PETROBRAS	TECHNICAL SPECIFICATION	Nº: I-ET-3010.00-1200-813-P4X-001	
	CLIENT:		SHEET 1 of 60
	JOB:		--
	AREA:		
SRGE	TITLE: GENERAL CRITERIA FOR FLOW METERING SYSTEMS		INTERNAL
			ESUP

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DESIGN	ESUP	ESUP	ESUP	ESUP	ESUP	ESUP	ESUP	ESUP	ESUP
EXECUTION	DVJH	EDYLARA	MOTTER	MOTTER	HRJ2	U44D	U5D6	HRJ2	CX2W
CHECK	HRJ2	MOTTER	FABIODUTRA	RAFAELJOSE	U49R	U5D6	U49R	CX2W	U5D6
APPROVAL	CDC1	RENNÓ	ANDREAZC	ANDRÉ LUIS	U4JB	U4JB	U4JB	CDC1	CDC1

SUMMARY

1 INTRODUCTION

1.1 Object

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

1.1.2 This document shall be read together with the documents listed in 2.2.

1.2 Definitions

FISCAL MEASUREMENT		Measurement of the gas and oil production volume where the government requires tax payments.
ALLOCATION MEASUREMENT		Measurement to determine the volume of production to be allocated at each well.
OPERATIONAL MEASUREMENT		Measurement for process control purposes, for production, transfer or storage, which are not classified as fiscal, allocation or custody transfer measurements.
CUSTODY TRANSFER MEASUREMENT		Measurement for totalization of transferred fluids when changed their ownership, for legal or commercial purposes.
CATEGORY METERING SYSTEM	A	Metering systems with installed capacity higher than 5.000 m³/d (oil) or 1.000.000 m³/d (gas)
CATEGORY METERING SYSTEM	B	Metering systems with installed capacity between 500 m³/d and 5.000 m³/d (oil) or between 50.000 m³/d and 1.000.000 m³/d (gas)
CATEGORY METERING SYSTEM	C	Metering systems with installed capacity between 5 m³/d and 500 m³/d (oil) or between 5.000 m³/d and 50.000 m³/d (gas)
CATEGORY METERING SYSTEM	D	Metering systems with installed capacity lower than 5 m³/d (oil) or 5.000 m³/d (gas)

NOTE: Refer to I-ET-3010.00-1200-940-P4X-002 – GENERAL TECHNICAL TERMS for the definition of other words emphasized in upper case along this document.

1.3 Abbreviations and Acronyms

The following abbreviations are used in this document:

AC/DC	Alternating Current/Direct Current
ANP	Brazilian National Agency of Petroleum, Natural Gas and Biofuels

ASTM	American Society for Testing and Materials
BS&W	Basic Sediments & Water
CGA	Chromatograph Gas Analyzer
CPL	Correction for the effect of Pressure on Liquid
CSS	Control and Safety System
CTL	Correction for the effect of Temperature on Liquid
DBB	Double Block and Bleed valve
DMZ	Demilitarized Zone
FAT	Factory Acceptance Test
FE	Shrinkage Factor (in Portuguese: *"Fator de Encolhimento"*)
FMS	Flow Metering System
FPSO	Floating Production, Storage and Offloading
GSV	Gross Standard Volume
HCS	Hull Control System
HMI	Human Machine Interface
IAAC	InterAmerican Accreditation Cooperation
ILAC	International Laboratory Accreditation Cooperation
Inmetro	Brazilian National Institute of Metrology, Quality and Technology
IV	Initial Verification per Inmetro
MFMS	Multiphase Flow Metering System
NSV	Net Standard Volume
PAM	*Portaria de Aprovação de Modelo de Instrumentos de Medição* (Inmetro certificate of type approval)
PCS	Process Control System
P&ID	Piping and Instrument Diagram
PI	Plant Information (software)
PID	Proportional, Integral and Derivative automation control
PLC	Programmable Logic Controller
QTR	Quantity Transaction Report
RBC	Brazilian Network of Calibration
RF	Raised Face (a type of flange)
RS	Solubility Ratio (in Portuguese: *"Razão de Solubilidade"*)
RTM	ANP/Inmetro Technical Regulation of Measurement of Oil and Gas
RVP	Reid Vapor Pressure
SAT	Site Acceptance Test
SI	International System of Units
SIT	Site Integration Test
SOS	Supervision and Operation System
VM	Virtual Machine
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

IEC	60079	EXPLOSIVE ATMOSPHERES - ALL PARTS
IEC	60529	DEGREES OF PROTECTION PROVIDED BY ENCLOSURES (IP CODE) - EDITION 2.2
IEC	61000	ELECTROMAGNETIC COMPATIBILITY (EMC) SERIES - ALL PARTS
IEC	61131	PROGRAMMABLE CONTROLLERS – ALL PARTS
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	2186	FLUID FLOW IN CLOSED CONDUITS - CONNECTIONS FOR PRESSURE SIGNAL TRANSMISSIONS BETWEEN PRIMARY AND SECONDARY ELEMENTS
ISO	4267-2	PETROLEUM AND LIQUID PETROLEUM PRODUCTS - CALCULATION OF OIL QUANTITIES - PART 2: DYNAMIC 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	5167-5	MEASUREMENT OF FLUID FLOW BY MEANS OF PRESSURE DIFFERENTIAL DEVICES INSERTED IN CIRCULAR CROSS-SECTION CONDUITS RUNNING FULL - PART 5: CONE METERS

ISO	5168	MEASUREMENT OF FLUID FLOW - PROCEDURES FOR THE EVALUATION OF UNCERTAINTIES
ISO	6974	NATURAL GAS - DETERMINATION OF COMPOSITION AND ASSOCIATED UNCERTAINTY BY GAS CHROMATOGRAPHY – ALL PARTS
ISO	6976	NATURAL GAS - CALCULATION OF CALORIFIC VALUES, DENSITY, RELATIVE DENSITY AND WOBBE INDICES FROM COMPOSITION
ISO	7278	LIQUID HYDROCARBONS - DYNAMIC MEASUREMENT - PROVING SYSTEMS FOR VOLUMETRIC METERS - ALL PARTS
ISO	10012	MEASUREMENT MANAGEMENT SYSTEMS - REQUIREMENTS FOR MEASUREMENT PROCESSES AND MEASURING EQUIPMENT
ISO	12213	NATURAL GAS CALCULATION OF COMPRESSION FACTOR - ALL PARTS
ISO	17089-1	MEASUREMENT OF FLUID FLOW IN CLOSED CONDUITS - ULTRASONIC METERS FOR GAS - PART 1: METERS FOR CUSTODY TRANSFER AND ALLOCATION MEASUREMENT
ISO	20456	MEASUREMENT OF FLUID FLOW IN CLOSED CONDUITS - GUIDANCE FOR THE USE OF ELECTROMAGNETIC FLOWMETERS FOR CONDUCTIVE LIQUIDS
ISO	20765	NATURAL GAS — CALCULATION OF THERMODYNAMIC PROPERTIES — ALL PARTS
ISO	GUM	GUIDE TO THE EXPRESSION OF UNCERTAINTY IN MEASUREMENTS

API – AMERICAN PETROLEUM INSTITUTE

API	MPMS	MANUAL OF PETROLEUM MEASUREMENT STANDARDS – ALL PARTS
API	MPMS TR 2570	CONTINUOUS ON-LINE MEASUREMENT OF WATER CONTENT IN PETROLEUM (CRUDE OIL AND CONDENSATE)
API	RP 14E	RECOMMENDED PRACTICE FOR DESIGN AND INSTALLATION OF OFFSHORE PRODUCTION PLATFORM PIPING SYSTEMS - FIFTH EDITION

API	RP 505	RECOMMENDED PRACTICE FOR CLASSIFICATION OF LOCATIONS FOR ELECTRICAL INSTALLATIONS AT PETROLEUM FACILITIES CLASSIFIED AS CLASS I, ZONE 0, ZONE 1, AND ZONE 2
API	RP 551	PROCESS MEASUREMENT – SECOND EDITION

AGA – AMERICAN GAS ASSOCIATION

AGA	REPORT Nº 7	MEASUREMENT OF NATURAL GAS BY TURBINE METERS
AGA	REPORT Nº 8	THERMODYNAMIC PROPERTIES OF NATURAL GAS AND RELATED GASES DETAIL AND GROSS EQUATIONS OF STATE – ALL PARTS
AGA	REPORT Nº 9	MEASUREMENT OF GAS BY MULTIPATH ULTRASONIC METERS
AGA	REPORT Nº 11	MEASUREMENT OF NATURAL GAS BY CORIOLIS METER

ASME – AMERICAN SOCIETY OF MECHANICAL ENGINEERS

ASME	PTC 19.3 TW	THERMOWELLS PERFORMANCE TEST CODES

ASTM – AMERICAN SOCIETY FOR TESTING AND MATERIALS

ASTM	D1945	STANDARD TEST METHOD FOR ANALYSIS OF NATURAL GAS BY GAS CHROMATOGRAPHY

OIML – ORGANISATION INTERNATIONALE DE METROLOGIE LEGALE

OIML	R117	DYNAMIC MEASURING SYSTEMS FOR LIQUIDS OTHER THAN WATER
OIML	R137	GAS METERS – ALL PARTS

ISA – INTERNATIONAL SOCIETY OF AUTOMATION

ISA	5.1	INSTRUMENTATION SYMBOLS AND IDENTIFICATION
ISA	RP31.1	SPECIFICATION, INSTALLATION, AND CALIBRATION OF TURBINE FLOWMETERS

2.1.2 Brazilian Codes and Standards

ABNT – ASSOCIAÇÃO BRASILEIRA DE NORMAS TÉCNICAS

NBR 16777	MEDIDORES DE VAZÃO DE GÁS DE TOCHA (*FLARE*) E DE GÁS VENTILADO PARA A ATMOSFERA

ANP – AGÊNCIA NACIONAL DO PETRÓLEO, GÁS NATURAL E BIOCOMBUSTÍVEIS

RESOLUÇÃO CONJUNTA ANP/INMETRO Nº 1 (10/JUNHO/2013)	REGULAMENTO TÉCNICO DE MEDIÇÃO (RTM) DE PETRÓLO E GÁS NATURAL, A QUE SE REFERE À RESOLUÇÃO CONJUNTA ANP/INMETRO Nº 1 DE 10 DE JUNHO DE 2013), RETIFICADA EM 17 DE JUNHO DE 2013.
OFÍCIO-CIRCULAR Nº1/2020/NFP/ANP (26/MAIO/2020)	ESCLARECIMENTOS DO REGULAMENTO TÉCNICO DE MEDIÇÃO (RTM).
RESOLUÇÃO ANP Nº 52 (26/DEZEMBRO/2013)	REGULAMENTO TÉCNICO DE IMPLEMENTAÇÃO DOS RESULTADOS DE ANÁLISES FÍSICO-QUÍMICAS NAS MEDIÇÕES SUBSEQUENTES DE PETRÓLEO E GÁS NATURAL, A QUE SE REFERE À RESOLUÇÃO ANP Nº 52 DE 26 DE DEZEMBRO DE 2013
RESOLUÇÃO ANP Nº 65 (10/ DEZEMBRO /2014)	REGULAMENTO TÉCNICO DE ENVIO DE DADOS DE PRODUÇÃO E MOVIMENTAÇÃO DE PETRÓLEO, GÁS NATURAL E ÁGUA A QUE SE REFERE À RESOLUÇÃO ANP Nº 65, DE 10 DE DEZEMBRO DE 2014
RESOLUÇÃO ANP Nº 737 (27/ JULHO /2018)	ALTERAÇÃO DA RESOLUÇÃO ANP Nº 65 DE 10/DEZEMBRO/2014

INMETRO - INSTITUTO NACIONAL DE METROLOGIA, NORMALIZAÇÃO E QUALIDADE INDUSTRIAL

NIT-SEFLU-014 (SETEMBRO/2018)	VERIFICAÇÃO INICIAL DE SISTEMAS DE MEDIÇÃO CONFORME A PORTARIA INMETRO N° 64/2003
PORTARIA Nº 115 (21/MARÇO/2022)	REGULAMENTO CONSOLIDADO PARA EQUIPAMENTOS ELÉTRICOS PARA ATMOSFERAS EXPLOSIVAS
PORTARIA Nº 188 (27/ABRIL/2021)	REGULAMENTO TÉCNICO METROLÓGICO CONSOLIDADO PARA CROMATÓGRAFOS A GÁS EM LINHA

PORTARIA Nº 291 (07/JULHO/2021)	REGULAMENTO TÉCNICO METROLÓGICO CONSOLIDADO PARA SISTEMAS DE MEDIÇÃO DINÂMICA EQUIPADOS COM MEDIDORES PARA QUANTIDADES DE LÍQUIDOS
PORTARIA Nº 298 (08/JULHO/2021)	REGULAMENTO TÉCNICO METROLÓGICO CONSOLIDADO PARA OS COMPUTADORES DE VAZÃO E CONVERSORES DE VOLUME
PORTARIA Nº 617 (20/DEZEMBRO/2023)	ALTERAÇÃO DA PORTARIA INMETRO Nº 298, DE 08 DE JULHO DE 2021
PORTARIA Nº 156 (30/MARÇO/2022)	REGULAMENTO TÉCNICO METROLÓGICO CONSOLIDADO PARA MEDIDORES DE VAZÃO DE GÁS NATURAL
PORTARIA Nº 236 (14/JUNHO/2022)	ALTERAÇÃO DA PORTARIA INMETRO Nº 156, DE 30 DE MARÇO DE 2022
PORTARIA Nº 615 (18/DEZEMBRO/2023)	QUADRO GERAL DE UNIDADES DE MEDIDA NO BRASIL
OFÍCIO CIRCULAR Nº 032/DIMEL (12/SETEMBRO/2017)	VERIFICAÇÕES METROLÓGICAS DE MEDIDORES, SISTEMAS DE MEDIÇÃO E COMPUTADORES DE VAZÃO

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

2.1.5 Classification Society

2.1.5.1 Detail design phase documentation of the project shall be submitted to approval by Classification Society. The design, installation and operation shall strictly follow the classification society requirements, along with the specific requirements identified in this document, also including all requirements of referenced documents.

2.2 Internal References

2.2.1 Typical Documents

2.2.1.1 Typical documents are those that contain functional and technical description of a system or equipment. They shall be used as the main specification for the project.

2.2.1.2 Typical Document List

I-ET-3000.00-1200-940-P4X-001	TAGGING PROCEDURE FOR PRODUCTION UNITS DESIGN

I-ET-3000.00-1400-196-P4X-001	ERGONOMICS REQUIREMENTS FOR TOPSIDE
I-ET-3010.00-1200-588-P4X-001	SAMPLE CONNECTIONS
I-ET-3010.00-1200-800-P4X-002	AUTOMATION, CONTROL, AND INSTRUMENTATION ON PACKAGE UNITS
I-ET-3010.00-1200-800-P4X-010	CRITERIA FOR ESTABLISHING CABLE CODES AND CABLE GLAND CODES
I-ET-3010.00-1200-800-P4X-013	GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS
I-ET-3010.00-1200-940-P4X-002	GENERAL TECHNICAL TERMS
I-ET-3010.00-1200-956-P4X-002	GENERAL PAINTING
I-ET-3010.00-5140-700-P4X-003	ELECTRICAL REQUIREMENTS FOR PACKAGES FOR OFFSHORE UNITS
I-ET-3010.00-5520-861-P4X-003	VIRTUALIZATION OF AUTOMATION SYSTEM COMPUTERS
I-ET-3010.00-5520-888-P4X-001	AUTOMATION PANELS

2.2.2 Specific Project Documents

2.2.2.1 This section mentions documents that are referenced along the text and that are part of a specific project. The documents title and number may vary slightly from one project to another. Project's DOCUMENT LIST shall be consulted in order to verify the correct document number and title.

2.2.2.2 Specific Project Document List

PIPING SPECIFICATION

FIELD INSTRUMENTATION

AUTOMATION AND CONTROL ARCHITECTURE

2.2.3 PETROBRAS Reference Documents

DR-ENGP-I-1.15-R.3 COLOR CODING

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 power supplies according to I-ET-3010.00-5140-700-P4X-003 – ELECTRICAL REQUIREMENTS FOR PACKAGES FOR OFFSHORE UNITS. SUPPLIER shall convert and distribute the different power supplies inside the panel, including voltage regulators where needed (e.g., for the cabinet's internal distribution of 24 Vdc).

3.2 FMS fiscal and offloading skids shall receive dedicated power supply in order to feed their Compact Provers, according to project electrical requirements.

4 FMS SCOPE

4.1 FMS shall be comprised by:

- Fiscal oil metering skids
- Allocation oil metering systems
- Fiscal natural gas metering skids
- Fiscal natural gas metering systems and metering runs
- Allocation natural gas metering systems and metering runs
- Fiscal condensate metering skids, metering systems and metering runs
- Custody transfer metering skids
- Operational oil, natural gas and water metering systems and metering runs
- FMS automation system
- Inmetro Initial Verifications execution
- Metering system approval by national regulation Agencies
- Documentation
- Integration, FAT, SAT, SIT, training, and start-up services
- Interface with CSS
- Interface with MFMS

4.2 FMS shall comply with Brazilian legislation, including ANP and 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 pipe runs, accessories, double block and bleed valves, flow control valves, interconnecting cables and junction boxes.

4.5 The scope of supply for the FMS Automation System shall include a Flow Metering System Panel with flow computers, Ethernet switches and a PLC; and the FMS Workstation, composed of one local HMI installed on panel, one FMS Monitor installed on CCR and the FMS Virtual Server installed in Topsides SOS Process Cluster with all the software needed for running the Flow Metering System. 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 and performance 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 SUPPLIER scope of supply.

4.6 The Initial Verification procedures and execution according to Inmetro rules shall be part of the FMS scope. It is SUPPLIER'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.

4.8 If the project includes a Multiphase Flow Metering System (MFMS), whether for allocation or operational purposes, a dedicated Technical Specification shall be created. The MFMS is not part of the FMS' scope of supply.

4.9 FMS and MFMS shall be integrated. FMS shall make available all required variables and registers to MFMS.

5 MEASUREMENT UNITS

5.1 The volume unit for oil and natural gas measurements shall be cubic meter (m^3) under the Brazilian reference conditions of 20 ºC for temperature and 101.325 kPa for pressure.

5.2 The following units shall be applied for the main variables, and International System of Units (SI) are acceptable:

- Temperature – ºC
- Liquid flow rate – m^3/h;
- Water vapor flowrate – t/h;
- Gas flow rate – m^3/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/m^3;
- 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 gauge pressure, except where explicitly indicated.

NOTE C: Absolute pressure.

5.3 In other cases, the PORTARIA Inmetro 615/2023, which approved the General Framework of the measurement units adopted by Brazil, shall be consulted.

6 GENERAL REQUIREMENTS

6.1 For additional requirements of instruments specification, identification, document symbology, supply systems, etc., the specific project guidelines shall be followed. Additionally, API RP 551 and ISA 5.1 standards shall be met .

6.2 The instruments and fittings shall be in accordance with the technical specification document of the project entitled PIPING SPECIFICATION.

6.3 All calibrations and dimensional inspections shall be done by accredited laboratories, except for the calibration of flare/vent meters (dry calibration). In Brazil, the laboratory shall be member of the RBC (Brazilian Network of Calibration), accredited by Inmetro. On other countries, the laboratory shall be accredited by an organism signatary of ILAC (International Laboratory Accreditation Cooperation) or IAAC (InterAmerican Accreditation Cooperation).

6.4 In the installation of flow meters, where required, the lengths of straight piping sections specified in the meter model approval and MANUFACTURER's recommendation, whichever is stricter, shall be followed. In the cases where the model approval is not required or length requirement is absent on PAM, the lengths of the runs determined by the meter MANUFACTURER manual or by the relevant standards, whichever is stricter (i.e., larger length for the run), shall be adopted. The designing and sizing shall address the mechanical characteristics, such as line scheduling (which shall meet the requirements of the suitable pressure class, even after machining and honing processes to specify internal roughness, etc.). These pipe sections shall have attached inspection and manufacturing (material) accredited certificates, meeting the relevant standards to allow complete traceability. These sections shall be supplied with the meters.

6.5 The flow metering systems for fiscal, allocation, custody transfer and operational applications shall consist of measurement lines with their respective flow computers installed in acclimatized area. Their instruments shall be dedicated to the flow and volume measurement and integrated independently of the rest of the UNIT's instrumentation system (from the field instruments to the flow computers, inclusive).

6.6 All data coming from flow computers shall be gathered at a specific server (FMS Server, part of the FMS Workstation) dedicated to FMS data record, storage and transmission.

6.7 Flow meters for fiscal, allocation and custody transfer applications shall be configured for pulse outputs, with the exception of differential pressure based meters and flare gas ultrasonic flow meters (see item 8). For fiscal, allocation and custody transfer applications classified as Category A, digital communication between meter and the flow computer shall be foreseen, additionnally to pulse communication, for monitoring and diagnostics whenever the instruments allow it.

6.8 Uncertainty measurement calculation reports of all metering systems shall be implemented according to the ISO GUM and ISO 5168.

6.9 All flow meters, flow computers and gas chromatograph analyzers applied in metering systems for fiscal, allocation and custody transfer shall have Model / Type / Pattern Approvals from Inmetro (PAM – *Portaria de Aprovação de Modelos de Instrumentos de Medição*) valid at the time of purchase, except the meters not regulated by Inmetro. This requirement may be valid for operational flowmeters if determined by current regulations. All PAM requirements shall be complied with (e.g., firmware version, flow rate ranges, minimum Reynolds number, etc.).

6.10 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 oil volumes shall be used and an operational metering system for the measurement of injected diesel volumes.

6.11 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.

6.12 The computation of produced volumes from flow meters shall be performed by flow computers with Model / Type / Pattern Approvals by Inmetro.

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

6.14 Complete access shall be provided for installation, maintenance, and removal (including lifting, if necessary) for all flow meters and other components by means of walkways, stairs, or decks. Space shall also be provided for removal and insertion of equipment aiming the maintenance and calibration tasks, such as for flare gas metering system sensors. Scaffolding as unique way of access shall not be accepted. For further details, see project's technical specification for ERGONOMIC REQUIREMENTS.

6.15 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.

6.16 Measurement system shall be designed in compliance with its accuracy class (for oil and natural gas linear meters) or maximum uncertainty allowable (for natural gas differential pressure meters 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.

6.17 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.

6.18 The length of straight pipe runs shall be calculated for maximum uncertainty of internal diameter, that is, nominal diameter plus maximum uncertainty. This is to guarantee that pipe run length will always be greater than actual diameter multiplied by the multiplying factor. To the multiplying factor, 0.5D shall be added. Example: for minimum straight pipe run of 17D it shall be used 17.5D. This shall also be applied for installation of flow conditioners and sampling probe positioning downstream any disturbance.

6.19 Meter tubes shall be furnished with a dimensional inspection report with all data (dimensions, roughness, etc.) according to international standards.

6.20 Each straight run pipe section shall have a nameplate on stainless steel with tag identification, unique serial number and flow direction.

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

6.22 Whenever the maintenance of an operational meter leads to an impact on the UNIT production or the stop of an entire UNIT system, a bypass line shall be foreseen.

6.23 Instruments of the same type and function shall be of the same MANUFACTURER. Exceptions shall be agreed previously by PETROBRAS.

6.24 All flow meters, secondary instruments and accessories (including samplers, analyzers, straight meter runs, flow conditioners, mixers, valves and so on) shall have unique identification code (tag) and serial numbers engraved on the body for easy visualization and identification on field. For additional requirements, see I-ET-3000.00-1200-940-P4X-001- TAGGING PROCEDURE FOR PRODUCTION UNITS DESIGN.

6.25 For field instruments and instrumentation accessories where painting is required, I-ET-3010.00-1200-956-P4X-002 – GENERAL PAINTING and DR-ENGP-I-1.15-R.3 – 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.

6.26 Equipment requirements for proper use in hazardous areas and equipment classification, see API RP 505, IEC 60079, IEC 60529, Portaria Inmetro 115/2022 and I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.27 For electrical and electronic characteristics, electromagnetic compatibility, radio frequency interferences, connections and additional installation requirements not listed on this document, see I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.28 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.

6.29 The instruments, valves, devices and materials shall be specified with appropriate materials in accordance with the technical specification documents of the project entitled FIELD INSTRUMENTATION and PIPING SPECIFICATION.

6.30 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.

6.31 On-Off Valves

6.31.1 On-Off Valves (XVs) shall be supplied, installed on oil, condensate and gas metering skids.

6.31.2 XV command shall be remote from FMS Workstation and the logic performed by the FMS Panel.

6.31.3 The valves shall be of high integrity double block and bleed (DBB). For liquid applications, it shall be plug type valve with expanding slips (DBBPTES).

6.31.4 DBB valves shall be equipped with a drain valve on the bleed to enable tightness verification.

6.31.5 DBB valves shall be equipped with limit switches to indicate their open/closed position on the FMS Workstation.

6.31.6 For additional requirements for actuated valves see project specification document FIELD INSTRUMENTATION and I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.32 Pneumatic Actuated Control Valves

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

6.32.2 FV command shall be remote from FMS Workstation and the logic performed by the FMS Panel.

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

6.32.4 FVs shall be of the butterfly body type.

6.32.5 Actuators shall be supplied with electro pneumatic positioner for these FVs.

6.32.6 For additional requirements for control valves see project specification FIELD INSTRUMENTATION and I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.33 Transmitters and secondary instruments

6.33.1 The taps used for secondary pressure and temperature instruments measurements shall be installed on piping or straight run of the same diameter of the primary flow meter, unless there is any normative restriction. Pressure taps shall be installed always upstream temperature taps.

6.33.2 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.

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

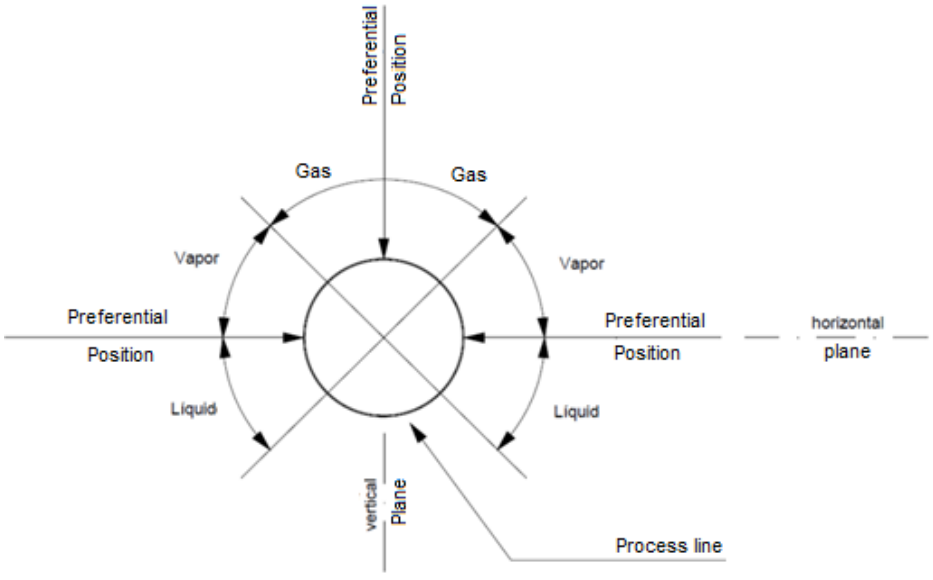

Figure 6.1 - Impulse tap orientation on horizontal process lines

6.33.4 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 downwards.

6.33.5 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: fiscal, allocation and custody transfer metering. For all other cases, the maximum length of the impulse lines shall be 6 m. In case it is not possible to comply with these requirements, minimum possible length shall be implemented, observing impulse lines diameter requirements from API RP 551 or ISO 2186.

6.33.6 The associated pressure and temperature transmitters shall be of the accuracy Class 0.3 as defined per latest revision of OIML R117 and Portaria Inmetro 291/2021. Current limits are as follows:

Transmitted Variable	Maximum permissible errors (MPE)
Temperature	+/- 0.3°C
Pressure less than 1 MPa	+/- 50 kPa
Pressure between 1 and 4 MPa	+/- 5%
Pressure greater than 4 MPa	+/- 200 kPa

6.33.7 The transmitters shall be smart microprocessor-based type, 4-20 mA output, 02 wires, with local digital display, 24 Vdc power supply and provided with HART protocol.

6.33.8 Sensors shall be made in AISI 316 stainless steel materials (sensor body and connectors).

6.33.9 Transmitters enclosure shall be weatherproof (IP-56) and explosion proof, Ex db Zone 2 and Group IIA T3. Enclosure shall be made of ASTM A351 Gr. CF8M stainless steel.

6.33.10 Transmitters shall be delivered with calibration reports issued by Inmetro or ILAC/IAAC accredited laboratories.

6.33.11 Additionally, transmitters and secondary instruments shall also be supplied in accordance with requirements from project specification FIELD INSTRUMENTATION and I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

6.33.12 Pressure Transmitters

6.33.12.1 Pressure transmitters shall be supplied, each one to be installed downstream of each flow meter in oil, water and flare ultrasonic applications. For differential pressure gas metering systems the pressure transmitters shall be supplied installed on the upstream pressure tap. For linear gas metering systems, the pressure transmitter installation shall comply to respective standard recommendation (ISO 17089, AGA 11 or AGA 7).

6.33.12.2 Pressure instrument for flare applications shall be installed directly on top of the pipe, 90º position.

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

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

6.33.12.5 Diaphragm seals shall not be used on vacuum services.

6.33.12.6 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.

6.33.13 Differential Pressure Transmitters

6.33.13.1 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.

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

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

6.33.13.4 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.

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

6.33.13.6 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.

6.33.13.7 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.

6.33.13.8 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.

6.33.13.9 Diaphragm seals shall not be used on vacuum services.

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

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

6.33.14 Temperature Transmitters and Thermowells

6.33.14.1 Temperature transmitters shall be supplied each one to be installed downstream of each flow meter. Exception is accepted for cone meters, according to ISO 5167-5.

6.33.14.2 Temperature transmitter shall be installed downstream the pressure transmitter, so that the thermowell does not influence the pressure reading. Exception is accepted for cone meters, when temperature transmitter is installed upstream the meter.

6.34 Piping and Accessories

6.34.1 Piping and accessories shall comply with project's document PIPING SPECIFICATION.

6.34.2 Drain and vent devices shall be provided.

6.34.3 Piping and valves shall be according to project's P&IDs.

6.35 Wiring

6.35.1 Wiring, cables and cable trays shall be according to I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS and I-ET-3010.00-1200-800-P4X-010 - CRITERIA FOR ESTABLISHING CABLE CODES AND CABLE GLAND CODES.

6.36 Security seals and locks

6.36.1 Security seals and locks shall be provided whenever necessary to guarantee control access to system parameters and configuration, in accordance with ANP and Inmetro regulations.

6.36.2 Prior to ANP inspection, there shall be installed security seals or locks at least on the following equipment:

- Instruments and meters body, taps and enclosures;
- Flow meter flanges;
- Manifold valves (using gate valve lockout);
- Impulse lines alignment valves;
- Orifice plate fitting, dual/single orifice chamber and cone meter impulse tapping valves;
- Flare transducers;
- Meter electronics;
- BS&W analyzer and densitometer electronic unit;
- Bypass valves;
- Bypass removable spools (installed on the blind flanges);
- Flow computers;
- FMS Panel (control by key).

6.36.3 Flow computers and FMS Workstation shall have passwords to avoid inadvertent access.

6.36.4 For equipment and instruments which Inmetro Initial Verification is required, security seals will also be installed by Inmetro. Care shall be taken on transport and during shipyard work, so that these seals are not voided. SUPPLIER is responsible for the seals maintenance.

6.36.5 Prior to ANP inspection, seal control sheet shall be updated with all installed seals, as per requirements on item 16.

7 CRUDE OIL METERING

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

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., static 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 Fiscal, allocation and custody transfer oil flow meters shall be calibrated to cover all the range of the application. The number of calibration points required shall take into account the +/-10% maximum flow rate interval accepted by the RTM.

7.6 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. Vents shall be installed at top of the oil lines on the metering skid to remove trapped gas.

7.7 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, among others.

7.8 Routing hydrocarbon volumes directly to cargo tanks of FPSO 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 UNIT shall be also capable of collecting and treating these streams and routing them back to the process plant upstream oil fiscal metering system, destined to cargo tanks.

7.9 Off-spec tanks, settling tanks or other tanks that may have crude oil not fiscal metered (oily water included) alignments that do not return the oil to process plant shall have removable spools sealed controlled (locked) with open/close register on UNIT'S Supervisory System (PI included). The removable spools shall have a nameplate on stainless steel with tag identification. The design shall have operational procedure to guarantee that the abovementioned alignments are used only in special circumstances and crude oil not fiscal metered is not routed to cargo tanks.

7.10 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 duty 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. For well injection service applications, it is acceptable for the spare meter to be supplied loose. The periods between successive calibrations shall be respected (authorized or indicated in RTM).

7.11 As a minimum, the fiscal oil to cargo tanks metering system shall comprise two duty measurement lines, each one designed to accommodate 50% of the maximum flowrate. Moreover, one spare measurement line with the same characteristics of the main measurement lines shall be installed (configuration commonly known as "3 × 50%"). If applicable, the master measurement line shall be comprised only by the flow meter, flow conditioner, and pressure and temperature transmitters. If necessary, more flow meters in parallel may be added to achieve the application flow range, in case it is technically justified.

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.

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 shall be installed upstream of the meter runs or downstream the calibration system.

7.14 Control valves shall be installed for each measurement line for fiscal and custody transfer applications in order to allow pressure equalization during the calibration process at the whole operation range. If necessary, they shall also be installed to allow calibration of allocation meters.

7.15 Each 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 level according to API MPMS 5.5.

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

7.17 Ultrasonic and turbine oil flowmeters shall be specified observing the minimum Reynolds Number limits provided in the PAM and in the MANUFACTURER's manual in its most updated version, in order to apply the most restrictive value. If this requirement is not specified in these documents, the minimum Reynolds Number value shall be in accordance with API MPMS 5.3 and API MPMS 5.8. If the manuals allow the application of meters in flow regimes below 10,000 Reynolds, without support from PAM, the MANUFACTURER shall issue a technical report proving that the performance for the desired application is not affected. The increase in measurement uncertainty due to operation outside the recommended Reynolds Number range is not acceptable.

7.18 Meters shall have local indication screen for visualization of flow rates on field. Additional electronics are acceptable if the meter does not have native local indication screen.

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

7.20 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 or ISA-RP31.1, whichever is more stringent. Differential pressure transmitters shall be provided for monitoring the filters and providing alarms.

7.21 When using Coriolis mass flow meters, special attention shall be given to 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 downwards (related 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.

7.22 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 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.

7.23 For ultrasonic and turbine meters, when calibrated at laboratories, the upstream and downstream meter tubes shall be connected to the flow meters, including the flow conditioners.

7.24 Thermal pressure relief valves (PSV) shall be supplied at strainers.

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

7.26 Flow meters enclosure shall be weatherproof (IP-56) and explosion proof, Ex db Zone 2, Group IIA T3, housing (ASTM A351 Gr. CF8M).

7.27 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.

7.28 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.

7.29 Skids

7.29.1 The fiscal and custody transfer crude oil metering systems shall be provided mounted on skids and able to be lifted.

7.29.2 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.

7.29.3 There shall be provided at the skids, resources to ease the assembling and disassembling of the metering devices and the inspection of the measurement lines. Special care shall be given to calibration stream, if applicable.

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

7.29.5 The skids shall be delivered totally mounted, with each flow meter and its associated instruments interconnected to 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 General

8.1.1 Fiscal gas metering shall be carried out, necessarily, downstream of the process plant. This metering shall be done upstream of any gas transferring or transportation system.

8.1.2 The natural gas properties calculation at the flow computers shall be carried out according to ISO 12213-2, ISO 20765-1 (AGA 8 Part-1) and ISO 6976 standards.

When required by the application's process conditions for better uncertainties results, AGA 8 Part-2 and ISO 20765-2 may be used.

8.1.3 Fiscal, allocation, custody transfer and operational natural gas metering systems shall be provided with static pressure and temperature transmitters for automatic correction. For gas metering systems where differential pressure transmitters are applied, if application's uncertainty limit is not achieved in all flow range with the use of only one transmitter, additional transmitters shall be foreseen.

8.1.4 For all natural gas metering points that operate with pressures below 21 bar (absolute), the pressure transmitters shall be of the absolute pressure type.

8.1.5 Ancillaries or additional devices and the associated measurement instruments (e.g. static 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.

8.1.6 The flow computers shall handle natural gas composition values at least within the range of C1 to C10+, in addition to the contaminants (O2, H2, N2, H2S, CO2, CO).

8.1.7 For Category A fiscal and custody transfer metering systems, meters of linear technology shall be used, thus the use of meters based on differential pressure is not allowed. A dedicated inline chromatograph gas analyzer connected to the metering system shall be foreseen, in order to automatically update gas properties in the flow computer.

8.1.7.1 If the project foresees the production of more than one field, metering systems used for the definition of injected gas volume shall follow fiscal requirements. Orifice plate type meters may exceptionally be used in this application if there is no solution based on linear technology, even if the expected flow rates fit them in Category A. In addition, a dedicated inline CGA shall be foreseen in the common injection gas header.

8.1.8 Whenever applicable, natural gas meters shall comply with Portaria Inmetro 156/2022

8.1.9 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.

8.1.10 Gas metering runs with possibility of condensate gas shall have a slope to avoid condensate accumulation in the meter.

8.2 Orifice Plates for Natural Gas Metering

8.2.1 Natural gas metering points implemented by orifice plate shall consist of: orifice plate, orifice fitting device, upstream meter run, downstream meter run, Zanker flow conditioner and flow, pressure and temperature transmitters. Flow, pressure and temperature transmitters shall be linked to their respective flow computer.

8.2.2 Orifice plates, both spare and the initial plates shall not be assembled in line until the conclusion of pipe cleaning and hydrostatic tests. Until such time, these plates shall be stored in a proper room with controlled temperature and humidity.

8.2.3 There shall be provided closets for proper storage of the spare and unused orifice plates on the metering office.

8.2.4 Orifice Plate Application Criteria

a) The projects shall follow ISO 5167-1 and ISO 5167-2 standards;

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

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

d) All gas metering points shall use orifice fittings provided with block valves for drainage during operation. For fiscal, allocation, 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 impact to the process, the use of single chamber orifice fitting devices is acceptable;

e) All gas metering system with orifice plates shall use flow conditioners. The flow conditioning devices shall be of the Zanker type;

f) Fiscal, allocation and custody transfer metering runs shall have internal diameters equal to or greater than 50 mm according to ISO 5167 standard;

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

h) Drain orifices at the orifice plates are not allowed. 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;

i) Orifice plate required thickness shall follow Table 8.1. These thickness values are applied for a maximum differential pressure of 2.5 bar;

j) The Zanker plate shall be equipped with a feature that allows for centralized alignment during insertion between flanges, especially for raised face (RF-type) flanges.

Table 8.1 – Line nominal diameter versus plate thickness

Line nominal diameter [mm / inch]	Thickness [mm / inch]
50-150 / 2-6	3.175 / 1/8
200-300 / 8-12	6.35 / ¼
350-500 / 14-20	9.525 / 3/8
550-900 / 22-36	12.7 / ½

8.2.5 Orifice Plate Installation

a) Each field component of the measurement system (straight meter runs, flow conditioners, orifice fittings, and orifice plates) shall be identified by means of an 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 way;

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

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

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

f) The thermowell shall be installed at the same spool of the downstream meter tube and placed after the minimum length of straight pipe run required by the standard;

g) For the sizing of rods and thermal wells, it shall be followed the requirements from I-ET-3010.00-1200-800-P4X-013 - GENERAL CRITERIA FOR INSTRUMENTATION PROJECTS.

8.2.6 Orifice Plate Sizing

a) Calculations shall be carried out in such a way that the usual (normal) flowrate is approximately 70% of the adopted calculated flowrate, the minimum flowrate is

less than 30% of the adopted calculated flowrate and the maximum flowrate is about 95% of the adopted calculated flowrate.

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. In any case, the orifice shall not be less than 12.5 mm. The system uncertainty shall be evaluated soon after the selection of the beta factor. The 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 additional uncertainty of the expansion factor shall be applied.

8.3 Cones for Natural Gas Metering

8.3.1 Metering points implemented by cone meters shall consist of cone, upstream meter run, downstream meter run and flow, pressure and temperature transmitters. Transmitters shall be linked to their respective flow computer.

8.3.2 Cone type meters shall be designed according to ISO 5167-5 standard, and calibrated in flow laboratories, in all cases.

8.3.3 Thermowell shall be installed upstream of the required upstream meter run.

8.3.4 Cone meters shall be supplied calibrated at the same Reynolds number equivalent of the application. Exceptions shall be previously approved by PETROBRAS.

8.3.5 The dimensional inspection procedure shall be presented for PETROBRAS comments during the detailed project.

8.3.6 Downstream meter run may be part of the cone spool.

8.3.7 Upstream meter run may be part of the cone spool only for meters with diameter equal to or less than 10 inches.

8.4 Gas Linear Flowmeters

8.4.1 Requirements of item 8.4 are applicable to gas linear meters (e.g. ultrasonic, Coriolis, turbine, etc.), except for flare ultrasonic meters (for this, see item 8.5).

8.4.2 Gas linear metering systems shall comply, in the entire operational range, with accuracy classes (maximum allowed errors) required by current RTM.

8.4.3 Meters shall be configured and calibrated to operate with volumetric flow, and shall operate simultaneously in accordance with requirements of PAM issued by Inmetro, with calibration certificate flow conditions and with manufacturer's specific orientations.

8.4.4 Fiscal and custody transfer metering systems that use gas linear meters shall be supplied mounted on skid, exception to fiscal metering Category D.

8.4.4.1 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.

8.4.4.2 There shall be provided at the skids, resources to ease the assembling and disassembling of the metering devices and the inspection of the measurement lines. Special care shall be given to calibration stream, if applicable.

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

8.4.4.4 The skids shall be delivered totally mounted, with each flow meter and its associated instruments interconnected to 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.

8.4.5 System shall be designed in order to avoid liquid accumulation in measurement lines. If necessary, it shall be foreseen input and output headers in a lower elevation than measurement streams.

8.4.6 System shall be comprised of duty meters runs, one standby meter run with the same characteristics of the main meter run and a master meter. The number of meter runs shall be such that the master meter can be calibrated in accredited laboratory under operating conditions as required by the RTM, including flowrate range. At least one duty meter run and one standby meter run shall be provided. In the event of failure or unavailability of the duty meter, the master meter shall not be used as the duty meter until the main meter is available for use. In this case, the standby meter shall be used.

8.4.7 Double block and bleed valves shall be foreseen in gas linear metering systems, to ensure proper tightness.

8.4.8 Control valves shall be installed in measurement lines from fiscal metering systems with linear meters to allow calibration in all operational range.

8.4.9 Each meter shall be equipped with a dual pulse train and connected directly to the flow computer.

8.4.10 Design for linear gas metering systems shall follow ISO 17089-1, AGA 11, or AGA 7, according to the technology applied.

8.4.11 Straight run length shall comply with meter type approval (PAM). In case absent, it shall follow above standards, according to meter technology.

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

8.4.13 Flow meters enclosure shall be weather proof (IP-56) and explosion proof, Ex db Zone 2, Group IIA T3, housing (ASTM A351 Gr. CF8M).

8.4.14 Gas linear measurement systems 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.

8.4.15 Gas linear flow metering systems shall comply with the accuracy class 0.5 according to OIML R137. Meter uncertainty shall be below 0.7% and maximum metering system uncertainty shall be of 1.0%.

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

8.4.17 Flow meters enclosure shall be weather proof (IP-56) and explosion proof, Ex db Zone 2, Group IIA T3, housing (ASTM A351 Gr. CF8M).

8.4.18 Upstream in-line filters shall be installed if turbine meters are used. Differential pressure transmitters shall be provided for monitoring the filters and providing alarms.

8.4.19 When using Coriolis mass flow meters, special attention shall be given to 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 upwards (related to the main process line).

8.4.20 Ultrasonic flow meters shall be of the transit-time type and built with spools with sensors in contact with the fluid. The number of paths for the ultrasonic flow meter shall be function of its application which will indicate its accuracy. For fiscal and custody transfer applications, a minimum of 4 paths is mandatory.

8.4.21 For ultrasonic and turbine meters, when calibrated at laboratories, the upstream and downstream meter tubes shall be connected to the flow meters, including the flow conditioners.

8.5 FLARE GAS METERING

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

8.5.2 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, ABNT NBR 16777 and API MPMS 14.10 shall be consulted.

8.5.3 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 allow the calibration on site, taking care for cable maximum length.

8.5.4 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 or dilution gas.

8.5.5 The purge gas and assistance gas metering systems shall meet the requirements for operational metering, as per RTM requirement, and they shall be provided with pressure and temperature compensation for the flowrate computation. These volumes of natural gas shall be computed for the burned gas at the flare system. These streams shall be fiscal measured at the flare gas meters or at fuel gas meters.

8.5.6 The pilot gas shall meet the requirements for fiscal metering category D, as per RTM requirement, and they shall be provided with pressure and temperature compensation for the flowrate computation. As fiscal metering, the pilot gas shall not be fiscal measured at fuel gas meters or flare gas meters.

8.5.7 In case the project design includes the flare dilution stream, it shall be fiscal measured at the flare gas meters. There shall be an operational meter for this individual stream.

8.5.8 The pressure and temperature signals shall be directly connected to the flow computer approved by Inmetro. If flare meter's MANUFACTURER recommends a link between the temperature and pressure transmitters and the flowmeter, this shall be achieved without interfering in the direct communication between these transmitters and the flow computer. The pressure and temperature compensation to the reference conditions shall be executed exclusively at the flow computer approved by Inmetro.

8.5.9 The flowrate signal transmission from the electronic unit of the flare gas flow meter to the flow computer shall be made by means of field network, e.g.: Modbus, in order to allow extended flow ranges. The flow correction and calculations shall be done at the flow computer.

8.5.10 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 meter tubes do not need to be obligatorily delivered along with the flow meter.

8.5.11 The meter spool shall be subject to a dimensional inspection procedure by an accredited laboratory prior to its installation in the field, in order to obtain measures of the transducer mounting angles, path distance between transducers and pipe internal diameter, among other parameters. Such parameters shall be used at the parameterization of the flow meters and flow computers.

8.5.12 Flare gas metering systems that use ultrasonic flowmeters shall be provided with minimum straight pipe sections of 20 nominal diameters upstream of the meter and

10 nominal diameters downstream of the meter. The MANUFACTURER shall prove by means of fluid dynamics simulations (Computer Fluid Dynamics - CFD) using the application and process data of the specific application that the total uncertainty of the metering point complies with the RTM requirement. The recommendations of ABNT NBR 16777 shall be observed.

8.5.13 Whenever the case, a tool shall be delivered for removal and reinstallation of the ultrasonic sensors (transducers) without shutting down the process (i.e., in full operation).

8.5.14 The transducers shall be installed on the horizontal plane or the upper section of the piping. Installation on the lower pipe section is not acceptable, in order to avoid condensate accumulation on the transducers.

8.5.15 The MANUFACTURER electronic unit shall be provided with protection against solar radiation.

8.5.16 If applicable on the project, Vent Gas Metering shall be applied according to Flare Gas metering requirements.

9 CONDENSATE METERING

9.1 Unless otherwise specifically stated, condensate shall be treated as oil for compliance with ANP and Inmetro requirements.

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

9.3 Calculation of the pressure correction (CPL) for the condensate volume shall comply with 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.

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

9.5 Fiscal condensate metering fitted in Category A or B shall be provided mounted on skids, following the same technical requirements for the skids of oil metering in this document.

10 WATER METERING

10.1 For applications such as produced, total injected or disposal water, bypass lines shall be provided in order to allow the meter calibrations and maintenance without process interruption. Exception given to metering systems for produced water discharged from the process plant, which shall have a measurement line with an installed standby meter, without bypass line.

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

10.3 For all water metering points, pressure and temperature transmitters shall be provided and shall be connected to the flow computer.

11 REQUIREMENTS FOR CRUDE OIL AND NATURAL GAS SAMPLING

11.1 For sampling point details and locations refer to project's P&IDs and I-ET-3010.00-1200-588-P4X-001 - SAMPLE CONNECTIONS.

11.2 Sample collection points shall comply with ANP Resolution 52/2013 and all its references.

11.3 Crude Oil Sampling

11.3.1 For all oil metering systems, there shall be a manual sample collection point at atmospheric pressure for BS&W and density determination purposes. For oil allocation points, the sample collection point shall also allow for the collection of pressurized oil under the same process conditions in order to determine the Shrinkage Factor (FE) and Solubility Ratio (RS). In the fiscal crude oil to cargo tanks measurement system, the manual sample collection point shall also allow the collection of pressurized oil under the process conditions for Reid Vapor Pressure analysis (RVP).

11.3.2 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 hoses.

11.3.3 Oil sampling probes shall be mounted in horizontal process lines or in vertical process lines with upward flows. The probe shall not be installed at the bottom position of the piping, in order to avoid accumulation of debris.

11.3.4 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 the flow. In case of crude oil allocation metering systems, and for probes installed in the main process line, the probes shall be of the bundle type (with 5 or more internal taps, see Figure 11.1).

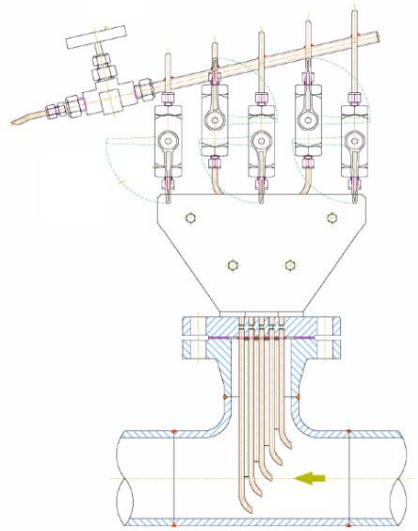

Figure 11.1- Typical arrangement of oil sample collectors for allocation metering systems with probe installed in the main process line.

11.3.5 For allocation metering (whenever fitted in Category A), fiscal and custody transfer metering systems shall also have automatic samplers.

11.3.6 For crude oil metering points, the manual and automatic samplers shall comply with API MPMS 8.1 and 8.2 respectively (plus related sections) for all expected flow rates.

11.3.7 A homogeneous fluid mixture shall be guaranteed for oil inline sampling and analysis systems, with concentration ratio C1/C2 above 0.9, according to ISO 3171. For fiscal, allocation and custody transfer metering systems, one mixing system (static or dynamic) shall be installed upstream of BS&W analyzer and sampling systems to guarantee homogeneity of the mixture for all expected flow range. If a dynamic mixing system is selected, the sampling systems shall be mounted in the main process line.

11.3.8 Whenever applicable, project shall install a single manual sampler, a single automatic sampler and a single inline BS&W analyzer to serve simultaneously all oil metering system measurement lines that belongs to the same stream. This equipment shall be installed in a common header downstream the flowmeters. They still need to be mounted together on the skid structure, where applicable

11.3.9 The automatic samplers of the intrusive probe type shall be designed in order to avoid the occurrence of vortex-induced vibration and other factors. In the absence of specific MANUFACTURER criteria, the requirements of ASME PTC 19.3 TW shall be complied with.

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

11.3.11 The automatic oil sampling system shall collect and store a representative oil sample at all projected flow conditions, allowing it to be transported to the laboratory for analysis. The collecting system shall be skid mounted. The

containers shall be installed inside local closed cabinets. For each container, a dedicated system shall be provided for detecting its status when the container is full (by level or weight measurement) and send it to the FMS Panel.

11.3.12 For the oil fiscal automatic sampler, in order to allow the removal of the probe during operation (without process shutdown), it shall be retrievable probe type or installed in a bypass line with a diameter smaller than the diameter of the main process line.

11.3.13 The automatic oil sampling system shall be controlled by the flow computer or by the PLC installed in the FMS Panel.

11.3.14 The local closed cabinets shall be located as close as possible to the sampling points.

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

11.3.16 The automatic oil sampling system shall be equipped with heat tracing in the sample transfer line from sample probe to the sampling panel to avoid wax formation.

11.4 Natural Gas Sampling

11.4.1 Each natural gas metering point, including flare systems, shall have a representative and manual sample collection point. The sampling points shall be as close as possible to their respective flow meter 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 meter and the sampling point.

11.4.2 For metering points following ISO 5167, the respective sample point shall be installed upstream the metering system without interference to the straight run requirements of the meter, so that change in composition due to pressure drop is avoided, particularly when the gas is near the dew point.

11.4.3 The sampling points associated with the gas metering system shall comply with API MPMS 14.1, including the need for a minimum distance of 5D downstream any disturbance or pipe accident.

11.4.4 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 sampling panel shall not be shared among different sampling probes for fiscal and allocation metering points.

11.4.5 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.

11.4.6 In case the project design includes a flare gas recovery system (closed flare), the sampling points shall be located immediately upstream of the branching to the flare gas recovery system.

11.4.7 For sampling points of individual gas-lift metering points, the use of a single sample 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.

11.4.8 The flare gas sampling panel shall be capable of collecting representative samples even with low pressure levels, therefore a vacuum pump shall be foreseen.

12 REQUIREMENTS FOR ONLINE ANALYZERS

12.1 Water in oil (BS&W) analyzers

12.1.1 For fiscal, allocation and custody transfer oil metering systems, BS&W analyzers shall be installed.

12.1.2 The instantaneous values of BS&W shall be available for the operator or directly for the UNIT'S Control System on a continuous and automatic basis for monitoring purposes.

12.1.3 It shall comply with requirements from API MPMS TR 2570 – Continuous On-line Measurement of Water Content in Petroleum (Crude Oil and Condensate).

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

12.1.5 Analyzers technology shall be selected according to technology as a function of the BS&W operational range.

Table 12.1 – BS&W analyzer technology selection according to range

Recommended Technology	Operational Range
Capacitive	BS&W < 30%
Microwave	0 % < BS&W < 100 %
Radiofrequency	0 % < BS&W < 100 %
Coriolis	BS&W > 5 %

12.1.6 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 (% volume);
- Oil continuous or water continuous regimes (oil continuous: BS&W ≤ 30%; water continuous: BS&W ≥ 50%; transition: 30% < BS&W < 50%).

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

12.2 Online chromatograph gas analyzers

12.2.1 In case of fiscal and custody transfer natural gas metering systems classified as Category A, it shall be foreseen a dedicated online chromatograph gas analyzer (CGA) connected to the FMS.

12.2.2 The CGA may be installed on the common header of the system, downstream the flow meters.

12.2.3 CGA shall be able to handle hydrocarbon composition (until C9+), CO2 and N2 and shall inform daily:

a) Gas composition;

b) Total Gas flow rate;

c) Gas flow rate per compound;

d) Gas Higher Heating Value.

12.2.4 H2S composition may be required, depending on the application.

12.2.5 CGA technology shall be in accordance with gas composition.

12.2.6 The FMS shall implement a validation function to discard invalid results from CGA.

12.2.7 CGA shall have a local manual sample collection point.

12.2.8 The maximum admitted uncertainty of the CGA shall be ±0.3 % of the compressibility factor.

12.2.9 CGA shall comply with Portaria Inmetro 188/2021 and ASTM D1945 requirements

12.2.10 For additional requirements see project FIELD INSTRUMENTATION technical specification.

13 CALIBRATION SYSTEMS

13.1 General

13.1.1 The fiscal crude oil to cargo tanks and custody transfer oil metering systems shall include a local calibration system composed of one or more standards, chosen among the following options.

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. Meter technology shall follow the requirements of Table 15.1.

b) Mechanical compact prover (Small Volume Prover) + duty flow meters. In this configuration, the compact prover shall be used to directly calibrate the duty flow meters. Meter technology shall follow the requirements of Table 15.1.

13.1.2 Natural gas fiscal metering systems, whenever using linear flowmeters, shall include a calibration system composed by a master meter, with exception of flare gas flowmeters.

13.1.3 For fiscal and custody transfer oil and natural gas metering systems designed to operate with more than one metering stream simultaneously, control valves shall be installed downstream of each meter run to allow the flow control of each stream. Additionally, a control valve shall also be installed downstream the compact prover to control the flow during the calibration of the flow meters.

13.1.4 The oil allocation flow meter (or the master meter, if available) shall be removed from its process line to be calibrated in one of the oil metering skids onboard. Therefore, one additional meter run shall be provided at the selected metering skid for calibrating the allocation meter (or the master meter, if available) against the compact prover (namely “calibration run”). This requirement is also applicable to well service oil flow meters.

13.1.5 If the calibration run for oil allocation or well service oil flow meters is installed on the fiscal crude oil to cargo tanks skid, it shall be installed in series with the fiscal duty meters of the skid.

13.1.6 It shall be possible to calibrate the flow meters over the full flow range, as defined by the project.

13.1.7 Installation of any non-leak-tight element between the flow meter under calibration and the reference (master meter or compact prover) is not allowed.

13.1.8 To allow for compact prover calibration on board, an adjacent space shall be provided, minimum of $3m^2$ in the direction of the prover axis.

13.2 Small Volume Prover

13.2.1 Compact provers shall be dimensioned according to API MPMS 4.2 or ISO 7278 and they shall be provided with bypass valves, and inlet and outlet valves of the double block and bleed type.

13.2.2 Compact provers shall have their instrumentation linked to the flow computers responsible for executing the main flow metering tasks, so that the flow computers may be used to execute the calibration process (proving).

13.2.3 Compact Provers shall be double chronometry type as per API MPMS 4.6, design according to API MPMS 4.2, primary volume shall be at least 0.265 m^3, and turn-down shall be at least 1000:1.

13.2.4 The compact provers shall be able to calibrate the flow meters and meet the RTM requirements;

13.2.5 The compact provers shall be mounted within the metering skid limits;

13.2.6 A skid-mounted control panel shall be included to provide local interface to the compact prover;

13.2.7 Repeatability factor shall be less than 0.02%;

13.2.8 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.

14 AUTOMATION REQUIREMENTS

14.1 FMS Automation System

14.1.1 The FMS Automation System shall include all required hardware, software and accessories to totalize and save metering data, implement standard algorithms for flow calculation, provide HMI to operators and metering technical responsible, provide data to onshore servers, guarantee data inviolability and comply with all legal requirements.

14.2 Communication and Network Requirements

14.2.1 An interface between the production UNIT's automation system and the FMS shall be provided in order to allow the transferring of operational data from the flow computers to the UNIT's supervisory system.

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

14.2.3 The FMS Workstation shall communicate with the automation firewall through Package Units LAN, for data communication with onshore servers and DMZ network.

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

14.2.5 If the project includes a Multiphase Flow Metering System (MFMS), whether for allocation or operational purposes, there shall designed a communication interface between FMS and MFMS. FMS shall make available registers and variables of allocation metering points to MFMS.

14.3 FMS Panel

14.3.1 The FMS Panel shall be delivered completely assembled with all components internally connected and shall be installed indoors, on acclimatized environment.

14.3.2 The flow computers shall be installed in the FMS Panel.

14.3.3 A spare flow computer for liquid metering and another spare flow computer for natural gas metering shall be installed in the FMS Panel.

14.3.4 Flow computers shall communicate with FMS Workstation through the FMS Ethernet Switches.

14.3.5 The FMS Panel shall comply with construction, environmental, power supply, electromagnetic interference and related requirements as per IEC 61000 and I-ET-3010.00-1200-800-P4X-002 - AUTOMATION, CONTROL AND INSTRUMENTATION ON PACKAGE UNITS.

14.4 PLC and Ethernet Switch

14.4.1 A simplex PLC shall be supplied with valves actuations, automatic sampler operation, filters differential pressure signals and any other auxiliary function required by the metering system.

14.4.2 The PLC shall comply with IEC 61131.

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

14.4.4 The Ethernet switch shall be connected to the following devices in the panel: PLC, FMS Local HMI and the flow computers. The Ethernet switch shall also be connected to the SOS/CSS, as per project's specific documentation.

14.4.5 For additional requirements for PLC and switches see I-ET-3010.00-1200-800-P4X-002 - AUTOMATION, CONTROL AND INSTRUMENTATION ON PACKAGE UNITS.

14.5 Flow Computers

14.5.1 All flow computers shall be Inmetro approved in accordance with PORTARIA Inmetro 298 of 08/07/2021 or any other that complements or replaces it. The installed firmware version shall follow its 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 installed inside FMS Panel and shall be linked to the FMS Workstation and UNIT's SOS HMIs.

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

14.5.5 Complete database of flow computers shall be available at FMS Workstation.

14.5.6 Variables from the FMS necessary for UNIT operation, such as differential pressure, static pressure, temperature, instantaneous flow rate, compensated and totalized flow for each measurement point, analyzer information, high/low flow and malfunction alarms shall also be available, as minimum, at the UNIT's SOS HMIs.

14.5.7 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.

14.5.8 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.

14.5.9 Each flow computers shall have an interface to allow the connection of external devices as notebook or hand-held for ANP audit purposes.

14.5.10 Flow computers shall have a local display to allow metering point selection and visualization of basic information and shall be furnished with all required software, licenses and configuration data.

14.5.11 All flow calculations shall be performed at flow computers with mechanisms to guarantee the inviolability of the configuration. Alarms, reports and event data files shall be generated and stored at flow computer and prevented from editing

14.5.12 The historical information of calibration data, intervention and access to the FMS (audit trail) shall be available at the flow computers and FMS Workstation to comply with RTM.

14.5.13 For required flow meters, it shall be foreseen a network link between meter and flow computer for diagnostics purposes.

14.5.14 Flow computer for flare gas flow meters shall be linked to the flow meter electronic unit by field network communication. The flow computer shall use the gross flow rate for the calculations.

14.5.15 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 or manually inputted;
d) Oil shrinking (Shrinkage Factor), for allocation measurement (FE) and Solubility Rate Factor (RS);
e) Thermal expansion between the reference temperature (20ºC) and water measurement temperature, for allocation measurement, when determining the Meter Factor;
f) Liquid compressibility between the reference pressure (101.325 kPa) and water measurement pressure, for the cases of allocation measurement, for the determination of the water;
g) Meter Factor, obtained by calibration (MF).

14.5.16 Normative reference for calculations and corrections shall be as per RTM (or any other regulation that updates it).

14.5.17 The algorithms of the gas flow computers shall comply with ISO 5167, AGA REPORT 7, AGA REPORT 8 PARTS 1 and 2, AGA REPORT 9, ISO 20765 PARTS 1 and 2, ISO 6976 and ISO 12213.

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

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

14.5.20 The flow computer shall be able to perform proving functions.

14.5.21 There shall be stored at the flow computers (in a first-in, first-out (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.

14.5.22 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, operator and viewer, as follows:

- Administrator: this level allows free access for changes at the configuration, including all passwords, data loggers' initialization and firmware downloading.
- Operator: allows the writing at the parameters, including the critical ones.
- Viewer: allows only data visualization.

14.5.23 All changes at the configuration shall be traceable. In order to allow the traceability, passwords shall be implemented.

14.5.24 Data fidelity at the FMS Workstation, flow computers and metering reports shall be guaranteed, once there can occur information with different number of bits (e.g.: software using 32 bits or 64 bits). In this case, the decimal digits shall be limited, observing the legal requirements. Also, data shall be available with enough decimal places (and no rounding) to cover ANP requirements for XML files.

14.6 FMS Workstation

14.6.1 The FMS Workstation is the dedicated interface for operation and maintenance of the Metering System, as well as its database and communication with other systems. The FMS Workstation comprises the FMS Virtual Server (running in Topsides SOS Process Cluster) and its clients FMS Local HMI (installed at FMS Panel) and FMS Monitor (located at the CCR). Whenever mentioned on text, FMS Workstation refers to the assemble of these equipment and software.

14.6.2 The information of all metering points shall be accessible through the FMS Workstation, even if the Metering System scope of supply is segmented. The FMS Workstation may have access clients (HMIs) in different locations of the UNIT, however the FMS Workstation, and its FMS Virtual Server, shall integrate all topsides and hull flow meters.

14.6.3 The FMS Virtual Server shall be installed and configured as a virtual machine in the Topsides SOS Process Cluster.

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

- Actuation of the valves;
- 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;
- Diagnostics functionalities of main flow meters parameters, received through digital communication;
- CGA validation function, to discard invalid results from CGA and only implement valid chromatograph results on the flow computer.
- Generation of metering reports with detailed visions on the FMS Workstation screens;
- Automatic register of operator interventions;
- Field equipment status;
- Supervisory screens with general and detailed visions including process variable values;
- System historical data register;
- Auto diagnosis system and automatic failure annunciation;
- Generation, uploading and downloading of configuration files and parametrization of flow computers;

- Access control to the flow computers configuration;
- Routine for oil offloading functioning start, including logic tasks at the flow computers.

14.6.5 There shall be available a FMS Local HMI (thin client) at the FMS Panel, connected to the FMS Virtual Server, for FMS commissioning and local maintenance.

14.6.6 There shall be available a FMS Monitor (thin client) at the CCR, connected to the FMS Virtual Server, as the main interface for the Metering System activities.

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

14.6.8 All flow computers data shall be available at the FMS Virtual Server.

14.6.9 All historical data (variables, parameters, events and interventions) shall be available at the FMS Virtual Server's storage device (on a proper historic application software) for, at least, 3 (three) months, increased daily.

14.6.10 FMS Workstation shall be responsible for the generation of all production data reports for audit purposes to enable the automatic sending of data to ANP. It 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.

14.6.11 The FMS Virtual Server shall provide all the necessary production data for the generation of XML electronic files by an external generator, including data from the flow computers, from FMS PLC and from the server itself. These XML files shall comply with ANP Resolutions 65/2014 and 737/2018. All data scope of these resolutions shall be available at the FMS Workstation.

14.6.12 FMS Virtual Server shall communicate to PETROBRAS Corporate Network via CSS architecture and firewall to allow the generation of XML electronic files onshore. For further details, see project's AUTOMATION AND CONTROL ARCHITECTURE.

14.6.13 Daily volume production for all metering points shall be closed at 00:00 (midnight).

14.6.14 The FMS Virtual Server machine shall meet the performance requirements for virtual machines described at I-ET-3010.00-5520-861-P4X-003 – VIRTUALIZATION OF AUTOMATION SYSTEM COMPUTERS.

14.6.15 Supervisory screens

14.6.15.1 An adequate number of dynamic high-resolution full-graphic video screens shall be prepared by SUPPLIER to allow direct monitoring, operation and maintenance of the Flow Metering Systems at FMS Workstation and its HMIs, taking into account all acquired data and commands, measurement line control, meter calibration control, security control of operator entered parameters, system monitoring, trouble-shootings etc. These screens shall be approved by PETROBRAS.

14.6.15.2 A minimum of the following screens for the FMS Workstation shall be implemented:

- Graphic based summary screen, design guided by the project's Flow Metering Locations;
- Graphic based process screens, design guided by project's P&ID;
- Summary tables for gas, oil and water metering;
- Specific screens for batch operations, such as well testing and offloading;
- Specific screens for automatic sampling operation;
- Specific screens for calibration routine;
- Reports and logs screen;
- Historical trend visualization of FMS variables;

14.6.15.3 Alarms shall be implemented at the FMS Workstation whenever necessary, including at least:

- Flow rate in each measurement line exceeds limits of the allowable uncertainty required (high and low flow rates);
- Pressure and temperature out of expected process conditions (high and low alarms);
- Sampling cans full;

14.6.15.4 All the screens and functionalities of FMS Workstation are valid for both FMS Local HMI and FMS Monitor.

14.6.15.5 For HMI and supervisory screens additional requirements, see I-ET-3010.00-1200-800-P4X-002 - AUTOMATION, CONTROL AND INSTRUMENTATION ON PACKAGE UNITS.

14.6.16 Reports and Logs

14.6.16.1 The FMS reports to be made available in the FMS Workstation shall be configurable and meet the criteria defined in the last issue of RTM. The reports and files shall be ready and delivered, when requested by PETROBRAS, ANP or Inmetro.

14.6.16.2 The FMS Workstation 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.

14.6.16.3 All data traffic shall have access restriction/control and shall be auditable, with audit log. The data shall be protected against unauthorized access, tampering and loss of information, whether accidental, intentional or environmental.

14.6.16.4 At least the below reports shall be generated by FMS:

- Production Metering Report: hourly, daily and monthly reports, for each flow computer;
- Well Test Report (for each well) – “Batch Report”;
- Quantity Transaction Report (QTR) (offloading) – “Batch Report”;
- Calibration Report (for each calibration done onboard) – “Proving Report”;
- Alarm and Event Report (for each flow computer);
- Audit Trail Report (for each flow computer);
- Configuration Report (for each flow computer);

14.6.16.5 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);

14.6.16.6 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.

14.6.16.7 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.

14.6.16.8 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, density, BSW;
- Last 35 (thirty five) days – daily values of the average values of: volume, flow rate, pressure, temperature, CTL, CPL, density, BSW.

14.6.16.9 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, pressure, temperature.

14.6.16.10 File recording at the FMS Workstation:

- All files mentioned at item 14 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 backup device in a monthly basis.

14.6.16.11 Synchronicity between flow computers and FMS Workstation:

- FMS Workstation shall have a functionality to synchronize the clock of all flow computers. FMS Virtual Server clock shall be the 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

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

14.6.16.13 All production volumes at the FMS Workstation shall be based on the variable "Previous Day Net (NSV) Totalizer" of each flow loop.

14.6.16.14 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, at least, the last 35 (thirty five) days.

15 SUMMARY TABLE FOR METERING SYSTEMS

Table 15.1 – Summary table for metering systems

Item	Fluids	Metering points	Duty	Type of meter	Accuracy (note 1)
1	Oil	Cargo pump discharge (offloading)	Custody transfer metering	Ultrasonic or Coriolis (note 2) or turbine meters or positive displacement (note 8). Minimum 1 spare meter installed.	± 0.3% (system) ± 0.2% (sensor)
2	Oil	Cargo pump discharge (offloading)	Calibration of custody transfer metering	Master meter and prover (notes 2, 3), or only prover;	± 0.1% (system)
3	BS&W	Cargo pump discharge (offloading)	Online	Online transmitter (microwave, radio frequency, capacitive)	0.05% (absolute)
4	BS&W	Cargo pump discharge (offloading)	Sampler	Automatic and manual	
5	Oil	Transference pump discharge (from the process plant to the cargo tanks)	Fiscal metering	Ultrasonic or Coriolis (note 2) or turbine meters or positive displacement (note 8). Minimum 1 spare meter installed.	± 0.3% (system) ± 0.2% (sensor)
6	Oil	Transference pump discharge (from the process plant to the cargo tanks)	Calibration of fiscal metering	Master meter and prover (notes 2, 3), or only prover;	± 0.1% (system)
7	BS&W	Transference pump discharge (from the process plant to the cargo tanks)	Online	Online transmitter (microwave, radio frequency, capacitive)	0.05% (absolute)
8	BS&W	Transference pump discharge (from the process plant to the cargo tanks)	Sampler	Automatic and manual	
9	Oil	Well service injection (crude oil)	Fiscal metering	Positive displacement, Coriolis (with volume indication) or helical turbine meter (notes 3, 4). Minimum 1 spare meter installed	± 0.3% (system) ± 0.2% (sensor)
10	BS&W	Well service injection (crude oil)	Online	Online transmitter (microwave, radio frequency, capacitive)	0.05% (absolute)
11	BS&W	Well service injection (crude oil)	Sampler	Automatic and manual	
12	Oil	Test separator	Allocation metering	Coriolis (with volume indication) (notes 3, 5);	± 1.0% (system) ± 0.6% (sensor)
13	BS&W	Test separator	Online	Online transmitter (Microwave 0-100%)	5% (measured value)

Item	Fluids	Metering points	Duty	Type of meter	Accuracy (note 1)
14	BS&W	Test separator	Sampler	Automatic and manual	
15	Oil	Production / Treatment	Operational metering	Positive displacement, Coriolis (with volume indication) or turbine meter	± 1.0% (system) ± 0.6% (sensor)
16	BS&W	Production / Treatment	Online	Online transmitter (microwave 0-100%)	
17	Diesel	Well service injection (diesel)	Operational metering	Positive displacement, Coriolis or turbine meter	± 0.3% (system) ± 0.2% (sensor)
18	Gas	Export Line	Fiscal metering	Ultrasonic or Coriolis or turbine meter; minimum 1 standby meter (note 9)	± 1.0% (system) ± 0.7% (sensor)
19	Gas chromatography	Export Line	Online	Online analyzer	± 0.3% (Z factor)
20	Gas	Import Line	Fiscal metering	Orifice plate meter; dual chamber orifice fittings and removable straight pipe sections to be provided (note 9)	± 1.5%
21	Gas	Gas Lift individual per Well	Allocation metering	Orifice plate meter; dual chamber orifice fittings and removable straight pipe sections to be provided	± 2.0 %
22	Gas	Gas Lift Total	Operational metering	Cone or orifice plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided)	± 3.0 %
23	Gas	Gas Injection individual per Well	Operational metering (note 7)	Cone or orifice plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided)	± 3.0 %
24	Gas	Gas Injection Total	Operational metering	Cone or orifice plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided)	± 3.0 %
25	Gas	Test separator	Allocation metering	Orifice plate meter; dual chamber orifice fittings and removable straight pipe sections to be provided	± 2.0 %
26	Gas	Production separators	Operational metering	Cone or orifice plate meter (dual chamber orifice fittings and removable straight pipe sections to be provided)	± 3.0 %

Item	Fluids	Metering points	Duty	Type of meter	Accuracy (note 1)
27	Gas	Fuel Gas	Fiscal metering	Orifice plate meter; dual chamber orifice fittings and removable straight pipe sections to be provided (note 9)	± 1.5 %
28	Gas	Flare	Fiscal metering	Ultrasonic flare meter	± 5.0 %
29	Gas	Vent (if needed)	Fiscal metering	Ultrasonic flare meter	± 5.0 %
30	Gas	Flare Pilot	Fiscal metering (Category D)	Coriolis	± 1.0% (system) ± 0.7% (sensor)
31	Gas	Flare Purge	Operational metering	Orifice plate meter (notes 6, 10)	± 3.0 %
32	Gas	Dilution for Flare	Operational metering	Orifice plate meter, cone or ultrasonic flare meter; (note 6)	± 3.0 %
33	Gas	Flare Assistant	Operational metering	Orifice plate meter (note 6)	± 3.0 %
34	Water	Test separator	Allocation metering	Orifice plate meter, magnetic meter (spool type) or Coriolis meter;	± 1.0%
35	Water	Individual Injection	Operational metering	Orifice plate meter, cone meter, magnetic meter (spool type)	± 1.0%
36	Water	Produced	Operational metering	Orifice plate meter, cone meter, magnetic meter (spool type)	± 1.0%
37	Water	Disposal	Operational metering	Orifice plate meter, cone meter, magnetic meter (spool type)	± 1.0%
38	Condensate	Import Gas (Slug Catcher Outlet)	Fiscal metering	Coriolis or ultrasonic meter; Minimum 1 standby meter	± 0.3% (system) ± 0.2% (sensor)
39	BS&W and Density	Import Gas (Slug Catcher Outlet)	Online	Online transmitter (microwave, radio frequency, capacitive) and online densitometer	
40	BS&W and Density	Import Gas (Slug Catcher Outlet)	Sampler	Automatic and manual	

NOTES:

(1) Maximum allowable errors for liquid metering; uncertainty for gas metering;

(2) In case of implementing a master meter, this shall be of helical turbine type. In case no master meter is applied, the duty meters shall be of helical turbine type;

(3) There shall be provided facilities for calibration of the meters onboard;

(4) It is optional the application of a master meter on the oil well service injection system. In case a master meter is foreseen, it shall be calibrated on one of the oil metering skids onboard with its compact prover. Otherwise, the duty oil well injection meters shall be directly calibrated on one of the oil metering skids onboard with its compact prover;

(5) The use of master meter on the oil allocation system is optional. In case master meter is used, it shall be calibrated on one of the oil metering skids onboard with its compact prover. Otherwise, the duty allocation meters shall be directly calibrated on one of the oil metering skids onboard with its compact prover.

(6) Purge, dilution and assist for flare, in case foreseen in the project, shall be individually metered. These streams shall be classified as operational, therefore they shall be fiscally measured by other metering systems (e.g.: flare or fuel gas). Exceptions to classify these meters as fiscal shall be previously approved by PETROBRAS.

(7) In case project produces gas from different fields and gas injection is foreseen, the individual gas meters shall be classified as fiscal, comply with all fiscal gas requirements, and use orifice plate on dual chamber orifice fittings.

(8) Positive displacement meter may be applied for fiscal or custody transfer oil applications only in the case the other listed technologies do not fully comply with expected Reynolds range for the flow stream.

(9) In case the natural gas metering system is classified as Category A, linear flow meters shall be used (ultrasonic, Coriolis or turbine), with a minimum of 1 standby meter, 1 master meter and 1 online gas chromatograph analyzer, supplied assembled on a skid. Otherwise, the natural gas metering system shall use orifice plate with equipped on a dual chamber orifice fitting.

(10) In case project foresees the use of a meter with diameter smaller than 2”, alternative technologies may be used, such as integral orifice or Coriolis.

16 DOCUMENTATION

16.1 The technical proposal documentation shall be supplied with at least the following documents:

a) The list of documents;

b) Datasheets and brochures for each device;

c) All equipment and installation data including material list, equipment list, spare part list for two years of operation, power consumption, weight, software manual, panel lay-out, system layout, etc.;

d) A deviations list related to this Technical Specification, including reasons for deviation, alternative proposals and impacts in performance;

e) Technical manuals with information about all components and devices;

f) Complete description of services and training courses;

g) A plan with inspections and tests schedule, including acceptance criteria for each test;

h) Other documents required for evaluation of technical proposal;

16.2 The SUPPLIER is responsible for the FMS approval by ANP. SUPPLIER shall provide the complete documentation of the FMS in accordance with requested by RTM.

Therefore, SUPPLIER is responsible for elaborating documentation for ANP approval and authorization of the metering system.

16.3 The SUPPLIER is responsible for all required documentation for Inmetro Initial Verification (VI) of the metering systems, flow computers and flow meters.

16.4 A copy of this legal documentation for compliance shall be kept segregated from PACKAGER DATABOOK, which is aimed for PETROBRAS use only.

16.5 All documentation shall be provided in digital media. All documents shall also be provided in editable format (.doc, .xls, or other compatible) and drawings in Microstation. Exceptions are acceptable to instrument manuals.

16.6 For calibration and dimensional inspections certificates, as well as uncertainty report, additionally to the .pdf of the original document, SUPPLIER shall also send XML files containing the results and relevant information of the documents. PETROBRAS will submit the files templates during detailed design phase.

16.7 ANP Databook

16.7.1 PETROBRAS shall previously approve all documents before PETROBRAS submit it to ANP. Therefore, SUPPLIER shall allocate sufficient PETROBRAS verification time when planning delivery deadlines and schedule.

16.7.2 All documentation that composes ANP Databook shall be in Portuguese language. Exceptions are acceptable to drawings (e.g.: isometric, P&ID, general arrangement), which may be delivered in English language.

16.7.3 Documentation shall be in accordance with “Resolução Conjunta ANP/ Inmetro nº1 of 10/06/2013” (or any other that supersede it) and “Ofício-Circular ANP/NFP nº1 of 26/05/2020” (and any other that complements it).

16.7.4 SUPPLIER shall provide for ANP Initial Approval, 180 days after the Kick Off Meeting, at least the following technical documents:

a) Technical description of the UNIT’s Metering System (“Memorial Descritivo dos Sistemas de Medição”);

b) Schematic Diagram of Metering System (“Diagrama Esquemático do Sistema de Medição de Vazão”) composed by a simplified P&ID of oil, gas and water flow metering system;

Note: These documents – 16.7.4 (a) and (b) – shall describe each fiscal, allocation, custody transfer and operational oil, gas and water flow measurement points, their applied technologies, system measurement maximum uncertainties, simplified information regarding FMS automation and production equation suggested for oil and gas.

16.7.5 SUPPLIER shall provide for ANP Databook first issuing (at least 120 days prior to ANP inspection on shipyard or 180 days prior to UNIT’s sail away, if no inspection is held on shipyard), at least the following technical documents:

16.7.5.1 Index 1 - General Items:

a) Updated technical description of the UNIT's Metering System ("Memorial Descritivo dos Sistemas de Medição");

b) Updated Schematic Diagram of Metering System ("Diagrama Esquemático do Sistema de Medição de Vazão");

c) Security seal and lock initial control sheet, in order to guarantee controlled access to system parameters and configuration. Even though the seals and locks will not be installed at this time, all necessary seal installation locations shall be here listed. Control sheet shall contain, at least, the following fields: the number of the seal, location of installation, associated instrument tag, date of installation, name of responsible for installation. This sheet shall also include Inmetro seals installed during Initial Verification. See item 6.36 for additional requirements;

d) Inmetro metering approvals (PAM) of flow meters (fiscal, allocation and custody transfer), metering systems, flow computers and CGA;

e) Inmetro Initial Verification approval report for each flow meter (fiscal, allocation and custody transfer);

f) Inmetro Initial Verification approval report for oil metering systems (fiscal, allocation and custody transfer);

g) Inmetro Initial Verification approval report for each flow computer;

h) Inmetro Initial Verification approval report for each CGA;

i) Operation manual of the FMS. Shall include information regarding proving procedures onboard;

j) Maintenance and operation manuals of the meters, flow computers, instruments, analyzers, and automatic samplers;

16.7.5.2 Index 2 – Information for each fiscal, allocation, custody transfer and operational metering point, grouped by metering point:

a) Piping and Instrumentation Diagrams of all metering points (metering P&ID and UNIT P&ID);

b) General arrangement drawing of each metering point;

c) Data sheets for each device and field instrument;

d) As built piping isometric drawings of all the metering points;

e) Calculation reports for design of primary elements (orifice plates, etc.) and associated downstream and upstream runs lengths and reports for pressure drop values;

f) Calculation report containing the uncertainty (preliminary, theory) of each metering point. Shall contemplate at least the minimum, normal and maximum flow rate cases for each flow element. For skids, it shall be calculated the uncertainty per stream and also for the complete system (skid);

g) Calculation report containing Reynold number range for the oil metering points from the start of operation, taking into account the maximum flare gas burn limit allowed by regulatory agencies, to the end of production (25 years in operation);

h) Dimensional inspection certificates, within their validity period, issued by an ILAC/IAAC or Inmetro accredited laboratory, for the oil and gas meters, including their respective upstream and downstream straight runs and flow conditioners. Certificates shall have attached a technical report containing critical analysis of the dimensional inspection certificates, verifying compliance with the required standard;

i) Computational Fluid Dynamics (CFD) report for flare gas flow metering points, to support uncertainty calculation;

j) Electronic configuration report extracted directly from electronic based flow meters (Coriolis, ultrasonic and magnetic);

k) Mix calculation reports (C1/C2 according to ISO 3171) to confirm oil homogeneity of samples for all expected flow range of the system.

16.7.5.3 Index 3 – Additional documents:

a) FMS automation architecture drawing;

b) FMS automation description manual;

c) Technical specifications comprising systems, equipment, accessories, cables, materials and software;

d) Calibration and dimensional inspection schedule, to comply with legal requirements at the beginning of UNIT operation;

e) Programming tools, system reports, system diagnosis;

f) FMS communication memory map.

16.7.6 SUPPLIER shall provide for ANP Databook second issuing (at least 30 days prior to ANP inspection offshore or 50 days prior to UNIT start of operation, whichever happens sooner), at least the following technical documents:

a) All documents listed in item 16.7.5 (ANP Databook first issuing) updated to as built status, where necessary;

16.7.6.1 Index 1 - General Items:

a) Updated seal control sheet, with all installed security seals and locks on the system.

16.7.6.2 Index 2 – Information for each fiscal, allocation, custody transfer and operational metering point, grouped by metering point:

a) Calibration certificates, within their validity period, issued by an ILAC/IAAC or Inmetro accredited laboratory of all instruments: temperature transmitters, temperature elements, pressure transmitters, differential pressure transmitters, flow meters, and provers;

b) Dry calibration certificates, within their validity period, of all flare/vent flow meters;

c) Valves tightness test certificates. All valves from fiscal, allocation and custody transfer metering system shall be tightness tested. Any valve that is somehow associated to a bypass prevention control shall also be tested;

d) Leak test for provers;

e) Uncertainty report for each metering point, updated by the latest calibration reports. They shall contemplate at least the minimum, normal and maximum flow rate cases;

f) Flow computer reports containing all metering system data updated and consistent with all other documents being ready to start production;

16.7.7 SUPPLIER shall guarantee that fiscal instruments (differential pressure, pressure, temperature sensors and transmitters) calibration is valid for at least 1 month when UNIT start operating (first oil);

16.7.8 SUPPLIER shall guarantee that allocation, custody transfer and operational instruments (differential pressure, pressure, temperature sensors and transmitters) calibration is valid for at least 3 months when UNIT start operating (first oil);

16.7.9 SUPPLIER shall guarantee that valves tightness certificates and analyzers calibration certificates are valid for at least 6 months when UNIT start operating (first oil);

16.7.10 SUPPLIER shall guarantee that provers calibration is valid for at least 1 year when UNIT start operating (first oil);

16.7.11 SUPPLIER shall guarantee that operational flow meters are calibrated just before UNIT sail away from shipyard;

16.7.12 SUPPLIER shall guarantee that fiscal, allocation and custody transfer flow meters calibrations, which do not have associated provers onboard, are valid for at least 1 month (positive displacement or turbine technology) or 3 months (other technologies) when UNIT start operating (first oil);

16.7.13 SUPPLIER shall guarantee that orifice plates dimensional inspection certificates are valid for at least 1 year when UNIT start operating (first oil);

16.7.14 SUPPLIER shall guarantee that orifice fittings, Zanker conditioner, upstream and downstream straight runs dimensional inspection certificates are valid for at least 3 year when UNIT start operating (first oil);

16.7.15 Design, installation and documentation shall take into account all ANP requirements and comments;

16.7.16 SUPPLIER shall provide any other documents to support metering system approval or authorization, if requested by ANP.

17 INTEGRATION AND ASSEMBLY SERVICES

17.1 The Integration and assembly services shall include:

17.1.1 Detailed project;

17.1.2 Installation and configuration of the FMS Virtual Server on Topsides SOS Process Cluster;

17.1.3 Interconnection and integration of the instruments, flow computer, FMS Virtual Server and thin clients (FMS Local HMI and FMS Monitor);

17.1.4 Interconnection and integration of the measurement system with the UNIT's Supervisory System;

17.1.5 Interconnection and integration of the FMS with the MFMS;

17.1.6 FMS Workstation screens customization;

17.1.7 Report implementation;

17.1.8 Tests, pre-operation, calibration and assisted startup;

17.1.9 Seals and locks installation;

17.1.10 Installation of user's applicative programs;

17.1.11 Training courses.

18 ACCEPTANCE TESTS

18.1 **General requirements**

18.1.1 The following tests and inspections shall be performed at supplier installations (FAT) prior to delivery:

- Physical assembly (visual and dimensional);

- Calibrated flow meters and field instruments;
- Dimensional inspection of straight pipes and primary flow elements (by accredited laboratory);
- Equipment functionality;
- Skid functionality, integrated with FMS Panel;
- Loop test of each instrument;
- Flow computers functionality, including calculation verification for each measurement;
- Flow computers communication with the FMS Workstation;
- Workstation functionality;
- Reports generation;
- All panel tests, as required at I-ET-3010.00-5520-888-P4X-001 - AUTOMATION PANELS.

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

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

18.1.4 Backup of all flow computers configuration and FMS Virtual Server software shall be supplied to PETROBRAS after completion of each test (FAT, SAT and SIT).

18.2 FAT minimum requirements

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

18.2.2 The metering skids shall be properly and completely assembled and shall be tested integrated to the FMS Panel and their associated flow computers and devices, such as the Flow Metering System Workstation.

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

18.2.4 All functionality and equipment of the metering skids shall be tested, such as automatic samplers, BSW, densitometers or CGA analyzers, valves operation, flow totalization, meter calibration, and so on.

18.2.5 The programming and parametrization of the flow computers and other programmable equipment/device shall be done prior to FAT, so that it is available for verification during the tests.

18.2.6 SUPPLIER shall test all flow computers and FMS Panel with their instruments and metering skids during FAT, validating in SAT and SIT. Pulse and 4–20 mA generators may be used to represent loose instruments for FAT purposes only.

18.2.7 All I/O (100%) of the FMS Panel, including spare ones and network connections, shall be tested during FAT. All Junction Boxes wired terminals (100%) from metering skids shall be tested during FAT.

18.2.8 FMS supervisory screens shall be sent to PETROBRAS for comments, so that all modifications are already implemented by SUPPLIER for verification during FAT.

18.2.9 All functionality of the FMS Workstation shall be checked and tested during FAT, such as:

- Screens validation, object animation, page and menu navigation;
- User control access protection;
- Alarm generation;
- Report generation;
- Historian;
- Flow computers communication map validation (all address shall be tested);
- Flow computer configuration and parametrization;
- Batch routines (offloading and well test);
- Calibration routines and prover operation;
- Automatic samplers routines;
- Valves operation;
- Meter diagnostics;
- Chromatograph results validation;
- Communication with CSS, with memory map validation.
- During FAT, this virtual machine (FMS Virtual Server) may run in a temporary computer (if the Topsides SOS Process Cluster is not available). The thin clients (FMS Local HMI and Monitor at CCR-OA) shall access this virtual machine.

18.3 SAT and SIT minimum requirements

18.3.1 After the installation of the equipment on the UNIT, all the tests shall be repeated, ensuring the integration of all field equipment, metering skids, FMS Panel, FMS Workstation and CSS (SAT and SIT).

18.3.2 All instruments and equipment (100%) shall have its communication tested with the flow computers, the FMS Virtual Server, the FMS HMIs and SOS (when applicable).

18.3.3 All FMS Junction Boxes terminals shall be tested with the FMS Panel.

18.3.4 All memory map address from flow computers shall be validated with the FMS Workstation.

18.3.5 All memory map address from FMS Workstation shall be validated with CSS/SOS (Package Unit Server and SOS HMI).

18.3.6 During SAT and SIT, the FMS Virtual Server shall be running in the Topsides SOS Process Cluster.

19 INMETRO INITIAL VERIFICATION

19.1 The Inmetro Initial Verification process shall be carried out for the regulated flow meters applied in metering systems for fiscal, allocation and custody transfer, as per Portarias Inmetro 291/2021 and 156/2022 or any other that complements or replace them.

19.2 The Inmetro Initial Verification process shall be carried out for the regulated flow computers applied in metering systems for fiscal, allocation, custody transfer and operational, as per Portaria Inmetro 298/2021.

19.3 Chromatograph Gas Analyzers part of the FMS shall be submitted to Inmetro Initial Verification process, as per Portaria Inmetro 188/2021.

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

- Portaria Inmetro 291/2021
- Ofício Circular Inmetro 032/2017
- Norma Inmetro NIT-SEFLU-014

19.4.1 The Initial Verification procedure on metering systems, which is metering system SUPPLIER responsibility, shall be executed on an onshore single-phase basis, according to recommendation cited in Note in document Inmetro NIT-SEFLU-014 page 14. All costs related to Initial Verification are of SUPPLIER scope and responsibility.

19.4.2 SUPPLIER's procedure proposal for Initial Verification shall be submitted for Inmetro approval for, afterwards, execution. Initial Verification procedure and Inmetro acceptance shall be sent to PETROBRAS, for information.

19.4.3 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.

19.5 Configuration report of electronic meters (ultrasonic, Coriolis and magnetic) shall be extracted prior to Inmetro seal of these equipment and sent to PETROBRAS.

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 10 (ten) technicians (a total of 30 technicians), in Brazilian Portuguese and shall be performed using identical equipment as supplied.

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 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.