The ERCB Directive 017 Overview

November 4, 2009

By Bill Cheung
Why measure and report production, flaring, and venting?

**Public Safety and Environment**
- Understand and monitor emissions

**Reservoir Engineering**
- Better understand the adverse impacts to reservoirs

**Conservation**
- To do proper economic evaluations to conserve

**Information and Statistics**

**Balance Facilities**

**AND Calculate Production and Royalty**
Directive 017 is designed to consolidate all of Alberta’s measurement requirement under one document when completed – it describes:

- What, where, and how volumes must be measured, calculated, or estimated
- If accounting procedures must be performed on the determined volumes and what they are
- What data must be kept for audit purposes
- What resultant volumes must be reported
Directive 017

The 15 sections planned are:

- Section 1 – Standards of Accuracy
- Section 2 – Calibration and Proving
- Section 3 – Proration and Allocation Factors, and Metering Differences
- Section 4 – Gas Measurement
- Section 5 – Site-specific Deviation from Base Requirements
- Section 6 – Conventional Oil Measurement
- Section 7 – Gas Proration Batteries
- Section 8 – Gas and Liquid Sampling and Analysis
Directive 017

- Section 9 – Cross Border Measurement
- Section 10 – Trucked Liquids Measurement
- Section 11 – Acid Gas and Sulphur Measurement
- Section 12 – Heavy Oil Measurement
- Section 13 – Condensate and HVP Liquid Measurement

Under Development are:
- Section 14 – Liquids Measurement
- Section 15 – Water Measurement

Appendices are provided for definitions, information, and calculation examples only and are not enforceable items and there are 8 appendices so far.
Section 1 – Standards of Accuracy

**Single Point Uncertainty** – this is the limits applicable to equipment and/or procedures used to determine a single-phase specific volume at a single measurement point.
Uncertainty Calculation for a Single Gas Measurement Point

**Primary measurement device** – gas meter
uncertainty = 1.0%

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

Secondary device **calibration** uncertainty = 0.5%

**Tertiary device** – (flow calculation, EFM, etc.)
uncertainty = 0.2%

**Gas sampling and analysis** uncertainty = 1.5%

**Combined** uncertainty = \( \sqrt{[1.0]^2 + (0.5)^2 + (0.5)^2 + (0.2)^2 + (1.5)^2]} = 1.95\% \) (rounded to 2.0%)
## Gas Uncertainty Limit Requirements

<table>
<thead>
<tr>
<th>Gas Measurement Type</th>
<th>Single point measurement uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas delivery (sales gas)</td>
<td>2%</td>
</tr>
<tr>
<td>Flare gas</td>
<td>5%</td>
</tr>
<tr>
<td>Acid Gas</td>
<td>10%</td>
</tr>
<tr>
<td>Fuel gas</td>
<td></td>
</tr>
<tr>
<td>$&gt; 0.50 \times 10^3$ m$^3$/d</td>
<td>3%</td>
</tr>
<tr>
<td>$\leq 0.50 \times 10^3$ m$^3$/d (estimation allowed)</td>
<td>10%</td>
</tr>
<tr>
<td>Other gas measurement points</td>
<td>3%</td>
</tr>
</tbody>
</table>
## Liquid Uncertainty Limit Requirements

<table>
<thead>
<tr>
<th>Liquid Measurement Type</th>
<th>Single point measurement uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delivery Point Hydrocarbon Liquid</td>
<td></td>
</tr>
<tr>
<td>&gt; 100 m³/d</td>
<td>0.5%</td>
</tr>
<tr>
<td>≤ 100 m³/d</td>
<td>1%</td>
</tr>
<tr>
<td>Well hydrocarbon production, Facility inlet or total facility hydrocarbon (if not delivery point)</td>
<td>2%</td>
</tr>
<tr>
<td>Injected water</td>
<td>5%</td>
</tr>
<tr>
<td>Produced Water</td>
<td>10%</td>
</tr>
</tbody>
</table>
General Facility Schematics of Measurement Points

- Inlet Meas. (when required)
- Well, Battery, or Gathering System
  - Flare
  - Vent
- Fuel
- Water Disposition
- Injection Facility
  - Gas Disposition
    - Gas gathering system, Gas plant, or Sales
  - Water Injection
Gas Plant Measurement Points

Receipts
- Wells, Gas Gathering Systems or Batteries

Dispositions
- Plant Fuel
- Field Fuel
- Flare
- Vent

- Acid Gas
- Gas to Sales Pipeline
- C2, C3, C4...Products
- Pentane Plus Product

\[ m \] = Measurement Point
Fuel Gas Usage Schematics of Measurement Points
Proration Oil Battery Schematic
Gas Proration Battery Schematic

Gas Well -> Test Taps -> Gas Well

Gas Well -> Gas Well

Separator

Compressor

Group Gas Meter -> Group Gas Meter (alternate location)

Produced Condensate

Produced Water

Gathering System or Sales
Gas Meter Instrumentation Calibration Frequency

- within the **first calendar month** of operation of a new meter,
- **immediately** (by the end of the calendar month) following service or repairs to the meter,
- **semiannually** thereafter if the meter is used in a gas plant or for sales/delivery point
- **annually** for all other meters
Gas Meter Inspections

For meters with no internal moving parts inspection of primary measurement element is required:

- **semiannually** if the meter is used in a gas plant or for sales/delivery point (royalty trigger points), and
- **annually** for all other meters
- **some** inspection is done at scheduled shutdowns only for those facilities, such as a gas plant, where the metering differences and balances are checked regularly to ensure measurement integrity
- **no** inspection required if there are sufficient internal diagnostics to detect problems with the primary measurement element
Gas Meter Proving

Proving:
Meters (rotary or turbine) with internal moving parts must be proved at a frequency of once every 7 years following an initial proving prior to installation.
<table>
<thead>
<tr>
<th>Meter application</th>
<th>Fluid type</th>
<th>Proving frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delivery point, LACT</td>
<td>Oil, condensate, live condensate, NGL, LPG</td>
<td>Monthly (see exceptions)</td>
</tr>
<tr>
<td>Gas plant, Cross-border</td>
<td>Live condensate, NGL, LPG</td>
<td>Semiannually</td>
</tr>
<tr>
<td>Wellhead, Group, Injection</td>
<td>Test oil, test emulsion, live condensate, water</td>
<td>Annually</td>
</tr>
</tbody>
</table>
Proration & Allocation Factors

It is generally used to:

- **Correct** bias error in the system and the factor range depends on the type of production – Gas, Conventional Oil, Heavy Oil, or Water

- **Target** factors – system performance monitors to **track** how the system is functioning and may be used to analyze or correct problems
Proration & Allocation Factors

- Facilities that should have proration or allocation factors are proration batteries and custom treaters.

- Facilities that should not have proration factors are gathering systems, gas plants, injection facilities, gas groups, and single well batteries.
## Proration & Allocation Factors

<table>
<thead>
<tr>
<th>Facility Type</th>
<th>Acceptable Factor Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional oil battery</td>
<td>oil = 0.95000 – 1.05000</td>
</tr>
<tr>
<td></td>
<td>gas = 0.90000 – 1.10000</td>
</tr>
<tr>
<td></td>
<td>water = 0.90000 – 1.10000</td>
</tr>
<tr>
<td>Gas battery</td>
<td>gas = 0.90000 – 1.10000</td>
</tr>
<tr>
<td></td>
<td>water = 0.90000 – 1.10000</td>
</tr>
<tr>
<td>Custom treating plant, clean oil terminal</td>
<td>oil = 0.95000 – 1.05000</td>
</tr>
<tr>
<td></td>
<td>water = 0.90000 – 1.10000</td>
</tr>
</tbody>
</table>
It is used to **balance**, on a monthly basis, any difference that occurs between the measured inlet volumes and the measured outlet / disposition volumes at a facility.

**Target** Metering Difference generally around +/- 5.0% for all facilities.
Gas Measurement

- Base Pressure and Temperature for Reporting: 101.325 kPa and 15 °C
- Gas volume reports in unit of 10^3 m^3 rounded to 1 decimal place
- The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections (where required)
Selection of meter type and size must consider:

- process operating conditions (e.g., pressure, temperature, flow rate, fluid phase)
- required accuracy to meet Section 1 uncertainty requirements
- meter pressure drop
- required straight lengths
- required back pressure
## Design and Installation Standards

<table>
<thead>
<tr>
<th>Meter Type</th>
<th>Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Orifice</strong></td>
<td>AGA #3 1991 and 2000</td>
</tr>
<tr>
<td><strong>Turbine, Vortex</strong></td>
<td>AGA #7</td>
</tr>
<tr>
<td><strong>Diaphragm or Rotary</strong></td>
<td>ANSI B109.1 &amp; B109.3</td>
</tr>
<tr>
<td><strong>Venturi or Flow Nozzle</strong></td>
<td>ISO 5167</td>
</tr>
<tr>
<td><strong>Ultrasonic</strong></td>
<td>AGA #9</td>
</tr>
<tr>
<td><strong>Coriolis</strong></td>
<td>AGA #11</td>
</tr>
<tr>
<td><strong>Others</strong></td>
<td>Applicable industry standard or manufacturer’s recommendation</td>
</tr>
</tbody>
</table>
Other Gas Measurement Requirements

- Electronic Flow Measurement (EFM) requirements and test cases
- Conventional & heavy oil gas production estimate – Gas-Oil-ratio (GOR) are required for low gas production wells ≤ 0.5 10³m³/day.
- Gas-in-Solution (GIS) calculations for associated gas production
- Physical Properties of Gas and Liquid Components use the latest version of Gas Processors Association 2145, or Gas Processors Suppliers Association SI Engineering Data Book published values
Other Gas Measurement Requirements

- Gas chart field and chart reading operation requirements
- Sensing line sloping, drip pot, and tap valves requirements
- New chart reading technology (chart scanning) requirements for data storage and accuracy
# Temperature Measurement Frequency

<table>
<thead>
<tr>
<th>Min. temperature reading frequency</th>
<th>Criteria or events</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Continuous</strong></td>
<td>Sales/delivery points and/or EFM devices</td>
</tr>
<tr>
<td><strong>Daily</strong></td>
<td>&gt; $1.69 \times 10^3$ m$^3$/d</td>
</tr>
<tr>
<td><strong>Weekly</strong></td>
<td>$\leq 1.69 \times 10^3$ m$^3$/d</td>
</tr>
<tr>
<td><strong>Daily</strong></td>
<td>Production (proration) volume testing, or Nonroutine or emergency flaring and venting</td>
</tr>
</tbody>
</table>
Gas Measurement Requirements

Compressibility Calculation Methods:
AGA8
Other methods used with Wichert-Aziz sour gas correction:
• Redlich-Kwong
• Standing and Katz
• Starling
• Hall, Yarborough
• Others
API MPMS 21.1 complaint systems are accepted

Performance Evaluation:
Performed within 2 weeks of installation or immediately after any changes to the algorithms or program

Reporting requirements – Daily, Monthly, and Configuration reports, Events and Alarm logs
EFM Systems Performance Evaluation

By inputting known values (provided 8 test cases - AGA3 and AGA7) of flow parameters into the EFM to verify the volume calculation, coefficient factors, and other parameters, or a snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to be taken from the EFM and input to a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases.

Accuracy requirements
Gas and Liquid Sampling and Analysis Frequency

- Flowrate > $16.9 \times 10^3 m^3/d$ - Annual
- Flowrate $\leq 16.9 \times 10^3 m^3/d$ - Biannual
- Sales, Gas Plants – Semi-annual
- Other schemes per approval
Flare & Vent Volume Determination

Flare and vent volumes can be determined using one of the following methods:

- equipment leak or flow test
- calculations based on beginning and final pressure and temperature and volume of equipment
- software program simulation
- 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
- operators must be able to demonstrate that volumes of gas are accurately and consistently determined
Gas-Oil-Ratio (GOR) & Gas-in-Solution (GIS) Determination

GOR & GIS can be determined using one of the following methods:

- 24 hour test
- Pressurized oil sample taken for Pressure-volume-temperature (PVT) or a laboratory analysis
- 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
- Use a rule-of-thumb estimate of 0.0257 m$^3$ of gas per m$^3$ of oil per kPa pressure drop for ≤ 2.0 m$^3$/d of oil production (not applicable for GIS)
Websites

ERCB regulations and directives

CAPP Flaring and Venting Estimation Guide