CORVELLE CONSULTING

Alberta Energy Regulator (AER)
Directive 017 - Measurement Requirements for Oil and Gas Operations
Version - September 2012

Measurement Schematics & Facility Delineation Requirements

Required by September 11, 2014

The following are excerpts from the ERCB's Directive 017 – Measurement Requirements for Oil and Gas Operations document outlining the new requirements for measurement schematics and facility delineation on those schematics. These new requirements are effective as of September 11, 2014**.**

1.9 Measurement Schematics

This section presents the requirements for measurement schematics used for measurement, accounting, and reporting of oil and gas facilities. Measurement schematics are required to ensure measurement, recording and reporting compliance. Schematics are a visual tool that shows the current physical layout of the facility. Schematics should be regularly reviewed and used by groups such as operations, engineering, and 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.

Definitions:

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

- process piping
- major bypass and recirculation lines
- major equipment symbols, names, and identification numbers
- flow directions
- control loops that affect operation of the system
- interconnection with other systems
- system ratings and operational values as minimum, normal, and maximum flow; temperature; and pressure
- composition of fluids

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

Process and instrumentation diagram — A family of functional one-line diagrams showing hull, mechanical, and electrical systems, such as piping and cable block diagrams.

Measurement schematic — A diagram used to show the physical layout of facilities that traces the normal flow of production from left to right as it moves from wellhead through to sales. A schematic must include the elements identified in Section 1.9.1.

Field flow diagram—A line diagram showing the delineation of facilities and the connectivity of wells to compressors, gathering systems, batteries, and/or gas plants. Equipment, vessels, meters, and sample points are typically not shown on field flow diagrams. A field flow diagram contains

- well location by unique well identifier (UWI)
- producing company
- well type (oil or gas), and if gas, wet or dry measured
- compressors complete with legal survey location (LSL)
- facility codes
- final destination – battery, plant, etc.

1.9.1 Measurement Schematics Requirements

The operator is responsible for creating, confirming, and revising any measurement schematics. The schematics must be used by Operations and Production Accounting to ensure that the reported volumes are in compliance with the ERCB reporting and licensing requirements. How the required information, see below, is shown on a measurement schematic is up to the operator to decide as long as the schematic is clear and comprehensive.

The measurement schematic can be stored electronically or in hard-copy format. A master copy of the measurement schematic must be retained at a central location and previous versions must be stored for a minimum of 18 months. Note that other jurisdictions may require a longer retention time.

The measurement schematic must include the following:

- Facility name, facility licensee name, and operator name if different
- LSL of surface facility and UWI, including downhole location if different
- Facility boundaries between each reporting facility with associated PRA codes and subtypes. For larger facilities, an optional field flow diagram may be used to show facility delineation. (See Appendix 9 for an example.)
- 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.
- Flow split or diversion points (headers) with LSL if not on a well or facility lease site
- 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.

- Measurement points and storage tanks or vessels that are used for estimating, accounting, or reporting purposes, including
  - type of measurement (meter, weight scale, or gauge)
  - type of instrumentation (charts, EFM, or readouts)
  - type of meter(s) if applicable
  - testing or proving taps required by the ERCB
- Fuel, flare, or vent take-off points – default to estimate if meter not shown
- Energy source (gas, propane, electricity) used for equipment if not measured or estimated as part of total site fuel
- Permanent flare points
- Fresh water sources, such as lakes and rivers

UWIs and LSLs 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 on the same page and a typical schematic may be used for wells or facilities with the same measurement configuration.

Additional information required on the schematic, as well as exceptions, is set out below.

Wells

- Include
  - all producing, water source, injection/disposal, and shut-in wells
  - reporting event for wells with downhole commingled zones
- Identify mechanical lift, such as plunger lift, pumpjack, etc. – default to well status of FLOW if not shown
- Suspended wells are optional; if shown, identify them as suspended

Process Equipment

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

Measurement Points

- Identify non-accounting meters if shown
- Originating facility ID or UWI / LSL for truck-in receipt points is not required

Storage Tanks and Vessels

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

Measurement, Accounting, and Reporting Plan for Thermal In-Situ Oil Sands Schemes (MARP)

- Include
  - blowdown lines
  - ponds – volume and fluid type
  - meter ID and sample point ID
  - tank gauge
  - pumps
  - secondary measurement points

1.9.2 Schematic Updates

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

- Physical changes, such as wells, piping, or equipment additions or removal, require a schematic update
- Temporary changes within the same reporting period do not require a schematic update

The master copy of the measurement schematic must be updated annually to reflect any changes or deletions. There must be verification of the revisions or, if no revisions, confirmation of no change. Documentation of the verification may be stored separately from the schematic but must be available on request.

Exceptions

Below are the simplified requirements for some battery subtypes:

For Heavy Oil/Crude Bitumen Administrative Grouping (subtype 343): The well list is not required to be on the schematic but should state how many wells are in the battery and must be available upon request.

For SE Alberta Shallow Gas Battery (subtypes 363 and 366): The well list is not required to be on the schematic but should state how many wells there are on each branch coming into the battery location and must be available upon request.

For 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.

1.9.3 Implementation

- An initial window of two years from September 11, 2012
- No grandfathering for active facilities
- Any reactivated facility must have an up-to-date schematic within three months of reactivation or after the implementation period, whichever is later.

1.9.4 Schematic Availability

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

- Facility licensee of the subject facility
- The company that performs the volumetric reporting for the facility
- The company that performs the product and residue gas allocations up to the allocation point(s)
- ERCB or other Alberta or cross-border regulatory bodies
- Operator of receipt/disposition points—all reporting measurement points for the facility only

1.10 Facility Delineation Requirements

Delineation of lease sites and geographic areas into reporting facilities is based on the measurement, accounting, and reporting rules described in this directive and *Directive 007*. Facility delineation requires accurate information on process flows and measurement points in the field, as well as a sound understanding of the ERCB facility definitions and subtypes outlined in *Directive 007*. 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.

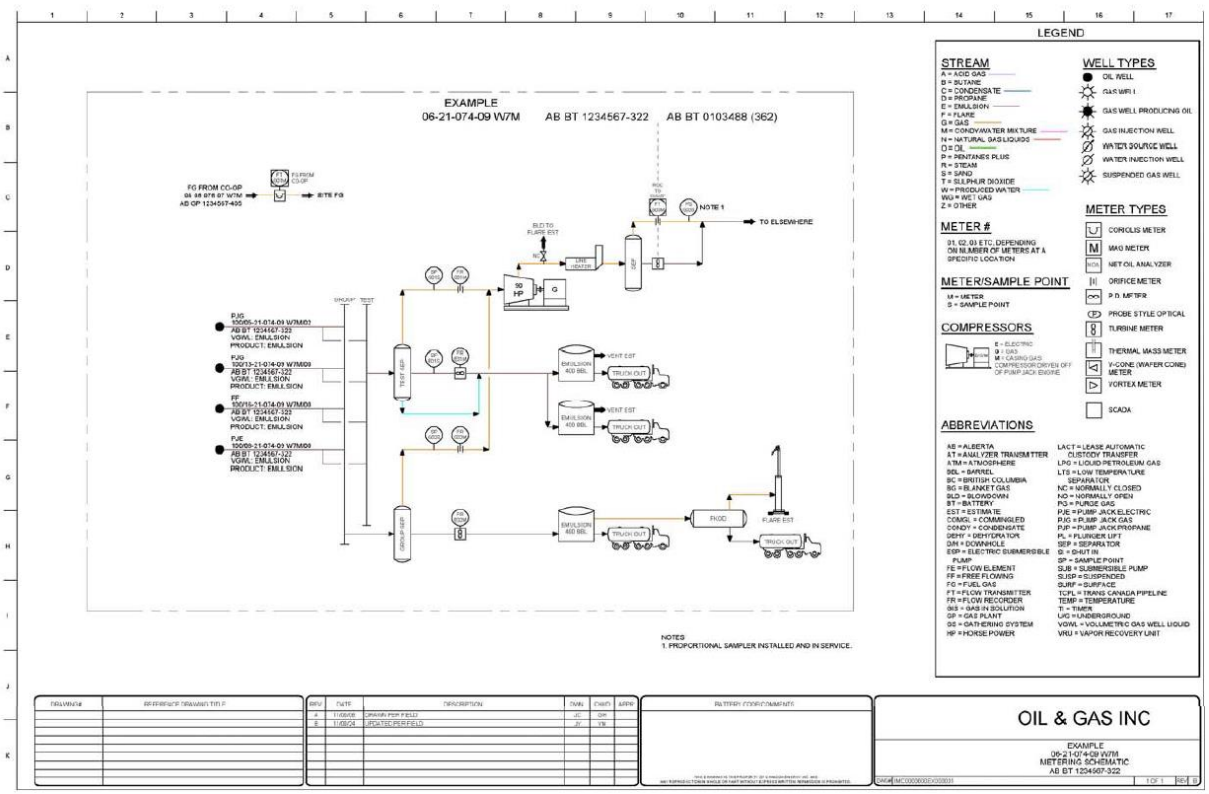
- All gas and liquid received into and delivered from a facility must be continuously or batch measured in a single phase.
- Wells and the associated equipment are only linked to and reported under batteries or injection facilities.

  Crude oil/bitumen wells are linked to and reported under Crude oil /bitumen batteries.
  - Gas wells are linked to and reported under gas batteries.
  - Disposal wells are linked to and reported under disposal facilities.
  - Injection wells are linked and reported under injection facilities.
  - Source water wells 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 production reporting.
- Measured and prorated wells should not be linked to the same battery and must be reported under separate reporting codes.

- 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.

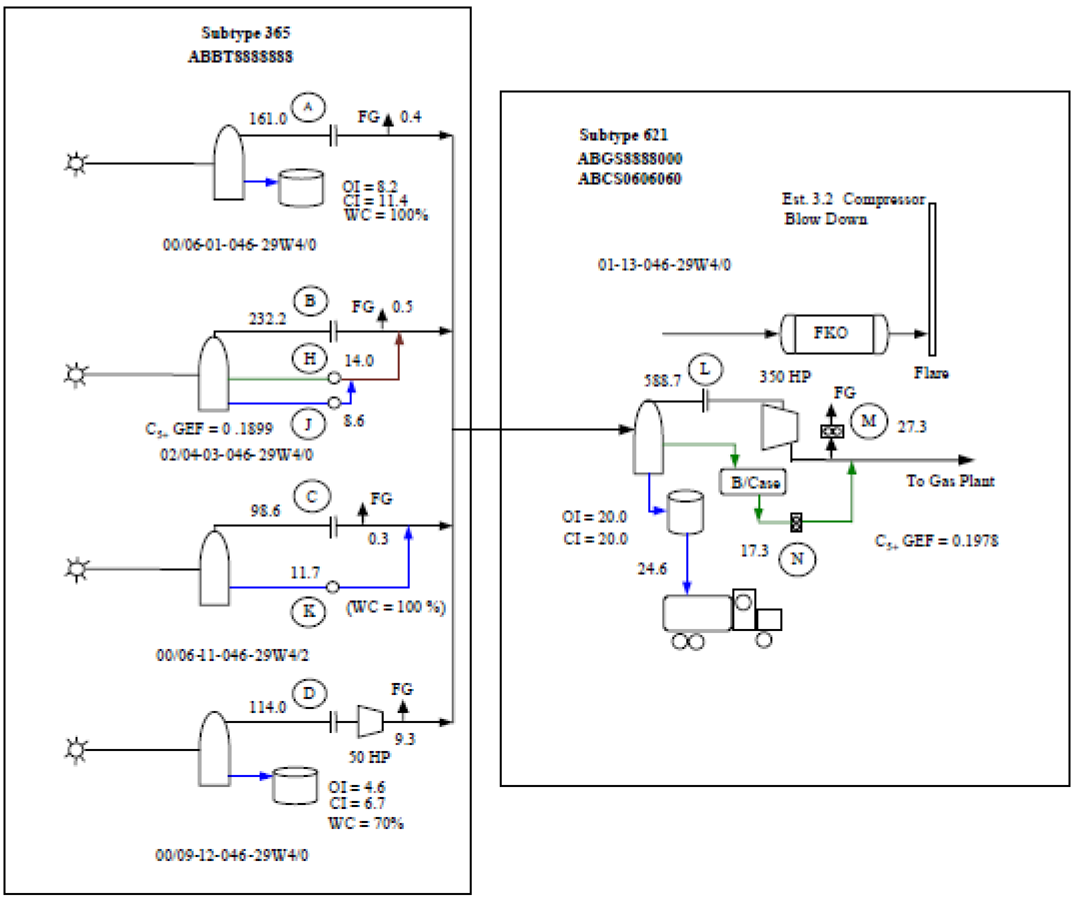
Appendix 9 Schematic Example

The example on the following page 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.



Appendix 10 Gas Group Delineation

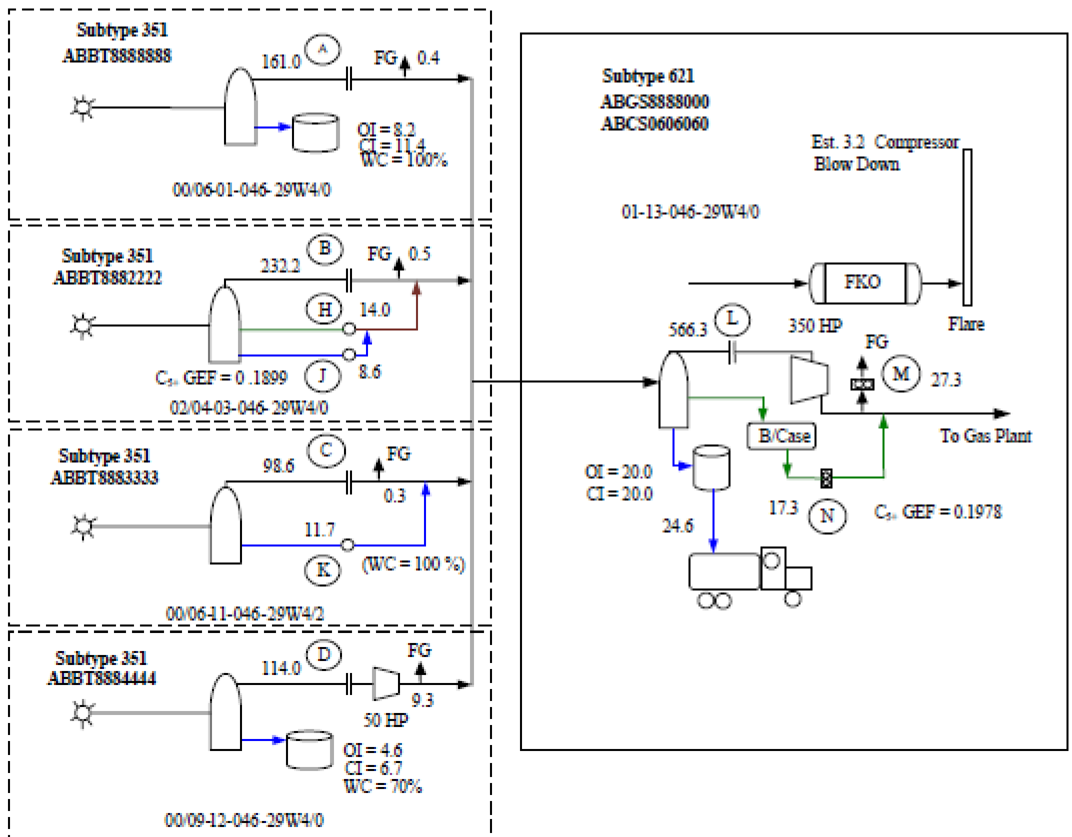
Case 1[1, 2]



ABBT8888888 Gas Production = 161.0 + 232.2 + (0.1899 x 14.0) + 98.6 + 114.0 = 608.5
ABBT8888888 Gas Delivered = 608.5 − (0.4 + 0.5 + 0.3 + 9.3) = 598.0
ABBT8888888 Water Production = 3.2 + 8.6 + 11.7 + [(6.7 − 4.6) x 0.7] = 25.0
ABBT8888888 Oil Production = [(6.7 – 4.6) x 0.3] = 0.6
ABGS8888000 Receipts = 598.0
ABGS8888000 Gas Delivered = 588.7 – 27.3 + (0.1978 x 17.3) – 3.2 = 561.6
ABGS8888000 MD = 598.0 – 588.7 – (0.1978 x 17.3) = 5.9 (1.0%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

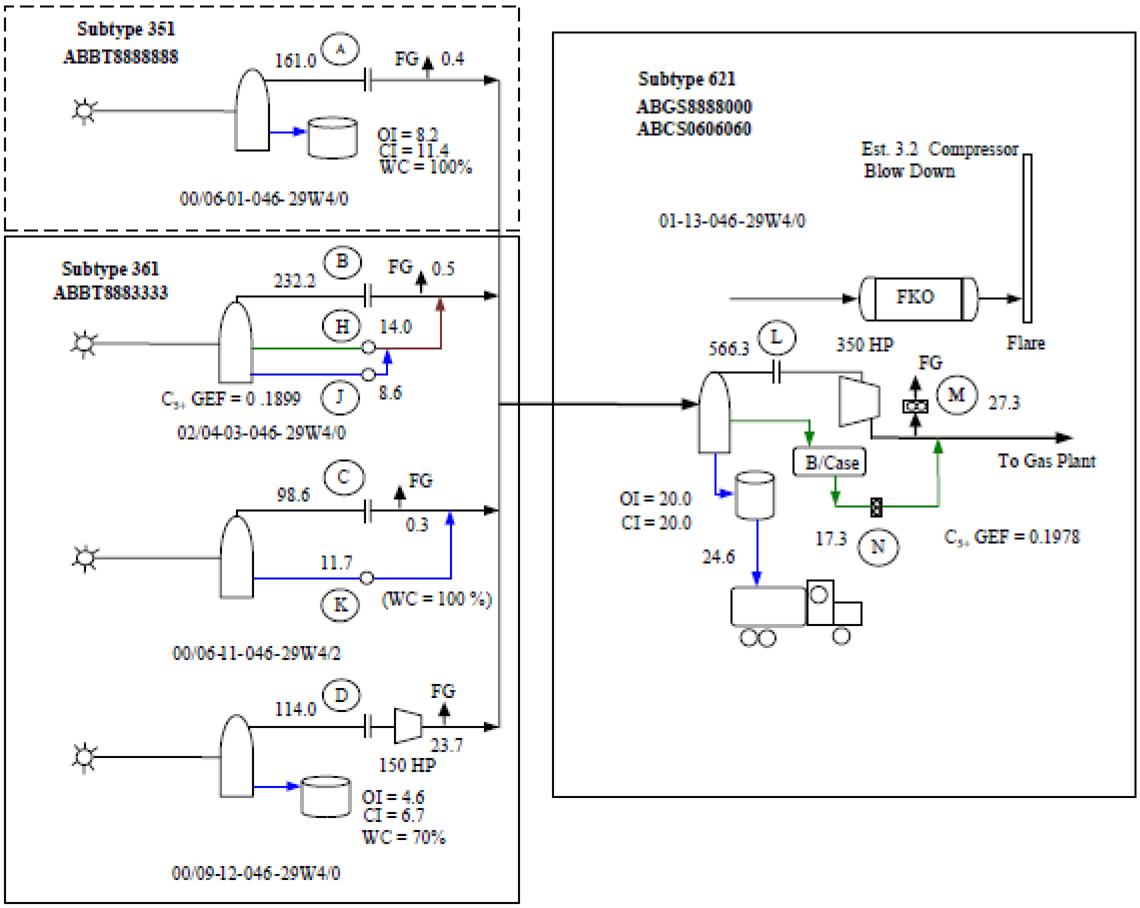
Case 2[1, 2]



ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.6
ABBT8888888 Water Production = 3.2
ABBT8882222 Gas Production = 232.2 + (14 x 0.1899) = 234.9; Delivered = 234.9 – 0.5 = 234.4
ABBT8882222 Water Production = 8.6
ABBT8883333 Gas Production = 98.6; Delivered = 98.6 – 0.3 = 98.3
ABBT8883333 Water Production = 11.7
ABBT8884444 Gas Production = 114.0; Delivered = 114 – 23.7 = 90.3
ABBT8884444 Water Production = (6.7 – 4.6) x 0.7 = 1.5
ABBT8884444 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Gas Receipts = 160.6 + 234.4 + 98.3 + 90.3 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

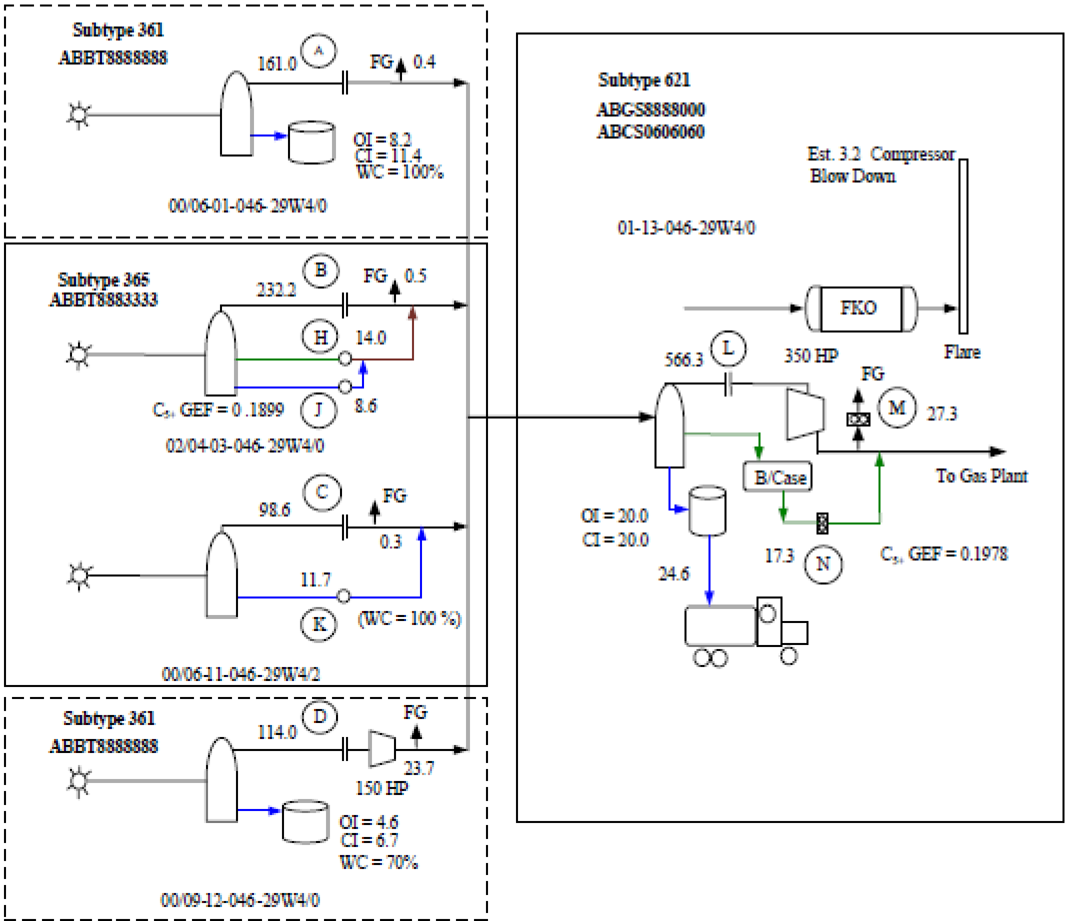
Case 3[1, 2]



ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.7
ABBT8888888 Water Production = 3.2
ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 + 114 = 447.5; Delivered = 447.5 – 24.5 = 423.0
ABBT8883333 Water Production = 8.6 + 11.7 + [(6.7 – 4.6) x 0.7] = 21.8
ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Receipts = 423.0 + 160.6 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

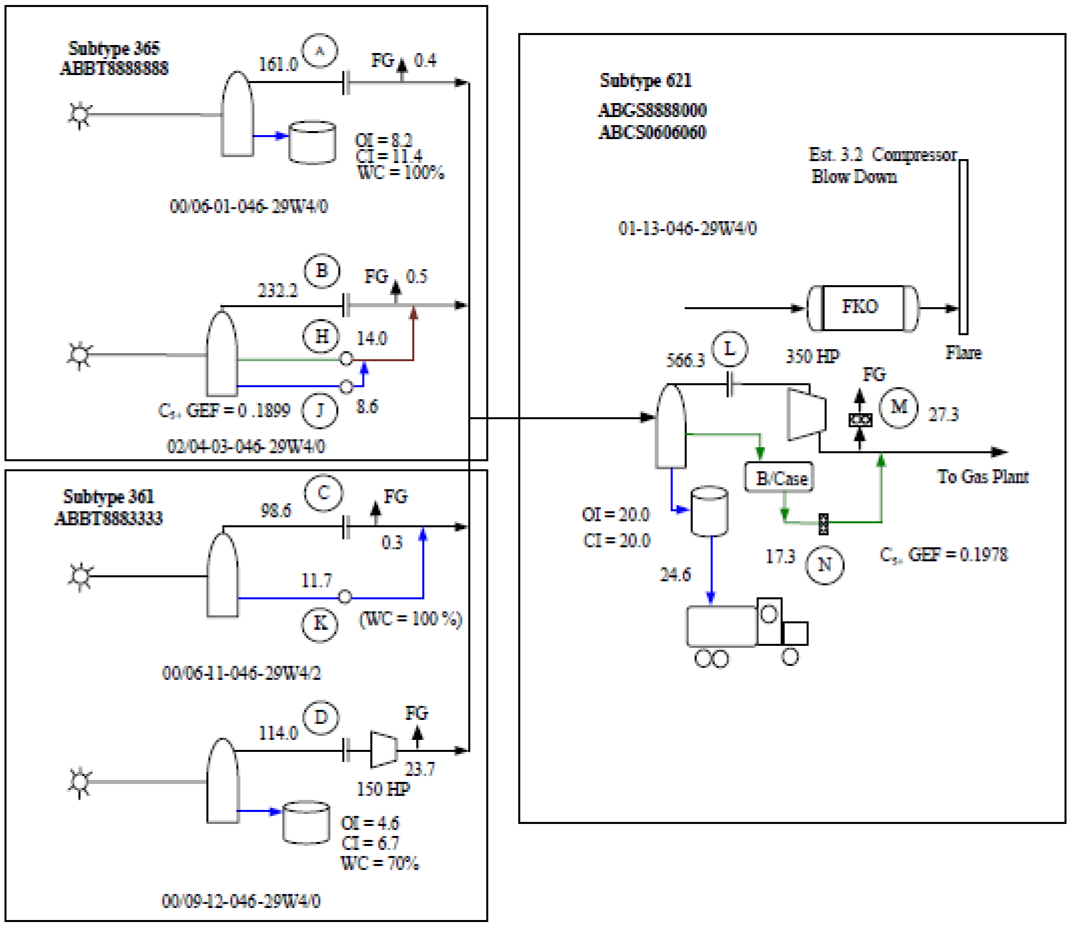
Case 4[1, 2]



ABBT8888888 Gas Production = 161.0 + 114.0 = 275.0; Delivered = 275 – 0.4 – 23.7 = 250.9
ABBT8888888 Water Production = (11.4 – 8.2) + [(6.7 – 4.6) x 0.7] = 4.7
ABBT8888888 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 = 333.5; Delivered = 333.5 – 0.5 – 0.3 = 332.7
ABBT8883333 Water Production = 8.6 + 11.7 = 20.3
ABGS8888000 Receipts = 250.9 + 332.7 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

Case 5[1, 2]



ABBT8888888 Gas Production = 161.0 + 232.2 + (14 x 0.1899) = 395.9; Delivered = 395.9 – 0.4 – 0.5 = 395.0
ABBT8888888 Water Production = (11.4 – 8.2) + 8.6 = 11.8
ABBT8883333 Gas Production = 98.6 + 114 = 212.6; Delivered = 212.6 – 24 = 188.6
ABBT8883333 Water Production = 11.7 + [(6.7 – 4.6) x 0.7] = 13.2
ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Receipts = 395 + 188.6 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly