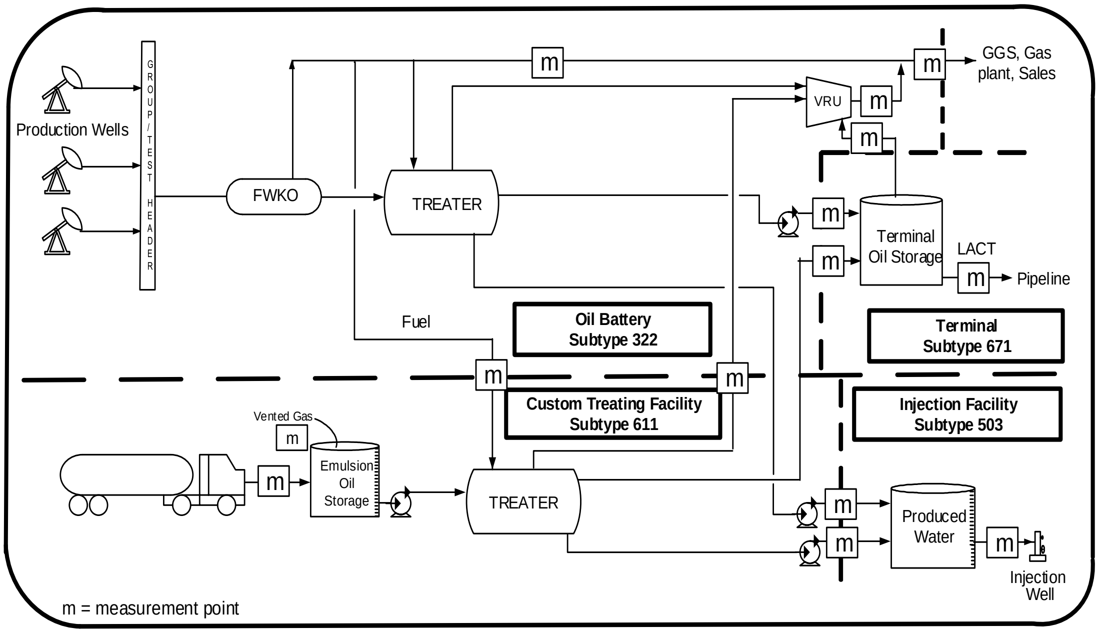
Scenario 1: Dedicated tankage for clean crude and produced water for both the crude proration battery and the custom treating battery.

Figure 10.2. Custom treating, oil battery, and terminal schematic – scenario 1



Scenario 2: Dedicated metering on treaters for water/oil and a shared tank for clean crude and produced water.

Figure 10.3. Custom treating, oil battery, 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 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.

10.2.2 Custom Treating Facilities

SK	The measurement requirements are the same as for trucking into a non-heavy oil battery, Section 10.2.1
AB	The measurement requirements are the same as for trucking into a non-heavy oil battery above, but the accounting and reporting must follow the requirements in *Appendix 6 of Manual 011: How to Submit Volumetric Data to the AER.*
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

10.2.3 Pipeline Terminals or Railcar Terminals

At the pipeline or railcar 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 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 Directive. However, if the downstream pipeline operator allocates to the shippers the imbalance generally less than 1% 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 10.2.4.

10.2.4 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.

Volumetric allocation of the monthly LACT volumes to the monthly truck receipt volume is not required at a clean oil terminal without Regulator site-specific approvals if the meter factor for each delivery point meter or the weigh scale accuracy verification does not deviate from the prior factor or verification by ±0.5%.

Any deviation >0.5% must be investigated and rectified, and allocation for the previous month(s) disposition volumes to the receipt volumes is required. The licensee must revert to allocating monthly pipeline LACT volumes to the receipt volumes if the deviation is not brought back with ±0.5%.

10.2.5 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 non-heavy oil battery.

10.2.6 Water Injection/Disposal Facilities

For water trucked into an injection or disposal facility, delivery point measurement accuracy is not required. See Sections 1.6.4.3 and 1.6.4.4 for facility accuracy requirements.

10.2.7 Waste Processing Facilities

A waste processing facility handles volumes of waste generated in the upstream petroleum industry. However, many Regulator-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 measured 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 CT 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.

SK	See *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting* (formerly known as Directive R01) for the requirements for waste stream measurement, accounting, and reporting.

AB	See *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry* for the requirements for waste stream measurement, accounting, and reporting.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

10.2.7.1 Integrated Waste Processing Facilities

Integrated waste processing facilities include:

1. Waste Plants (WP)
2. Custom Treating (CT)
3. Water Disposal (IF)
4. Terminal (TM)

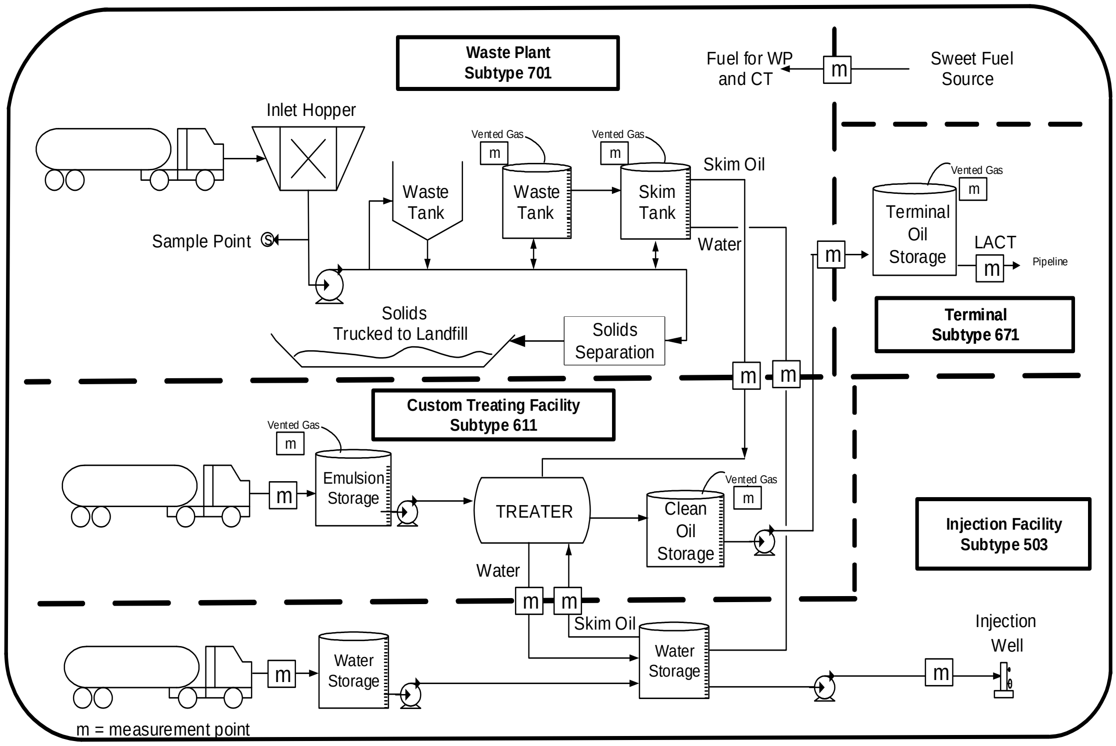
Integrated oil and water processing and waste facilities are ones with various distinct processing and reporting entities. They are referred to as oilfield waste management facilities (OWMFs), see Figure 10.4.

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 scenario.

SK	See *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting* (formerly known as Directive R01) for more details.
AB	See Section 5 of *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* for more details.
BC	See BCOGC's Directives

Figure 10.4. Integrated waste processing facility delineation



10.2.8 Facilities that Produce Heavy Oil

To meet heavy oil trucked production delivery point measurement requirements, the licensee must use an appropriate method based on the fluid characteristics, such as viscosity, temperature, and sand content of the load. Generally, delivery point measurement is performed by using weigh scales or tank gauging with sampling to determine the S&W and/or density. Meters are used only when there are minimal or no solids present in the oil/emulsion, similar to trucking into an oil battery that produces non-heavy oil.

10.3 Design and Installation of Measurement Systems

Delivery point measurement is required for most trucked fluids delivery/receipt except as mentioned in Section 10.2.8. 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 such as 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 facility volume measurement. Therefore, truck ticket estimates must not be used for determining volumes unless the requirements in Section 10.3.4 are met.

See Section 14 for liquid measurement design and installation requirements.

10.3.1 Meters

Turbine meters are typically not suitable for viscous fluids and therefore are not recommended for unloading crude oil.

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

For some types of meters and applications, a strainer and a back pressure control system are required. Refer to Figure 14.1 for more information.

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, mechanical ATC and ATG must not be used.

SK	No grandfathering in Saskatchewan.
AB	All existing ATC and ATG are grandfathered at their existing applications and must not be relocated or reused for other applications.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

    b. The difference between actual density and compensation density must be less than 40 kg/m^3.
    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.

10.3.2 Weigh Scales

Weigh scales for the purpose of delivery point measurement must be verified in accordance with Section 2.12. For sampling points and methods, see Sections 14.6 and 8.5. 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

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.

10.3.3 Exemptions for Truck Measurement Systems

10.3.3.1 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 receives not more than 100 m^3 of trucked-in oil per day
2. The maximum percentage of trucked-in oil to any battery is 10% of the monthly total battery 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, see Section 10.3.2, item 2
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 12.7 mm of a known gauge level marker if used
2. The depth of liquid is determined while the tank trailer is level to within 150 mm over its length
3. The minimum load on the trailer is more than 65% of full load

10.3.3.2 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 facilities or facilities with no equity or royalty concerns, 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 sending the liquid production or truck-mounted meter, for determining inlet volumes at a proration battery if certa*in situ*ations exist. The S&W per cent and corrected opening and closing readings must be on the ticket or available on a summary sheet for Regulator audit purposes. An individual truck load must be recorded on its own ticket.

The Regulator may accept low-accuracy measurement with an overall uncertainty of ±1% or less for trucked liquid production at a proration battery if:

1. Trucked production is temporary, pending battery consolidation within one year or less.
2. Individual well oil volumes being trucked are less than 2.0 m^3/day, see Section 10.3.5.

3. The crude oil volume receipt net of water is 5% or less of the total receiving battery oil production.
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 Section 2.

10.3.4 Load Fluids

Load fluids, at a minimum, must be measured using devices that meet the requirement for low-accuracy measurement with 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.

Load fluids are to be reported at the well level except when in an SW Saskatchewan or SE Alberta shallow gas battery, since there is no requirement to measure and report water production at this type of well. The load fluid reporting then can be done at the battery level.

SK	See the *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting* (formerly known as Directive R01) for more reporting procedures.
AB	See the *Manual 011: How to Submit Volumetric Data to the AER*, Appendix 8 for more reporting procedures.
BC	See BC OGC's Directives

10.3.5 Split Loads

A split load is defined as existing when a truck takes on partial loads from more than one well or battery in a single trip or when load oil is delivered to more than one receipt point or wells.

Requirements: If the densities of the split load components are different by more than 40 kg/m^3, blending tables are required to calculate shrinkage. The shrinkage volume is to be prorated back to each battery on a volumetric basis.

Measurement: Volume from each well or facility must be measured at the time of loading onto the truck (or off-loading from the truck for load oil) by one of the methods:

1. Gauging the battery lease tank.
2. Gauging the truck tank not allowed for density difference over 40 kg/m^3 for any oils or emulsions.
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.

Sampling: Fluid from each single-well oil battery must be sampled to determine the S&W and the oil/water volumes. The truck driver is to collect the samples by taking at least three well-spaced grab samples during the loading period, see Section 14.6 and 8.5.

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 emulsions, the total load is to 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.

Allowed:

1. Single-well oil battery delivering to other facilities.
2. Gas wells with condensate-water tanks and production less than 2.0 m^3 of total liquids per day.
3. Blending of heavy oil and condensate.
4. Load oil for well servicing only, specifically load oil from a single source only.

Not Allowed

1. Multiwell batteries delivering to other facilities other than load oil.
2. Gas wells with production greater than 2.0 m^3 of total liquids per day.

10.4 Sampling and Analysis

For trucked-in hydrocarbons and emulsions receipt/delivery, a truck sampler or a proportional sampler may be used to obtain a sample from the truck tank, see Section 14.6 and 8.5. In some scenarios 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 described in Sections 10.4.1 and 10.4.2.

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 must be used for accurate sampling, also see Sections 8.2.1 and 8.2.2.

The licensee 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.

10.4.1 Automatic Sampling

Automatic sampling is typically conducted through the use of proportional samplers. If automatic sampling procedures are used, a manual procedure must 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:

1. Containers made of suitable material for handling and storage of the sample must be used. Container lids must be vapour tight.
2. All sample containers must be cleaned and dried prior to collection of the next sample.
3. Sample containers must allow adequate room for expansion and content mixing, taking into consideration the temperature of the liquid at the time of filling.
4. The sample containers must be housed in a secured enclosure to prevent any tampering with the sample.
5. Sample lines must be as short as practical and sloped downward to reduce the possibility of plugging up the sample line.

10.4.2 Manual Spot (Grab) Sampling

Manual spot (grab) sampling may be acceptable *in situ*ations 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, see Section 14.6 and 8.5. A single grab sample is not acceptable when there is stratification of S&W within the truck.

The use of manual sampling techniques, either 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 sample therefore may not be representative of the entire load. In such cases multiple grab samples are to be used.

Lease tank manual sampling 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 manual sampling 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.

10.4.3 S&W Determination

The licensee must select the most appropriate method for determining the S&W, see Section 14.8 and Appendix 3.

10.4.4 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 reservoir conditions. 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 to determine density of the liquid hydrocarbon phase and the liquid water phase (if required). The density found in this analysis must be applied to all hydrocarbon liquids coming from the specific facility; or
2. Truck load samples or samples from automatic samplers may be tested for density as outlined in Section 14.6 and 8.5.

In applications where the truck volumes have an S&W greater than 1%, density determination at 15°C of an emulsion sample is difficult, as there are two different thermal corrections to be applied, one for the water and one for the oil.

There are two options available:

1. The first is to determine the sample density using a precision densitometer that has its measuring cell at 15°C. No further corrections are required.
2. The second is to separately predetermine the density at 15°C of the water and the oil. When using this option, the emulsion density is calculated by applying the S&W cut to the density of each component. The calculation is

$$\rho_{emulsion} = \left(\rho_{oil} \times \left(100 - \%S\,\&W\right)\right) + \left(\rho_{water} \times \%S\,\&W\right)$$

Where:

$\rho_{emulsion}$ is the calculated density of the emulsion at 15°C

ρ_{oil} is the density of the oil portion at 15°C

ρ_{water} 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 14.7. 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 base 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 is to 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. 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 unless it is used in cold heavy oil measurement.

To determine the density of the load, an on-line densitometer maybe 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°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 Section 14.

11 Acid Gas and Sulphur Measurement

The sulphur measurement requirements in this section do not apply to operations and reporting in the Province of Saskatchewan.

This section presents the base requirements and exemptions 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 the Regulator.

SK	Saskatchewan does not have specific sulphur measurement requirements.
AB	S-30 Monthly Gas Processing Plant Sulphur Balance Report requirements are also included, with instructions provided in Section 11.6.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

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.

11.1 General Requirements

<table>
<tr><td>SK</td><td>The sour gas plant inlet and acid gas streams must be measured and reported.</td></tr>
<tr><td>AB</td><td>
The sour gas plant inlet and acid gas streams must be measured and reported. The inlet sour gas stream volume including GEV of condensate, sour gas in solution in water, the sulphur disposition tonnage, and the sulphur balance must be reported on a monthly basis on the S-30 report if the plant is approved with a sulphur inlet of more than one tonne per day to the Regulator. See Table 11.1 for the monthly S-30 sulphur balance requirement. For sour gas plants with less than one t/d of approved sulphur inlet, the S-30 report must be submitted to Alberta Environment at its required timing, with the exception of grandfathered plants that would still be required to submit S-30 reports to the Regulator until December 31, 2016. For plants that are licensed as sweet but use a sweetening process to strip out excess CO_2, the reporting of the acid gas (CO_2) volume must be the same as sour plants under one tonne per day.
Table 11.1. Monthly S-30 Sulphur Balance Requirement
<table>
<tr><th>Monthly average actual sulphur inlet (tonne/day)</th><th>Maximum Sulphur balance % error</th></tr>
<tr><td>< 1</td><td>20%</td></tr>
<tr><td>≥ 1</td><td>5%</td></tr>
</table>
In accordance with Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta, other upstream oil and gas facilities with sulphur emissions
</td></tr>
</table>

	greater than one tonne/day that are not required to submit S-30 reports must maintain daily sulphur balance records and calendar quarter-year recovery calculations. These records must be available for inspection or audit at the request of the Regulator.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

The acid gas from the sweetening process is generally saturated with water vapour. This water vapour portion must be subtracted from the saturated acid gas to obtain the dry volume without water vapour. For more information refer to Section 11.2.

11.2 Acid Gas Measurement

The quantity of acid gas going to sulphur plants, to compression and injection, or to flaring is generally measured at a low pressure of 50 to 110 kPag; therefore, the orifice meter, or any other meter, must be appropriately sized and maintained to manufacturer's recommended specifications 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 4.3) to calculate the correct acid gas volume as outlined in this section. 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 annually verified to ensure that acid gas measurement uncertainty is within tolerance.

11.2.1 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.

11.2.1.1 Calculating Acid Gas Flow Rate

The calculation method for the acid gas flow rate is as follows:[3]

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.

[3] Wichert, E., "Water content affects low pressure, acid-gas metering," *Oil & Gas Journal*, January 2, 2006, pp. 44–46.

Step 2: Convert the acid gas composition from dry basis to 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 base conditions of 101.325 kPa(a) and 15°C.

Step 4: The volume calculated in step three contains water vapour in the percentage determined in step one and must be converted to dry basis volume for reporting purposes. An acid gas flow 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

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 percentage of H_2S divided by 100 in the acid gas on a dry basis.

11.2.1.2 Calculating Vapour Pressure of Water

The formula for determining the vapour pressure of water[4] is

$\log P = (A – B) \div (C + T_{RD})$

where: P = water vapour pressure in mm of mercury

A = 8.10765

B = 1750.280

C = 235

T_{RD} = temperature of acid gas in reflux drum (°C)

The direct formula for determining the vapour pressure of water in kPa(a) is thus

$P_{H2O} = 0.13332 \times 10^{(8.10765 – 1750.280/(235 + T))}$

Where: P_{H2O} = water vapour pressure in kPa(a) at T°C

% H_2O in the acid gas = $(100\ \% * P_{H2O}) \div (P_{RD} + P_{atm})$

Where: P_{RD} = reflux drum pressure, kPag

P_{atm} = atmospheric pressure, kPa(a)

11.2.1.3 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 as follows:

A. Reflux drum data

Reflux drum temperature = 40°C

Reflux drum pressure = 70 kPag

Atmospheric pressure = 95.0 kPa(a)

[4] 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 = (100% x Vapour pressure of water at 40˚C) ÷ (Reflux drum gauge pressure + atmospheric pressure)

$$P_{H2O} = 0.13332 \times 10^{(8.10765 - 1750.280/(235 + 40))}$$
$$= 7.377 \text{ kPa(a)}$$

(Vapour pressure of water at 40°C is 7.384 kPa(a), from the Saturated Steam Table in the Thermodynamics section of the GPSA *SI Engineering Data Book,* Figures 24-36.)

Percentage of water vapour = 7.377÷(70 + 95) x 100% = 4.47%

Enter into column 2 (see Table 11.2) and normalize.

Table 11.2. Calculation of relative density (RD) on wet basis

	Column 1	Column 2	Column 3	Column 4	Column 5
Comp.	**Dry basis (%)**	**Wet basis (%)**	**Molar mass (kg/kmol)***	**(Col. 1 * Col. 3) /100**	**(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**

* 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 is to be used in the flow calculation for acid gas volumes).

11.2.1.4 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:

1. Orifice meter diameter: 154.051 mm
2. Orifice plate diameter: 76.200 mm
3. Meter upstream pressure: 70.00 kPag
4. Differential pressure: 10.00 kPa
5. Meter temperature: 40°C
6. Atmospheric pressure: 95.0 kPa
7. Acid gas composition: as per Table 11.2

Results with AGA #3 1992 or later method:

1. Flow rate, dry basis without accounting for moisture content = 33.126 $10^3 m^3/d$
2. Sulphur content = (33.126 x 65) ÷ (100 x 1.35592) = 29.20 tonne/day
3. Flow rate, wet basis = 33.499 $10^3 m^3/d$, containing 4.47 percent H_2O
4. Flow rate, wet basis converted to dry basis = (33.499 x (100 – 4.47)) ÷ 100
   = 32.002 $10^3 m^3/d$ dry acid gas equivalent

This volume, 32.0 $10^3 m^3$, is to be reported as Acid Gas on the monthly volumetric submission.

An example for percentage difference in acid gas volume between dry and wet basis:

1. Percentage difference in flow rate = (33.126 – 32.002) x 100 % ÷ 32.002 = 3.51%
2. Sulphur content = (32.002 x 65) ÷ (100 x 1.35592) = 28.21 tonne/day
3. Difference in calculated sulphur balance between dry and wet basis metering
   = 29.20 – 28.21 = 0.99 tonne/day
4. 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, specifically if it was done on a 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 11.3 summarizes the previous example 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

	AGA #3, post-1992		**AGA #3, 1985, W-A Z factors***	
Item	**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, $10^3 m^3/d$	33.126	33.499	33.096	33.481
Corrected to dry gas	-	32.002	-	31.984
% difference	-	3.51	-	3.48
Sulphur flow, tonnes/day	29.20	28.21	29.17	28.19
% difference, tonnes/day		3.51		3.48

*Z factors by Wichert-Aziz method, including water content in wet gas.

11.2.1.5 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 in the previous example, 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 must be used to estimate the water content. However, since the flow data from the meter includes the temperature at the meter run, the reflux drum temperature can be estimated on the basis of the meter temperature, as follows:

$$T_{RD} = (T_m + 2.28 – 2.28 * P_2) \div (P_{RD} + P_{atm})$$

Where: T_{RD} = reflux drum temperature, °C

P_2 = the downstream meter tap pressure, kPa(a)

P_{RD} = reflux drum pressure, kPag

P_{atm} = atmospheric 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 calculations shown in Section 11.2.1.2. 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 example shown in Section 11.2.1.3 can be used to calculate the acid gas flow rate.

11.2.1.6 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, refer to Section 11.4.6.3. 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.

11.3 Sulphur Measurement and Pit Volume Determination

11.3.1 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 must 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 six mm.
4. It is acceptable to have one reading per determination.
5. The sulphur density at pit temperature is obtained from Figure 11.1.[5]

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

11.3.2 Sulphur Measurement

For sulphur sales/delivery point measurement using meters, see Section 1.6.3.7 and 6.3.1. 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 Sections 2.12, 10.3.2 and 10.5.2.

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 must be adjusted by the total monthly disposition at the end of the month.

11.3.2.1 Exemption for Sulphur Tonnage Entering a Gas Plant

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:

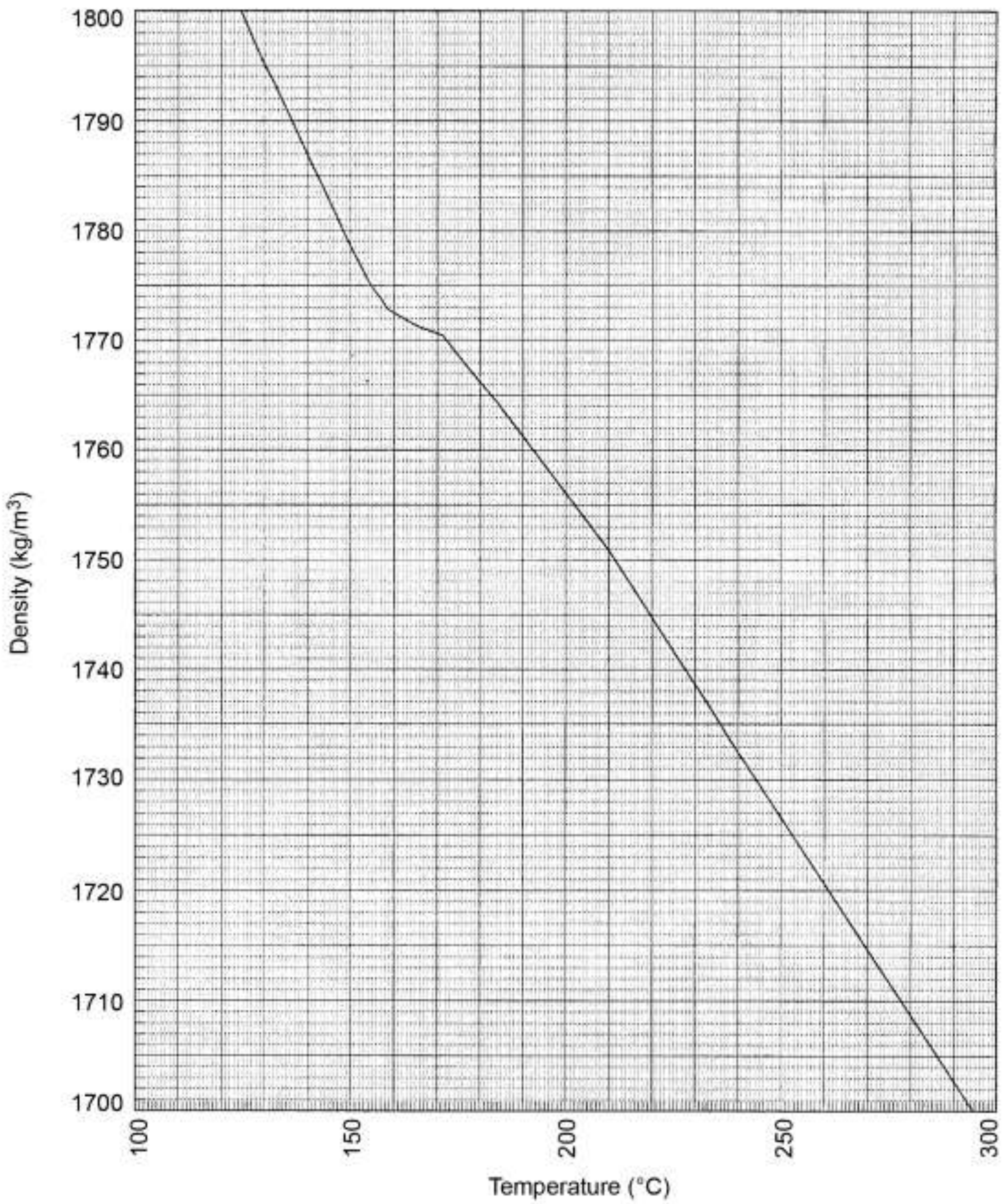
Sulphur proration factor (S_{pf}) = Total monthly sulphur disposition tonnage (including inventory changes) ÷ Total estimated daily sulphur production tonnage

Actual daily sulphur production (t) = Estimated daily sulphur production (t) × S_{pf}

SK	Saskatchewan does not have a sulphur balancing report.
AB	The actual daily sulphur production is the daily production tonnage to be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

[5] Tullen, W. N., *The Sulphur Data Book*, New York: McGraw-Hill Book Company, Inc., 1954, p. 17.

Figure 11.1. Liquid sulphur density vs. temperature



11.4 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.

SK	Saskatchewan does not have a sulphur balancing report.
AB	The S-30 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 one tonne/day.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

To achieve accurate volumetric reporting, 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 Table 11.1 in Section 11.1 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.
4. Improving the methodology for determining sulphur content in inlet condensate and water.

11.4.1 Overview of Plant Inlet and Outlet Points for H_2S

Figure 11.2 illustrates the paths by which H_2S enters the sour gas plant and by which method it can exit from the plant.

SK	Saskatchewan does not have a sulphur balancing report.
AB	The H_2S entering the plant in the gas, condensate, and water has to be accounted for on the S-30 report in terms of tonnes of elemental sulphur.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

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.

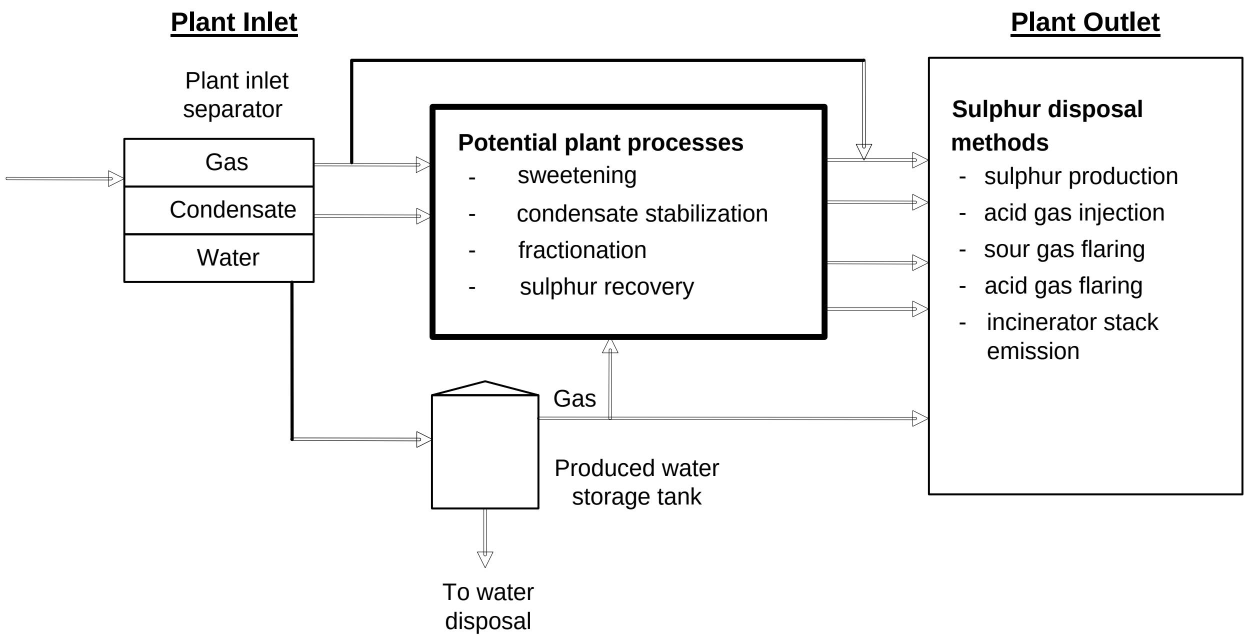
11.4.2 Determining H_2S in Sour Gas

See Section 8.2 for the determination of H_2S concentration in the inlet gas stream.

11.4.3 Determining the Concentration of H_2S 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 11.2. 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.

SK	In such scenarios, 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 percentage of H_2S.
AB	In such scenarios, 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 percentage of H_2S to ensure acceptable accuracy for the S-30 report balance.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

11.4.4 Determining Concentration of H_2S 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 0.05 tonne/day (50 kg/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.

11.4.5 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, $10^3 m^3/d$
   b. sour condensate out of the separator, converted to gas equivalent volume, $10^3 m^3/d$
   c. sour water out of the separator or into the storage tank, m^3/d.
2. The sulphur content in the sour gas out of the separator can be calculated:

   Sulphur equivalent in sour gas, tonne/day = (Q, $10^3 m^3/d$) x (y) x (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 Section 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 following formula should be used. Any alternative methods used must be supported by documentation that it is equivalent to the method outlined in item 1 & 2 and made available to the Regulator upon request.

$x = y \div K$

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

$K = A + (B-A) \times (T/66)^{1.2}$

$A = -0.7034\ (LOG_{10}(P))^3 + 9.1962\ (LOG_{10}(P))^2 - 39.58\ LOG_{10}(P) + 56.695$

$B = -3.9694\ (LOG_{10}(P))^3 + 46.021(LOG_{10}(P))^2 - 178.95\ LOG_{10}(P) + 234.35$

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, tonne/day = (Gas equiv. of condensate, $10^3m^3/d$) x (x) x (1.35592)

The range of applicability of item 3 for determining x, the mole fraction H_2S in condensate, is between 700 to 9000 kPa(a) and 0 to 80°C.

4. The amount of H_2S dissolved in the water, z (mole fraction), in the plant inlet separator can be estimated by the following formula[6]:

$z = y \div ((4.53 - 7494.6) \div (P + 758.4\ (1.8\ T + 32))) \div (P + 4.65 \times y))$

where all terms are as defined in this section.

Sulphur equivalent in water, t/d, = (1.31) x (water production, m^3/d) x (z) x (1.35592)

The sum of the results of items 2, 3, and 4 for each sour gas inlet separator is the total sulphur inlet to the plant in tonne/day.

11.4.6 Calculation Procedure for Estimating Plant Sulphur Outlet Mass per Day

There are three sulphur disposal methods approved by the Regulator:

1. Sulphur recovery
2. Acid gas flaring
3. Acid gas compression and injection

SK	Each of these methods is treated separately as far as collecting the disposition data. The plant inlet data are collected identically for the different sulphur disposal methods.
AB	Each of these methods is treated separately as far as collecting the disposition data for the S-30 report is concerned. The plant inlet data are collected identically for the different sulphur disposal methods.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Potential sulphur disposal methods from sour gas plants are:

[6] 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.

1. Sulphur recovery
2. Sour gas flaring or incineration
3. Acid gas flaring or incineration
4. Sulphur plant incinerator stack emissions
5. Sour gas flaring or incineration from the produced water storage tank (> 0.05 tonne/day)

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 can be on a dry basis or a wet basis. The operator must determine on which basis the analysis is determined.

The water content of the acid gas out of the reflux drum can be estimated by the procedure in Section 11.2.1.

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 previously in Section 11.2.1.3. In any scenario, the wet acid gas composition is to 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.

11.4.6.1 Approved 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 0.5 $10^3m^3/d$ 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 total sulphur out of the plant must include:

1. The sum of any liquid production
2. Any amount flared
3. Any amount contained in emissions related to the stack and tank vapours.

The difference between sulphur in and sulphur out of the plant must be no greater than ±5% if the actual inlet is ≥ 1 tonne/day or ±20% if the actual inlet is < 1 tonne/day. The acid gas sent to the sulphur plant is to be reported as shrinkage (SHR), and acid gas flaring at the plant is to be reported as FLARE on Petrinex.

11.4.6.2 Approved 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. The concentration of the H_2S content of the acid gas stream must be checked at least once per week by a qualified person using the Tutweiler technique and by applying 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 than once per week. A record of the H_2S analysis determinations must be maintained for inspection by the Regulator.

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 0.5 10^3m^3/d on an annual basis. This generally requires a high turndown ratio meter or a combination of a high-range and a low-range meter.

The emissions of 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 the volumes are > 0.05 tonnes/day. 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 from the plant.

The sum of the Sulphur, noted in the paragraphs above, must be the sulphur from 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 tonne/day or ±20% if the actual inlet is < 1 tonne/day. The acid gas flared must be reported on Petrinex as flared acid gas (product type: ACID GAS and activity: FLARE).

11.4.6.3 Approved Acid Gas Injection Plants

Plants 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, 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 must be checked at least once per week by a qualified person using the Tutweiler technique or gas chromatography and by applying the calculation procedure to determine the H_2S concentration in the acid gas. 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 than once per week. A file must be set up to provide a record of the Tutweiler determinations for inspection by the Regulator.

Once the acid gas is compressed, it must be measured 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 measured before commingling as per the following 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 injection facility.

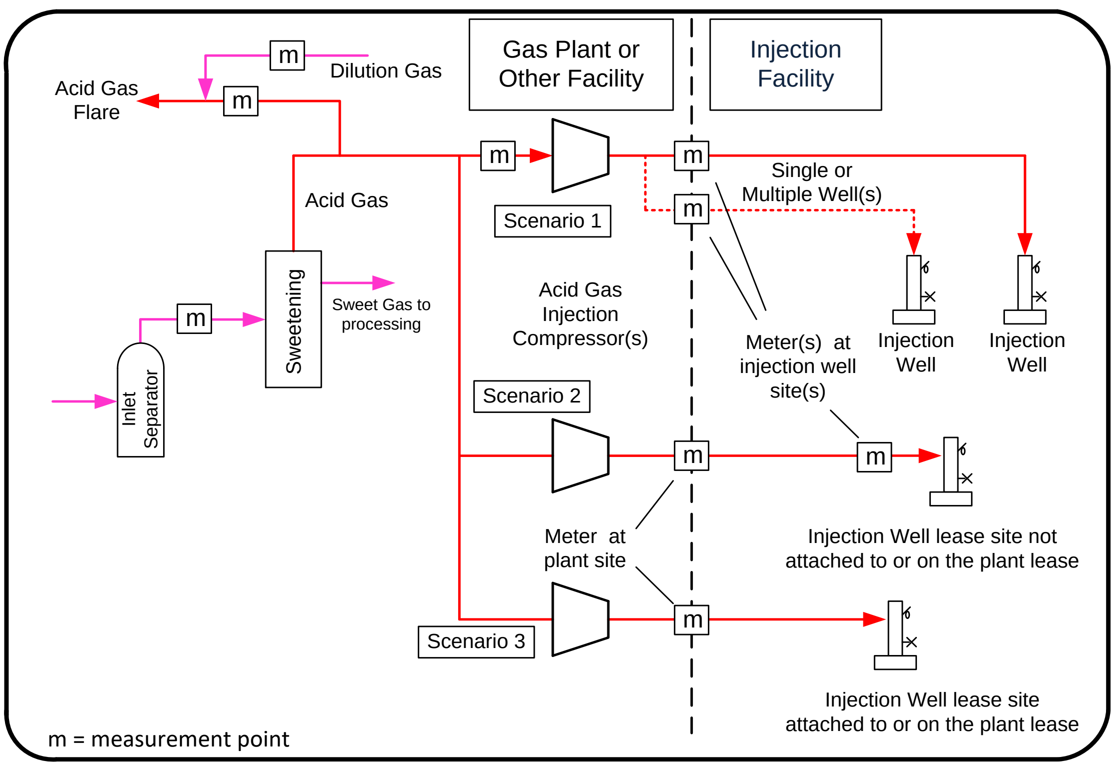
Scenario 2

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 injection facility and injection wellhead meter is required. Metering difference is to be reported at the injection 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 injection facility and injection wellhead meter is not required.

Figure 11.3. 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 0.5 10^3m^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 > 0.05 tonne/day. 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 Section 11.4.6.2 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 tonnes/day or ±20% if the actual inlet is < 1 tonnes/day. The acid gas injected is to be reported as a disposition (DISP) to the injection facility, and acid gas flaring at the plant is to be reported as FLARE on Petrinex.

11.5 Production Data Verification and Audit Trail

The field data, records, any calculations or estimations, and EFM records relating to Regulator-required production data submitted to Petrinex must be kept for inspection upon request by ER. 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 including electronic, magnetic, or paper form produced in the determination of measured volume/tonnage in accordance with the EFM requirements in Section 4.4 for gas and Section 14.9.2 for liquids.

11.6 How to Complete the S-30 Monthly Gas Processing Plant Sulphur Balance Report

This section is reference for Alberta S-30 reporting and does not apply to Saskatchewan.

The S-30 Monthly Gas Processing Plant Sulphur Balance Report must be submitted to the Alberta Regulator using the electronic Digital Data Submission (DDS) system under Submit Monthly Sulphur Balance Reporting, according to the instructions that follow the form.

Figure 11.4. Monthly Gas Processing Plant Sulphur Balance Report (S-30)

ERCB Energy Resources Conservation Board

Monthly Gas Processing Plant Sulphur Balance Report (S-30)

Gas Volumes in $10^3 m^3$ at 101.325 kPa and 15°C
Sulphur Measurements in Tonnes (t)

Plant Name

Operator

Location

LSD	SEC	TWP	RGE	W	M
				W	

Monthly Measurement Diff (%)

Emission Monitor Down (h)

PLANT CODE	YEAR	MONTH

Day	Sulphur In: Plant Feedstock: Approved Max. ($10^3 m^3$) / Actual $10^3 m^3$	Actual % H_2S	Approved Max. (t) / Actual t	Sulphur Out: Sulphur Production t	Sulphur Stack Emission t	Flared Gas $10^3 m^3$	Flared Gas % H_2S	Flared Gas t	Injected / Other $10^3 m^3$	Injected / Other % H_2S	Injected / Other t	Total t
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
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22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
Month Total												
Qtr Total												

Sulphur Recovery Efficiency	Minimum Approved %	Actual Monthly %	Cumulative Quarterly %

Contact Name

Telephone

Signature

Date

S - 30 - 2006-05

Energy Resources Conservation Board Suite 1000, 250 - 5 Street SW, Calgary AB T2P 0R4

How to Complete the S-30 Monthly Gas Processing Plant Sulphur Balance Report

Identification	
Plant Name	Enter the name of the gas processing plant as given on your gas processing facility approval or from *ST50: Gas Processing Plants in Alberta* (typically licensee name and the first field name).
Operator	Enter the operator name.
Location	Enter the legal description of the plant as shown on the approval.
Monthly Measurement Difference (%)	This field will be calculated using the following formula: Monthly measurement difference (%) = [Monthly sulphur in (t) – Monthly sulphur out total (t)] ÷ Monthly sulphur in (t)
Emission Monitor Down (h)	Enter the number of hours the continuous stack emission monitor (CSEM) was not in service during the reporting month.
Plant Code	Enter the gas processing plant facility ID. The field size is four numeric characters. The facility ID must exist on Petrinex.
Year and Month	Enter the four-digit year and the two-digit number of the month being reported. The field size is six numeric characters.

Reporting Data (General)	
	You must file an S-30 report if you are an operator of a gas processing plant in which raw gas is processed for the removal of H_2S. Report gas volumes in 10^3m^3 at 101.325 kPa pressure and 15ºC. Report sulphur in tonnes (t) to one decimal place, with the option to report to two decimal places if required to meet measurement difference requirements.
Day	Enter the data on the row of the corresponding day of the month.

Sulphur In	
Plant Feedstock— **Approved Maximum (10^3m^3)**	Enter the approved maximum volume of plant feedstock, the raw gas plus gas equivalent of inlet condensate, as stated in the approval or the most recent application approved in 10^3m^3 to one decimal place. Refer to *Directive 056: Energy Development Applications and Schedules, Schedule 2* for more information.
Plant Feedstock— **Approved Maximum (t)**	Enter the approved maximum of inlet sulphur in tonnes per day to one decimal place, as stated in the approval or the most recent application approved; refer to *Directive 056, Schedule 2* for more information. Enter the daily values for sulphur inlet and outlet as detailed in the row alongside each appropriate date.

Plant Feedstock **(10^3m^3)**	Enter the actual volume of plant feedstock, the raw gas plus gas equivalent of inlet condensate received by the plant on this day in 10^3m^3 to one decimal place; refer to Section 8.3 for more information. This must not be entered as a daily average volume for the entire month.
Plant Feedstock **(% H_2S)**	Enter the daily percentage of H_2S contained in the recombined plant feedstock, the raw gas and condensate and/or water on this day to one decimal place. If percentage is < 0.10%, enter the percentage to four decimal places.
Plant Feedstock (t)	This field will be calculated using the following formula: Sulphur (t) = Plant feedstock volume (10^3m^3) × Recombined H_2S% × 1.35592 (Conversion factor) ÷ 100
Sulphur Out	
Sulphur Production (t)	Enter the daily sulphur produced in tonnes to one decimal place, with the option to report to two decimal places if required to meet measurement difference requirements.
Sulphur Stack Emission (t)	Enter the daily sulphur emissions in tonnes to one decimal place, with the option to report to two decimal places if required to meet measurement difference requirements as recorded by the continuous stack emission monitor (CSEM).
Flared Gas (10^3m^3)	Enter the amount of gas flared from the plant in 10^3m^3 to one decimal place. 1. Include all sour gas flared, 2. In this column, also report acid gas flared from plants that do not recover sulphur.

Flared Gas (% H_2S)	Enter the daily percentage of H_2S contained in the flared gas to one decimal place.
Flared Gas (t)	This field will be calculated using the following formula: Sulphur (t) = Flared gas volume (10^3 m^3) × Flared gas H_2S% × 1.35592 (Conversion factor) ÷100
Injected/Other (10^3 m^3)	Enter the daily volume of sulphur injected to subsurface formations or disposed of in any manner other than described for example nonregenerative sweetening in $10^3 m^3$ to one decimal place. 1. Include all sour gas injected. 2. In this column, also report acid gas injected from plants that do not recover sulphur. 3. Other disposition, if used, must be identified and separately quantified (monthly total) as part of the S-30 submission.
Injected/Other (% H_2S)	Enter the daily percentage of H_2S contained in the injected gas to one decimal place.
Injected/Other (t)	This field will be calculated using the following formula: Sulphur (t) = Injected gas volume ($10^3 m^3$) × Injected gas H_2S% × 1.35592 (Conversion factor) ÷100
Total (t)	This field will be calculated using the following formula: Total daily tonnage = Sulphur production (t) + Sulphur stack emission (t) + Flared gas (t) + Injected/others (t)

Month Total	This field will be calculated automatically.
Quarterly Total	This field will be calculated automatically.
Sulphur Recovery Efficiency	
Complete this section only if the plant recovers elemental sulphur or injects acid gas.	
Minimum Approved %	Enter the approved minimum quarterly sulphur recovery efficiency as stated in the approval or from *ST50: Gas Processing Plants in Alberta*.
Actual Monthly %	This field will be calculated using the following formula: Actual monthly sulphur recovery efficiency = $\frac{\text{(Sulphur production (t) + Sulphur injected)} \times 100}{\text{Sulphur production (t) + Emissions (t) + Flared (t) + Sulphur injected}}$
Cumulative Quarterly %	This field will be calculated automatically.
Contact	Enter the full name of the person who accepts responsibility and to whom inquiries regarding this report should be directed. Sign the statement. Enter the person's business telephone number, including area code. (Please print.) Enter the date this S-30 report is completed.

When to File	Your monthly S-30 report must be submitted to the Regulator Technical Operations Group via DDS by 4:30pm on the 18th day of the month following the month being reported. If the 18th day is not a business day, you must submit on the first business day after the 18th.

12 Heavy Oil Measurement

This section presents the requirements and exemptions for heavy oil facilities. This section does not cover crude bitumen production through mining.

SK	The term heavy oil in this section is defined as oil with a density ≥ 920 kg/m^3. Crude bitumen is not defined in Saskatchewan.
AB	The term heavy oil in this section includes crude bitumen for the oil sands area (other than that produced through mining or *in situ* processes).
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

There are two general categories for the production of heavy oil:

1. primary/secondary which includes cold production and water flood techniques; and
2. *in situ* thermal and solvent schemes.

Blending of heavy oil with lighter hydrocarbon liquids may occur. The lighter hydrocarbon liquids, often called diluent or condensate, are used to reduce the viscosity of the heavy oil and make it easier to process and/or transport.

12.1 General Measurement Requirements

In all scenarios, a licensee must measure produced heavy oil volumes, unless otherwise stated in this Directive. The Regulator will consider a heavy oil measurement system to be in compliance if the fuel measurement requirements in Sections 1.6.3.5 and 4.2, the calibration and proving requirements in Section 2, and measurement requirements in Section 14 and in this section are met.

12.1.1 Temperature Correction Requirements

See Section 14.4: Temperature Correction Requirements

12.1.1.1 Exemption for Temperature Corrections

If testing heavy oil by test tanks, temperature correction is not required. However, the operator must be aware that if the temperatures are elevated above base conditions, the proration factors will be biased by the amount of the temperature correction, approximately 0.07 per cent per degree Celsius (%/°C) at a density of 920 kg/m^3.

12.1.2 Pressure Correction Requirements

See Section 14.5: Pressure Correction Requirements.

12.1.3 EFM Requirements

See Section 14.9.2: Electronic Flow Measurement for Liquid Systems.

12.1.4 Diluent/Condensate Receipts and Blending Shrinkage

Blending shrinkage occurs when two oils of dissimilar properties are mixed. This mixing results in volumetric discrepancies from the ideal combination, which would yield a volume that would be the sum of the two products. The discrepancy is blending shrinkage, which is the result of smaller molecules of the lighter hydrocarbon filling in the voids or spaces between larger molecules of the heavier hydrocarbon. The result is a combined liquid volume that is less than the sum of the two original volumes. This shrinkage must be determined and properly applied to volumes making up the liquid to ensure proper allocation and reporting.

12.1.5 Hydrocarbon Blending and Flashing Shrinkage

Generally, heavy oil is not significantly affected by shrinkage caused by flashing of light ends. However, there is always potential for flashing shrinkage depending on the actual operating pressure at which the wells are produced. Operators must evaluate each facility based on its operating characteristics. See Section 14.3 for details.

12.1.6 Water Measurement

Operators must have proper procedures in place to measure produced water, water receipts, and water injection/disposal to ensure that the information used for reporting is accurate. See Section 1 for measurement accuracy requirements.

As sand may constitute a significant percentage in the S&W content of heavy oil production, it is expected that operators will follow Section 14.6 and 8.5 requirements for sampling and analysis to quantify these volumes. The sand volume is to be included as part of the S&W determination and reported as water.

12.1.7 Well Proration Testing

For heavy oil well testing, operators must follow the testing frequency requirements in Section 6.4.4. For additional heavy oil well testing requirements refer to Section 12.2.4.

12.1.8 Heavy Oil Receipt, Delivery, or Sales

This includes the delivery or receipt of heavy oil (diluted or non-diluted), diluent, or other hydrocarbon products. For the single point measurement uncertainty of these measurement points see Section 12.2.3.

12.2 Primary and Secondary Production

Well effluent produced from heavy oil wells using natural or other drive mechanisms, such as water-flood wells, flowing wells, or wells with conventional lifting technologies such as pump jacks, progressive cavity pumps, submersible and pumps, is considered primary and secondary production. The well effluent could be flow lined to field test satellites or group production facilities, or the fluids could be produced to tanks at surface and trucked out to a treatment facility. These production wells are subject to the same measurement and reporting requirements as non-heavy oil wells, refer to Section 6, unless otherwise noted in this section.

12.2.1 Battery Subtypes

Battery subtypes are the same as in Section 6.2.2, with the following exceptions:

12.2.1.1 Single-Well Battery (Disposition = Production) (Petrinex facility subtypes: 325 in SK and 331 in AB)

Oil and water volumes trucked from lease production tanks must be used to calculate the well production reported on Petrinex. Where a well is producing as a single-well battery (SWB) to a lease tank, the lease tanks can be considered as part of the reservoir and the inventory in the tanks is not reported.

SK	This procedure is referred to as the disposition equals production (disposition = production) accounting method. This applies to heavy oil production from an area north of Township 21 and west of Range 4 W3.
AB	This procedure is referred to as the disposition equals production (disposition = production) accounting method and is only applicable to production within the designated oil sands areas with the well status fluid code "17."
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Oil and water production are only reported when the fluids are trucked from the lease tank to another location.

If a well is on a restricted gas production order or has unrecovered load fluids, the disposition = production method may not be appropriate and the reporting of oil and gas production must be done monthly based on inventory change. If there is receipt(s) into the single-well battery, monthly production must be reported based on receipt and inventory volumes and the disposition equals production methodology does not apply.

When using the disposition = production accounting method, it is correct to show hours on production and no production volume if a shipment was not made from a lease tank of a producing well during the reporting period. Conversely, produced fluid removed from a lease tank during a month that a well is shut in is to be shown on the reports as with zero hours of production. Suspended and abandoned heavy oil batteries can report dispositions (and production) up to six months after they become inactive.

12.2.1.2 Heavy Oil Paper Battery (Petrinex facility subtypes: 313 in SK and 343 in AB)

Paper batteries are developed to reduce the number of reporting entities for submission to Petrinex. Paper batteries are made up of multiple single heavy oil wells, that are grouped for reporting purposes into one larger battery. This allows operators to report production and dispositions from a number of individual wells in one battery, thereby reducing the administrative burden. Paper batteries are treated as multiwell group batteries even though the single wells are not on a common production site.

It is acceptable to move fluids between locations within the same paper battery. These volume movements are not reported to Petrinex but must be managed in a field data capture (FDC) system.

Wells in a paper battery are eligible for reporting using the disposition = production methodology (see Section 12.2.1.1).

As paper batteries are for administrative ease, they must comply with the following criteria:

SK	1) All wells linked to a paper battery must: i. Have an oil density greater than or equal to 920 kg/m^3 and be located north of Township 21 and west of the Third Meridian, in Saskatchewan; ii. Not be connected to a flowlined battery and not be part of an approved Enhanced Oil Recovery project, waterflood project, or any other approved project; iii. Have a common operator; iv. Receive the same well-head price from sales of crude oil during the month (i.e. Averaging of gross prices or trucking charges from multiple sales transactions associated with different wells in a paper battery will not be permitted. *This means that all oil delivered for sale from any of the single wells linked to the paper battery must receive the same net price at the well-head in order to eliminate averaging of gross prices and trucking charges which creates inequities with respect to the calculation of royalties and taxes on both Crown and Freehold lands.);* v. Be within a geographic area no larger than six contiguous townships; and vi. Have approval from the Regulator *in situ*ations where any of the requirements listed in points a) through e) are not met. 2) VENT, FLARE, FUEL or EMIS cannot be reported at the paper battery level. Any VENT, FLARE, FUEL and EMIS activity must be reported at the location where it physically occurred (i.e. at the well) 3) The operator must use one of the single-well battery well locations within the paper battery for reporting.
AB	Wells within the crude bitumen administrative battery must have common equity and royalty. No flaring, venting or fuel can be reported at the crude bitumen administrative battery level. Flaring, venting and fuel activity must be reported at the location where it physically occurred, i.e., at the well level. Wells within a crude bitumen administrative battery must be within a geographic area no larger than six contiguous townships. The operator must use one of the SWB locations within the crude bitumen administrative battery for reporting.
BC	Not in Petrinex

12.2.1.3 Multiwell Group Battery (Petrinex facility subtypes: 326 in SK and 341 in AB)

Each well must have its own separation and measurement equipment similar to a single well battery. The disposition = production accounting method may be used for each well when appropriate.

All equipment for the wells in the battery must share a common surface location.

If the disposition = production method is not used or cannot be used, inventory at the group battery is to be reported monthly to Petrinex.

12.2.1.4 Multiwell Proration Battery (Petrinex facility subtypes: 327 in SK and 342 in AB)

All well production is commingled prior to the total battery oil/emulsion being separated from the gas and measured. Individual monthly well oil and water production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor as stated in Section 6.4.4.

Inventory at the proration battery is to be reported monthly to Petrinex.

Wells included in a proration battery are not eligible for the disposition = production methodology.

12.2.2 Gas Measurement and Reporting

Any single stream of produced gas, flared gas, or vented gas volume exceeding 2.0 10^3m^3/day must be metered. If the annual average fuel gas usage exceeds 0.5 10^3m^3/day on a per site basis, the fuel gas must be metered.

SK	For single-well batteries (facility subtype 325) or paper batteries (facility subtype 313), fuel gas, vented gas or flared gas at a well site must be reported at the well level. For a multiwell group, or proration, individual well flared or vented gas must be reported at the well level. Gas collected at a common point prior to being flared or vented may be reported at the battery level.
AB	Vent volumes for crude bitumen batteries included in the crude bitumen fleet average vent gas limit, as described in section 8 of *Directive 060*, must be determined by conducting tests in accordance with table 12.1. For single-well batteries (subtype 331), fuel gas, vented or flared gas at a well site must be reported at the well level. For a multiwell group, proration, or crude bitumen administrative batteries (subtype 341, 342, 343), individual-well flared or vented gas must be reported at the well level unless the gas is collected at a common point and then flared or vented. Then it can be reported at the battery level.
BC	See BC OGC Directives.

For single point measurement uncertainty refer to Section 1.7.4

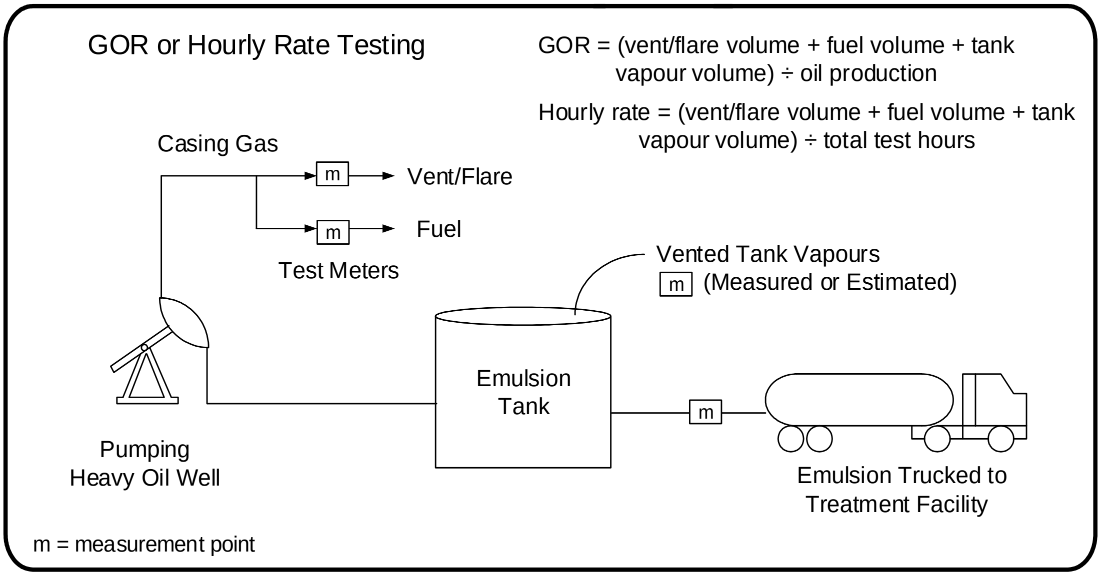
12.2.2.1 Single-Well Batteries

For initial well startup, in the absence of suitable reservoir information, monthly tests must be conducted to determine the GOR factor or the hourly rate if gas volumes are not dependent upon oil production volumes (see Section 4.3.8.5) for six months or until gas production stabilizes and measurement is required if > 2.0 10^3m^3/day.

If total gas production per well does not exceed 2.0 10^3m^3/day, the producer may use the GOR or hourly rate testing to determine gas volumes.

A well test may be conducted such that all the applicable gas, including fuel, flared and vented gas, and oil volumes produced during the test are measured, see Figure 12.1. The gas volume is to be divided by the oil volume to result in the GOR factor or divided by the test hours to obtain an hourly rate. For single-well oil batteries the oil volume used in the determination of the GOR factor can be based upon the monthly total oil production (monthly total volume ÷ hours produced in month × test duration).

Figure 12.1. GOR or hourly rate testing schematic



GOR or hourly rate test frequencies are detailed in the Table 12.1.

Table 12.1. GOR or hourly rate test frequency requirements

Gas rate ($10^3m^3/d$)	Test frequency
≤ 0.1	Once every 3 years
> 0.1 but ≤ 1.0	Annually
> 1.0 but < 2.0	Semiannually

12.2.2.2 Proration Multiwell Batteries

If gas disposition is metered at a multiwell proration battery and is sold or used at a point farther on,

1. Gas production volumes for each well > 2.0 10^3m^3/day must be tested, unless metered, on a per stream basis at the same frequency as the emulsion testing, or
2. If ≤ 2.0 10^3m^3/day, calculated using the well GOR or hourly rate at the same initial frequency as a single-well battery, and then in accordance with Table 12.1 after stabilization, refer to Section 12.2.2.1 for more detail.

If associated gas is flow lined to a central facility or collection point and gas production rates at the point of collection or emission are < 2.0 10^3m^3/day and not metered, a battery or facility GOR may be determined, but gas volumetric reporting must be at the individual well level. Initial and updated factors may be determined by any of the applicable tests or procedures described in Section 4.3.8.5 and at the same frequency as a single-well battery, refer to Section 12.2.2.1 for more detail.

12.2.3 Oil and Water Deliveries to a Treatment Facility

Liquid volumes are trucked from single-well batteries, multiwell batteries, and wells within paper batteries to a custom treater or battery. These facilities produce oil, water, and sand for disposal from the trucked-in fluids. Typically, received products are measured using weigh scales or inlet meters but tank gauging could also be used, see Section 10.3. The oil and water densities from every well must be updated in accordance with Section 10.4.4 and the S&W of the emulsion delivered to these facilities must be determined on a per-load basis, see Sections 14.8.

For single point measurement uncertainty refer to Section 1.

12.2.4 Well Test Measurement with Tank Gauging or Metering

Wells in primary/secondary production of heavy oil must be tested at the same frequency stated in Section 6.4.4 for non-heavy crude oil wells. The tests must be conducted in a consistent manner throughout the month and a test must be conducted when there is a change in well parameters (pump speed, work-over, reactivation, flush-by, etc.) as soon as possible.

A water cut must be determined for each test, and collecting a wellhead sample during a test is acceptable. See Sections 14.8.

Temperature correction is not required for well tests using test tanks, see Section 12.1.1.

Tests may be conducted by using a single isolated tank for the well. Table 12.2 may be used by the licensee to determine the height-to-diameter ratio requirements in accordance with Section 14.7.2, with the exception that the accuracy coefficient in Table 12.2 is a suggested minimum for test fluid volumes.

Table 12.2. Accuracy coefficients for various measurement types for test tanks

Level measurement technique	Accuracy coefficient “a”	Maximum level reporting resolution (mm)
Gauge board	1.6	25
Manual dip of the tank	0.4	10
Electronic (e.g., radar)	0.4	10

The accuracy coefficient “a” can be used in the following equation:

$V \geq a \times d^2$ or $d \leq (V \div a)^{0.5}$

where:

V = test fluid volume, m^3

a = accuracy coefficient

d = tank diameter, m

On the tank being used for testing, the gauge board float, linkage, and scale must be in good condition. The gauge board markings must be no further than 60 mm apart. For gauge measurement on test tanks, one reading of the gauge board is acceptable for the start and end of the test. Where safe work conditions permit, gauge boards should be read at eye level.

If the well emulsion is to be tested using a meter, the meter must be sized to operate within 20% to 90% of its flow range and installed and operated in accordance with Sections 2.4 and 14.2.

For single point measurement uncertainty refer to Section 1.

12.3 Thermal In Situ Operations (Petrinex facility subtypes: 344 in SK and 344 and 345 in AB)

Crude bitumen and heavy crude oil enhanced recovery typically requires the injection of steam, sometimes with added solvent or gas.

For thermal production operations, operators deal with a variety of measurement challenges:

1. Steam injection may be of variable quality at the wellhead, resulting in systematic errors, and may also be present in the vapour state at production facilities, creating further measurement issues.
2. Most thermal projects require the use of a diluent to assist in the separation of water/oil emulsions, so production may not be directly measured at these facilities.
3. Produced fluids are at high temperatures, so all measurements must be temperature corrected except for well testing volumes.
4. At some facilities, highly abrasive fluids are observed as a result of entrained sand, which can damage meters and introduce systematic errors.
5. Injected solvent and gas may be difficult to fully differentiate from produced fluids, especially since the composition of the oil can change across a scheme area and vertically within a stratigraphic unit or zone, and can be further changed due to *in situ* high-temperature reactions.

For these reasons, the measurement plan at thermal operations must be thoroughly considered.

SK	*Guideline PNG042: Measurement, Accounting, and Reporting Plan (MARP) Requirements for Thermal Heavy Oil Recovery Projects* is also an integral part of a projects measurement plan in Saskatchewan. It provides information on the submission and approval requirements of a MARP before facility licensing.
AB	*Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirements for Thermal Bitumen Schemes* is also an integral part of a scheme's measurement plan. It provides information on the submission and approval requirements of a MARP before facility licensing.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Unless otherwise stated, all existing thermal *in situ* facilities must meet the requirements set out in this section. For new facilities and expansions to existing facilities, the steam and water measurement requirements are effective immediately.

12.3.1 Bitumen, Diluent, Dilbit or Heavy Crude Oil Delivery Point Measurement

Each operator is responsible for determining the total heavy crude oil or bitumen production at its scheme, regardless of whether another party is responsible for operation of the delivery point measurement. The delivery and receipts of bitumen, diluent, dilbit, or heavy crude oil all affect the final determination of production of a scheme. The following are requirements for delivery and receipt points of diluent, bitumen, dilbit or heavy crude oil:

Delivery/receipt point measurement must meet a single point measurement uncertainty of ±0.5% and must be proved in accordance with Section 2.4 where applicable.

Density measurement must be taken on the delivery/receipt product using one of the following methods:

1. On-line densitometer or Coriolis meter
2. ASTM D4052 - Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter
3. ASTM D5002 - Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer
4. ASTM D1298/6822 - Standard Test Method for Density and Relative Density or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method

Water content must be determined for delivery/receipt product using the following methods:

1. ASTM D95 - Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation
2. ASTM D4006 - Standard Test Method for Water in Crude Oil by Distillation
3. ASTM D4377 - Standard Test Method for Water in Crude Oils by Potentiometric Karl Fischer Titration

Solids content must be determined for delivery/receipt product using the following methods:

1. ASTM D4807 – Standard Test Method for Sediment in Crude Oil by Membrane Filtration; applicable to samples with low mineral content
2. Mineral by Centrifuge Separation; applicable to samples with high mineral content.

For static testing methods, all samples for density, solids, and water must be obtained using proportional sampling and adhere to all requirements in Section 10.4.1.

Trucked in volumes must adhere to sampling requirements in Section 10.4.1 or 10.4.2.

Determination of shrinkage must be consistent with Section 14.3.

Sand volume is to be included as part of the S&W determination and reported as water, as stated in Section 12.3.4.

All measurement methods must be conducted in a manner satisfactory to the Regulator. Additional requirements may apply depending on circumstances specific to each project through MARP approval or site-specific requests.

12.3.2 Gas Measurement

Gas production measurement from thermal wells can be problematic, particularly at high temperatures where steam and solvent may be present with the gas and the combined flow of gas, steam, and/or solvent would be metered together.

For multiwell proration facilities, the group gas measurement can be used to prorate back to well gas test rates using one of the following methods:

1. If a test separator exists, the total battery gas is prorated back based on the individual test gas rates after subtracting the steam produced with the gas and any lift gas volumes.
2. The individual well GOR may be used in accordance with Section 12.2.2.2.
3. If test gas rates are not consistent and not used or well gas is not measured but total well fluid production and water cut can be determined at the battery, well gas production may be determined using a battery-level GOR. The battery-level GOR and the application to each well can be calculated as follows and will result in a gas proration of 1.00000:

   Battery GOR = Total monthly measured produced gas at battery ÷ Total monthly measured produced oil at battery

   Well gas volume = Battery GOR x Well prorated (reported) oil volume

   The battery-level GOR can only be used if these criteria are met:

   a. There is common working interest ownership of all the wells in the battery; and
   b. There are no gas sales or use of the produced gas that would trigger a gas royalty payment.

Total gas flared and total vented gas must be measured and reported using sound engineering practices.

Gas can be injected into a reservoir for a variety of different purposes over the life of a well. If gas is injected into a reservoir other than for lift gas, it must be measured and reported. If lift gas is used, the total lift gas volume must be measured and netted off the total produced gas volume before prorating to the wells.

The single point measurement uncertainty for gas produced at a battery or injected at a wellhead is ±3%.

SK	It is expected that when operators are injecting gas into the reservoir, there is a methodology in place to determine the resulting production of the injected gas. A *Guideline PNG042* - MARP application must be submitted to address the details of the gas injection and resulting production. If a MARP already exists, an update must be submitted for Regulator approval prior to commencing any gas injection.
AB	It is expected that when operators are injecting gas into the reservoir, there is a methodology in place to determine the resulting production of the injected gas. A *Directive 042* - MARP application must be submitted to address the details of the gas injection and resulting production. If a MARP already exists, an update must be submitted for Regulator approval prior to commencing any gas injection.

BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

All gas measurement devices must be calibrated, proved, or verified annually or as otherwise stated in Section 2.

12.3.3 Steam Measurement

Direct measurement of injected steam is challenging. Operators must contend with steam losses, unmetered utility steam, and changes in steam quality from steam generator to wellhead. Steam must be reported as a CWE at 15˚C. If it is delivered from another facility for injection, it must be reported on Petrinex as a receipt of the product [STEAM].

The steam injected into each well must be measured on a per-well basis and reported monthly. When measuring wellhead injected steam, the devices used must have a single point measurement uncertainty of ±5% at the time of installation. Wellhead injection meters with no internal moving parts must have the instrumentation calibrated annually, or before every steam cycle.

At a minimum of once every two steam cycles, operators that use cyclic steam stimulation (CSS) as a recovery method must visually inspect the primary element of one wellhead steam injection meter for every five wells on a pad. At a minimum of once per year, steam assisted gravity drainage (SAGD) or other thermal operations must visually inspect the primary element of one wellhead steam injection meter for every five wells on a pad, see Section 2.3.4 for exemption. For example, pads that have 6 to 10 wells would require a two well sample set, 11 to 15 wells would require a three well sample set, and so forth. The well(s) chosen to act as a sample set on a given pad must be representative and not have been selected in the previous five years. If any of the inspected sample set meters be compromised, the operator is required to service (clean or replace) all wellhead injection meters included on the pad within 12 months of discovering the compromised meter. Visual evidence of the primary element condition during the meter inspections must be kept on site and made available to the Regulator upon request.

Radiography, optical techniques, or other nonintrusive methods may be used in lieu of physical inspections provided that the images are of sufficient quality to discern any damage to the primary element or the presence of scale. If any of the inspected sample set meters be compromised, the operator is required to inspect (non-intrusively) all wellhead injection meters on that pad within one month of discovering the compromised meter. The operator is required to service, clean or replace those meters that showed damage, scaling, or yielded inconclusive results within one month. Other verification methods will be considered on a scenario-by-scenario basis.

The wellhead volumes reported to Petrinex must be prorated from the total steam volume leaving the steam plant. The monthly facility proration factor and the data used in its calculation must be kept on site and made available to the Regulator upon request. The volume of steam leaving the steam plant may be determined from:

1. Total steam volume leaving the steam plant separator; or
2. Boiler feed water and boiler blowdown.

The steam injected into each well must be measured on a per-well basis and reported monthly. Where steam chambers belonging to a single subsurface drainage area have coalesced for projects using SAGD, operators may measure steam injected on a grouped basis for the associated wells in place of individual well measurement. Steam injection must continue to be reported to Petrinex for each well using its UWI; it is the operator's responsibility to justify to the Regulator how individual well injection will be determined.

A maximum single point measurement uncertainty of ±2% is required for:

1. Steam entering or leaving the injection facility, excluding wellhead injection, for example steam transferred to a battery or to or from another injection facility.
2. Steam used for emissions control at the injection facility, e.g., NOx, unless the volume is < 2.0% of the injection facility's total water out, in which case it may be estimated using sound engineering practices.
3. Steam leaving a steam plant.

All steam measurement devices must be calibrated/proved/verified on an annual basis or as otherwise stated in this section or in Section 2.3.

12.3.4 Water Measurement

The measurement of water at thermal *in situ* facilities is a key component to evaluating the plant performance and compliance with approvals and regulations. Therefore, a higher degree of accuracy is required than at conventional production operations.

A maximum single point measurement uncertainty of ±2.0% is required for the following water streams at injection facilities associated with thermal *in situ* schemes:

1. Fresh, brackish, and produced water entering or leaving the injection facility;
2. Water injection/disposal;
3. Boiler feed water and boiler blowdown;
4. Water used for emissions control at the injection facility, e.g. NOx, unless the volume is < 2.0% of the injection facility's total water OUT, in which case it may be estimated using sound engineering practices;
5. Camp wastewater entering an injection facility, unless the volume is < 2.0% of the injection facility's total water OUT, in which case it may be estimated using sound engineering practices.
6. Freshwater diversion points:

SK	Licensed by Water Security Agency.
AB	Licensed by Alberta Environment and Sustainable Resource Development under the Water Act .
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Upon application, the Regulator may approve alternative methods for determination of the water stream volumes stated in items 1-6 if it is satisfied that they can be determined with a maximum uncertainty of ±2.0%, for example calculating produced water by subtracting measured fresh and/or brackish water from a measured mixed water stream.

A maximum single point measurement uncertainty of 5.0% is required for all other water uses reported to Petrinex, except if the water streams are small < 2.0% of the total OUT in the facility water balance determination, in which case they may be estimated using sound engineering practices.

All water measurement devices must be calibrated/proved/verified on an annual basis or as otherwise stated in Sections 2.4 and 2.8.

12.3.5 Water/Steam Primary and Secondary Measurement

For produced water entering a steam injection facility and steam leaving a steam plant, primary measurement must be verified with secondary measurement. This secondary measurement is subject to the same maximum single point measurement uncertainty as the primary measurement. On a monthly basis, differences between the primary and secondary measurement of > 5.0% must be reconciled using sound engineering practices. The reconciliation must be recorded and made available to the Regulator upon request.

If both the primary and secondary measurements are on the same pipe run, the operator must use differing measurement technologies to aid in preventing measurement failures from the same mechanism.

If the design of the metering system includes the provision to inspect, conduct maintenance, and repair the primary element without shutting in the stream flow, i.e., meter bypass and repair of the meter can be completed within two weeks of ceasing primary measurement, then secondary measurement is not required.

12.3.6 Solvent Measurement

The addition of solvent(s) to steam injection can accelerate and improve the recovery of heavy crude oil. Injected substances used as solvents can include, but are not limited to, ethane, propane, butane, and carbon dioxide or some combination of these hydrocarbons.

Individual types of solvents injected into the formation must be measured prior to mixing with steam and/or other solvents. Operators must comply with the standards of accuracy requirements in Section 1 and the liquid solvent injection requirements stated in Section 12.3.6.

The determination of produced solvent is key to evaluating process performance and economics and determining production volumes. The determination of solvent production is complex and includes, but is not limited to, volumetric measurement, sampling, and compositional analysis.

SK	Consequently, a *Guideline PNG042*- MARP application must be submitted to address the details of the solvent injection and corresponding production. If a MARP already exists, an update must be submitted for Regulator approval prior to commencing any solvent injection.
AB	Consequently, a *Directive 042*- MARP application must be submitted to address the details of the solvent injection and corresponding production. If a MARP already exists, an update must be submitted for Regulator approval prior to commencing any solvent injection.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

2.

Where steam chambers belonging to a single subsurface drainage area have coalesced for projects using SAGD, operators may measure solvent injected on a grouped basis for the associated wells in place of individual well measurement. Solvent injection must continue to be reported to Petrinex for each well using its UWI.

The single point measurement uncertainty for liquid solvent injection is ±2%.

All injected solvents measured in the gaseous phase are subject to requirements in Sections 12.3.1 and 12.3.2.

All solvent injection measurement devices must be calibrated/proved/verified on an annual basis or as otherwise stated in accordance with Section 2.

12.3.7 Production Measurement

The need for accurate production measurement for heavy crude oil, water, and gas is no different from non-thermal facilities. However, due to the nature of the heavy crude oil in a high temperature production environment, it is impractical to prove meters in the field in a manner used for non-thermal oil. Proving trucks cannot handle high temperature fluids or the high viscosity of cooled heavy crude oil. Therefore, for thermal *in situ* oil production, annual verification of measurement devices is sufficient provided that the facility proration factor is within the targets specified in Section 3. If targets are not being met, more frequent verification may be required. For delivery point measurement, sales, or LACT, see Sections 12.3.1 and 14.

Verification can be achieved using:

1. Internal diagnostics of the measurement device if present to check the structural integrity of the primary element;
2. Bench proving; or
3. Other Regulator-approved methods.

The single point measurement uncertainty for emulsion is ±2%, excluding the effects of steam and hydrocarbon vapours, as well as the effect of S&W determination.

Determination of S&W from wells faces the same challenges as the production measurement. For this reason, it is necessary that S&W methods take into account the temperature and pressure of the sampled emulsion. All manual S&W samples must be adequately cooled to mitigate the flashing of components. If S&W is determined using an on-line analyzer, provisions to take manual samples must be present to compare against the analyzer if necessary. On-line analyzers must be calibrated annually.

12.3.8 Well Production Measurement

Well testing in enhanced thermal operations can only be performed under certain conditions and must done using a test separation vessel. Operators using test separation to determine well production must comply with the following:

1. At minimum, each production well must have one valid testing hour for every 40 hours the well is in operation.
2.

SK	One well in the test cycle at all times is not a requirement in Saskatchewan.
AB	One well must be in the test cycle at all times.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

3. The test duration must be optimized to obtain as many representative production well tests as possible for each month.
4. Where it has been demonstrated that steam chambers have coalesced, operators may commingle the production of a SAGD producer will and an infill production well before testing the wells. Production of oil, gas, and water must continue to be reported to Petrinex for each well. Operators are permitted to use engineering estimates to allocate tested commingled production to individual wells.
5. Sufficient time must be provided between tests to purge the test separator of the emulsion from the previous test.
6. S&W must be determined for each test.
7. Test durations and methods must be reassessed annually to verify that current practices are sufficient to obtain representative data, and this information must be made available to the Regulator upon request.

Notwithstanding these items, at certain points in a high-pressure cyclic steam well's production cycle, the process fluids cannot be tested due to high temperatures. In such instances, engineering estimates may be used until tests can be conducted.

Where steam chambers belonging to a single subsurface drainage area have coalesced for projects using SAGD, operators may measure well production for the associated wells on a grouped basis rather than individually. Operators must continuously monitor S&W for the grouped wells. Production of oil, gas, and water must continue to be reported to Petrinex for each well using its UWI; operators must be able to justify how they are determining individual well production to the Regulator.

The single point measurement uncertainty for emulsion is ±2 per cent for individually measured wells, excluding the effects of steam and hydrocarbon vapours, as well as the effect of S&W determination. The single point measurement uncertainty for group metered emulsion is ±5 per cent, excluding the effects of steam and hydrocarbon vapours, as well as the effect of S&W determination.

Determining well S&W faces the same challenges as measuring production. For this reason, S&W methods must take into account the temperature and pressure of the sampled emulsion. All manual S&W samples must be adequately cooled to mitigate the flashing of components. If S&W is determined using an on-line analyzer, operators must take manual samples for comparison to the analyzer, if necessary. On-line analyzers must be calibrated annually.

Operators wishing to use production measurement methods other than test separation and the aforementioned grouped measurement must be approved by the Regulator.

SK	If a different method of production measurement is proposed, it must be explicitly stated during the *Guideline 042*- MARP application process.

AB	If a different method of production measurement is proposed, it must be explicitly stated in the *Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project* application and included within the conceptual measurement plan. The proposed measurement method will be finalized during the *Directive 042*- MARP application process.
BC	NA

12.3.9 Proration Factors

If the proration factor targets described in Table 3.1 are not being met, the Regulator may require an investigation to determine why. Action required by the operator may include, but is not limited to:

5. Verifying S&W measurement practices.
6. Verifying related fluid measurement system performance.
7. Proving or calibration of measurement equipment.
8. Inspecting the primary element for meters with no internal moving parts.

12.3.10 Uncertainty and Proration Factor Summary

Refer to Section 1.7 for a summary of uncertainties for heavy oil and to Section 3.1.1.1 for a summary of proration factors for heavy oil.

12.3.11 Internal Inspection Exemptions

The inspection requirements stipulated in this exception only apply to measurement devices, including flow meters, used in thermal *in situ* facilities to determine volumes reported to Petrinex. If the internal components of meters used at thermal *in situ* facilities have been found to be clean and undamaged for three consecutive inspections conducted over at least three years, operators may extend internal inspection frequencies to once every three calendar years. Operators may not apply this exemption if:

1. The meter is used for the measurement or calculation of delivery point, sales, or LACT volumes, including diluent measurement, or
2. The meter is used for flare measurement. For flare meter internal inspection requirements, refer to Section 2.5.2.

Operators applying the exception criteria must comply with the following:

1. A tag must be attached to the meter indicating that this exception is being applied and the date of the last inspection.
2. If any individual meter fails during a scheduled or nonscheduled calibration or verification or inspection the meter must requalify for the exception.
3. Operators must keep records of the internal inspections associated with this exception for at least six years and make them available to the Regulators on request.

13 Condensate and High Vapour Pressure Liquid Measurement and Reporting

This section presents the requirements and exemptions for condensate measurement and reporting associated with gas well production.

Condensate is a generic term used to describe various types of hydrocarbon liquid products such as: field condensate, separator liquids condensate, stock tank liquids condensate and stabilized liquid condensate. See Glossary in Appendix 2 for definitions.

High vapour pressure liquids is a generic term for hydrocarbon liquids that are stored and transported under pressure at all times in a liquid phase.

13.1 General Measurement and Reporting Requirements

13.1.1 Measurement Requirements

For measurement of condensate and high vapour pressure liquids at all accounting locations within the upstream oil and gas facilities, the Regulator will consider the measurement system to be in compliance:

a. if the measurement requirements in Sections 1.6.3.1 through 1.6.3.13, and 4.2, the calibration and proving requirements in Section 2, the design and installation of liquid (oil) measurement requirements in Section 14, the sampling and analysis requirements in Section 8, and the trucked liquid requirements in Section 10 are fulfilled or

b. if the measurement requirements of Measurement Canada for high vapour pressure liquids are fulfilled.

13.1.2 Reporting Requirements

Hydrocarbon liquid production can be reported as a gas or liquid or both, depending on how it is disposed. The general rules are as follows for Petrinex reporting:

SK	1. Hydrocarbon liquids with density > 780 kg/m^3 produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent measurement batteries, measured and recombined or trucked out for sale must be reported as a liquid OIL volume. 2. Hydrocarbon liquids with density ≤ 780 kg/m^3 produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent measurement batteries, measured and recombined with the gas for further processing must be converted to and reported as GAS production. 3. Hydrocarbon liquids with density ≤ 780 kg/m^3 produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent measurement batteries and trucked for sale or for further processing are considered field condensate and must be reported as a liquid COND volume at the well level. 4. Hydrocarbon liquids with density ≤ 780 kg/m^3 separated from a gas gathering system at group separation points and stored in a tank for disposition are considered pentanes plus and must be reported as a liquid C5-MX volume.

	5. Hydrocarbon liquids recovered from processing at a gas processing plant are considered by-products of processing and must be reported as specific liquid volumes. 6. The receipt and disposition of load condensate injected, recovered, separated, and stored in a tank at a gas well must be reported as COND or C5-SP volume. 7. Load condensate received from an outside source at any gas well, injected, recovered, separated, recombined with production, and sent to a gas plant must be reported as a receipt of COND or C5-SP at the battery level and a disposition of GAS to the gas plant. A corresponding disposition of COND or C5-SP to SKGE and receipt of GAS from SKGE must also be reported to balance the products at the battery.
AB	1. Hydrocarbon liquids produced from a gas well producing oil must be reported as a liquid oil volume at the well level, regardless of whether they are trucked or recombined. The *Petroleum Royalty Regulation 2008*, AR 248/90 (PRR), under the *Mines and Minerals Act* applies for Crown royalty. 2. Hydrocarbon liquids received from wells designated as VGWL OIL that are separated at group separation points at batteries or gathering systems and directed to a tank for disposition are considered OIL and must be reported as a liquid volume. 3. Hydrocarbon liquids produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent measurement batteries producing condensate, measured, and recombined with the gas or trucked out for further processing must be converted to and reported as gas production (see Scenarios 1 and 5 below). The NGRR applies for Crown royalty. 4. Hydrocarbon liquids produced and separated from a gas well producing condensate or at the group measurement points of multiwell gas proration or effluent measurement batteries, stored in a tank, and trucked for sales are considered field condensate and must be reported as a liquid condensate volume at the well level (see Scenarios 2 and 3 below). The NGRR applies for Crown royalty. 5. Hydrocarbon liquids separated from a gas gathering system at group separation points and stored in a tank for disposition are considered pentanes plus (C_{5+}) and must be reported as a liquid volume (see Scenario 4 below). The NGRR applies for Crown royalty. 6. Hydrocarbon liquids recovered from processing at a gas processing plant are considered by-products of processing and must be reported as a liquid volume. The NGRR applies for Crown royalty. 7. Load condensate (or oil or water) received, injected, recovered, separated, and stored in a tank at a measured gas well is to report load fluids, in accordance with *Manual 011: How to Submit Volumetric Data to the AER* Appendix 8 Reporting Procedures. 8. Load condensate received from an outside source at any gas well, injected, recovered, separated, recombined with production, and sent to a gas plant must report condensate receipt at the battery level and report disposition of C_{5+}

	with From/To of ABGE to balance the condensate receipt to avoid double paying royalty. 9. Load LPG, NGL, C_3, or C_4 received from an outside source at any gas well, injected, recovered, separated, recombined with production, and sent to a gas plant must report hydrocarbon receipt at the battery level and report disposition of the hydrocarbon with From/To of ABGE to balance the hydrocarbon receipt to avoid double paying royalty. 10. Load oil received from an outside source at any gas well, injected, recovered, recombined with production, and sent to a gas plant must report oil receipt at the battery level and report disposition of the oil.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

13.2 Reporting Scenarios for Gas Wells Producing Condensate

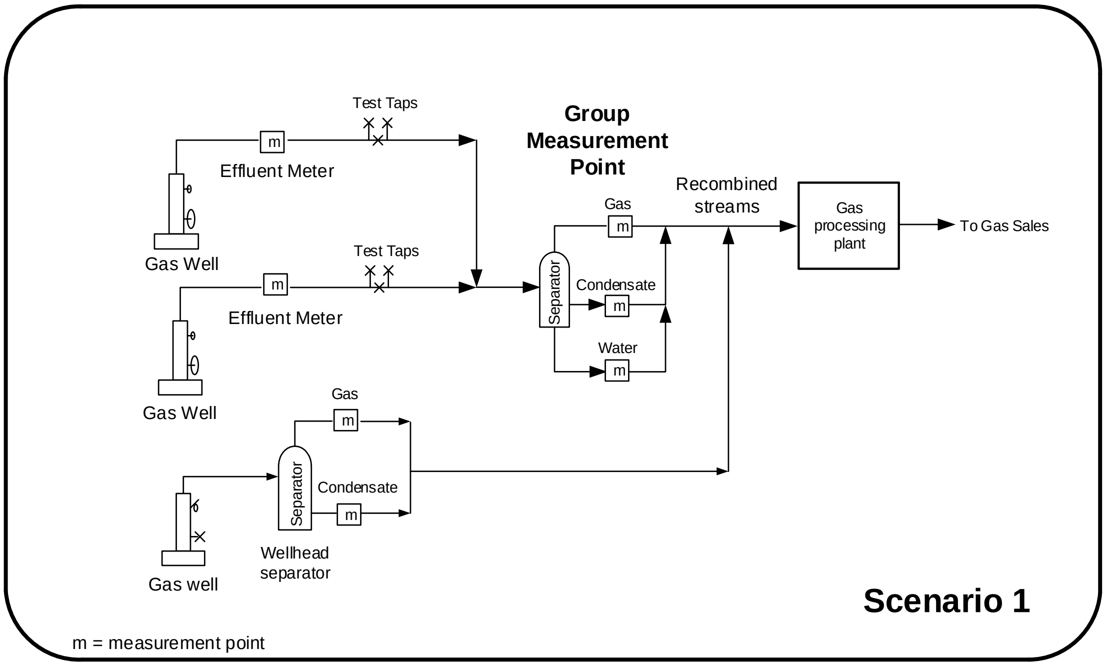
Condensate is associated with gas well production within gas facilities. If there is condensate, the total battery liquid volume must be measured.

13.2.1 Scenario 1 – Condensate that is Effluent Metered, Tested or Proration Tested or Separated and Recombined

Gas, condensate, and water being wet metered and tested or proration tested only, or separated from other well effluent, metered, combined with gas (single well or multiwell group batteries), and sent to a gas plant for further processing must be converted to its GEV and added to the gas production for reporting purposes.

SK	Gas plant products are not assessed royalties in Saskatchewan.
AB	The NGRR applies to this volume as part of the total production and disposition at the gas plant for Crown royalty.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

Figure 13.1. Scenario 1

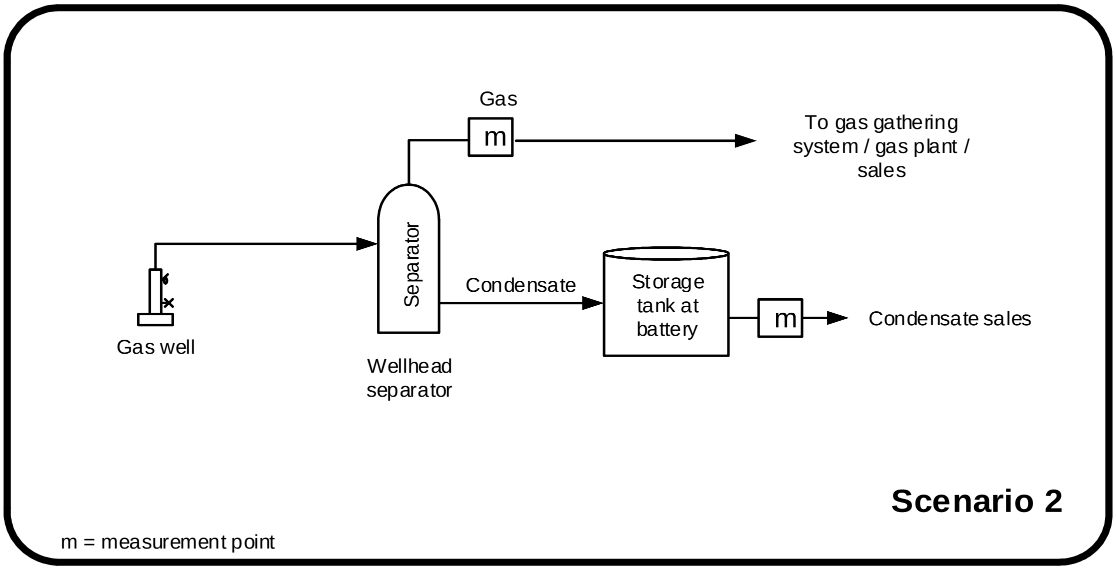


13.2.2 Scenario 2 – Liquid Production and Separated from the Well

Field condensate (COND) must be reported as a liquid production at the well if separated from well effluent, measured, and disposed of without further processing and before being delivered to a gas gathering system.

SK	Gas plant products are not assessed royalties in Saskatchewan.
AB	The NGRR applies to this volume for Crown royalty.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Figure 13.2. Scenario 2

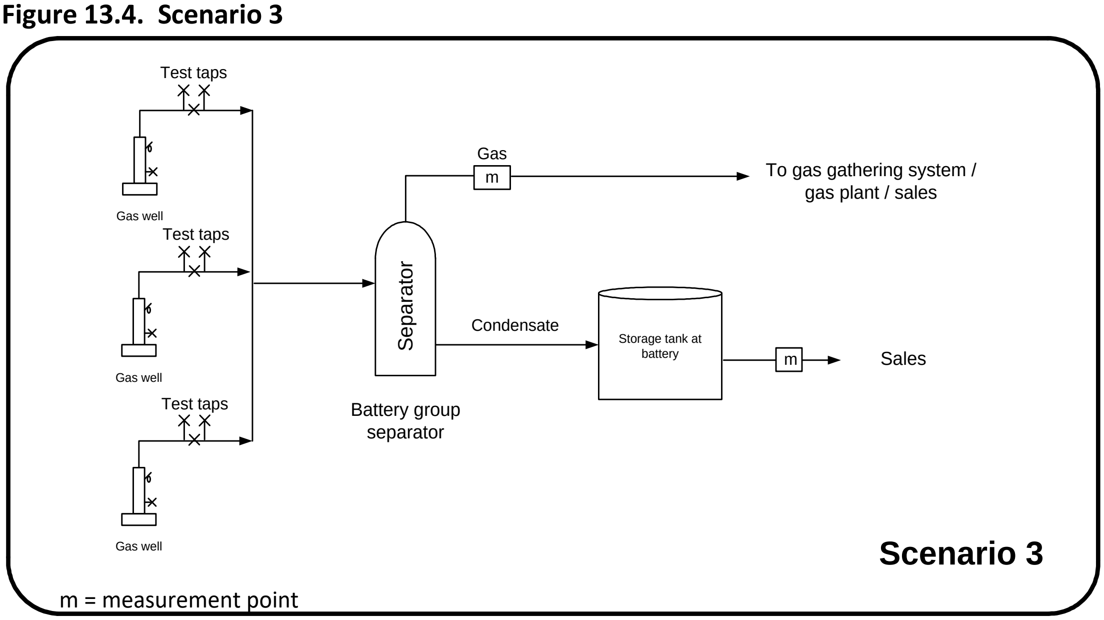


13.2.3 Scenario 3 – Liquid Production Separated from a Multiwell Battery

Field condensate (COND) must be reported as a liquid production at the well level if separated from multiwell gas proration or effluent measurement batteries, measured, and disposed of from the group separator without further processing and before being delivered to a gas gathering system.

SK	Gas plant products are not assessed royalties in Saskatchewan.
AB	The NGRR applies to this volume for Crown royalty.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Figure 13.4. Scenario 3

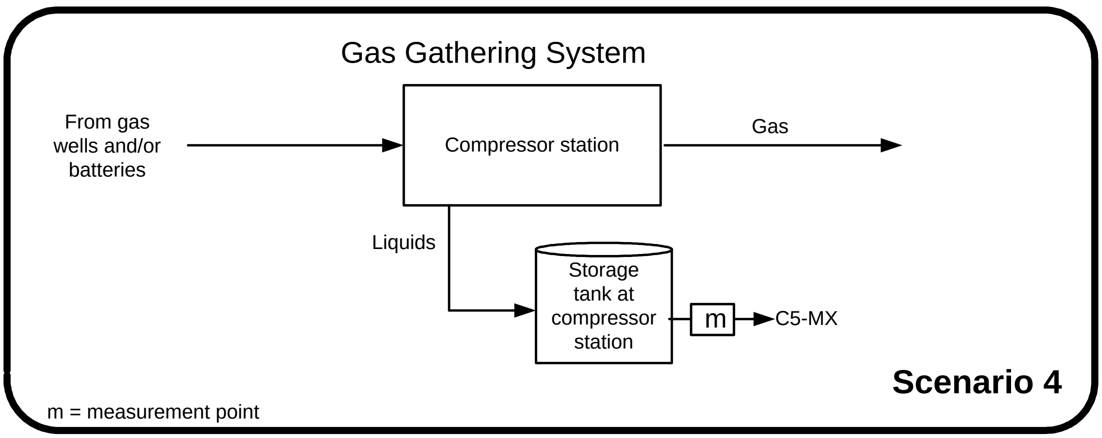


13.2.4 Scenario 4 – Liquid Recovered from Gas Compression

Hydrocarbon liquid from one or more batteries recovered as a result of gas compression at a gas gathering system or a gas group battery and disposed of without further processing must be reported as C5-MX at the gas gathering system.

SK	Gas plant products are not assessed royalties in Saskatchewan.
AB	The NGRR applies to this volume for Crown royalty.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

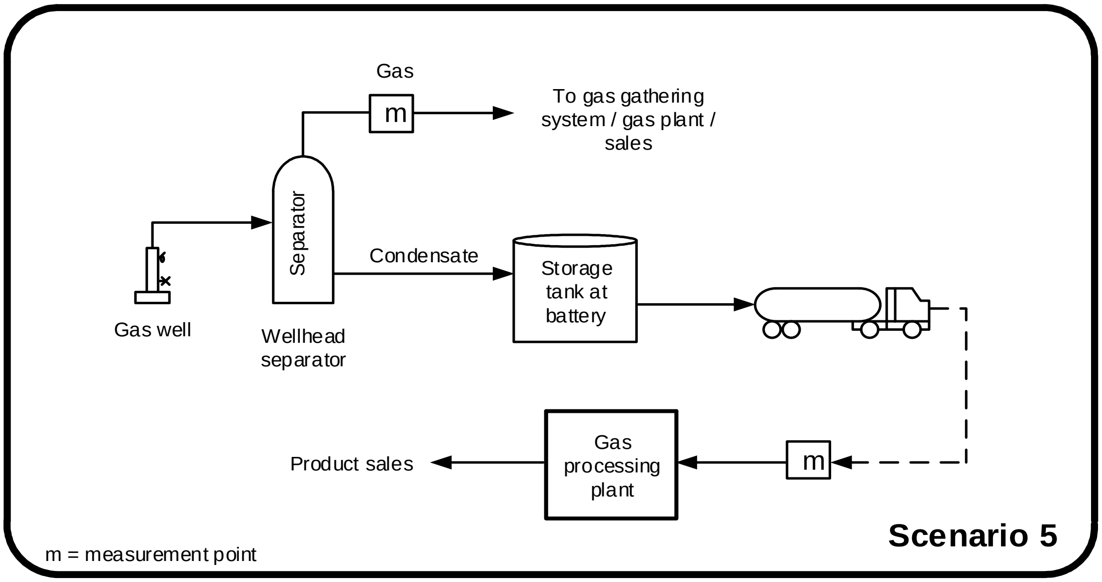
Figure 13.4. Scenario 4



13.2.4.1 Scenario 5 – Condensate Separated for Processing

SK	Condensate separated from well effluent, measured, and trucked to a gas plant for processing must be reported as COND. Gas plant products are not assessed royalties in Saskatchewan.
AB	Condensate separated from well effluent, measured, and trucked to a gas plant for processing must be converted to its GEV and added to the gas production for reporting purposes. If there is no processing before sales, see Scenarios 2 and 3 This scenario is the same as Scenario 9 in Alberta Energy *IL 87-3*. The NGRR applies to this volume as part of the total production and sale at the gas plant.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Figure 13.5. Scenario 5



14 Liquid Measurement

14.1 General Requirements

14.1.1 Scope

This section presents the requirements for liquid hydrocarbons measurement related to:

1. crude oil
2. condensate
3. liquefied petroleum gases
   a. propane
   b. butane
4. dense phase hydrocarbons
   a. ethane
   b. NGLs
5. water

14.1.2 Application of API Measurement Standards

For petroleum liquids, the API MPMS provides requirements for custody transfer measurement of hydrocarbons. For the purposes of this section, the degree of application of MPMS is determined by the level of uncertainty as required in Section 1.

14.1.3 System Design and Installation

The meter system design must meet the overall system uncertainty requirements of Section 1. The Regulator 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 14.10 of this Directive.

Liquid measurement systems typically consist of:

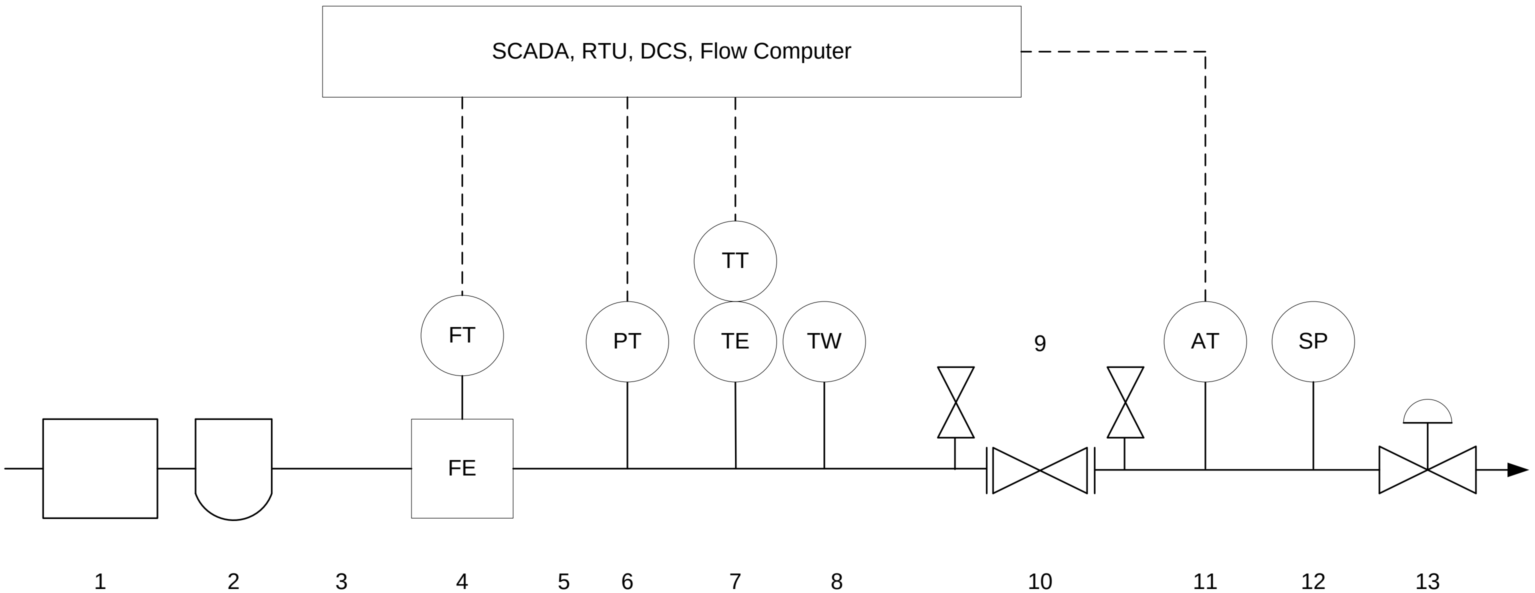
1. primary elements, such as a meter;
2. secondary elements, such as temperature and pressure transmitters;
3. in some cases, differential pressure transmitters, level transmitters, and densitometers
4. tertiary elements collectively termed electronic flow measurement (EFM), for example:
   a. distributed control system (DCS)
   b. supervisory control and data acquisition system (SCADA)
   c. flow computers
5. in some cases, mechanical totalizers are used in place of EFM.

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 is to 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, refer to Section 2.4 for more detail.

Components of a liquid measurement system are shown in Figure 14.1.

Figure 14.1. 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.

Rev. 2

14.2 Volume Measurement

14.2.1 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 such as pressure, temperature, flow rate;
2. Fluid properties such as viscosity, density, contaminants, bubble point;
3. Required accuracy to meet Section 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 such as viscosity and flow rate, must be considered for all operating scenarios like 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).

SK	No grandfathering.
AB	All existing ATC and ATG are grandfathered at their existing applications and must not be relocated or reused for other applications.
BC	No grandfathering

For meters to be proved using a conventional displacement prover, such as a ball prover or a captive displacer prover such as piston and shaft, pulse outputs are required. For master meter proving, pulse outputs are recommended.

In addition to the meter selection parameters listed above in this section, some upstream applications such as propane sales loading rack at gas plants may also have to meet Measurement Canada requirements.

There are two broad meter types, linear and nonlinear differential producer. The output of linear meters is proportional to flow rate. The output of differential producers is proportional to the flow rate squared. Table 14.1 lists various meter types for volume determination.

Table 14.1. Meter types

Linear meters	Nonlinear meters
Positive displacement	Orifice (see Section 4.3.1)
Turbine	Venturi
Vortex	Flow nozzle
Coriolis	Cone
Ultrasonic	Wedge
Magnetic (water or conductive fluids only)	Other differential devices

14.3 Shrinkage

For the purpose of this Directive, shrinkage refers to a volume reduction associated with one or more of the following processes:

1. Blending of hydrocarbon streams of varying density such as heavy oil and condensate to reduce the viscosity of the heavy oil for transport by pipeline; and/or
2. Loss of volatile components through vapourization such as flashing, weathering due to a pressure reduction and/or temperature increase or to continued exposure to atmospheric conditions like the conversion of live oil to base conditions.
3. Acid Gas removal

Petrinex-reported shrinkages other than Sections 11 and 14.3 and shrinkage or system loss/gains across facilities or pipeline system are outside the scope of this Directive.

14.3.1 Live Oil Shrinkage

Until produced hydrocarbon fluids are stabilized, the oil is normally at its bubble point, also referred to as the 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 in such equipment as test separators, a shrinkage factor must be applied to correct the measured liquid volume from the metering pressure and temperature to base conditions. When the meter is proved to base conditions, the shrinkage factor is incorporated into the meter factor.

14.3.2 Hydrocarbon Blending and Flashing Shrinkages

When hydrocarbon molecules of different molecular sizes and intermolecular spacing, also referred to as the 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 procedure accepted by an appropriate industry technical standards association.

In some cases, volume reduction is a combination of the effects of loss of volatile components and intermolecular spacing. For example, blending of condensate or diluent with heavy oil can occur at any point in the production process. 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 these ways of introducing the condensate. 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 40.0 kg/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 0.1 m^3 reporting limit on Petrinex. Flashing shrinkage must be determined if the added diluent volume is > 2.0 m^3/day and/or > 5.0% of total oil production, refer to Table 5.6 for details.

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 (ABGE) 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.

14.3.3 Shrinkage Factor Determination

Live oil shrinkage with entrained gas must be determined by any one of the following techniques:

1. Process simulation software;
3. Manual sampling and laboratory procedure, as referred to in API MPMS, Chapter 20; or
4. Physically degassing the prover oil volumes during meter proving of live oils, as referred to in Section 2.5.1.

Calculation of shrinkage volumes or factors is most often used to mitigate safety and environmental concerns if the live oil volumes are measured 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 level. The frequency of shrinkage factor determination must 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.

14.3.4 Shrinkage Factor Application

Shrinkage factors must be applied by being:

1. Incorporated into a meter factor by degassing during proving;
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, such as degassing during meter proving and then applying it again as a factor to measured volumes.

14.4 Temperature Measurement

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 14.2.

Table 14.2. 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

Fluid	Approximate error per 1°C temperature measurement error (%)
Crude oil (820 kg/m^3@15°C)	0.09
Crude oil (920 kg/m^3@15°C)	0.07
Water	0.02

Therefore, temperature compensation of measured volumes must be provided as required to meet the uncertainty requirements detailed in Section 1 and the requirements of this section. This applies to delivery point measurement, provers, and others such as LACT's 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, for example in 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 downstream of the meter. 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 element. Meter runs designed for trucked liquid measurement with the existing thermowell(s) within 20 diameters of the meter are grandfathered for the existing location and usage. If the meter run is modified or relocated, then these requirements must be met.

Resistance temperature devices (RTD) are the preferred temperature measurement element. Other types of temperature measurement elements, such as thermocouples and thermistors, are acceptable provided that uncertainty requirements are met. Dial thermometers are not acceptable for pipeline-based delivery point measurement.

For pipeline delivery point measurements, two thermowells should be provided, one for measurement and one for verification.

SK	Mechanical temperature compensators are not acceptable for newly constructed facilities. For facilities constructed before February 2, 2009, mechanical temperature compensators are acceptable if the operator can show that the uncertainty requirements of Section 1 are met (also see Section 10.3.2) for more detail.
AB	Mechanical temperature compensators are not acceptable for new installations. For existing installations (installed before February 2, 2009), mechanical temperature compensators are acceptable if the operator can show that the uncertainty requirements of Section 1 are met (also see Section 10.3.2) for more detail.
BC	See *Measurement Guideline for Upstream Oil and Gas Operations*

Temperature measurement type, tolerances, and calibration frequency are detailed in Table 14.3.

Table 14.3. Temperature measurement type, calibration frequency, resolution, and calibration tolerances

Application	Temperature measurement type[1]	Minimum resolution (°C)	Maximum calibration tolerance (°C)	Verification frequency
Delivery point with meter	Continuous with EFM	0.1	±0.5	Monthly[2]
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 14.9)	0.5	±1.0	Semiannual
Delivery point batch volumes into a pipeline or receipt at a battery/facility using tank gauging	One reading per load	0.1	±0.5	Semiannual

1 For mechanical ATCs, see Section 10.3.2.

2 Calibration frequency may be changed to bimonthly if three consecutive verification periods pass without the error exceeding the tolerance.

14.5 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 base conditions. The pressure correction referred to as 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 Section 1 uncertainty requirements.

Pressure transmitters and gauges must be installed in accordance with applicable standards of an appropriate industry technical standards association or manufacturer's recommendations, normally 5 to 10 pipe diameters downstream of the meter.

14.6 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 applicable standards of an appropriate industry technical standards association or manufacturer's recommendations, normally 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, for example 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 for more detail. If practical, densitometer measurements should be made at 15°C to preclude the requirement for temperature compensation. If this is not practical for such applications as viscous heavy oil or when using a hydrometer, manual temperature compensation must be provided using the appropriate API MPMS table. Refer to Section 14.9 for more detail.

SK	All density analyses are required to be submitted to ER through IRIS (see *Directive PNG013*).
AB	Upon Regulator request
BC	Upon Regulator request.

14.7 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 < 103 kPa.

Volumetric measurement using storage tanks is based upon a level measurement used in conjunction with a strapping table.

Provided that Section 1 uncertainty tolerances are met, the licensee may use storage tanks for determination of inventory, well test, or delivery point volume measurements. The licensee must ensure that the tank diameter, gauging equipment such as 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 recommendations and must be maintained in good working order.

14.7.1 Tank Strapping

Tank strapping tables convert or relate the 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.

14.7.2 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 (delivery point) or test volume compared to the overall tank height.

Tank sizing must address the intended use such as delivery point or well test, level measurement technique such as 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:

$d \leq (V \div a)^{1/2}$

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 metres

a = accuracy coefficient

The accuracy coefficients for non-heavy crude oil applications are:

a = 0.39 for all test fluid volumes

a = 0.39 for delivery point batch volumes ≤ 100 m^3/d

a = 0.92 for delivery point batch volumes > 100 m^3/d

The accuracy coefficients for heavy crude oil applications are:

a = 0.39 for treatment facility receipt batch volumes

a = 0.92 for sales/delivery point batch volume

a = 1.6 for primary heavy oil test fluid volumes

14.7.3 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 14.4 for marking gradations.

Gauge tapes must have a minimum resolution of 3 mm.

Table 14.4. Gauge board marking gradations

Gauge board application	Maximum marking separation (mm)
Non-heavy oil testing	25
Heavy crude oil testing	60
Inventory	150

If safe work conditions permit, gauge boards are best read at eye level.

On an annual basis, the operator must ensure the gauge board is in good working order and the strapping tables are appropriate for the type of measurement and fluid as per API MPMS.

14.7.4 Automatic/Electronic Tank Gauging

Electronic tank gauges must have a minimum resolution of 3 mm. One reading of the instrument is acceptable.

Instruments must be calibrated in accordance with the manufacturer's recommendation. See Section 2.10 for frequency requirement.

14.7.5 Tank Gauging Applications

14.7.5.1 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 75 mm.

The tank does not need to be stabilized or isolated for inventory measurements.

14.7.5.2 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 10 mm.

14.7.5.3 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. The licensee must ensure that the strapping table has been prepared in accordance with API MPMS, Chapter 2.
2. The licensee 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.
3. All gauge tapes and electronic level devices must have a minimum resolution of 3 mm.
4. Manual tank dips are performed in accordance with API MPMS, Chapter 3.1A. For tanks with a nominal capacity > 160 m^3, two consecutive readings within 10 mm of each other are required. The two readings are averaged. For tanks with a nominal capacity of ≤ 160 m^3, one reading is acceptable.
5. Automatic tank gauging is performed in accordance with API MPMS, Chapter 3.1B.
6. Temperature measurements are performed in accordance with API MPMS, Chapter 7.
7. Gauge boards must not be used for delivery point measurement.

14.8 Sampling and Analysis for S&W and Density Determination

Sampling and analysis must be in accordance with Sections 6, 8, and 10 or other equivalent method approved by an appropriate industry standards association.

14.8.1 Fluid Sampling Requirements for S&W and Density Determination

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 such as 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 recommendations.

For a single-well battery or a multiwell group battery, 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, 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. Refer to Section 15.2.2.1 for the exemption to these sample taking methods. This is a measurement-by-difference situation at the receiving battery/facility. For more detail on measurement-by-difference refer to Section 5.5.

For an oil battery 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 sample, also referred to as a grab sample anywhere between the wellhead or separator and the tank and applying the percentage of sediment and water (percent 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. Taking the average percent S&W of the total battery production and applying that to the tank inventory;
4. Using the average percent S&W of the trucked out volumes; or
5. Deeming the tank inventory to be entirely oil and making changes/amendments based on delivery volumes.

14.8.2 S&W Determination

The licensee must select the most appropriate method for determining the percent S&W. There are three static analysis methods of the sampled fluid generally considered acceptable by the Regulator based on the percent 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.

Recommended procedures for these three methods are shown in Appendix 3. Any alternative methods must be supported by testing that shows representative results are achieved and these alternative procedures must be made available to the Regulator 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 measured 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 or some other industry recognized standard.

14.9 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 metres. 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 totaled 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 0 kPa 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, either daily, weekly, or 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 oil, the percentage of water in the gross volume is determined by measuring the percent S&W of a representative sample or by continuous on-line measurement. The result is a quantified volume of oil and of water.
4. For oil, a shrinkage factor is applied to the volume in order to determine the volume at base conditions, also referred to as atmospheric pressure. Some applications may already have the shrinkage factor incorporated into the meter factor.

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.

14.9.1 General Equations for Determining Liquid Volumes at Base Conditions

14.9.1.1 Linear Meters

Indicated Volume

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 $DEN_{obs} \div DEN_b$

or

GSV = Mass ÷ DEN_b

Net Standard Volume

CSW = 1 - (%S&W ÷ 100)

NSV = GSV x CSW x SF

Water Cut

$DEN_{obs,o} = DEN_{b,o} \times CTL_o$

$DEN_{obs,w} = DEN_{b,w} \times CTL_w$

Water Cut = $(DEN_{obs,e} - DEN_{obs,o}) \div (DEN_{obs,w} - DEN_{obs,o})$

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.

CTL_o – Correction for the effect of Temperature on Oil: Correction for effect of temperature on oil at normal operating conditions.

CTL_w – 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.

DEN_b – Base Density: Liquid density in kilograms per cubic metre at base pressure and temperature.

$DEN_{b,o}$ – Base Density – Oil: Liquid density of oil in kilograms per cubic metre at base pressure and temperature.

$DEN_{b,w}$ – Base Density – Water: Liquid density of water in kilograms per cubic metre at base pressure and temperature.

DEN_{obs} – Observed Density: Liquid density in kilograms per cubic metre at observed pressure and temperature.

$DEN_{obs,o}$ – Observed Density – Oil: Oil density in kilograms per cubic metre at observed pressure and temperature.

$DEN_{obs,w}$ – Observed Density – Water: Water density in kilograms per cubic metre at observed pressure and temperature.

GSV – Gross Standard Volume: The volume at base conditions corrected also for the metre'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 base conditions during proving by the indicated standard volume (ISVm) as registered by the meter.

SF - Shrinkage Factor: a factor reflecting the volume reduction associated with one or both of the following two processes:

1. Blending of hydrocarbon streams of varying density such as bitumen and condensate to reduce the viscosity of the bitumen for transport by pipeline; and or
2. Loss of volatile components through vaporization such as flashing or weathering due to a pressure reduction and/or temperature increase or to continued exposure to atmospheric conditions such as conversion of live oil to base conditions.

NSV – Net Standard Volume: The gross standard volume corrected for shrinkage and nonmerchantable quantities such as sediment and water.

14.9.1.2 Composite Meter Factors (CMF)

A composite meter factor (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 Section 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:

$CMF_T = IV_P \times CTL_P \div IV_M$

Where:

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}).

14.9.1.3 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 (AGA-3):

$$Q_b = \frac{Q_m}{\rho_b} = \frac{N_1 C_d E_v Y d^2 \sqrt{\rho_f \Delta P}}{\rho_b}$$

API MPMS 14.8 (Natural Gas Fluids Measurement – Liquefied Petroleum Gas Measurement):

$$Q_b = N_1 C_d E_v Y d^2 \sqrt{\frac{\Delta P}{\rho_f}} \left(C_{tl} C_{pl} \right)$$

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 (kg/m^3)

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 standard of an appropriate industry technical standards association or manufacturer's documentation for determining base volumes.

14.9.1.4 Pressure and Temperature Compensation

CTL and CPL must be calculated as per the current standards in Table 14.5 for the applicable density and temperature range. Applications using the superseded standards list in Table 14.5 that were in use prior to the implementation of these standards do not require upgrading. Calculations for determining CTL or CPL not listed in Table 14.5 are not acceptable.

Table 14.5. Pressure and temperature compensation standards*

Standard	Product and density range	Calculation input(s)	Calculation output(s)	Comments
API MPMS 11.1 May 2004	Crude oil, refined products, and lubricating oils 611.16–1163.85 kg/m^3	Observed density Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	Density @ 15°C CTL CPL VCF	Current
API MPMS 11.2.2M 1986	Hydrocarbon liquid 350–637 kg/m^3	Density @ 15°C Flowing temperature Flowing pressure Equilibrium vapour pressure	CPL	Current
API MPMS 11.2.4 GPA TP-27 Table 53E September 2007	NGL and LPG 210–740 kg/m^3	Observed density Observed temperature	Density @ 15°C	Current

Standard	Product and density range	Calculation input(s)	Calculation output(s)	Comments
API MPMS 11.2.4 GPA TP-27 Table 54E September 2007	NGL and LPG 351.7–687.8 kg/m^3	Density @ 15°C Flowing temperature	CTL	Current

* 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.

14.9.2 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.

Hardware and software requirements:

1. The EFM data storage capability must exceed the time period used for data transfer from the EFM.
2. The EFM must be provided with the capability to retain data in the event of a power failure such as battery backup, UPS or EPROM.
3. The system must have appropriate levels of access for security, with the highest level of access to the system restricted to authorized personnel.
4. The EFM must be set to alarm on out-of-range inputs, such as temperature, pressure, differential pressure if it is applicable, flow, low power, or communication failures.
5. Any EFM configuration changes or forced inputs that affect measurement computations must be documented through either electronic audit trails or paper records.
6. The values calculated from forced data must be identified as such.

14.9.3 Performance Evaluation

If an EFM is used to calculate net liquid volumes, the licensee must be able to verify that it is performing within the Regulator 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 Regulator audit upon request. For existing EFM systems, the licensee must conduct a performance evaluation to ensure that they are performing adequately. A performance evaluation must be conducted and submitted for Regulator audit on request. The Regulator 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 14.6 to 14.9) 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 15°C. 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 recommended methodologies 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 specified in Section 14.9.4. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to 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 in test cases 1 to 5, and 11 to 15 or volumes in test cases 6 to 10, and 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.

14.9.4 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).

14.9.5 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 14.6. 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	120.0	942.9	945.0
2	693.0	11.4	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	25.0	786.7	786.8

Table 14.7. Volume correction test cases at atmospheric pressure—volume correction to 15°C and 0.0 kPa(g)

	Inputs				Outputs				
Test case	Metered volume (m^3)	Density (kg/m^3) @ 15°C	Observed temp. (°C)	Observed pressure (kPag)	CTL	CPL	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)	CTL & CPL corrected volume (m^3) 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 14.8. Other liquid hydrocarbon density correction test cases—density correction to 15°C

	Inputs		Outputs	
Test case	Liquid density @ observed temperature and base pressure (kg/m^3)	Observed temperature (°C)	Liquid density corrected to 15°C (kg/m^3) with hydrometer correction	Liquid density corrected to 15°C (kg/m^3) without hydrometer correction
11	525	92.5	614.2	614.9
12	412.5	11.4	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	661.3	661.5

Table 14.9. Volume correction test cases at equilibrium vapour pressure—volume correction to 15°C and equilibrium vapour pressure

	Inputs					Outputs				
Test case	Metered volume (m^3)	Density (kg/m^3) @ 15°C and EVP	Observed temp. (°C)	Observed pressure (kPag)	Equilibrium vapour pressure (kPa) @ observed temp.	CTL	CPL	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)	CTPL corrected volume (m^3) 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.

14.10 Measurement 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 Regulator. 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 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 12 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 on the EFM), printed, or handwritten media and retained for a minimum of 12 months. They must be produced upon request by the Regulator.

14.10.1 The Daily Report

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.

SK	Hours on production.
AB	Hours on production or hours of flow – specify either hours on production or hours on flow.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

14.10.2 The Monthly Report

The monthly report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

1. Monthly cumulative flow
2. Indications of any change made to volumes, and supporting documentation
3.

SK	Total hours on production for production or test meters only.
AB	Total hours on production or hours of flow - specify which hours are used. This applies only to production or test meters only.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

14.10.3 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 the change. In an EFM system this can 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:

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.

14.10.4 EFM Specific Reports

The following reports are required together with those in 14.11.1 and 14.11.3 where applicable.

14.10.4.1 The Daily Report

The following information must be recorded on a daily basis:

1. Meter identification
2. Daily accumulated flow
3.

SK	Hours on production or hours of flow for production or test meters only.
AB	Hours on production or hours of flow - specify which hours are used. This applies to production or test meters only.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

4. Production data audit trail—include at least one of the following:
    a. Instantaneous values for flow rate, operating pressure if it is applicable, and temperature taken at the same time each day
    b. Daily volume and average daily values for operating pressure if it is applicable and temperature
    c. Hourly accumulated flow rate and average hourly values for operating pressure if it is applicable and temperature

14.10.4.2 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 it is applicable
    d. Flowing temperature
    e. Flowing density
    f. Sediment and water content if an on-line S&W monitor is used
    g. CTL
    h. CPL
    i. 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 it is applicable

14.10.4.3 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:

1. Master terminal unit failures
2. Remote terminal unit failures
3. Communication failures
4. Low-power warning
5. High/low volumetric flow rate
6. Overranging of end device

15 Water Measurement

This section presents the requirements for measurement and reporting of water from oil and gas production, water source, water injection and disposal, waste processing and disposal, storage and disposal cavern, and thermal *in situ* schemes.

All liquid water produced at wellhead or group separator conditions is considered production and must be reported to Petrinex. Water that is in the vapour phase under these separator conditions must not be reported as production even if it drops out later in the gas system, refer to Section 15.2.1.6 for more details. Reported water volumes must be corrected to 15°C when so stipulated in this Directive. All sample analyses, test data, and test date records must be submitted to the Regulator upon request.

SK	For the purpose of this Directive, water types are: 1. Water 2. Fresh Water 3. Brine, see Section 15.2.9 Production of nonsaline water may require a groundwater diversion permit from the Water Security Agency.
AB	For the purposes of this Directive, water types are: 1. Water 2. Fresh Water 3. Brine 4. Brackish Water Water from a saline water source is considered as brackish (Product: BRKWTR) and water from a nonsaline water source (with total dissolved solids ([TDS]) less than 4000 milligrams per litre ([mg/L]) is considered as fresh. Production of nonsaline water may require a groundwater diversion permit under the *Water Act* from the AER. Contact ESRD for requirements or see its Groundwater Evaluation Guideline document for details.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

15.1 Base Requirements for Water Measurement, Volume Calculation, Production Data Verification, and Audit Trail

For general liquid measurement, inventory determination, liquid volume calculation, production data verification, audit trail, and EFM requirements, see Section 14.

For water meter proving method, see Sections 2.4 and 2.7.

The main difference between measurement of water and other hydrocarbon fluids is that the uncertainty limits are generally less stringent for water. See Sections 1.7.

15.2 Water Measurement and Accounting Requirements for Various Facility Types

15.2.1 Gas Facilities

The three methods for determining gas production for a gas well are separated gas measurement, effluent measurement, and gas proration. The requirements for determining water production vary among these three methods, and there are also some variations within each method.

15.2.1.1 Gas Single-Well Battery (Petrinex facility subtype: 351) or Gas Multiwell Group Battery (Petrinex facility subtypes: 361 in SK and 365 in AB)

Each gas well must have permanent separation facilities. Water production must be determined by one of the following methods:

1. Metering at the water leg of a three-phase separator;
2. Metering at the water/condensate leg of a two-phase separator and taking a sample of the liquid phase to determine the percent S&W and liquid hydrocarbon. Refer to Section 6.4.3 for more detail;
3. Directing water production to a tank and delivering by either truck or pipeline for disposition. The monthly production volume is then determined from the delivery volume measured by the receiving facility and tank inventory change by gauging the tank; or
4. Using a WGR if:
   a. a three-phase separator is used and the separated water is recombined with the metered gas and metered condensate at the well site in the same pipeline; or
   b. a two-phase separator is used and there is no condensate/oil.

15.2.1.2 Gas Multiwell Proration SW Saskatchewan and SE Alberta Battery (Petrinex facility subtype 363)

Water determination and reporting are not required inside SW Saskatchewan and SE Alberta shallow gas areas and stratigraphic units or zones at the well level. They are only required at the battery level. See Section 0 for more detail.

15.2.1.3 Gas Multiwell Proration Outside SW Saskatchewan and Outside SE Alberta Batteries (Petrinex facility subtype 364)

Outside SW Saskatchewan and SE Alberta shallow gas areas and stratigraphic units or zones that satisfy the proration requirements in Section 5.4, an individual well WGR may be used to determine water production volume. See Section 7.3 for more detail.

15.2.1.4 Gas Multiwell Effluent Measurement Battery (Petrinex facility subtype: 362)

Gas wells not configured with separation and measurement of each phase at the wellhead and at which all of the multiphase fluid passes through the same meter are subject to effluent or wet gas measurement. The water production volume is calculated based on the WGR. See Section 7.4 for ECF-WGR testing and actual well water production calculation requirements and Section 8.4.3 for sampling and analysis requirements.

15.2.1.5 Low-Pressure Gas Systems

If all wells at a gas battery operate at a pressure less than 350 kPa without any mechanical or other external means of water lifting used at any of the wells in the battery, operators may determine water production using one of the following methods:

1. Group WGR, which is determined by metering the group water production and dividing it by the group gas production on a monthly basis. The resulting WGR is then applied to all wells within the battery based on the wells' reported gas production to determine each well's reported water production; or
2. Engineering estimates based on the water vapour pressure at the well's flowing conditions, and other methods supported by good engineering practice.

15.2.1.6 Water at Gas Gathering System (GS) (Petrinex facility subtypes: 621 in SK and 621 and 622 in AB)

When water is received or disposed of from the gas gathering system, the volume must be measured and reported in accordance with the following requirements:

1. If there is no known source(s) of water coming into the gas gathering system, all collected water must be reported as water condensation on Petrinex as:

   Activity: REC
   Product: WATER
   From/To: ABWC or SKWC receipt

2. If there is some known source of water, any delivery volume over and above the known source of water delivered into the gas gathering system must be reported on Petrinex as ABWC or SKWC receipt. This applies when there are multiple single wells, gas group, and/or other facilities tied into the gas gathering system with commingled water.
3. If there is only a single-well battery or one proration battery as the upstream source of the produced water with no water measurement upstream of the disposition location, this location may be designated as the facility group measurement point at the battery, and all water collected can be used for reporting from the battery.
4. The gas gathering system must report receipt of water from any upstream facilities and report disposition if water is going through the gas gathering system to other facilities further downstream.

15.2.1.7 Gas Plants (Petrinex facility subtypes: 401 to 407)

Gas plant inlet water measurement is required at each inlet separator when the total receipt volume is > 50 m^3 per month for the entire plant. If there is only one inlet separator and no other source of water entering the plant, the plant water disposition plus inventory change may be used for inlet water reporting.

15.2.2 Crude 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 exceeds 50 m^3 per month and the water cut is in excess of 0.5 per cent of the total liquid production. The battery water disposition must be measured if over the 50 m^3 per month limit. The receiving 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. See Section 6.4.

15.2.2.1 Crude Oil Single-Well Battery (Petrinex facility subtype: 311) and Heavy Crude Oil Single-Well Battery (Petrinex facility subtype: 325 in SK only)

For an single-well battery trucking its emulsion off site, the water production volume is determined by the receiving facility plus the change in inventory when required. Refer to Section 14.8.1 for more details.

Exemption to Single-Well Battery Water Production Volume

If a single-well battery with a two-phase or three-phase separator is delivering produced oil/emulsions by pipeline to another battery and the water production does not exceed 50 m^3 per month, the water cut may be determined by taking three spot samples at intervals at least one week apart within the month and averaging the results. Refer to Section 14.8.1 for more details.

15.2.2.2 Crude Oil Multiwell Group Battery (Petrinex facility subtype: 321) and Heavy Crude Oil Multiwell Group Battery (Petrinex facility subtype: 326 in SK only)

Total water production from a multiwell group oil battery must be determined in the same way as from an oil single-well battery. Refer to Section 15.2.2.1 for more details.

15.2.2.3 Crude Oil Multiwell Proration Battery (Petrinex facility subtype: 322) and Heavy Crude Oil Multiwell Proration Battery (Petrinex facility subtype: 327 in SK only)

Water production from a multiwell proration oil battery is determined based on well testing and proration from the battery disposition volumes plus inventory change at month end. (see Sections 6.4 and 6.5.)

15.2.2.4 Heavy Crude Oil Paper Battery (Petrinex facility subtypes: 313 in SK and 343 in AB) and Crude Oil Multiwell Swab Battery (Petrinex facility subtypes: 314 and 316 in SK only)

SK	Total water production from a heavy crude oil paper battery or a crude oil multiwell swab battery must be determined in the same way as from an oil single-well battery. Refer to Section 15.2.2.1 for more details.
AB	Alberta does not use these facility subtypes.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

15.2.3 Water Source Production

Water produced from water source wells or other sources, such as rivers and lakes, must be continuously measured before commingling with water or fluids from another source. If a source well is producing gas, the related gas production must be separated and measured or estimated and reported.

15.2.3.1 Reporting Requirements

SK	1. Reporting on Petrinex must be under the SKWS facility subtype code 905 for oil and gas non-Regulator licensed surface water sources, such as rivers and lakes. If the water is delivered to a thermal *in situ* scheme, the water receipt must be reported at the injection facility and not the battery facility of the thermal *in situ* scheme. 2. For oil and gas Regulator licensed water source wells, reporting on Petrinex must be under the SKWI code and the applicable facility subtype code. If the water is produced from a fresh-water-bearing formation, the water is considered fresh water and reported under the SKWT facility subtype code 907. If the water is produced from a stratigraphic unit that is not fresh-water-bearing, the water is reported under the SKWT facility subtype code 906. If the water production is delivered to a thermal *in situ* scheme, the water receipt from the SKWS facility must be reported at the injection facility and not the battery facility of the thermal *in situ* scheme.
AB	1. Reporting on Petrinex must be under the ABWS code for oil and gas non-Regulator licensed water sources, such as rivers and lakes. If the production is delivered to a thermal *in situ* scheme, it must report disposition to the injection facility and not the heavy oil battery of the thermal *in situ* scheme. 2. For oil and gas Regulator licensed water source wells, reporting on Petrinex must be under the ABWI code for the well and the ABBT code with subtype 902 code for the battery, (either single or multiwell) or under the injection facility. If the production is delivered to a thermal *in situ* oil sands scheme, the well/battery must report disposition to the injection facility and not the heavy oil battery of the thermal *in situ* scheme. 3. For oil and gas Regulator licensed brine production being used for purposes other than the upstream oil and gas industry, see Section 15.2.9 for more details
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

Figure 15.1. Example of water source reporting setup for Alberta

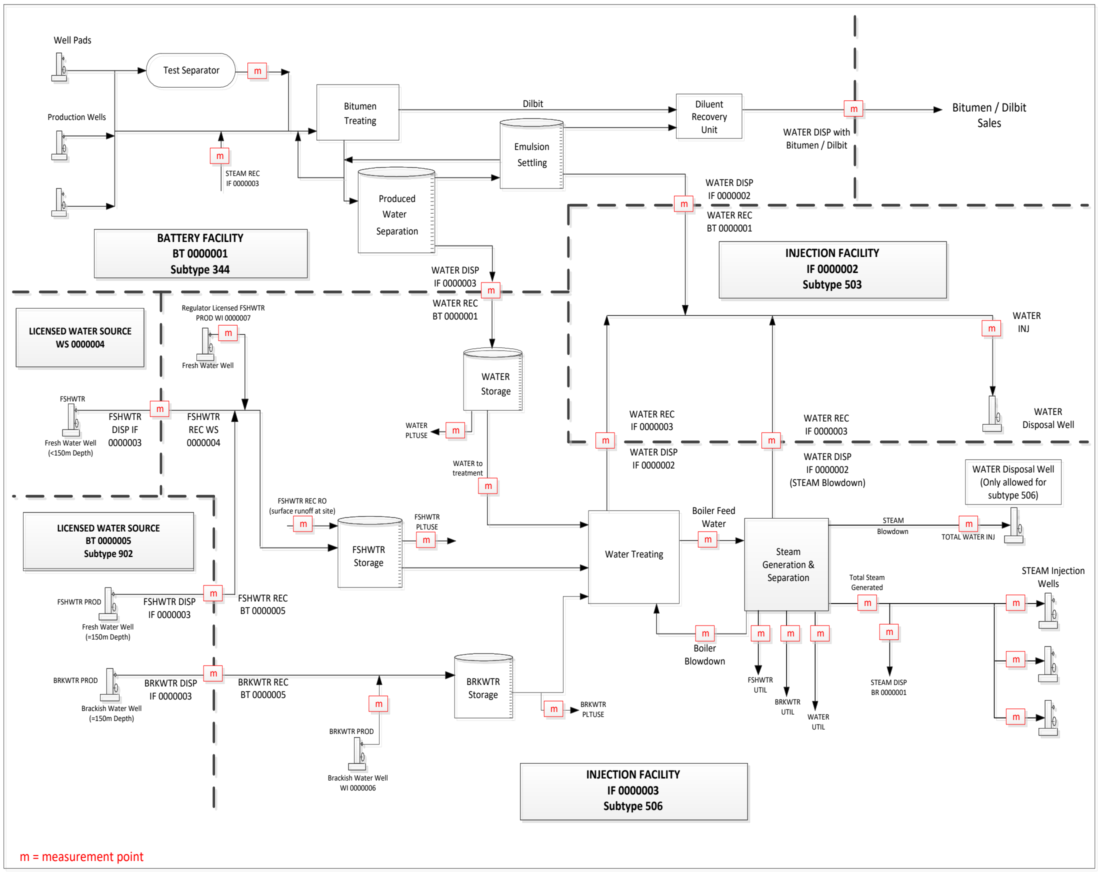
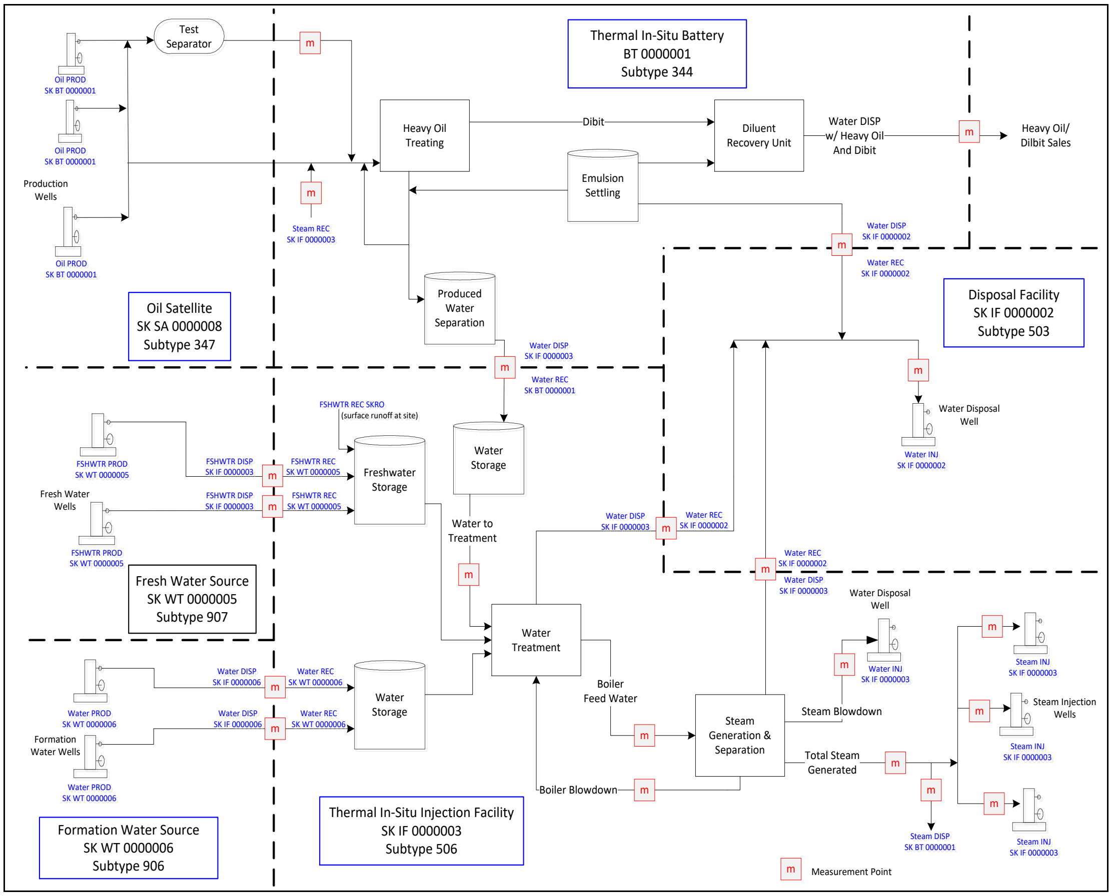


Figure 15.1. Example of water source reporting setup for Saskatchewan



15.2.4 Water Injection and Disposal Facility

Water injected into injection or disposal wells must be continuously metered at each wellhead at the injection site and used for reporting to Petrinex. Water injected into injection or disposal wells constructed prior to September 11, 2012 must be continuously metered into individual wells but may be metered at the injection facility or a field injection header if the meter is not located at the wellhead.

The acid gas injection/disposal measurement scenarios in Section 11.4.6.3 can also be applied to these types of wells, but injection and disposal wells cannot be in the same injection facility except for facility subtype 506. Each injection/disposal well may have its own injection facility reporting code or may be part of another injection facility. If there is more than one facility sending water to the injection facility, each receipt must be measured before commingling.

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. If the 1.0% skim oil limit is exceeded, the Regulator 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 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 facility.

15.2.5 Waste Processing and Disposal Facility

All products received at a waste processing facility must be measured, sampled, analyzed, and reported as oil, water, and solids according to the approval conditions. The disposal facility will auto-populate Petrinex with the source of oil and/or water including solids if the fluid is produced from an upstream oil and gas facility, such as tank bottom fluids.

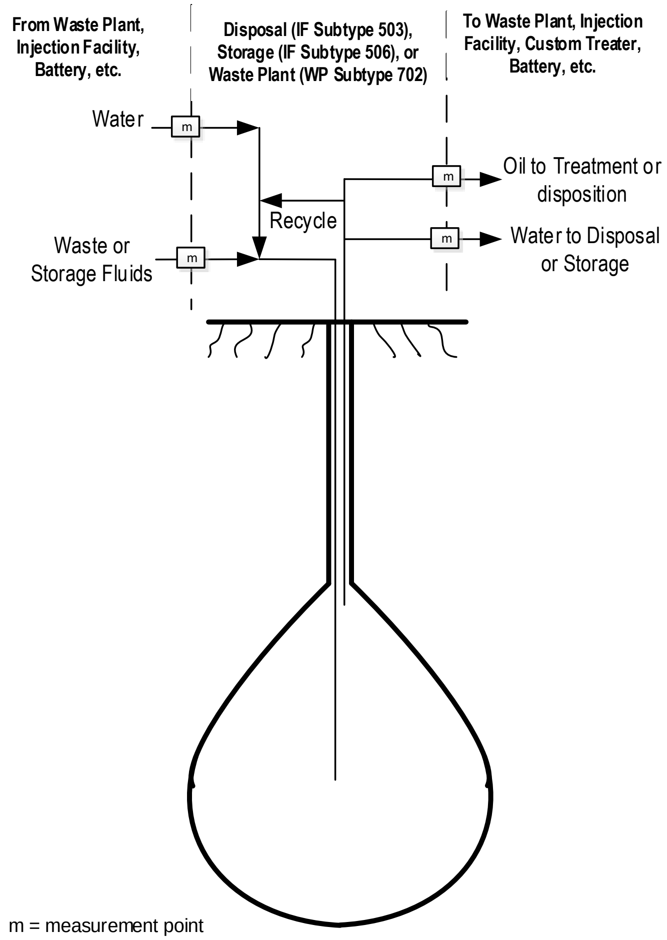
SK	There is no equivalent directive to AER's *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities*.
AB	See *Directive 047*: *Waste Reporting Requirements for Oilfield Waste Management Facilities* and *Directive 058: Oilfield Waste Management Facility Approvals—Notification and Amendment Procedures* for more details related to products received at a waste processing facility.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

15.2.6 Storage and Disposal Cavern

Each storage and disposal cavern must have its own inlet and outlet measurement system, reported as a separate facility on Petrinex from the cavern washing stage onwards, and maintain separate oil, water, and solids inventory.

SK	There is no equivalent directive to AER's *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities*.
AB	See *Directive 047*: *Waste Reporting Requirements for Oilfield Waste Management Facilities* and *Directive 058: Oilfield Waste Management Facility Approvals—Notification and Amendment Procedures* for more details related to products received at a waste processing facility. The operator must use the appropriate Petrinex subtype code for cavern reporting: 506 - associated with thermal *in situ* oil sands schemes 702 - associated with a waste processing facility 503 or 509 - other waste disposal schemes
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

Figure 15.2. Cavern measurement



15.2.7 Thermal In Situ Scheme (Petrinex facility subtype: 506)

Thermal *in situ* schemes use water to generate steam for injection into formations to produce heavy oil which is referred to as either heavy oil or bitumen in Alberta. The single point measurement uncertainty requirements for the critical measurement points have been tightened to facilitate water balancing, refer to Sections 12.3.2 through 12.3.4 for more details. The operator must use the Petrinex subtype code 506 for an injection facility, but a disposal facility can be a facility subtype 503 or part of the facility subtype 506. See Figure 15.1.

All steam volume is to be reported as cold water equivalent volume at 15°C.

15.2.8 Downhole Water Disposal or Injection

When water is separated from the gas down hole and injected into another stratigraphic unit or zone or formation without coming to surface, the water volume must be measured if it is > 50 m^3/month or estimated if it is ≤ 50 m^3/month.

15.2.9 Brine Measurement and Reporting (Petrinex facility subtype in AB: 903 and Petrinex facility subtype in SK: 518)

SK	This section presents the requirements for measurement and reporting of brine injection into potash disposal wells and only applies to Saskatchewan. The product BRINE is only reported at licensed disposal wells and injection facilities related to the potash industry. All brine injected into potash disposal wells must be reported to Petrinex. Reported brine volumes must be corrected to 15°C. Brine injected into disposal wells must be continuously metered at each wellhead at the injection site and used for reporting to Petrinex. Brine injected into disposal wells constructed prior to September 11, 2012 must be continuously metered into individual wells but may be metered at the injection facility or a field injection header if the meter is not located at the wellhead. For general liquid measurement, liquid volume calculation, data verification, audit trail, and EFM requirements, see Section 14. For brine meter proving method, see Sections 2.4 and Section 2.8. See Sections 1.7 for uncertainty limits.
AB	When only brine is produced from an oil and gas Regulator licensed well and is not used for any upstream oil and gas application, the well must be reported to Petrinex under a subtype 903 battery code. The production must be reported as BRKWTR from the well and also BRKWTR disposition to code ABMC.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

15.2.10 Load Water Reporting

Current Regulator load water reporting requirements state that when a well is put on production following load water injection, the water produced from the well must be reported into Petrinex as load water recovery until the entire volume of injected load water is recovered. After all of the load water has been recovered, the water produced from the well must be reported as water production.

In most cases, it is unlikely that all of the injected load water during a well completion operation will be recovered after the well is put on production; some load water will remain in the formation. Operators may, at their discretion, discontinue reporting load water recovery after a well has been on production for 12 months following load water injection. In this case, the operator would “zero out” the load water inventory using the load fluid inventory adjustment—LDINVADJ—activity in Petrinex. Water produced from the well after zeroing out the load water inventory must be reported as water production.

It is the responsibility of the licensee to ensure that fluids such as flow back, load fluid, and produced water are managed properly based on their composition (e.g., sent to an appropriate waste management facility or injection/disposal well, or treated and reused). Information regarding fluid management can be obtained from:

SK	The Field Services Branch.
AB	The Waste and Storage Authorizations Group.
BC	See *Measurement Guideline Upstream Oil and Gas Operations*

15.3 Water Gas Ratio (WGR) Testing Methodology

Well testing requirements are as follows:

1. A WGR test is required for a noneffluent well without continuous water measurement and other well water that is not separated and measured.
2. An ECF-WGR test is required for an effluent well. Refer to Section 7.4 for more details.
3. New wells must have the required tests conducted within the first 30 days of production and annually thereafter, unless otherwise stated or exempt, refer to Section 5.4 for more detail. If the operator 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 can have operation or production characteristics changed because of such events as workovers or chemical stimulations must have a test conducted within 30 days.

15.3.1 WGR Testing

The WGR test must be conducted using a properly sized three-phase separator with measurement of all phases as follows:

1. The test must begin only after a stabilization period.
2. The test duration must be a minimum of 12 hours.
3. If the well is occasionally slugging water, the test duration must be increased to ensure that the test is representative.
4. Consistent testing procedures must be used for consecutive tests to identify when a change in a well's flow characteristics has occurred.
5. The water volume must be measured by collecting it in a suitable container or by using a water meter.
6. The gas and condensate volumes must be measured.
7. The condensate must be sampled during every test and analyzed for the components to determine an updated gas equivalent factor. The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator. The water must be removed from the condensate before the analysis.
8. The test volumes and date for each test must be recorded.

9. The WGR must be determined by dividing the water volume by the sum of the measured gas volume and the gas equivalent volume (GEV) of the measured condensate. For more details refer to Section 7.3.2.
10. If 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. Other options that provide equivalent liquid volume accuracy may also be considered on a case-by-case basis by the Regulator.

15.3.2 WGR Calculation

WGR calculation for a gas multiwell battery is as follows:

5. Calculate the total monthly gas production volume.

   Total monthly well gas volume = Well measured gas volume + GEV of well measured condensate if recombined

6. Calculate the WGR for each well.

   The WGR is to be calculated to six decimal places and then rounded to five decimal places, as follows:

   WGR = Well test water volume ÷ (Well test gas volume + GEV of well test condensate if recombined)

7. Calculate actual water production for each well.

   Using the WGR, actual water production for the well is calculated as follows:

   Actual monthly well water volume = Total monthly well gas volume x WG

For gas multiwell proration batteries, refer to Section 7

Appendix 1 Documents Replaced Fully or Partially by *Directive PNG017: Measurement Requirements for Oil and Gas Operations*

Saskatchewan

Total Replacement (rescinded on date Directive PNG017 becomes effective):

Sections 78 through 82 of *The Oil and Gas Conservation Regulations, 2012*

Sections 84 through 87 of *The Oil and Gas Conservation Regulations, 2012*

PNG Guideline 17: Production Testing of Gas Wells

PNG Guideline 23: Monthly Gas Measurement Exemption – Oil Wells

MRO 37/85 - Individual Well Tests in Units – March 11, 1985

All special measurement exemptions granted by Minister's Order for certain designated pools

Alberta

Total Replacement (rescinded on date Directive 017 becomes effective):

Directive 004: Determination of Water Production at Gas Wells

Directive 049: Gas Density Measurement Frequency

Interim Directive (ID) 90-2: Gas Meter Calibration

ID 91-3: Clarification (May 2001): Heavy Oil/Oil Sands Operations

ID 94-1: Measurement of Oil, Gas & Water Production

Informational Letter (IL) 86-03: Automated Measurement Systems

IL 87-1: Compressibility Factors Used in Gas Volume Calculations and Physical Property Data for Natural Gases

IL 89-16: Guidelines for Automated Measurement System Applications, ERCB Guide G-34 Comparative Chart Data

IL 90-6: Measurement Guidelines—Trucked Oil Production

IL 91-9: Exemption from Gas Measurement Crude Oil/Bitumen Wells

IL 92-8: Crude Oil Pipeline Truck Terminal Measurement Guidelines

IL 92-9: Revised Reporting Procedures—Load Fluids

IL 93-1 Gas Density Measurement Frequency—Orifice Meter

IL 93-10 Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells

IL 94-7: Coriolis Force Flowmeters

Partial Replacement:

For sections in ILs, IDs, and directives that are no longer effective, see the documents on the AER website www.aer.ca:

Directive 046: Production Audit Handbook

Directive 060: Upstream Petroleum Industry Flaring Guide

Guide 34: Guidelines for Automated Measurement System Applications—Note that for those systems approved under *Guide 34*, the guide is still in effect.

ID 91-3: Heavy Oil/Oil Sands Operation

Appendix 2 Glossary

The definitions that follow are for the purposes of this Directive only.

Absolute Density – The mass per unit volume of a gas or liquid at a specific pressure and temperature. Absolute densities are generally expressed in kg/m³ at 101.325 kPa(a) and 15°C.

Accuracy – The ability of a measuring instrument to indicate values closely approximating the true value of the quantity measured.

Acid Gas – Gas separated out during the treating of sour gas to make a sweet gas stream and an acid gas stream that contains must higher concentration of hydrogen sulphide (H_2S), totally reduced sulphur compounds, or carbon dioxide (CO_2) than the process inlet stream.

Allocation Factor – A factor, that is used to correct the fluid receipt volumes (considered estimates) to actual volumes based on inventories and disposition measurements at facilities where only fluids received by truck are handled, such as custom treaters or terminals.

American Petroleum Institute – Is the source of many measurement standards in the oil and gas industry. (API Manual of Petroleum Measurement Standards).

Analog Transmitter – Transmitters that use analog circuity to convert their sensor output to either 4-20 milliamps or 1-5 volts.

Annually – Once every four calendar quarters (once a year).

API – see **A**merican **P**etroleum **I**nstitute.

(Source: Definition 20 on this web page: http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00451.html)

Approved – Written acceptance by the Regulator that has jurisdiction.

Associated Gas – Gas produced in association with oil production at oil wells. Commonly known as solution gas.

ATC – see Mechanical **A**utomatic **T**emperature **C**ompensators without Gravity selection.

ATG – see Mechanical **A**utomatic **T**emperature Compensators with **G**ravity selection.

Atmospheric Pressure – The pressure exerted by the weight of the atmosphere at the point of measurement.

BA ID – see **B**usiness **A**ssociate **Id**entifier.

Base Conditions – For Gaseous fluids are 101.325 kPa at 15°C and for liquids are 101.325 kPa at 15°C. Also known as standard conditions, stock tank conditions or reference conditions.

Base Pressure – Atmospheric pressure of 101.325 kPa

Base Temperature – 15.0°C

Battery

SK	Common storage facilities receiving production from a well or wells and includes equipment for separating the fluid into oil, gas, water and any other substances and for measurement. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	A system or arrangement of tanks or other surface equipment receiving the effluents of one or more wells prior to delivery to market or other disposition, and

	may include equipment or devices for separating the effluents into oil, gas or water and for measurement; (Source: *The Oil and Gas Conservation Act)*
BC	A system or arrangement of tanks or other surface equipment receiving the effluents of one or more wells prior to delivery to market or other disposition, and may include equipment or devices for separating the effluents into oil, gas or water and for measurement; (Source: *Drilling and Production Regulation)*

Bias – Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

Biennially – Once every eight calendar quarters (once every two years).

Bimonthly – Once every two calendar months.

Bitumen – Refer to the definition of Crude Bitumen.

Boiler Blowdown – Boilers used in thermal recovery processes typically produce steam with a quality between 75% and 80%. This results in 20% to 25% of the boiler feed water not being vaporized In steam-assisted gravity drainage (SAGD) schemes, the resulting liquid is separated from the steam. This separated water stream leaving the boiler is called blowdown and contains more concentrated total dissolved solids, typically 4 to 5 times more, than the boiler feed water.

Brackish Water

SK	The product Brackish Water (BRKWTR) is only used to accommodate cross border receipts from Alberta and should not be used in any other situations.
AB	Water from a saline water source with more than 4000 milligrams per litre (mg/L) of total dissolved solids.
BC	Undefined.

Brine

SK	A product, comprised of water saturated with salt, only reported at disposal wells and injection facilities related to the potash industry.
AB	Brine is not a product type for Petrinex reporting. Refer to brine well.
BC	Undefined.

Brine Well

SK	Does not apply in Saskatchewan.
AB	A well used to produce/inject water containing a high concentration of salts and associated with a cavern storage facility.
BC	Undefined.

Business Associate Identifier

SK	A unique five-digit identifier assigned to each corporate entity for use in Petrinex.
AB	A unique four-digit identifier assigned to each corporate entity for use in Petrinex.
BC	Undefined.

Butanes – A liquid mixture mainly of butanes that ordinarily may contain some propane or pentanes plus. For reporting purposes there are NC4-SP, NC4-MX, IC4-SP, and IC4-MX.

Calendar Quarter – January to March, April to June, July to September, October to December.

Calibration – The process or procedure of adjusting an instrument, such as a meter, so that its indication or registration is in satisfactory or close agreement with a reference standard. (Source: API MPMS)

Calibration Standard – A certified device used in calibration or proving that has a known value traceable to national reference standards maintained by the National Research Council in Ottawa, Ontario.

CBM – see **C**oal**b**ed **M**ethane

CF – see **C**orrection **F**actor.

CFM – see **C**omposite **M**eter **F**actor.

CGR – see **C**ondensate-**G**as **R**atio.

Clean Oil – Oil with 0.5% sediment and water or less.

Clean Oil Terminal – Terminals that receive trucked or pipelined clean oil.

Coalbed Methane – Natural gas that is found in coals.

CMF – see **C**omposite **M**eter **F**actor.

Cold Water Equivalent – Steam volume measurements corrected to a base temperature of 15°C and reported in cubic metres (m^3).

Common Crown or Freehold Royalty – When all the wells in a battery are produced:

1) under Crown mineral leases and the royalty status is the same for each well;
2) under leases granted by one Freehold mineral owner and the Freehold mineral owner receives the same royalty rate for each well; or
3) under leases granted by more than one Freehold mineral owner, and the total royalty rate for each owner for each well is the same.

Common Ownership – All wells in a battery 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.

Composite Meter Factor – A factor that is calculated by dividing the temperature corrected prover volume by the indicated meter volume for a prover run. The final CMF is often averaged from the results of multiple prover runs. The CMF includes corrections for the effects of any combination of temperature, pressure or shrinkage.

Compressibility (apparent) – The algebraic sum of the actual compressibility of a liquid and the volume change per unit of volume of the confining container caused by a unit change in pressure at a constant temperature.

Compressibility (liquid) – The change in volume per unit of volume of a liquid caused by a unit change in pressure at constant temperature.

Compressibility factor – The ratio of the actual volume of gas at a given temperature and pressure to the volume of gas when calculated by ideal gas law.

Compressibility – The property of a material which permits it to decrease in volume from the ideal state when subjected to an increase in pressure at constant temperature. (Source AGA)

For liquids, see Correction for Pressure and Liquid (CPL)

For gas, compressibility factor "Z" is the deviation from the ideal Boyle's and Charles' law behaviour.

Compressor Station – An installation of service equipment that receives natural gas from a well, facility, or gathering system prior to delivery to market or other disposition and is intended to maintain or increase the flowing pressure of the gas; includes any equipment for measurement.

Condensate

SK	A liquid hydrocarbon product with a density of ≤ 780 kg/m^3 that existed in the reservoir in a gaseous phase at original conditions and that is recovered from a gas stream when pressure and temperature are reduced to and not lower than those at base conditions.
AB	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that i. Is recovered or is recoverable at a well from an underground reservoir and may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated, ii. Is recovered from an *in situ* coal scheme and is liquid at the conditions under which its volume is measured or estimated (Source: *The Oil and Gas Conservation Act*)
BC	A mixture mainly of pentanes and heavier hydrocarbons, which may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured. (Source: *Measurement Guideline for Upstream Oil and Gas Operations*)

Condensate, Separator Liquids – Separator liquids are a mixture of hydrocarbon components that remain in a liquid state under the equilibrium pressure and temperature conditions established in a two-phase or three-phase separator. The composition and physical properties of separator liquids are highly variable and are a function of separator inlet fluid composition and separator pressure and temperature conditions.

Condensate, Stock Tank Liquids – Stabilized liquids are a mixture of hydrocarbon components that remain in the liquid state following single-stage flash evaporation. Stabilized condensate is expected to have low concentrations of light ends (C_1-C_4) components. The composition and physical properties of the stabilized condensate is a function of the equilibrium pressure and temperature conditions of the stabilizer and the composition of the stabilizer feed from which it was derived.

Condensate-Gas Ratio – Is calculated by dividing the condensate volume by the gas volume of a well test. See Table 7.1. for calculation and rounding requirements.

Condensate Proration Factor – Total battery measured daily or monthly condensate volume divided by total battery estimated daily or monthly condensate volume. See Sections 7.3.2 and 7.4.2.

Continuous Stack Emission Monitor – A device that measures sulphur stack emissions at a sour gas processing facility. In Alberta, the volume measured is reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report.

Continuous Measurement – Uninterrupted measurement

Correction Factor – A correction factor is any mathematical adjustment made to take into account deviations in volume related to temperature or pressure in either the sample or the measured volume. It must be determined in accordance with API MPMS, Chapter 11.

Crude Bitumen

SK	Undefined.
AB	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well. (Source: *The Oil and Gas Conservation Act*.)
BC	Undefined.

Crude Oil

SK	Crude petroleum oil and any other hydrocarbon, regardless of density, that is or is capable of being produced from a well in liquid form, but does not include condensate. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	A mixture of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen. (Source: *The Oil and Gas Conservation Act*)
BC	See “Oil”

Crude Oil Swab Well – A well without downhole production tubing, mechanical lift and well control equipment. Production occurs through the lifting of well liquids by a device installed on a wireline.

CSEM – see **C**ontinuous **S**tack **E**mission **M**onitor.

CSS – see **C**yclic **S**team **S**timulation.

CTL – see **C**orrection for the effect of **T**emperature on **L**iquids.

Custody Transfer Point – The point where legal and commercial transfer of production physically or is deemed to occur. Every physical custody transfer point is always a delivery point. In Saskatchewan, this custody transfer point is different than the Petrinex custody transfer point which generates a pipeline split.

Custom Treater – A system or arrangement of tanks and other surface equipment receiving oil or water emulsion exclusively by truck for separation prior to delivery to market or other disposition.

CWE – see **C**old **W**ater **E**quivalent.

Cyclic Steam Stimulation – A thermal enhanced oil recovery process where alternate cycles of steam injection and oil production are conducted in a reservoir through the same wellbore.

DCS – see **D**istributed **C**ontrol **S**ystem.

Dead Oil – Oil not containing any entrained or formation gas and stabilized to ambient conditions.

Dead Oil Meters – Dead oil meters are typically those used for delivery point or custody transfer point measurement of hydrocarbon liquids that has been degassed to ambient conditions.

Deemed Dry Production – Applies to gas effluent wells that qualify for testing exemption based on the effluent testing decision tree. This includes wells that are categorized within a stratigraphic unit or zone-based effluent testing exemption where the average liquid gas ratio results of testing are less than 0.056 $m^3/10^3m^3$.

Dehydrator – An apparatus designed and used to remove water from raw gas.

Delivery Point

SK	The points at which the production or disposition of hydrocarbon liquid or gas from a facility is measured. Every physical custody transfer point is always a delivery point. A delivery point is not always a custody transfer point. See Section 1 for further information.
AB	The points at which the disposition of hydrocarbon liquid or gas from a facility is measured. The volumes at this point are typically used in royalty calculations (royalty trigger point). Every physical custody transfer point is always a delivery point. A delivery point is not always a custody transfer point. See Section 1 for further information.
BC	The point at which the delivery of oil or gas production from a battery/facility is measured. The volumes determined at this point are typically used in royalty calculations (royalty trigger points), such as sales, cross border, gas plant to battery/facility, or gas plant to gas plant meters. (Source: Measurement Guideline for Upstream Oil and Gas Operations)

Delivery Point Measurement – The level of measurement uncertainty required at a delivery point.

Dew Point – The temperature at any given pressure at which liquid initially condenses from a gas or vapour. It is specifically applied to the temperature at which water vapour starts to condense from a gas mixture (water dew points) or at which hydrocarbons start to condense (hydrocarbon dew point). (Source AGA Definitions).

Digital (Smart) Transmitter – Transmitters which contain a microprocessor that is used for digital signal processing and calculation purposes. The calculations apply factory characterization of the sensor calibration and dynamic compensation for the other process and the environmental effects to the sensor output.

Dilbit – Diluted bitumen or heavy oil that will satisfy the pipeline specifications for transportation, for example viscosity ≤ 350 centistoke (cSt).

(Source: *Properties of Dilbit and Conventional Crude Oils, Alberta Innovates – Technology Futures, February 2014*)

Dilbit Blends – Blends made from bitumen or heavy oil and a diluent, usually condensate, for the purpose of meeting pipeline viscosity and density specifications.

Diluent – Hydrocarbon such as condensate or C_5-SP blended with oil to meet pipeline viscosity and density targets.

Dilution Gas – Typically fuel gas used to provide adequate fuel for incineration or flaring of acid gas.

Distributed Control System – A control system for a process or plant, wherein control elements are distributed throughout the system. This is in contrast to non-distributed systems, which use a single controller at a central location.

Dry Gas – Natural gas without free liquid as per contract conditions consists of little more than methane, producing little condensable heavier hydrocarbon compounds such as propane and butane when brought to the surface.

Effluent – Commingled well production that may contain a mixture of hydrocarbon liquids and gas or water in the stream.

Effluent Measurement – The metering of effluent without separation.

EFM – see **E**lectronic **F**low **M**easurement.

Electronic Flow Measurement – Any flow measurement and related system that collects data and performs flow calculations electronically. For more information, reference API MPMS 21.1 and 21.2.

Emulsion – A combination of two immiscible liquids, or liquids that do not mix together under normal conditions.

End Device – The device or equipment that records the various values used to calculate a volume such as a chart recorder or EFM system. In the scenario of an EFM system, the end device may also perform the calculations necessary to arrive at the measured and corrected gas volume.

Equilibrium Vapour Pressure – The pressure at which a liquid and its vapour are in equilibrium at a given temperature. When a hydrocarbon liquid has an EVP above the standard pressure (101.325 kPa at 15˚C), the EVP at 15˚C is the pressure base.

Equity

SK	See common ownership and common royalty.
AB	Refers to the proportional distribution of working interest participation among a group of wells or commingled oil or gas stream.
BC	Undefined.

Error – The difference between true and observed values. For more information, see ISO 5168 and ASME MFC 2M.

Error (random) – An error that varies in an unpredictable manner when a large number of measurements of the same variable are made under effectively identical conditions.

Error (spurious) – A gross error in procedure for example, human errors or machine malfunctions

Error (systematic) – An error that in the course of a number of measurements made under the same conditions on material having the same true value of a variable either remains constant in absolute value and sign or varies in a predictable manner. Systematic errors result in a bias.

Estimate – The approximation of a value based on documented and traceable methodologies, calculation, based on adequate knowledge of applicable facility processes, metering technology, measurement principles and hydrocarbon and water physical properties.

Ethane – A mixture mainly of ethane that ordinarily may contain some methane or propane. Petrinex reporting product types are C2-SP (pure ethane) and C2-MX (mixture of ethane and propane and other products).

(Alberta Source: *The Oil and Gas Conservation Act*)

EVP – see **E**quilibrium **V**apour **P**ressure.

Exemption – Circumstances under which if specific qualifying criteria are met or approval is granted, measurement devices or procedures are allowed to deviate within specified limits from base measurement requirements.

Facility

SK	Any building, structure, installation, equipment or appurtenance that is connected to or associated with the recovery, development, production, storage, handling, processing, treatment or disposal of oil, gas, water, products or other substances, that are produced from or injected into a well, but does not include a pipeline. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	Any building, structure, installation, equipment or appurtenance over which the Regulator has jurisdiction and that is connected to or associated with the recovery, development, production, handling, processing, treatment or disposal of hydrocarbon-based resources, including synthetic coal gas and synthetic coal liquid, or any associated substances or wastes or the disposal of captured carbon dioxide and includes, without limitation, a battery, a processing plant, a gas plant, an oilfield waste management facility, a central processing facility as defined in the rules made under the *Oil Sand Conservation Act*, a compressor, a dehydrator, a separator, a treater, a custom treating plant, a produced water disposal plant, a miscible flood injection plant, a satellite or any combination of any of them, but does not include a well, a pipeline as defined in the *Pipelines Act*, a mine site or processing plant as defined in the rules made under the *Oil Sands Conservation Act* or mine site or coal processing plant as defined in the *Coal Conservation Act*. (Source: *The Oil and Gas Conservation Act*)
BC	Means a system of vessels, piping, valves, tanks and other equipment that is used to gather, process, measure, store or dispose of petroleum, natural gas, water or a substance referred to in paragraph (d) or (e) of the definition of "pipeline"; (Source: *The Oil and Gas Act*)

Facility Subtype

SK	See *Directive PNG032: Volumetric, Valuation and Infrastructure Reporting in Petrinex* (formerly known as Directive R01)

AB	See Manual 011: How to Submit Volumetric Data to the AER
BC	To be determined

FDC system – see **F**ield **D**ata **C**apture system.

Field Condensate – Products obtained from natural gas or solution gas before they are delivered to a gathering system. Typically, Field Condensate is a hydrocarbon liquid separated from raw production at a well or a group measurement point, stabilized in a tank, and sold or otherwise disposed of without further processing before entering a gas gathering system.

(Alberta Source: *Natural Gas Royalty Regulations, 2002, AR 220/2002 (NGRR)*, under the *Mines and Minerals Act*)

Field Data Capture System – A system collects well and facility data about production activities including:

a. Meter readings and estimates
b. Production and test hours.
c. Calculated proration factors and metering differences.
d. Pressure and temperature readings.
e. Downtime hours and reasons.
f. Downtime hours and reasons.

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, that must be reported as flare gas include the following:

- Acid gas (routine and non-routine);
- Blanket gas, purge gas, or sweep gas;
- Dilution and make-up gas added to a flare gas stream before flaring or incineration;
- Gas from dehydrator still columns;
- Gas produced during well completions;
- Gas produced during well unloading operations;
- Gas that is flared or incinerated as a result of equipment failures or plant upsets;
- Gas used to operate pneumatic devices (instruments, pumps and compressors starters);
- Pilot gas; and
- Waste gas

Flow Computer – A device that calculates and/or compensates the flow or volume based on the meter flow variables. This can be integral to the metering system or completely separate. Examples include, but not limited, are RTU, DCS, or a Net Oil Computer (NOC).

Flow Meter - A device used to measure the mass or volumetric flow rate or quantity of a liquid or a gas moving through a pipe.

Fresh Water

SK	"fresh-water-bearing formation" means a permanent subsurface water bearing formation with a significant volume of recoverable water that has total dissolved solid concentrations of less than 4 000 milligrams per litre; (Source: *The Oil & Gas Conservation Regulations, 2012*)
AB	Non saline water with total dissolved solids (TDS) less than 4000 milligrams per litre (mg/L).
BC	Undefined.

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:

- Catalytic heaters and other building heaters;
- Engines;
- Line heaters;
- Process vessel burners;
- Sulphur recovery unit reaction furnaces; and
- Thermoelectric generators.

Fugitive Emissions – Unintentional release of hydrocarbons to the atmosphere.

Gas

SK	Natural gas, both before and after it has been subjected to absorption, purification, scrubbing or other treatment or process, and includes all liquid hydrocarbons other than oil and condensate. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	Raw gas, synthetic coal gas or marketable gas or any constituent of raw gas, synthetic coal gas, condensate, crude bitumen or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated. (Source: *The Oil and Gas Conservation Act*)
BC	Raw gas or marketable gas or any constituent of raw gas, condensate, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated. (Source: Measurement Guideline for Upstream Oil and Gas Operations)

Gas Battery – A battery for single or multiple gas wells where production is measured or prorated. Gas batteries include single-well batteries, multiwell group batteries, effluent batteries, and multiwell proration batteries.

Gas Chromatograph – An analytical instrument that separates a gas sample into its components and then measures the amount of each separated component. This information is used to determine gas composition for calculating energy content, relative density (specific gravity), compressibility and other related parameters.

Gas Equivalent Factor – 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.

Gas Equivalent Volume – The volume of gas (10^3m^3) that would result from converting 1 m^3 of liquid into a gas by applying a GEF to the liquid volume.

Gas Fractionation Plant – A gas plant that reprocesses natural gas liquids into one or more in-stream components.

Gas Gathering System – A reporting entity that may consist of pipelines used to move gas production from oil batteries, gas batteries, or other facilities to another facility, such as a gas plant. This may include compressors, line heaters, dehydrators, measurement, and other equipment.

Gas in Solution – Gas dissolved in liquid under pressure.

Gas Meter – Broadly used to describe all the equipment or devices that are collectively used to arrive at an indication of a gas volume.

Gas-Oil Ratio – The ratio of the number of cubic metres of gas produced from a given source in a given period to the number of cubic metres of oil produced from that source in that period.

Gas Plant – A system or arrangement of equipment used for the extraction of hydrogen sulphide, helium, ethane, natural gas liquids, or other substances from raw gas or natural gas liquids.

SK	A system or arrangement of equipment used for the extraction of H_2S, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigerant, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of non-regenerative scavenging chemicals that generate no H_2S or SO_2. (Source: *Directive S10* under “gas processing plant”)
AB	Does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process, for example refrigeration and desiccant. In addition, does not include an arrangement of equipment that removes small amounts of sulphur less than 0.1 tonne/day through the use of non-regenerative scavenging chemicals that generate no hydrogen sulphide or sulphur dioxide. (Source: *Directive 056* under “gas processing plant”)
BC	A facility for the extraction from natural gas of hydrogen sulphide, carbon dioxide, helium, ethane, natural gas liquids or other substances, but does not include a facility that (a) uses, for the exclusive purpose of processing low-volume fuel gas, (i) 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; (Source: *Drilling and Production Regulation)*

Gas Well

SK	Means: (i) a well that is capable of producing gas not associated with oil at the time of production; (ii) that part of a well in which the gas-producing stratigraphic unit or zone is successfully segregated from the oil and in which gas is produced separately from the oil; (iii) a well from which gas is or is capable of being produced from a reservoir in association with no more than one cubic metre of oil for every 3 500 cubic metres of gas produced from the reservoir; or (iv) any other well that may be classified by the minister pursuant to clause 17(1)(l) of the Act as a gas well for the purposes of the Act and these regulations; (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	Means: (i) a well that produces primarily gas from (A) a pool or portion of a pool in which the hydrocarbon system is gaseous or exhibits a dew point on reduction of pressure, or (B) coal by *in situ* gasification, and (ii) any well designated as a gas well by the Regulator; (Source: *Oil and Gas Conservation Rules*)
BC	Means: a well in which casing is run and that, in the opinion of the commission, is producing or is capable of producing from a natural gas bearing zone; (Source: *Drilling and Production Regulation*)

GEF – see **G**as **E**quivalent **F**actor.

GEV – see **G**as **E**quivalent **V**olume.

GIS – see **G**as **I**n **S**olution.

Good Production Practice

SK	Production of oil or gas from a well at a rate not governed by an allowable rate of production but limited to what can be produced on the basis of technical parameters without adversely and significantly affecting: (i) the ultimate recovery of oil or gas; or (ii) the opportunity of other owners to obtain their share of production from the pool; (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	Production of crude oil or raw gas at a rate • not governed by a base allowable, but • limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production. (Source: *Oil and Gas Conservation Rules*)
BC	Undefined.

GOR – see **G**as-**O**il **R**atio

GPP – see **G**ood **P**roduction **P**ractice.

Heavy Oil – Crude oil having a density ≥ 920 kg/m^3 at 15°C.

High Vapour Pressure Liquids – Any hydrocarbon and stabilized hydrocarbon mixture with a Reid Vapour Pressure greater than 14 kilopascals (Source: *Oil and Gas Conservation Rules*)

Hydrocarbon Liquid – A fluid in the liquid state that primarily consist of one or more of the following: oil, bitumen, condensate, ethane, propane, butane, pentane, or other heavier hydrocarbon compounds.

Industry Technical Standards Association – An industry- and Regulator-recognized technical association that develops and publishes upstream oil and gas measurement standards and procedures. Organizations include

- the American Petroleum Institute,
- the American National Standards Institute,
- the American Gas Association
- the Gas Processors of America,
- the Internationals Standards Organization, and
- Measurement Canada

Injection/Disposal Facility – A system or arrangement of surface equipment associated with the injection or disposal of any substance through one or more wells.

In Situ Operation – A scheme or operation ordinarily involving the use of well production operations for the recovery of crude bitumen from oil sands, or a scheme or operation designated by the Regulator as an *in situ* operation, but does not include a mining operation.

ISO – see **I**nternational **S**tandard **O**rganization

Internal Inspection – A visual inspection of the condition of the internal components of a primary element. The internal components must be removed from service, inspected, replaced or repaired if found to be damaged, and then placed back in service in accordance with this Directive.

International Standard Organization – ISO (International Organization for Standardization) is an independent, non-governmental membership organization and the world's largest developer of voluntary International Standards.

KF – see **K**-**F**actor.

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**.**

KPa – Common multiple units of the pascal are the hectopascal (1 hPa ≡ 100 Pa) which is equal to 1 mbar, the kilopascal (1 kPa ≡ 1000 Pa), the megapascal (1 MPa ≡ 1,000,000 Pa), and the gigapascal (1 GPa ≡ 1,000,000,000 Pa). Standard atmospheric pressure is defined as 101.325 kPa.

LACT – see **L**ease **A**utomatic **C**ustody **T**ransfer.

Lease Automatic Custody Transfer – An arrangement of equipment that measures the net volume and quality of liquid hydrocarbons. This system provides for the automatic measurement, sampling, and transfer of oil from the lease location into a pipeline. A system of this type is applicable where larger volumes of oil are being produced and must have a pipeline available in which to connect.

Legal Survey Location

SK	Is used to identify the location of land parcels in Western Canada. The Legal Survey Locations are based on the Dominion Land Survey (DLS) which is the method used to divide most of Western Canada into one-square-mile (2.6 km^2) sections for agricultural and other purposes.
AB	Is used to identify the location of land parcels in Western Canada. The Legal Survey Locations are based on the Dominion Land Survey (DLS) which is the method used to divide most of Western Canada into one-square-mile (2.6 km^2) sections for agricultural and other purposes.
BC	NTS and the Legal Survey Locations are based on the Dominion Land Survey (DLS) and NTS. DLS which is the method used to divide most of Western Canada into one-square-mile (2.6 km^2) sections for agricultural and other purposes. NTS which is the method used to divide British Columbia into grid areas, blocks and units.

LGR – see **L**iquid to **G**as **R**atio.

Licensee – The holder of a license according to the records of the Regulator and includes a trustee or receiver-manager of property of a licensee.

(Alberta Source: *The Oil and Gas Conservation Act*)

Light Oil – Oil with a density less than 870 kg/m^3 at 15°C

Liquefied Petroleum Gas – LPG consists primarily of propane (C_3) and butane (C_4) in a mixture or essentially pure form, with minor components ranging from ethane (C_2) to normal hexane (C_6). It is produced either as a by-product of natural gas processing or during refining and processing operations.

Liquid to Gas Ratio – A ratio calculated by dividing the total water and/or condensate test volumes by the measured test gas volume.

Live Oil – Oil containing mainly pentanes and heavier hydrocarbons that may also contain lighter hydrocarbons with entrained or formation gas, and is not in a stabilized form. Live oil is commonly measured at the wellhead or facility.

Live Oil Meters – Live oil meters are typically those used to measure volumes of oil or oil/water emulsion that are not stabilized.

Load Fluids – Any hydrocarbon- or water-based fluids used at any stage in the life of a well including completion, servicing, regular operation, or abandonment. It includes fluids injected into a flowline between a well and the battery to which it produces, e.g., hot oil, dewaxing chemicals.

Load Oil – Hydrocarbon-type fluids used as load fluid, including crude oil, condensate, refined oils, and oil-based or oil-soluble chemicals.

Load Water – Water-type fluids used as load fluid, including produced, fresh or brackish water and water-based or water-soluble chemicals.

LPG – see **L**iquefied **P**etroleum **G**as.

Makeup Gas – Raw or processed gas that is added to another gas stream in order to maintain an adequate heating value during flaring or incineration.

MARP – see **M**easurement, **A**ccounting, and **R**eporting **P**lan.

Master Meter – A meter of known accuracy that is temporarily connected in series with another meter for the purpose of proving the accuracy of that meter and providing a meter factor.

Maximum Uncertainty of Monthly Volume – Relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume.

MbD – see **M**easurement **b**y **D**ifference

Measured Gas Source(s) – Single-phase measured gas source(s) downstream of separation and removal of liquids and also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined after measurement with the gas downstream of the separator.

Measurement – In an oil and gas industry context, the principal measurement technologies and procedures are:

1. Meters for determining flow volumes.
2. Calculated volumes using a proration formula based on test volumes.
3. Estimates of volumes based on production facility and product characteristics.
4. Scales for samples and vehicles.
5. Gauge boards for tanks.
6. Gauges for temperature and pressure.

Measurement, Accounting, and Reporting Plan

SK	Defined in Saskatchewan *Directive PNG042: Measurement, Accounting and Reporting Plan (MARP) Requirement for Thermal In-Situ Recovery Projects.*
AB	Defined in *AER Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirement for Thermal Bitumen Schemes.*
BC	Not Applicable

Measurement by Difference – Any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes.

Measurement Canada – An agency of Industry Canada that is responsible for ensuring businesses and consumers receive fair and accurate measure in financial transactions involving goods and services. The agency develops and administers the laws and requirements governing measurement; evaluates, approves and certifies measuring devices; and investigates complaints of suspected inaccurate measurement.

Measurement Schematic – A diagram used to show the actual layout of facilities that traces the normal flow of production from left to right as it moves from wellhead through to sales.

Medium Oil – Oil with a density between ≥ 870 and < 920 kg/m^3 at 15°C

Meter (noun) – See Flow Meter.

Meter (verb) – To measure using a flow meter.

Meter Element – There are three types of meter elements: primary, secondary, and tertiary.

1. Primary element – the internal components of the meter and associated meter tube that establishes the flow variables e.g., orifice, meter plate, shedder bar, or venturi.
2. Secondary element – the part of the meter that senses and records the flow variables, e.g., chart recorder or transmitter.
3. Tertiary element – flow computer that calculates the flow and volume.

Meter Factor – A dimensionless term obtained by dividing the volume of gas or liquid passed through a prover (as measured by the prover during proving) by the corresponding meter indicated volume. A further correction could be required for pressure and temperature.

Metering Difference – Any difference that occurs between the measured inlet or receipt volumes and the measured outlet or disposition volumes at a facility.

Meter Run – A flow meter installed and calibrated in a section of pipe having adequate upstream and downstream pipe lengths to create stable flow.

Methane – A mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

(Alberta Source: *The Oil and Gas Conservation Act*).

MF – see **M**eter **F**actor.

Monthly – Once per calendar month.

MPMS – American Petroleum Institute's **M**anual of **P**etroleum **M**easurement **S**tandards.

Multiphase Fluid – Unseparated fluid that contains liquids, gases and or solids in a single stream.

Natural Gas Liquid – Includes propane, butanes or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

(Alberta Source: *The Oil and Gas Conservation Act*)

Net Standard Volume – The gross standard volume corrected for shrinkage and non-merchantable quantities such as sediment and water.

NGL – see **N**atural **G**as **L**iquid.

Non-Heavy Oil – Crude oil having a density of ≤ 920 kg/m^3 at 15°C.

NSV – see **N**et **S**tandard **V**olume.

OGR – see **O**il-**G**as **R**atio.

Oil

SK	Crude petroleum oil and any other hydrocarbon, regardless of density, that is or is capable of being produced from a well in liquid form, but does not include condensate. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	Condensate, crude oil or synthetic coal liquid or a constituent of raw gas, condensate or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated. (Source: *The Oil and Gas Conservation Act*)
BC	Crude petroleum and all other hydrocarbons, regardless of gravity, that are or can be recovered in liquid from a pool through a well by ordinary production methods or that are or can be recovered from oil sand or oil shale. (Source: *Petroleum and Natural Gas Act* defined as "Petroleum")

Oil Battery – A battery for single or multiple crude oil wells where production is measured or prorated. Oil batteries include single-well batteries, multiwell group batteries, and multiwell proration batteries.

Oil-Gas Ratio – Is calculated by dividing the oil volume by the gas volume of a well test. See Table 7.1. for calculation and rounding requirements.

Oilfield Waste

SK	Physical waste as that term is ordinarily understood in relation to the activities of the oil and gas industry, but does not include physical waste. (Source: *The Oil and Gas Conservation Act*)
AB	An unwanted substance or mixture of substances that results from the construction, operation, abandonment or reclamation of a facility, well site or pipeline, but does not include an unwanted substance or mixture of substances from such a source that is received for storage, treatment, disposal or recycling at a facility that is regulated by the Department of Environment and Sustainable Resource Development. (Source: *Oil and Gas Conservation Rules*)
BC	Undefined

Oilfield Waste Management Facility (OWMF)

SK	Undefined.
AB	A facility, the operation of which is approved by the Regulator, including, without limitation, a waste processing facility, a waste storage facility, a waste transfer station, a surface facility associated with a disposal well, a biodegradation facility, an oilfield landfill, a thermal treatment facility and any other facility for the processing, treatment, storage, disposal or recycling of oilfield waste. (Source: *Oil and Gas Conservation Rules*)
BC	Undefined

Oil Sands

SK	All sands and rocks that: Contain a highly viscous mixture, composed mainly of hydrocarbons heavier than pentanes, that will not normally flow, in its natural state, to a wellbore; Lie above the top of the Devonian System; and Lie north of Township 73 (Source: *The Crown Oil and Gas Royalty Regulations, 2012*)
AB	Means: Sands and other rock materials containing crude bitumen, The crude bitumen contained in those sands and other rock materials, and Any other minerals substances, other than natural gas, in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (Source: *The Oil and Gas Conservation Act)*
BC	Sand or other petroliferous substance from which oil sand products can be produced and includes any other substance defined by the Lieutenant Governor in Council as oil sand (Source: *Petroleum and Natural Gas Act*)

Oil Well

SK	Any well capable of producing oil other than a gas well. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	A well that produces primarily liquid hydrocarbons from a pool or portion of a pool wherein the hydrocarbon system is liquid or exhibits a bubble point on reduction of pressure, or any well so designated by the AER.
BC	Defined as "petroleum well" means a well in which casing is run and that, in the opinion of the commission, is producing or is capable of producing from a petroleum bearing zone. (Source: *Petroleum and Natural Gas Act)*

Operator

SK	Means: A person who, as owner, licensee, lessee, sublessee or assignee, has the right to carry on drilling, construction, operation, decommissioning or abandonment of a well or facility and the reclamation of the well or facility site; A contractor who on behalf of the person mentioned in subclause (i) engages in any of the activities described in that subclauses; or The person designated by the minister as the operator of the well or facility. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	With respect to a well or facility, means a person who Has control of or undertakes the day to day operations or activities at a well or facility, or Keeps records and submits production reports for a well or facility to the Regulator, Whether or not that person is also the licensee or approval holder is respect of the well or facility; (Source: *The Oil and Gas Conservation Act*)
BC	A common term for "permit holder" or “producer” which means: (a) a person who holds a permit, and (b) a person, if any, who is the holder of a location with respect to that permit or "producer" means (a) a holder of a location who markets or otherwise disposes of petroleum, natural gas or both produced by (i) the holder of the location, or (ii) a person authorized to produce the petroleum, natural gas or both by the holder of the location, and

	(b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder's behalf, petroleum, natural gas or both. (Source: *The Oil and Gas Activities Act*)

P&ID – see **P**iping and **I**nstrumentation **D**iagram.

PD Meter – see **P**ositive **D**isplacement **M**eter.

Pentanes Plus – A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and that is obtained from the processing of raw gas, condensate or crude oil.

(Alberta Source: *The Oil and Gas Conservation Act*)

Petrinex – A centralized web based shared computer system that hosts and disseminates upstream well and facility volumetric data for government regulator and industry operator stakeholders. Each month industry operators load volumetric data for the wells and facilities they operate into Petrinex and it is then available to the Regulators and industry operators for their specific needs. Petrinex also includes the Enhanced Production Audit Program (EPAP) for both Saskatchewan and Alberta, Oil Valuation in Saskatchewan only, and other functionality. Petrinex was developed and is administered jointly by the Regulators and industry operators.

PFD – see **P**rocess **F**low **D**iagram.

Pipeline

SK	Means (i) a pipe or system of pipes for the transportation of: a. Liquid hydrocarbons, including crude oil, multiphase fluids containing hydrocarbons, oil and water emulsions, condensate, liquid petroleum products, natural gas liquids and liquefied petroleum gas; b. Gaseous hydrocarbons, including natural gas, manufactured gas and synthetic gas; c. Water, steam or any other substance where the water, steam or other substance is incidental to or used in the production of crude oil or natural gas; or d. Carbon dioxide; (ii) includes any of the following that are incidental to or used in connection with the pipeline: a. Tanks, tank batteries, pumps, compressors and racks; b. Storage facilities, loading facilities, terminal facilities, and other similar facilities; (Source: *The Pipelines Act, 1998*)
AB	Any pipe or any system or arrangement of pipes wholly within Alberta and whereby oil, gas or synthetic crude oil or water incidental to the drilling for or production of oil, gas or synthetic crude oil is conveyed, and (i) includes all property of any kind used for the purpose of, or in connection with, or incidental to, the operation of a pipeline in the gathering, transporting, handling and delivery of oil, gas, synthetic crude oil or water but,

	(ii) does not include any pipe or any system or arrangement of pipes that constitutes a distribution system for the distribution within a community of gas to ultimate consumers (Source: *The Oil and Gas Conservation Act*)
BC	Piping through which any of the following is conveyed: (a) petroleum or natural gas; (b) water produced in relation to the production of petroleum or natural gas or conveyed to or from a facility for disposal into a pool or storage reservoir; (c) solids; (d) substances prescribed under section 133 (2) (v) of the Petroleum and Natural Gas Act, (e) other prescribed substances, and includes installations and facilities associated with the piping, but does not include (f) piping used to transmit natural gas at less than 700 kPa to consumers by a gas utility as defined in the Gas Utility Act, (g) a well head, or (h) anything else that is prescribed; (Source: *Petroleum and Natural Gas Act*)

Piping and Instrumentation Diagram – A schematic diagram showing piping, equipment, and instrumentation connections within process units.

Pool

SK	i. An underground reservoir that: a) Contains or appears to contain an accumulation of oil or gas; and b) Is separated or appears to be separated from any other reservoir or accumulation in the general structure; ii. A portion of an underground reservoir described in subclause (i) that is determined by the minister to be a pool for reasons of development or administration; or iii. A group of underground reservoirs described in subclause (i) that is determined by the minister to be a pool for reasons of development or administration; (Source: *The Oil and Gas Conservation Act*)
AB	A natural underground reservoir containing or appearing to contain an accumulation of oil or gas, or both, separated or appearing to be separated from any other such accumulation, or In respect of an *in situ* coal scheme, that portion of a coal deposit that has been or is intended to be converted to synthetic coal gas or synthetic coal liquid;

	(Source: *The Oil and Gas Conservation Act*)
BC	An underground reservoir containing an accumulation of petroleum or natural gas, or both, separated or apparently separated from another reservoir or accumulation; (Source: *The Petroleum and Natural Gas Act*)

Positive Displacement Meter – A type of flow meter that measures the volume of fluid by counting repeatedly the filling and discharging of known fixed volumes.

Primary Measurement – Measurement used to determine a process stream volume that is reported to Petrinex typically only applies to thermal facilities.

Primary Element – See meter element also known as primary flow element.

Process and Instrumentation Diagram – A family of functional one-line diagrams showing hull, mechanical, and electrical systems, such as piping and cable block diagrams.

Process Flow Diagram – A diagram commonly used in chemical and process engineering to indicate to the general flow of plant processes and equipment.

Produced Water – Water produced in connection with oil and natural gas production.

Propane – A mixture mainly of propane ordinarily may contain some ethane and butanes.

(Alberta Source: *The Oil and Gas Conservation Act*)

Prorated Production – Total battery production allocated to wells based on periodic individual well tests.

Proration – A procedure in which the total actual monthly battery production is allocated to wells based on periodic individual well tests.

Proration Battery – A battery for which well production is allocated using proration.

Proration Factor – Ratio of the sum of the total actual battery production volumes for a fluid divided by the sum of the total estimated well production volumes for that fluid. Separate proration factors are calculated for each fluid (e.g. oil, water and or gas).

Prover – A device used to determine the volume of a sample of fluid, to a known standard, that has passed through the meter being proved.

Prove (proving, proved) – The procedures or operations whereby a prover volume is compared to an indicated meter volume and both volumes are corrected to applicable pressure and temperature conditions. The prover volume divided by the indicated meter volume yields a meter factor. The meter factor is subsequently applied to indicated meter volumes to determine the adjusted or corrected volume.

Qualifying Criteria – Criteria that must be met to qualify for an exemption by exception. If the qualifying criteria have been met and the exemption is implemented, it may remain in place indefinitely, as long as the exemption qualifying criteria continues to be met.

Quarterly – Once every calendar quarter. Calendar quarters are:

a. January – March

b. April – June

c. July – September

d. October – December

Raw Gas

SK	Natural gas before it has been subjected to absorption, purification, scrubbing or other treatment or process, and includes all liquid hydrocarbons other than oil and condensate.
AB	A mixture containing methane, other paraffin hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them that is recovered or is recoverable at a well from an underground reservoir and that is gaseous at the conditions under which its volume is measured and estimated. (Source: *The Oil and Gas Conservation Act*)
BC	Undefined.

RD – see **R**elative **D**ensity.

Regulator

SK	Saskatchewan Ministry of Energy and Resources (ER).
AB	Alberta Energy Regulator (AER).
BC	British Columbia Oil and Gas Commission (BCOGC).

Remote Terminal Unit – A microprocessor-controlled electronic device that captures and transmits readings from the physical world, such as flow rate, temperature or pressure. Usually an extension of a SCADA system; communicates with a host and can operate independently and measure flow parameters, perform calculations, digital control, PID control, etc.

Relative Density – Is the ratio of the density (mass of a unit volume) of a substance to the density air or water at base conditions.   Specific gravity is and equivalent term.

Representative Flow – Used when stabilized flow is not achievable, such as for wells with artificial lift systems and wells with slugging characteristics. The test volumes of gas, condensate, or water must be representative of the well's production capability under normal operating conditions.

Resistance Temperature Devices – Sensors used to measure temperature by correlating the electrical resistance of the sensor with temperature. See Section 14.4 Temperature Measurement.

Return Gas – Any gas coming back to the battery it was produced from, from a gas plant, facility after sweetening, or processing.

Royalty

SK	For the purpose of this Directive, includes Crown royalties payable pursuant to *The Crown Oil and Gas Royalty Regulations, 2012* and freehold production taxes payable pursuant to *The Freehold Oil and Gas Production Tax Regulations, 2012* and royalties paid to freehold mineral owners. Also see Common Crown or Freehold Royalty.

AB	Royalty is the price that the owner of a natural resource charges for the right to develop the resource. Also see Common Crown or Freehold Royalty. (Source: *Alberta Royalty Review 2007, Royalty Information Briefing #1*)
BC	A royalty reserved under section 73 (1) and required to be paid by a regulation under section 73 (2) or an agreement under section 78 or 78.1; (Source: *Petroleum and Natural Gas Act*)

RTD – see **R**esistance **T**emperature **D**evices.

RTU – see **R**emote **T**erminal **U**nit.

S&W – see **S**ediment and **W**ater.

Sales Gas – A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for the pipeline receiving the gas.

Satellite – Surface equipment located between a number of wells and the main battery that is intended to separate and measure the production from each well during the well tests, after which the fluids are recombined and piped to the main battery for separation or treating, measurement, and storage or delivery.

SCADA – **S**upervisory **C**ontrol **a**nd **D**ata **A**cquisition System. A system for gathering and sending coded signals over communication channels to provide control of remote equipment. Typically, the remote equipment is an RTU – see Remote Terminal Unit. See also Electronic Flow Measurement.

Secondary Element – See Meter Element.

Secondary Measurement – Alternative measurement or calculation method used to validate the measurement volume and used during repair or downtime of primary measurement equipment. Typically used in thermal projects for water or steam stream which allows operators to identify metering inaccuracies in advance of annual facility turnarounds, meter provings, calibrations, and inspections, resulting in timely repairs.

Sediment and Water – The measurement of the sediment and water content of the oil. Generally determined at the point the oil is sold.

Semiannually – Once every two calendar quarters.

Separator – An unfired apparatus specifically designed and used for separating fluids produced from a well into two or more streams, but does not include a dehydrator.

(Alberta Source: *The Oil and Gas Conservation Act*)

Shrinkage – Refers to a volume reduction associated with one or both of the following two processes:

1. Blending of hydrocarbon streams of varying density such as bitumen and condensate; and / or
2. Loss of volatile components through vaporization such as flashing or weathering due to a pressure reduction and/or temperature increase or to continued exposure to atmospheric conditions such as conversion of live oil to base conditions, and/or
3. Acid gas removal.

Shrinkage Factor – A factor that accounts for a volume reduction due to the blending of liquid hydrocarbons or flashing of gas in solution from a liquid.

Single Point Measurement Uncertainty – The uncertainty or accuracy of the equipment and/or procedures used to determine a single phase specific volume at a single measurement point.

Single-Well Battery – A licensed well that treats production exclusively from that licensed well.

(Source: *The Oil and Gas Conservation Regulations, 2012*)

Site – Refers to a surface lease and the equipment related to that surface lease. It does not necessarily align with a facility license.

Sour Gas – Sour gas is natural gas or any other gas containing more than trace amounts of hydrogen sulfide (H_2S).

Southeastern Alberta – Gas production from pools and stratigraphic units or zones, including coals and shales, from the top of the Edmonton Group to the base of the Colorado Group, in the area in the Province of Alberta South of Township 31 and East of the 5th Meridian. (Source: *AER MU 7490*).

Southwestern Saskatchewan – Gas wells located south of Township 28 and West of the Third Meridian in Saskatchewan with completions within the stratigraphic units from the base of the Glacial Drift to the base of the Upper Cretaceous.

Split Load – When a truck takes on partial loads from more than one well or battery in a single trip or when load fluids are delivered to more than one receipt point or well.

Stabilized Flow – A point at which flowing parameters of gas, condensate, or water are producing under normal operation conditions and represent production level equal to the well's normal average flow rate. See Section 7.1.2 and 7.2.3.

Steam – The vapour into which water is changed when heated to the boiling point. For reporting to Petrinex the sum of all steam injection volumes of varying quality, reported as a cold water equivalent volume.

Steam Quality – The measure of the amount of saturated steam in the vapour phase (mass fraction).

Stock Tank Vapours – Gas in a tank that has been released from the liquid it was entrained in.

SWB – see **S**ingle-**W**ell **B**attery

Sweet Gas – Natural gas that contains little or no hydrogen sulfide.

Sweet Oil – Oil that contains little or no hydrogen sulfide.

Synthetic Crude Oil

SK	A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is derived from the processing of heavy oil and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures.
AB	A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is derived from crude bitumen and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so derived. (Source: *The Oil and Gas Conservation Act*)
BC	Undefined.

Tertiary Element – See Meter Element.

Thermal (Recovery/Production) – Refers to the use of heat (generally in the form of steam) to lower the viscosity of bitumen/heavy oil in the reservoir to the point it can be made to flow out of the production well.

Treater – A fired apparatus specifically designed and used for separating gas and water from crude oil.

(Alberta Source: *The Oil and Gas Conservation Act*)

Triennially – Once every twelve calendar quarters (once every three years).

Uncertainty – The expected range of the true value, given a measurement. Can be expressed as a percentage (±1%) or as an absolute measurement (± 1 Meter). Different from accuracy in that the true value is not known, only the measurement. Expressed with a specific confidence level (e.g. 95%).

Unique Well Identifier – Is the standard well identification that was developed for the petroleum industry by the Geoscience Data Committee of the Canadian Petroleum Association (CPA) and has been adopted by the oil and gas Regulatory agencies of the four western provinces and federal areas. It consists of 16 characters, which make up four basic components:

a. legal survey location
b. survey system code
c. location exception code
d. event sequence code

Together these define the approximate geographical location of the bottom of a drill hole and a specific drilling or producing event at the drill hole.

The unique well identifier, although based on the legal survey position of a well, is primarily for identification rather than location. The location component describes the bottomhole location of the well, not the surface position of the well.

(Alberta Source: *Directive 059: Well Drilling and Completion Data Filing Requirements*)

UWI – see **U**nique **W**ell **I**dentifier.

Vent Gas – Uncombusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas includes:

- Blanket gas;
- Facility upsets and emergency shutdown;
- Fugitive emissions;
- Gas from compressor seals, starters, and blowdowns;
- Gas from dehydrator still columns;
- Gas from production tanks, not including methanol and chemical tanks;
- Gas produced during well completions;
- Gas produced during well unloading volumes;
- Gas released during pigging operations;
- Gas used to operate pneumatic devices; and

- Waste gas.

Verification – Procedures that establish the accuracy of the "as found" values indicated by a measuring device as compared to the values indicated by a reference standard.

Water - For the purpose of this Directive, when the term 'water' is used it applies to all types of water such as Water, Fresh Water, and Brine.

Water Cut – The ratio of the relative water to oil fractions in a liquid sample or stream. For production determination solids are included in the water volume.

Water to Gas Ratio – A ratio calculated by dividing the water volume by the gas volume of a well test. See Table 7.1. for calculation and rounding requirements.

Well

SK	(i) any opening in the ground made within Saskatchewan from which any oil, gas, oil and gas or other hydrocarbon is, has been or is capable of being produced from a reservoir; (ii) any opening in the ground that is made for the purpose of: (A) obtaining water to inject into an underground formation; (B) injecting any substance into an underground formation; (C) storing oil, gas or other hydrocarbons underground; or (D) monitoring reservoir performance and obtaining geological information; or (iii) any opening in the ground made for informational purposes pursuant to The Subsurface Mineral Conservation Regulations; but does not include seismic shot holes; (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	An orifice in the ground completed or being drilled (i) for the production of oil or gas, (ii) for injection to an underground formation, (iii) as an evaluation well or test hole, or (iv) to or at a depth of more than 150 metres, for any purpose, but does not include one to discover or evaluate a solid inorganic mineral and that does not or will not penetrate a stratum capable of containing a pool or oil sands deposit; (Source: *The Oil and Gas Conservation Act*)
BC	A hole in the ground (a) made or being made by drilling, boring or any other method to obtain petroleum or natural gas, (b) made or being made by drilling, boring or any other method to explore for, develop or use a storage reservoir for the storage or disposal of petroleum,

	natural gas, water produced in relation to the production of petroleum or natural gas, waste or any other prescribed substance, (c) used, drilled or being drilled to inject natural gas, water produced in relation to the production of petroleum or natural gas or other substances into an underground formation in connection with the production of petroleum or natural gas, (d) used to dispose of petroleum, natural gas, water produced in relation to the production of petroleum or natural gas, waste or any other prescribed substance into a storage reservoir, or (e) used, drilled or being drilled to obtain geological or geophysical information respecting petroleum or natural gas, and includes a water source well; (Source: *Petroleum and Natural Gas Act*)

WGR – see **W**ater-**G**as **R**atio.

Working Interest Participant

SK	A person who owns a legal or beneficial interest in a well or facility pursuant to an agreement that relates to the ownership of the well or facility. (Source: *The Oil and Gas Conservation Regulations, 2012*)
AB	A person who owns a beneficial or legal undivided interest in a well or facility under agreements that pertain to the ownership of that well or facility. (Source: *The Oil and Gas Conservation Act*)
BC	Undefined.

Appendix 3 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 Regulator 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: Water Cuts Between 0% and 10%

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 (50 ml) of the sample.
2. Fill each tube with the solvent solution, consisting of premixed solvent and demulsifier to the 200-part mark (100 ml).
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 within ±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.

   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.
10. Calculation and reporting:

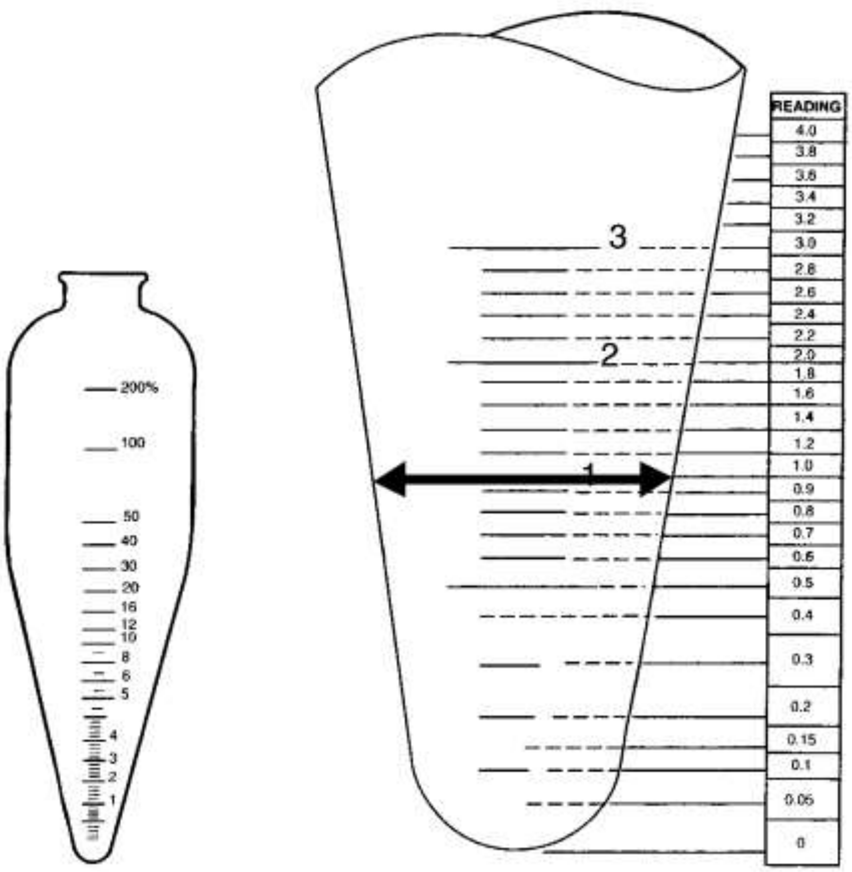
    For 200 ml tubes: the percentage of water and sediment is the average, to three decimal places, of the values read directly from the two tubes.

For 100 ml 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 Figure A4.1)

100 ml centrifuge tubes	**200 ml centrifuge tubes**
If reading from each tube is the same:	
Reading from each tube = 0.50 ml	Reading from each tube = 1.00 ml
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, 0.60 ml	Reading from 1st run of each tube = 1.00, 1.05 ml
Reading from 2nd run of each tube = 0.50, 0.55 ml	Reading from 2nd run of each tube = 1.00, 1.10 ml
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%

Figure A4.1. Reading a centrifuge tube



Category 2: Water Cuts Between 10% and 80%

Obtain the maximum representative sample of liquid feasible. The representative sample must be a minimum of 800 ml.

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:

1. at or above treater temperature

   or

2. 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 100 ml from the oil/emulsion portion in the graduated cylinder and fill each of two 100 ml centrifuge tubes to exactly the 50 ml mark. Add solvent to bring the level in the tubes to exactly the 100 ml mark. The procedures previously outlined for samples with 0% to 10% water cut are to be followed, with the exception that the water-cut readings from both tubes are to be added together, even if they are not the same.

Note that if 200 ml tubes are to 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 is to 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:

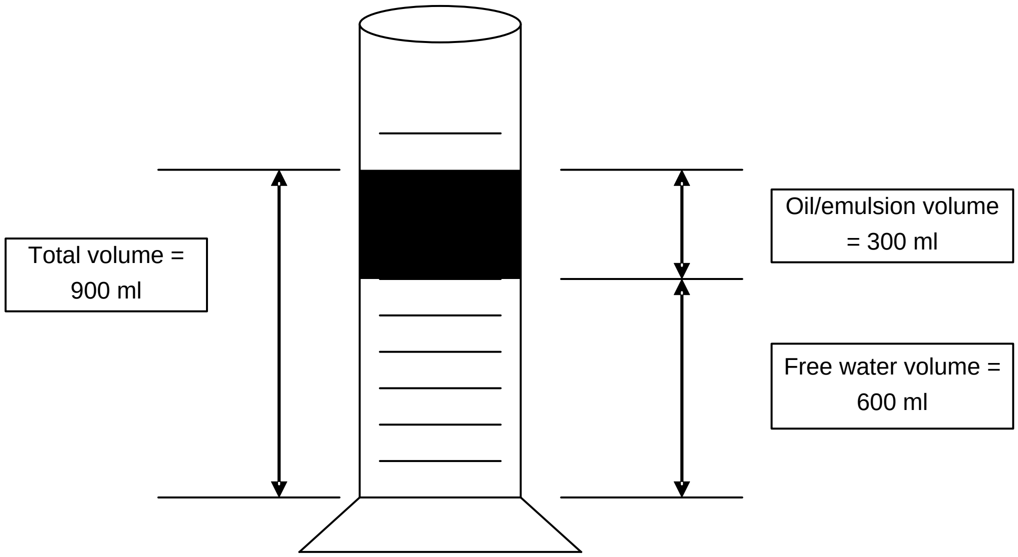
Total water-cut % = % free water + % water remaining

Example 2 (see Figure A4.2)

1000 ml graduated cylinder
% of free water = 600 ml ÷ 900 ml x 100% = 66.7%
% of water remaining = 300 ml x 10%[1] ÷ 900 ml = 3.3%
Total water-cut % = 66.7% + 3.3% = 70.0%

[1] Water cut of oil portion determined by spinning samples

Figure A4.2. Water-cut percentage > 10% to ≤ 80%



Category 3: Water Cuts Between 80% and 100%

Obtain the maximum representative sample of liquid feasible. The representative sample must be a minimum of 800 ml.

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

1. at or above treater temperature; or
2. 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%. Refer to Figure A4.4 for an example.

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 Figure A4.3)

1000 ml graduated cylinder
Water-cut % = 900 ml ÷ 1000 ml x 100%
= 90.0%

Figure A4.3. Water-cut percent > 80%

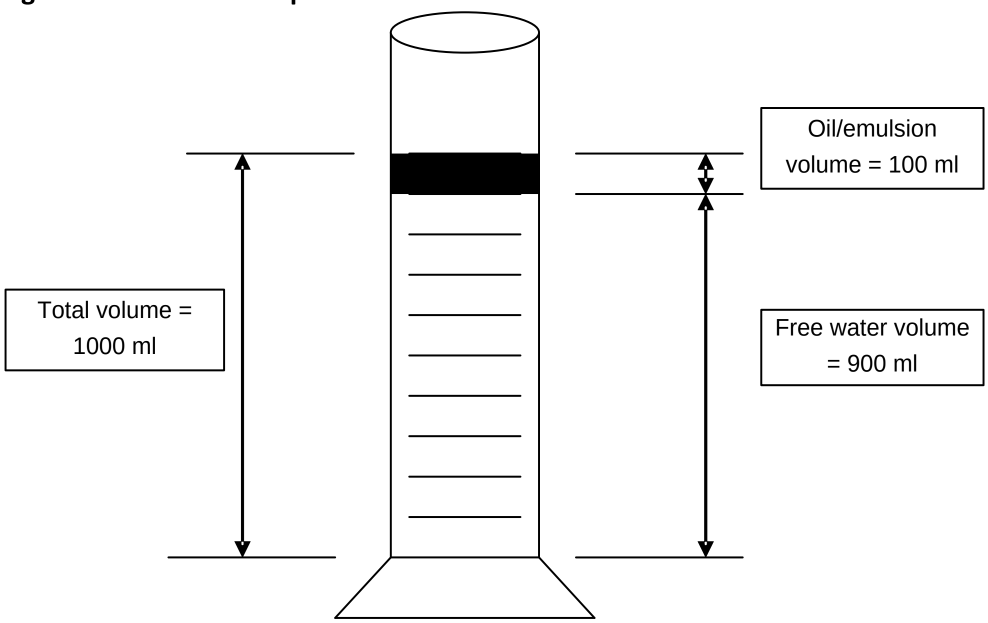
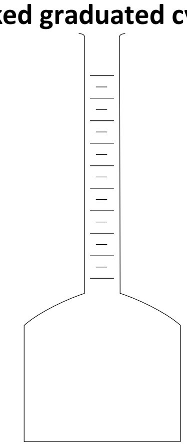


Figure A4.4. Narrow-necked graduated cylinder



Appendix 4 On-site Analytical Techniques for H_2S Measurement

Refer to Section 11 for related requirements.

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 1500 ppm, 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 1500 ppm. 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.

Instrumental (in-lab) Analytical Techniques for H_2S 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 H_2S. H_2S 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 H_2S) and low adsorption of H_2S. Detection limits for H_2S levels as low as 300 ppm can be achieved under the right conditions, and the method can also be calibrated for values approaching 100 per cent H_2S. 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.

Appendix 5 Gas Equivalent Volume Determination

Liquid Analysis Example (GPA Standard 2145-09)			
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
C_1	0.0828	0.1617	0.0405
C_2	0.1117	0.1462	0.0687
C_3	0.1275	0.1533	0.1056
IC_4	0.0394	0.0398	0.0362
NC_4	0.0891	0.0935	0.0849
IC_5	0.0483	0.0436	0.0492
NC_5	0.0540	0.0493	0.0556
C_6	0.0765	0.0614	0.0835
C_7	0.0880	0.0678	0.1054
C_8	0.0827	0.0589	0.1032
C_9	0.0570	0.0368	0.0726
C_{10}	0.0363	0.0222	0.0480
C_{11}	0.0225	0.0131	0.0305
C_{12+}	0.0755	0.0347	0.1044
TOTAL	1.0000	1.0000	1.0000

Properties of C_{5+} & C_{7+} portion of sample					
	Mol. Fractions	**Wt. Fractions**	**Liq. Vol. Fractions**	**Mol. Wt. (kg/kmol)**	**Absolute Density (AD) (kg/m^3)**
C_5+	0.3878	0.6524	0.5408	107.7	739.33
C_7+	0.2335	0.4641	0.3620	127.2	785.29

A5.1 Gas Equivalent Factor by Volume Fraction Calculation

GEF = Total (Pseudo 10^3m^3 Gas / m^3 Liquid)

Condensate Stream : ____

Component	Vol. Fraction Liquid Analysis		10^3m^3 Gas / m^3 Liquid @ 101.325 kPa & 15°C		Pseudo 10^3m^3 Gas / m^3 Liquid
N_2		x	0.68040	=	
CO_2		x	0.44120	=	
H_2S		x	0.55460	=	
C_1		x	0.44217	=	
C_2		x	0.28151	=	
C_3		x	0.27222	=	
IC_4		x	0.22906	=	
NC_4		x	0.23763	=	
IC_5		x	0.20468	=	
NC_5		x	0.20681	=	
C_6		x	0.18216	=	
C_7		x	0.16234	=	
C_8		x	0.14629	=	
C_9		x	0.13303	=	
C_{10}		x	0.12194	=	
				Total =	

Note: For C_{5+}, C_{6+}, or C_{7+} Sample:

Properties of C_{5+}, C_{6+}, or C_{7+} sample @ 15°C

AD =	
Mol. Wt. =	

10^3m^3 Gas / m^3 Liquid = 23.645 (m^3/kmol) x AD (kg/m^3) / Mol. Wt. (kg/kmol)

= ____________ Input this factor to the table above for C_{5+}, C_{6+}, or C_{7+}

GEF = Total (10^3m^3 Gas / m^3 Liquid)

= | | (10^3m^3 Gas / m^3 Liquid)

Example 1 – Gas Equivalent Factor by Volume Fraction Calculation

GEF = Total (Pseudo 10^3m^3 Gas / m^3 Liquid)

Condensate Stream : ____

Component	Volume Fraction Liquid Analysis		10^3m^3 Gas / m^3 Liquid @ 101.325 kPa & 15˚C		Pseudo 10^3m^3 Gas / m^3 Liquid
N_2	0.0006	x	0.68040	=	0.0004
CO_2	0.0081	x	0.44120	=	0.0036
H_2S	0	x	0.55460	=	
C_1	0.0828	x	0.44217	=	0.0366
C_2	0.1117	x	0.28151	=	0.0314
C_3	0.1275	x	0.27222	=	0.0347
IC_4	0.0394	x	0.22906	=	0.0090
NC_4	0.0891	x	0.23763	=	0.0212
IC_5	0.0483	x	0.20468	=	0.0099
NC_5	0.0540	x	0.20681	=	0.0112
C_6	0.0765	x	0.18216	=	0.0139
C_{7+}	0.3620	x	0.14598	=	0.0528
		x		=	
	1.0000		**Total =**		0.2247

Note: For C_{7+} Sample:

Properties of C_{7+} sample @ 15°C

AD = 785.29

Mol. Wt. = 127.2

10^3m^3 Gas / m^3 Liquid = 23.645 (m^3/kmol) x AD (kg/m^3) / Mol. Wt. (kg/kmol) / 1000 (m^3/10^3 m^3)

= 0.14598 Input this factor to the table above for C_{7+}

GEF = Total (Pseudo 10^3m^3 Gas / m^3 Liquid)

= **0.2247** **(10^3m^3 Gas / m^3 Liquid)**

A5.2 Gas Equivalent Factor by Mole Fraction Calculation

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($m^3/10^3\ m^3$)

Condensate Stream : ____

Component	Mol. Fraction Liquid Analysis		10^3m^3/kmol @ 101.325 kPa & 15°C		Pseudo 10^3m^3/kmol
N_2		x	0.03475	=	
CO_2		x	0.05359	=	
H_2S		x	0.04263	=	
C_1		x	0.05348	=	
C_2		x	0.08399	=	
C_3		x	0.08686	=	
IC_4		x	0.10322	=	
NC_4		x	0.09950	=	
IC_5		x	0.11552	=	
NC_5		x	0.11433	=	
C_6		x	0.12980	=	
C_7		x	0.14565	=	
C_8		x	0.16163	=	
C_9		x	0.17774	=	
C_{10}		x	0.19391	=	
				Total =	

Note:

Properties of C_{5+}, C_{6+}, or C_{7+} Sample @ 15°C:

AD =	
Mol. Wt. =	

For C_{5+}, C_{6+}, or C_{7+} Sample:

10^3m^3/kmol = Mol. Wt. / AD

= ____________

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($m^3/10^3\ m^3$)

= [ ] **($10^3 m^3$ Gas / m^3 Liquid)**

Example 2: Gas Equivalent Factor by Mole Fraction Calculation

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($m^3/10^3 m^3$)

Condensate Stream : ______________________________

Component	Mol. Fraction Liquid Analysis		m^3/kmol @ 101.325 kPa & 15°C		Pseudo m^3/kmol
N_2	0.0019	x	0.03475	=	0.0001
CO_2	0.0158	x	0.05359	=	0.0008
H_2S	0	x	0.04263	=	0
C_1	0.1617	x	0.05348	=	0.0086
C_2	0.1462	x	0.08399	=	0.0123
C_3	0.1533	x	0.08686	=	0.0133
IC_4	0.0398	x	0.10322	=	0.0041
NC_4	0.0935	x	0.09950	=	0.0093
IC_5	0.0436	x	0.11552	=	0.0050
NC_5	0.0493	x	0.11433	=	0.0056
C_6	0.0614	x	0.12980	=	0.0080
C_{7+}	0.2335	x	0.16198	=	0.0378
		x		=	
		x		=	
	1.0000			**Total =**	0.1049

Note:

Properties of C_{7+} sample @ 15°C:

AD =	785.29
Mol. Wt. =	127.2

For C_{7+} Fraction:

m^3/kmol = Mol. Wt. / AD

= 0.16198 Input this factor to the table above for C_{7+}

GEF = 23.645 (m^3/kmol) / Total (Pseudo m^3/kmol) / 1000 ($m^3/10^3\ m^3$)

= **0.2254** **($10^3 m^3$ Gas / m^3 Liquid)**

A5.3 Gas Equivalent Factor by Mass Fraction Calculation

Step 1. Calculate Pseudo Volume (L) = Mass Fraction ÷ Liquid Density x 1000 L/m^3

Step 2. Calculate Volume Fraction = Component Pseudo Volume ÷ Total Pseudo Volume

Step 3. Calculate Component Pseudo GEF = Volume Fraction x ($10^3 m^3$ Gas / m^3 Liquid)

Condensate Stream : ______________________________

					Step 1	**Step 2**				**Step 3**
Component	**Mass Fraction Liquid Analysis**		**LiquidDensity (kg/m^3)**		**Pseudo Volume (L)**	**Volume Fraction**		**$10^3 m^3$ Gas /m^3 Liquid @ 101.325 kPa & 15°C**		**Pseudo $10^3 m^3$ Gas / m^3 Liquid**
N_2		÷	806.10	=			x	0.68040	=	
CO_2		÷	821.22	=			x	0.44120	=	
H_2S		÷	799.40	=			x	0.55460	=	
C_1		÷	300.00	=			x	0.44217	=	
C_2		÷	358.00	=			x	0.28151	=	
C_3		÷	507.67	=			x	0.27222	=	
IC_4		÷	563.07	=			x	0.22906	=	
NC_4		÷	584.14	=			x	0.23763	=	
IC_5		÷	624.54	=			x	0.20468	=	
NC_5		÷	631.05	=			x	0.20681	=	
C_6		÷	663.89	=			x	0.18216	=	
C_7		÷	687.98	=			x	0.16234	=	
C_8		÷	706.73	=			x	0.14629	=	
C_9		÷	721.59	=			x	0.13303	=	
C_{10}		÷	733.76	=			x	0.12194	=	
									Total =	

Note: For C_{5+}, C_{6+}, or C_7+ Sample:

Mol. Wt.=

AD = (kg/m^3)

10^3m^3 Gas / m^3 Liquid = 23.645 x AD / Mol. Wt. / 1000 $m^3/10^3m^3$

= [ ] Input this factor to the table above for C_{7+}

GEF = Total (Pseudo 10^3m^3 Gas / m^3 Liquid)

= [ ] (10^3m^3 Gas / m^3 Liquid)

Example 3: Gas Equivalent Factor by Mass Fraction Calculation

Step 1. Calculate Pseudo Volume (L) = Mass Fraction ÷ Liquid Density x 1000 L/m^3

Step 2. Calculate Volume Fraction = Component Pseudo Volume ÷ Total Pseudo Volume

Step 3. Calculate Component Pseudo GEF = Volume Fraction x ($10^3 m^3$ Gas / m^3 Liquid)

Condensate Stream : ____

					Step 1	Step 2				Step 3
Component	**Mass Fraction Liquid Analysis**		**Liquid Density (kg/m^3)**		**Pseudo Volume (L)**	**Volume Fraction**		**$10^3 m^3$ Gas / m^3 Liquid @ 101.325 kPa & 15°C**		**Pseudo $10^3 m^3$ 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	÷	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	0.28148	=	0.0329
C_3	0.1056	÷	507.67	=	0.2080	0.1266	x	0.27221	=	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	=	0.0140
C_{7+}	0.4641	÷	785.29	=	0.5910	0.3598	x	0.14598	=	0.0525
	1.0000				1.6425	1.0000	**Total =**			0.2251

Note: For C_{7+} Sample:

Mol. Wt. =	127.2	
AD of C_7+ liquid =	785.29	(kg/m^3)

$10^3 m^3$ Gas / m^3 Liquid = 23.645 x AD / Mol. Wt. x 999.10 / 1000 ($m^3/10^3 m^3$)

GEF = Total (Pseudo $10^3 m^3$ Gas / m^3 Liquid)

= 0.2251 ($10^3 m^3$ Gas / m^3 Liquid)

Appendix 6 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 (10^3m^3)	10000.0
Composition	*Mole %*
N_2	1.00
CO_2	2.00
H_2S	2.40
C_1	80.00
C_2	8.00
C_3	3.00
IC_4	1.00
NC_4	1.50
IC_5	0.20
NC_5	0.50
C_6	0.30
C_{7+}	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
C_1	3.00
C_2	4.00
C_3	7.00
IC_4	10.00
NC_4	15.00
IC_5	7.00
NC_5	11.00
C_6	10.00
C_{7+}	30.00
	100.00

Step 2: Convert the condensate liquid volume to a 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 ($10^3m^3/m^3$) = 44.024 10^3m^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 (10^3m^3) = [Component mole percent] x [GEV]

Example: n-pentane equivalent volume:

Volume of condensate = 200 m^3

Gas Equivalent Factor = 220.12

Equivalent n-pentane (NC_5) gas volume = [11.0%] x [44.024 10^3 m^3] = 4843 m^3

Liquid	
Liquid Volume (m^3)	200.0
Composition	*Mole %*
N_2	0.00
CO_2	1.00
H_2S	2.00
C_1	3.00
C_2	4.00
C_3	7.00
IC_4	10.00
NC_4	15.00
IC_5	7.00
NC_5	11.00
C_6	10.00
C_{7+}	30.00
	100.00

A

B

Liquid	
Gas Equivalent Volume (10^3m^3)	44.024
Composition	*10^3m^3 gas*
N_2	0.00
CO_2	0.44
H_2S	0.88
C_1	1.32
C_2	1.76
C_3	3.08
IC_4	4.40
NC_4	6.60
IC_5	3.08
NC_5	4.84
C_6	4.40
C_{7+}	13.21
	44.02

Step 3: Add the gas volumes and liquid gas equivalent volumes and normalize to mole fraction 1 or 100%.

Gas			**Liquid**			**Recombined Volume**			**Recombined Composition**	
Gas Volume (10^3m^3)	10000.0		*Gas Equivalent Volume (10^3m^3)*	44.0		*Gas Equivalent Volume (10^3m^3)*	10044.0		*Gas Equivalent Volume (10^3m^3)*	10044.0
Composition	*10^3m^3 gas*		*Composition*	*10^3m^3 gas*		*Composition*	*10^3m^3 gas*		*Composition*	*Mole %*
N_2	100.0		N_2	0.00		N_2	100.0		N_2	1.00
CO_2	200.0		CO_2	0.44		CO_2	200.4		CO_2	2.00
H_2S	240.0		H_2S	0.88		H_2S	240.9		H_2S	2.40
C_1	8000.0	+	C_1	1.32	=	C_1	8001.3		C_1	79.66
C_2	800.0		C_2	1.76		C_2	801.8		C_2	7.98
C_3	300.0		C_3	3.08		C_3	303.1		C_3	3.02
IC_4	100.0		IC_4	4.40		IC_4	104.4		IC_4	1.04
NC_4	150.0		NC_4	6.60		NC_4	156.6		NC_4	1.56
IC_5	20.0		IC_5	3.08		IC_5	23.1		IC_5	0.23
NC_5	50.0		NC_5	4.84		NC_5	54.8		NC_5	0.55
C_6	30.0		C_6	4.40		C_6	34.4		C_6	0.34
C_{7+}	10.0		C_{7+}	13.21		C_{7+}	23.2		C_{7+}	0.23
	10000.0			44.00			10044.0			100.00

Calculated Group Compositional Analysis Example

Step 1:

Collect volumetric and compositional data for both gas and liquid phases for all streams. This 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 *(10^3 m^3)*	10000
Composition	*Mole %*
N_2	1.14
CO_2	0.16
H_2S	0.00
C_1	85.31
C_2	6.44
C_3	3.77
IC_4	0.63
NC_4	1.32
IC_5	0.33
NC_5	0.41
C_6	0.26
C_{7+}	0.23
	100.00

Liquid	
Gas Equivalent Volume (10^3 m^3)	800
Composition	*Mole %*
N_2	0.12
CO_2	0.08
H_2S	0.00
C_1	22.02
C_2	6.14
C_3	8.56
IC_4	2.62
NC_4	7.11
IC_5	3.66
NC_5	5.73
C_6	9.73
C_{7+}	34.23
	100.00

Recombined Fluid	
Gas Equivalent Volume (10^3 m^3)	10800
Composition	*Mole %*
N_2	1.06
CO_2	0.15
H_2S	0.00
C_1	80.62
C_2	6.42
C_3	4.12
IC_4	0.78
NC_4	1.75
IC_5	0.58
NC_5	0.80
C_6	0.96
C_{7+}	2.75
	100.00

Stream 2: Gas	
Gas Volume *(10^3 m^3)*	15000
Composition	*Mole %*
N_2	1.00
CO_2	2.00
H_2S	2.40
C_1	80.00
C_2	8.00
C_3	3.00
IC_4	1.00
NC_4	1.50
IC_5	0.20
NC_5	0.50
C_6	0.30
C_{7+}	0.10

Liquid	
Gas Equivalent Volume (10^3 m^3)	200
Composition	*Mole %*
N_2	0.00
CO_2	1.00
H_2S	2.00
C_1	3.00
C_2	4.00
C_3	7.00
IC_4	10.00
NC_4	15.00
IC_5	7.00
NC_5	11.00
C_6	10.00
C_{7+}	30.00

Recombined Fluid	
Gas Equivalent Volume (10^3 m^3)	15200
Composition	*Mole %*
N_2	0.99
CO_2	1.99
H_2S	2.39
C_1	78.99
C_2	7.95
C_3	3.05
IC_4	1.12
NC_4	1.68
IC_5	0.29
NC_5	0.64
C_6	0.43
C_{7+}	0.49

Total Recombined Fluid	
Gas Equivalent Volume (10^3 m^3)	36000
Composition	*Mole %*
N_2	0.76
CO_2	1.44
H_2S	1.01
C_1	82.37
C_2	6.95
C_3	2.94
IC_4	0.79
NC_4	1.37
IC_5	0.32
NC_5	0.54
C_6	0.47
C_{7+}	1.04

	100.00
Stream 3: Gas	
Gas Volume ($10^3 m^3$)	10000
Composition	*Mole %*
N_2	0.10
CO_2	2.00
H_2S	0.00
C_1	89.40
C_2	6.00
C_3	1.50
IC_4	0.30
NC_4	0.50
IC_5	0.08
NC_5	0.10
C_6	0.01
C_{7+}	0.01
	100.00

	100.00
Liquid	
Gas Equivalent Volume ($10^3 m^3$)	0
Composition	*Mole %*
N_2	0.00
CO_2	0.00
H_2S	0.00
C_1	0.00
C_2	0.00
C_3	0.00
IC_4	0.00
NC_4	0.00
IC_5	0.00
NC_5	0.00
C_6	0.00
C_{7+}	0.00
	0.00

	100.00
Recombined Fluid	
Gas Equivalent Volume ($10^3 m^3$)	10000
Composition	*Mole %*
N_2	0.10
CO_2	2.00
H_2S	0.00
C_1	89.40
C_2	6.00
C_3	1.50
IC_4	0.30
NC_4	0.50
IC_5	0.08
NC_5	0.10
C_6	0.01
C_{7+}	0.01
	100.00

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 = 10000 10^3m^3

Methane = 80.00 mole %

Methane Volume = 10000.0 10^3m^3 x 0.8000 = 8000.0 10^3m^3

Step 3: Normalization: Individual component volumes are summed. The individual component volumes are then be divided into the total to create a normalized (calculated) compositional value.

Example: Ethane (C_2), Calculation of Mole %

Gas Sample #1, C_2 volume: 800 10^3m^3

Gas Sample #2, C_2 volume: 560 10^3m^3

Combined, C_2 volume: 1360 10^3m^3

Total gas volume: 18000 10^3m^3

Calculated C_2 concentration = 1360.0 10^3m^3 ÷ 18000 10^3m^3 = 7.56 mole %

Gas Sample #1		
Gas Volume (10^3 m^3) = 10000.0		
Component	*Mole %*	*10^3 m^3 gas*
N_2	1.00	100.0
CO_2	2.00	200.0
H_2S	2.40	240.0
C_1	80.00	8000.0
C_2	8.00	800.0
C_3	3.00	300.0
IC_4	1.00	100.0
NC_4	1.50	150.0
IC_5	0.20	20.0
NC_5	0.50	50.0
C_6	0.30	30.0
C_{7+}	0.10	10.0
	100.00	10000.0

+

Gas Sample #2		
Gas Volume (10^3 m^3) = 8000.0		
Component	*Mole %*	*10^3 m^3 gas*
N_2	0.60	48.0
CO_2	2.00	160.0
H_2S	1.50	120.0
C_1	83.00	6640.0
C_2	7.00	560.0
C_3	2.50	200.0
IC_4	1.00	80.0
NC_4	1.40	112.0
IC_5	0.18	14.4
NC_5	0.45	36.0
C_6	0.28	22.4
C_{7+}	0.09	7.2
	100.00	8000.0

=

Calculated Single Compositional Analysis		
Gas Volume (10^3 m^3) = 18000.0		
Component	***Calculated Mole %***	*10^3 m^3 gas*
N_2	**0.82**	148.0
CO_2	**2.00**	360.0
H_2S	**2.00**	360.0
C_1	**81.33**	14640.0
C_2	**7.56**	1360.0
C_3	**2.78**	500.0
IC_4	**1.00**	180.0
NC_4	**1.46**	262.0
IC_5	**0.19**	34.4
NC_5	**0.48**	86.0
C_6	**0.29**	52.4
C_{7+}	**0.10**	17.2
	100.00	18000.0

Appendix 7 Blending Shrinkage Calculation Example

API MPMS, Chapter 12.3, Section 5.3 Equation 3

$$\% \, Shrinkage = 26900 \times C \times (100 - C)^{0.819} \times (1/dL - 1/dH)^{2.28}$$

Where:

- % Shrinkage = volumetric shrinkage expressed as a % of the total blended mixture volume.
- C = the concentration, in the liquid volume %, of the lighter component in the blended mixture.

  C = Lighter component volume ÷ (Heavier component volume + lighter component volume)
- dL = weighted average lighter component density in m^3/kg.
- dH = weighted average heavier component density in m^3/kg.
- (1/dL – 1/dH) = inverse density difference of the light (dL) and heavy (dH) components in the blended mixture.

Example Calculation:

Lighter Component	Volume = 800.0 m3	Density = 700.0 kg/m3
Heavier Component	Volume = 2300.0 m3	Density = 963.0 kg/m3

C = (800/ (800 + 2300)) x 100 = 25.81 %

1/dL = 1/700 = 0.00143

1/dH = 1/963 = 0.00104

% Shrinkage = 26900 x C x $(100 – C)^{0.819}$ x $(1/dL – 1/dH)^{2.28}$

% Shrinkage = 26900 x 25.81 x $(100-25.81)^{0.819}$ x $(0.00143 – 0.00104)^{2.28}$

% Shrinkage = 0.3990

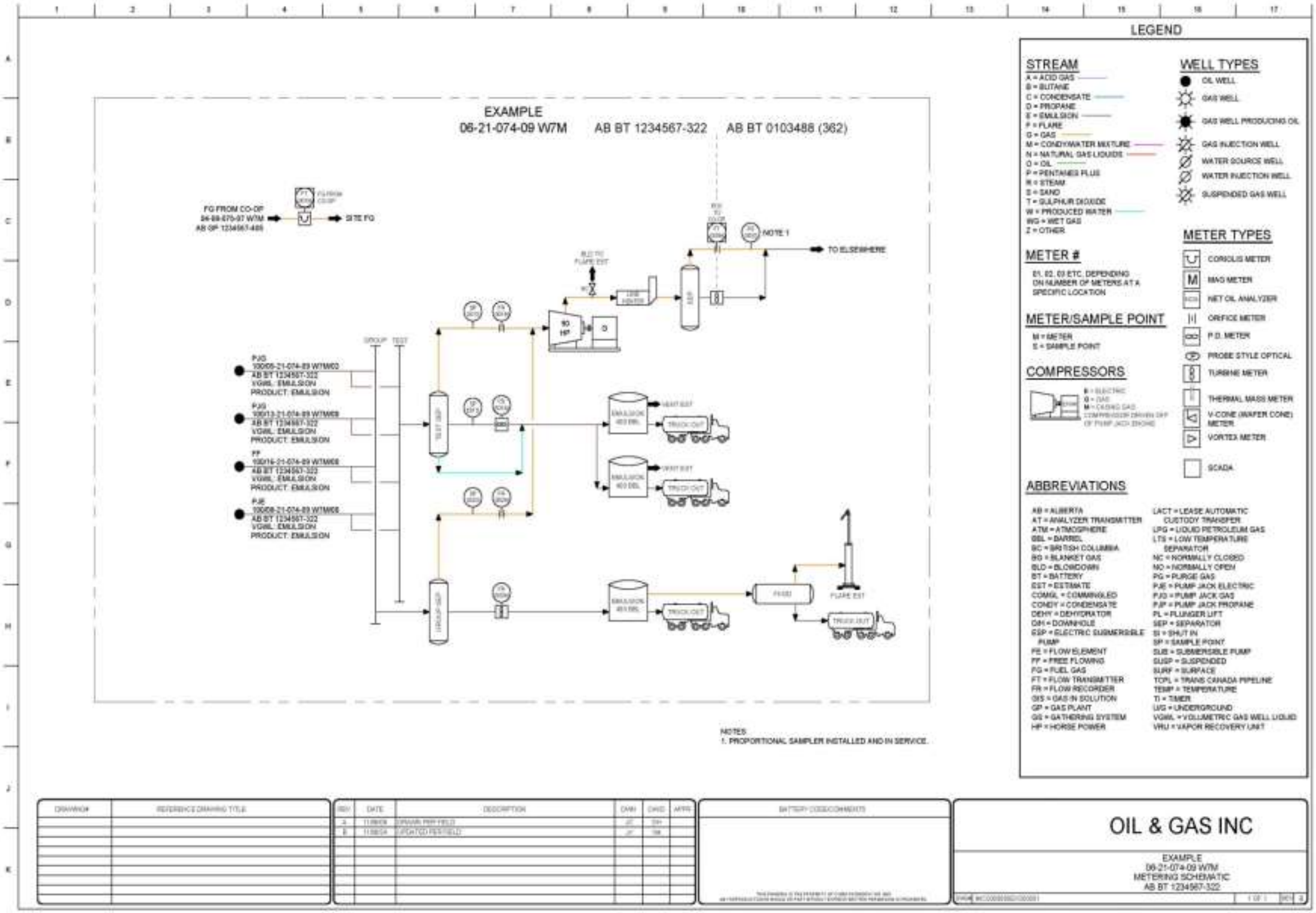
For blending 2300 m3 of 963 kg/m3 oil and 800 m3 of 700 kg/m3 diluent:

Shrinkage Volume = 0.3993% x (800+2300) = 12.37 m3

Appendix 8 Measurement Schematic Example

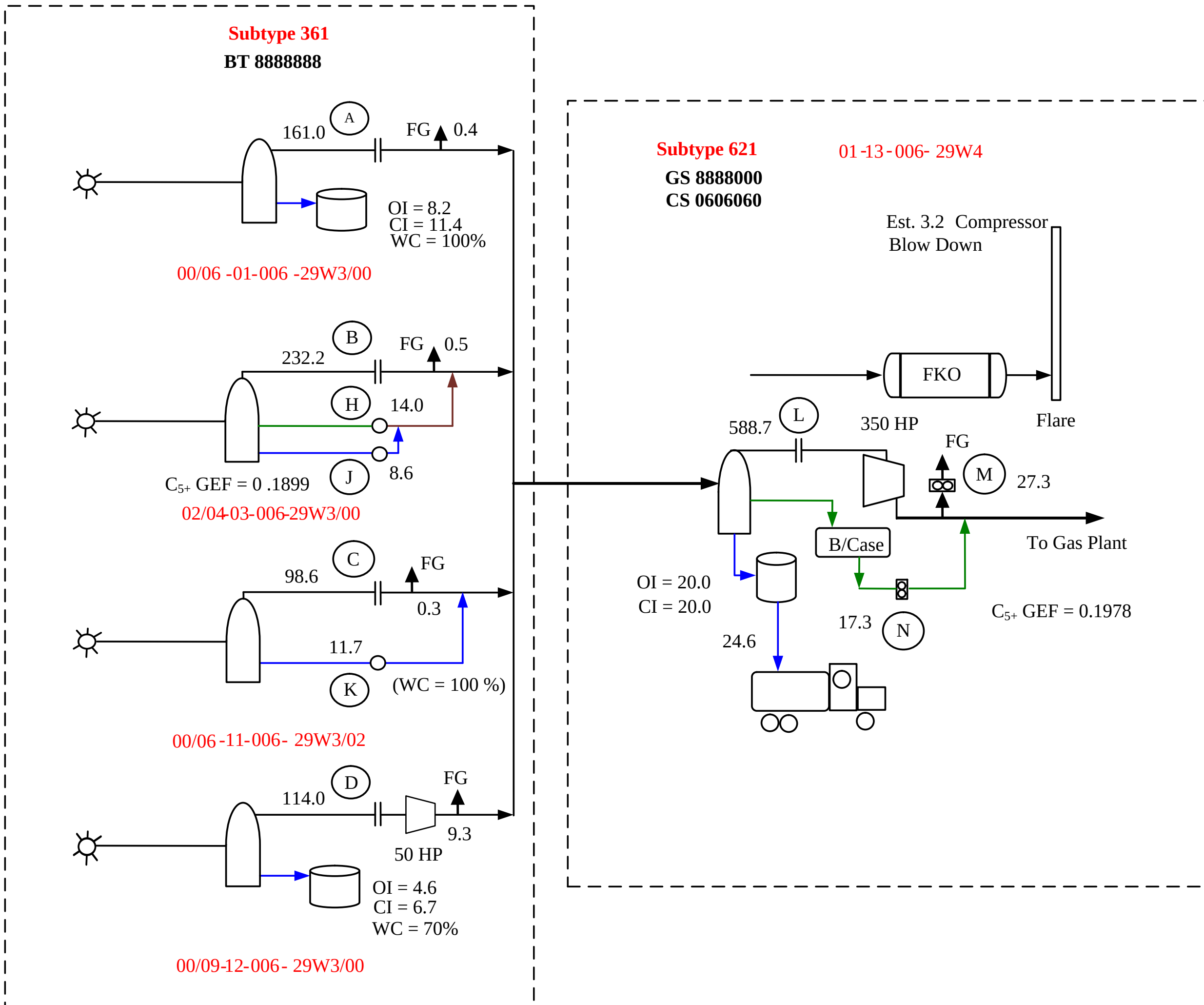
The measurement schematic on the following page is an example of a measurement schematic that is required as described in Section 1.8 and is for information purposes only. An operator may use other symbols, letters, or words as long as it is clear in the legend or in the schematic what they stand for.

The facilities and wells identified in this schematic are from Alberta but are also representative of Saskatchewan.


LEGEND
EXAMPLE
06-21-074-09 W7M
AB BT 1234567-322
AB BT 0103488 (362)
STREAM
WELL TYPES
METER TYPES
METER #
METER/SAMPLE POINT
COMPRESSORS
ABBREVIATIONS
TO ELSEWHERE
NOTES
1. PROPORTIONAL SAMPLER INSTALLED AND IN SERVICE.
OIL & GAS INC
EXAMPLE
06-21-074-09 W7M
METERING SCHEMATIC
AB BT 1234567-322

Appendix 9 Gas Group Delineation

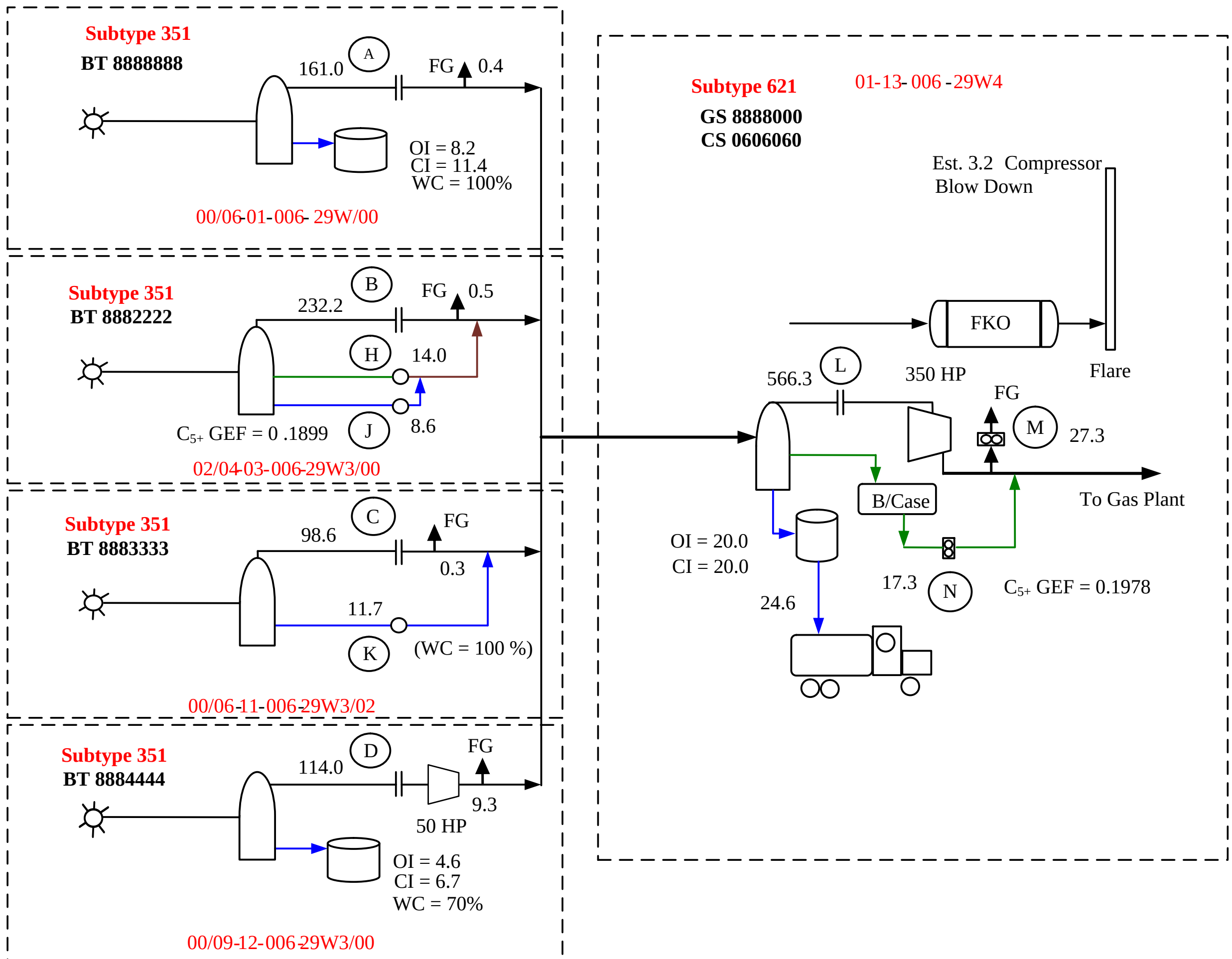
Case 1[1, 2]



BT 8888888 Gas Production = 161.0 + 232.2 + (0.1899 x 14.0) + 98.6 + 114.0 = 608.5
BT 8888888 Gas Delivered = 608.5 − (0.4 + 0.5 + 0.3 + 9.3) = 598.0
BT 8888888 Water Production = 3.2 + 8.6 + 11.7 + [(6.7 − 4.6) x 0.7] = 25.0
BT 8888888 Oil Production = [(6.7 – 4.6) x 0.3] = 0.6
GS 8888000 Receipts = 598.0
GS 8888000 Gas Delivered = 588.7 – 27.3 + (0.1978 x 17.3) – 3.2 = 561.6
GS 8888000 MD = 598.0 – 588.7 – (0.1978 x 17.3) = 5.9 (1.0%)
GS 8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
WC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

Case 2[1, 2]



BT 8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.6

BT 8888888 Water Production = 3.2

BT 8882222 Gas Production = 232.2 + (14 x 0.1899) = 234.9; Delivered = 234.9 – 0.5 = 234.4

BT 8882222 Water Production = 8.6

BT 8883333 Gas Production = 98.6; Delivered = 98.6 – 0.3 = 98.3

BT 8883333 Water Production = 11.7

BT 8884444 Gas Production = 114.0; Delivered = 114 – 23.7 = 90.3

BT 8884444 Water Production = (6.7 – 4.6) x 0.7 = 1.5

BT 8884444 Oil Production = (6.7 – 4.6) x 0.3 = 0.6

GS 8888000 Gas Receipts = 160.6 + 234.4 + 98.3 + 90.3 = 583.6

GS 8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2

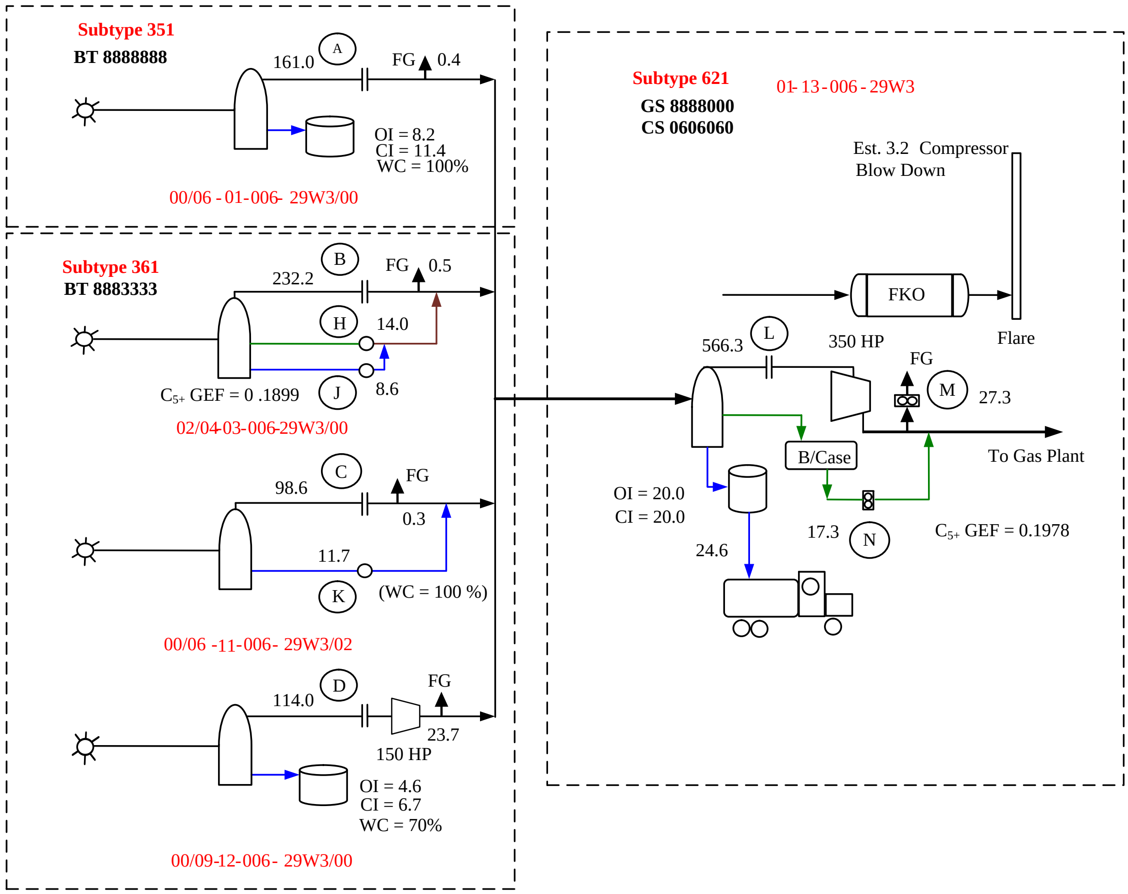
GS 8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)

GS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6

[1] All wells sweet

[2] All volumes monthly

Case 3[1, 2]



BT 8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.7

BT 8888888 Water Production = 3.2

BT 8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 + 114 = 447.5; Delivered = 447.5 – 24.5 = 423.0

BT 8883333 Water Production = 8.6 + 11.7 + [(6.7 – 4.6) x 0.7] = 21.8

BT 8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6

GS 8888000 Receipts = 423.0 + 160.6 = 583.6

GS 8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2

GS 8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)

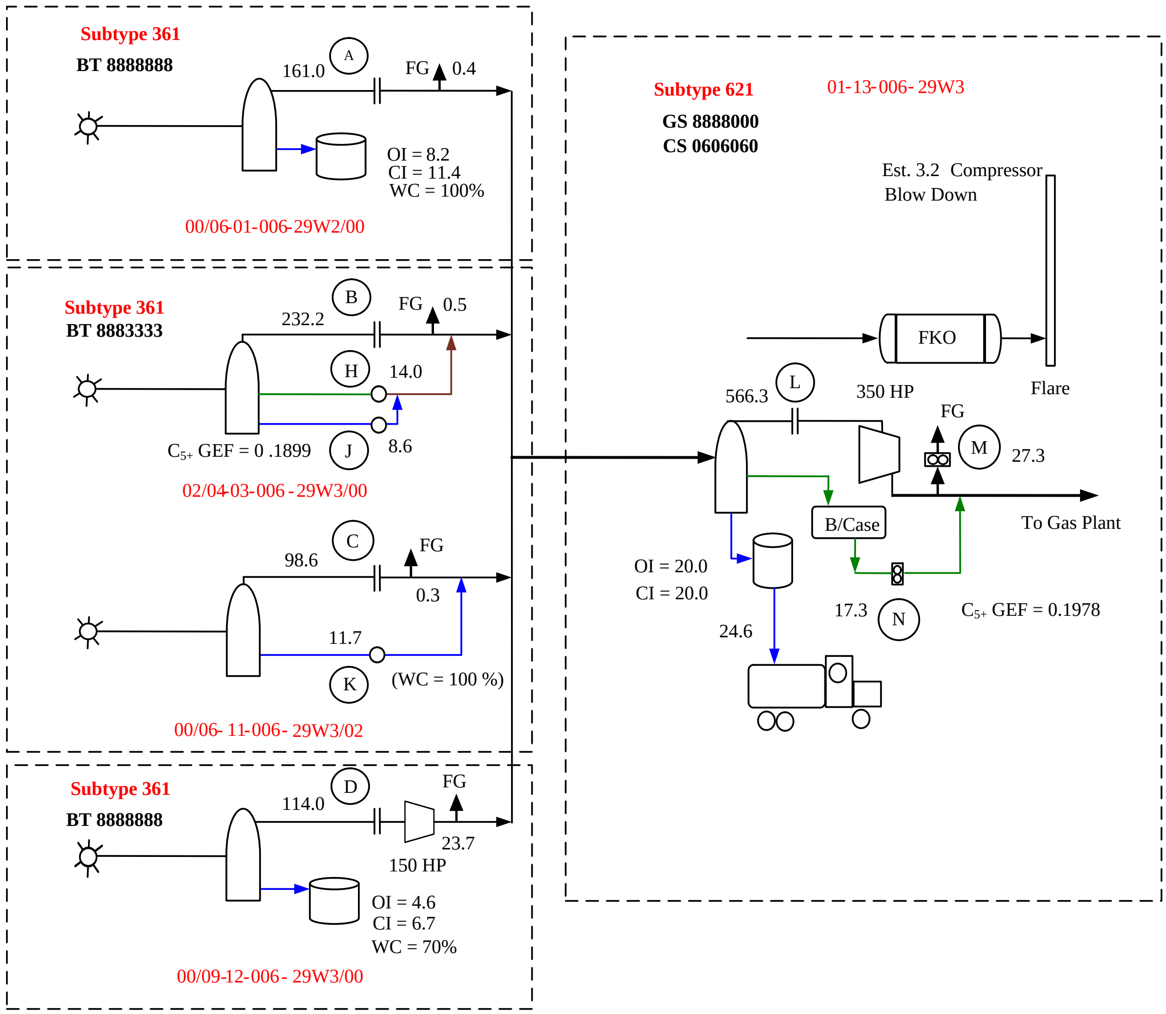
GS 8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6

WC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet

[2] All volumes monthly

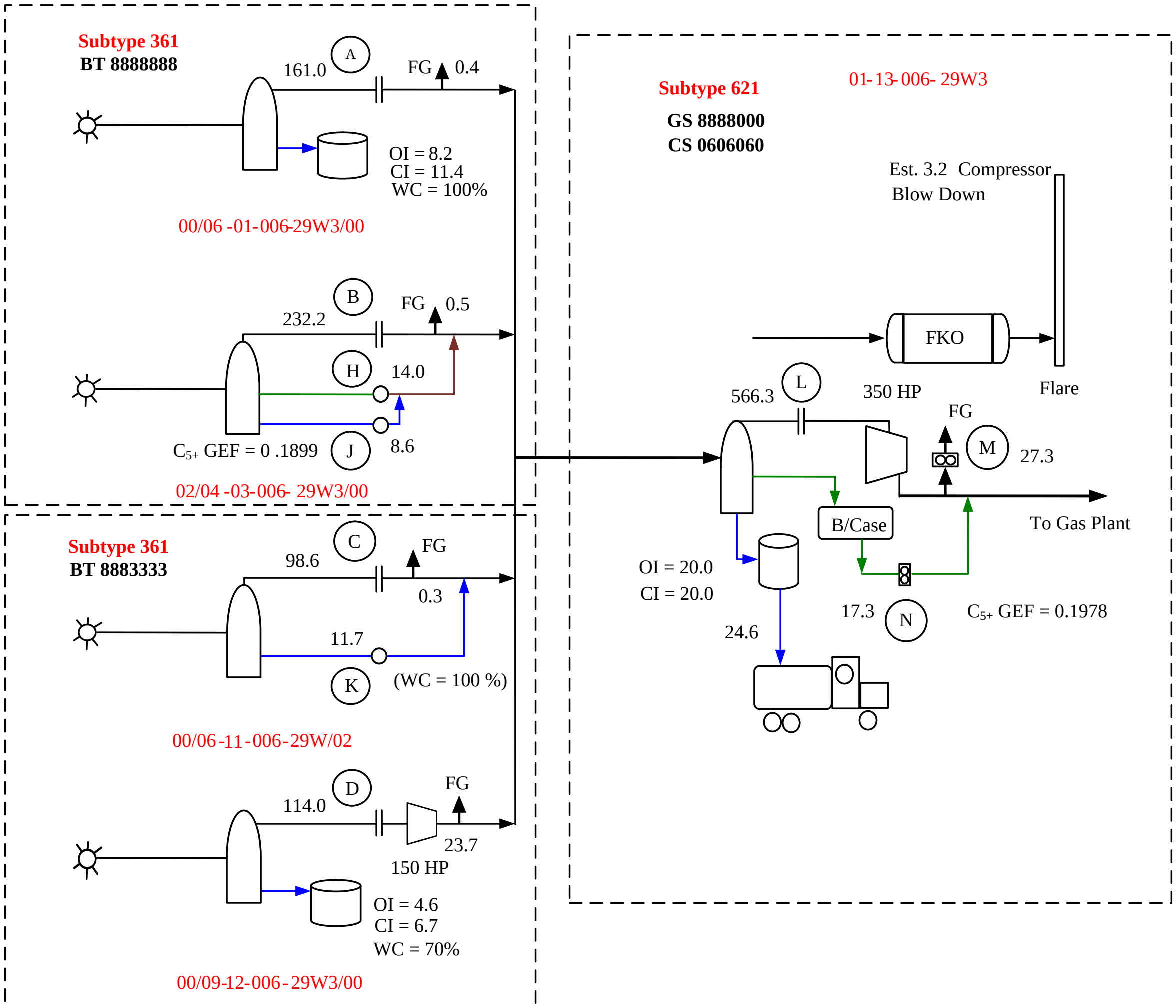
Case 4[1, 2]



BT 8888888 Gas Production = 161.0 + 114.0 = 275.0; Delivered = 275 – 0.4 – 23.7 = 250.9
BT 8888888 Water Production = (11.4 – 8.2) + [(6.7 – 4.6) x 0.7] = 4.7
BT 8888888 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
BT 8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 = 333.5; Delivered = 333.5 – 0.5 – 0.3 = 332.7
BT 8883333 Water Production = 8.6 + 11.7 = 20.3
GS 8888000 Receipts = 250.9 + 332.7 = 583.6
GS 8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
GS 8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
GS 8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
WC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

Case 5[1, 2]



BT 8888888 Gas Production = 161.0 + 232.2 + (14 x 0.1899) = 395.9; Delivered = 395.9 – 0.4 – 0.5 = 395.0
BT 8888888 Water Production = (11.4 – 8.2) + 8.6 = 11.8
BT 8883333 Gas Production = 98.6 + 114 = 212.6; Delivered = 212.6 – 24 = 188.6
BT 8883333 Water Production = 11.7 + [(6.7 – 4.6) x 0.7] = 13.2
BT 8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
GS 8888000 Receipts = 395 + 188.6 = 583.6
GS 8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
GS 8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
GS 8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
WC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly