INDEX OF REVISIONS

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0   ORIGINAL ISSUE
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1 INTRODUCTION

1.1 Object

1.1.1 This Technical Specification describes the minimum requirements for the project of the Flow Metering System (FMS) package of a typical UNIT.

1.2 Definitions

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<th>Measurement of the gas and oil production volume where the government requires taxation payments.</th>
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**NOTE:** Other words emphasized in upper case letters are defined in Coordination document I-ET-3010.1M-1200-940-P4X-001 - GENERAL TECHNICAL TERMS.

1.3 Abbreviations

The following abbreviations are used in this document:

- AC/DC: Alternating Current/Direct Current
- BS&W: Basic Sediments & Water
- CPL: Correction for the effect of Pressure on Liquid
- CSS: Control and Safety System
- CTL: Correction for the effect of Temperature on Liquid
- ELM: Electronic Locking and Monitoring
- FAT: Factory Acceptance Test
- FE: Shrinkage Factor (in Portuguese: “Fator de Encolhimento”)
- FMS: Flow Metering System
- GSV: Gross Standard Volume
- HCS: Hull Control System
- HMI: Human Machine Interface
- MrC: Closing Readings
- MrO: Opening Readings
- NSV: Net Standard Volume
- PCS: Process Control System
- P&ID: Piping and Instrument Diagram
- PI: Plant Information (software)
QTR  Quantity Transaction Report
RS   Solubility Ratio (in Portuguese: “Razão de Solubilidade”)
RTM  ANP/INMETRO Technical Regulation of Measurement of Oil and Gas
SAT  Site Acceptance Test
SIT  Site Integration Test
SOS  Supervision and Operation System
TWA  Temperature Weighted Average
XML  Extensible Markup Language

2  REFERENCE DOCUMENTS, CODES AND STANDARDS

2.1  External references

2.1.1  International codes, recommended practices and standards

**IEC - INTERNATIONAL ELECTROTECHNICAL COMMISSION**

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GENERAL CRITERIA FOR FLOW METERING SYSTEMS

IEC 62381 AUTOMATION SYSTEMS IN THE PROCESS INDUSTRY – FACTORY ACCEPTANCE TEST (FAT), SITE ACCEPTANCE TEST (SAT), AND SITE INTEGRATION TEST (SIT) - EDITION 2.0

ISO - INTERNATIONAL ORGANIZATION FOR STANDARDIZATION

ISO GUM PETROLEUM MEASUREMENT TABLE – PART 2: TABLES BASED ON A REFERENCE TEMPERATURE OF 20°C

ISO 91 PETROLEUM AND LIQUID PETROLEUM PRODUCTS – CALCULATION OF OIL QUANTITIES – PART 2: DYNAMIC MEASUREMENTS

ISO 4267-2 PETROLEUM AND LIQUID PETROLEUM PRODUCTS - CALCULATION OF OIL QUANTITIES - PART 2: DYNAMIT MEASUREMENT

ISO 5167-1 MEASUREMENT OF FLUID FLOW BY MEANS OF PRESSURE DIFFERENTIAL DEVICES INSERTED IN CIRCULAR CROSS-SECTION CONDUITS RUNNING FULL - PART 1: GENERAL PRINCIPLES AND REQUIREMENTS

ISO 5167-2 MEASUREMENT OF FLUID FLOW BY MEANS OF PRESSURE DIFFERENTIAL DEVICES INSERTED IN CIRCULAR-CROSS SECTION CONDUITS RUNNING FULL - PART 2: ORIFICE PLATES

ISO 5167-3 MEASUREMENT OF FLUID FLOW BY MEANS OF PRESSURE DIFFERENTIAL DEVICES INSERTED IN CIRCULAR-CROSS SECTION CONDUITS RUNNING FULL - PART 3: NOZZLES AND VENTURI NOZZLES

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### TECHNICAL SPECIFICATION

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| API – AMERICAN PETROLEUM INSTITUTE |

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| AGA – AMERICAN GAS ASSOCIATION |

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| NACE – THE NATIONAL ASSOCIATION OF CORROSION ENGINEERS |

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| OIML – ORGANISATION INTERNATIONALE DE METROLOGIE LEGALE |
### Title: General Criteria for Flow Metering Systems

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#### 2.1.2 Brazilian Codes and Standards

**ABNT – ASSOCIAÇÃO BRASILEIRA DE NORMAS TÉCNICAS**

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<th>MEDIÇÃO DE VAZÃO DE FLUIDOS POR DISPOSITIVOS DE PRESSÃO DIFERENCIAL, INSERIDO EM CONDUTOS FORÇADOS DE SEÇÃO TRANSVERSAL CIRCULAR. PARTE 1: PRINCÍPIOS E REQUISITOS GERAIS</th>
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**ANP – AGÊNCIA NACIONAL DO PETRÓLEO, GÁS NATURAL E BIOCOMBUSTÍVEIS**

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2.1.3.1 All MTE – Ministério do Trabalho regulations (NRs) shall be followed.

2.1.4 Classification Society

2.1.4.1 Detail design phase documentation of the project shall be submitted to approval by Classification Society. The design and installation shall take into account their requirements and comments.

2.1.4.2 The design, installation and operation shall strictly follow the classification society requirements, along with the specific requirements identified in this document, including also all requirements of referenced documents.
2.2 Internal References

2.2.1 Project Documents
- I-ET-3010.1M-1200-940-P4X-001 GENERAL TECHNICAL TERMS
- I-ET-3000.00-1200-940-P4X-001 TAGGING PROCEDURE FOR PRODUCTION UNITS DESIGN
- I-ET-3010.00-1200-800-P4X-002 AUTOMATION, CONTROL AND INSTRUMENTATION ON PACKAGE UNITS
- I-ET-3010.00-5520-888-P4X-001 CSS / SOS PANELS
- I-ET-3010.00-1200-956-P4X-002 GENERAL PAINTING
- I-ET-3010.00-1200-956-P4X-502 COLOR CODING
- I-ET-3010.00-1200-800-P4X-013 GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS
- I-ET-3010.00-1200-800-P4X-010 CRITERIA FOR ESTABLISHING CABLE CODES AND CABLE GLAND CODES
- I-ET-3010.00-5140-700-P4X-003 ELECTRICAL REQUIREMENTS FOR PACKAGES FOR OFFSHORE UNITS

2.2.2 PETROBRAS Reference Documents
- DR-ENGP-M-I-1.3-R.4 SAFETY ENGINEERING

2.3 Brazilian regulation (MTE section) and INMETRO regulation superpose all codes and regulations listed in item 2.2, since they are enforced by Brazilian law.

3 ELECTRICAL REQUIREMENTS

3.1 FMS Panel shall be fed by 2 (two) 220 Vdc (HOLD) power supplies according to I-ET-3010.00-5140-700-P4X-003 – ELECTRICAL REQUIREMENTS FOR PACKAGES FOR OFFSHORE UNITS. PACKAGER shall convert and distribute the different power supplies inside the panel, including voltage regulators (HOLD) where needed (eg. for the cabinet’s internal distribution of 24 VDC).

3.2 FMS skid shall receive a 480 Vac – 60 Hz power supply in order to feed the Compact Prover (see item 13.9.5).

4 FMS SCOPE

4.1 FMS shall be comprised by:
- Fiscal Oil Metering skids
- Allocation Oil Metering systems
- Fiscal Natural Gas Metering systems and metering runs
- Allocation Natural Gas Metering systems and metering runs
- Custody Transfer Metering skids
- Operational Oil, Natural Gas and Water Metering systems and runs
- FMS Automation System
- INMETRO Initial Verifications execution
• Documentation
• Integration, FAT, SAT, training and start-up services

4.2 FMS shall comply with Brazilian legislation, including National Agency of Petroleum, Natural Gas and Biofuels (ANP) and Brazilian National Institute of Metrology, Quality and Technology (INMETRO) regulations and all other documentation listed under section 2.

4.3 FMS shall be designed, selected, installed, commissioned and tested in order to comply with all technical requirements mentioned in the Technical Regulation Measurement of Oil and Natural Gas, or just “RTM”, approved by Resolução Conjunta ANP/INMETRO nº1 de 10/06/2013 (or other updated document which substitutes it), other supplementary regulations issued by ANP/INMETRO and in manufacturer’s recommendations, including all applicable standards and reference technical documents.

4.4 The scope of supply for the FMS shall include the field instrumentation: flow meters, pressure and temperature transmitters, BS&W analyzers, manual and automatic samplers, in-line filters (if applicable), flow conditioners, upstream and downstream straight meter runs, accessories, pneumatic actuated double block and bleed valves, pneumatic actuated butterfly flow control valves, interconnecting cables and junction boxes.

4.5 The scope of supply for the FMS Automation System shall include one Flow Metering System Panel with flow computers and Ethernet switches, and one dedicated Flow Metering System Workstation “HMI” with software. Also, the technical specifications and data sheets of panels, materials and devices required for flow measurements and issuing of measurement reports and uncertainty reports shall be included. Technical services regarding integration tests, tests, training, field instrument installation, verification, assistance to start-up and pre-operation, as well as the engineering check services related to field instrument data sheets provided by others shall also be part of the selected PACKAGER scope of supply.

4.6 The Initial Verification procedures and execution according to INMETRO rules shall be part of the FMS scope. It is PACKAGER’s responsibility the approval of its procedures at INMETRO prior to the construction of FMS.

4.7 A measurement management system shall be applied to the UNIT according to ISO 10012 “Measurement management systems — Requirements for measurement processes and measuring equipment” in order to assure the effectiveness and adequacy to the intended use, besides managing the risk of incorrect metering results. This system shall be implemented according to PETROBRAS project documents.

5 MEASUREMENT UNITS

5.1 The volume unit shall be cubic meter (m³) under the reference conditions of 20 °C for temperature and 101,325 kPa for pressure.
5.1.1 Volume unit for oil and gas measurements is the cubic meter (m³) at the reference conditions of 20 °C temperature and 101,325 kPa pressure.

5.2 The SI units shall be applied as follows:

- Temperature – °C
- Liquid flowrate – m³/h;
- Water vapour flowrate – t/h;
- Gas flowrate – m³/h (NOTE A);
- Pressure – bar or kPa (NOTE B);
- Vacuum and low pressure – bar abs. or kPa abs. (NOTE C);
- Level – % of span or mm;
- Density – kg/m³;
- Dynamic viscosity – cP or mPa.s (temperature informed);
- Cinematic viscosity – cSt (temperature informed).

NOTE A: For representation purposes on HMI screens (but not on documents), m³/d (cubic meters per day) or Mm³/d (thousand cubic meters per day) may be used.

NOTE B: All pressure measurements refer to manometric pressure, except where explicitly indicated.

NOTE C: Absolute pressure.

6 GENERAL REQUIREMENTS FOR THE INSTRUMENTATION SPECIFICATION AND STRUCTURE

6.1 The flow metering systems for fiscal, allocation, custody transfer and operational applications shall be comprised by complete meter runs with their respective flow computers, the latter being installed inside acclimatized area. Their instruments shall be dedicated to the flow and volume measurement and integrated in an independent way with respect to the UNIT’s instrumentation system (from the field instruments to the flow computers).

6.2 All data coming from flow computers shall be gathered in one unique workstation ("FMS HMI") dedicated to data record, storage and transmission.

6.3 Flow meters for fiscal, allocation and custody transfer applications shall be configured for pulse outputs, with the exception of differential pressure based meters (which shall use 4-20mA output) and ultrasonic flow meters for flare gas systems (which shall use field network).

6.4 Uncertainty measurement calculation reports of all metering systems shall be implemented according to ISO GUM, INMETRO, and ISO 5168 - MEASUREMENT OF FLUID GUIDE FOR EXPRESSION OF UNCERTAINTY OF MEASUREMENT FLOW - EVALUATION OF UNCERTAINTIES.
6.5 All flow computers, flow meters (except orifice plate based meters) and oil metering systems shall have Model / Type / Pattern Approvals from INMETRO (“PAM”) valid at the time of purchase, except the flow meters which do not need to be regulated by INMETRO. All PAM requirements, such as firmware version, flowrate ranges, etc. shall be attended.

6.6 The INMETRO “Initial Verification” process for the regulated flow meters, flow computers and oil metering systems (fiscal, allocation and custody transfer) shall be carried out according to the Brazilian Legislation.

6.7 In case of applying diesel or treated oil in the operations carried out at the wells, like operations for avoiding hydrates in flow lines, a fiscal metering system for the measurement of the injected volumes shall be used.

6.8 Pressure and temperature instruments shall be installed on piping or straight run of the same diameter of the primary flow meter, unless there is any normative restriction.

6.9 According to the fluid to be measured, the impulse tap orientation on the horizontal process lines shall be as indicated in Figure 6.1, as recommended by API RP 551.

![Figure 6.1 - Impulse tap orientation on horizontal process lines](image)

6.10 For natural gas metering, the instruments shall be installed “above the taps” and for liquid metering they shall be installed “below the taps” or at the same level.

6.11 All horizontal impulse lines shall have a minimum inclination of 1:10, avoiding the formation of slugs and aiming to ease the drainage or vent. In natural gas metering, the impulse lines shall be mounted inclined upwards. In liquid metering, the impulse lines shall be mounted inclined downward.

6.12 The maximum impulse line length shall be 1 m for applications that require low response time and compliance to a better measurement uncertainty level such as:
The metering technologies to be employed at the metering points shall follow the SUMMARY TABLE FOR METERING SYSTEMS presented in item 15. Attention shall be addressed to the calibration / inspection / verification of these flow meters as required by the current RTM, without causing production losses to the UNIT.

The computation of produced volumes by means of flow meters shall be performed by flow computers with Model / Type / Pattern Approvals by INMETRO.

It is allowed to send the instantaneous flowrate to CSS by means of a 4-20 mA analog output signal from the flow computer, for flow control purpose only.

All Cone meters shall be constructed according to items 5 and 6 of ISO-5167-5 and calibrated in flow laboratories.

For applications where there may be process instability with the possibility of eventual flow inversion, a check valve shall be installed downstream of the flow meter.

Complete access shall be provided for installation, maintenance, and removal (including lifting, if necessary) for all flow meters and components by means of walkways, stairs or decks. Additional space shall also be provided for removal and insertion of equipment aiming at maintenance and calibration tasks. Scaffolding as unique way of access shall not be accepted.

Measurement system shall be designed in compliance with its accuracy class – for oil – or maximum uncertainty allowable – for natural gas and water – in its full operation range (not necessarily its nominal range). Each metering point shall be designed for continuous measurement of all expected flow rates.

Meter tubes shall be mounted between flanges (spools) in order to allow periodic internal inspections of internal surface wall of the meter tube, as foreseen in the RTM. For the construction of straight upstream and downstream meter tubes, commercial tubes with flat internal walls shall be selected. In order to improve the internal surface roughness, the walls shall be machined, polished or covered to comply with the technical specifications.

Meter tubes shall be furnished with a certification document with all data (dimensions, roughness, etc.) according to international standards.

Fiscal, allocation and custody transfer metering systems shall not have bypass line arrangements.

Operational metering systems shall have bypass line for maintenance.

For field instruments and instrumentation accessories where painting is required, GENERAL PAINTING and COLOR CODING shall be followed. Internal and external panel color shall be light cream (Munsell notation 2.5 Y 9/4). Other panel colors, such as
SUPPLIER standard color, may be used, but shall be submitted to PETROBRAS written approval.

6.25 All instruments and electronic equipment shall be type approved and shall meet the requirements of IEC-61000-6-1/2 regarding electromagnetic compatibility and radio-frequency interferences (EMI/RFI).

6.26 All instruments, panels, materials and equipment proper to be used in hazardous areas, shall have conformity certificates complying with PORTARIA INMETRO Nº 179 de 18/maio/2010, and its annexes, changed by PORTARIA INMETRO Nº 89, de 23/fevereiro/2012, and shall be approved by Classification Society.

6.27 Local instruments and local panels located in Topsides non-classified open areas shall be certified to operate in Zone 2, Group IIA, T3 classified areas.

6.28 Instruments of the same type and function shall be of the same manufacturer.

6.29 In general, field instruments shall be direct mounted on piping. However, they shall be remote mounted in a tubular column or wall type support of 2 (two) inch, in the following cases:
- If high vibration is expected;
- Pressure instruments subjected to high temperature;
- Level instruments based on differential pressure;
- Flow instruments based on differential pressure;
- If instruments are not accessible for maintenance;
- When used for services where the process temperature exceeds +70ºC or below 0ºC.

6.30 Inline instruments as flow instruments or valves subjected to high vibration shall have electronic components remotely mounted.

6.31 Instrument air-supply regulator filters shall be of coalescent type.

6.32 The materials of casings or enclosures of all field instruments shall be according to I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS. For instruments where this requirement cannot be followed, the deviation shall be reported and the alternative submitted to PETROBRAS for approval.

6.33 Solenoid valves shall not be used for diameters larger than 1”.

6.34 For air consumption calculation, in addition to item 5.1.3 of I-ET-3010.00-1200-800-P4X-013 – GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS, gastight dampers can be considered as intermittent consumers and, thus, do not need to be taken into account for air consumption calculation.

6.35 The Instruments, valves, devices and materials shall be specified with appropriate materials for services with H₂S content so that the parts in contact with the fluid can resist to concentration in gas and oil according to Process Data. It shall take into account recommendations of the following standards, in the latest revisions:
6.36 Ball valves used for instrument installation shall have a protection avoiding the ejection of the ball when the valve is being maneuvered or removed by the body extremities.

6.37 Pneumatic Actuated Valves

6.37.1 Pneumatic Actuated Valves (XV) shall be supplied, installed for fiscal and custody transfer metering skids.

6.37.2 XV command shall be remote from FMS HMI and the logic performed by the FMS panel.

6.37.3 The valves shall be of high integrity ball type double-block-and-bleed.

6.37.4 All remote pneumatic actuated valves shall be supplied with solenoid valves, magnetic limit switches (with no moving parts) and have both remote and local position indication, “beacon type”. The limit switch shall permit set-point adjustment without disassembling the valve bodies.

6.37.5 Electrical enclosures shall be weather proof (IP-56) and explosion proof, Ex d, Zone 1, Group IIA T3, housing (stainless steel 316).

6.37.6 For additional requirements for actuated valves see I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.38 Pneumatic Actuated Control Valves

6.38.1 Pneumatic Actuated Control Valves (FV) shall be supplied and installed downstream of the flow meters on oil skids to provide flow stability during proving operation.

6.38.2 FV command shall be remote from FMS HMI and the logic performed by the FMS panel.

6.38.3 FV shall only be manually operated and not PID controlled.

6.38.4 FVs shall be of the butterfly body type.

6.38.5 Actuators shall be supplied with electro pneumatic positioner for these FVs.
6.38.6 Electrical enclosures shall be weather proof (IP-56) and explosion proof Ex d, Zone 1, Group IIA T3 housing (stainless steel 316).

6.38.7 For additional requirements for control valves see FIELD INSTRUMENTATION.

6.39 Transmitters

6.39.1 The associated pressure and temperature transmitters shall be of the accuracy Class 0.3 as defined in OIML R117 and Portaria Inmetro 64/2003, as follows:

<table>
<thead>
<tr>
<th>Transmitted Variable</th>
<th>Maximum permissible errors (MPE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature</td>
<td>+/- 0.3°C</td>
</tr>
<tr>
<td>Pressure less than 1 MPa</td>
<td>+/- 50 kPa</td>
</tr>
<tr>
<td>Pressure between 1 and 4 MPa</td>
<td>+/- 5%</td>
</tr>
<tr>
<td>Pressure greater than 4 MPa</td>
<td>+/- 200 kPa</td>
</tr>
</tbody>
</table>

6.39.2 The transmitters shall be smart microprocessor based type, 4-20 mA output, 2 wires, with alphanumeric display, 24 VDC power supply and provided with HART protocol.

6.39.3 Sensors shall be made in AISI 316 materials (sensor body, enclosure, connectors).

6.39.4 The transmitters shall be constructed with digital alphanumeric displays.

6.39.5 The transmitters shall be delivered with calibration reports issued by INMETRO or ILAC laboratories.

6.39.6 Pressure, differential pressure and temperature transmitters shall also comply with requirements from I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.40 Pressure Transmitters

6.40.1 Pressure transmitters shall be supplied, each one to be installed downstream of each flow meter. For gas metering systems, the pressure transmitters shall be supplied, each one to be installed upstream each flow meter.

6.40.2 For flare systems and measurement points where static pressure is below 10 bar, the pressure transmitters shall be of absolute pressure type.

6.40.3 Pressure instruments in hot condensable gas, vapors and steam service shall be protected from process media by siphons coils or condensate seals.

6.40.4 Pressure transmitters for crude oil service (or for corrosive or viscous fluid) shall use diaphragm seal.

6.40.5 Block valve and vent valve shall be provided for impulse line installation or alternately, close-coupled AISI 316 stainless steel 2-valve manifold according to API 551.
6.41 Differential Pressure Transmitters

6.41.1 Differential pressure transmitters shall be capable of withstanding full static pressure, on either port with, zero pressure on the other port, without damage or loss of calibration.

6.41.2 All differential pressure transmitters shall have both high and low pressure taps ("H" and "L" respectively) clearly and visibly indicated on their bodies.

6.41.3 Differential pressure transmitters shall be provided with close-coupled AISI 316 stainless steel 5-valve manifold.

6.41.4 For connection of pressure instruments, see item 6.9.

6.41.5 When using diaphragm seals, they shall be provided with a flushing ring between the process and the instrument connection to facilitate flushing with liquid from an external source. There shall be 2 (two) flushing connections ½" NPT(F) located on opposite sides of the ring and provided with isolation valves.

6.41.5.1 The filling liquid chosen shall be compatible with the maximum process temperature.

6.41.5.2 The type of capillary extension or sealing system legs (filling fluid, diameter etc.) shall minimize the influence of process and ambient temperature changes on the measurement. Response time of sealing systems shall be 5 s maximum.

6.41.5.3 Diaphragm seals shall be of the integral design. Where capillary extensions shall be used, the extension shall be AISI 316 stainless steel with AISI 316 stainless steel armoring and PVC covering. Capillary extensions shall be welded on both diaphragm seal and instrument sides. If required, provision shall be made to heat tracing the capillary extensions.

6.41.5.4 Care shall be taken in routing the capillary or sealing system legs to avoid effects of ambient temperature on the thermal expansion of the filling liquid. The capillary extension, if required, shall be provided with thermal insulation.

6.41.5.5 Diaphragm seals shall not be used on vacuum services.

6.41.5.6 Diaphragm seals shall be installed in a position avoiding deposit of dirt or debris on the seal surface.

6.41.6 Diaphragm seals in piping application shall be 2" diameter flanged, as a minimum.

6.42 Temperature Transmitters and Thermowells

6.42.1 Temperature transmitters shall be supplied, each one to be installed downstream of each flow meter.

6.42.2 For protection and test wells and internally lined vessels, nozzles shall be 3" flanged.
6.43 Manometers (Pressure Gauges)

6.43.1 Pressure gauges for crude oil service (or for corrosive or viscous fluid) shall be of diaphragm seal type.

6.43.2 Pressure gauges on steam service shall be provided with a siphon coil (pig tail type) connection.

6.43.3 Pressure gauges on pulsating service measurements (such as discharge of reciprocating compressors, pumps etc.) shall be provided with a pulsation damper.

6.43.4 Block valve and vent valve shall be provided for impulse line installation or alternately, close-coupled AISI 316 stainless steel 2-valve manifold according API 551.

6.43.5 Manometers shall also comply with I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS requirements.

6.44 Piping and Accessories

6.44.1 Piping and accessories shall comply with project’s Technical Specification document regarding piping specification.

6.44.2 Drain and vent devices shall be provided.

6.44.3 Piping and valves shall be according to project’s P&IDs.

6.45 Wiring

6.45.1 Wiring shall be according to I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.45.2 Cables shall be according to I-ET-3010.00-1200-800-P4X-010 - CRITERIA FOR ESTABLISHING CABLE CODES AND CABLE GLAND CODES.

6.45.3 Cable trays routed at the ground floor shall be of closed type and made in AISI 316.

7 CRUDE OIL METERING

7.1 Oil flow metering systems attending requirements such as fiscal, allocation, custody transfer and operational shall include transmitters for automatic compensation of the variations of pressure and temperature.

7.2 Oil flow metering systems shall comply with the accuracy classes (maximum allowable errors) required by the current RTM within the whole operating range.

7.3 Ancillaries or additional devices and the associated measurement instruments (e.g. pressure and temperature transmitters) shall be selected and operated so that their measured values are within the metering range and their accuracies shall be compatible with the metrological characteristics specified in the current RTM.
7.4 The flow meters shall be configured and calibrated in order to operate with volumetric flowrates, and shall operate according to the requirements established in the respective PAM, the flowrates indicated at the calibration certificates and the specific guidelines issued by the manufacturers, simultaneously.

7.5 The metering system shall be designed to prevent the flow of gases and vapors through the flow meters. The upstream operational pressure at the flow meter shall be greater than the liquid saturation pressure (or vapor pressure). If necessary, provision shall be made for the installation of a pump upstream of the metering system or, alternatively, installation of the metering system in a location below the upstream process equipment, in order to achieve an adequate hydrostatic column.

7.6 Any type of flow meter shall be installed at a point free from mechanical vibration or noise. If necessary, additional resources for minimizing vibrations shall be employed, such as expansion rings, damping devices, etc.

7.7 Routing hydrocarbon volumes directly to cargo tanks without fiscal metering is not acceptable. This requirement also includes any recovered oil volume and condensate streams from H.P Flare K.O Drum, L.P Flare K.O Drum, Closed Drain (if applicable), overflow (oil stream) from hydrocyclones, overflow (oil stream) from the flotation unit, overflow (oil stream) from slop tanks and others. The production unit shall be also capable of collecting and treating these streams and routing them back to the process plant upstream oil fiscal metering system.

7.8 Off-spec tanks, settling tanks or other tanks that may have crude oil not fiscal metered, which alignments do not return the oil to process plant shall have valves sealed controlled (locked) with open/close register on unit supervisory system (PI included). Unit shall have operational procedure to guarantee that the above mentioned alignments are used only in special circumstances and crude oil not fiscal metered is not routed to cargo tanks.

7.9 Fiscal, allocation and custody transfer oil metering systems shall have spare flow meters in order to not interrupt the metering process, in case of failure of any flow meter. In case of fiscal and custody transfer applications, the spare flow meter shall be installed in line and ready to operate. In case of failure or non-availability of the duty flow meter, the master meter (if existing) shall not be used as a duty meter, the spare flow meter being used meanwhile. The periods shall be observed (authorized or indicated in RTM) between successive calibrations.

7.10 The fiscal oil metering system shall comprise two duty meter runs, each one attending 50% of the maximum flowrate. Moreover, one spare meter run with the same characteristics of the main meter runs shall be installed (configuration commonly known as “3 × 50%”). If applicable, the master meter run shall be comprised only by the flow meter, flow conditioner, and pressure and temperature transmitters.

7.11 Sampling devices (manual and automatic sampler and BS&W analyzer) may be installed at common downstream the meter streams, in order to attend all meter runs. They still need to be mounted together on the skid structure, where applicable. The pertinent standards shall be addressed aiming at the correct installation of the samplers and in-line analyzers in order to guarantee their efficiency. For more
requirements regarding crude oil sampling, see item 11.1. For BS&W requirements, see item 12.

7.12 For leakage test purposes in metering systems equipped with associated calibration devices (fiscal, custody transfer and, eventually allocation), there shall be provided all necessary “double block and bleed” plug type valves with expanding slips – DBBPTES.

7.13 Installation of non-watertight elements between the duty flow meter and the calibration system, such as thermal relief valves, drains, etc., is not permitted. If it is necessary to install elements that present a leakage possibility, they must be installed upstream of the meter runs or downstream the calibration system.

7.14 Control valves shall be installed for each meter run for fiscal and custody transfer applications in order to allow flowrate control during the calibration process at the whole operation range. If necessary, they shall also be installed in the allocation meter runs.

7.15 Each oil flow meter shall be equipped with a dual pulse output arrangement and shall be linked directly to the flow computer. The pulse integrity and fidelity shall comply with the pertinent standards and shall be specified as B safety according to API MPMS 5.5.

7.16 In the initial calibration of the flow meters, the Meter Factors or K-Factor linearization shall be implemented in the flow computers.

7.17 Flow meters shall be able to withstand maximum design pressure and temperature conditions without the need for recalibration.

7.18 Upstream in-line filters shall be installed if turbine meters or positive displacement meters are used. The filter elements shall follow the meter manufacturer’s recommendation. Differential pressure transmitters shall be provided for monitoring the filters and providing alarms.

7.19 When using turbine type flow meters, the limits imposed by the PAM shall be observed in terms of viscosities, Reynolds Numbers and flow rate.

7.20 When using coriolis mass flow meters, special attention shall be considered regarding the upstream and downstream flange alignments and body ground supporting. In case of curve tube arrangement, the flow meter shall be installed with the curve down (relate to the main process line). The flow meter shall be installed in such a way it stays above the floor and the curve is not supported by the floor. Vibrations from the main piping and flow pulsation shall be avoided. The fluid velocities shall be below the erosional velocity limits imposed by API RP 14E. The manufacturer shall be consulted.

7.21 Ultrasonic flow meters shall be of the transit-time type and built with spools with sensors in contact with the fluid. They shall not be used for applications where the oil presents gas in solution greater than 5% and/or BS&W greater than 15%. The limits imposed by the PAM shall be observed in terms of viscosities and Reynolds Numbers. The number of paths for the ultrasonic flow meter shall be function of its
application which will indicate its accuracy. For oil fiscal and custody transfer applications, a minimum of 4 paths is mandatory. When calibrated at laboratories, the upstream and downstream straight tubes of the meter shall be connected to the flow meters, including the flow conditioners, if available.

7.22 Thermal pressure relief valves (PSV) shall be supplied at strainers or just before the strainers.

7.23 For any type of flow meters, the straight upstream/downstream meter run lengths shall comply with the respective PAM. In cases of PAM not being required, the respective standards shall be followed. If the standards are not prescriptive, the manufacturer recommendations shall be followed.

7.24 If required, upstream straightening vanes or flow conditioning devices shall be supplied to ensure accuracy and proper functioning of the meters.

7.25 For the straight upstream/downstream meter runs, there shall be considered the mechanical characteristics like the line schedule (which shall attend the adequate pressure class, even after the machining and lapping for internal wall roughness specification, etc.).

7.26 The meter runs shall be supplied with their respective inspection dimensional certificates and fabrication (material) certificates, complying with the pertinent standards in order to enable the complete traceability.

7.27 Flow meters enclosure shall be weather proof (IP-56) and explosion proof, Ex d Zone 1, Group IIA T3, housing (stainless steel 316).

7.28 Crude oil measurements shall be designed, selected, installed, commissioned and tested in order to comply with all technical requirements of the RTM, including all applicable standards and reference technical documents, instruments and devices manufacturer’s recommendations.

7.29 Crude oil flow metering systems shall comply with the following accuracy classes, according to OIML R117:

a) Accuracy class 0.3 – for the fiscal and custody transfer measurements, with maximum permissible relative error 0.2 % of the measured value for the flow meters and 0.3 % for the whole system;

b) Accuracy class 1.0 – for allocation and operational measurements, with maximum permissible relative error 0.6 % of the measured value for the flow meters and 1 % for the whole system.

7.30 Skids

7.30.1 The Fiscal and Custody Transfer Crude Oil Metering Systems shall be provided mounted on skids and able to be lifted.

7.30.2 The skids shall be mounted over a rigid steel stand-alone structure. The metering station design shall be developed so that it shall provide the ergonomic facilities for operation, inspection and maintenance procedures.
7.30.3 There shall be provided at the skids, resources to ease the assembling and disassembling of the metering devices and the inspection of the meter runs.

7.30.4 The skid shall be furnished fully mounted with all required accessories, such as: vent, drain, junction boxes, cable tray, cable, etc.

7.30.5 The skids shall be delivered totally mounted, with each flow meter and its associated instruments interconnected with the junction boxes, checked, ready to be installed and connected to the external equipment of the FMS. All junction boxes shall be installed in the same location at the skid limit.

8 NATURAL GAS METERING

8.1 Fiscal natural gas production metering shall be carried out, necessarily, downstream of the process plant. This metering shall be done upstream of any gas transferring or transportation system (see ANNEX A – EXAMPLE OF METERING SYSTEM DIAGRAM).

8.2 Fiscal and allocation gas flow metering shall be done by means of orifice plates, with the exception of flare gas metering systems. Integral orifice flow meters are not acceptable.

8.3 Metering runs shall have internal diameters equal to or greater than 50 mm according to NBR ISO 5167 standard.

8.4 The natural gas properties calculation at the flow computers shall be carried out according to ISO 12213 (AGA 8) and ISO 6976 standards, independently of the associated CO\textsubscript{2} content.

8.5 Fiscal, allocation, custody transfer and operational metering systems shall be provided with pressure and temperature transmitters for automatic correction of their timely variations. For gas metering systems where differential pressure transmitters are applied, if the rangeability may be greater than 3:1 or 4:1, two transmitters shall be used.

8.6 For all natural gas metering points that operate with pressures below 10 bar, the pressure transmitters shall be of the absolute pressure type.

8.7 Ancillaries or additional devices and the associated measurement instruments (eg.: pressure and temperature transmitters) shall be selected and operated in order to have their measured values within the metering range and their accuracies shall be compatible with the metrological characteristics specified in the current RTM.

8.8 The flow computers shall allow at least the uploading of the natural gas composition values within the range of C1 to C6+, in addition to the contaminants (O\textsubscript{2}, H\textsubscript{2}, N\textsubscript{2}, H\textsubscript{2}S, CO\textsubscript{2}, CO).

8.9 Flow metering uncertainty level (expanded), for the whole system at all expected flow rates shall be calculated with an approximately 95% confidence level and shall be according to item 15 - SUMMARY TABLE FOR METERING SYSTEMS.
8.10 Natural gas metering points implemented by orifice plate shall consist of: orifice plate, dual chamber orifice fitting device (where required for P&IDs), upstream meter tube, downstream meter tube, Zanker conditioner and flow, pressure and temperature transmitters. Flow, pressure and temperature transmitters shall be linked to their respective flow computer.

8.11 Metering points implemented by cone meters shall consist of cone and flow, pressure and temperature transmitters. Transmitters shall be linked to their respective flow computer. Bypass and block valves shall be provided for operational metering points. A set of non-installed stand-by meters shall be supplied, at least one per diameter, for the same process condition.

8.12 Orifice Plates for Natural Gas Metering

8.12.1 Orifice Plate Application Criteria

c) The projects shall follow the standards (NBR) ISO 5167-1 and (NBR) ISO 5167-2;

d) The pressure taps shall be of the “flange taps” type and the orifice plates shall be installed in meter runs in the horizontal plane;

e) In cases of larger flowrate ranges, if one single orifice plate with two transmitters for increasing rangeability is not sufficient, then a set of orifice plates shall be provided in order to cover the whole expected flowrate range;

f) For fiscal, allocation and custody transfer metering points, and operational metering points that operate continuously, dual chamber orifice fitting devices shall be used. For operational metering points that do not operate with continuous flows, in which it is possible to change or inspect the orifice plate without impacts to the process, the use of dual chamber orifice fitting devices is not obligatory;

g) All orifice plate gas metering points shall use flow conditioners to reduce meter run length and to keep meter run dimensions independent of upstream piping features. The flow conditioning devices shall be of the Zanker type;

h) Orifice plates shall be constructed in AISI 316, unless the service conditions require other special material;

i) Drain orifices at the orifice plates are not allowable. Drainage shall be provided at the dual chamber orifice fittings drains, including block valve and needle valve. This drainage shall be provided in order to enable the complete depletion of the liquid accumulated at the system. Drain devices shall be sealed;

j) Square edge orifice plate required thickness shall follow Table 8.1. These thickness values are applied for a maximum differential pressure of 2.5 bar.
8.12.2 Orifice Plate Installation

a) Each field component of the measurement system (straight sections, flow conditioner, plate holder, orifice plates) shall be identified by means of an alphanumeric identification code ("Tag") and a serial number, which shall be engraved on its body in a way that it does not interfere the metering process. The tags directives shall be according to I-ET-3000.00-1200-940-P4X-001- TAGGING PROCEDURE FOR PRODUCTION UNITS DESIGN;

b) Interference with structural beams, structure frames, etc. shall be avoided whenever positioning the orifice fitting devices so as to allow the removal and placement of orifice plates in a safe manner;

c) It shall be assured that the impulse lines of any metering point are exposed to the same ambient temperature. Therefore, it is recommended that the impulse lines be aligned and mounted alongside each other;

d) The impulse lines shall be the shortest possible ones. It is recommended that the line length is shorter than 1 m (API 551 item 8.3.1);

e) The impulse lines internal diameter shall be equal and within the 10-13 mm range;

f) The straight upstream/downstream meter runs shall be installed between flanges in order to facilitate the periodic internal inspections. Attention shall be considered to the maximum bounce required by standard for mounting of these flanges upstream of the orifice plate, including the flow conditioner. A minimum of 2D (two diameters) pipe length shall be included (integral part of the orifice fitting device) between the upstream face of the orifice plate and the flanges;

g) The static pressure tap shall be connected to the high pressure tap of the orifice fitting device;

h) The process connections shall be ½”;

i) The thermal well shall be installed at the same spool of the straight downstream meter run and placed after the minimum length of straight pipe run required by the standard;
j) For the sizing of rods and thermal wells, the immersion length shall be according to Table 8.2 and Figure 8.1. The distance "A" shall be standardized at 152 mm (6") as indicated in Figure 8.1.

Table 8.2 – Immersion lengths for thermal wells in piping

<table>
<thead>
<tr>
<th>Line nominal diameter [mm / inch]</th>
<th>Immersion length [mm / inch]</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-250 / 4-10</td>
<td>1/3 - 1/2 of internal nominal diameter</td>
</tr>
<tr>
<td>above 250 / above 10</td>
<td>1/4 - 1/3 of internal nominal diameter</td>
</tr>
</tbody>
</table>

Figure 8.1 – Piping flange installation for thermal well

8.12.3 Orifice Plate Sizing

a) The calculations shall be carried out in such a way that the usual (normal) flowrate is approximately 70% of the calculated flowrate value adopted, the minimum flowrate is less than 30% of the adopted calculated flowrate value and the maximum flowrate is about 95% of the calculated flowrate value.

b) The maximum differential pressure value shall be selected so that the beta factor (d / D) of the orifice plate lies between 0.2 and 0.67 for plates applied on fiscal, allocation and custody transfer metering systems. In any case, the orifice shall not
be less than 12.5 mm. The final metering uncertainty shall be evaluated soon after the selection of the beta factor. The final metering uncertainty shall be within the admissible uncertain limits for the type of metering application (fiscal, allocation, custody transfer or operational).

c) The maximum differential pressure value for the orifice plate calculation shall not exceed 250 kPa (2500 mbar). The differential pressure value shall not exceed 20% of the normal upstream static pressure. If the differential pressure is greater than 2.5% of the static pressure, an increase in the uncertainty of the expansion factor shall be considered.

8.13 FLARE GAS METERING

8.13.1 The flare gas metering systems, where large variations of pressure are observed (including atmospheric pressure) and flowrates as well, shall be provided with ultrasonic transit time flow meters mounted in spools with live retrievable transducers (retrievable during normal operation) and in direct contact with the fluid.

8.13.2 The flare metering systems shall be designed for the entire flowrate range of the main process line. In case of impossibility on the range determination, 0.03 to 120 m/s shall be used. For more details, API MPMS 14.10 shall be consulted.

8.13.3 The ultrasonic flow meters shall allow the removal of their transducers during normal operation for intrinsic calibration (dry calibration). The cable length between the transducers and the electronic equipment shall be long enough to enable the calibration at the proper meter installation site.

8.13.4 The flare gas, pilot gas and purge gas metering systems shall be provided with flow computers with model/type approval by INMETRO. The same shall be applied whenever the project includes gas metering for assistance gas and/or dilution gas.

8.13.5 The pilot gas, purge gas and assistance gas metering systems shall meet the requirements for production operational control (ANP classification) and shall be provided with pressure and temperature compensation for the flowrate computation. These volumes shall be computed for the burned gas registration at the flare system. These streams shall be measured at the fiscal flare gas meters or shall be derivate at downstream of the metering point of the consumed fuel gas fiscal metering point.

8.13.6 In case the flare dilution gas stream exists, it shall be measured fiscally at the high and low flare gas flow meters.

8.13.7 For all metering points of the flare gas system (flow meters at the flare main lines, purge, pilot, dilution, assistance) which operate below 10 bar, pressure transmitters shall be of the absolute pressure type.

8.13.8 A tool shall be delivered for removal and reinstallation of the ultrasonic sensors (transducers) without shutting down the process (i.e., in full operation).
8.13.9 The flow meters mounting shall be according to Figure 9.1 (or other arrangement recommended by manufacturer), considering the necessary physical space (horizontal plane) for the sensors removal during the normal operation and their position shall be in horizontal process lines, with easy access.

8.13.10 The pressure and temperature signals shall be linked to the electronic unit of the flare flow meter manufacturer and transmitted to the flow computer. The pressure and temperature compensation to the reference flow conditions shall be executed exclusively at the flow computer and not on the flare flow meter.

Figure 9.1 – Available space for sensors removal (horizontal plane)

8.13.11 The flowrate signal transmission from the electronic unit of the flare gas flow meter (flow meter manufacturer’s model) to the flow computer shall be made by means of field network, e.g.: Modbus. It shall be observed that the implementation enables the correct signal transmission within the entire flowrate range of the flow meter.

8.13.12 The transducers shall be spool mounted delivered along with the flow meter. The spool piece shall contain the pressure and temperature taps positioned according to the standards and manufacturer recommendations. The straight upstream/downstream pipe runs do not need to be obligatorily delivered along with the flow meter.

8.13.13 The spool piece shall be subjected to a dimensional inspection procedure (INMETRO / ILAC) prior to its installation in the field, in order to obtain transducer mounting angles and pipe internal diameter, among other parameters. Such parameters shall be used at the internal programming of the flow meters and flow computers.
8.13.14 The manufacturer electronic unit shall be provided with protection against solar radiation.

8.13.15 The upstream and downstream straight pipe runs shall have minimum lengths of 20D and 10D respectively (nominal diameters). For different lengths, additional technical studies shall be presented (Computational Fluid Dynamics) in order to demonstrate the mounting possibility and the required flow metering uncertainty compliance with ANP and INMETRO regulations. Manufacturer shall be consulted.

9 CONDENSATE METERING

9.1 The calculation of the temperature correction in the condensate volume (CTL) shall follow API MPMS 11.2.4 TEMPERATURE CORRECTION FOR THE VOLUME OF NGL AND LPG TABLES 23E, 24E, 53E, 54E, 59E AND 60E.

9.2 Calculation of the pressure correction (CPL) for the condensate volume shall use the API MPMS 11.2.2M COMPRESSIBILITY FACTORS FOR HYDROCARBONS: 350-637 KILOGRAMS PER CUBIC METER DENSITY (15 DEG C.) AND 46 DEG. C TO 60 DEG. C METERING TEMPERATURE.

9.3 Special care shall be taken regarding the pressure drop in the flow meters in order to avoid condensate vaporization. Ultrasonic flow meters shall be applied in the most critical cases, following the same technical requirements for the oil metering in this document.

10 WATER METERING

10.1 For applications such as produced, injected or disposal water, the following technologies shall be used: magnetic, cone or orifice plate. In the case of water metering in the test separator outlet, coriolis mass meters may be considered as well.

10.2 For applications such as produced, injected or disposal water, bypass lines shall be provided in order to enable the meter calibrations.

10.3 Sizing and other requirements shall comply with ISO 20456 (magnetic flow meters), (NBR) ISO 5167-2 (orifice plates) and ISO 5167-5 (cone meters).

10.4 For all cases, temperature transmitters and flow computers shall be included. In case of water metering at the test separator outlet and for the injected water metering (pressure greater than 40 bar), pressure transmitters shall also be included. For the individual water metering points (per well), it is acceptable to use single pressure and temperature transmitters at the downstream injection pumps, provided the metering uncertainties comply with the limits defined at item 15 - SUMMARY TABLE FOR METERING SYSTEMS and there is no relevant pressure drop between the pressure transmitter and the primary flow element.

11 SAMPLING REQUIREMENTS

11.1 Crude Oil Sampling - General
11.1.1 For oil metering points, sampling shall be carried out by manual means in all cases.

11.1.2 For fiscal and custody transfer oil metering systems, automatic sampling shall also be performed additionally to the manual sampling required in item Erro! Fonte de referência não encontrada.

11.1.3 For every oil metering point, there shall be a sample collection point at atmospheric pressure for determining BS&W and density. For oil production allocation points, the sample collection point shall also allow for the collection of pressurized oil under process conditions in order to determine the Shrinkage Factor (FE) and Solubility Ratio (RS).

11.1.4 Pressurized samples shall be provided with sampling local panels containing brackets for cylinders/bottles. The fixation brackets shall be adjustable in order to allow the use of cylinders of various lengths. The fluid inlet and outlet connections shall be made exclusively by means of short hoses.

11.1.5 Oil sampling probes shall be mounted in horizontal process lines or in vertical process lines with upward flows.

11.1.6 Sampling probes shall have a 45° beveled cut and shall be installed in the central third (1/3 of the diameter) of the pipe with the opening feature facing upstream. In case of crude oil allocation metering systems, the probes shall be of the bundle type (with 5 or more internal beams, see Figure 11.1).

11.1.7 The sampling system shall be designed in accordance with API MPMS Chapter 8 (plus related sections) for continuous measurement and calculations of all expected flow rates. For crude oil metering points, the manual and automatic samplers shall comply with API MPMS 8.1 and 8.2 respectively.

11.1.8 If the sampling systems adopt collector vessels instead of vertical containers, they shall comply with NR-13 requirements.

11.1.9 For inline crude oil allocation metering points, a homogeneous mixture shall be guaranteed. Preferably, the sampling point shall be installed in a vertical process line with upward flow. If the sampling point is installed in a horizontal process line, a mixer shall be provided upstream of this sampling point.

11.1.10 For metering systems with more than one meter run, a single manual sampling point shall be provided for the main stream. The same applies to the automatic sampling system, if available.

11.1.11 The automatic oil sampling system shall collect and store a representative oil sample at flow conditions, allowing it to be transported to the laboratory for repeatable analysis. The collecting system shall be skid mounted. If containers are used, they shall be installed inside local closed panels. For each container, a dedicated system shall be provided for detecting its status and when the container is full (by level or weight measurement) to the flow computer.

11.1.12 The automatic oil sampling system control shall be controlled by the flow computer or by the PLC installed in the FMS panel.
11.1.13 The local closed panels shall be located as close as possible to the sampling points.

11.1.14 The local closed panels shall contain a manual sample point, equipped with flushing facilities with required valves and quick connectors, in addition to the containers facilities.

11.2 Natural Gas Sampling – General

11.2.1 Each natural gas metering point, including flare gas metering points, shall have a representative and manual sampling point. The sampling points shall be as close as possible to their respective metering point, and shall be designed to be easily accessible by the operator, without the need for scaffolding or other means. There shall be no elements which could alter the pressure and temperature conditions between the metering point and the natural gas sampling point.

11.2.2 The sampling points associated with the gas metering system shall comply to API MPMS 14.1, emphasizing the need for a minimum distance of 5D (5 pipe nominal diameters) downstream of any disturbance or pipe accident.
11.2.3 The sampling points shall be provided with local sampling panels with brackets for the cylinders/bottles and the sampling process shall be performed in a closed circuit with alignment of the purge gas to the flare system. A tap on a sampling panel shall not be shared among different fiscal metering points.

11.2.4 Gas sampling probes shall be intrusive and mounted at the top of horizontal process pipelines, and the mounting arrangement shall comply with API MPMS 14.1. Sampling probes shall have a 45° beveled cut and shall be installed in the central third (1/3 of the diameter) of the pipe with the opening feature facing downstream the flow direction.

11.2.5 In case of the production unit having a flare gas recovery system (closed flare), the sampling points shall be located immediately upstream of the derivation to the flare gas recovery system.

11.2.6 For all sampling points of individual gas-lift metering points, the use of a single collector at the total gas-lift metering point is allowed. In this case, the sampling can be done without installation of sampling points at the individual gas-lift streams, provided that it is possible to show that the total gas-lift stream is representative of the individual streams.

11.2.7 For flare gas sampling points, there shall be installed a collecting system provided with vacuum pumps.

11.2.8 For sampling point details and locations refer to project’s P&IDs and SAMPLING POINT TECHNICAL SPECIFICATION.

12 IN-LINE BS&W ANALYZER REQUIREMENTS

12.1 For fiscal, allocation and custody transfer oil metering systems, in-line BS&W analyzers shall be installed.

12.2 The BS&W instantaneous values shall be available to the operator and to the production unit control system on a continuous and automatic basis for monitoring purposes.

12.3 In order to allow the removal of the analyzer during operation (without process shut-down), it shall be retrievable probe type or installed in a bypass line with a diameter smaller than the diameter of the main process line.

12.4 Analyzers shall be selected according to technology as a function of the BS&W operational range.
Table 13.1 – BS&W analyzer technology selection according to range

<table>
<thead>
<tr>
<th>Recommended Technology</th>
<th>Operational Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacitive</td>
<td>BS&amp;W &lt; 30%</td>
</tr>
<tr>
<td>Microwave</td>
<td>0 % &lt; BS&amp;W &lt; 100 %</td>
</tr>
<tr>
<td>Radiofrequency</td>
<td>0 % &lt; BS&amp;W &lt; 100 %</td>
</tr>
<tr>
<td>Coriolis</td>
<td>BS&amp;W &gt; 5%</td>
</tr>
</tbody>
</table>

12.5 There shall be observed all the possible variation influences which might alter the BS&W analyzer performance, as follows:

- Salinity variations in the produced water;
- Density variations in the fluids;
- Free gas presence (% vol);
- Oil continuous or water continuous regimes (consider oil continuous: BS&W ≤ 30 %; water continuous: BS&W ≥ 50 %; transition: 30 % < BS&W < 50 %).

12.6 When BS&W ≥ 50 %, the automatic compensation for the water salinity shall be evaluated.

12.7 For in-line oil allocation metering points, a homogeneous mixture shall be guaranteed. Preferably, the in-line BS&W analyzer shall be installed in a vertical process line with upwards flow. A mixer shall be installed upstream of the analyzer in case it is installed in a horizontal process line. API MPMS 8.2 shall be considered.

13 CALIBRATION SYSTEMS

13.1 The fiscal and custody transfer oil metering systems shall mandatorily include local calibration systems composed of one or more standards, chosen among the following:

a) Mechanical Compact Prover (Small Volume Prover) + Master Meter + Duty Flow meters. In this configuration, the Compact Prover shall be used for calibrating the Master Meter and the Master Meter shall be used for calibrating the Duty Flow meters. For this case, the Master Meter shall be turbine type and the Duty Flow meters can be of the following types: ultrasonic (with 4 or more paths/channels), turbine or Coriolis.

b) Mechanical Compact Prover (Small Volume Prover) + Duty Flow meters. In this configuration, the Compact Prover shall be used for calibrating the Duty Flow meters directly. In this case, the Duty Flow meters shall be turbine type only.
13.2 For fiscal and custody transfer oil metering points, control valves shall be installed downstream of each meter run, in order to enable the flowrate control for each meter run. Additionally, a control valve shall also be installed downstream of the Compact Provers, so as to enable flowrate control during flow meter calibration.

13.3 The oil allocation flow meter (or the Master Meter, if available) shall be removed from the line for calibration at the oil fiscal metering system. Therefore, one additional meter run shall be provided at the oil fiscal metering system for calibrating the allocation flow meter (or the Master Meter, if available) against the Compact Prover (namely “calibration run”).

13.4 Special attention shall be considered when the additional meter run for the calibration of the allocation meter is installed parallel to the fiscal metering system. The flow meter shall also be in accordance with all fiscal metering requirements.

13.5 It shall be possible to calibrate the flow meters over the full flowrate range (as defined by the Project).

13.6 One Compact Prover shall be installed at the oil fiscal metering system and one Compact Prover shall be installed at the oil custody transfer metering system (if custody transfer point is available).

13.7 The presence of any non-leak-tightness element between the flow meter under calibration and the Master Meter or Compact Prover is not allowed.

13.8 In order to enable the compact prover calibration on board, an available adjacent space shall be provided, minimum of 3 m² in the direction of the prover axis.

13.9 **Compact Prover (Small Volume Prover – SVP)**

13.9.1 Compact provers shall be sized according to API MPMS 4.3 or ISO 7278 and be provided with bypass valves, and inlet and outlet valves of the double block and bleed type.

13.9.2 Compact provers shall have their instrumentation integrated to the flow computers responsible for executing the main flow metering tasks, so that the flow computers may be used to execute the calibrating operations (proving).

13.9.3 Compact Provers shall be Double Chronometry type as per API 4.6, design according to API 4.2 Displacement Provers, primary volume shall be at least 0.265 m³, and turn-down shall be at least 1000:1.

13.9.4 The compact provers shall be:

- Able to calibrate the flow meters and meet the RTM requirements;
- Delivered with calibration certificate issued by organization accredited by INMETRO or ILAC;
- Connected to the flow computers in order to calibrate all flow meters;
- Mounted inside the skid limits;
- Able to withstand maximum design pressure and temperature process conditions.
13.9.5 The Compact Prover shall be installed at the Compact Prover Skid and shall have the following requirements:

- Be able to perform the calibration of the master meter flow meter;
- There shall be provided inlet and outlet valves;
- The instrumentation and controls shall be integrated to the Crude Oil Fiscal Flow Computer in charge of executing the proving flow measurements, making sure that calibration and operation will be carried out by the same instrument;
- A skid-mounted control panel shall be included to provide remote interface to the Compact Prover;
- shall comply with API MPMS, Chapter 4.3 or ISO-7278;
- shall utilize double chronometry pulse interpolation to prove the flow meter as per API 4.6;
- All prover seals shall be filled PTFE. The flow tube, end flanges, connection flanges and internals shall be in AISI 316 L;
- repeatability factor shall be less than 0.05%;
- All skid electrical components shall be pre-wired to this control panel. The panel enclosure shall meet the requirements for use in hazardous areas (Zone 1, Group IIA, Temperature Class T3, according to IEC-60079) and it shall be proper for marine atmosphere (minimum protection IP-56);
- The skid shall be designed in order to provide all the resources to allow the flow meters calibration as well as the compact prover calibration, including: piping, manual valves, flanges, required space and resources for the installation of the prover calibration tools, trays, draining, drip pan, power supply, etc;
- For each operation of meter proving, it shall be generated, at least, the following information, automatically:
  - Calibration of gross K-Factor;
  - Calibration of K-Factor, corrected for temperature and pressure or meter factor;
  - Flow during the meter prover run;
  - Frequency of pulses;
  - Number of counted pulses in prover run;
  - Calibration Factors related to the correction of the effects of temperature and pressure of the fluid, temperature and pressure of the piping, temperature and pressure of the prover, etc;
  - Repeatability Factor.
- The available power supply shall be 480 Vac.
14 AUTOMATION REQUIREMENTS

14.1 FMS Automation System

14.1.1 An interface between the production UNIT’s CSS and the FMS shall be provided in order to allow the transferring of operational data from the flow computers to the UNIT’s SOS.

14.2 Communication Architecture

14.2.1 Flow computers shall communicate with FMS Workstation and HMI through the FMS Ethernet Switch such as defined by I-ET-3010.00-1200-800-P4X-002 - AUTOMATION, CONTROL AND INSTRUMENTATION ON PACKAGE UNITS.

14.2.2 The interface with SOS HMIs shall be made through Package Units LAN.

14.2.3 FMS Workstation shall communicate with automation firewall by Ethernet link, for onshore communication, through a dedicated network card.

14.2.4 Ethernet standard for switches, cables, network cards and network links shall be according to project’s specific documentation.

14.3 FMS Panel

14.3.1 The FMS Panel shall accommodate the flow computers, PLC, Ethernet switch and all the necessary devices related to the valves alignment actuation.

14.3.2 The FMS Panel shall be free-standing type, protection class IP-22, with frontal door with acrylic window frame. It shall have a locking key or seal and shall be protected from opening by unauthorized personnel.

14.3.3 The FMS Panel shall be delivered completely assembled with all components internally connected and shall be installed indoors.

14.3.4 All external communication digital networks shall be properly prepared to allow the interconnections to/from the field and to/from FMS Panel.

14.3.5 An Ethernet switch shall be provided in order to manage all Ethernet links. Ethernet standard and switch manufacturer shall be according to documentation specific to the project.

14.3.6 An additional flow computer (backup) shall be provided for metering of liquids and another additional flow computer (backup) for natural gas metering, which shall be installed in the FMS panel.

14.4 PLC and Ethernet Switch

14.4.1 A simplex PLC shall be supplied.

14.4.2 The PLC also controls the actuations of the valves and the automatic sampler.
14.4.3 The PLC shall be supplied with I/O cards to attend the signals of the valves and signals of the automatic sampler.

14.4.4 The PLC shall comply with IEC 61131 parts 1, 2, 3, 4, and 5.

14.4.5 The PLC shall have an Ethernet standard IEEE 802.3 TCP/IP communication port.

14.4.6 The Ethernet switch shall be connected to the following devices in the panel: PLC; HMI and Flow computer. The Ethernet switch shall also be connected to the SOS, CSS-PCS and/or CSS-HCS.

14.4.7 Ethernet Protocol shall be OPC.

14.5 Flow Computers

14.5.1 All flow computers shall be INMETRO approved in accordance with Portaria INMETRO 499 de 02/10/2015 or any other that complements or replaces it, observing the firmware version indicated in the respective PAM.

14.5.2 The calibration information and the intervention history of the FMS shall be provided by the flow computers.

14.5.3 Flow computers shall be arranged segregating flow loops as below:
- Fiscal flare gas measurements;
- Fiscal natural gas measurements;
- Allocation natural gas measurements;
- Operational CO₂ and natural gas measurements;
- Fiscal oil measurement (at least one for each skid), including the Compact Prover and the turbine master meter;
- Custody transfer oil measurement (at least one for each skid), including the Compact Prover and the turbine master meter;
- Allocation oil measurement;
- Operational oil and water measurements.

14.5.4 Flow computers shall be installed inside FMS Panel and shall be linked to the FMS HMI and UNIT’s SOS HMIs.

14.5.5 All associated devices for each metering point shall be interconnected to the flow computers according to P&IDs.

14.5.6 Complete database of flow computers shall be available at FMS HMI.

14.5.7 Some data base of flow computers with information such as: differential pressure, static absolute pressure, temperature, instantaneous flow rate and compensated and totalized flow for each measurement point, high/low flow and analyzer malfunction alarms shall also be available, as minimum, at the UNIT’s SOS HMIs.

14.5.8 All BS&W measurements of FMS shall have their analyzers interconnected to the respective flow computer and the data shall be available at the FMS Workstation and at UNIT’s SOS HMIs.
14.5.9 In specific situations, flow computers shall have analog outputs to send the instantaneous flow rate to CSS – PCS and/or CSS – HCS in order to control process variables.

14.5.10 Flow computers shall have 1 (one) interface in order to allow the connection of external devices as notebook or hand-held for ANP audit purposes.

14.5.11 Flow computers shall have an alphanumeric display in order to allow measuring point selection and information and shall be furnished with all required software, licenses and configuration data.

14.5.12 All flow calculations shall be performed at flow computers and taken into account the inviolability of the configuration. Alarms, reports and event files shall be prevented from editing.

14.5.13 The hardware and software shall be protected from editing and changing parameters by means of passwords, hardware keys, etc. There shall be at least, 3 (three) access levels.

14.5.14 Calibration data and historian intervention data (audit trail) shall also be available at the flow computer to comply with RTM.

14.5.15 Flow computer for flare gas flow meters shall be linked to the flow meter electronic unit by RS-485 MODBUS network communication.

14.5.16 Oil flow computers shall provide the calculations according to ISO-4267-2, proven by independent certification. The correction factors for flow measurements shall include:

   a) Thermal expansion within operation temperature and reference temperature (20 °C) and the oil measurement temperature;
   b) Liquid compressibility between the reference pressure (101,325 kPa) and the oil measurement pressure;
   c) Contents of sediments and water in oil (BS&W), obtained by online analyzers and manual means;
   d) Oil shrinking (Shrinkage Factor), considered in cases of allocation measurement (FE) and Solubility Rate Factor (RS);
   e) Thermal expansion between the reference temperature (20 °C) and water measurement temperature, considered in cases of allocation measurement, when determining the Meter Factor;
   f) Liquid compressibility between the reference pressure (101,325 kPa) and water measurement pressure, considered for the cases of allocation measurement, at the determination of the water;
   g) Meter Factor, obtained by calibration (MF).

14.5.17 The algorithms of the gas flow computers shall comply with ISO 5167-1.

14.5.18 Each flow computer (FQIT in the P&IDs) is related to a metering point. Each flow computer shall manage up to 4 (four) metering points.
14.5.19 The oil fiscal meter run loops shall be distributed in 2 separated flow computers at least.

14.5.20 Pulse transmission between flow meters and flow computers shall be compatible, observing the passive pulses cases.

14.5.21 Flow computer shall perform all functions required by PETROBRAS standards and shall comply with the requirements of RTM.

14.5.22 The flow computer shall be supplied with all required software, licenses and configuration data and shall have a Touch-screen display. Additionally they shall have one USB interface in order to allow the connection of external devices as notebook and all functions necessarily for the complete and safe operation of the metering system.

14.5.23 The flow computer shall be able to perform proving functions. All basic flow metering information as: currently flow rate, compensated and totalized flow, pressure, temperature, BS&W, Flow control, valve position (where applicable), and all functions necessarily for the complete and safe operation of the metering system, shall also be available at FMS Workstation.

14.5.24 All flow calculations shall be performed at flow computer taken into account the inviolability of the configuration. Alarms, reports and event data files shall be generated and stored at flow computer and prevented from editing.

14.5.25 Calibration data and historical intervention data shall also be available at the flow computer.

14.5.26 All pressure, temperature, instantaneous / compensated flow rate and totalized flow values, at the minimum, shall be available in FMS Workstation and UNIT’s SOS.

14.5.27 The flow computer shall have a communication link RS-485 Modbus RTU or Ethernet Modbus TCP/IP to transfer data.

14.5.28 There shall be stored at the Flow Computers (in a FIFO-type queue), at least the following reports, in order to allow ANP audit:
   - Last 200 (two hundred) system events.
   - Last 200 (two hundred) system alarms.

14.5.29 The hardware and software shall be protected from editing and changing parameters by means of passwords. Restricted access shall have at least, three levels: administration level, level 1, and level 2, as follows:
   - Administration level: this level allows free access for changes at the configuration, including all passwords, data loggers’ initialization and firmware downloading.
   - LEVEL 1: allows the download and writing at the parameters, including the critical ones.
   - LEVEL 2: allows the writing at ordinary parameters.
**Note:** All changes at the configuration shall be traceable. In order to allow the traceability, passwords shall be implemented as follows: before writing in the flow computer parameters, it is necessary to write at the LOGIN parameter, and then at the PASSWORD_CODE. If the logon is successful, user shall have the period of time specified at FCT.LOGON_TIMEOUT to write in those parameters. Every time anything is written at a password protected parameter, the timeout is re-started. After this, it is necessary to re-write at the parameter PASSWORD_CODE (HOLD).

14.5.30 Data fidelity at the HMI, flow computers and metering reports shall be guaranteed, once there can occur information with different number of bits (e.g.: HMI with 32 bits and flow computer with 64 bits). In this case, the decimal digits shall be limited, observing the legal requirements.

14.6 **FMS HMI**

14.6.1 An additional FMS dedicated interface shall be provided with the UNIT’s SOS. This interface shall be named “FMS HMI” (or, in Portuguese, “IHM de Medição”) and is responsible for transferring operational data from the flow computers to the UNIT’s supervisory system (SOS).

14.6.2 There shall be only one FMS HMI concentrating the information of all metering points, even if the FMS scope of supply of the metering system is segmented.

14.6.3 The FMS HMI shall integrate topsides and hull flow metering systems.

14.6.4 The FMS HMI shall be installed in a conditioned room, along with the flow computers which shall be placed in a single panel.

14.6.5 The FMS HMI shall provide the necessary functionalities for complete operation and calibration of the flow meters, including:

- Actuation of the alignment valves (automatic or manual, remote or local);
- Alarm generation and recognizing related to abnormal conditions at the metering systems;
- Manual input of system configuration data and parameters;
- Adjustment of the post-calibration flow meters and flow computers settings;
- Generation of metering reports with detailed visions on the HMI screens;
- Automatic register of operator interventions;
- Automatic register at the HMI of the panel and field equipment status;
- HMI screens with general and detailed visions including process variable values;
- System historical data register at the HMI;
- Auto diagnosis system and automatic failure annunciation;
- Generation, uploading and downloading of configuration files and parametrization of flow computers via HMI and local;
- Access control to the flow computers configuration via proper resources of the flow computers or HMI;
- Routine for oil offloading functioning start, including logic tasks at the flow computers.
14.6.6 FMS Workstation and HMI Requirements

14.6.6.1 The HMI Touch Panel Computer shall be proper for installation on the front panel and its minimum requirements (including supervisory software) shall be according to documentation specific to the project.

14.6.6.2 The workstation shall be based on an IBM-PC compatible microcomputer, with minimum configuration requirements defined at documentation specific to the project.

14.6.6.3 All software installed shall be provided with licenses and media for installation, as well a backup of all configuration and programs implemented.

14.6.6.4 All flow computers data shall be available at the FMS workstation.

14.6.6.5 An alarm shall be provided at HMI, at FMS Workstation and at SOS if the flow rate in each meter run exceeds limits of the allowable uncertainty required.

14.6.6.6 Historical data (variables, parameters, events and interventions) shall be available at the FMS Workstation’s storage device for, at least, 3 (three) months, increased daily.

14.6.6.7 An adequate number of dynamic high-resolution full-graphic video pages and windows shall be prepared by PACKAGER to allow direct on-screen monitoring and operation of the Flow Metering Systems at FMS Workstation, taking into account all acquired data and commands, meter run control, meter calibration control, security control of operator entered parameters, system monitoring, trouble-shootings etc. These screens and windows shall be approved by PETROBRAS.

14.6.6.8 FMS Workstation shall be responsible for the generation of all production data reports for audit purposes in order to enable the automatic sending of data to ANP. The workstation shall have the following features:

- The measurement system shall provide means of storing the daily production data and configuration of flow computers aiming future audits;
- Files shall be sent in batch mode (not in line);
- The synchronization of clocks between the flow computers and supervisory system shall be provided;
- All data from production volumes shall be based on the flow computer variable “Previous Day Net (NSV) Totalizer” of each measurement net to ensure the fidelity of all systems.

14.6.7 The FMS HMI shall generate the XML electronic files automatically. The FMS HMI shall also provide all the necessary data for the generation of these XML electronic files by an external generator. The XML files shall attend ANP Resolutions 65/2014 and 737/2018.

14.6.8 Reports and Logs

14.6.8.1 FMS shall update and keep reports and files in order to comply with the last
issue of RTM. The reports and files shall be ready and delivered, when requested by PETROBRAS, ANP or INMETRO.

14.6.8.2 The HMI shall keep the historical registers, reports of the fiscal, allocation and custody transfer metering systems for, at least, 10 years, in hard disk, solid state drive or in the automation network server at an incremental daily basis. Automatic recording shall be provided for the historical registers in order to ensure the backup recording of the information required by ANP.

**NOTE:** See ANNEX B for the FMS Automation Architecture.

14.6.8.3 All data flow and XML file generation shall have access restriction / control and shall be auditable. The data shall be protected against unauthorized access, tampering and/or loss of information, whether accidental, intentional or environmental.

14.6.8.4 There shall be a communication link between the FMS HMI and PETROBRAS Corporate Network, in order to enable the availability of the XML electronic files or the necessary data needed for their generation.

14.6.8.5 General reports to be generated by FMS:
- Well Test Report (for each well) – “Batch Report”;
- Fiscal Quantity Transaction Report (QTR) (for cargo tanks and/or offloading) – “Batch Report”;
- Calibration Report (for each calibration done onboard) – “Proving Report”;
- Audit Trail Report (for each flow computer);
- Configuration Report (for each flow computer);
- Alarm Report (for each flow computer);
- Hourly Report (for each flow computer).

14.6.8.6 General log files to be generated by FMS:
- Daily Configuration Data Log (for each flow computer);
- Daily Input and Output Data Log (for each flow computer);
- Daily Audit Trail Log (for each flow computer);
- Daily Alarm Log (for each flow computer).

14.6.8.7 All log files shall be generated according to formats defined in (last editions):
- API/MPMS 21.1 – ELECTRONIC GAS MEASUREMENT;
- API/MPMS 21.2 – FLOW MEASUREMENT-ELECTRONIC LIQUID MEASUREMENT.

14.6.8.8 Reports to be generated by FMS, related to gas measurements:
- Last 24 (twenty four) hours – hourly average values of: volume, flow rate, differential pressure, static pressure, temperature, density;
• Last 35 (thirty five) days – daily values of the average values of: volume, flow rate, differential pressure, static pressure, temperature, density.

14.6.8.9 Reports to be generated by FMS related to Crude Oil measurements:
• Last 24 (twenty four) hours – hourly average values of: volume, flow rate, pressure, temperature, CTL, CPL;
• Last 35 (thirty five) days – daily values of the average values of: volume, flow rate, pressure, temperature, CTL, CPL.

14.6.8.10 Reports to be generated by FMS related to water measurements:
• Last 35 (thirty five) days – daily values of the average values of: volume, flow rate.

14.6.8.11 File recording at the FMS Workstation
• Refer to the item Erro! Fonte de referência não encontrada. for communication between the Flow Computers and the FMS Workstation.
• All files mentioned at in item Erro! Fonte de referência não encontrada. shall be created based at the actual data from the flow computer simply by uploading, keeping its inviolability.
• Files shall be kept at the FMS Workstation’s non-volatile memory / dedicated directory and shall be recorded at a main USB flash drive and a backup device in a monthly basis.

14.6.8.12 Synchronicity between flow computers and FMS Workstation
• In order to set up the better synchronicity between all Flow Computers and the FMS Workstation clocks, there shall be a means of synchronization of the Flow Computer with the FMS, consider the FMS clock as reference.
• The FMS Workstation shall read and write time and date in the flow computers once a day for the following registers:
  Current - Hour  
  0 - 23
  Current - Minute  
  0 - 59
  Current - Second  
  0 - 59
  Current - Month  
  1 - 12
  Current - Day of Month  
  1 - 31
  Current - Year  
  0 - 99; Year 2000 = 00
  Current - Day of Week  
  Read only. 1 = Monday; 7 = Sunday

14.6.8.13 Fidelity between flow computers, FMS Workstation and other automation systems.

14.6.8.14 All production volumes at the FMS Workstation shall be based on the variable “Previous Day Net (NSV) Totalizer” of each flow loop.
14.6.8.15 The following registers shall be updated once a day:

- Total quantities for the previous day; ‘day start hour’ to ‘day start hour’:
  - Previous Day’s - Gross (IV) Totalizer
  - Previous Day’s - Net (GSV) Totalizer
  - Previous Day’s - Mass Totalizer
  - Previous Day’s - NSV Totalizer

- The same for the average data:
  - Previous Day’s - Average Flow
  - Previous Day’s - Average Temperature
  - Previous Day’s - Average Pressure
  - Previous Day’s - Average Density
  - Previous Day’s - Average CTL
  - Previous Day’s - Average CPL
  - Previous Day’s - Average Meter Factor
  - Previous Day’s - Average Specific Gravity
  - Previous Day’s - Average Density @ Reference Temperature
  - Previous Day’s - Average Density Temperature
  - Previous Day’s - Average Density Pressures
  - Previous Day’s - Average Density Correction Factor
  - Previous Day’s - Average Unfactored density
  - Previous Day’s - Average K Factor
  - Previous Day’s - Average Viscosity
  - Previous Day’s - Average Linear Correction Factor
  - Previous Day’s - Average Gross Flowrate
  - Previous Day’s - Average % BS&W
  - Previous Day’s - Average Equilibrium Pressure

**Note:** All these log files shall be kept at the flow computers for FMS Workstation reading during the last 35 (thirty five) days.

14.6.8.16 PETROBRAS will define how to generate the XML file in the Detailing Design.

14.6.8.17 The FMS Workstation shall have a dedicated window for viewing the XML files.
# 15 SUMMARY TABLE FOR METERING SYSTEMS

<table>
<thead>
<tr>
<th>Item</th>
<th>Fluids</th>
<th>Metering points</th>
<th>Duty</th>
<th>Type of meter</th>
<th>Accuracy (note 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Oil</td>
<td>Cargo pump discharge (offloading)</td>
<td>Custody transfer metering</td>
<td>Ultrasonic or Coriolis (note 2) or turbine meters; flow computer. Minimum 1 spare meter installed.</td>
<td>± 0.3% (system) ± 0.2% (sensor)</td>
</tr>
<tr>
<td>2</td>
<td>Oil</td>
<td>Cargo pump discharge (offloading)</td>
<td>Calibration of Custody transfer metering</td>
<td>Master meter and Prover (note 2), or only Prover; flow computer</td>
<td>± 0.1% (system)</td>
</tr>
<tr>
<td>3</td>
<td>Oil</td>
<td>Transference pump discharge (from the process plant to the cargo tanks)</td>
<td>Fiscal metering</td>
<td>Ultrasonic or Coriolis (note 2) or turbine meters; flow computer. Minimum 1 spare meter installed.</td>
<td>± 0.3% (system) ± 0.2% (sensor)</td>
</tr>
<tr>
<td>4</td>
<td>Oil</td>
<td>Transference pump discharge (from the process plant to the cargo tanks)</td>
<td>Calibration of fiscal metering</td>
<td>Master meter and Prover (note 2), or only Prover; flow computer</td>
<td>± 0.1% (system)</td>
</tr>
<tr>
<td>5</td>
<td>Oil</td>
<td>Well injection operations (Diesel and/or Treated Oil)</td>
<td>Fiscal Metering</td>
<td>Positive Displacement, Coriolis (with volume indication) or helical turbine meter (note 3); flow computer (note 10)</td>
<td>± 0.3% (system) ± 0.2% (sensor)</td>
</tr>
<tr>
<td>6</td>
<td>Oil</td>
<td>Test separator</td>
<td>Allocation metering</td>
<td>Coriolis (with volume indication) (note 3); flow computer</td>
<td>± 1.0% (system) ± 0.6% (sensor)</td>
</tr>
<tr>
<td>7</td>
<td>Oil</td>
<td>Production / Treatment</td>
<td>Operational metering</td>
<td>Positive Displacement, Coriolis (with volume indication) or turbine meter with flow computer</td>
<td>± 1.0% (system) ± 0.6% (sensor)</td>
</tr>
<tr>
<td>8</td>
<td>BSW</td>
<td>Transference pump discharge (from the process plant to the cargo tanks)</td>
<td>Online</td>
<td>Online transmitter (Microwave, RF) with static mixer (note 4)</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>BSW</td>
<td>Transference pump discharge (from the process plant to the cargo tanks)</td>
<td>Sampler</td>
<td>Automatic and manual (installed downstream of the static mixer)</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>BSW</td>
<td>Well injection operations (Diesel and/or Treated Oil)</td>
<td>Sampler</td>
<td>Automatic and Manual (note 10)</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>BSW</td>
<td>Test separator</td>
<td>Online</td>
<td>Online transmitter (Microwave 0-100%) with static mixer</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>BSW</td>
<td>Test separator</td>
<td>Sampler</td>
<td>Manual (installed downstream of the static mixer)</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>BSW</td>
<td>Cargo pump discharge (offloading)</td>
<td>Online</td>
<td>Online transmitter (Microwave, RF) (note 4)</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>BSW</td>
<td>Cargo pump discharge (offloading)</td>
<td>Sampler</td>
<td>Automatic and manual (installed downstream of the static mixer)</td>
<td></td>
</tr>
<tr>
<td>Item</td>
<td>Fluids</td>
<td>Metering points</td>
<td>Duty</td>
<td>Type of meter</td>
<td>Accuracy (note 1)</td>
</tr>
<tr>
<td>-------</td>
<td>--------------</td>
<td>-------------------------------</td>
<td>-----------------</td>
<td>-------------------------------------------------------------------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td>15</td>
<td>Gas</td>
<td>Export Line (note 9)</td>
<td>Fiscal metering</td>
<td>Orifice plate meter with flow computer; dual chamber orifice fittings and removable straight pipe sections to be provided</td>
<td>± 1.5%</td>
</tr>
<tr>
<td>16</td>
<td>Gas</td>
<td>Import Line (note 9)</td>
<td>Fiscal metering</td>
<td>Orifice plate meter with flow computer; dual chamber orifice fittings and removable straight pipe sections to be provided</td>
<td>± 1.5%</td>
</tr>
<tr>
<td>17</td>
<td>Gas</td>
<td>Gas Lift individual per Well</td>
<td>Allocation metering</td>
<td>Orifice plate meter with flow computer; dual chamber orifice fittings and removable straight pipe sections to be provided</td>
<td>± 2.0%</td>
</tr>
<tr>
<td>18</td>
<td>Gas</td>
<td>Gas Lift Total</td>
<td>Operational metering</td>
<td>Cone (note 8) or Orifice Plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided) with flow computer</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>19</td>
<td>Gas</td>
<td>Gas Injection individual per Well</td>
<td>Operational metering</td>
<td>Cone (note 8) or Orifice Plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided) with flow computer</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>20</td>
<td>Gas</td>
<td>Gas Injection Total</td>
<td>Operational metering</td>
<td>Cone (note 8) or Orifice Plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided) with flow computer</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>21</td>
<td>Gas</td>
<td>Test separator</td>
<td>Allocation metering</td>
<td>Orifice plate meter with flow computer; dual chamber orifice fittings and removable straight pipe sections to be provided (note 8)</td>
<td>± 2.0%</td>
</tr>
<tr>
<td>22</td>
<td>Gas</td>
<td>Production separators</td>
<td>Operational metering</td>
<td>Orifice plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided) or Cone meter with flow computer (note 8)</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>23</td>
<td>Gas</td>
<td>Fuel Gas Consumers (notes 5, 5.1 and 5.2)</td>
<td>Operational Metering</td>
<td>Orifice plate meter or Cone meter (note 8) with flow computer</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>24</td>
<td>Gas</td>
<td>Fuel Gas Total (note 5)</td>
<td>Fiscal Metering</td>
<td>Orifice plate meter with flow computer; dual chamber orifice fittings and removable straight pipe sections to be provided</td>
<td>± 1.5%</td>
</tr>
<tr>
<td>25</td>
<td>Gas</td>
<td>Service Gas Total</td>
<td>Operational metering (note 6)</td>
<td>Cone (note 8) or Orifice Plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided) with flow computer</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>26</td>
<td>Gas</td>
<td>HP Flare</td>
<td>Fiscal metering</td>
<td>Ultrasonic flare meter with flow computer</td>
<td>± 5.0%</td>
</tr>
<tr>
<td>27</td>
<td>Gas</td>
<td>LP Flare</td>
<td>Fiscal metering</td>
<td>Ultrasonic flare meter with flow computer</td>
<td>± 5.0%</td>
</tr>
<tr>
<td>28</td>
<td>Gas</td>
<td>CO₂ Vent (if needed)</td>
<td>Fiscal metering</td>
<td>Ultrasonic flare meter for natural gas with high CO₂ content with flow computer</td>
<td>± 5.0%</td>
</tr>
<tr>
<td>29</td>
<td>Gas</td>
<td>Flare Pilot</td>
<td>Operational metering</td>
<td>Orifice plate meter with flow computer (note 5.1)</td>
<td>± 3.0%</td>
</tr>
<tr>
<td>30</td>
<td>Water</td>
<td>Test separator</td>
<td>Allocation metering</td>
<td>Orifice plate meter, magnetic meter (spool type) or Coriolis meter; pressure and temperature transmitter, flow computer</td>
<td>1.0%</td>
</tr>
</tbody>
</table>
### GENERAL CRITERIA FOR FLOW METERING SYSTEMS

<table>
<thead>
<tr>
<th>Item</th>
<th>Fluids</th>
<th>Metering points</th>
<th>Duty</th>
<th>Type of meter</th>
<th>Accuracy (note 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>Water</td>
<td>Individual Injection</td>
<td>Operational metering</td>
<td>Orifice plate meter, Cone meter, magnetic meter (spool type) with flow computer</td>
<td>1.5% (individual) (note 7)</td>
</tr>
<tr>
<td>32</td>
<td>Water</td>
<td>Produced</td>
<td>Operational metering</td>
<td>Orifice plate meter, Cone meter, magnetic meter (spool type) with flow computer</td>
<td>1.0%</td>
</tr>
<tr>
<td>33</td>
<td>Water</td>
<td>Disposal</td>
<td>Operational metering</td>
<td>Orifice plate meter, Cone meter, magnetic meter (spool type) with flow computer</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

NOTES:

1. Maximum allowable errors for liquid metering; uncertainty for gas metering;

2. Ultrasonic meter shall have 4-channels as minimum. In case of using ultrasonic or Coriolis meters as duty meter, a master meter and a prover are required and the master meter shall be a turbine meter;

3. The duty meter shall be calibrated against a master meter or a prover at the UNIT’s facilities. If a master meter is used, it shall be proved against a prover at the UNIT’s facilities;

4. The analyzer shall be able to be disassembled without interruption of the whole metering system operation;

5. INTEGRATOR shall provide means to measure separately the gas flow rates of the following fuel gas consumers (if applicable): gas-turbines, turbo-generators and boilers; flow meters as part of those equipment packages are acceptable.

5.1) Flare pilot or any other flow which is flared without being previously measured by LP Flare Meter or HP Flare Meter shall automatically generate Daily Metering Reports in “.XML” files containing production, configuration and log data extracted from flow computers according to ANP specifications (“Resolução ANP 65/2014” and other supplementary regulations issued by ANP/INMETRO);

5.2) Fiscal gas meter configuration shall avoid metering gas streams twice or more, i.e. in case a process unity uses fuel gas and returns it to process, this fuel gas shall be derived upstream the fuel gas total fiscal meter;

6. If not measured in other flows, the service gas shall comply with fiscal measurement requirements and shall comply with the same requirements as other fiscal gas meters with dual chamber orifice fittings (i.e.: purge gas);

7. The water injection metering shall be designed to allow the water injection flow rate measurement of each well separately. One temperature transmitter and one pressure transmitter shall be provided. Shared temperature and pressure transmitters for injected water points are acceptable depending on the design;

8. When using Cone meter for operational purposes, a bypass line may be required in order to do maintenance on the flow meter without process interruption. Also a means of dimensional verification and/or calibration shall be provided. The verification procedure shall be presented for PETROBRAS comments during the basic project. For each metering point, one spare Cone shall be available.
16 DOCUMENTATION

16.1 Complete documentation of the FMS, covering all devices and services, shall be supplied with the proposal, for approval, and for final acceptance.

16.2 All documentation shall be provided in physical means (printed on paper) and in digital media. All documents shall be provided in editable format (.doc, .xls, or other compatible) and drawings in Microstation.

16.3 Proposal Documentation

16.3.1 There shall be supplied with the proposal, in the number of copies defined at SUPPLIER documents, at least the following technical documents:

- Technical specifications, comprising: system, equipment, accessories, cables, materials and software;
- Document List;
- Data-sheets and brochures for each equipment;
- All equipment and installation data including: material list, equipment list, spare part list, power consumption, weight, software manual, panel lay-out, system layout, etc.;
- Complete description of services, training courses, tests, etc.

16.4 Approval Documentation

16.4.1 There shall be supplied for approval, in the number of copies defined at SUPPLIER documents, at least the following technical documents:

- Technical description of the production unit metering system (“Memorial Descritivo dos Sistemas de Medição”); (in Portuguese language)
- Schematic Diagram for Metering System (“Diagrama Esquemático das Instalações”); (in Portuguese language)
- PAM of flow meters and flow computers (fiscal, allocation and custody transfer); (in Portuguese language)
- Maintenance, calibration and operation manual of the FMS; (in Portuguese language)
- Calculation Memory containing the sizing of primary elements (orifice plates, etc.) and associated meter run lengths, sampling systems and pressure drop values;
- FMS automation architecture drawing;
- FMS automation description manual; (in Portuguese language)
- Technical specifications comprising: systems, equipment, accessories, cables, materials and software;
- Data-sheets and drawings for each equipment and field instruments;
- Flow meters Vendor User Manuals;
- Technical documents as installation drawings including general arrangement, isometrics, P&ID, automation and control system architecture,
electrical diagrams, wiring diagrams, cables layout, cable list, material list, equipment list, spare parts list, loop diagrams, primary flow devices sizing worksheets, uncertainty calculations and associated calibration certificates;

- Test procedures, training course program, services schedule;
- Programming tools, system reports, system diagnosis;
- BS&W calculation and sampling procedures (HOLD);
- Wells Production Allocation Descriptive Memorandum (HOLD);
- Well Test Report – Template (HOLD);
- Flow Metering System Report – Template;
- Estimated chemical composition of gas production for each well (chromatography) (HOLD);
- Estimated crude oil, gas and water production for each well (HOLD);
- Calibration certificate of each calibration standard;
- As-built isometric drawings of metering points;
- Flow computers configuration reports;
- Flow meters configuration reports;
- Calibration certificate of all instruments, latest version;
- Calculations about estimated measurement uncertainties for each fiscal, allocation and custody transfer metering points.

16.5 FMS Schematic Diagram and Technical Description Documents

16.5.1 The following documents (in Portuguese language) shall be submitted to ANP for approval: (1) “Schematic Diagram for Metering System/Diagrama Esquemático das Instalações”; and (2) “Technical description of the production unit metering system /Memorial Descritivo dos Sistemas de Medição”.

16.5.2 These documents shall be issued when the FMS basic project is concluded, prior to the construction phase.

16.5.3 If there are ANP comments on these documents that might cause changes in the project, they shall be complied with.

16.5.4 These documents shall describe each fiscal, allocation, custody transfer and operational oil, gas and water flow measurement points, their applied technologies and system measurement uncertainty (preliminary) calculations.

16.6 FMS Detailment Documents

16.6.1 The scope shall contain, at least but not limited to, the following technical documents:

- Flow Measurement System architecture drawing and description;
- Data-sheets and drawings for each equipment;
- Data-sheets of all instruments and primary elements;
### Installation drawings with straight meter tube dimensions, including general arrangement;
- Simplified P&IDs of oil flow measurement system;
- Simplified P&IDs of gas flow measurement system;
- Simplified P&IDs of water flow measurement system;
- Instrument and equipment list;
- Oil and gas flow calculation procedure;
- Uncertainty calculations;
- Memorial Description;
- Maintenance, prover, calibration and operation procedures and recommendations;
- Description of programming tools, system reports, system diagnosis, etc.

### 16.7 Final Acceptance (FAT) Documentation

16.7.1 Complete FMS certified documentation, including the following documents shall be provided, in the number of 2 (two) copies of the originals on paper and digital media (USB flash drive), as requested.

16.7.2 FMS certified documentation shall include also maintenance manual, including all programming and configuration software.

16.7.3 FMS supplier shall develop a functional technical specification for the Flow Metering Workstation, including the operation of the flow computers. This document shall clearly specify all functions and features, e.g., the applied algorithms, the sequences of the system, instructions for entering data and parameters for each flow measurement, instructions regarding the data base and alarm, event and intervention of the operator logs, operator responses, explanation related to the types of measurement, calibration and inspection reports to be issued, instructions for registering the realized calibration and inspection, how to operate the access control with passwords for configuration functions, calibration, adjustment and parameterization, how the warranty of inviolability of the configuration works, alarms, reports and events files, the HMI screens and error handling.

### 17 INTEGRATION AND ASSEMBLY SERVICES

17.1 The Integration and assembly services shall include:
- Detailed project;
- Interconnection and integration of the instruments, Flow computer and FMS Workstation;
- Interconnection and integration of the measurement system with the production unit supervisory;
- FMS Workstation screens customization;
- Report implementation;
- Tests, pre-operation, calibration and assisted startup;
18 ACCEPTANCE TESTS

18.1 The following tests shall be performed at supplier installations (FAT) prior to delivery:
- Physical assembly (visual and dimensional);
- Calibrated flow meters and field instruments;
- Equipment functionality;
- Loop test of each measurement;
- Check of Flow computer calculations for each measurement;
- Communication with the workstation;
- Reports generation;
- All panel tests, as required at I-ET-3010.00-5520-888-P4X-001 - CSS / SOS PANELS.

18.2 There shall also be provided for FAT: transmitters (one of each type) of the gas flow measurements to verify the communication with the Gas Flow Computers and FMS Workstation.

18.3 There shall also be provided for FAT: transmitters (one of each type) of the water measurements to verify the communication with the FMS Workstation.

18.4 After the installation of the equipment on board, all the tests shall be repeated (SAT).

18.5 For Site Integration Tests (SIT) refer to IEC-62381 – AUTOMATION SYSTEMS IN THE PROCESS INDUSTRY – FACTORY ACCEPTANCE TEST (FAT), SITE ACCEPTANCE TEST (SAT) AND SITE INTEGRATION TEST (SIT).

18.6 SUPPLIER shall submit to PETROBRAS, for approval, detailed FAT, SAT and SIT programs at least 60 (sixty) days in advance of programmed test date.

18.7 Functionality Tests

18.7.1 SUPPLIER shall take into account the following additional technical requirements for developing and implementing the FAT program with respect the FMS Functionality Tests.

18.7.2 The Oil Fiscal Metering skid and Custody Transfer Metering skid shall be properly and completely assembled and shall be integrated to the FMS Panel and their associated flow computers and devices, such as the Flow Metering System Workstation, and the Compact Prover.

18.7.3 All equipment, panel, devices and instruments shall be energized for testing.

18.7.4 The programming of the flow computers and other programmable equipment/device shall be updated.
19 INMETRO INITIAL VERIFICATION

19.1.1 The oil fiscal, oil allocation and oil custody transfer metering systems shall be submitted to INMETRO Initial Verification procedure realization, according to the following documents:

- Portaria INMETRO 64/2003
- Ofício Circular INMETRO 032/2017
- Norma INMETRO NIT-SEFLU-014

19.1.2 The Initial Verification procedure, which is metering system vendor’s responsibility, shall be executed on an onshore single phase basis, according to recommendation cited in Note in document INMETRO NIT-SEFLU-014 page 14.

19.1.3 Vendor’s procedure proposal for Initial Verification shall be submitted for INMETRO approval and, afterwards, execution.

19.1.4 Fluid to be used during the Initial Verification test shall be compatible with the final installation fluid (similar density and viscosity) in accordance with RTM criteria.

20 TRAINING

20.1 SUPPLIER shall provide training to qualify PETROBRAS technicians to operate and maintain (erect, dismantle, replace parts, make adjustments, etc.) each equipment. The training shall encompass all items to its understanding.

20.2 The training shall be performed at Platform construction yard and/or aboard the Platform, after completion of the Performance Acceptance Tests and prior to PETROBRAS approval of the system acceptance term.

20.3 SUPPLIER shall provide all documentation and materials required for the training program (including the latest revision of the as built documentation, brochures, booklets, material for presentations, transparencies, etc.).

20.4 Each individual equipment training program shall encompass all operation and maintenance aspects. All trainees shall be operational and maintenance professionals. The participants shall be awarded certificates after the completion of the training course.

20.5 3 (three) Operation and Maintenance training courses shall be delivered for 8 (eight) technicians, in Brazilian Portuguese and shall be performed using identical equipment as supplied (HOLD).

20.6 SUPPLIER shall take full responsibility for the professionals teaching the training course, including for their transportation and lodging.

20.7 SUPPLIER shall submit for approval the detailed training program.
20.8 SUPPLIER shall supply 2 (two) digital media copies (USB flash drive) of the Brazilian Portuguese training course.

20.9 The training program shall cover, at least, the following items, taking in account all ANP/INMETRO requirements:

- System overview;
- Functional operation of each component;
- Operation/navigation through the viewing screens;
- Operation routines and procedures;
- Reports generation;
- Configuration;
- Troubleshooting;
- Maintenance.
21 ANNEX A – EXAMPLE OF METERING SYSTEM DIAGRAM

Description:
- GAS
- OIL
- WATER
- ALLOCATION METERING
- OPERATIONAL METERING
- FISCAL METERING
- CUSTODY TRANSFER

Produced Gas -> Royalty payment
Exportation + Utilization + HP Flare + LP Flare - Importation

Total Produced Oil
Oil that goes to cargo tanks
22 ANNEX B – AUTOMATION ARCHITECTURE

Flow Metering System Architecture

Control Room

HMI

FLOW METERING SYSTEM STATION

SOS HMIs

DATA SERVER

Panels Room

GAS FLOW COMPUTERS

OIL FLOW COMPUTERS

WATER FLOW COMPUTERS

Field

GAS

OIL

WATER
23 ANNEX C – REQUIRED INFORMATION FOR LOGS

23.1 Liquid – API/MPMS 21-2

23.1.1 Configuration Log

23.1.1.1 A configuration log is one source of the information required to audit calculated quantities for an accounting period. The configuration log will be generated from data and information listed below:

- **Linear meter:**
  a. Meter identifier and/or serial number;
  b. Meter factor;
  c. Base temperature;
  d. Equilibrium pressure;
  e. Base pressure;
  f. Meter K-factor;
  g. Input/output assignments;
  h. Engineering units;
  i. Configuration log printout date and time;
  j. Product internal diameter (ID);
  k. Span/zero information, dead band, and offsets used;
  l. High and low flow alarm limits;
  m. Out of range alarm limits for measured values;
  n. Software revision number;
  o. Algorithm identifier (e.g., standard used to calculate CTL and CPL);
  p. Coefficient of thermal expansion if not already specified in the tables used;
  q. Default values for any live inputs in case of failure such as temperature, pressure, density, vapor pressure, sediment and water (BS&W).

- **Prover Data (if applicable):**
  a. Prover identifier;
  b. Base prover volume;
  c. Serial number for prover;
  d. Inside diameter of prover;
  e. Wall thickness;
  f. Input/output assignments;
  g. Metallurgical data to calculate CTSp and CPSp;
  h. Prove acceptance criteria; repeatability, reproducibility, number of runs.

- **Master meter:**
  a. Meter factor;
  b. Meter identifier;
  c. Serial number;
  d. K-factor.

23.1.2 Quantity Transaction Record (QTR)

a. Opening and closing date and time;

b. Opening and closing readings (MRo, M Rc);

c. Product type identifier where multiple products are measured with a single
meter;

d. Meter bank identifier where there is more than one bank;

e. Meter identifier;

f. Meter factor (MF) or Composite Meter Factor (CFM) and/or K-factor (KF);

g. Average temperature correction factor (CTL);

h. Average pressure correction factor (CPL);

i. Observed density and temperature when a sample is used to determine density at base conditions;

j. Pressure Weighted Average (PWA);

k. Temperature Weighted Average (TWA);

l. Density Weighted Average (DWA) or default density, at reference conditions;

m. BS&W or Correction for BS&W (CSW) where water or sediment exists in nonmarketable quantities;

n. Net standard volume (NSV);

o. QTR identifier (e.g., meter ticket number);


23.1.3 Event Log

a. System power failure time and/or start-up time;

b. ELM hardware error diagnostic messages;

c. Sign-on and sign-off times for password-protected ELM systems;

d. Forcing a default value in place of a live input or output;

e. Download time to install a new program or configuration file during which data is not collected.

23.1.4 Alarm or Error Log

23.1.4.1 Any system alarm or user-defined alarm or error conditions (such as temperature or pressure out of range) that occur. A description of each alarm condition and the times the condition occurred and cleared. At a minimum, an alarm must be logged whenever any input exceeds its defined span of operation.

23.1.5 Data Retention

23.1.5.1 Retention of hourly records is not required. Regulation, tariff, or contract will specify the minimum retention period for all audit trail data.
23.2 Gas – API/MPMS 21-1

23.2.1 Configuration Log

Table 1 - Configuration Log

<table>
<thead>
<tr>
<th>Differential Meter</th>
<th>Linear Meter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meter Identifier</td>
<td>Meter Identifier</td>
</tr>
<tr>
<td>Date and Time</td>
<td>Date and Time</td>
</tr>
<tr>
<td>Contract Hour</td>
<td>Contract Hour</td>
</tr>
<tr>
<td>Atmospheric Pressure (if appropriate)</td>
<td>Atmospheric Pressure (if appropriate)</td>
</tr>
<tr>
<td>Pressure Base ( (P_b) )</td>
<td>Pressure Base ( (P_b) )</td>
</tr>
<tr>
<td>Temperature Base ( (T_b) )</td>
<td>Temperature Base ( (T_b) )</td>
</tr>
<tr>
<td>Meter Tube Reference Inside Diameter ( (D_r) )</td>
<td>Meter Factor</td>
</tr>
<tr>
<td>Orifice Plate Reference Bore Size ( (d_r) )</td>
<td>k Factor</td>
</tr>
<tr>
<td>Static Pressure Tap Location</td>
<td>Relative Density (If Not Live)</td>
</tr>
<tr>
<td>Orifice Tap Configuration</td>
<td>Compressibility (If Not Live)</td>
</tr>
<tr>
<td>Orifice Plate Material</td>
<td>Gas Components (If Not Live)</td>
</tr>
<tr>
<td>Meter Tube Material</td>
<td>Calibrated Static Pressure Range</td>
</tr>
<tr>
<td>Calibrated Static Pressure Range</td>
<td>Calibrated Temperature Range</td>
</tr>
<tr>
<td>Calibrated Differential Pressure Range</td>
<td></td>
</tr>
<tr>
<td>Calibrated Temperature Range</td>
<td></td>
</tr>
<tr>
<td>Low Differential Cut Off</td>
<td></td>
</tr>
<tr>
<td>Relative Density (If Not Live)</td>
<td></td>
</tr>
<tr>
<td>Compressibility (If Not Live)</td>
<td></td>
</tr>
<tr>
<td>Gas Components (If Not Live)</td>
<td></td>
</tr>
</tbody>
</table>

23.2.2 Quantity Transaction Record (QTR)

23.2.2.1 Set of historical data and information supporting the accounted quantity or quantities of volume, mass, or energy.

23.2.2.2 Daily Quantity Transaction Record for Differential Type Meters

- Average or summation of data collected and calculated during a contract day. A daily quantity transaction record will end and a new daily record begin at the end of each contract day or any time a constant flow parameter is changed;
- The following data shall be collected in the daily quantity transaction record: date period, time, quantity, flow time, differential pressure, flow temperature, static pressure, composition and relative density.

23.2.2.3 Hourly Quantity Transaction Record for Differential Type Meters

- The hourly quantity transaction record is the average or summation of data collected and calculated during a maximum of 60 consecutive minutes. An hourly quantity transaction record will end, and a new record begins at the end of each hour or any time one or more constant flow parameters are changed;
There shall be 24 hourly quantity transaction records for each contract day plus additional quantity transaction records for each time one or more constant parameters are changed;

The following data shall be collected in the hourly quantity transaction record: date period, time, quantity, differential pressure, flow temperature, static pressure, composition, and relative density, if live.

23.2.2.4 Daily Quantity Transaction Record for Linear Type Meters

The daily quantity transaction record is the average or summation of data collected and calculated during a contract day. A quantity transaction record will end and a new daily record begin at the end of each contract day or any time a constant flow parameter is changed;

The following data shall be collected in the daily quantity transaction record: date period, time, quantity, flow time, uncorrected quantity, flow temperature, static pressure, composition and relative density.

23.2.2.5 Hourly Quantity Transaction Record for Linear Type Meters

The hourly quantity transaction record is the average or summation of data collected and calculated during a maximum of 60 consecutive minutes. A quantity transaction record will end and a new record begin at the end of each hour or any time one or more constant flow parameters are changed;

There shall be 24 hourly quantity transaction records for each contract day. These quantity transaction records shall reflect the effect of any constant flow parameter changes;

The following data shall be collected in the hourly quantity transaction record: date period, time, quantity, uncorrected quantity, flow temperature, static pressure, composition and relative density, if live.

23.2.3 Event Log

23.2.3.1 The event log shall be a part of the Audit Package for the accounting period. The event log is used to note and to record exceptions and changes to the flow parameters, contained in the configuration log, that occur and that have an impact on a quantity transaction record. The events include, but are not limited to, changes or modifications to item in 13.2.1.

23.2.3.2 Each time a constant flow parameter that can affect the quantity transaction record is changed in the system, the old and new value, along with the date and time of the change, shall be logged.

23.2.3.3 The date and time of all events in the log shall be identified chronologically.

23.2.4 Alarm or Error Log
23.2.4.1 API/MPMS 21-2 (liquid):

“This log is used to note any system alarm or user-defined alarm or error conditions (such as temperature or pressure out of range) that occur. This includes a description of each alarm condition and the times the condition occurred and cleared. At a minimum, an alarm must be logged whenever any input exceeds its defined span of operation”.

23.2.5 Data Retention

23.2.5.1 Unless specified by regulation, tariff, or contract, the minimum retention period for the electronic flow measurement audit trail data shall be 2 (two) years.

23.2.6 Algorithm Identification

23.2.6.1 Algorithm identification shall be provided to identify the calculations performed in the electronic gas measurement system, such as software or manufacturer’s version.