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NOTE: The items highlighted in yellow and green in this document and its attachments are related to information that may change from project to project. In addition, the configuration of the process plant and subsea information are also subject to change.

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SUMMARY

1 GENERAL

1.1 INTRODUCTION

1.1.1 The intent of this specification and documents referenced hereinafter is to provide the CONTRACTOR with general information of intended service and requirements for the design, construction (or conversion), assembly, transport, installation and operation of one Floating Production Storage and Offloading System (FPSO), also called “the Unit” in this document.

1.1.2 All requirements herein provided must be considered as a minimum, according to the terms agreed upon in the Contract. All regulatory rules (Classification Society (CS), Brazilian Administration (including "Portaria 787 de 27 de novembro de 2018" from Brazilian Labor and Welfare Ministry (“Ministério do Trabalho e Emprego”), Flag Administration, International Maritime Organization (IMO) and applicable rules and laws) shall be complied with. In addition, CONTRACTOR shall comply with PETROBRAS Technical Requirements outlined in this GENERAL TECHNICAL DESCRIPTION (GTD), which are considered mandatory unless it is not accepted by regulatory rules. In case of conflicting information among PETROBRAS’ technical requirements, PETROBRAS shall be notified to define the way forward.

1.1.2.1 Unless otherwise expressed herein or in clarifications letters during Tender, recommended practices, technical bulletins, technical standards and other technical documents issued by standardizing institutions shall be considered as references by their latest editions or revisions in force by the date of Tender commencement.

1.1.3 This GTD provides necessary information for the development of the Basic and Detailed Design. However, they do not exempt CONTRACTOR from contractual responsibilities during operation lifetime. CONTRACTOR shall be responsible for the provision of all services and other requirements necessary to deliver one complete functional Production Unit as described herein. Any calculation presented in this document is preliminary and shall be revised during the Detail Design Phase.

1.1.4 In all documents, the word “shall” and equivalent expressions like “to be”, “is to”, “is required to”, “has to”, “must” and “it is necessary” are used to state that a provision is mandatory.

1.1.5 Unless otherwise expressed, any reference to “CONTRACTOR responsibility” or “CONTRACTOR’s responsibilities” means that the CONTRACTOR will design, supply, install, operate and maintain according to the Contract provisions with no commercial interference or responsibility from PETROBRAS.

1.1.6 PETROBRAS “approval” or "comments" on the documents shall not exempt CONTRACTOR from responsibility to carry out the work in accordance with contractual and legal requirements.

1.1.7 The design of the Unit shall be based on field proven solutions and PETROBRAS, at their sole discretion, have the right to reject any detail of the Unit’s design.

1.1.8 CONTRACTOR shall provide stand-by equipment, ready to operate, for systems which require full capacity on continuous operation, in order to guarantee no process capacity reduction or degradation of the oil, gas and water specification. CONTRACTOR shall also comply with stand-by philosophy for equipment whenever specifically required in this GTD. This requirement includes the necessary redundancy for pressure safety valves (PSVs).

1.1.9 CONTRACTOR shall perform during Detail Design two workshops to address constructability and commissioning. The agenda and topics to be addressed on these workshops shall be mutually agreed between CONTRACTOR and PETROBRAS. The actions and outcomes from these workshops shall be shared with PETROBRAS.

1.2 GENERAL DESCRIPTION

1.2.1 REFERENCE DOCUMENTS

1.2.1.1 Throughout this document, the following Technical Specifications and drawings are referenced:

Table 1.2.1.1 – Reference Documents

#	Document Number	Rev.	Title
1	I-ET-3A36.00-1000-941-PPC-001	F	METOCEAN DATA
2	I-ET-RISER SYSTEMS REQUIREMENTS	0	RISER SYSTEM REQUIREMENTS
3	I-ET-SPREAD MOORING SYSTEMS REQUIREMENTS	0	SPREAD MOORING SYSTEM REQUIREMENTS
4	I-ET-3010.00-1500-274-PLR-001	E	RISERS TOP INTERFACE LOADS ANALYSIS
5	I-ET-XXXX.XX-1200-813-P4X-001	B	FLOW METERING SYSTEM FOR LEASED UNITS
6	I-ET-3010.00-5400-947-P4X-001	Q	SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS
7	I-ET-3010.00-1359-960-PY5-001	V	OFFSHORE LOADING SYSTEM REQUIREMENTS
8	I-DE-0000.00-0000-140-P56-002	0	CONICAL RECEPTACLE “TYPE B” – BASKET PROFILE DIMENSIONS
9	I-DE-0000.00-0000-140-P56-003	0	CONICAL RECEPTACLE “TYPE C” – BASKET PROFILE DIMENSIONS
10	I-ET-3000.00-1500-800-PEK-016	0	SUBSEA PRODUCTION CONTROL SYSTEM FOR FPSO
11	I-ET-XXXX.XX-5510-760-PPT-579	B	TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED
12	I-ET-3000.00-5521-931-PEA-001	0	METOCEAN DATA ACQUISITION SYSTEM REQUIREMENTS
13	I-ET-3000.00-5139-800-PEK-005	A	HYDRAULIC POWER UNIT FOR SUBSEA EQUIPMENT WITH MULTIPLEXED ELECTROHYDRAULIC AND DIRECT HYDRAULIC CONTROL SYSTEM (FLOATING PRODUCTION UNIT)

#	Document Number	Rev.	Title
14	FD-XXXX.XX-1500-800-PEK-001	0	DADOS PARA PROJETO DA HPU DOS EQUIPAMENTOS SUBMARINOS [Refer to I-ET-3000.00-5139-800-PEK-005 Annex I for sample]
15	I-RL-3A00.00-1000-941-PPC-001	A	DURATION OF EXTREME CURRENT PROFILES AND CLUSTERS OF SIMULTANEOUS METOCEAN CONDITIONS
16	I-DE-0000.00-0000-140-P56-001	B	RISER TOP CONNECTOR MOCK-UP GEOMETRY REFERENCE
17	I-ET-3010.00-5529-812-PAZ-001	H	ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM
18	I-ET-XXXX.XX-1200-000-P4X-001	0	OPERATION PHILOSOPHY
19	I-DE-3000.00-1500-941-P56-002	0	RISER SUPPORTS ARRANGEMENT CONCEPTUAL DESIGN - FPSO BALCONY (NOTE 1)
20	I-ET-3000.00-5530-850-PEA-001	0	POSITIONING AND NAVIGATION SYSTEMS
21	I-ET-3010.00-5529-854-PEK-001	G	MODA RISER MONITORING SYSTEM – FPU SCOPE (SPREAD MOORING)
22	I-ET-3010.00-1300-279-PPC-350	F	DIVERLESS BELL MOUTH SUPPLY SPECIFICATION
23	I-LI-3010.00-1300-279-PPC-350	G	BSDL-SI PART LIST
24	I-ET-3000.00-1210-010-P8J-001	0	FLUIDS FOR SPECIAL OPERATIONS
25	I-ET-3000.00-5529-850-PEK-001	A	RIGID RISER MONITORING SYSTEM (RRMS) – FPU SCOPE
26	I-ET-XXXX.XX-5524-941-XXX-001	A	PERMANENT RESERVOIR MONITORING SYSTEM – SPREAD MOORING - FPSO SCOPE
27	I-ET-XXXX.XX-1200-600-P4X-1BE	0	PIG FACILITIES
28	I-ET-3010.00-1359-940-P4X-001	B1	OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS
29	I-ET-3010.00-1200-901-P4X-002	0	AVAILABILITY AND MAINTAINABILITY (RAM) ANALYSIS REQUIREMENTS FOR LEASED UNITS WITH COMBINED CYCLE GENERATION

NOTE 1: To be confirmed at Project kick-off meeting.

1.2.2 GENERAL DESCRIPTION

1.2.2.1 The Unit design life shall be at least XXX years. During the Contract period, the Unit shall be adequate for uninterrupted operation, without the need of dry-docking.

1.2.2.2 The Unit shall be capable to be moored offshore Brazil, at a location with water depth of XXX meters.

1.2.2.3 As a brief overview, the Unit will receive the production from subsea oil, condensate or gas wells and shall have production plant facilities to process fluids, stabilize them and separate produced water and natural gas. Processed liquids will be metered, stored in the vessel cargo storage tanks and offloaded to shuttle tankers.

1.2.2.4 Produced gas, with CO2 and H2S, shall be compressed, dehydrated, and used as a fuel gas and for lifting oil production. Remaining gas will be exported/reinjected in the reservoir. Produced water will be reinjected into reservoir or disposed overboard. The Process Plant shall have the processing capacities as listed in Table 1.2.2.4.

Table 1.2.2.4- Process Plant Capacities

Parameter	Capacity
Total Maximum Liquids	28,600 Sm^3/d
Total Maximum Oil	28,600 Sm^3/d
Total Produced Water	24,000 Sm^3/d
Total De-Sulphated Sea Water Injection	39,800 Sm^3/d
Total Gas Handling, including lift gas, treatment and compression	12,000,000 Sm^3/d

1.2.2.5 The Unit shall have the minimum facilities specified in this document to send part of the injection gas to another Unit and/or be connected to a subsea separator (HISEP™, see item 2.11 for detail). These scenarios may occur during the production life. All additional facilities required for these scenarios and not specified in this GTD will be mutually agreed with CONTRACTOR.

1.2.2.6 CONTRACTOR shall consider the SUBSEA LAYOUT documents. The Unit shall consider 23 wells in the design (see section 15).

Table 1.2.2.6Wells

Wells	Quantity
Production	11
Injection WAG (Water Alternating Gas)	11
Injection Gas	1

1.2.2.7 In summary, the Unit shall have the following main characteristics:

- Ship-shaped or barge-shaped Unit of Very Large Crude Carrier (VLCC) size or greater, with a minimum storage capacity, i.e. minimum volume of oil available, in the cargo tanks, to be offloaded, of 1,450,000 bbl of crude oil;
- Offloading system, including hawser and export hose;
- Spread Mooring System;
- Process plant, comprising deck structure, safety facilities, steel flare tower or flare boom, equipment for oil processing, associated gas treatment, compression and re-injection, sea water treatment and injection, produced water treatment and re-injection, etc.;

- Utilities necessary to keep the Unit's standalone operation capacity;
- Power generation system to meet all the needs of the Unit, based on dual fuel gas turbine-generators in cogeneration (i.e., gas turbine + waste heat recovery unit) or in combined cycle (gas turbine + waste heat recovery unit and steam generator + steam turbine generators);
- Turbines are accepted as drivers exclusively in Power Generation (all-electric concept). As such, all main equipment loads (gas compressors and water injection pumps) shall be driven by electric energy from power generation system;
- Gas compression plant comprising high-pressure centrifugal compressors driven by electric motor;
- Accommodation for normal operation crew, maintenance technicians required for contracted performance and for PETROBRAS representatives. The Unit design accommodation size shall be compatible with the People On Board (POB) required to accomplish the CONTRACTOR's operation, maintenance and asset integrity management plans;
- Facilities to connect risers for oil production, gas-lift, gas transfer, gas export, water/gas injection and HISEP™ connection;
- Cargo handling systems, including cranes, monorails, rail cars, etc.;
- Helideck;
- Telecommunication facilities.

1.3 CLASSIFICATION

1.3.1 CONTRACTOR shall contract a single CS to follow and approve the whole FPSO project comprising the design, construction, installation on site, operation and decommissioning phases.

1.3.2 The CS shall also consider all construction loads and the environmental loads during transportation from construction/conversion shipyard to Brazil and, after decommissioning, from Brazil to a point outside its territory. The CS shall consider those conditions for the final approval of the Unit design.

1.3.3 The CS's Certificates shall clearly specify that the Unit shall comply with all requirements for continuous operation during its design life, as stated in item 1.2.2, at the site without the need to be dry-docked in a shipyard.

1.3.4 Acceptable CSs are DNV (Det Norske Veritas), BV (Bureau Veritas), ABS (American Bureau of Shipping) and LRS (Lloyd's Register of Shipping).

1.3.5 The Unit shall obtain Main Class and/or Class Notation encompassing the following items:

- Vessel structure, equipment and marine systems;
- Permanent mooring system;

- Production facilities and utilities;
- Fuel gas system;
- Oil storage;
- Offloading;
- Inert gas system;
- Automation and control systems;
- Centralized Control Room Operation;
- Lifting Appliances;
- Safety System/Equipment;
- Lifesaving System/Equipment.

1.3.6 Riser System Classification is not part of CONTRACTOR's scope of work. CONTRACTOR's scope shall cover down to the last flanged connection in all risers.

1.3.7 During construction and operational phase, CONTRACTOR shall provide, whenever requested by PETROBRAS, the Classification and Regulatory status reporting the pending items with corresponding due dates, and any other relevant information about the Unit.

1.4 UNITS AND IDENTIFICATION OF EQUIPMENT

1.4.1 The metric system complying with International Organization for Standardization (ISO) standard, as far as practicable shall be used for equipment, machinery and fittings identification and data.

1.4.2 The Standard conditions are defined as:

- Sm^3 @ 15.6 ºC and 101.3 kPa(a);
- Nm^3 @ 20 ºC and 101.3 kPa(a), as per *Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* (ANP) metering regulation requirement.

1.4.3 All Unit identification, signs and documents shall be written according to the Brazilian Administration and Flag Authorities requirements. All stationary equipment, including those to which *Norma Regulamentadora* Nº 13 (NR-13) does not apply, must be identified on the field.

2 PROCESS

2.1 GENERAL

2.1.1 CONTRACTOR shall design Process plant according to the following norms: API RP 14C.

2.1.2 Process Plant and Utilities shall operate normally when subjected to the motions induced by the environmental conditions (see section 13).

2.1.3 CONTRACTOR shall bear in mind that, as the design is part of the Contract and falls under CONTRACTOR's responsibility, production shutdown or degraded oil, water or gas specification or any other equipment malfunction due to vessel motions shall not be acceptable. CONTRACTOR shall minimize vessel motions in all environmental conditions.

2.1.4 CONTRACTOR shall also design the topsides facilities according to riser characteristics included but not limited to item 15.2.

2.1.5 CONTRACTOR shall adopt an isolation philosophy for equipment/piping maintenance taking into consideration that the gas volume to be sent to flare shall be minimized.

2.1.6 CONTRACTOR shall implement piping arrangement to allow operational/start-up procedures to minimize or avoid gas volume to be sent to flare.

2.2 FLUID CHARACTERISTICS

2.2.1 PRODUCED OIL AND RESERVOIR

2.2.1.1 The typical range of properties for the oil is indicated in the Table below and shall be taken into account for all design purposes. CONTRACTOR shall design the Unit to process oil with any blend within these properties. CONTRACTOR shall make simulations to assess the correct design parameters.

2.2.1.2 CONTRACTOR shall submit the process simulation files and report to PETROBRAS for comments considering the range of fluid components.

Table 2.2.1.2Oil Properties and Contaminants

Oil Properties and contaminants	
Oil API grade	29
Viscosity (dry – dead oil) (1)	378.1 cP @ 4 ºC 226.9 cP @ 10 ºC 34.9 cP @ 25 ºC 10.7 cP @ 50 ºC 5.9 cP @ 70 ºC
Wax Appearance Temperature (2, 3)	46.1 ºC (1st event) 19.8 °C (2nd event)
Pour Point	12°C
Foam	Yes (severe)
Sand/Solids (2,4)	0,XX% m/m (5)

NOTE 1: Pressure loss due to emulsified oil viscosity shall be considered.

NOTE 2: CONTRACTOR shall design production plant to ensure operational continuity considering wax crystals and wax deposition.

NOTE 3: Wax is expected to deposit only in the second event.

NOTE 4: The installation of facilities to remove solids (corrosion products, precipitated salts and sand) is required for High Pressure (HP) Separator, Free Water Knockout Drum (FWKO), Test Separators and electrostatic treaters. The system shall include sand wash connections as well as the flushing inside the vessel. It is CONTRACTOR's decision to use online or offline sand removal system taking into consideration the assurance of production continuity.

NOTE 5: To be informed during detail design phase.

2.2.2 PRODUCED WELLS COMPOSITION

2.2.2.1 CONTRACTOR shall design the Unit with the compositions given below. CONTRACTOR shall submit to PETROBRAS, during the execution phase, for comments the process simulation considering the range of reservoir fluid components.

2.2.2.2 These simulations shall clearly show the operating conditions of process plant equipment.

2.2.2.3 These simulations shall consider the premises in Table 2.2.2.3 (steady flow condition):

Table 2.2.2.3 Design Cases

Cases			Temp. (ºC) (1)	Oil Flow rate (2) (Sm^3/d)	Liquid Flow rate (Sm^3/d)	Gas Flow rate (3) (Sm^3/d)
Max Oil / Max Gas	1	Well A	30	28,600	28,600	12,000,000
	2	Well C	45	28,600	28,600	12,000,000
Max Liquid / Max Gas	3	Well A	40	17,160	28,600	12,000,000
50% BSW / Max Liquid	4	Well D	40	14,300	28,600	6,000,000
Max Water / Max Liquid	5	Well A	70	4,600	28,600	3,000,000
Max Arriving Temperature	6	Well B	95	4,000	24,000	10,000,000
Max Water / Max Liquid	7	Well D	85	4,600	28,600	12,000,000
Max Gas / Low Liquid	8	Well A	20	14,300	14,300	12,000,000
	9	Well D	20	14,300	14,300	12,000,000
Max Gas / Low Liquid	10	Well D	30	7,150	14,300	12,000,000
	11	Well B	10	4,000	4,000	10,000,000
	12	Well A	20	4,000	4,000	1,800,000

Low Flow (representative)	12 A	Well B	10	2,000	2,000	4,000,000

NOTE 1: Operational temperature for the blend downstream of production choke valve. During the production the blend temperature can vary from 10ºC to 95ºC.

NOTE 2: The standard flow rate shall be applied to oil conditions as per item 2.3.1. It refers to dead oil conditions.

NOTE 3: Gas Flow rate at inlet of the dehydration unit, considering gas from HP separator and LP Gas compressor. Any recirculation of gas streams shall be added onto this Gas Flow Rate. Gas Lift recirculation should not be considered.

NOTE 4: In order to achieve the desired Gas Oil Ratio (GOR) for each design case, simulation may be adjusted by subjecting Well Fluids through a series of flashes and recombining the gas and oil rates to match the flowrates indicated in Table 2.2.2.3.

NOTE 5: The design water cut at the production header goes from 0% up to 95%.

NOTE 6: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions (steady flow and well start-up) to size production choke valves.

NOTE 7: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions to size lift gas, water injection and gas injection/transfer choke valves.

NOTE 8: The shut-in pressure at top production riser is 36,500 kPa(a).

NOTE 9: The normal pressure range upstream of production choke valve is 7,500 to 31,000 kPa(a). Under some conditions, e.g. intermittent flow, pressure can achieve lower values.

NOTE 10: It shall be considered 60 ppmv of H_2S in the produced gas.

NOTE 11: For simulation cases with 0% BS&W (Basic Sediment & Water), if necessary to recirculate fluids for heating, CONTRACTOR shall consider recirculation of 100% oil stream.

NOTE 12: For HISEPTM design cases, refer to item 2.11.2.

2.2.2.4 Table 2.2.2.4 shall be considered for the fluid composition.

Table 2.2.2.4: Well Fluid Composition

Component	Well A	Well B	Well C	Well D
CO_2	37.78	60.05	31.74	54,42
N_2	0.20	0.20	0.25	0,2
C1	36.27	32.32	36.27	35,42
C2	4.86	2.76	5.99	3,71
C3	3.31	1.56	4.08	2,1
iC4	0.54	0.26	0.67	0,34
nC4	1.40	0.66	1.72	0,89

iC5	0.45	0.21	0.55	0,29
nC5	0.71	0.34	0.87	0,45
C6	0.81	0.10	1.00	0,14
Benzene	x	x	x	x
C7	x	x	x	x
Toluene	x	x	x	x
C8	x	x	x	x
C2-Benzene	x	x	x	x
M. and P. Xylenes	x	x	x	x
O. Xylene	x	x	x	x
C9	x	x	x	x
C10	0.82	0.10	1.01	0,14
C11	0.72	0.09	0.89	0,12
C12	0.65	0.08	0.80	0,11
C13	0.67	0.08	0.83	0,11
C14	0.57	0.07	0.70	0,1
C15	0.54	0.07	0.67	0,1
C16	0.42	0.05	0.52	0,07
C17	0.38	0.05	0.47	0,06
C18	0.40	0.05	0.49	0,07
C19	0.35	0.04	0.43	0,06
C20+	5.23	0.48	6.44	0,64
Mol. Weight C20+	529	559	523	558
Density C20+	0.9443	0.8810	0.9075	0,882

NOTE 1: Identify process currents (or fluid) with benzene at a concentration of 1% or more in volume, control actions shall be provided to eliminate/mitigate possible occupational exposures.

NOTE 2: Identify currents with H2S and define or estimate their concentration in ppm and control actions shall be provided.

2.2.3 WELL TEST CHARACTERISTICS

2.2.3.1 Table 2.2.3.1 shall be taken into account to define the test separator system (test heater, three-phase test separator, pumps and other related items).

Table 2.2.3.1a: FPSO Capacities

CHARACTERISTICS	NOTE	VALUE
Oil Flow rate	Maximum	8,000 Sm^3/d (note 1)

	Minimum, for accuracy of measurement purpose	300 Sm³/d
Gas Flow rate	Maximum	4,000,000 Sm³/d
	Minimum	75,000 Sm³/d
Water cut	For accuracy of measurement purpose	0 to 95%
Arrival temperature upstream choke valve	-	15 ºC to 95 ºC (Note 2)

NOTE 1: The standard flow rate shall be applied to oil conditions as per item 2.3.1. It refers to dead oil conditions.

NOTE 2: CONTRACTOR shall consider the following scenarios for well test header:

Table 2.2.3.1b: Scenarios for Well Test Header

Scenario	Gas Flowrate (MM Sm³/d)	Oil Flowrate (Sm³/d)	Water Flowrate (Sm³/d)	T (°C)
1	4.0	8,000	0	25
2	4.0	4,000	4,000	30
3	4.0	2,400	0	10
4	3.0	1,000	0	-10

NOTE 3: The well test system shall be able to operate with one or more wells within the capacities informed on table 2.2.3.1a.

2.2.3.2 CONTRACTOR shall consider that test separator will have a recycle of oil stream from a point upstream oil allocation metering to one point in the test header as close as possible to the choke valve. This recycle will be used to maintain the temperature upstream test heater above 15ºC.

2.2.3.3 Well test separator shall be able to operate from low pressure up to the HP separator normal operating Pressure of 6,500 kPa(a). During low pressure operations, expected for well kick-off purpose, produced gas from test separator may be routed to flare and liquids routed to further lower pressure separation stages.

An interconnection from gas outlet of test separator to FWKO or LP Compressor shall be provided to reduce flaring during operations with a pressure around 2,000 kPa(a). LP compressor may be operated in its maximum capacity; however, its design shall not be impacted by this flow.

2.2.3.4 Test separator shall be sized for the maximum liquid and gas flow with the normal operating pressure of 6,500 kPa(a).

2.2.3.5 Test separator will also receive fluids such as wells completion fluids and special operations fluids. The list of expected completion and special operations fluids can be found in the FLUIDS FOR SPECIAL OPERATIONS (see item 1.2.1). Completion

Fluids and special operations fluids shall be routed to oil offspec tank in order to prevent impacts in production. CONTRACTOR shall be responsible to treat completion fluids and special operations fluids for final destination.

2.2.3.6 Test separator pumps shall be installed in N+1 configuration to allow recirculation to oil treatment plant. Test separator pumps flow capacities shall be designed to handle well flow rates and to allow well service operations.

2.2.3.7 The test separator system shall be sized to guarantee a minimum operating temperature of 40ºC for any of the scenarios presented on item 2.2.3.1 NOTE 2 above.

2.2.3.8 The well test heater and well test separator may receive wax crystals.

2.2.3.9 CONTRACTOR shall provide test heater bypass.

2.2.4 PRODUCED GAS

2.2.4.1 The complete description of the gas treatment and compression plant is found on item 2.7.3.

2.2.5 PRODUCED WATER

2.2.5.1 Salinity range: from 30,000 to 320,000 mg/L (as NaCl).

2.2.5.2 The complete description of the produced water plant is found on item 2.7.4.

2.3 PROCESS

2.3.1 CARGO TANKS/ EXPORTED OIL

2.3.1.1 The oil to be stored and exported shall meet the following specification:

- Basic Sediment & Water content (BS&W): lower than 0.5% vol.;
- Salinity: less than 285 mg/L (as NaCl);
- Reid Vapor Pressure (RVP): < 68.9 kPa (a) at 37.8°C (for storage purpose);
- Reid Vapor Pressure (RVP): 43 kPa (a) at 37.8°C. This value is intended for measurement purpose to comply with required TVP and can be reassessed in operation phase;
- H_2S: < 1 mg/kg;
- Maximum Oil True Vapor Pressure (TVP) at measurement temperature at the oil fiscal metering defined by FLOW METERING SYSTEM (see item 1.2.1): 70 kPa (a) (for measurement purpose - Resolução Conjunta ANP/Inmetro nº1 de 10/06/2013 or another updated documents which substitutes it);

- Maximum Storage temperature (for design purpose): 40ºC;
- Resolução Conjunta ANP/Inmetro nº1 de 10/06/2013 (or another updated documents which substitutes it).

2.3.2 PRODUCED WATER DISPOSAL

2.3.2.1 The disposal of produced water shall comply with the Brazilian Administration regulations issued by Environmental Ministry, through its *Conselho Nacional do Meio Ambiente* (CONAMA) Resolutions 393/2007. The analytical method used to determine the content of Oil & Grease (TOG) in produced water to be discharged to overboard shall be the Standard Method (SM) SM-5520B, which determines the total hexane extractable material (HEM).

2.3.3 SERVICE AND LIFT GAS

2.3.3.1 The lift gas to provide artificial lift shall meet the following specification:

- Gas lift riser:
  - Normal lift gas temperature at the top of the riser: 40 ºC;
  - Normal Operating Pressure at the top of the riser: 25,000 kPa (a);
  - Design Pressure: 36,500kPa (a);
  - Maximum 120 ppmv of H_2S;
  - Maximum 85% mol CO_2;
  - Maximum H_2O content: according to Gas Dehydration Unit (GDU) specification and process plant configuration;
  - Design Temperature: -20°C to 50°C, to be confirmed during execution phase.
- Gas injection riser:
  - Normal gas injection temperature at the top of the riser: 40 ºC;
  - Normal Operating Pressure: see item 15.2.2;
  - Design Pressure: 60,500 kPa (a);
  - Maximum 120 ppmv of H_2S;
  - Maximum 85% mol CO_2;
  - Maximum H_2O content: according to GDU specification and process plant configuration;
  - Design Temperature: see item 15.2.2.

2.4 WATER INJECTION

2.4.1 The Unit shall be able to operate continuously with only one injection well up to 11 (eleven) connected wells through 11 positions: I1A/B, I2 A/B, I3 A/B, I4 A/B, I5 A/B and I6. I7, the 12th injection slot, is connected to a gas only injection well.

2.4.2 The Unit shall be able to inject seawater, produced water and mixtures of them. The decision to switch from one mode to another mode (seawater or produced water injection or mixture) is a PETROBRAS prerogative. The mixture of sea water and produced water shall be done upstream water injection pumps.

2.4.3 Water injection facilities must be designed according to the operational cases listed in table 2.4.3.

Table 2.4.3: Water Injection Operational Cases

Cases		Flow rate	Water injection pressure (1,2)
		Sm^3/d	kPa(a)
Max Flowrate / Max Pressure	1	39,800 (3)	35,000
Max flowrate / high injectivity	2	39,800 (3)	20,000
Ramp-up	3	13,267	35,000
Mid Life	4	26,533	30,000
Multiple simultaneous injection scenarios	5	26,533	35,000
		13,267	15,000
…		…	…
Max flowrate/one well	n-1	12,000	35,000
Min flowrate / one well	n	800	15,000

NOTE 1: Pressure value upstream water injection choke valve. Pressures at the top of water injection risers may be significantly lower.

NOTE 2: During project execution phase PETROBRAS will provide to CONTRACTOR the pressure, temperature and flow rate conditions to size water injection choke valves.

NOTE 3: Extra flow rate design capacity does not need to be considered for Well Service Operations.

2.4.4 Seawater quality specification to injection shall meet the following specification:

- Operating Pressure: See item 15.2.2
- Operating Temperature: from 25ºC up to 55ºC;
- The system shall have a Sulphate Removal Unit (SRU);
- Seawater quality specification (maximum values):

- Content of suspended solids: 1.5 mg/L, according to ISO 11923:1997 (E) – Annex B method;
- Maximum particles/mL greater than 5 µm: 10 (ten) per milliliter;
- Dissolved oxygen: 10 ppb (vol) O_2;
- Soluble sulfide content: 2 ppm (vol);
- Bacteria (SRB planctonic – mesophile): 50 NMP/mL;
- Total anaerobic bacteria (TAHB planctonic): 5,000 NMP/mL;
- Maximum sulphate content: 100 mg/L (this value can be higher if requested by PETROBRAS during operational lifetime);

- pH of injected water: to be daily monitored.

2.4.5 Produced water quality specification to reinjection shall meet the following specification:

- Operating Pressure: see item 15.2.2;
- Operating Temperature: from 25ºC up to 55ºC;
- Produced Water quality specification (maximum values):
  - Dispersed Oil, as measured by SM5520F: 40 mg/L;
  - Content of suspended solids (TSS): 10 mg/L;
  - Particle size: 25 µm;
  - Dissolved oxygen: 10 ppb (vol) O_2;
  - Soluble sulfide content: 15 ppm (vol);
  - Bacteria (SRB planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (TAHB planctonic): 5000 NMP/mL;
- pH of injected water: to be daily monitored.

2.4.6 Water injection riser characteristics:

- Normal Operating Pressure: see item 15.2.2;
- Design Pressure: see item 15.2.2;
- Maximum dissolved oxygen: 10 ppb (vol) O_2;
- Design Temperature: see item 15.2.2.

The system shall consist of filtration, sulphate removal unit (including Clean-in-Place (CIP) system), deaerator system, chemical injection and injection pumps for a total flow rate of 39,800 m^3/d of injected desulphated water. For the SRU configuration, at least three trains (3x50%) are required, however, 4x33%, 5x25%, 6x20% can also be considered. At least three trains (3x50%) are required for SRU feed pumps. At least three trains (3x50%) are required for the booster pumps, if applicable. At least three trains (3x50%) are required for the injection pumps. When heating of injection water is required, it shall be done by the hot return stream of the cooling water system or any other hot stream. The system shall be designed considering that, during operation, PETROBRAS may require lower injection flowrates that shall be achieved with the minimum number of injection pumps in operation.

2.4.6.1 Filtration system shall be, as a minimum, one of the following options:

- Self-cleaning filter and cartridge filter;
- Multi-media filter and cartridge filter;
- Self-cleaning coarse filter and ultra-filtration (UF);

2.4.6.2 For ultra-filtration option, design of UF recovery shall consider inlet solid content defined by membrane supplier. UF unit shall comply with the following specifications as a minimum:

- The permeate flux (normal and maximum) to maintain the required water injection flowrate shall be kept constant even during backwashing, cleaning procedure and routine maintenance;
- Maximum permeate flux in operation during cleaning: 80 LMH@25ºC;
- Membrane shall be sodium hypochlorite (NaOCl) resistant to a minimum of 500 ppm during cleaning procedure;
- Membrane absolute pore size: maximum of 0,22 µm;
- Ultrafiltration design specification shall be in accordance to SRU supplier's requirements.
- Full bypass of UF unit.

2.4.7 Full and partial bypass of SRU Unit shall be considered (bypass shall not cover the filtration system upstream membranes). The bypass may be used to sustain water injection flow, only whenever requested by PETROBRAS.

2.4.8 The Sulphate Removal Unit shall be located upstream Deaerator. Seawater deaeration with hydrocarbon gas stripping shall not be used.

2.4.9 Means shall be provided to allow water injection at the correct specification, even when operating at minimum flow rate (only one well connected with minimal flow) or at full capacity (all wells connected). Means shall be provided for individual well flow rate control, using information from operational flow meters. The water injection system shall have no stagnation points. If inevitable, water drainage points shall be provided.

2.4.10 The injection water system shall have an online O_2 analyzer installed on the water injection header and another one installed downstream of the deaerator system and oxygen scavenger injection point. The analyzer installed on the water injection header shall be connected to process interlock system. This interlock actuation will be defined later on by PETROBRAS. The analyzer shall have an installed stand-by instrument.

2.4.11 The produced water shall have options to be discharged overboard or reinjected in the reservoir, as shown on figure 2.4.11. It is PETROBRAS decision to discharge overboard or reinject the produced water.

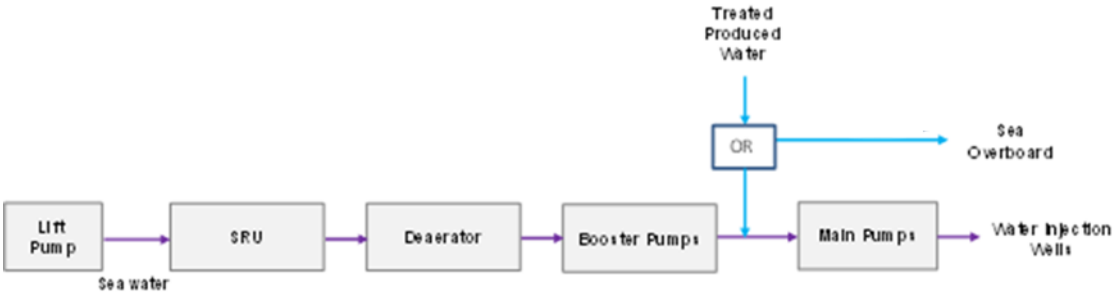


Figure 2.4.11- Simplified Diagram for Produced Water and/or Seawater Injection

2.4.12 The produced water treatment system description is detailed on item 2.7.4.

2.4.13 Means shall be provided to allow pressure equalization between pumps discharge and injection header during start-up procedures. Pressure transmitters shall be installed downstream and upstream of shutdown valves in order to enable control by differential pressure.

2.4.14 The water injection pumps (main, seawater booster, produced water booster and SRU feed pumps) shall comply with API 610. Pump drivers shall be electric motors.

2.4.15 The main water injection pump shall be monitored for bearing and motor temperature, axial displacement and vibration as specified in item 8.12.

2.4.16 The water injection pumps sealing system shall comply with API 682 and, for pumps with produced water as working fluid, its design and sealing plan shall be suitable for salty and hot produced water where applicable. Additionally, API 62 auxiliary sealing plan (quench) shall be provided.

2.4.17 For acceptable vendor list for water injection system, see item 19.

2.4.18 UV-c Sterilizer reactors shall be installed upstream of UF in order to inactivate microorganisms and minimize biofouling formation/deposition. The minimum requirements for this system shall be:

- Configuration: N+1 (one stand-by);
- Design UV dose ≥ 40 mJ/cm².

2.5 DESIGN SUMMARY

2.5.1 WELL DESIGN SUMMARY

Table 2.5.1: Well Design Data

Design data	
Maximum liquid production flow rate per well	8,000 Sm³/d(2)
Minimum liquid production flow rate per well	300 Sm³/d (1)(2)
Water cut from one well	0% to 95%
Maximum gas production flow rate per well	4,000,000 Sm³/d
Maximum gas injection flow rate per well position	4,500,000 Sm³/d
Minimum gas injection flow rate per well position	500,000 Sm³/d (1)
Maximum water injection flow rate per well position	12,000 Sm³/d
Minimum water injection rate per well position	800 Sm³/d (1)
Maximum water injection operational pressure (top of risers)	35,000 kPa (a)
Maximum lift gas flow rate	2,000,000 Sm³/d
Maximum lift gas flow rate per well	500,000 Sm³/d
Arrival temperature(3)	XxºC to yyºC

NOTE 1: For measurement accuracy purposes.

NOTE 2: The standard flow rate shall be applied to oil conditions as per item 2.3.1, that refers to dead oil conditions.

NOTE 3: Temperature in steady state condition. During transient conditions temperatures can be lower.

2.6 TOPSIDE MANIFOLDS

2.6.1 All oil production wells shall be connected to 1 (one) oil production header and 1 (one) oil test header. Both these headers shall be able to accommodate all producer wells.

2.6.2 Emergency Shutdown Valves (ESDV) shall be installed in all wells' lines. ESDVs shall be in a position:

- Such that it is above water;
- Such that its exposure to topsides incidents is minimized;
- Subject to the above, such that the distance from the ESD valve to the base of the riser is as short as reasonably practicable. Scenarios of risers releases shall be evaluated as part of Hazard Identification, Risk assessment and Consequence Analyses.

2.6.3 Problems on the test train shall not affect the main process train. The same philosophy applies to the production riser producing to the test header. Facilities to inject hot Diesel (maximum 90ºC) upstream each production choke valve shall be provided to recirculate diesel towards the processing plant and/or towards the subsea lines. Facilities shall consider the possibility to inject diesel during shut-in conditions. The expected rate of hot Diesel injection is 34 m^3/h. Pigging will not use hot Diesel.

2.6.4 The Flow Metering System (FMS) flow meter of each gas injection flexible line shall have its instantaneous flow rate signal sent to Process Shutdown System (PSD) through a hardwired connection. Logic implementation shall be discussed during detail design with PETROBRAS.

2.6.5 The Test Header and the Test Separator shall provide periodical production test for each well or each manifold with one or more wells connected.

2.6.6 Production and test headers shall be provided with chemical injection to enhance the separation and/or protect the facilities (anti-foaming, demulsifier, scale inhibitor, etc.).

2.6.7 Each production well shall have adjustable chokes at both lines (production and service/gas-lift). All choke valves shall be remotely actuated by electrical actuator. All choke valves (production, gas lift, gas injection and water injection) shall be able to be locally/manually and remotely actuated from the Central Control Room. The choke valves shall have a multistage trim throughout the whole valve stem travel with an equal percentage or linear characteristic curve (Cv). Characteristic curves with abrupt changes of slope shall not be accepted.

2.6.8 CONTRACTOR shall provide temperature and pressure transmitters both upstream and downstream each choke valve connected to Process Shutdown System (PSD), as well as differential pressure indication on each production choke valve. Logic implementation associated to differential pressure interlock will be discussed during detail design.

2.6.9 A service header to allow flexibility to access each well with no disturbance to the others shall also be provided. This service header may be used to perform Diesel injection (pigging operations, Diesel circulation, bullhead operation, etc.), dead oil circulation, desulphated/deaerated water circulation, gas circulation as service gas (pigging operations). The service header shall also have facilities to inject ethanol or monoethylene glycol (MEG) bed during pigging, commissioning, WAG fluid change-over operations.

2.6.10 All Gas Lift Slots shall be capable to receive (back flow from well) small amounts (up to 10 m^3) of liquid. This is not to be used often and is restricted to cases of depressurization to remove hydrate blockage in any part of the subsea system.

2.6.11 Each I1 to I5 positions from both slots (A and B), I6 and I7 shall have a connection to the test header. This alignment refers to service header operations. The fluids from WAG positions shall be sent to test header.

2.6.12 PIG FACILITIES

2.6.12.1 For PIG facilities, see item 1.2.1(PIG FACILITIES).

2.6.13 WELL SERVICE SYSTEM

2.6.13.1 All subsea service operations (Diesel circulation, desulphated/deaerated water circulation, leak test, pigging, etc.) shall be done using facilities onboard. CONTRACTOR shall take into account the requirements of those operations, for example, volume control, pressure control, etc. Seawater could be used for well service operations until seawater injection treatment system is fully commissioned.

2.6.13.2 The Unit shall have facilities and space to allow the injection of nitrogen and service gas on top of production risers. The Nitrogen Generator Unit (NGU) will be supplied by PETROBRAS.

2.6.13.3 Well service system requirements:

- The well service system shall be able to inject desulphated/deaerated water, an ethanol or MEG bed, diesel and oil from the cargo tanks in each of the production, service, water/gas injection lines. The system shall be able to inject in more than one line simultaneously with flow rate and volume control in each line.
- The service pump shall operate with desulphated/deaerated water, diesel, crude oil or a mixture of Diesel and crude oil. In case of Ethanol or MEG bed injection, the well service pump will not run with ethanol/MEG; the pump to be used for this operation is the pump referenced in Table 2.8.12 (Product: Gas hydrate inhibitor: ethanol or MEG for oil production wells (subsea)).
- It shall be possible to inject a mixture of Diesel and oil in any proportion, it is under CONTRACTOR responsibility to provide proper facilities to measure and control the mixture. The fluids to be injected (Diesel, and crude oil or a mixture of Diesel/oil) shall be metered with dedicated fiscal metering.
- Protection filters shall be provided upstream of each pumps suction, the filter specification shall be according to manufacturer´s pump recommendation.
- A dedicated atmospheric Diesel/oil service tank/vessel shall be installed at topsides for well service system operations (including Diesel and oil mixture) in order to avoid the return of reservoir fluid/gas to hull, protecting the Unit in case of gas return during well service operations. The minimum volume required for atmospheric Diesel /oil service tank/vessel shall be 30 m^3. The atmospheric tank vent design shall comply with GTD item 2.7.5.10. The tank relief device shall be specified for emergency condition to avoid structural damage to the tank.
- The service pumps and tanks/vessels shall be sized for a total flow of 34 to 340 m^3/h of Diesel at maximum discharge pressure up to 33,000 kPa(a) (The service pump shall be positive displacement type according to API 674 and shall have a flow fiscal meter, one flow meter for each fluid). Flow control shall be obtained by variation in pump speed with a variable speed drive, with or without supplemental recycle. If supplemental recycle is needed, CONTRACTOR shall take special care to avoid cross contamination between the different operating fluids and recycle shall return to the dedicated atmospheric tank/vessel installed at topsides, recirculation to hull is not allowed. In case of recirculation is necessary, besides variable control, the necessity of recycle cooling shall be evaluated. A minimum arrangement of 3x50% to the service pump is required. A spare connection from

laydown area to downstream of well service pump shall be available to allow connection (chicksan) of a Diesel motor driven service pump (including connections for supply to rented pump tank).

- The service pumps range shall not comprise very low flow and very high pressure, related to piping leak test services. This application shall be attended by separated pump (leak test pump).
- It shall be provided means to perform the system flowrate test during commissioning.
- The well service system shall be prompt to be aligned, without the need to reassemble any piping element (e.g. removable spool, spectacle blind etc). CONTRACTOR shall consider Well Service pump operating continuously as an input for load balance calculation.
- Each well shall be capable to operate from 2,5 to 200 m^3/h.
- The system shall be also able to perform pressurization after production stop, pressurization to equalize WCT valves pressure and pressurization to equalize DHSV. The system shall be composed by two different sets of pumps to perform high flow rate operations (e.g circulation and bull heading) and low flow rate operations (e.g pressurization). An additional pumps arrangement of 2 x 50% to the low flow rate operations (lines pressurization) shall be provided with a total flow rate of 4 m^3/h of diesel at maximum operational discharge pressure of 32,000 kPa(a). Flow control is not required.

2.6.13.4 WAG operations requirements:

- The Unit shall have specific devices to monitor pressure on topsides water injection lines in order to detect gas leakage to water injection subsea lines during gas injection operation in WAG loop paired line. In this case, an automatic action shall be activated to isolate pressure source.
- CONTRACTOR shall also consider specific control philosophies for water and gas operations.
- The Unit shall be able to inject hydrate inhibitor in Wet Christmas Tree for the WAG wells and depressurize the water injection line in case of gas leakage to water injection piping during gas injection operation.
- The Unit shall be able to inject Diesel and a MEG/ethanol bed (see Table 2.8.12 - NOTE 1).

2.6.13.5 Special operations requirements:

- The Unit shall also be prepared to perform remote operations using pumps from Special Purpose Boats (squeeze, xylene, etc.) to operate alongside of the FPSO. Therefore, CONTRACTOR shall provide one permanent and dedicated line from the bunkering station to be tied into well service pump discharge header. This line shall be designed considering the pressure rating of the well service pump.
- The CONTRACTOR shall provide facilities to isolate and drain service line and also flush topsides piping (using inert fluid) after the remote operation.

- The Unit shall have a special permanent support with access and railing located at the side shell to fit the flexible lines coming from the special boat. Means for spill containment must be provided at the support. The place where the platform will install the special permanent support shall have structural capacity to support 18,000 kg. The flexible line shall be fitted using the FPSO crane. The flexible line weight will be 12,000 kg.

2.6.14 CONTRACTOR shall guarantee the performance of pigging operation regarding service fluid flowrate control.

2.6.15 PETROBRAS is responsible to supply those pigs during operational lifetime.

2.6.16 The gas-lift header shall allow individual injection to each gas-lift riser. CONTRACTOR shall comply with the requirements to control the flow rate at normal well production and during pigging operations.

2.6.17 An individual flow meter shall be installed for each gas-lift riser, including the production satellite wells and gas injection riser of WAG wells. For pigging purposes, the gas flow rate shall be controlled and totalized.

2.6.18 Facilities shall be provided to allow the depressurization of any riser, including production, gas lift, gas injection with no production disturbance. These facilities shall allow:

a) Depressurization of all production risers within one hour (it shall consider the proposed subsea arrangement issued by PETROBRAS) in order to avoid hydrate blockage. Contractor shall consider as maximum subsea riser volume xxx m³ and initial conditions xxx kPa(a) and xxx ºC (to be confirmed in KoM);

b) Depressurization of each gas lift riser within one hour and thirty minutes (it shall consider the proposed subsea arrangement issued by PETROBRAS). Contractor shall consider as maximum subsea riser volume xxx m³ and initial conditions xxx kPa(a) and xxx ºC (to be confirmed in KoM);

c) Depressurization of gas exportation riser with no time constraint. CONTRACTOR shall consider as maximum subsea riser volume XXX m³ and initial conditions XXX kPa(a) and XXX ºC (to be confirmed in KoM);

d) Control and monitoring the depressurization of production, gas lift, gas export and gas injection risers at a rate up to 6 bar/min, according to operational procedure to be defined by PETROBRAS.

NOTE 1: CONTRACTOR shall submit to PETROBRAS for comments simulation report of the subsea flowlines depressurization that shows that requirements (a) through (c) were fulfilled.

NOTE 2: The design may consider the depressurization through the pig receiver, where available.

NOTE 3: Export gas pipeline depressurization through flare shall be minimized.

2.6.19 Drainage shall be in accordance with the same philosophies of the process plant.

2.6.20 CONTRACTOR shall take care during the design and construction phase to avoid any pigging problems such as protruding welds inside piping or other arrangement that cause risk to the pigging operation. Barred tees shall be provided when the diameter of a branch is equal to or larger than half main piping diameter, as required by NBR 16381.

2.6.21 All wells (oil or gas production and injection) shall be controlled and monitored through the Central Control Room Workstations, as described in section 7.

2.6.22 FPSO shall have manifolds with well piping flexibility as per Figure 2.6.22 in order to ensure that all well positions and manifolds are fitted before FPSO sails away from shipyard (including hard piping, instrumentation, valves, etc.).

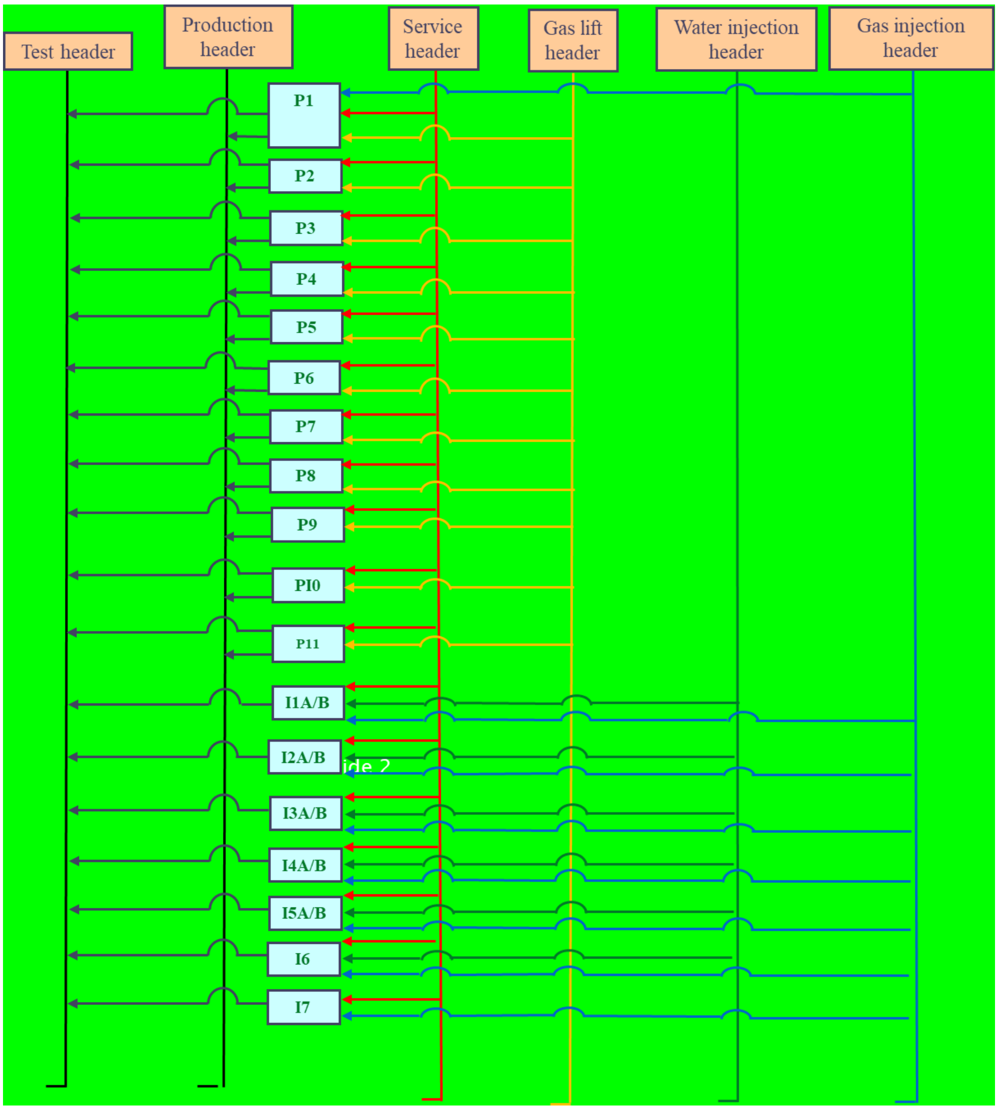


Figure 2.6.22 - Wells Piping Arrangement

NOTE 1: Positions I1 to I5 shall receive independent lines from Water injection header and Gas injection header for each injection slot (A and B).

NOTE 2: Positions I1 to I5 will be subsea interconnected pair of wells (slot A/B) and I6 and I7 will be injection satellite wells. Each slot may inject water or gas alternately and independently, except for I7 which will inject only gas.

2.6.23 A preliminary description of all intended procedures for Subsea operations can be found in OPERATION PHILOSOPHY (see item 1.2.1). Design and operational philosophy are CONTRACTOR's scope and shall be sent to PETROBRAS for comments. CONTRACTOR to guarantee that these operations are included in Risk Assessment Studies.

2.7 PROCESS FACILITIES

2.7.1 SEPARATION AND TREATMENT

2.7.1.1 The oil processing will be carried preferably through one production train. It shall be constituted of a first stage two-phase separator (HP Separator), a three-phase separator (Free Water KO Drum), pre-heaters of produced liquid (using the heat recovered from the processed oil), oil heater, degasser, electrostatic pre-treater, degasser for RVP/TVP specification, electrostatic treater, oil cooler as shown in Figure 2.7.1.22. A test separator for the wells production test shall also be installed.

2.7.1.2 The producing oil wells will flow to the test and production headers. From there oil is sent directly to a first stage two-phase separation, HP Separator, operating at 6,500 kPa(a). The gas stream shall be sent to the Dehydration Unit, while the liquid stream is to be sent to the Free Water KO Drum.

2.7.1.3 Free Water KO Drum is to operate at 2,000 kPa(a). Gas separated in the FWKO is to be sent to LP Gas Compressor.

2.7.1.4 Cyclone type or vane-type device shall be installed in the HP Separator, Free Water KO Drum and Test Separator for mist removal from the outlet gas.

2.7.1.5 Part of the water separated in the electrostatic pre-treater is pumped to upstream of the HP Separator and optionally to the Free Water KO Drum.

2.7.1.6 The temperature increases due to the return of this water to the free water separator results in advantages like increasing in gas/liquid and liquid/liquid separation efficiency and the elimination the oil/water pre-heater upstream FWKO. Then, the free water separator operating temperature is a function of the temperatures and the flow rates of the inlet crude streams and the temperature and flow rates of the discharged water in the next stages of separation.

2.7.1.7 If the BS&W is low, part of heated and treated oil shall be pumped to upstream of the HP Separator and/or Free Water KO Drum, in order to keep the HP Separator operating temperature minimum 20ºC (preferably around 40ºC) and FWKO operating temperature minimum 40°C.

2.7.1.8 This part of water or oil separated in the electrostatic pre-treater shall be pumped to upstream HP Separator in one point in the production header as close as possible to the choke valve. A tie-in point downstream each production choke valve shall be installed to connect this line in the future, if necessary. Oil or water flow rate for design purpose of each tie-in point is about 1,450 m³/d@90ºC. The maximum expected overall flowrate for these tie-in points is 3350 m^3/d.

2.7.1.9 The oil stream from the Free Water KO Drum is heated to reach the treatment temperature. CONTRACTOR shall consider carryover of 40% water from FWKO. Heat should be recovered from hot treated oil stream and complemented by the hot water system. The heating system shall be sized considering the flexibility of recirculating water, oil or no recirculation, even at lower arriving temperatures. CONTRACTOR shall consider oil recirculation to size LP Gas Compressor and Vapor Recovery Unit (VRU) flowrates. Dilution (deaerated fresh or deaerated desulphated) water injection shall be provided upstream oil/oil pre-heater to avoid salt precipitation in the heaters in case BS&W in the produced oil is low. Dilution (deaerated fresh or deaerated desulphated) water use may be requested by PETROBRAS during all lifetime of the Unit and shall be ready to use.

2.7.1.10 The heated oil at the treatment temperature, is sent to a flash vessel/electrostatic pre-treater, which has the function to specify the outlet oil phase for the final stage of treatment, constituted by an electrostatic treater, with addition of dilution deaerated fresh water obtained from a reverse osmosis unit. CONTRACTOR shall include of energy recovery device in the rejected water stream of reverse osmosis unit to reduce total electrical demand. CONTRACTOR shall foresee facilities to allow maintenance of dilution water mixing valve without loss of production.

2.7.1.11 The operational oil treatment temperature for design purpose shall be at least 90°C and CONTRACTOR may apply higher temperatures, if necessary, to meet GTD requirements. For oil treatment, the maximum heating medium temperature shall be at 120°C.

2.7.1.12 In the pre-treater outlet, the oil stream is sent to the electrostatic treater, where it shall be specified with the desired quality as per item 2.3.1. It is not expected the need of any additional crude processing to meet this H_2S specification. The design shall include ability to inject H_2S scavenger into the offloading pumps header or upstream offloading metering skid.

2.7.1.13 The produced water from the electrostatic pre-treater is pumped to mix with the oil stream upstream of the HP separator and optionally upstream of the free water separator, in order to heat the oil stream and to help emulsion breaking. The produced water from the electrostatic treater is to be directed to the Produced Water Treatment System.

2.7.1.14 Regarding the field instrumentation required for oil-water interface level measurement: Standpipes shall not be used for oil-water interface level measurement neither in Gravitational Separators nor in Oil Dehydrators. In such cases, the oil-water interface level measurement shall be performed in the interior of the vessels, directly immersed in process fluid, using one of the following technologies: energy absorption, nuclear or electric conductivity profiler. For nuclear profiler, CONTRACTOR shall comply with *“Resolução CNEN 215/17”* and *"Anexo D – SMS – Segurança, Meio Ambiente e Saúde Ocupacional"*.

2.7.1.15 The treated oil from the electrostatic treater is cooled in the oil/oil pre-heater and in the oil cooler. The stabilized oil will be metered and pumped to the cargo tanks of FPSO. If oil is not specified, it shall be aligned to an oil offspec tank. From this tank, oil shall be pumped to be reprocessed. The oil offspec tank shall have a minimum volume of 10.000 m^3. Alignments of offspec tanks to cargo tanks or directly to offloading shall be avoided. If strictly required, please refer to I-ET-XXXX.XX-1200-813-P4X-001 - FLOW METERING SYSTEM FOR LEASED UNITS, item 5.2.3.

2.7.1.16 Oil processing plant heat exchangers, heaters and coolers shall be designed to guarantee high availability in the oil treatment and shall be provided with by-pass lines. CONTRACTOR shall provide spare heat exchanger for oil/oil pre-heater, production heater and oil cooler. Spare exchangers shall be installed and ready to operate.

2.7.1.17 CONTRACTOR shall provide stand-by pumps for all process oil treatment system pumps. For test separator pumps configuration see item 2.2.3.6.

2.7.1.18 CONTRACTOR shall consider slug volume (Normal Liquid Level (NLL) to Level Alarm High (LAH) of the vessel) in the HP Separator and Test Separator design (20.0 m^3 for HP Separator and 10.0 m^3 for Test separator). The HP Separator, FWKO and Test Separator design shall consider wax crystals dispersed in oil phase.

2.7.1.19 Test Separator heat exchanger shall be shell and tube type.

2.7.1.20 PETROBRAS highlights that in scaling and salt precipitation, including CaCO3, BaSO4, SrSO4, or NaCl, will have varying potential as oil, water and gas production progresses, and can occur even at very low water cuts. Facilities to by-pass and to clean critical equipment and instrumentation on the oil processing plant shall be provided.

2.7.1.21 Optimizations on the Process described in items 2.7.1 and 2.7.3 or different solutions can be submitted to PETROBRAS approval. The same final specifications shall be met.

2.7.1.22 The Figure 2.7.1.22 present simplified proposed flow diagram of the Oil Processing scheme.

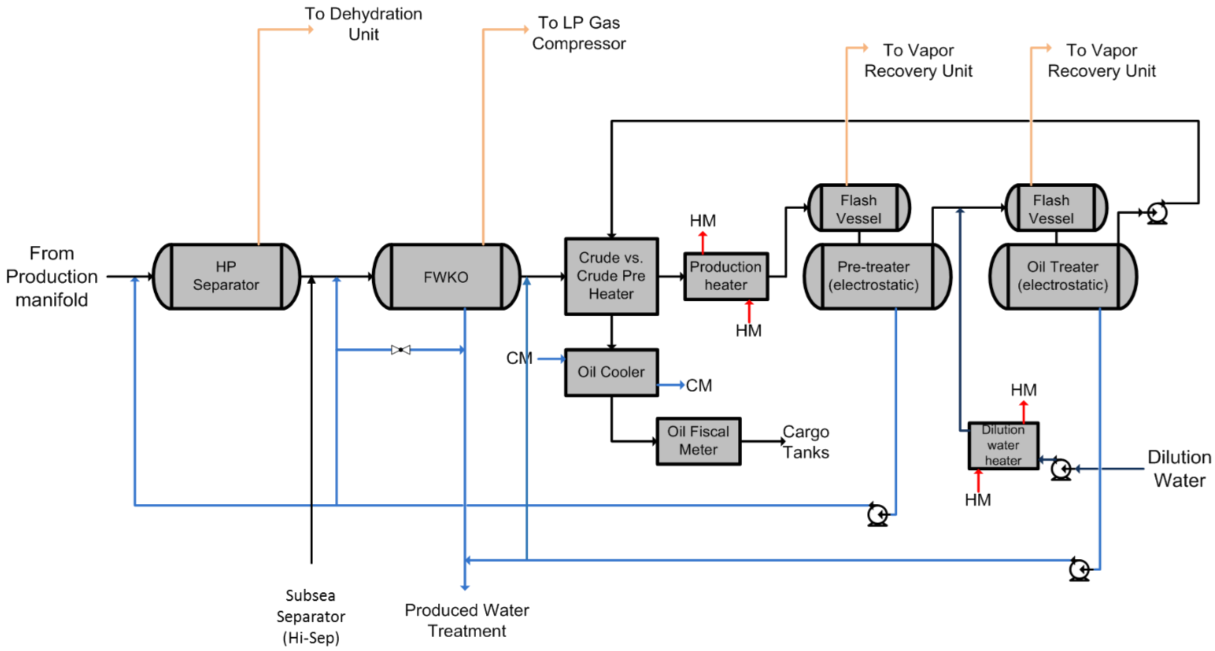


Figure 2.7.1.22 – Oil Processing Scheme

2.7.2 OIL TRANSFER SYSTEM

2.7.2.1 For Oil Transfer System, see item 16.3.

2.7.3 GAS PROCESS PLANT

2.7.3.1 OBJECTIVES

2.7.3.1.1 The gas shall be gathered, treated and compressed, to comply with main applications:

- reservoir injection;
- fuel gas;
- lift gas for the producing wells.

2.7.3.1.2 Additionally, the Unit may be required to transfer gas to another Unit, using gas injection facilities detailed in this document.

2.7.3.1.3 A CO_2 removal system using membranes, as well as adequate pretreatment, is required for treatment of the fuel gas to be consumed within the Unit. The rejected CO_2 stream (separated from produced gas) shall be compressed in a dedicated compressor to be directed to the gas injection.

2.7.3.1.4 The gas injection wells will also be submitted to water injection, according to WAG planning, to enhance oil recovery. The gas and the water will be injected through separate lines and the unit shall comply with WAG operating procedure.

2.7.3.1.5 CONTRACTOR shall install online Chromatographic Analysis for hydrocarbon (up to C6+), CO_2 and N_2 to the following streams, as a minimum:

- Upstream Dehydration Unit (in addition, H_2S content shall be measured) ;
- Inlet Main/Injection compressor;
- Gas to HP and LP flare tips;
- CO_2 Removal Unit inlet;
- Import/Export;
- Inlet CO_2 Compressor;
- Inlet Vapor Recovery Unit Compressor;
- Fuel Gas.

2.7.3.2 DESIGN CASES

2.7.3.2.1 See item 2.2.2.

2.7.3.3 PROCESS CONFIGURATION – BASE CASE

2.7.3.3.1 The gas treatment plant shall consist of different units, in order to attain the contaminants removal, according to Figure 2.7.3.3.1.

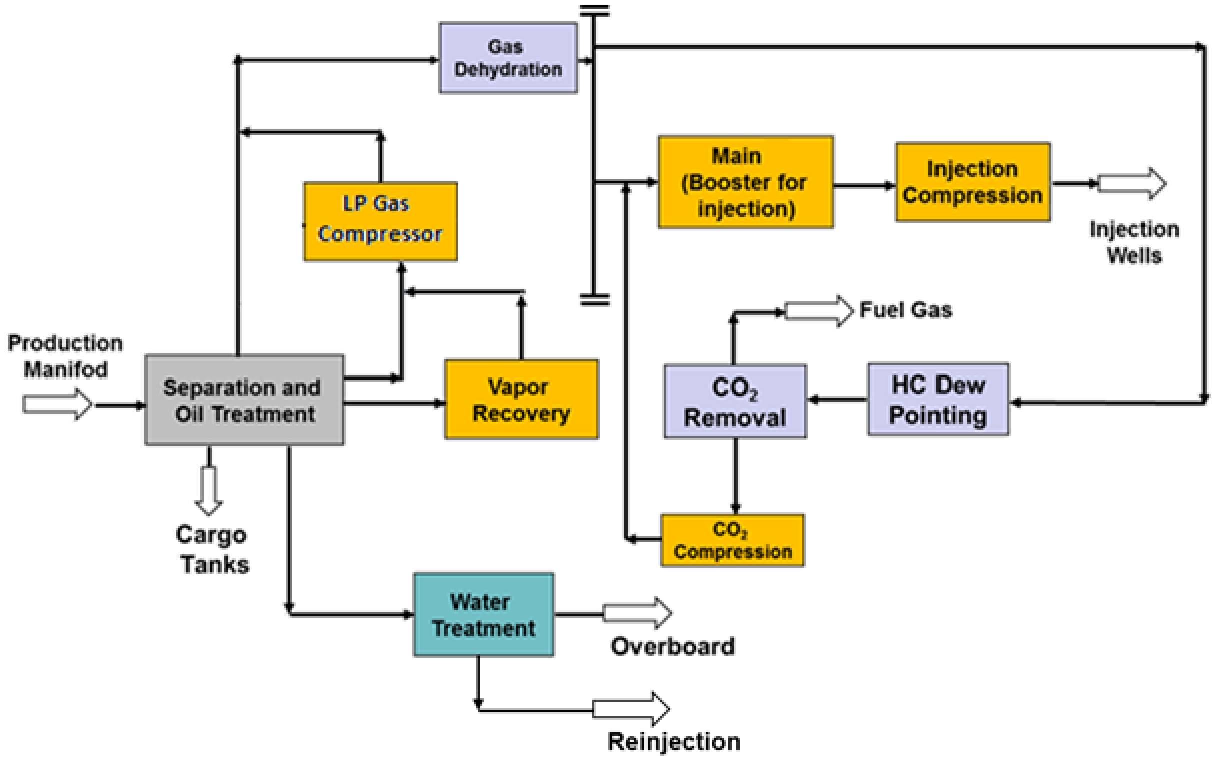


Figure 2.7.3.3.1 – Gas Treatment Plant

2.7.3.4 DEHYDRATION UNIT

2.7.3.4.1 The Gas Dehydration Unit shall be designed as following:

- Inlet gas specification = 2400 ppmv H2O;
- Inlet gas H2S content = 60 ppmv;
- Inlet pressure = direct from HP Separator (HP Separator operating pressure minus head loss);
- Outlet gas specification = 2 lb/MMscf/ 42 ppmv H2O.

2.7.3.4.2 Two technology options are acceptable for the Dehydration Unit, according to the following:

2.7.3.4.2.1 MOLECULAR SIEVES UNIT

2.7.3.4.2.1.1 A standby vessel is required allowing bed replacement during normal operation.

2.7.3.4.2.1.2 The Molecular Sieve shall not adsorb H2S. The Molecular Sieve shall be resistant to the expected CO2 concentrations.

2.7.3.4.2.1.3 All molecular sieves manufacturer recommendations shall be followed, including design parameters, monitoring instruments, subsystems and facilities for bed discharge and replacement. For Molecular Sieve design and specification purposes, maximum H2S content shall be considered and heat and mass balance for the unit shall include the maximum concentration on regeneration gas and recirculating H2S destiny after regeneration cycle.

2.7.3.4.2.1.4 A scrubber (1x100%) and a coalescer filter (2x100%) upstream the Molecular Sieve Unit shall be installed to avoid liquid carry over. A combined scrubber/filter configuration is acceptable. In this case a stand-by set (scrubber/filter) shall be considered (2x100%). The coalescer filter shall comply with the minimum following performance:

- Removal of 99% of solids with particle size higher than 1µm;
- Removal of 99% of liquid droplets with diameter higher than 0.3 µm;
- The liquid allowed in the outlet gas shall be maximum of 5 ppm weight;
- The maximum ΔP allowed shall be 0.1 bar (clean) and 0.5 bar (dirty).

2.7.3.4.2.1.5 Layout and piping arrangement of the unit shall minimize risk of liquid condensation downstream coalescer filter, by avoiding liquid pocket points, using thermal insulation, minimizing piping length and height difference. A heater shall be installed upstream the molecular sieve unit, in order to guarantee superheating of at least 5ºC and avoid condensation in the molecular sieve bed. The heater shall be downstream the coalescer filter. Inlet piping upstream the adsorbent beds, that have no flow during regeneration cycle, shall have electric tracer to avoid liquid condensation due to heat exchange with the external environment.

2.7.3.4.2.1.6 The scrubber design shall take in consideration:

- Three individual separation stages to ensure the required gas-liquid separation:
  - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
  - Mesh or Vane device to separate large liquid droplets and drain them without re-entrainment;
  - Demisting cyclones to ensure high efficiency of droplet removal;
- The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow.

2.7.3.4.2.1.7 The molecular sieves regeneration gas shall be indirectly heated (electrical or hot water). Thermal oil fluid and directly heating by turbine exhaust gases will not be allowed. A stand-by heater shall be provided ready to operate.

2.7.3.4.2.1.8 For electrical requirements for heating systems, see item 2.7.3.4.3. Additionally, for electrical heating systems applied to Molecular Sieves Unit, the following requirements shall be complied with:

- Electrical heater bundle (resistance) shall be fully redundant and arranged in independent and separated gas heater vessels in order to allow maintenance and replacement of bundles in a way not to impact heating system availability. Disconnecting switch or circuit breakers shall be provided for quick change over of bundles.

- The method for sheath element to tubesheet joint of electrical heater bundle, shall be by means of a strength weld. Sheath´s elements shall be directly connected to the tubesheet and to the power terminal box. The use of offset sleeves or standpipe is not acceptable. Sheath element shall be supplied in seamless incoloy 800H or inconel 625 grade 2.

2.7.3.4.2.1.9 A proper outlet gas filter (2x100%) shall be provided in the Molecular Sieves Unit to avoid fine particles carry-over to downstream units and to the regeneration gas system. CONTRACTOR to evaluate potential of hydrate formation on condensate/liquid return lines of the scrubber and coalescer filter and forecast a mitigation solution, such as a condensate heater, if required.

2.7.3.4.2.1.10 For the regeneration gas recycle, a specific blower may be used (2x100%). In this case, blowers shall comply with API Std 617 and API 692. If CONTRACTOR decides to send regeneration gas back to LP Gas Compressor, this machine capacity shall be increased to accommodate this additional flow.

2.7.3.4.2.1.11 CONTRACTOR shall provide means of isolating and depressurizing each vessel, so that they can be operated separately, enabling bed exchange operation, without stopping the system. Bed pressurization and programmed shutdown depressurization rates shall be limited to a maximum of 3 bar/min or supplier requirement rate, whichever is lower. Vessels Emergency depressurization shall be downward flow.

2.7.3.4.2.1.12 CONTRACTOR shall install equalization valve to allow pressurization of each bed at the recommended rate, as well as individual pressure gauge, with reading in the supervisory, to monitor the pressurization and depressurization rates of each bed.

2.7.3.4.2.1.13 CONTRACTOR shall design unit considering procedure for change out of molecular sieve bed, including support structure for the new and spent molecular sieves, facilities to remove solids from the vessel, required purge gas (N2), among others. A material handling plan shall be provided evidencing that the arrangement of the process plant equipment complies with the requirements above. CONTRACTOR shall, during project execution phase, detail the procedure for solids bed replacement. A dump to flare valve shall be provided downstream the unit.

2.7.3.4.2.1.14 CONTRACTOR shall consider the following requirements regarding each molecular sieve vessel bed support, as minimum:

- Ceramic spheres to support molecular sieve bed;
- Mesh screen above the ceramic spheres.

NOTE 1: CONTRACTOR shall design the vessels with insulation.

NOTE 2: CONTRACTOR shall consider that all gaskets materials be suitable for high temperature.

NOTE 3: Any different solution shall be presented to PETROBRAS during project execution phase.

2.7.3.4.2.1.15 CONTRACTOR shall install proper online instrumentation and analysis devices to determine H2O content in the outlet gas stream downstream of the gas outlet filter.

2.7.3.4.2.1.16 The analyzer shall be adjusted to execute gas water content validation by internal permeation tube (at least weekly checked) without the need of manual water make up in the tube.

2.7.3.4.2.1.17 CONTRACTOR to provide calibration of gas water content analyzer according to supplier recommendation or when it occurs some divergence during periodical check.

2.7.3.4.2.1.18 For acceptable vendor list for Moister Analyzer, see item 19.1.1.3.

2.7.3.4.2.1.19 For Acceptable vendor list for Molecular Sieve Solid Bed (Zeolite), see item 19.1.1.2.

2.7.3.4.2.2 TRIETHYLENE GLYCOL (TEG) UNIT

2.7.3.4.2.2.1 The gas dehydration unit by TEG absorption shall be designed to a maximum inlet gas operational temperature of 40ºC. CONTRACTOR shall ensure this temperature as the maximum one and may consider design alternatives to achieve lower inlet gas temperatures. Only shell and tube heat exchangers are acceptable for TEG Unit inlet gas.

2.7.3.4.2.2.2 A scrubber (1 x 100%) and a coalescer filter (2 x 100%) upstream the TEG Unit shall be installed to avoid liquid carry over. A combined scrubber/filter configuration is acceptable. In this case a stand-by set (scrubber/filter) shall be considered (2 x 100%). The coalescer filter shall comply with the minimum following performance:

- Removal of 99% of solids with particle size higher than 1µm;
- Removal of 99% of liquid droplets with diameter higher than 0.3 µm;
- The liquid allowed in the outlet gas shall be maximum of 5 ppm weight;
- The maximum ΔP allowed shall be 0.1 bar (clean) and 0.5 bar (dirty).

2.7.3.4.2.2.3 Layout and piping arrangement of the unit shall minimize risk of liquid condensation downstream coalescer filter, by avoiding liquid pocket points, using thermal insulation, minimizing piping length and height difference. CONTRACTOR shall provide an additional gas-liquid separation step, built into the bottom of the TEG absorber column. This does not exclude the external scrubber + coalescer filters upstream TEG Absorber.

2.7.3.4.2.2.4 The scrubber design shall consider:

- Minimum three different gas-liquid separation zones/devices:
  - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;
  - Mesh or Vane device to separate large liquid droplets and drain them without re-entrainment;
  - Demisting cyclones to ensure high efficiency of droplet removal.
- Range of operational flowrate shall be from 15% to 100% of nominal design gas flow;
- The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow;
- Minimum removal of 99.5% of liquid droplets with diameter higher than 10 µm.

2.7.3.4.2.2.5 CONTRACTOR shall provide two level meters for the scrubber and two for each section of the coalescer filter. In each vessel, CONTRACTOR shall adopt two different technologies for the level meters and one of them will be used for controlling purpose. The measurements shall be displayed on the supervisory system of the Unit. In addition, a field level gauge shall be provided for each vessel.

2.7.3.4.2.2.6 CONTRACTOR to evaluate potential of hydrate formation on condensate/liquid return lines of the scrubber and coalescer filter and forecast a mitigation solution, if required.

2.7.3.4.2.2.7 TEG Unit shall meet the following specification:

- TEG Unit range of operational flowrate: from 15% to 100% of nominal design gas flow;
- Lean TEG specification: minimum 99.95% (mass %);
- Rich TEG specification: minimum 95% (mass %).

2.7.3.4.2.2.8 TEG absorber column shall be fitted with proper packing and liquid distributor in order to achieve a high efficiency. Means for minimizing TEG carry over shall also be provided in the form of column internals or a separate K.O. drum. Pressure Differential Transmitters shall be provided to monitor differential pressure across the packing.

2.7.3.4.2.2.9 Temperature of lean TEG entering the top of the absorber shall be controlled at 5ºC higher than inlet gas temperature.

2.7.3.4.2.2.10 A by-pass around the absorber column shall be provided for lean TEG as to allow startup of the unit.

2.7.3.4.2.2.11 It shall consider 10ºC of approach between the desired water dewpoint and equilibrium theoretical water dewpoint to design the number of equilibrium stages of absorber tower.

2.7.3.4.2.2.12 TEG Flash drum shall be designed considering 20 minutes of residence time for Rich TEG.

2.7.3.4.2.2.13 2x100% cartridge filters shall be provided for 100% of rich TEG flow. Activated carbon filter and a secondary cartridge filter, with a by-pass, shall be provided for 20% of rich TEG flow.

2.7.3.4.2.2.14 A flow meter shall be provided to deviated rich TEG flow.

2.7.3.4.2.2.15 TEG circulation pump shall meet the following specifications:

- Configuration: N+1 (one stand-by);
- Reciprocating pump diaphragm type;
- Pumps shall be designed according to API 674 or 675;
- PSV shall return to surge vessel;
- Pulsation damper in discharge pump is required;
- Flow control with Variable Speed Driver (VSD);
- Glycol flow rate: minimum $1m^3/h/m^2$ of dehydration column area section to ensure sufficient wetting of the structure packing.

2.7.3.4.2.2.16 A Coriolis flow meter shall be provided to measure the lean TEG flow. This equipment shall be installed as close as possible the absorber, downstream of any by-pass line to measure the TEG flow through the absorber.

2.7.3.4.2.2.17 The Reboiler shall operate as close as possible to atmospheric pressure. The backpressure shall not exceed 0.2 barg.

2.7.3.4.2.2.18 Flash vapor from Flash drum and Exhaust gas from still column shall be sent to VRU, using a boosting device if necessary. In case the streams are routed directly to Flare Gas Recovery System, the flowrate shall be added to flowrate defined on Item 2.7.5.9.5.

2.7.3.4.2.2.19 For TEG design and material specification purposes, maximum H2S content shall be considered and heat and mass balance for the unit shall include concentration on regeneration gas and recirculating H2S destiny.

2.7.3.4.2.2.20 Chemical injection skid(s) for pH control and antifoaming shall be provided.

2.7.3.4.2.2.21 For electrical requirements for heating systems, see item 2.7.3.4.3. Additionally, for electrical heating systems applied to TEG Unit, the following requirements shall be complied with:

- Electrical heater shall be fully redundant (N+1, with one standby unit) to allow maintenance and replacement of heater in a way to not impact heating system availability and to not lead to any production loss. Disconnecting switch or circuit breakers shall be provided for quick change over of bundles.

- The maximum heat flux to be considered for electrical heating design shall be 1.25 W/cm² and the maximum skin temperature shall not exceed 230°C.
- The Reboiler shall control the glycol temperature in 204ºC.

2.7.3.4.2.2.22 CONTRACTOR shall provide a secondary stripping gas distribution system in the bottom of the reboiler. Automated gas stripping flow control shall be provided using an exclusive Cone flowmeter for this system.

2.7.3.4.2.2.23 CONTRACTOR shall provide Stahl Column with a main stripping gas injection, containing a minimum of 3 equilibrium stages, at a lower level than the reboiler. Automated gas stripping flow control shall be provided using an exclusive Cone flowmeter for this system.

2.7.3.4.2.2.24 Surge Vessel shall be designed to store the entire TEG inventory during maintenance shutdowns.

2.7.3.4.2.2.25 Sampling points shall be provided in accordance with item 2.9.

2.7.3.4.2.2.26 CONTRACTOR shall install proper online instrumentation and analysis devices to determine H2O content in the gas dehydration outlet stream. Analyzer shall be installed downstream of absorber, upstream CO2 membrane pre-treatment.

2.7.3.4.2.2.27 The analyzer shall be adjusted to execute gas water content validation by internal permeation tube (at least weekly checked) without the need of manual water make up in the tube.

2.7.3.4.2.2.28 CONTRACTOR to provide calibration of gas water content analyzer according to supplier recommendation or when it occurs some divergence during periodical check.

2.7.3.4.2.2.29 At any time, analyzer measurement will be compared to most recent version of GPSA Equilibrium Chart “Equilibrium H2O Dew point vs. Temperature at Various TEG Concentrations”. These results will be used to mediate divergences about measured values. CONTRACTOR shall consider McKetta Method (GPSA chart: “Water Content of Hydrocarbon Gas”) to convert equilibrium dew point to lb/MMscf.

2.7.3.4.2.2.30 At any time, PETROBRAS can ask gas water content analyses by manual chilled mirror according to ASTM D-1142 to mediate divergences about measured values. CONTRACTOR shall consider “GPSA + Wichert (acid gases correction)” to convert equilibrium dew point to lb/MMscf.

2.7.3.4.2.2.31 The off-spec treated gas shall be deviated to flare, through a pressure control valve, installed downstream TEG Contactor.

2.7.3.4.2.2.32 For acceptable vendor list for Moister Analyzer, see item 19.1.1.3.

2.7.3.4.2.2.33 Minimum Requirements for TEG Units Suppliers:

- Proven experience on offshore TEG units design with 6 MM Sm³/d gas capacity;
- Proven experience on onshore or offshore TEG units design to dehydrate the gas with minimum 30% mol CO2 content. These units shall be in operation.

2.7.3.4.3 ELECTRICAL REQUIREMENTS FOR HEATING SYSTEMS:

2.7.3.4.3.1 If electrical heating is used, the electrical heater panel shall be powered by 2x100% transformers from different panels to assure high reliability:

- Redundant feeding transformers, each one capable of supplying 100% load.
- Transformers shall be suitable for low power factor and high harmonic content.

2.7.3.4.3.2 Silicon Controlled Rectifiers (SCRs) shall have (n+1) configuration, with one standby unit.

2.7.3.4.3.3 At least one spare resistance bundle shall be available for prompt replacement of faulty resistance bundle. In warehouse where stored, the resistive bundle set will have low insulation if not well preserved. It shall be kept heated and housed in moisture-free environments.

2.7.3.4.3.4 It shall be considered a 10% additional margin in the maximum estimated heating demand;

2.7.3.4.3.5 All resistance systems shall be of encapsulated type to assure better isolation from environmental moisture and longer life expectancy.

2.7.3.4.3.6 For electrical heating panels, the following requirements apply:

2.7.3.4.3.6.1 The Power Panel shall contain thyristors suitable for the requested power, the thyristors control system and all necessary components for the temperature control.

2.7.3.4.3.6.2 In order to modulate the semiconductors conduction time, Thyristors control system shall receive an external set point signal.

2.7.3.4.3.6.3 The Thyristors triggering shall be controlled in such way to synchronize this triggering to the instant the sine wave has a zero value, avoiding undesirable transients in the electrical system.

2.7.3.4.3.6.4 Harmonic content shall be kept within IEEE Std. 519 and on IEC 61892-1 limits. For Power Panel, the control system shall automatically bypass/skip and do the compensation for an out of service stage.

2.7.3.4.3.6.5 In order to make easy the installation and maintenance, the control system shall be constructed in a modular way.

2.7.3.4.3.6.6 A prompt replacement of the damaged module shall assure the non-interruption of the equipment operation.

2.7.3.4.3.6.7 Power Panel shall be fitted with a double cooling system with automatic changeover and alarm, so that in case of failure of a set, the remaining units shall be enough to permit the panel operation without restrictions.

2.7.3.4.3.6.8 All external control (ON/OFF) and set point signals (that may be 4~20 mA) shall be received from Control Panel, besides any other interface defined by Packager and from Automation and Control (A&C), according to interface requirements.

2.7.3.4.3.6.9 The Power Panel shall be controlled by its respective control package unit.

2.7.3.4.3.6.10 Communication shall be according to unit Packager Standard.

2.7.3.4.3.6.11 The Power Panel shall have local visual alarms for internal malfunction and shutdown. Resume alarm signals shall be sent to Control Panel according to Packager standard. All signals from the Package to A&C shall be sent by Control Panel.

2.7.3.4.3.6.12 The communication standard (network or hardwired) between Power Panel and Control Panel shall be defined by Packager.

2.7.3.4.3.6.13 Emergency shutdown signals from A&C shall be sent to Control Panel that shall be responsible to turn off the Power Panel.

2.7.3.4.3.6.14 For each Regeneration gas heater shall be provided a self-standing Heater control panel. The location of these panels shall be in the electrical room in safe area. These panels shall be responsible for control and safeguarding of the heaters.

2.7.3.4.3.6.15 In order to control the temperature of the heater the control panels will receive a 0-100% reference signal from the unit control panel. The safeguarding system of the Heater control panel will protect the heater from overheating and secures the vessel temperature in order to comply with the temperature class.

2.7.3.4.3.6.16 The power terminal boxes shall be fitted with sunshades, with anti-condensation heaters (fed from external 220Vac 2phases ungrounded) controlled by thermostats and with thermal cutouts to guarantee that the limit of the temperature class T3 will not be exceeded. The construction of power terminal box shall comply with IEC 60079. The power terminal box shall have type protection Ex e in accordance with IEC 60079-7.

2.7.3.4.3.6.17 The power terminal boxes shall be fitted with gas detection system.

2.7.3.5 CO2 MEMBRANE PRE-TREATMENT (HYDROCARBON DEW POINT CONTROL UNIT)

2.7.3.5.1 The required outlet gas hydrocarbon dew point is 10°C @ 5,300 kPa(a) (to be confirmed). This specification complies with the following purposes:

- Minimum capacity to be determined by turndown case as per item 2.2.2;
- To control membrane unit feed gas C6+ content, to avoid poisoning by aromatics and heavy hydrocarbons. This requirement shall be confirmed by membrane supplier.

2.7.3.5.2 The process shall be based on a Joule-Thomson expansion process and/or refrigeration with R-134a and/or turboexpander. Stand-by compressors are required for Refrigeration Units. For turboexpander, 2x100% configuration is required.

2.7.3.5.3 The inlet gas is pre-cooled by the cold separator outlet streams. The gas separator outlet stream shall be used for at least one out of the two following options: (1) pre-cooling of the inlet gas stream of the dehydration unit; (2) for pre-cooling of the inlet gas of Hydrocarbon Dew Point Control Unit. CONTRACTOR to evaluate potential of hydrate formation on condensate/liquid return lines and forecast a mitigation solution, if required.

2.7.3.5.4 For startup purposes, part of the gas from Cold Separator can be expanded and blended with the expanded liquid stream, in order to help achieving the required inlet temperature in the Liquid/Gas exchanger.

2.7.3.5.5 Pre-treatment shall be specified according to membrane supplier requirements, taking into account the dehydration technology selection:

- MOLECULAR SIEVES UNIT
  - In case Molecular Sieve technology is the chosen alternative, a minimum arrangement including a coalescer filter shall be provided downstream Hydrocarbon Dew Point Control Unit as pre-treatment for the CO2 Separation Membrane Unit.
- TEG UNIT
  - In case TEG absorption technology is the chosen alternative, a minimum arrangement including a coalescer filter, a guard bed and a cartridge filter shall be provided downstream Hydrocarbon Dew Point Control Unit as pre-treatment for the CO2 Separation Membrane Unit.

2.7.3.5.6 The liquid outlet from the vessels of the CO2 membrane pre-treatment shall be routed to an oil plant stage, CO2 compression or another point of the plant, according to operating conditions, analyzing the reduction in electrical demand, start/stop procedures and flaring/vent minimization.

2.7.3.6 CO2 SEPARATION – MEMBRANE UNIT

2.7.3.6.1 The Membrane Unit shall be designed according to the design cases previously presented and the following:

- Inlet pressure = 4,800 kPa(a) (estimated, to be confirmed);

- Minimum capacity to be defined by CONTRACTOR according to Process Simulation;
- Maximum outlet gas CO2 content = 3% mol for all well A and well C cases, no more than 20% mol for well B cases;

  NOTE: For CO2 inlet content from Well A up to Well B - CO2 separation system shall run with full capacity (no deviation or flow restriction). If necessary, for CO2 inlet content from Well A up to Well B, CONTRACTOR may consider isolation/blanking of membranes/trains as long as CO2 compressor is operating at full design capacity.
- Outlet gas H2S content = according to membrane performance;
- Permeate CO2 stream H2S content = according to membrane performance;
- Permeate stream = 400 kPa(a) to 800 kPa(a).

2.7.3.6.2 For acceptable vendor list for Membranes for CO_2 Removal Unit, see item 19.1.1.4.

2.7.3.6.3 All recommendations from the membrane manufacturer shall be followed, including design parameters, inlet gas pre-heating, monitoring instruments, subsystems and facilities for elements replacement.

2.7.3.6.4 CONTRACTOR shall install proper online real time analysis devices to determine CO2 and H2S content in the treated gas stream, to deviate the non-specified gas, in the following streams:

- Inlet membrane system;
- Treated gas outlet;
- Permeate gas outlet; Reject.

2.7.3.6.5 Fuel gas consumers (including Hull consumers) shall be able to receive fuel gas as per expected produced gas and membrane performance data, considering CO2 and H2S. Whenever possible, CONTRACTOR shall guarantee use of fuel gas by consumers when the CO2 removal unit is not operational. For this purpose, a full and partial by-pass of the membrane unit shall be provided and its use during operation shall be approved by PETROBRAS. In any case, the fuel gas shall meet the equipment manufacturers requirements.

2.7.3.6.6 CONTRACTOR shall provide facilities to avoid /minimize flaring during starts and restarts.

2.7.3.7 VAPOR RECOVERY UNIT (VRU)

2.7.3.7.1 The Vapor Recovery Units (VRU) shall be dry screw compressor type according to API 619.

2.7.3.7.2 Vapor Recovery Unit shall be supplied as complete package by the compressor Original Equipment Manufacturer (OEM). Package means main equipment train (dry screw(s) compressor(s) Gear Unit Variable Speed Drive (HVSD or VSD) and driver) and all auxiliaries equipment and components required for proper functioning of the gas compression service (accessories, control panels, machinery protection system, oil system, sealing system as minimum).

2.7.3.7.3 The shaft seals shall be of self-acting tandem dry gas seals (DGS) type with intermediate seal gas labyrinth as per API 692. For the VRUs the primary seal gas shall be fuel gas, or nitrogen in case of plant start up or commissioning.

2.7.3.7.4 The primary seal gas shall be sufficiently clean to avoid particulate and its temperature far from the dew point to avoid liquid condensation. Each compressor package shall include a seal gas treatment system for each compressor casing consisting, as a minimum, of a booster compressor to provide the required positive feed pressure to the seals on any operating/stop condition, one dedicated scrubber (upstream to the duplex coalescent filters), one separator/coalescer duplex filter and either one electric heater with spare heater element installed or, alternatively, a duplex electric heater. Seal gas system shall be supplied by the DGS manufacturer. The requirement for a seal gas booster can be disregarded for the VRU compressor package if an alternate seal gas supply is provided in accordance with the following.

2.7.3.7.4.1 Alternate seal gas supply shall be immediately available and used as a backup in standby mode whenever main seal gas source is not available. CONTRACTOR may also submit an alternative primary gas supply for fuel gas during normal operation, when necessary, taken from downstream of dehydration unit.

2.7.3.7.4.2 The nitrogen supply capacity shall be defined for VRU seal system considering all compressor cases including commissioning, startups, normal stops, emergency shutdowns and lube oil running conditions, if any, CONTRACTOR is required to demonstrate.

2.7.3.7.4.3 Alternate seal gas supply shall be also conditioned by seal gas treatment system.

2.7.3.7.4.4 Undersized Seal Treatment Gas system, including DGS, or unproven designs or prototypes (including parts) with no previous service on offshore installations are not acceptable: A minimum of 25.000 hours continuous operation under similar operating conditions shall be demonstrated for, at least, 4 machines of the same model and same size to meet data sheet operating conditions required.

2.7.3.7.4.5 Alternate seal gas supply shall maintain the minimum sealing gas conditions required by DGS Manufacturer and API Std. 692, 20ºC higher than the dew point line (see Figure B.1 – Annex B), during all normal and alternate operating conditions, including compressor and/or process plant commissioning, startups, normal stops, emergency shutdowns and other transient conditions (CONTRACTOR is required to demonstrate).

2.7.3.7.4.6 Main/alternate seal gas systems changeover shall be automatic, performed or commanded by compressor PLC. Actual running system status signals shall be sent from compressor PLC to plant control system.

2.7.3.7.5 O-rings and any other polymer-based sealing element in contact with process gas shall be strongly resistant to explosive decompression taking into account a large number of compressor starts/stops.

2.7.3.7.6 Nitrogen as the secondary seal gas shall be injected in the intermediate labyrinth seal. The separation seal gas shall be also nitrogen.

2.7.3.7.7 A stand-by unit installed is required (2x100%). CONTRACTOR shall consider “unit” as compressor machine, scrubber, coolers, etc.

2.7.3.7.8 VRU capacity shall be defined by CONTRACTOR, in accordance with all design cases simulations and it shall consider all recycles.

2.7.3.7.9 Capacity of VRU 1st and 2nd Stages shall be defined based on process simulation output plus a design margin of 20%. Nevertheless, the capacity of the 1st Stage shall not be lower than XXXXX Sm^3/d and the capacity of the 2nd stage shall not be lower than XXXXX Sm^3/d.

2.7.3.7.10 The compressor shall be designed for continuous operation at any flow rate between zero and 100% of the design capacity.

2.7.3.7.11 The driver shall be electric motor. The capacity control may be performed by recycling and/or HVSD (Hydraulic Variable Speed Drive) or VSD (Variable Frequency Drivers).

2.7.3.7.12 For acceptable vendor list for Rotary Compressor for Vapor Recovery Unit API 619, see item 19.1.1.5.

2.7.3.8 CENTRIFUGAL GAS COMPRESSORS

2.7.3.8.1 All centrifugal gas compressors shall be designed according to API 617.

2.7.3.8.2 Centrifugal Gas Compressor shall be supplied as complete package by the compressor OEM. Package means main equipment train (centrifugal(s) compressor(s) Gear Unit/Variable Speed Driver (HVSD or VSD) and driver) and all auxiliaries equipment and components required for proper functioning of the gas compression service (accessories, anti-surge valve, control panels, machinery protection system, oil system, seal system as minimum).

2.7.3.8.3 The shaft seals shall be of self-acting tandem dry gas seals (DGS) type with intermediate seal gas labyrinth as per API 692.

2.7.3.8.4 For the Centrifugal Gas compressors, the primary seal gas shall be treated and conditioned from compressor discharge process gas or fuel gas.

2.7.3.8.5 The primary seal gas shall be sufficiently clean to avoid particulate and its temperature far from the dew point to avoid liquid condensation. Each compressor package shall include a seal gas treatment system for each compressor barrel consisting, as a minimum, of a booster compressor to provide the required positive feed pressure to the seals on any operating/stop condition, one separator/coalescer duplex filter and either one electric heater with spare heater element installed or, alternatively, a duplex electric heater. For LP Gas Compressors, one dedicated scrubber shall also be included in the seal gas treatment system, upstream to the duplex coalescent filters. Seal gas system shall be supplied by the DGS manufacturer and according to API 692.

2.7.3.8.6 O-rings and any other polymer-based sealing element in contact with process gas shall be strongly resistant to explosive decompression taking into account a large number of compressor starts/stops.

2.7.3.8.7 Nitrogen as the secondary seal gas shall be injected in the intermediate labyrinth seal. The separation seal gas shall be also nitrogen.

2.7.3.8.8 The condensate from inlet, inter-stage and final compressor stage collected on the scrubber vessels shall be routed to the oil plant or to upstream gas scrubbers. They shall not be sent to slop or drain system.

2.7.3.8.9 The compressors shall be designed for continuous operation from full recycle to full capacity (0 to 100%), considering all the design cases.

2.7.3.8.10 Recycle system for anti-surge control shall be “hot recycle”, meaning that there is no cooler or scrubber vessel installed in between the compressor discharge and the related recycle valve. CONTRACTOR shall consider one antisurge recycle line for each stage. Overall recycle line shall not be accepted. Additionally, CONTRACTOR should also provide cooled recycle, nevertheless a hot recycle in a secondary recycle line shall be provided.

2.7.3.8.11 An electronic decoupling algorithm (decoupling control) shall be used to avoid interaction between anti surge control and performance/load sharing control for each compressor package service. A similar control strategy shall be designed in order to avoid trip from different service compressor.

2.7.3.8.12 The compressor packages shall have their own Control and Automation System. All data shall be available to PETROBRAS (read access). All safety functions shall be implemented on dedicated and autonomous hardware units, separated from all other control systems, eliminating common-cause failure modes and protecting the machine in the event of failure of its associated machinery control system. The Capacity Controls, Load Sharing and Anti-surge of the compressors shall be segregated from Sequencing and Process Control PLC and from the Safety PLC of the compressor package.

2.7.3.8.13 Each compressor package shall include a dedicated lube oil system (in accordance with the applicable requirements of API 614 for special purpose applications).

2.7.3.8.14 Each compressor package shall include a dedicated and control process panel (in accordance with the applicable requirements of API 670). Machinery Protection System (MPS) shall be also in accordance with API 670.

2.7.3.8.15 Extraction/injection gas stream from/into a compressor casing (except for sealing or balance line) or between two compressor casings of one train are not acceptable.

2.7.3.8.16 CONTRACTOR shall design the compressor package considering pressurized shutdowns. The design of all equipment in the compressor service, including the auxiliaries (e.g. seal gas system) and static equipment (e.g. vessels), shall be suitable to compressor Settle Out Pressure (SOP).

2.7.3.8.17 CONTRACTOR shall consider the molecular weight range corresponding to all design cases.

2.7.3.8.18 CONTRACTOR shall perform a stability test at compressor manufacturer shop for any compressor which fails to meet the minimum log decrement of 0.2 during the analysis. These tests shall be witnessed by PETROBRAS. During these tests, shop driver may be used.

2.7.3.8.19 Each compression stage shall have a compressor suction scrubber. The suction scrubber of the 1st compression stage shall be different from the Safety K.O. Drum (described in item 2.7.3.8.20.2).

2.7.3.8.20 LOW PRESSURE GAS COMPRESSOR

2.7.3.8.20.1 The first step compressors shall be designed according to the following:

- inlet pressure = XXXX kPa(a) (estimated, depends on previous pressure drop);
- discharge pressure range = XXXX kPa(a) (estimated, determined by dehydration unit operating pressure), shall consider the molecular weight range corresponding to all design cases;
- A stand-by unit is required as follows: 2x100% or 3x50% or 4x33%.

2.7.3.8.20.2 A Safety K.O. drum shall be installed upstream Low Pressure Gas Compressor, in order to separate the condensate formed due to inlet gas cooling, as well as to avoid any liquid carried-over. This condensate shall be routed back to oil plant. Under no circumstances it shall be sent to the slop or drain system.

2.7.3.8.20.3 The Safety K.O. drum design shall take in consideration:

- Minimum three different gas-liquid separation zones/devices:
  - Inlet device to receive the incoming process stream and evenly distribute the flow to improve gravitational liquid separation in the vessel inlet zone;

  - Mesh or Vane device to separate large liquid droplets and drain them the liquid without re-entrainment;
  - Demisting cyclones to ensure high efficiency of droplet removal.
- The maximum condensate liquid simulated increased by the condensate volume that corresponds to 5% of gas mass flow.

2.7.3.8.21 BOOSTER/INJECTION COMPRESSORS

2.7.3.8.21.1 The second step compressors shall be designed according to the following:

- capacity and gas compositions = according to process simulations for all design cases and Operation Modes;
- inlet pressure = XXXX kPa(a) (estimated, to be confirmed);
- discharge pressure = up to XXXX kPa(a);
- Normal operating temperature downstream discharge cooler (due to riser limitation): 40ºC;
- H2S content at least XXX ppmv, according to Membrane Unit performance for all design cases and Operation Modes;
- A stand-by unit is required as follows 2x100% or 3x50% or 4x33%.

2.7.3.8.21.2 For Booster/Injection Compressors, the condensate from inlet, inter-stage and final coolers vessels shall be routed to oil plant or to previous gas scrubbers. It shall not be sent to slop or drain system.

2.7.3.8.21.3 Gas Lift extraction point shall be downstream Injection Compressor if Booster/Injection Compressors are driven by a common driver.

2.7.3.8.21.4 CONTRACTOR shall perform a full-pressure, full-load, full-speed test at compressor manufacturer shop for booster and injection compressors. This test shall be witnessed by PETROBRAS. The test procedures and the approval criteria shall demonstrate the Unit's performance and reliability. During execution phase, CONTRACTOR shall provide Lateral Analysis and Stability Analysis Reports as per API 617.

2.7.3.8.21.5 CONTRACTOR shall provide a tie-in point in the gas injection header to connect a future chemical injection line if needed.

2.7.3.8.22 CO2 COMPRESSORS

2.7.3.8.22.1 The CO2 stream compression system shall be designed as follows:

- Capacity to be determined by simulation;
- Inlet pressure = XXX kPa(a) (estimated, according to CO2 removal membrane design);

- Discharge pressure to allow feed into Booster/Injection Compressors;
- Compositions = according to Membrane Unit performance for all design cases and Operation Modes;
- H_2S content at least 375 ppmv, according to Membrane Unit performance for all design cases and Operation Modes;
- A stand-by unit is required as follows 2x100% or 3x50% or 4x33%.

2.7.3.8.23 CENTRIFUGAL COMPRESSOR DRIVERS

2.7.3.8.23.1 Compressors shall be driven by electric motors.

2.7.3.8.23.2 For speed variation solutions with hydraulic variable speed drive (HVSD) or variable frequency drive (VFD) are accepted.

2.7.3.8.23.3 Cancelled.

2.7.3.8.23.4 Cancelled.

2.7.3.8.23.5 The available electrical motor power shall be at least 12% higher than compressor greatest power required (including gear and coupling losses) indicated in the supplier data sheet.

2.7.3.8.24 For acceptable vendor list for Gas Compressor API 617, see item 19.

2.7.3.9 OTHER REQUIREMENTS

2.7.3.9.1 Utilities (including power generation system) shall be designed considering at least the capacity of XXXXXXX Sm^3/d representing the produced gas including lift gas, for the compression system, without considering internal recycles. All internal recycles from process plant shall be added to this flowrate to define the total compression capacity. The utilities shall be designed to allow one standby train start-up of any compression unit with no capacity reduction.

2.7.4 PRODUCED WATER TREATMENT

2.7.4.1 The following figure presents the simplified scheme proposed for the Produced Water System considering both alternatives, reinjection back to reservoir as well as disposal to overboard.

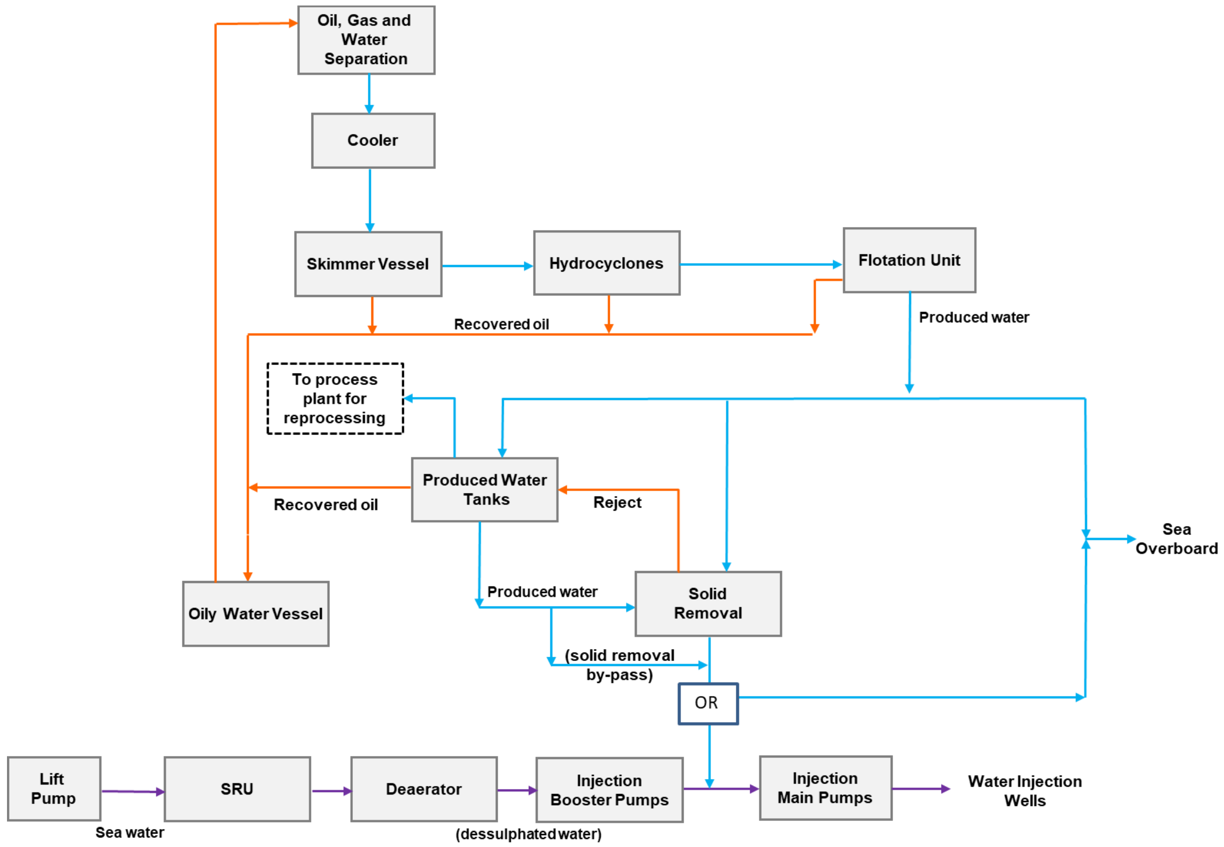


Figure 2.7.4.1 - Simplified Diagram for Produced Water Treatment, Reinjection and Seawater Injection

2.7.4.2 Alternative configuration shall be submitted for PETROBRAS approval.

2.7.4.3 Produced water plant shall be designed to treat as per Table 1.2.2.4 and to meet specification described on item 2.3.2.

2.7.4.4 Configurations of the following equipment shall be assessed for disposal treatment: skimmer vessel, hydrocyclones, and flotation unit.

2.7.4.5 Configuration of the following equipment shall be assessed complementing treatment for water reinjection: produced water tank and solid removal system.

2.7.4.6 Recovered oil from produced water treatment shall be sent to the oil process plant.

2.7.4.7 The produced water from Process Plant is accumulated in the Skimmer and further routed to Hydrocyclones and Flotation Unit. Treated Produced Water may be routed to one of the following destinations:

- Overboard;
- Produced Water Tank for additional polishing or to be routed back to process plant for reprocessing;
- Solid Removal step, bypassing the Produced Water Tank.

2.7.4.8 For produced water reinjection, the water from Flotation Unit shall be routed to Produced Water Tank from where it shall be pumped to Solid Removal Unit and then to reinjection in the reservoir (with or without mixing with seawater).

2.7.4.9 A by-pass of Solid Removal Unit shall be provided.

2.7.4.10 The filtration step – Solid Removal Unit – shall be one of the following: self-cleaning filters or ceramic membranes or multi-media filters. Additionally, CONTRACTOR shall use hydrocyclones upstream the filtration step in order to guarantee produced water quality specification to reinjection.

2.7.4.10.1 The hydrocyclones for solid removal shall be designed considering the following data:

- Maximum DP: 5 bar;
- Split: 2 (min) and 5 (max);
- Maximum solids content at inlet: 100 mg/L;
- Solid density: 1,5 kg/cm^3;
- Average particle size (d50): 30 µm;
- Maximum particle size at water outlet (d98) 25 µm.

2.7.4.11 The system shall consider that desulphated water (sea water) will supply the necessary water injection flowrate of production life of the Unit. However, if produced water is available for injection, it will be another possible source for injection and in this case, total injection flowrate may be produced water complemented with desulphated water.

2.7.4.12 Connection with overboard (ex.: from pressure valves or flow control valves for pump capacity control) is not allowed after the mixture of streams, during the reinjection operation.

2.7.4.13 Based on the expected range of temperature for produced water, produced water cooler location and target temperature shall be defined taking into account at least the following requirements:

- Adequate temperature for the operation of hydrocyclones and floatation unit;
- Maximum allowed temperature for the Produced Water Tank;
- Normal, maximum and minimum temperatures for the injection risers;

2.7.4.14 Produced Water Tank

2.7.4.14.1 The tank is an accumulator before solid removal in the case of produced water is reinjected into reservoir.

2.7.4.14.2 CONTRACTOR shall provide facilities and develop a procedure to remove solids accumulated in the produced water tank.

2.7.4.14.3 The following configuration shall be considered for Produced Water Tank: at least two separated Produced Water tanks. The volume of each tank shall be at least 10,000 m^3. One of these Produced Water tanks shall be capable to receive cargo.

2.7.4.14.4 The fluid inlets and outlets should be designed to minimize turbulence and recirculation, hampering the separation process by decantation.

2.7.4.14.5 Shock Biocide shall be foreseen to be injected in the inlet line of tank in order to allow a proper mixing and effectiveness of chemical product as well as to minimize turbulence in the tank.

2.7.4.14.6 Produced water tanks shall be provided with proper device (ex.: collector, pumps) installed at a convenient vertical level in order to remove skimmed oil from tank.

2.7.4.15 Pumps

2.7.4.15.1 Produced Water tanks shall be fitted with bottom pumps (hydraulic or electrical driven submerged on main deck) for water removal and to route to solid removal. The pumps shall be provided with variable flow and automatic control, taking into account the expected produced water forecast and shall be dimensioned to keep oil water surface within an acceptable level range, during the whole field production life.

2.7.4.15.2 The configuration for water pumps shall consider at least 2x50% (2x9,500 m^3/d), per tank.

2.7.4.15.3 For skimmed oil pumps, the configuration shall be defined by CONTRACTOR.

2.7.4.15.4 If produced water booster pumps are specified, they shall comply with API 610. Their sealing system shall comply with API 682 and its design and sealing plan shall be suitable for salty and hot produced water where applicable. Additionally, API 62 auxiliary sealing plan (quench) shall be provided.

2.7.4.16 Solid Removal

2.7.4.16.1 The necessary injection flowrate and produced water required specification (see item 2.4) shall be kept during the cleaning step of device.

2.7.4.16.2 The reject stream of this system shall be sent back to Produced Water Tank and may also be sent back the Oily Vessel. The reject return line to Produced Water Tank shall be provided anyway. The inlet pipe in the tank shall be arranged in order to not cause re-entrainment of solid in the water stream to be filtered. CONTRACTOR shall be responsible for managing residual disposal. Different configuration for the solid removal reject routing shall be submitted to PETROBRAS approval.

2.7.4.16.3 The minimum requirements for filtration are summarized below.

- The configuration shall consider at least 3x50% (3xXX,000 m^3/d) trains.
- Filters shall have differential pressure transmitter.
- Filtration shall collect particles above 25 μm.
- Self-cleaning filters shall have a maximum filtration flux of 1,200 m^3/m^2.h.
- Multimedia filters shall have a maximum filtration flux of 15 m^3/m^2.h.
- Ceramic membranes filters shall have a maximum filtration flux of 4.5 m^3/m^2.h.
- The filter vessel and backwashing facilities shall be designed in order to allow interchangeability considering the range of 25 μm and 80 μm filtering element set. Filtration elements fall under CONTRATOR's scope of supply.

2.7.4.17 For produced water reinjection, the produced water quality specification defined on item 2.4 shall be met.

2.7.4.18 For produced water disposal line, 2x100% online TOG analyzer (Content of oil and grease in water) shall be provided and the minimum requirements are summarized below:

- UV-fluorescence technology;
- Automatic cleaning system of acoustic (ultrasonic) type and manual sampling devices shall be provided;
- Guarantee the minimum analyzer flow as per supplier specification;
- The analyzer shall be installed close to the sampling points, with preference at upwards flow points, aiming to avoid possible interference from phase stratification commonly observed in horizontal flows;
- Logics shall also be implemented so that the overboard is interrupted if produced water is out of discharge limits.

2.7.4.19 Slop tanks shall not be used for treating produced water.

2.7.4.20 The produced water shall not be mixed with any other water or effluent.

2.7.4.21 Only one discharge point for produced water shall be considered in order to facilitate the routine of oil content monitoring (sample daily routine).

2.7.4.22 The end of the disposal line shall be above sea level, on all draft of the vessel, in order to allow visual inspection of the quality of the water.

2.7.5 FLARE AND VENT SYSTEM

2.7.5.1 The Unit shall be equipped with at least 2 (two) independent disposal systems, one receiving gas from higher operating pressure sources (HP) and the other receiving gas from lower operating pressure sources (LP), to collect and safely discharge residual gases released from safety valves, pressure control valves, blow down valves, pipelines, etc. Flare headers and equipment shall be designed to withstand temperature as low as -100ºC unless specific study results in different temperature value. These systems shall be designed to operate simultaneously. Design of the disposal systems shall comply with API STD 521, CS Requirements and Guidelines, and NR-13 requirements for periodical testing of PSVs.

2.7.5.2 Refer also to API 521, clause 4.4, for possible causes of overpressure to be considered in the design, such as choke valve failure and check valve failure.

2.7.5.3 The system shall be designed for emergency disposal, as well as for a continuous disposal from low flowrates to at least 4,000,000 Sm³/d. Process disposal streams like regeneration and flash gas from TEG Unit, outlet gas from produced water flash drum, flotation unit, flash gas from low pressure vessels with continuous operation, liquid from compressor scrubbers shall be sent back to the treatment plant. CONTRACTOR to evaluate the possibility of routing the gas to production plant in order to minimize gas flaring and its consequences.

2.7.5.4 CONTRACTOR shall submit to PETROBRAS a complete Depressurization System Study assumptions, methodology and results for comments during the engineering design phase. Assumptions and methodology shall be submitted prior to the development of the study. The Depressurization System Study shall contain an evaluation of flare depressurization rate obtained in each scenario and the implemented safeguards to prevent the occurrence of those in which flare system capacity is exceeded.

2.7.5.5 The disposal system K.O. drums shall be designed to accommodate gas and liquids relief flows and have effective level measurement and control. Disposal system headers shall be designed to accommodate multiphase flow depending on the characteristics of the relief.

2.7.5.6 Relief lines and headers shall be provided with adequate slope and drain points to guarantee liquid drainage considering all operational trim conditions.

2.7.5.7 CONTRACTOR shall submit to PETROBRAS the Gas Dispersion Study for Cargo Vent Post Location assumptions, methodology and results for comments during the engineering design phase. Assumptions and methodology shall be submitted previously of development of the study.

2.7.5.8 The venting system shall be provided with devices to prevent against passage of flame into the cargo tanks.

2.7.5.9 FLARES

2.7.5.9.1 The methodology established in API 521 shall be followed to determine radiation levels limits during emergency and continuous flaring. CONTRACTOR shall also conduct dispersion analysis during flare snuffing scenarios and noise level studies for the determination of the flare stack height.

2.7.5.9.2 The required radiation levels shall not be exceeded in any weather condition and in any continuous or emergency gas flow. Special attention shall be given on radiation levels on offloading equipment, flare startup system location (propane/ liquefied petroleum gas), electrical, and gas and flame detectors.

2.7.5.9.3 CONTRACTOR shall guarantee that:

- Flare system has suitable supports in order to avoid transferring vibration to the flare piping system;
- Flare design be a non-pollutant type, with low NOx emissions. Combustion efficiency shall be high enough (CE>99% and 98% conversion to CO2) to guarantee low HC emissions to atmosphere;
- Operational flaring scenarios be evaluated to guarantee flame stability and quality, especially for the lowest expected flowrates. Concern is excessive radiation and damage to flare structure and combustion efficiency;
- Flare designs consider fire scenarios according to fire propagation study results which can lead to high depressurization flow rates;
- Flare lines, including the vertical lines in the flare stack, are designed avoiding pockets and considering possible rainwater accumulation;
- Pressure relief/depressurization systems and flare system design and calculation consider all scenarios that might lead to simultaneous opening of all blowdown valves (BDVs) and fail-open pressure control valves (PVs), such as (but not limited to):
  - Electric systems' shutdown (black out, UPS failure);
  - Automation system's shutdown (PLC shut down, I/O card failures);
  - Loss of instrument air;
  - Loss of hydraulic pressure;
- Safeguards are provided to prevent that flare system capacity is exceeded in any of the presented depressurization scenario.

2.7.5.9.4 The flare system shall be designed with a gas recovery. Outlet gas from either low pressure or high pressure flare knockout drums shall be routed to Flare Gas Recovery System (FGRS). The FGRS shall consist of a complete system with a pressure recovering equipment to make possible to return gas to process. FGRS compressors shall be either liquid-ring compressors (as per API Std. 681) or screw compressors (as per API Std. 619). Configuration shall be N+1.

2.7.5.9.5 CONTRACTOR shall consider minimum the capacity of 75,000 Sm^3/d for FGRS design. The pressure recovering equipment shall start to recover the flare gas as the flare header pressure reaches a control set point. Whenever discharges exceed FGRS capacity, the system shall stop and gas shall be directed to the flare stack. In order to keep system reliability, QOVs (Quick Opening Valves) shall be installed on HP and LP headers. Each QOV shall have at least 2 (two) Buckling Pin Valve (BPV) protection with a bypass line. Each header pressure shall be monitored by 3 (three) pressure transmitters, located upstream QOV, and shall be configured with a voting logic of 2 (two) of 3 (three) in order to open/close QOV.

2.7.5.9.6 For the design of the Safety Instrumented Functions (SIFs) responsible for the QOVs actuation, installed in the flare gas relief lines (low and high pressure), SIL (Safety Integrity Level) 3 shall be considered as the level of integrity required.

2.7.5.9.7 Flares shall be designed with a backup of the ignition system. Flare and pilot shall be designed to guarantee flammability and flame stability considering the range of CO2 concentration expected.

2.7.5.9.8 Flare pilots shall comply with NR-37. Furthermore, the flare pilots project shall consider the flexibility to operate with the flare flame pilot "on" and "off".

2.7.5.9.9 Purge gas shall be injected in the gas piping system to the flare at the farthest point(s) upstream flare so that all the piping shall be full of purge gas.

2.7.5.9.10 For staged systems, provide a point for nitrogen purge downstream each valve of the stages normally closed, in order to maintain a continuous flow of purge gas up to the top of the flare.

2.7.5.9.11 The minimum purge gas flow shall be according to API STD 521 requirements or supplier information, whichever is higher.

2.7.5.9.12 In the Flare Gas Recovery System (FGRS), the high pressure and low pressure headers shall be purged with nitrogen locally generated from the atmosphere. The nitrogen generators shall have a 2x100% configuration and its electrical energy source shall be from emergency generator (Essential Switchgear). The nitrogen generators shall be dedicated and exclusive for flare purge, it shall not be shared with other plant consumers.

2.7.5.9.13 The Nitrogen Generator Units shall be connected in the supervisory system to allow an automatic start-up. In case of failure of both generators, a dedicated fuel gas source shall be used to purge the flare system. Purge gas shall be injected in HP and LP headers downstream respective QOV (Quick Opening Valve) valves.

2.7.5.9.14 At least two sources of purge gas shall be provided, with provision for measuring flow, low flow alarm and automatic changing between sources. The maximum oxygen content of purge gas shall be 5%.

2.7.5.10 ATMOSPHERIC VENTS

2.7.5.10.1 The design of Atmospheric Vents shall follow the API STD 2000.

2.7.5.10.2 CONTRACTOR shall consider proper access to flame arrestor for all atmospheric vents. Flame arrestors shall be installed in safe location complying with API 14C.

2.7.5.11 Special Considerations for CO2

2.7.5.11.1 CONTRACTOR may evaluate the use of alternative design for emergency disposal of rich CO2 stream, such as header segregation and venting. CONTRACTOR shall also evaluate if CO2 affects the combustion efficiency requirements stated in clause 2.7.5.1.

2.7.5.11.2 Designing relief systems of process plants (equipment or piping) shall take into account the possibility of low temperatures and associated solid CO2 formation, hydrate formation, adhesion, risk of plugging, and multi-phase flow analysis, according to ISO 17349.

2.7.5.11.3 The following requirements shall be met in the Unit design, as a minimum:

- The solid CO2 flowrate during the depressurization and relief of gas streams containing CO2 shall be estimated based on correlations available for this purpose in commercial process simulators;
- Volume design and structural calculations of the knockout vessels in the flare systems shall take into account the possibility of solid CO2 presence and accumulation;
- For the cases where potential for CO2 solid formation is identified, methods to monitoring the PSVs and BDVs tightness/leakage shall be implemented. Temperature transmitters shall be installed immediately at valves outlet for monitoring. These devices shall be configured with alarm and shutdown action based on risk assessment analysis.

2.7.5.11.4 The following information shall be provided during execution phase:

- CONTRACTOR shall present a calculation sheet and report covering the relief and depressurization of gas streams containing CO2 solid, showing relief and CO2 freeze-out temperatures;
- CONTRACTOR shall present the calculation methodology adopted to evaluate the risk of plugging, blocking and solid displacement in relief and depressurization lines.

2.8 CHEMICAL INJECTION

2.8.1 The Unit shall be equipped with a chemical injection system, which shall be used to improve and enhance the operating conditions of equipment and subsea lines. The oil, gas, water treatment and water injection systems shall be designed to inject the following main products:

- H2S scavenger for subsea;
- H2S scavenger for offloading;
- Gas hydrate inhibitor for topside and subsea;
- Scale inhibitor for topside;

- Scale inhibitor for subsea;
- Wax inhibitor for subsea;
- Asphaltene inhibitor for subsea;
- Water-in-oil demulsifier for topside;
- Water-in-oil demulsifier for subsea;
- Oil defoamer for topside;
- Polyelectrolyte;
- Sodium Hydroxide;
- Biocide for Slop Tank, Off-spec Tanks and Cargo Tanks;
- All the manufacturer recommended chemicals for the Sulphate Removal Unit and Ultrafiltration Unit. As a minimum CONTRACTOR shall consider:
  - Membrane biocide and/or shock biocide;
  - Chlorine scavenger and/or oxygen scavenger;
  - Scale inhibitor for SRU;
  - Acid cleaning for SRU;
  - Alkaline cleaning for SRU;
  - Water Injection Shock biocide;
  - Biofouling disperser.

2.8.2 Where not specifically mentioned, storage tanks for chemicals shall have enough capacity for 10 days of normal consumption, calculated by using 50% of the maximum injection rate indicated in Table 2.8.12.

2.8.3 All the chemical products tanks shall have a level transmitter and inclined bottom with a drain, containments for leaks, manhole for inspection, easy access to instruments and valves, high and low level alarms and sampling point. Sampling point can be at the pump.

2.8.4 Chemical tanks and their lines should be made of stainless steel, except if not compatible with the fluid. Tanks shall be installed in naturally ventilated areas and equipped with individual vents. The flammable products tanks must have flame arresters.

2.8.5 Vents for flammable and combustible products shall be in accordance to API STD 2000 or NFPA 30. For vent sizing, external fire scenarios shall be considered, whereas reduction factors foreseen in API STD 2000 and NFPA 30 shall not be considered. CONTRACTOR may use pressurized vessel for flammable and combustible products.

2.8.6 At least scale inhibitor (topside and subsea), demulsifier (topside and subsea), defoamer, biocide for water injection and tanks (slop, off-spec and cargo) and polyelectrolyte tanks/vessels shall be divided in two partitions with isolating valves from the common pump suction header and also isolating valves on filling line. Instrumentation, drains and vents shall consider the partition. These facilities are to be used during testing of new products or different batches of the same products.

2.8.7 For umbilical (subsea) injection, filters (2x100%, 400 mesh stainless steel) on pump discharge shall be added. The discharge filters shall have remote differential pressure alarm for replacement. CONTRACTOR shall follow practices and recommendations of API TR 17TR5 (Avoidance of Blockages in Subsea Production Control and Chemical Injection System) during design and operation. A specific drainage routine/procedure shall be established in agreement with PETROBRAS during operation phase.

2.8.8 All chemical injection pumps shall have a filter upstream. CONTRACTOR shall install stand-by pumps at all chemical units to guarantee continuous performance, except for ethanol/MEG pumps. Also, chemical dosing pumps shall have an adjustable flow range of 10:1 unless if defined differently on Table 2.8.12.

2.8.9 Each injection point shall have individual pump or multi head pump or dedicated head in a multi head pump, including online pressure meter (transmitter).

2.8.10 Each injection point shall have an online flow meter (transmitter) and a calibration gauge glass in order to measure the injection rate. CONTRACTOR shall comply with flow meter maintenance plan recommended by the supplier. Flow meters for topside scale inhibitor, oil defoamer, demulsifier and subsea chemicals shall be Coriolis type, transmitting online flow and density.

2.8.11 Each injection point shall be in the center of pipe. All topsides injection points in gas streams shall be installed with spray nozzle to accelerate chemical mixing.

2.8.12 Concentration ranges for each chemical to be complied with when designing the chemical injection system are (during operational life, different dosages within pump or system capacities may be applied):

Table 2.8.12 – Chemical Injection Rates & Requirements

PRODUCT	INJECTION RATE
H_2S scavenger for subsea	The injection system provided shall operate in the range of 1 to 50 L/h per well. There shall be a storage of 2 (two) tanks of 20 m³ each. Each scavenger line will pass through X-tree and tubing hanger(TH) down to the well bottom to allow H_2S scavenger to react with H_2S in the tubing;
H_2S scavenger for topsides	Injection point: upstream each offloading pump. The injection system provided shall operate in the range of 200 to 1,000 L/h. There shall be a total storage of 10m³. This product should be used just contingently and in agreement with PETROBRAS.

PRODUCT	INJECTION RATE
Gas hydrate inhibitor: ethanol or MEG (1)	Topside: 1 to 100l/h (multi head pump) (10) Subsea: 7,000 L/h. Two pumps are required. There shall be a storage of 2 (two) tanks of 40 m^3 each. At any time, each of the tanks may be used for ethanol of MEG.
Scale inhibitor for topside (2)	Topside: from 1 to 100 L/h in each injection point. Minimum tank capacity: 15.0 m^3.
Scale inhibitor for subsea (2)	Each scale inhibitor line will pass through X-tree and TH down to the well bottom to guarantee the scale inhibition as close as possible of perforations; The injection system provided shall operate in the range of 0.1 to 20 L/h per well. More than one head pump may be required to reach the maximum injection rate. There shall be a total storage of 15 m^3 One of the H_2S scavenger tanks shall be able to be used for Scale inhibitor.
Wax inhibitor for subsea (3)	The injection system provided shall operate in the range of 1 to 300 L/h per well. There shall be a total storage of 20 m^3 The Wax Inhibitor tank shall be able to be used for hydrate inhibitor. Water-in-oil demulsifier for subsea may use the same tank. These products will not be used simultaneously.
Asphaltene inhibitor for subsea (3)	The injection system provided shall operate in the range of 1 to 300 L/h per well. There shall be a total storage of 20 m^3
Water-in-oil demulsifier for topsides (4)	The injection system shall provide 10 a 100 L/h. Minimum tank capacity: 17.5 m^3
Water-in-oil demulsifier for subsea	The injection system provided shall operate in the range of 1 to 300 L/h per well There shall be a total storage of 20 m^3 Wax Inhibitor may use the same tank. These products will not be used simultaneously.
Oil defoamer (4,5)	The injection system shall provide 10 a 100 L/h. Minimum tank capacity: 15.0 m^3
Oil Defoamer (for subsea HISEPTM) (14)	Flowrate: defined on Table 2.11.3.7.1 There shall be a total storage of XXm^3
Biocide for Slop Tank, Produced Water Tank, Cargo Tanks and Off-spec Tanks (6)	Batch treatment uses 1 m^3/h as product flow rate. There shall be a total storage of 5 m^3
(SRU) Acid cleaning	Batch use (7) Tank capacity: To be defined by CONTRACTOR.
(SRU) Alkaline cleaning	Batch use (7)

PRODUCT	INJECTION RATE
	Tank capacity: To be defined by CONTRACTOR.
Water injection shock Biocide: DBNPA (8)	From 100 to 500 ppm twice a week during one hour, upstream SRU Tank capacity: To be defined by CONTRACTOR.
Water injection shock biocide: THPS (tetrakis hydroxymethyl phosphonium sulfate) or Glutaraldehyde	from 100 to 1000 ppm twice a week during one hour, upstream deaerator Tank capacity: To be defined by CONTRACTOR.
Scale inhibitor for SRU	from 1 to 10 ppm upstream SRU Minimum tank capacity: 6 m^3
Chlorine scavenger	from 1 to 20 ppm upstream SRU • Tank capacity: To be defined by CONTRACTOR.
Oxygen scavenger	from 5 to 20 ppm (operational deaerator) from 100 to 200 ppm (non-operational deaerator) Tank capacity: To be defined by CONTRACTOR.
Biofouling disperser	from 5 to 20 ppm downstream deaerator Tank capacity: To be defined by CONTRACTOR.
Polyelectrolyte (inverted emulsion inhibitor) (9)	From XX to XX ppm Tank capacity: XXX
Oxygen Scavenger (for produced water)	Injection point: upstream Solid Removal Unit From XX to XX ppm No additional storage required; CONTRACTOR may use the same system mentioned for injection water.
Coagulant	Injection point: upstream and downstream hydrocyclone From XX to XX ppm There shall be a total storage of XXm^3
Sodium Hydroxide (up to 50%) (11,12, 13)	Injection points: in the dilution water stream downstream electrostatic pre-treater and oil transfer pump suction header. Dilution water and upstream oil transfer pumps: from 1 to 100 L/h There shall be a total storage of 22m^3.
Acid for Water Treatment (15,16)	Injection points: upstream of FWKO, upstream first stage electrostatic treater. The injection system provided shall operate up to XXL/h There shall be a total storage of XXm^3

NOTE 1: To inhibit hydrate formation, ethanol / MEG shall be injected into the Wells Wet Christmas Trees. The injection is not planned to be continuous, however, it should be possible to inject it in up to two points at the same time. CONTRACTOR shall provide the required flow rate and pressure at the top connection of each control umbilical at the FPSO. The Subsea pump shall be used in the commissioning of all risers. The Subsea pumping system shall have a configuration of at least 2x50%

pumps, with a total flowrate of 7,000 L/h for top of riser injection. For umbilicals, please refer to tables 2.8.20 and 2.11.3.7.1.

Injection points are required at the top of all risers, and on the chemical routing plates shown in Figure 2.8.16. No injection of gas hydrate inhibitor in a gas injection riser while gas injection is in operation.

The tanks may store ethanol or MEG.

The pumps may be used to inject ethanol or MEG, not simultaneously. No dedicated headers are required.

Ethanol or MEG may be used for umbilical cleaning before a chemical product exchange. CONTRACTOR shall provide a permanent or removable connection of ethanol/MEG line to the other chemical products umbilical tubes as presented in Figure 2.8.15.

NOTE 2: The Unit shall be prepared to inject the scale inhibitor continuously at the well down hole (in all production wells at the same time) and at the topside facilities (production header, test header, upstream of treaters and/or heat exchangers, upstream of hydrocyclones, upstream mixing with desulphated water (reinjection scenario) and others) whenever required by PETROBRAS. Separate systems shall be provided, as different products are injected topsides and subsea. PETROBRAS informs that there is a high potential of scaling at topside and subsea. In the case of dosage ranges exceeding 10: 1, the CONTRACTOR must provide sets of heads / pumps of complementary ranges.

NOTE 3: This chemical uses Xylene as solvent. Facilities should be provided to allow the use of wax and asphaltene inhibitor systems for pumping hydrate inhibitors.

NOTE 4: The Unit shall be prepared to inject this product continuously topsides.

NOTE 5: Points of injection: production and test headers, upstream of the liquid level control valve of the HP Separator, upstream of the oil level control valve of the FWKO and upstream flash vessels.

NOTE 6: If CONTRACTOR decides to use a combo product for Biocide/Biostatic, only one tank is necessary. The value of 5mg / L of H2S should be used in the aqueous phase of the slops tanks as a reference for the control of the biocide dosage. The methodology to be used for the measurement of sulfides is that referenced in NOTE 3 of item 2.10.1. As per Contract requirement, CONTRACTOR must have an operating procedure and facilities that incorporates the injection of biocide and/or other means that may be necessary, so as to keep the Unit's tanks free from sulfate reducing bacteria.

NOTE 7: During project execution phase, SRU cleaning procedure shall be submitted to PETROBRAS for comments.

NOTE 8: DBNPA is a corrosive product so its injection system shall not be metallic However, titanium/hastelloy C is acceptable for use with DBNPA.

NOTE 9: Polyelectrolyte must be injected upstream of the flotation cell and the injection points must be downstream of the hydrocyclones, as close as possible to hydrocyclones. This product should be diluted 10 to 30 times in fresh water. The CONTRACTOR must use in-line dilution systems or pumps that allow automatic product dilution in water, without the need for a dilution tank.

NOTE 10: Injecting the product at the topside during commissioning of the gas plant may be required due to the bypass of the molecular sieves or because of the import of gas through the export pipeline (when applicable). The minimum injection points required are: export pipeline (when applicable), one point upstream and another point downstream of the fuel gas scrubber vessel.

NOTE 11: An in-line system with fresh water to reduce Sodium Hydroxide concentration from 50% m/m to 18% m/m shall be provided. The Sodium Hydroxide solution tank material should be stainless steel 316L, dedicated for this product. This tank should never have contact with chlorides, in order to prevent Steel Cracking Corrosion. On-line pH analyzers shall be provided at dilution water downstream sodium hydroxide injection and at the produced water outlet from electrostatic treater. Additionally, sample points shall be provided for pH lab analysis as a back-up for the on-line pH analyzers.

NOTE 12: These values are calculated based on total oil and produced water flowrate. For the chemicals that are injected in each oil treatment train, CONTRACTOR shall use these values as basis to calculate flowrate injected in each train.

NOTE 13: Dilution water line to be provided upstream oil/oil pre-heater shall be sodium hydroxide free. It shall be drawn upstream sodium hydroxide injection.

NOTE 14: Storage tanks for Oil Defoamer and Oil Defoamer for HISEP shall be segregated, chemical products are different.

NOTE 15: The necessary amount of acid and coagulant will be provided by PETROBRAS at no cost. For design purpose, acetic acid 75% shall be considered.

NOTE 16: Facilities defined for acid and coagulant may be the same. These products will not be used simultaneously.

2.8.13 Chemicals are received from supply vessels in portable tanks (tote tanks) within 5m^3 capacity and must be stored in specific chemical storage areas within the range of at least one of the Unit's cranes. These chemical storage areas shall preferably allow the gravity transfer of chemicals to the storage tanks in the chemical injection unit.

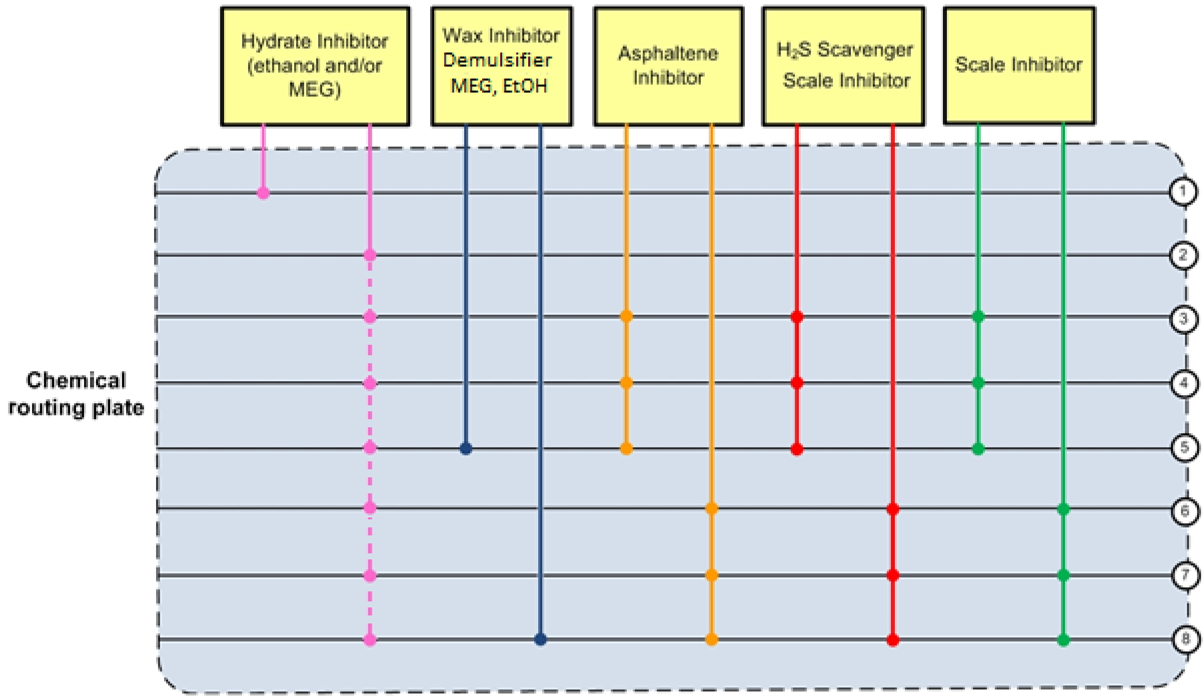
2.8.14 Sufficient area shall be provided for receiving and storing a quantity of tote tanks as per Table 2.8.14. Products of non-continuous use shall not be considered in this calculation. No stacking of tote tanks is allowed.

Table 2.8.14 – Tote Tanks Quantity for Storage Area Definition

PRODUCT	TOTE TANKS QUANTITY (reference 5m^3)
H_2S scavenger for subsea	2
H_2S scavenger for topsides	0
Gas hydrate inhibitor: ethanol or MEG (1)	5
Scale inhibitor for topside	5
Scale inhibitor for subsea	2

Wax inhibitor	2
Asphaltene inhibitor	2
Water-in-oil demulsifier for topsides	4
Water-in-oil demulsifier for subsea	2
Oil defoamer	5
Biocide for Slop Tank, Produced Water Tanks, Cargo Tanks and Off-spec Tanks	1
Biostatic for Slop Tank, Produced Water Tanks, Cargo Tanks and Off-spec Tanks	1
(SRU) Acid cleaning	1
(SRU) Alkaline cleaning	2
Water injection shock Biocide: DBNPA	1
Water injection shock biocide: THPS (tetrakis hydroxymethyl phosphonium sulfate) or Glutaraldehyde	1
Scale inhibitor for SRU	1
Chlorine scavenger or Oxygen scavenger	1
Biofouling disperser	1
Polyelectrolyte	1
Sodium Hydroxide	4
Acid for produced water treatment	X

2.8.15 Configuration for Chemical Routing Panels is presented in the following Figure. For subsea chemical injection and Chemical Routing Panels requirements for HISEP™ slots, see item 2.11.



Umbilical tube/hose	Chemicals				
	Hydrate Inhibtor	Wax Inhibitor, Demulsifier, MEG, EtOH	Asphaltene Inhibitor	H2S Scavenger, Scale Inhibitor	Scale Inhibitor
1	x				
2	x				
3	x		x	x	x
4	x		x	x	x
5	x	x	x	x	x
6	x		x	x	x
7	x		x	x	x
8	x	x	x	x	x

Figure 2.8.15: Chemical Routing for all Wells

NOTE 1: Design shall consider the risk of reverse flow from chemical injection hoses from subsea.

2.8.16 CONTRACTOR shall also provide a connection point for eventual injection of chemical tracers in the reservoir. This connection point must be available in the injection line of the gas, water and WAG wells, in a point where the flow is specific for each injection well. The point must be such that it is possible to connect a portable (pneumatic) injection skid without depressurizing the injection line and header (double blocking/purging and/or other mechanism).

2.8.17 PETROBRAS will provide the following chemicals up to the limit mentioned in the table below, measured monthly. These quantities are referred to the maximum flowrate (refer to item 1.2.2.4) or storage capacity mentioned in the table 2.8.12. For flow rates smaller than the maximum, a proportional amount will be considered.

Table 2.8.17 – Chemicals Provided

PRODUCT	Quantities (Maximum limits / month)
Scale inhibitor for subsea	See remark 2 below
Scale inhibitor for topside	74 m^3 (1)
Water-in-oil Demulsifier	42 m^3 (2)
Oil defoamer	71 m^3 (2)
Polyelectrolyte (inverted emulsion inhibitor)	28 m^3 (1)
Biocides to water injection	DBNPA – 6 m^3 THPS or Glutaraldehyde – 4.5 m^3
Hydrate inhibitor	See remark below
Chemicals to be used in the Sulphate Removal Unit and Ultrafiltration Unit (if necessary)	Oxygen scavenger and chlorine scavenger - 36 m^3 Scale inhibitor for SRU- 10 m^3 Acid Cleaning - 4 m^3 (for 3 months) Alkaline Cleaning - 4 m^3 (for 3 months)
Wax inhibitor	See remark 2 below
Asphaltene inhibitor	See remark 2 below
H_2S scavenger for subsea	See remark 2 below
Biofouling disperser	25 m^3
Acid for produced water treatment	XXXX

NOTE 1: Based on Produced Water.

NOTE 2: Based on Produced Liquids.

Remarks:

1. The necessary amount of hydrate inhibitor necessary for cleaning the flowlines will be provided by PETROBRAS at no cost.
2. Subsea chemicals will be provided by PETROBRAS at no cost. CONTRACTOR must use the volume or dosage requested by PETROBRAS.
3. The quantities above may be revised during the operation, if CONTRACTOR presents technical evidence that supports such need and is accepted by PETROBRAS.
4. As chemical injection facilities may contain low flashpoint, flammable and/or toxic substances, these risks shall be used in development of the appropriate protection requirements.
5. Due to potential hazards, the location of chemical injections packages shall not obstruct escape and evacuation routes by any very toxic substances that might result from an incident.

2.8.18 PETROBRAS will provide reference chemical product data sheets for each function during design phase. However, the supplier of the chemicals will be defined based on PETROBRAS internal procedures and regulations and might change suppliers during operation phase.

2.8.19 For tote tanks dimensions, CONTRACTOR shall consider:

Table 2.8.19 – Tote Tank Dimensions

m³	Valve	Connection	PB	Dimension	Tare (kg)
1,0	ball Ø2"	Screw BSP	restricted gate	H=1,5m X L=1,3m X W=1,5m	265
1,5	ball Ø2"	Screw BSP	restricted gate	H=1,9m X L=1,3m X W=1,5m	440
3,0	ball Ø3"	Screw BSP	restricted gate	H=2,3m X L=2,3m X W=2,3m	1.500
5,0	ball Ø3"	Screw BSP	restricted gate	H= 2,3m X L= 3,0m X W=2,3m	1.700
5,2	ball Ø3"	Screw BSP	tripartite restricted gate	H=2,3m X L=3,1m X W=2,3m	1.700

W: Width, H: Height, L: Length

2.8.20 Required pressure at top of riser and flowrates per well for the subsea chemical injection is presented in Table 2.8.21. During execution phase, PETROBRAS will confirm these values.

Table 2.8.20 – Subsea Chemicals Requirements

Product	Injection Point	Pressure at top of riser/umbilical (bara)	Min Flow Rate (m^3/d)	Max Flow Rate (m^3/d)
Ethanol	Subsea Tree(1)	350	6.8	68.0
MEG	Subsea Tree(1)	350	3.2	32.0
Wax Inhibitor/ Water-in-oil Demulsifier	Subsea Tree	370	0.4	4.0
Scale Inhibitor	Well	260	0.16	1.6
H_2S Scavenger	Well	370	0.3	3.4
Asphaltene Inhibitor	Well	370	0.65	6.5

NOTE 1: For Production and Injection positions.

2.9 SAMPLE COLLECTORS

2.9.1 Provisions to collect samples shall be designed in such a way as to guarantee correct sample accuracy. Each collecting point shall be in accordance with regulations and shall allow safe operation with no environmental impact. Therefore, CONTRACTOR shall install an adequate drain and/or vent system, for each of the collecting points listed below:

Table 2.9.1 – Sample Points

POINTS	SAMPLE COLLECTION

Produced oil /Condensate (1,2,3,8)	• Test and production header (upstream from the chemical injection points); • Upstream and downstream of process vessels; • Tlry-cocks on electrostatic treater and free water separators (FWKO); • Transference pump discharge (from the process plant to the cargo tanks); • All production lines; • Offloading line; • Slop and Cargo Tanks.
Gas (3,4,5, 11)	• Upstream and downstream of process vessels; • Fuel Gas; • High Pressure Flare gas; • Low pressure Flare gas; • Service header; • Gas lift header; • Gas reinjection; • Slop and Cargo Tanks; • Membrane unit: inlet gas, treated gas and CO_2 rich stream (each elements cluster, as a minimum).
Produced water (6)	• Upstream and downstream of process vessels • Produced water tank (inlet and outlet) • Solid removal unit (inlet and outlet). The outlet point shall be upstream the produced water and desulphated water mixture. • Any points to allow control/troubleshooting of produced water treatment • Water discharge piping to overboard (located near and downstream the oil and water online analyzer) (9)
Injection water	• Upstream and downstream of deaerator; • Seawater intake, upstream of water lift pumps; • Sulfate removal membrane unit: inlet, treated water and Sulfate stream (in each vessel); • Injection header and risers.
Dilution water	• Upstream dilution water heater.
Cooling Water	• Downstream circulation pumps. • Downstream heat exchangers

Hydraulic control fluid	• High pressure header for Down hole Safety Valves (DHSVs); • Low pressure header for Wet Christmas Trees (WCTs).
Slop water	• Slop tank water disposal line to overboard • Upstream and downstream of slop water treatment systems.
Ballast water	• Ballast water disposal line to overboard
Subsea Chemicals	• Upstream of the Subsea chemical injection pumps
Sewage system (10)	• Upstream (after mixture of grey and black waters) and downstream sanitary effluent treatment unit to allow quantification of COD (chemical oxygen demand) and BOD (biological oxygen demand) reduction efficiency.
TEG Unit	• Lean TEG stream in the inlet of absorber • Rich TEG stream upstream of absorber level control valve • Rich TEG stream downstream of activated carbon filter • Wet gas stream upstream of absorber, downstream of coalescer filter • Dry gas stream downstream of absorber
CO_2/H_2S Removal Unit	• Sour gas - at gas inlet of amine contactor (s) • Sweet gas - at gas outlet of amine contactor • Lean amine - at inlet of amine contactor(s) • Rich amine - downstream of amine contactor(s) level control valve • Rich amine - downstream of activated carbon filter • Reflux water to the stripper tower • Make-up water • Sour gas - at gas outlet of regeneration tower • Sour gas - at gas outlet of Amine Flash Drum

NOTE 1: CONTRACTOR shall provide means to collect samples and to determine BTEX content in produced oil (according to EPA 8260D e EPA 3585), condensate (ASTM D 3606) and produced water (according to EPA 8015D).

NOTE 2: CONTRACTOR must provide facilities to collect samples of oil in vessels of 0,25L up to 1,000 L (container). Sampling condition must be at atmospheric pressure (test and production separators and crude oil fiscal meter to cargo tanks shall also foresee pressurized samples). All the gas released in this process must be sent to a safe place.

NOTE 3: For gas and oil sampler points related to the flow meters of the FMS, *Resolução Conjunta ANP/Inmetro nº1* of 2013 shall be complied with. For a list of all metering points and additional requirements see FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1).

NOTE 4: CONTRACTOR shall also provide manual sample collection in every online analyzer (gas chromatographer, moisture analyzer, oil in water content, etc.) and meter.

NOTE 5: CONTRACTOR shall provide means to collect and to determine BTEX content in produced gas according to GPA 2286.

NOTE 6: Sample points shall be representative and located at turbulent flow line.

The sample points shall be, at least, according to the following requirements:

- It shall be intrusive, positioned in the center line of piping and with a curvature of 90º against the flow (see Figure 2.9.1);

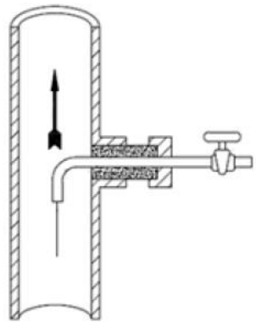


Figure 2.9.1 – Intrusive Sample Point

- It shall be located in a vertical section of piping with ascendant flow;
- The piping shall be of stainless steel with a minimum diameter of ½";
- In case where intrusive sampling is not practicable (e.g.: small diameter piping), a lateral nozzle shall be used;
- The length of sampling piping shall be as minimum as possible, preferably lower than 4 (four) meters;

NOTE 7: The sample systems shall have material specification compatible with sampled fluids.

NOTE 8: CONTRACTOR shall provide a hermetic system to collect and determine benzene content (%v/v) in all condensate streams, as presented in *Norma Regulamentadora Nº 15 – NR-15* (*Portaria SSST n.º 14*, December 20, 1995) Annex 13 A.

NOTE 9: Additionally to the NOTE 6 requirements, this sample point shall comply with the following requirements:

- It shall be located downstream the last equipment before produced water discharge;
- It shall be kept constantly opened in the maximum opening of sampling valve.

NOTE 10: Sampling points shall comply with *NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11.*

NOTE 11: In high pressure compression systems (above 5000 psig (34,474 kPag)), sampling points may be installed at lower pressure points as long as there is no change in the composition of the gas along this system.

2.10 LABORATORY

2.10.1 CONTRACTOR shall provide onboard a Laboratory equipped to perform, as a minimum, the following analysis onboard:

Table 2.10.1.a – Laboratory Analyses - Offshore

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Produced Oil and Condensate	BS&W and watercut	ASTM D4007 or API MPMS 10.4 ; ASTM D4928; ASTM D4377
	Salinity	ASTM D3230 or ASTM D6470
	Sand content	ASTM D4381
	Density/API gravity	ASTM D5002
	H2S content	UOP 163
	pH; two-phase oil (1)	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	RVP	ASTM D6377
Cargo and Slop tanks	BS&W and watercut	ASTM D4007 or API MPMS 10.4; ASTM D4928; ASTM D4377
	H2S content in oil	UOP 163
	H2S content in water	UOP 209
	H2S content in vapor phases	ASTM D4810
Produced and discharged water	Oil content (2)	API RP 45; ASTM D8193
	Chloride content	ASTM D512; ASTM D4458
	Calcium and Magnesium content	ASTM D511
	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	O2 content (3)	ASTM D5543
Injection water (from sea water treatment or produced	O2 content (3)	ASTM D5543
	SDI (Silt Density Index)	ASTM D4189.
	Number of particles	SMEWW 2560 C. Light-Blockage Method

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
water treatment)	Sulfate Content	ASTM D516, EPA 375.4, SMEWW 4500-SO42− (turbidimetric method) or ASTM D4327 (ion chromatography)
	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method
	H2S content in water	UOP 209 (potentiometric method) or SMEWW 4500-S2− G (ion-selective electrode method)
	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	Sulfite	SMEWW 4500-SO32- B (iodometric method)
	Oil content in water	API RP 45
Produced gas	H2S content	GPA STD 2265; ASTM D2385; ISO 6326-3; ASTM D4810
	Composition of natural gas by Gas Chromatography (5)	ASTM D1945; ABNT NBR 14903; ISO 6974;
Treated gas	H2O content (6)	ASTM 1142 and ASTM D 5454
	H2S content	GPA STD 2265; ASTM D2385; ISO 6326-3; ASTM D4810
	Composition of natural gas by Gas Chromatography	ASTM D1945; ABNT NBR 14903; ISO 6974;
	Gas Compliance Certificate	Note (7)
Heavy Hydrocarbon Rich Stream	Composition by Gas Chromatography	ASTM D1945; ABNT NBR 14903
	Density	ASTM D1657;ASTM D2598; ISO 3993 or ISO 8973
	H2O content	ASTM 1142; ASTM D 5454
Hydraulic control fluid	Cleanliness	ISO 11500; ISO 4406; SAE AS4059
Sea Water Lift System	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method
Cooling and Heating	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Medium Systems;	Chloride	ASTM D512; ASTM D4458
	Corrosion inhibitor content	Hach Method 8153 Nitrite, or another test method depending on the type of corrosion inhibitor used.
	Iron content	Hach Method 8008 Iron; Application Note Merck MColortestTM Iron Test; SMEWW 3500-Fe-B
Make-up water	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	Chloride	ASTM D512; ASTM D4458
	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method
	Iron content	Hach Method 8008 Iron; Application Note Merck MColortestTM Iron Test; SMEWW 3500-Fe-B
	Sulfate Content	ASTM D516; EPA 375.4
	O2 content (3)	ASTM D5543
Potable Water (8)	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	Chloride	ASTM D512; ASTM D4458
	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method
	Iron content	Hach Method 8008 Iron; Application Note Merck MColortestTM Iron Test; SMEWW 3500-Fe-B
	Color	SMEWW 2120-B (Visual Comparison Method)
	Turbidity	SMEWW 2130-B (Nephelometric Method)
	O2 content	ASTM D5543
Subsea Chemicals	Cleanliness	ISO 11500; ISO 4406; SAE AS4059
Lean and Rich MEG	MEG Content	ASTM E1064; ASTM D4928; ASTM E203
	Salinity	ASTM D3230
Lean and Rich TEG	Glycol Concentration	ASTM E1064; ASTM D4928; ASTM E203

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Sewage system (8)	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method

Table 2.10.1.b – Laboratory Analyses - Onshore

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Produced Oil and Condensate	PVT - shrinkage factor and gas oil ratio	PETROBRAS Test Method (Pressurized density and flash release)
Produced and discharged water	Composition (9)	USEPA Method 300; ASTM D4327; SMEWW 4110 B; ASTM D691; ASTM D1976.
	Oil content (8)	SMEWW 5520 B and SMEWW 5520 F
Injection water (from sea water treatment or produced water treatment)	Bacteria SBR planktonic, mesophilic and thermophilic	Standard Test Method to be defined by PETROBRAS
	BANHT - Total Anaerobic Heterotrophic Bacteria	Standard Test Method to be defined by PETROBRAS
	Total suspended solids (TSS)	SMEWW 2540 D or ISO 11923
Potable Water	Water potability requirements	Note (8)
Sewage system (8)	BOD	SMEWW 5210 B. 5-Day BOD Test; SMEWW 5210 D. Respirometric Method
	COD	SMEWW 5220 C. Closed Reflux, Titrimetric Method; SMEWW 5220 D. Closed Reflux, Colorimetric Method
	Oil content	SMEWW 5520 B; SMEWW 5520 D; SMEWW 5520 D;
	Total coliform bacteria; E.coli	9223 Enzyme Substrate Coliform Test

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
	Organochlorine compounds (chlorobenzenes, dichloroethene, trichloroethene, chloroform, carbon tetrachloride)	EPA 8260
	Polychlorinated Biphenyls (PCBs)	EPA 8082; EPA7270

NOTE 1: Endpoint titration with potentiometric pH measurement (SET pH) and Dynamic equivalence point titrations with potentiometric voltage measurement (DET U). CONTRACTOR may request a pH analysis of the water separated in the laboratory from a mixture of oil, deionized water, demulsifier and toluene, at a frequency and with an experimental procedure to be defined later.

NOTE 2: OIL CONTENT AT ALL POINTS OF DISCHARGE TO OVERBOARD, UPSTREAM AND DOWNSTREAM OF PROCESS VESSELS. API RP45 MUST BE APPLIED TO DETERMINE THE OIL IN WATER CONTENT IN SLOP TANK SAMPLES. CONTRACTOR SHALL BE ABLE TO PERFORM STANDARD METHODS 5520 B ONSHORE TO COMPLY WITH CONAMA REGULATIONS.

NOTE 3: Measurement range shall be from 0 to 1000 ppb.

NOTE 4: Laboratory analyses should be able to measure at least the specification of 0,1 to 2 ppm of chlorine content.

NOTE 5: CONTRACTOR shall supply chromatographic analysis of any gas sampling point, under PETROBRAS occasional demands.

NOTE 6: CONTRACTOR have to be able to perform analysis with chandler chanscope digital dew point meter, including accessories for dew points down to -100°f (-75°c). contractor shall provide portable aluminum oxide moisture sensor according to astm d 5454. the portable aluminum analyzer SHALL BE ABLE TO MEASURE H2O CONTENT IN THE TREATED GAS STREAM WITHIN THE MOISTURE SPECIFICATION RANGE.

NOTE 7: The CONTRACTOR shall carry out the tests required by the current ANP Technical Regulation and issue a Quality Certificate proving compliance with the specification of natural gas to be marketed throughout national territory.

NOTE 8: CONTRACTOR shall carry out the tests in accordance with current legislation.

NOTE 9: Composition shall include: Salinity, Organic acids, Bicarbonates, Calcium, Magnesium, Bromide, Barium, Strontium, Iron, Manganese, Potassium, Lithium, Boron, Sulfate.

NOTE 10: CONTRACTOR shall carry out the tests required by Combined Cycle equipment suppliers, if applicable, to assure proper and safe operation of every equipment of the steam power generation system.

2.10.2 All Laboratory equipment and analysis methodology shall provide reliable results and shall be submitted to PETROBRAS for comments/information during the engineering design phase. PETROBRAS at their own discretion will collect samples for further comparison with the measured results obtained in the Unit.

2.10.3 All glassware and equipment should be calibrated with certified standards of RBC/Inmetro.

2.10.4 Laboratory shall be located in a non-hazardous area, next to the Utilities Module and as close to the Accommodation Module as possible.

2.10.5 All organic or toxic reagents shall be stored in cabinets with proper exhaustion.

2.10.6 Laboratory drain system shall prevent the possibility of back-flow of flammable vapors.

2.10.7 Air conditioning should be exclusive for laboratory facilities.

2.10.8 Separates sinks shall be installed. One sink dedicated to inorganics (e.g. water) and other sink dedicated to organics (e.g. kerosene).

2.10.9 An eye-washer and shower shall be provided inside the laboratory.

2.10.10 Each equipment should have its own socket.

2.10.11 CONTRACTOR shall calibrate all laboratory equipment according to the manufacturer's guidelines on a regular basis, calibration certificates must be kept onboard.

2.10.12 CONTRACTOR shall provide a local test certificate for fume hood with face speed measurement and smoke test according to ANSI/ASHRAE 110 standard.

2.11 SUBSEA SEPARATION SYSTEM (SSS) - HISEP™

2.11.1 SYSTEM DEFINITION

2.11.1.1 The HISEPTM is a subsea high pressure gas-oil separation system and consists in a liquid-gas separation unit, followed by a dense gas phase pumping in order to reinject dense gas phase back into reservoir. The separated liquid phase from

HISEP™ with a lower GOR is routed to the Unit. Figure 2.11.1.1 below shows the HISEP™ configuration.

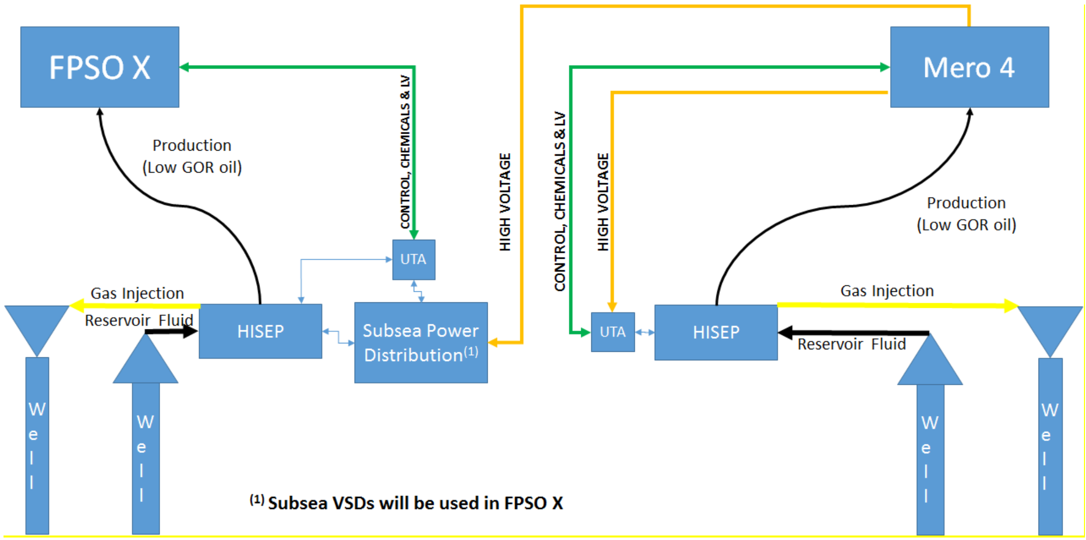


Figure 2.11.1.1 – HISEP™ System Configuration

2.11.1.2 As mentioned in item 1.2.2, FPSO may be connected to a SSS (HISEP™) at any time during the production lifetime. The liquid flow and its associated gas after arriving the topsides are routed to the three-phase separator (Free Water Separator) located downstream the HP separator, in the oil separation and treatment system.

2.11.1.3 4 (four) production slots in the riser balcony will be selected for future connection with HISEP™. Those selected slots will be defined as two groups with two slots positions each. Each production slot will need one position for its service line. Therefore, each pair of HISEP™ production slot needs a pair of service slot.

2.11.1.4 During normal operation, the production from HISEP™ will arrive through one of 4 (four) production slots selected. The four selected slots will be informed during Kick-off Meeting. Those positions shall have possible straight alignment to the Free Water K.O. Drum (2nd stage of separation) besides the normal alignment to the production header and test header.

2.11.1.5 HISEP™ always will be connected to 2 (two) positions from the 4 (four) production slots above mentioned. One of them will be always aligned to the FWKO and the other one will be always connected to the production header for HISEP™ start up purposes. Occasionally, one the of the 2 (two) positions may be aligned to the test header for well test.

2.11.1.6 FPSO will provide high voltage, low voltage, chemicals, hydraulic control, hydraulic barrier fluid and control to its HISEP™ system. Besides, FPSO will provide high voltage and fiber optics connection point to another HISEP™ system that will be connected to a FPSO "X" as it was illustrated in Figure 2.11.1.1.

2.11.2 DESIGN CASES

2.11.2.1 CONTRACTOR shall design the Unit considering the following design cases for the production arriving from HISEP™. The produced fluid from HISEP™ shall be received in a specific header and sent directly to the FWKO during normal operation. Each HISEP™ design case shall be associated with the design cases presented in Table 2.2.2.3, as indicated in Table 2.11.2.1, resulting in additional design cases. Fluid compositions from HISEP™ are presented in Table 2.11.2.4. For design cases from 10 through 16, CONTRACTOR shall use flowrates from HISEP™, while still complying with maximum nominal flowrates from the respective design cases.

Table 2.11.2.1 – Design Cases for HISEP™ Production

Cases			Temp. (ºC) (1)	Oil Flow rate (2) (Sm³/d)	Liquid Flow rate (Sm³/d)	Gas Flow rate (Sm³/d)	Corresponding case in table 2.2.2.3
Max Oil / Max Gas	13	Well E	30	10,000	10,000	2,000,000	1
50% BSW / Max Liquid	14	Well E	50	5,000	10,000	1,000,000	4
	15	Well F	45	5,000	10,000	1,000,000	4
Max Water / Max Liquid	16	Well E	70	500	10,000	100,000	5
	17	Well F	70	500	10,000	100,000	7
Low Liquid	18	Well E	5	1,500	1,500	300,000	1
	19	Well F	0	1,000	1,000	200,000	11

NOTE 1: Operational temperature downstream of production choke valve. During the production, the temperature can vary from 0ºC to 70ºC.

NOTE 2: The standard flow rate shall be applied to oil conditions as per item 2.3.1.

2.11.2.2 The normal pressure range upstream of production choke valve is 2,500 to 12,000 kPa(a).

2.11.2.3 The HISEP™ production line that will not be used during normal operation will be kept with Diesel or gas, as detailed in item 10 of Operation Philosophy. The HISEP™ production lines may reach a pressure up to 526 bar at the top of riser.

2.11.2.4 CONTRACTOR shall design the Unit considering a scenario of HISEP™ shutdown. In this scenario, the Unit shall be prepared to isolate the HISEP™ production risers from the topside processing plant. Furthermore, in this scenario FWKO shall continue operating and processing the fluids from HP Separator. CONTRACTOR shall provide means to depressurize the lines upstream of FWKO. It is important to notice that during a HISEP™ shutdown, the FWKO may receive higher liquid and gas flowrates, equivalents to 12,000 Sm^3/d with 6,000,000 Sm^3/d, in case of failure of the dispositive at topsides to isolate the HISEP™ production line.

Table 2.11.2.4: Well Fluid Composition for HISEP™

Component	Well E	Well F

CO_2	33.81	48.12
N_2	0.14	0.10
C1	27.06	20.40
C2	4.83	2.79
C3	3.81	2.25
iC4	0.67	0.44
nC4	1.83	1.26
iC5	0.63	0.57
nC5	1.02	0.55
C6	1.28	0.34
C7	1.51	0.49
C8	1.89	0.72
C9	1.63	1.25
C10	1.45	0.70
C11	1.29	0.73
C12	1.18	0.76
C13	1.22	0.89
C14	1.05	0.92
C15	1.00	1.06
C16	0.78	0.86
C17	0.71	0.94
C18	0.75	1.02
C19	0.65	0.86
C20+	9.79	11.98
Mol. Weight C20+	515	515
Density C20+	0.9413	0.9413

2.11.3 HISEP™ REQUIREMENTS AND INTERFACE CONNECTIONS WITH FPSO

2.11.3.1 Complete independent HISEP^{TM} topside containers or modules will be installed in the future. Figure 2.11.3.1 shows the scheme.

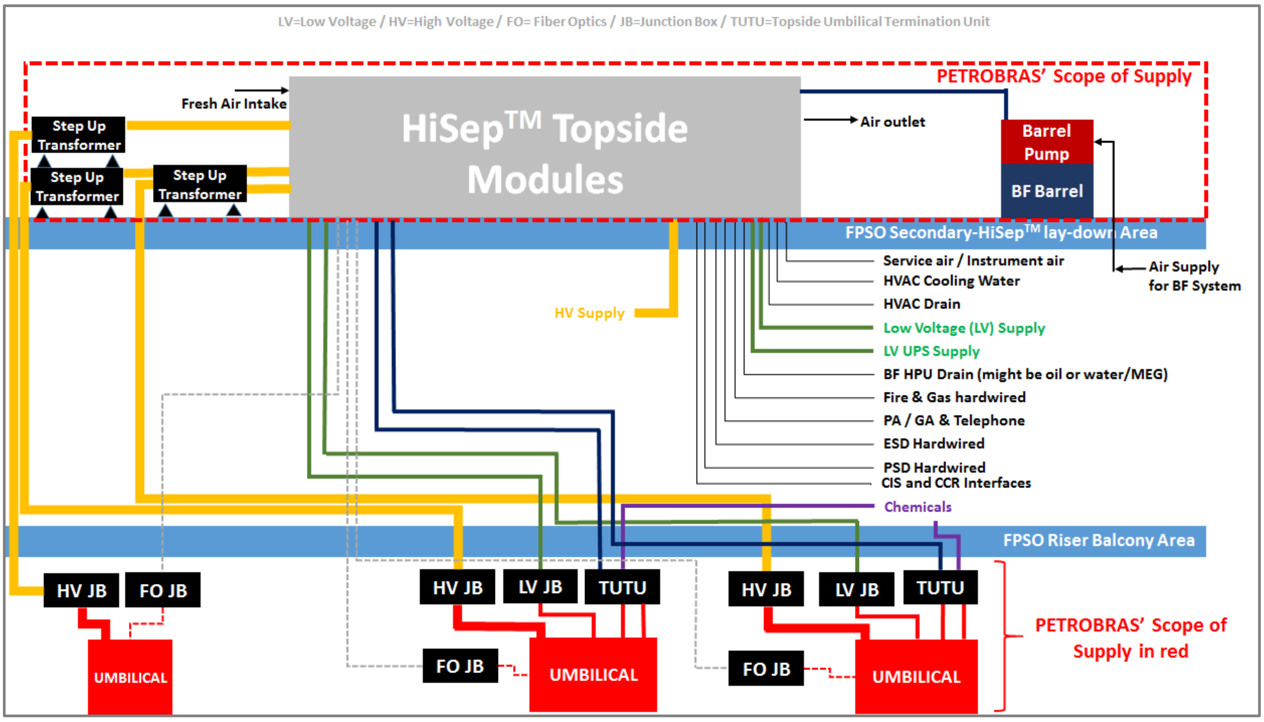


Figure 2.11.3.1 – HISEP^{TM}`s Containers and Umbilicals Schematic Interfaces with Unit Facilities

2.11.3.2 CONTRACTOR shall supply all features that are highlighted in Figure 2.11.3.1 except what is identified as PETROBRAS' scope.

2.11.3.3 CONTRACTOR shall provide all supplies mentioned in Figure 2.11.3.1, as follows:

- HVAC Cooling Water;
- HVAC Drain;
- High Voltage (HV) supply;
- Low Voltage (LV) supply;
- Low Voltage UPS (Uninterruptible Power Supply) supply;
- Barrier Fluid (BF) Hydraulic Power Unit (HPU) Drain (might be oil or water/MEG);
- Fire and Gas hardwired (see 2.11.4);
- PA/GA & Telephone;
- ESD hardwired;
- PSD hardwired;
- CSS and CCR interface;
- Chemicals (see 2.11.3.7);
- Service air;

- Fresh air intake;
- Air outlet;
- Air Supply for BF System;
- High Voltage Junction Boxes;
- Low Voltage Junction Boxes;
- Fiber Optic (FO) Junction Boxes;
- TUTU plates.

2.11.3.4 AREA, MATERIAL HANDLING AND INSTALLATION

2.11.3.4.1 CONTRACTOR shall provide:

- Overall free Area: 300 m^2 (designed for 500 ton) – Dimensions at least 15 x 20 m^2;
- The free area shall be located within a Non-Hazardous Zone so called “secondary-HISEP™ lay-down area” covered by fixed crane provided by CONTRACTOR;
- The area shall be covered by FPSO offshore crane capable to make an offshore lifting operation of maximum 25 ton;
- Proper means (cranes, mono-rails, skidding, crawlers, slings, rigging, etc.) for the installation/de-installation of equipment shall be available. The heaviest piece of equipment to be handled is 25 ton;
- For lifting purposes, It shall be considered that the maximum dimensions of each module are length of 15 m, width of 5 m and height of 3 m;
- The modules of Power Control Module (PCM) may be stacked in 2 levels;
- The “secondary-HISEP™ lay-down” if located adjacent to the FPSO main lay-down area shall be provided with structural barriers to avoid damaging the HISEP™ containers during any material handling operations;
- Dedicated team and infrastructure to support all HISEP™ installation services in the Floating Production Unit (FPU), including but not limited to cable laying, scaffolding assembly, cable interconnection and termination, cargo handling, equipment installation and fastening, etc.

2.11.3.5 PIPING FACILITIES

2.11.3.5.1 CONTRACTOR shall provide the following infrastructure from Unit facilities to Secondary-HISEP™ Lay-Down Area:

- Service Air Supply: 400 scfm @ 100 psi;
- Fresh Cooling Water Supply: 200 m^3/h @ 32 ºC;

- Instrument Air, Nitrogen, Pneumatic Fluids;
- Location of supplies in the Secondary HISEP™ lay-down area shall be mutually agreed during early stage of the detailed design.

The utilities supply data informed in this item 2.11.3.5.1 shall be confirmed during detailed design.

2.11.3.6 ELECTRICAL AND INSTRUMENTATION FACILITIES

2.11.3.6.1 CONTRACTOR shall provide 16 MVA (13,6MW @ 0.85" power factor) in high voltage to drive subsea pumps and an additional "1.2" MW in low voltage to feed the auxiliary and control equipment for the first HISEPTM connected to the FPSO, totalizing "14.8"MW power demand.

2.11.3.6.2 CONTRACTOR shall provide additional 16 MVA (13,6MW @ 0.85" power factor) to drive the subsea pumps in high voltage and an additional "1.2" MW in low voltage to feed the auxiliary and control equipment for the second HISEPTM connected to the FPSO, totalizing "14.8" MW power demand. This additional power supply might be complemented using part of the electrical load of the water injection pumps, produced water system and/or oil offloading pumps, if necessary, to be defined by PETROBRAS during Unit operation lifetime. CONTRACTOR shall consider that this additional 16 MVA (13,6MW @ 0.85" power factor) in high voltage and 1.2 MW in low voltage are conditioned to power availability based on the actual operation mode during the operational phase. CONTRACTOR do not need to increase the sizing of the operation capacity of the electrical power generation system due to the above-mentioned requirement of “additional 16 MVA (13,6MW @ 0.85" power factor) power factor” for high voltage and 1.2 MW for low voltage.

2.11.3.6.3 CONTRACTOR shall provide the following infrastructure (circuit breakers, cables, supports, junction boxes, etc.) from LER to Secondary-HISEP™ Lay-Down Area:

- 02 (two) high voltage (HV) circuit breakers to protect HISEP™ feeder cables and HISEP™ VFDs input transformers: 7.7 MVA – Voltage: the same of main electrical bus - 3 phases - 60Hz each, for HISEP™;
- 01 (one) high voltage (HV) circuit breakers to protect HISEP™ feeder cables and HISEP™ transformer: 15.4 MVA – Voltage: the same of main electrical bus - 3 phases - 60Hz for FPSO “X”’s HISEP™;
- Redundant cabling (2x3off) for from HV Circuit Breakers to an Electrical Remote Termination Unit for MODBUS communication between HISEP™ VSDs and HV Circuit Breaker;
- Main Power: 02 (two) junction boxes with 7.7 MVA – Voltage: the same of main electrical bus - 3 phases - 60Hz each for HISEP™;
- Main Power: 01 (one) junction box with 15.4 MVA – Voltage: the same of main electrical bus - 3 phases - 60Hz for HISEP™;

- Auxiliary Power for HVAC: 02 (two) junction boxes with 400-690V – 400 KW each;
- Auxiliary Power for control: 02 (two) junction boxes with 110-230V – 500 KW each;
- UPS: 02 (two) junction boxes with 110-230V – 50 KW each.

2.11.3.6.4 CONTRACTOR shall provide the following infrastructure (cables, supports, junction boxes, etc.) from Secondary-HISEP™ Lay-Down Area to Riser Balcony Area:

- HV junction box at secondary-HISEP™ lay-down area (02 off) + HV electrical cabling (02 off) + HV junction box (02 off) at riser balcony positions: 7.7 MVA – 30 KV – 33kV operational voltage/45 kV insulation voltage – 3 phases - 60Hz each for HISEP™. Electrical Cable shall be designed by CONTRACTOR during execution phase.
- HV junction box at secondary-HISEP™ lay-down area (01 off) + HV electrical cabling (01 off) + HV junction box (01 off) at riser balcony positions: 15.4 MVA – 30 KV – 33kV operational voltage/45 kV insulation voltage – 3 phases - 60Hz each for FPSO "X"'s HISEP™. Electrical Cable shall be designed by CONTRACTOR during execution phase.
- LV junction box at secondary-HISEP™ lay-down area (04 off) + LV electrical cabling (04 off) + LV junction box (04 off) at riser balcony positions. Electrical Cable specification: 4 cables x 4 conductors x 16 mm2, 1.8/3 kV, Type: Twisted, Screened, Armored Quad. Junction Box insulation voltage 3 kV.
- Fiber Optic junction box at secondary lay-down (06 off) + Fiber Optic cabling (06 off) + Fiber Optic junction box (06 off) at riser balcony positions. Fiber Optic Cable specification: Single Mode Fiber Optic Cable (ITU-G.652), 6 cables, each containing 24 individual fibers rating 9/125 µm, wavelength 1550 nm.

NOTE 1: HV, LV and FO junction boxes as well as TUTU plate distance from the umbilical shall be 1 m maximum. The final layout shall be agreed with PETROBRAS.

2.11.3.6.5 CONTRACTOR shall also provide tubing for the barrier fluid HPU from secondary-HISEP™ lay-down to riser balcony area.

2.11.3.6.6 CONTRACTOR shall consider scope listed in item 8.5 (integration between containers and FPSO CSS at Central Control Room).

2.11.3.6.7 CONTRACTOR shall provide proper means for hard-wire signals and serial links to FPSO facility control system to secondary-HISEP™ lay-down area.

2.11.3.7 CHEMICALS AND HYDRAULICS FLUIDS

2.11.3.7.1 Required pressure at top of riser and flowrates per well for the subsea chemical injection in HISEP™ is presented in Table 2.11.3.7.1. During execution phase, PETROBRAS will confirm these values.

Table 2.11.3.7.1– Subsea Chemicals Requirements For HISEP™

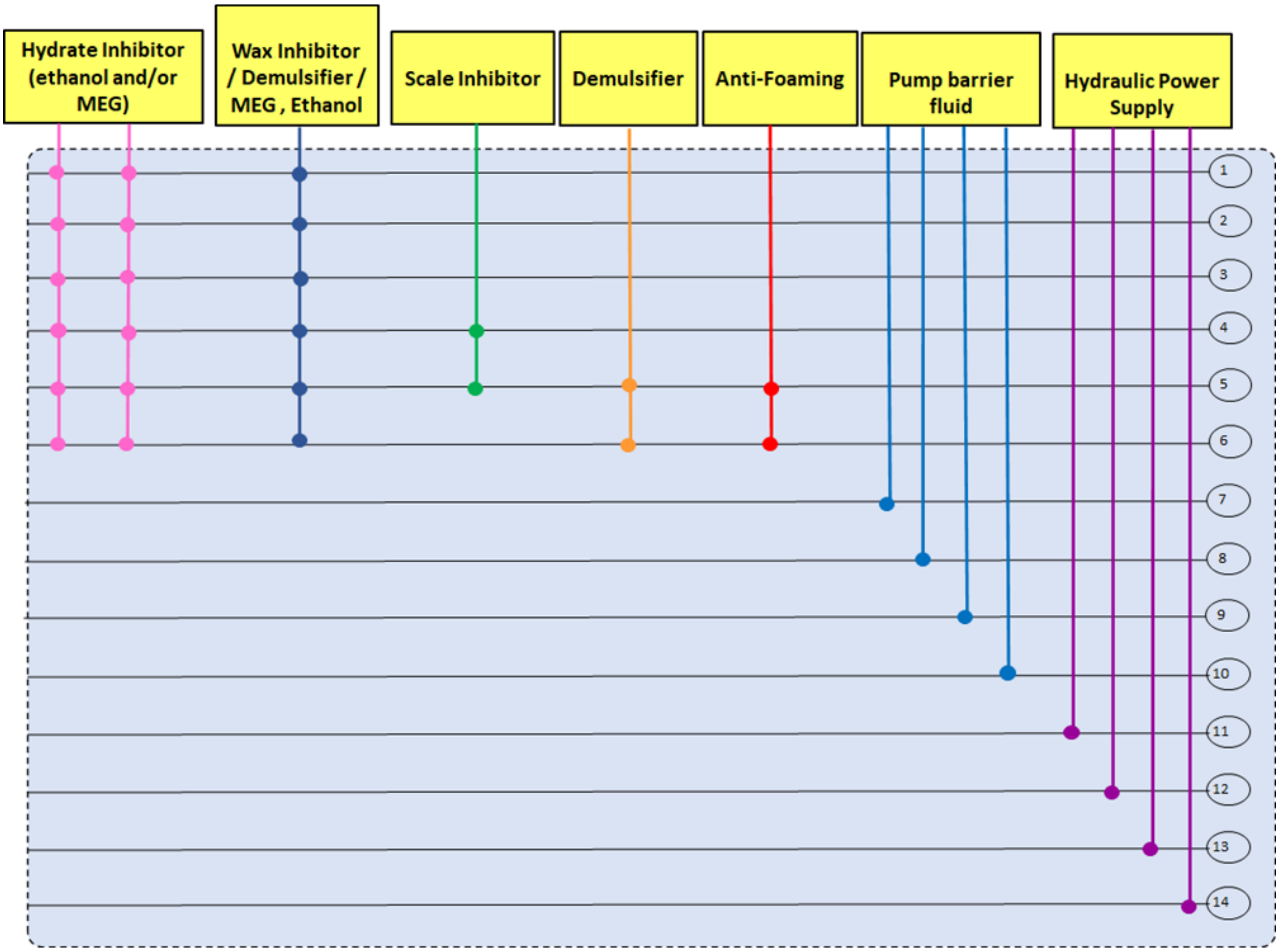
Product	Injection Point	Pressure at top of riser/umbilical (bara)	Min Flow Rate (m^3/d)	Max Flow Rate (m^3/d)
Ethanol(1)(2)	HISEP™	350	6.8	68.0
MEG(1)(2)	HISEP™	350	3.2	32
Anti-foaming(3)	HISEP™	350	0.3	4.8
Demulsifier(3)	HISEP™	350	0.2	3.2
Scale Inhibitor(3)	HISEP™	260	0.3	7.2
Wax Inhibitor/Solvent(3)	HISEPTM	370	0.4	4.0

NOTE 1: Flowrates calculated for two tube/hose of umbilical.

NOTE 2: 4 (four) tubes/hoses will inject simultaneously. Consequently, the maximum flowrate for this service is 136 m^3/d per umbilical. HISEP may use 2 (two) umbilicals simultaneously. Overall maximum simultaneous flow rate 272 m^3/d. The flow rate for one well as per table 2.8.20 shall be added to the flow rate for HISEP for the overall ethanol demand.

NOTE 3: flowrates calculated for each tube/hose of umbilical.

2.11.3.7.2 For each one of the 4 production selected slots selected, CONTRACTOR shall provide, besides regular Chemical Routing Panel mentioned in item 2.8, another Chemical Routing Panel with the configuration presented in Figure 2.11.3.7.2. The routes of “Pump Barrier Fluid” and “Hydraulic Power Supply” connect “secondary-HISEP™ lay-down area” to riser balcony area.



Umbilical tube/hose	Chemicals						
	Hydrate Inhibitor	Wax Inhibitor / Demulsifier / MEG or Ethanol	Scale Inhibitor	Demulsifier	Anti-foaming	Pump Barrier Fluid	Hydraulic Power Supply
1	X	X					
2	X	X					
3	X	X					
4	X	X	X				
5	X	X	X	X	X		
6	X	X		X	X		
7						X	
8						X	
9						X	
10						X	
11							X
12							X
13							X
14							X

Figure 2.11.3.7.2 - Chemical Routing for HISEP™ Production Slots

2.11.4 SAFETY REQUIREMENTS

2.11.4.1 CONTRACTOR shall provide all safety equipment needed for this room in accordance with applicable rules and standards, including but not limited to: fire detection, gas detection at air intakes, manual alarm call point (MAC), fire extinguishers, telecommunication means (PA speakers, telephone), safety signaling. Fire/gas detectors and MAC shall be hardwired to the F&G System.

2.11.4.2 Consequence analysis to be performed by CONTRACTOR, such as fire propagation study, explosion study and gas dispersion for air intakes, shall take into consideration the PCM module location to assess impacts of accidental loads on this module, according to requirements of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

2.12 ENERGY EFFICIENCY & ATMOSPHERIC EMISSIONS

2.12.1 CONTRACTOR shall comply with "Zero Routine Flaring by 2030" initiative of the World Bank (https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030). This requirement applies for flaring and hydrocarbon venting from process plant. It does not apply for venting of cargo tanks neither flare pilots. Emergency conditions and safety reasons shall not be considered "routine".

2.12.2 FUGITIVE EMISSIONS

2.12.2.1 Valve specifications shall comply with the following ISO 15848 requirements:

- tightness class = BH;
- endurance = CC1 (control) or CO1 (on-off);
- temperature = according to temperature range;
- test pressure = according to valve pressure rate;
- number of stem seal adjustments = maximum of 1 (one),

where the handled fluid has at least one of the characteristics below:

- methane and/or NMHC (Non-Methane Hydrocarbon) content higher or equal to 20% mass;
- BTEX content higher or equal to 1 % weight;
- benzene content higher or equal to 1 % vol.

2.12.2.2 Pump seal specifications shall comply with API 682 requirements where the handled fluid has at least one of the characteristics below:

- methane and/or NMHC (Non-Methane hydrocarbon) content higher or equal to 20% mass;
- BTEX content higher or equal to 1 % weight;
- benzene content higher or equal to 1 % vol.

2.12.3 During the execution phase CONTRATOR shall provide 18 months after LOI, only for information, Energy Efficiency report(s) having the following analysis during FPSO design phase, after issue of HAZOP report:

- Analysis of the use of mechanical energy from streams (e.g. turboexpander, hydraulic turbines);
- Optimization of heat exchange processes;
- Analysis of application of VSD;
- Internal process plant gas recirculation;
- Optimization of electrical consumption for liquid and gas transfer equipment.

2.12.4 In case of speed variation solutions for pumps capacity control, hydraulic variable speed drive (HVSD) or variable frequency drive (VFD) shall be adopted.

3 UTILITIES

3.1 GENERAL

3.1.1 This item describes the minimum requirements and specifications that shall be applied to utility systems and equipment of the Unit.

3.2 SEAWATER LIFT SYSTEM

3.2.1 A Sea Water Lift System shall be installed to supply seawater to the deaerated water injection system, to the production plant cooling water system and to meet other Unit's needs. For seawater characteristics, CONTRACTOR shall consider sea water composition in item 3.2.9 and METOCEAN DATA (see item 1.2.1). For seawater temperature, CONTRACTOR shall consider p95 temperature at each water depth.

3.2.2 The seawater lift system shall be designed in order to supply, besides all other consumption requirements, fresh/sea water to fill the subsea system (riser and flow lines) before pressurization and leak test.

3.2.3 Ionized chlorine shall be injected at the inlet of the seawater lift system, to avoid fouling or marine growth.

3.2.4 There shall be modules of independent electrochlorination cells, including a stand-by module, allowing isolation for maintenance without dosage interruption for consumers.

3.2.5 CONTRACTOR is responsible to supply the ionized chlorine to be used onboard. To control the injection, according to demand, the residual chlorine content shall be monitored through the redox potential, which shall be between 0.5 and 1 mg/L. The design shall define the monitoring point to assure the entire system protection.

3.2.6 For installation/maintenance purposes, the Unit shall be designed to install and repair the intake water extension hose in the final location offshore.

3.2.7 Sea Water Lift pumps may be dry mounted or submerged types. For acceptable vendor list for Submerged Electric Sea Water Lift Pumps, see item 19.1.1.8.

3.2.8 During project execution phase, CONTRACTOR shall evaluate the seawater intake depth in order to reduce seawater intake temperature and achieve lower organic residual content. For each seawater intake, CONTRACTOR shall provide an extension hose with length at least 100m below hull base line.

3.2.9 Seawater Composition:

Table 3.2.9A: Seawater Composition

SEAWATER ANALYSIS	
pH	8.45
Conductivity	5,800 µmho/m
K^+	500 mg/L
Na^+	12, 000 mg/L
Ca^{++}	500 mg/L
Mg^{++}	1,700 mg/L
Ba^{++}	<1 mg/L
Sr^{++}	9 mg/L
Fe total	<1 mg/L
CO_3^{--}	31 mg/L
HCO^-	101 mg/L
NO_3^-	<1 mg/L
Cl^-	21,347 mg/L
SO_4^{--}	2,800 mg/L
Salinity	35,177 mg/L (as NaCl)
Total suspended solids	2.0 mg/L
Oxygen content	7 mg/L
Turbidity	0.20 FTU
Silt density index	5.1
m-SRB	25 MPN/mL
Aerobic bacterias	7,500 MPN/mL
Facultative bacterias	44 CFU/mL

MPN – Most Probable Number CFU – Colony Formation Unit

Table 3.2.9B: Seawater Particle Size Distribution

PARTICLE SIZE DISTRIBUTION	
SIZE RANGE (µm)	NUMBER OF PARTICLES (part./mL)

3 to 5	424.1
5 to 7	151.1
7 to 10	103.4
10 to 15	52.8
15 to 30	30.5
30 to 50	5.8
50 to 100	1.2
100 to 250	0.0
TOTAL	**769.2**

NOTE 1: This information does not take into consideration the vessel and UNIT overboard lines interferences, e.g., temperature, particles and others.

NOTE 2: First filter downstream sea water lift pumps shall be specified for 1,000 µm.

3.3 COOLING WATER SYSTEM

3.3.1 For fluids that classify the area, for cooling system applicable to turbogenerators, lube oil, biodegradable lube fluids, oil based hydraulic fluid and produced water, cooling with seawater is not acceptable. Exception is made for fire water pumps cooling system.

3.3.1.1 Acceptable alternatives are fresh water closed cooling system or air coolers. Other alternatives (e.g. double plate heat exchangers for lube oil cooling) might be proposed, subject to Petrobras approval.

3.3.2 A closed freshwater cooling system shall be provided to supply cooling medium to the Unit systems as follows:

- Independent cooling medium for marine and utilities systems located within machinery spaces and accommodation;
- Independent cooling medium for topsides hazardous area consumer (gas-cooling water or oil-cooling water heat exchangers). This system cannot be used for cooling any topsides non-hazardous area (E-house, Turbo-Generators, Water Injection, etc.);
- For topsides non-hazardous consumers the following is acceptable to be adopted if allowed by CS: (i) air cooling, (ii) utilization of cooling medium for marine and utilities system or (iii) direct sea water open circuit provided will not cool any hydrocarbon fluid.

3.3.3 For heat exchangers design, see item 10.3.

3.3.4 CONTRACTOR shall fulfill all Brazilian Administration regulations issued by Environment Ministry (“Ministério do Meio Ambiente”), through its *CONAMA Resolução Nº357/2005* and *CONAMA Resolução Nº430/2011*.

3.3.5 CONTRACTOR shall provide a temperature transmitter with high temperature alarm to monitor sea cooling water overboard discharge temperature.

3.4 HEATING MEDIUM SYSTEM

3.4.1 A Heating Medium System shall be provided to recover the heat from the turbines exhaust gas and, if applicable, from other systems.

3.4.2 For cogeneration, each turbogenerator shall have its own individual Waste Heat Recovery Unit (WHRU). For heat exchangers design, see item 10.3.

3.4.2.1 Cancelled.

3.4.3 For combined cycle power generation, each gas turbogenerator shall have its own individual steam generator and Waste Heat Recovery Unit (WHRU). WHRU coil shall be segregated from the steam loop, serving as a backup source of heat to the process in case of steam system outages. WHRUs shall be capable of providing the full amount of heat required by the FPSO at peak thermal demand conditions. The Heat Recovery Steam Generator (HRSG) or Once Through Steam Generator (OTSG) shall use the exhausted gases from gas turbines.

3.4.3.1 The routing of steam through FPSO shall be minimized for safety reasons. Steam shall be generated at HSTG/OTSG and it shall be treated, conditioned and used only to steam turbogenerators and to transfer heat to hot water heating medium.

3.4.3.2 The steam generator shall be capable of running dry indefinitely, and the gas turbogenerators shall run even with its steam generator out of service.

3.4.3.3 Hot water heating medium shall be available even if steam turbine is not available; steam turbine by-pass shall be available.

3.4.3.4 CONTRACTOR and Steam Generator/WHRU Vendor shall pay special attention to the presence of sulfur in fuel gas/diesel, which might cause acid corrosion in case of condensation. The minimum margin from metal surface temperature to dew point shall be 10°C.

3.4.3.5 The steam line shall be designed considering a minimum amount of flanged connections, basically considering it on equipment nozzles. The steam lines routing shall be far away from escape routes and areas with permanent presence of people, in cases it is not feasible, flanged connections shall not be used and line personal protections shall be provided. In other areas with presence of people for maintenance or operations close to steam lines means of personal protection against contact with lines and vapor jets, such as thermal insulation and flange covers, shall be provided.

3.4.3.6 CONTRACTOR is responsible to provide the laboratory equipment to perform the necessary analysis associated to the water quality used on combined cycle system.

3.4.3.7 CONTRACTOR is responsible to provide the chemical products required for combined cycle system operation.

3.5 DRAIN SYSTEMS

3.5.1 CONTRACTOR shall design drain system to collect and convey Unit drained liquids to an appropriate treating and/or disposal system in such a way as to protect personnel, equipment and to avoid environmental pollution. Drainage system shall comply with *NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11* and MARPOL requirements. The effluents shall be segregated, treated (TOG lower than 15 ppm) and monitored through dedicated TOG analyzer(s), previously to being discharged overboard.

3.5.2 Drains systems from hazardous areas shall be collected and routed completely separated from the non-hazardous areas drains.

3.5.3 Drain systems shall be segregated into specific systems, each designed for a particular type of stream, with no interconnection between the systems. Further to this, when appropriate, features such as seal loops and air gaps shall be used to segregate areas served for the same drain system.

3.5.4 Process vessels, piping or other sources containing hazardous liquids which need to be drained for interventions/maintenance/inspection reasons and may not be drained directly to atmosphere without undue risk to personnel, environment or assets from release of toxic vapors, shall be connected to a permanent and contained drain system (closed drain). By toxic vapors CONTRACTOR shall consider streams containing poisonous substances at critical concentrations, such as, but not limited to H2S and benzene. For critical concentrations refer to Brazilian Regulations (NR-15) and API RP 55. Pig launchers and receivers shall be drained to a closed drain system, even though the fluids are not considered hazardous.

3.5.5 Instrument drains shall be accounted for in hazardous area classification. The handling of instrument drains shall be on a case by case analysis (special attention for poisonous substances at critical concentrations), however in all cases, the instrument drain piping or tubing shall be arranged so that the draining liquid is visible to the operator when the instrument is being drained.

3.5.6 The drainage system shall follow ISO 13702 and additionally be designed to handle credible spills, rainwater and coincident with deluge and/or fire-fighting activities.

3.5.7 Means for oil containment and drainage shall be considered at the main deck and in each section of upper riser balcony (perimeter) including connections and SDVs in the production lines and gas injection lines in order to prevent oil, chemical products or oily water spill on the sea. BSDVs shall have independent and segregated containment and drainage of adjacent areas (such as main deck, for instance).

3.5.8 Drain piping shall be designed according to NORSOK P-002, clause 7.2.

3.5.9 The location of the drain pits and drain boxes shall take into consideration the vessel motion (roll and pitch) and the ship trim to avoid liquid accumulation. Open drain piping diameters shall have at least 3” to avoid clogging.

4 MATERIALS AND CORROSION MONITORING

4.1 GENERAL SELECTION RULE

4.1.1 CONTRACTOR must perform the material selection as oriented in ISO 21457, with the additional requirements and limitations herein stated.

4.1.2 Material selection must be compatible with the Unit design lifetime, as stated in item 1.2.2.1.

4.2 MATERIAL SELECTION REPORT

4.2.1 CONTRACTOR must issue a Material Selection Report for the UNIT as described in ISO 21457. This report must explicitly include all the piping and valves (as per the piping specifications) and the equipment of the UNIT (all TAGs).

4.2.2 The Material Selection Report must also include due considerations regarding corrosion allowances, predictions for regular replacements, corrosion protection systems applied (e.g. cathodic protection, scavengers, inhibitors), as well as the efficiencies of the protection systems applied.

4.2.3 The Material Selection Report must include General Corrosion Studies, which must explicit the corrosion models and the corrosion allowances calculated for the equipment and piping systems.

4.2.4 The Material Selection Report must include Corrosion Sensibility Studies, that must evaluate the effect of operational transients and temporary conditions (e.g. temporary by-passes or shut down of processing units), the effect of possible deviations from normal operating conditions (higher temperature, lower pH or higher water cut, for example) and the effect of failure of the corrosion protection systems. Temporary conditions must include upset conditions such as units malfunction (e.g. dehydration and gas sweetening units malfunction).

4.2.5 All the data necessary to perform the material selection, including the General Corrosion Studies, The Corrosion Sensibility Studies, and the Low Temperature Effect Studies, must be included in the Material Selection Report.

4.3 SPECIAL CONSIDERATIONS ABOUT MATERIAL SELECTION

4.3.1 LOW TEMPERATURE SERVICE

4.3.1.1 CONTRACTOR must perform the selection with due considerations regarding low temperature due to supercritical CO_2 depressurization and the compatibility of CO_2 with non-metallic materials and high strength ferritic materials. For materials selection purposes, CONTRACTOR must determine the lower design temperature (LDT) or alternatively the minimum allowable temperature (MAT) for all unfired pressure vessels, heat exchangers, piping, piping components and valves (including control valves) or rotating equipment containing compressed gas (hydrocarbon or CO_2) or liquefied gas.

4.3.1.2 CONTRACTOR must also take measures to prevent the equipment from being at temperature below the LDT or alternatively ensure the equipment metal temperature is not below the appropriate MAT, at any given operating pressure. CONTRACTOR must consider scenarios in which equipment temperature can drop such as blowdowns, as well as scenarios of subsequent repressurization of equipment.

4.3.1.3 LDT or MAT must be specified as the lowest of the following values:

- The minimum operating temperature;
- The minimum startup/shutdown, test or upset temperature while at normal operating pressure;
- The minimum temperature during depressurization or repressurization.

4.3.1.4 CONTRACTOR must also take in account the low temperature effects of sudden fluid depressurization and leakage in connections (e.g. flanges, threaded connections), since low temperature may affect the selection of the parts (e.g. low temperature bolting materials shall be selected).

4.3.2 FLUID COMPOSITION AND CONTAMINANTS

4.3.2.1 Materials selection must be carried out based on the fluid compositions, as described in Chapter 2 of this General Technical Description, including all of the contaminants therein cited (e.g. CO_2 content, H_2S content, H_2O content, BS&W) and the worst scenarios.

4.3.2.2 Materials selection shall also meet the inlet fluids characteristics and normal operating conditions below:

- Produced gas CO_2 content: up to 60% mol;
- Produced gas H_2S content: up to 60 ppmv;
- Produced gas H_2O content: up to saturated;
- BS&W: up to 95%;

- Chloride (Cl-1): up to 193,000 ppm;
- Minimum pH: 4.3.

4.3.3 H_2S SERVICE

4.3.3.1 Where H2S is expected as a contaminant in the fluids, all materials shall meet the requirements of ISO 15156 for the lowest anticipated pH and the highest H2S partial pressure (carbon steel shall be compatible with Sulfide Stress Cracking (SSC) region 3 of ISO 15156-2 as a minimum, with due consideration regarding the lowest pH).

4.3.3.2 All welding procedures will have to be qualified taking into account requirements of piping/equipment construction codes plus the applicable requirements of ISO 15156.

4.3.3.3 Maximum hardness as prescribed by ISO 15156 for both base material and welds must be ensured to all vessels, equipment, piping, fittings and accessories. Dehydration of gas, organic coatings, use of corrosion inhibitors or even H2S scavengers will not, in any case, be accepted as measures to relax the requirement to use H2S resistant materials, if the operational conditions are categorized as sour in accordance with ISO 15156 (all parts). Operational conditions must include upset conditions such as, but not limited to, dehydration and H2S removal systems malfunction.

4.3.4 EQUIPMENT MANUFACTURED IN DSS OR SDSS

4.3.4.1 Any part of any equipment that is manufactured from any grade of duplex stainless steel (DSS) or super duplex stainless steel (SDSS) that is hot formed during any stage of the equipment's manufacturing shall receive a solution annealing heat treatment after forming in order to reestablish its mechanical and corrosion resistance properties.

4.3.4.2 The solution annealing heat treatment shall be performed as per the material specification, and shall be followed by fast cooling, so that no precipitates are formed. The effectiveness of the heat treatment shall be demonstrated by performing an *in situ* optical metallography (portable equipment). Acceptance criteria shall be as per ISO 17781.

4.4 MINIMUM MATERIAL GRADE SELECTION

4.4.1 CONTRACTOR must also comply with the following minimum materials specifications, for the indicated portions of the topsides process facilities. Deviations from the materials specifications mentioned must be submitted for PETROBRAS approval, and shall always be fully justified based on technical reasons.

4.4.1.1 Piping that will connect the rigid risers (usually starting at the lower riser balcony) to the top side piping (at the upper riser balcony), will cross the splash zone of the unit, and therefore shall be designed with due consideration regarding the hydrogen charging caused by the cathodic protection potential (from both the hull and the riser protection systems) and the extreme corrosivity of this area. As such, the material of construction for these piping (a.k.a. "hard pipes") shall be carbon steel (with external corrosion allowance of 6 mm minimum) with internal overlay of Inconel 625 (with 3 mm thickness minimum). The hard pipe system shall be externally coated with polychloroprene as per ISO 18797-1. Field repair of the polychloroprene coating shall also be performed as per the same standard.

4.4.1.2 From the top of the hard pipe up to HP separator , away from the splash zone, where cathodic protection potential does not affect the material, either of the options below may be followed:

a) Carbon steel with Inconel 625 or 825 cladding (min. cladding thickness 3 mm);

b) Duplex (22Cr) or Super duplex stainless steel (25Cr).

4.4.1.3 Heat exchangers:

- Shell: Carbon steel with 625 or 825 cladding (3 mm) or weld overlay. Accepted alternative:
- carbon steel with 3 mm corrosion allowance, if the cooling/heating fluid is not corrosive;
- Super duplex 25Cr or duplex 22Cr, when corrosion studies have shown it must be suitable for service and there is no risk of crevice corrosion, stress corrosion cracking and/or corrosion under deposits.
- Tube: Super duplex 25Cr, duplex 22Cr, or Titanium.

4.4.1.4 Choke and downstream lines must be compatible with depressurizing temperature during well startup with gas segregation in the riser top. Minimum temperature to be considered downstream the choke is at least -50°C. Depressurizing temperatures may also occur at service lines.

4.4.1.5 Separation (including HP separator and Free water KO drum) and degassing vessels must follow (a) or (b) or (c) below:

a) Carbon steel with Inconel 625 or 825 cladding (min. cladding thickness 3 mm);

b) Carbon steel with 904L overlay;

c) Duplex (22Cr) or Super duplex stainless steel (25Cr), when corrosion studies have shown it must be suitable for service and there is no risk of crevice corrosion, stress corrosion cracking and/or corrosion under deposits.

4.4.1.6 Saturated Gas lines must follow (a), (b) or (c) below, taking into consideration operating parameters such as temperature and chlorine content:

a) Carbon steel with 625 or 825 (3 mm) clad;

b) Duplex 22Cr or Super duplex 25Cr;

c) AISI 316L with external coating if temperature greater than 60°C.

4.4.1.7 K.O. Drum & Scrubbers:

- K.O. Drum & Scrubbers (upstream and including Gas Dehydration Unit): Carbon steel with AISI 316L, Inconel 625 or 825 cladding (3 mm) or 904L weld overlay;
- K.O. Drum & Scrubbers (downstream Gas Dehydration Unit): Carbon Steel according to item 4.3.3, with 3mm corrosion allowance. 904L is an acceptable alternate material;
- All equipment, piping and accessories of TEG Unit submitted to contact with wet gas plus CO_2 and H_2S or TEG and presence of Water, CO_2 and H_2S must consider Corrosion Resistant Alloy as a basic material;
- At least the following equipment are included with such characteristics: Gas Scrubber, Coalescer Filter, Absorber Column, Flash Vessel, TEG Filters, Reboiler, Surge Vessel, Stahl Column.

4.4.1.8 Seawater lines upstream deaerator and Produced Water upstream Solid Removal Unit:

- Carbon steel with internal coating or Fiber Reinforced Plastic (FRP);
- The use of alternative materials must take into consideration operating parameters such as temperature and chlorine content;

  NOTE: SRU Package lines must not be internally coated. In this case, as an alternative to FRP, lines may be of superduplex material;

  NOTE: In case of polyethylene (PE) be used, CONTRACTOR must reinforce quality control of applied coating.

4.4.1.9 Water injection lines downstream deaerator and Produced water lines downstream Solid Removal Unit:

- Superduplex or Carbon steel with 625 clad (3mm) considering the operational limits of pressure, temperature and water composition for each material. Oxygen contamination must be taken into account for materials selection. Oxygen scavenger must not be taken into consideration for material selection due to uncertainties of produced water compatibility.
- From Deaerator to SW Booster Pumps, FRP material may be used, considering the pressure rating.

4.4.1.10 For the LP Gas Compressors, construction materials must be selected considering the following contents on the process gas:

- CO_2: up to 60% mol (or higher, as per process simulations);
- H_2S: up to 200 ppmv (or higher, as per process simulations);
- H_2O: up to saturated.

4.4.1.11 For the VRU compressors, construction materials must be selected considering the following contents on the process gas:

- CO_2: To be determined by simulation;
- H_2S: To be determined by simulation;
- H_2O: up to saturated at all conditions.

4.4.1.12 For the Booster/Injection Compressors, construction materials must be selected considering the following contents on the process gas:

- CO_2: at least 60% mol (or higher, as per process simulations);
- H_2S: at least 200 ppmv (or higher, as per process simulations);
- H_2O: saturated during commissioning.

4.4.1.13 For the CO_2 Compressors, construction materials must be selected considering the following contents on the process gas:

- CO_2: at least 85% mol (or higher, as per process simulations);
- H_2S: at least 375 ppmv (or higher, as per process simulations);
- H_2O: saturated during commissioning.

4.4.1.14 In case CONTRACTOR decides to use stainless steel material for pneumatic and hydraulic instruments and transmission lines, including its connections (junction boxes), CONTRACTOR must use ASTM A269 Gr TP 316L (or EN 1.4435) with minimum molybdenum content of 2.5% Mo. As a substitute CONTRACTOR may select other stainless steel material with higher corrosion resistance, such as 904L stainless steel grade or superduplex and Monel 400 or Inconel 625 for seawater application. Tubing must be electrically isolated from carbon steel supports and materials to avoid galvanic corrosion.

4.4.1.15 CONTRACTOR must consider the marine atmosphere (CX for atmospheric zone and IM-2/Im1 for splash and immersion zone according to ISO 12944-Part 2) for the design of external coating of piping and equipment. Carbon steel piping provided with thermal insulation must also be painted in order to avoid corrosion in case of liquid accumulation.

4.4.1.16 CONTRACTOR must consider flowrate regime (stagnant, intermittent or continuously flowing) when evaluating corrosivity and selecting piping and equipment material.

4.5 CORROSION MONITORING

4.5.1 Due to the presence of contaminants in the oil, CONTRACTOR provide means to monitor the corrosion on piping and equipment.

4.5.2 As a minimum, corrosion monitoring equipment shall be provided in the points along the produced oil, gas and water flow, as follows:

4.5.2.1 Gas injection:

- Coupon and electrical resistance at a common point on reinjection compressor discharge, in order to monitor subsea and well material;
- Non-intrusive monitoring at a common point on reinjection compressor discharge, in order to monitor carbon steel piping on topsides;
- Placement of corrosion monitoring must guarantee exposure to flow conditions irrespective of the slots/risers being used for injection.

4.5.2.2 Water injection lines:

- Linear polarization resistance (LPR) sensor, electric resistance sensor (ER) and galvanic sensor provided on the common water injection header installed downstream of water injection pumps;
- Oxygen analyzer downstream water injection pumps;
- Placement of corrosion monitoring must guarantee exposure to flow conditions irrespective of the slots/risers being used for injection.

4.5.2.3 Produced water lines:

- Linear polarization resistance (LPR) sensor, electric resistance sensor (ER) and galvanic sensor provided on the produced water piping downstream produced water treatment and upstream mixing point with treated seawater;
- The analyzer shall be installed upstream the solid removal unit and shall be connected to process interlock system. This interlock actuation will be defined later on by PETROBRAS. The analyzer shall have an installed stand-by instrument.

4.5.2.4 Not applicable.

4.5.2.5 Production chokes:

- Probe for erosion evaluation installed upstream of the production choke and coupon of mass loss installed downstream of the production.

4.5.3 Lines and equipment built in CRA (Corrosion Resistant Alloys) or internally coated on CRA can be considered as exempted from monitoring the corrosion, unless otherwise cited in item 4.5.2 above.

4.5.4 The coupons, ER/LPR probes shall be tangential type if they will be installed in the “PIG” path.

4.5.5 All ER and LPR probes shall be provided with automated transmission of corrosion data to the Unit supervisory system. The maximum scan time allowed for those transmitters shall be 6 hours.

4.5.6 The places for installing the monitors shall be according the criteria below:

- At least two points of access, one for coupon and one for probes, spaced at least 500 mm;
- Downstream of corrosion inhibitors injection.

4.5.7 All coupons and probes access fitting bodies shall be high pressure type, regardless of the operating pressure, welded to the pipe.

4.5.8 PETROBRAS highlights the following:

- Coupons positioning in horizontal section should be at 6 o'clock position and optionally at12 o'clock position;
- Enough clearance and access shall be provided to enable the coupons exchange, with no impact to Unit operation.

4.5.9 Not Applicable.

5 ARRANGEMENT

5.1 GENERAL

5.1.1 In the developing of the facility layout, the following Health, Safety and Environment (HSE) points shall be considered, as a minimum:

- Outputs of risk assessments shall be incorporated into the layout development and optimization;
- Maximize natural ventilation;
- Minimize escalation of ignited flammable or toxic release;
- Minimize probability of ignition;
- Continuous permanent ignition sources shall always be installed in non-classified areas;
- Layout shall provide the maximum practical separation between: Classified Areas vs. Non Classified Areas, Systems with hydrocarbon-containing inventory vs. potential sources of ignition;
- The risk of loss of containment should be minimized by minimizing the possibility of mechanical damage. Protecting hydrocarbon equipment from dropped objects should be a main consideration;
- Provision of suitable means for escape (whether or not these are regularly manned), temporary refuge and evacuation. Stairs shall be used as the mainly way to escape from areas. The use of ladders shall be minimized. Note: In accordance with item 11.2.1 of ASTM F1166 (Standard practice for human engineering design for marine systems, equipment and facilities) angle of Inclination for Stairs shall be determined by the vertical change in height. Angles between 30º and 50° are acceptable but a stair angle of 38° is preferred;

- Proper implementation of working environment (Human Factors) guidelines, tools and techniques into the design;
- Human Factors Engineering shall be considered in the design, according to NR-17 (Ergonomics). Specific report shall be issued, according to the NR-17 (Ergonomics) and its application manual. All reports shall be issued according the Ergonomic Analysis of Work method;
- All equipment associated with emergency power (Emergency generator, emergency switchboard, storage batteries and inverters, etc.) shall be situated in non-hazardous areas, with adequate protection against fire and explosion.
- An area for temporary waste storage shall be provided, in compliance with *Nota Técnica IBAMA 01/2011* and *Resolução Conama nº 275/01*.

5.1.2 CONTRACTOR shall carry out Layout Reviews considering HSE aspects.

5.1.3 The objective of these Layout Reviews is to identify any issues associated with the overall planned layout of the topsides, utilities, marine systems and accommodations.

5.1.4 Layout review activities shall take place at different stages during the project development cycle including all changes during the course of the project. These reviews shall be conducted with a multidisciplinary team to ensure that the requirements of all disciplines have been incorporated in the layout design.

5.2 SUPERSTRUCTURE (ACCOMMODATIONS)

5.2.1 Accommodation refurbishment shall follow the “all new” philosophy as described in section 16 (MARINE SYSTEMS AND HULL UTILITY SYSTEMS). It means all systems (piping, electrical, HVAC , drainage, water, cabling, furniture, etc.) and related outfitting shall be brand new. The only exemption is steel that can be kept however fully painted.

5.2.2 Concepts for living quarters and storage areas shall comply with the CS Rules, Brazilian Regulations (NRs, especially NR 37) and safety requirements of SOLAS.

5.2.3 In addition, CONTRACTOR shall provide accommodations for PETROBRAS / partners representatives onboard as defined on Operation Contract. One of these cabins shall be 1 (one) single bed cabin, equivalent to the Offshore Installation Manager’s or the Chief Unit Superintendent’s, and the others cabins shall be for 2 persons each with bunk bed. An office and a meeting/video-conference room (as per TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED – see item 1.2.1) shall also be provided for PETROBRAS representatives onboard. Both PETROBRAS office and PETROBRAS main Fiscal cabin shall be fitted with windows at front wall of the accommodation Block.

5.2.4 The smoking area shall be an open safe area, 360 degrees open (no shelter is acceptable) to the environment with natural ventilation.

5.2.5 Galley, mess room and storage area shall comply with *Agência Nacional de Vigilância Sanitária (ANVISA)*, especially *Resolução da Diretoria Colegiada (RDC) 216/2004* *and RDC 72/2009* and their updates, with emphasis on the separation between vegetables, meat (poultry, fish and red meat), pasta and storage areas, and waste disposal.

5.2.6 The infirmary installations shall comply with NORMAM 01 CHAPTER 9, SECTION V; ANVISA, especially RDC 50/2002 and RDC 222/2018 and their updates.

5.2.7 Food waste disposal facilities shall meet the following requirements:

- Compliance with MARPOL Convention;
- Compliance IBAMA Technical Note 08/2012;
- 2 x 100% configuration for food waste disposers;
- The waste disposers shall be installed in the waste treatment area, preferably located as close as possible to the place of dumping of waste at sea and served by pipes with minimal length and curves;
- Capacity to crush any debris and leftovers from biodegradable food, including animal bones, lumps and fruit peels in general;

5.3 PROCESS PLANT

5.3.1 CONTRACTOR shall submit a maintenance and load handling plan evidencing that the arrangement of the process plant equipment, skids and accessories allows maintenance at site without affecting the production/processing capacity of the Unit according to the technical specification hereinafter considered.

5.3.2 Enough space for operational maintenance of production plant equipment shall be provided, taking into account the personnel circulation, safety and CS requirements. Human Factors Engineering shall be considered as part of this assessment.

5.3.3 CONTRACTOR shall define the height of the main process plant deck level as well as its layout. CONTRACTOR shall take into account the effects of green water, with the vessel in a maximum draft condition.

5.3.4 For the design of layout, drainage system and firefighting means of the areas reserved for storage of chemicals and gas cylinders, CONTRACTOR shall follow applicable requirements for safety, health and environment, as well as take in consideration chemical compatibility. The storage areas for chemical products used for maintenance (lube oil, grease, etc.) shall be sheltered and bounded with dedicated coamings, in compliance with Nota Técnica IBAMA 08/2012.

5.3.5 Each module shall be provided with proper means of containment with a coaming to prevent liquids falling on sea, main deck or the deck below.

5.3.6 Additionally, areas around equipment containing liquid hydrocarbons, chemicals, flammable liquids, combustible liquids or contaminated liquids shall be provided with a secondary coaming / bounding or drip pan to prevent these liquids spreading over the module.

5.4 UTILITY ROOM (ENGINE ROOM)

5.4.1 CONTRACTOR shall submit a maintenance procedure plan evidencing that the Unit arrangement for utility systems, skids and accessories allows maintenance at site with a minimum disturbance of the Unit's performance.

5.5 DIVING AREAS

5.5.1 Any facility related to diving operation shall fall under CONTRACTOR's responsibility.

5.5.2 CONTRACTOR shall provide diving stations to be used during CS underwater surveys, pull-in/pull-out operations, etc.

5.5.3 The number and location of diving stations shall be defined in accordance with NR-15 and NORMAM 15. Section 4 (Diver Launch and Recovery System (LARS)) Item 4 (Secondary Recovery) of IMCA D023 is mandatory.

5.5.4 In order to assist pull-in operations, at least two fixed stations or one movable station throughout the riser balcony shall be provided. In case of fixed stations, at least two shall be equipped in order to avoid time concerns related to diving operations. The pull-in diving stations shall be positioned considering 33 m as the maximum allowable outreach (measured from the diving bell) and diving operations at night. During operational phase, these stations may be used by PETROBRAS for riser inspections.

5.5.4.1 The areas must be large enough to accommodate all diving equipment with minimum distance between parts of 600mm. These areas shall be projected with 12m x 6m at a minimum, outside of the ship's deck. The total diving system weight is 30t. In locations where diving areas are provided, the handrail must be removable, because the system will extend through it.

5.5.5 The stations shall not interfere with the Unit facilities and operations (cargo transfers, etc.). All diving stations shall be fully equipped in accordance with the requirements listed below:

- Proper means (cranes, mono-rails, skidding, crawlers, slings, rigging, etc.) for the installation/de-installation of diving equipment on the stations shall be available. The heaviest piece of equipment to be handled is 5 t.
- Each station shall be provided with the utilities listed below:
    - Compressed air - 2 outlets for each Launch and Recovery System (LARS) (according to IMCA D023, the stations shall be provided with 2 independent LARS systems):
        - Required pressure: 7 kg/cm^2;
        - Required Outflow: 20 Nm^3/min (Approximately 2,85 m^3/min, at constant pressure of 7 kgf/cm^2), allowing ± 10% of tolerance.

- Electric power supply - electrical outlets shall be fed from different power sources and backed-up by the emergency generator:
  - two (2) electrical outlets 440V/60Hz/max 100 A;
  - two (2) electrical outlets 220V/60Hz/30 A.
    NOTE: All 440V diving power sockets shall be fed by emergency generation systems, or by panels connected to them (220V sockets).
- Fresh water supply – one outlet for cleaning diving equipment and clothes:
  - Required pressure: 1 kg/cm²;
  - Required outflow: 20 l/min.
- Communication:
  - One telephone connection for internal and external calls.

5.5.6 Access to the diving stations shall not be dependent on vertical ladders, which may require specific training for work at height and hinder evacuation of injured personnel.

5.5.7 Gas discharges (e.g. inert gas vent posts) and overboard points (e.g. slop tanks, produced water) shall not interfere with diving operations from the FPSO or Shallow Diving Support Vessel (SDSVs).

5.5.8 Sea chests and other hull openings below maximum draft line shall be provided handrails nearby to help divers work during CS inspections.

5.5.9 The underneath of the LRB (Lower Riser Balcony) shall be provided with four padeyes for each I-tube (minimum safe working load 12 t) and a handrail system in a closed pattern.

5.5.10 CONTRACTOR shall provide the necessary facilities to enable remote monitoring of the pull-in operations and risers inspections by electric ROVs (Remoted Operated Vehicle). The specification and requirements of the ROV will be informed by PETROBRAS during execution phase.

5.5.11 The diving stations location and handling plan shall be submitted to PETROBRAS for comments. See also reference document SPREAD MOORING AND RISER SYSTEM REQUIREMENTS (see item 1.2.1) for additional provisions.

5.6 HELIDECK

5.6.1 Helideck shall be suitable for landings of the helicopter types: frequent operation (S-92, S-76, AW-139, AW-189, AW-101, H175, BELL430) and eventual search & rescue operations (UH-60M, EC 225 and EC725).

5.6.2 The helideck shall be designed and located according to Brazilian Navy Regulations (NORMAM) including NORMAM 27 and CAP 437. In addition, the following international/national standards shall also be complied with:

- *ICA 63-10 Estações Prestadoras de Serviços de Telecomunicações e de Tráfego Aéreo – EPTA – DECEA*;
- *ICA 63-25 Preservação e Reprodução de Dados de Revisualizações e Comunicações ATS – EPTA – DECEA*;
- “Standard Measuring Equipment for Helideck Monitoring System (HMS) and Weather Data", HCA, Bristow Group, Bond Offshore, CHC;
- *MCA 105-2/2013 Manual de Estações Meteorológicas de Superfície - DECEA*.

5.6.3 Meteorological and ship motion data shall be transmitted to HMS (Helideck Monitoring System) in real time, through analogic or digital applicable interface.

5.6.4 CONTRACTOR shall ensure remote access to HMS, at any time, through internet. Such access shall be available in real time to PETROBRAS and Helicopter Operator Company through the same screen/system used by radio-operator of FPU. The Internet access shall be compatible with readily available browsers.

5.6.5 HMS and all related systems/sensors shall be considered emergency loads and shall operate even in case of loss of power in the main generators.

5.6.6 In addition, CONTRACTOR shall present evidence that there is no interference between Unit’s normal operation and helicopter operations.

5.6.7 To establish the safe location of the helideck, the environmental effects shall be considered, such as wind direction and velocity, as well as aerodynamic aspects (turbulence over the helideck), and the temperature rise due to exhaust gases. Hot plumes over the helideck, generally, are related to main turbo-generator exhaust outlet, however, the other equipment (for instance: emergency generators or auxiliaries and fire-fighting pumps, etc.) should also be considered in the identification of potential sources of hot gases.

5.6.8 CONTRACTOR shall present evidence that helideck final location minimizes downtime by using computational fluid dynamics (CFD) studies, considering all the aspects mentioned above. CONTRACTOR shall submit to PETROBRAS CFD studies for the evaluation of hot air flow and exhaust according to CAP 437, section 3.10. PETROBRAS recommends using Method 3 described in Norsok C-004, section 5.4: "A method using Computational Fluid Dynamics (CFD) codes to determine the acceptable level of risk for helicopter offshore operations in relation to the emission of hot gas of Turbine Exhaust Outlets - "Method 3".

5.6.9 CONTRACTOR shall paint in the helideck a codification (to be informed during execution phase) as per NORMAM 27.

6 HEATING, VENTILATION AND AIR CONDITIONING SYSTEMS (HVAC)

6.1 GENERAL

6.1.1 The air conditioning and ventilation systems shall be calculated to suit the site environmental conditions (see METOCEAN DATA). For determining the climatic design conditions (dry-bulb temperature and coincident-wet bulb temperatures – 0,4% summer cumulative frequency of occurrence), CONTRACTOR to use ASHRAE methodology (Fundamentals Handbook - Climatic Design Information – 2013 edition).

- Dry Bulb Temperature (TBS): 32ºC
- Relative Humidity: 61%
- Daily Temperature Range: 3,6ºC

6.1.2 The HVAC safety requirements shall comply with SAFETY GUIDELINES (see item 1.2.1).

6.2 HVAC SYSTEMS

6.2.1 Cooling fluids with hydrochlorofluorocarbons (HCFC) and Chlorofluorocarbons (CFC) are not acceptable. Only cooling fluids with hydrofluorocarbon (HFC) and hydrofluoro-olefin (HFO) (not flammable) are acceptable.

6.2.2 In case of application of insulation with foam injected under pressure polyurethane, it shall be provided with CFC-free.

6.2.3 The air intakes shall be placed in a safe area and, whenever possible, where the prevailing winds are favorable.

6.2.4 All air intakes shall have devices to avoid gas entrance to the inner side of protected areas.

6.2.5 All Fire Dampers and Tightness/Shut-Off Dampers shall have a manual opening means.

6.2.6 There shall be a dedicated HVAC system for batteries room. The selection and operational condition of the HVAC equipment for these rooms shall be 2x100%, always with a standby unit. The minimum airflow rate (changes per hour) shall comply with SOLA/MODU and Classification Society. The minimum airflow shall be also calculated for H2 dilution as defined in IEC 61892-7.

6.2.7 All Battery Rooms with sealed batteries and/or valve regulated lead–acid (VRLA) batteries installed shall have independent dedicated exhaust fans and air conditioning system (maximum room internal temperature 25ºC). The selection and operational condition of the HVAC equipment for these rooms shall be 2x100%, always with a standby unit. The minimum airflow rate (changes per hour) shall comply with, SOLAS/MODU and Classification Society. The minimum airflow shall be also calculated for the H2 dilution as defined in IEC 61892-7.

6.3 REFRIGERATION SYSTEM (PROVISIONS)

6.3.1 Cooling fluids with HCFC and CFC are not acceptable. Only cooling fluids with HFC and HFO (not flammable) are acceptable.

6.3.2 In case of application of insulation with foam injected under pressure polyurethane, it shall be provided with CFC-free.

6.4 CONTROL AND OPERATION

6.4.1 Pneumatic and electrical fire dampers actuators are acceptable. In case the pneumatic actuator is chosen an independent air supply system, with their own air reservoirs, shall be provided for fire dampers and pressurization of instrumentation panels located in hazardous areas. This shall be provided in order to avoid any further consequence caused by a fault in the air supply.

6.4.2 All the fire dampers shall be CS type approval.

6.4.3 Application and installation of fire damper shall be based on the recommendations of SOLAS and Classification Society requirements.

6.4.4 The HVAC system shall be capable of sustaining an adjustable range of air temperatures in indoor manned personnel accommodation spaces. This temperature shall be maintained by a temperature controller according with NR-37.

6.5 VENTILATION OF THE TURRET AREA (NOT APPLICABLE)

6.5.1 Not applicable.

6.6 STANDARDS AND BRAZILIAN REGULATION

6.6.1 CONTRACTOR shall comply with applicable Brazilian Regulations. ISO 15138 shall be used as reference for HVAC System design.

6.6.2 The minimum outside airflow per person is 27 m^3/h, in order to comply with Brazilian Legislation for Conditioned Rooms (“*Portarias do Ministério da Saúde MS 3523/1998*” and “*MS 9/2003*”). Ducts shall be designed and assembled taking into consideration the requirements for inspection and maintenance established by Health Ministry.

6.7 ELECTRICAL SWITCHBOARD ROOMS (E-HOUSE)

6.7.1 E-House (Electrical Switchboard Room) shall be pressurized and air-conditioned (maximum room internal temperature 24ºC), 2x100% or 3x50% equipment configuration machines with a stand-by unit.

6.7.2 Variable Speed Drive, if used, shall be installed in air-conditioned rooms (maximum room internal temperature 24ºC).

6.7.3 The battery rooms shall comply with the item 6.2. UPS and battery chargers shall be installed in air-conditioned rooms.

6.7.4 Chilled Water Pipes and/or Cooling Water shall not be installed inside panels rooms, electrical equipment, transformers rooms, control rooms, radio room and telecom. Exception to condensed water piping from Air Cooled HVAC machines coil, if there is any. In this case, equipment and piping shall be installed at floor level, closed to a wall, contained by physical barrier and with a drain directly to outside.

6.7.5 The E-HOUSE air conditioning design shall also consider cabinets supplied by PETROBRAS.

7 SAFETY

7.1 GENERAL

7.1.1 The Unit's safety philosophy shall comply with SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

7.1.2 For acceptable vendor list for Diesel-Hydraulic Fire Water Pumping Unit, see item 19.1.1.9.

7.2 RISK MANAGEMENT

7.2.1 A Risk Management Program shall be implemented, to continuously monitor and control the risks identified in risk assessment studies during the operational lifetime, as defined in SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

7.2.2 PETROBRAS at their sole discretion shall take part in any Risk Assessment or workshop, for example: Layout Reviews, HAZOPs, HAZIDs, ALARP, SIL and BOW-TIE.

7.2.3 An independent Consultant Company shall be hired to perform the risk assessment studies established in the scope of the project. This Consultant Company shall have a proven previous experience in this type of studies.

7.3 PEOPLE ON BOARD (POB) MANAGEMENT SYSTEM

7.3.1 CONTRACTOR shall design and install an Electronic POB Management System incorporated to Unit's Safety Procedures. This System aims to:

- Provide in real time the number and identification of persons on site (POB system);

- Provide an electronic solution to perform the mustering process in case of General Alarm (E-mustering system);
- Register the personnel location and control the access (E-Tracking system);
- The Electronic POB Management System shall be based on RFID technology. Different solutions can be accepted by PETROBRAS, provided the following:
  - Same final specifications;
  - Any different solution must be presented to PETROBRAS.

7.3.2 The system shall be able to accommodate extraordinary events (major maintenance, construction work, etc.) leading to the presence of additional personnel and also some routine events such as daily visitors.

7.3.3 E-MUSTERING (POB-M)

7.3.3.1 The system shall provide accurate on-line real-time information to site relevant personnel in order to control/manage the mustering and evacuation process and allow emergency follow-up:

- Allow people to check at mustering area;
- Allow follow-up of mustered people on the site itself and on connected installation (if relevant);
- Allow identification and location of people member of the Emergency Response Team;
- Allow management of escape means;
- Allow the possibility of managing people having evacuated and then returning to the Unit;
- Identify missing personnel during mustering process.

7.3.3.2 Each person allocated to an emergency role must be clearly identified in the system.

7.3.3.3 The system shall be able to generate a report which will indicate, as a minimum, personnel’s name and surname, assigned TAG number, his/her last registered location, his/her job position and eventually his emergency role, his/her assigned lifeboat, his/her assigned muster point.

7.3.3.4 The System shall also be able to provide typical statistics and indicators (timing of movements of people, duration of mustering, anomalies, etc.).

7.3.4 E-TRACKING (POB-T)

7.3.4.1 The system shall record when personnel is entering/exiting selected locations to be defined by CONTRACTOR, for example, restricted access areas, accommodations, e-house, pump room, machinery room. Readers shall be placed at entry/exit points to allow personnel to register in/out. Real-time information shall be available on the central system concerning identification and tracking of all personnel on each location. A general view shall represent the status of the site.

7.3.4.2 All events (entry allowed or refused, bad TAG reading) shall be logged.

7.3.5 TECHNICAL REQUIREMENTS

7.3.5.1 All system equipment shall be adequate for the hazardous zone it will be installed/used. POB-M/T field equipment shall be certified for zone 1 so that they can remain energized in case of gas detection.

7.3.5.2 The full system shall be suitably designed for permanent operation in marine environment.

7.3.5.3 Considered as a safety system, the POB-M/T system shall be fully redundant.

7.3.5.4 The POB-M/T system shall be designed in such a way that the failure of any server, communication or network equipment, power supply unit, interconnection cables shall not result in a loss of service in any situation. The POB-M/T hard disk backup shall be performed using RAID technology.

7.3.5.5 The POB-M/T system shall be stand-alone (dedicated system), with minimum interaction with CSS.

7.3.5.6 The POB-M/T central system shall be duplicated on site in two systems (system “A” and “B”) located in different technical rooms. Those systems shall be interconnected through duplicated link and synchronized at all time. Sign-in operations shall be updated on both systems in real time.

7.3.5.7 POB-M/T central systems shall be fed from redundant UPS power supplies with minimum autonomy of 12 hours.

7.3.5.8 At the Muster Points, Emergency Response Room, PETROBRAS’ representative office and Control Room, a secured Wireless Access point and HMI (Humam Machine Interface) shall be provided. The HMI of the application shall be user friendly and provide in a very clear way all useful information for the mustering process. All wireless access point shall be duplicated; one connected to System “A” and the other one to System “B”. Wireless network for POB-M/T shall be independent from other operational wireless networks.

7.3.5.9 It shall be ensured that all POB-M/T field equipment are always connected and synchronized with the system in operation. All field equipment shall be powered, and data connected to both systems “A” and “B” through segregated cable route, for real-time update.

7.3.5.10 Readers shall be equipped with LED and sounders to show correct sign-in regarding POB-M/T and refused sign-in (location overmanned, tag incorrect, etc.), as well as lost link with POB-M/T system. Readers and their supports shall be visible and clearly identified.

7.3.5.11 In case of central systems failure, readers shall be equipped with buffer in such a way to ensure local sign-in storage. Reader memory capacity shall allow local sign-in operations (capacity to be defined during execution phase). Sign-in data shall be updated on servers as soon as systems recover.

7.3.5.12 The TAG shall be generated on site. TAG shall be based on a bracelet waterproof or equivalent. It shall be ensured that the tag shall be easily worn by personnel at all time, without creating any safety risk.

7.3.5.13 The system shall take future requirements into consideration: 20% input/output spare shall be supplied for future expansion (i.e. increase in number of readers). In addition, 20% of unused shelf space shall be available in the cabinets.

7.3.5.14 The system access shall be controlled according to the level of authorization to access/modify the system.

7.3.5.15 The System shall allow remote access using IP protocol and shall be directly connected to the FPSO firewall.

7.3.6 INTERFACES

7.3.6.1 The POB-M system shall be connected to the General Alarm system to allow beginning of muster process as soon as an alarm occurs.

7.3.6.2 POB-M/T systems shall be minimally interfaced with the CSS system:

- POB-M/T shall report system failure alarm to CSS (alarm shall be available in control room);
- CSS shall send shutdown signals to POB-M/T.

7.4 HUMAN FACTORS ENGINEERING (HFE)

7.4.1 CONTRACTOR shall establish and apply Human Factors Engineering (HFE) guidelines as defined in IOGP Report 454 - Human Factors Engineering in projects.

7.4.1.1 CONTRACTOR shall perform the HFE activities following the best practices contained on the IOGP Report 454, which shall also be considered as mandatory.

7.4.2 CONTRACTOR shall consider human factors input into hazard identification and risk management activities, applying one of the recognized methods of quantitative Human Reliability Analysis (HRA) to the safety critical procedures, identifying as minimum:

- Safety critical tasks;
- Potential human errors;
- Performance influencing factors;
- Human error probability;

- Safety measures to control human errors.

7.4.2.1 The recognized quantitative HRA method shall be one of the listed on the following references:

- Table 2 - “A list of the 17 tools considered to be of potential use to HSE major hazard directorates” contained on “RR679 Report - Review of human reliability assessment methods” issued by HSE - Healthy and Safety Executive;
- The Petro-HRA Guideline, Vol. 1 & 2, issued by IFE - Institute for Energy Technology.

7.4.2.2 For the safety critical procedures which have interface between PETROBRAS and CONTRACTOR, PETROBRAS team shall participate in HRA.

7.4.2.3 CONTRACTOR shall integrate the quantitative HRA results to the risk analysis (e.g., HAZOP, HAZID, etc.) to evaluate if the risks are within the risk tolerability criteria.

7.4.2.4 A report for registering the HRA method, premises, attendance team, results (items 7.4.2.a to 7.4.2.e), and risk tolerability criteria shall be issued for PETROBRAS comments.

7.4.3 CONTRACTOR shall define the minimum effective staff of each safety critical procedure of the Unit to safely perform it, considering regular, degraded and emergency operational mode.

7.4.4 CONTRACTOR shall issue for PETROBRAS comments a Human Factors Engineering (HFE) Report, following the IOGP Report 454, consolidating all HFE activities, the HRA and Minimum Effective Staff Analysis, including the HFE recommendations generated from the HFE activities and HRA. HFE recommendations implementation status and deadline shall be part of close out Report.

8 INSTRUMENTATION, AUTOMATION AND CONTROL

8.1 GENERAL

8.1.1 The Instrumentation/Automation design is to be mainly based on an integrated operation and supervision system of the Unit as a whole, through graphics interfaces.

8.1.2 The Unit shall be supplied with an overall Automation and Control (A&C) Architecture composed by field instruments and control/automation systems. The main characteristic of the Architecture is the integration promoted among these systems by means of redundant digital communications along all layers, including optical and electrical networks, switches, hubs modems, etc.

8.1.3 The AC and DC power supply for all components of the A&C Architecture shall be redundant, fed from duplicated and redundant UPS. Common failure mode shall not be present.

8.1.4 The systems of the A&C Architecture encompass the following:

- Control & Safety System (CSS);
- Central Control Room (CCR) Systems;
- Cargo Tank Monitoring System (CTMS);
- Optimization and advanced control server;
- Machinery Monitoring System (MMS).
- Flow Metering System (FMS);
- Offshore Loading System;
- Subsea Production Control System (SPCS);
- HISEP™ Control and Monitoring System;
- Addressable Fire Detection System (AFDS).

8.1.5 Redundancy shall be applied to the A&C systems and field instrumentation for maintaining the safe and reliable operation of the Unit and for achieving the required overall reliability, maintainability and availability.

8.1.6 The A&C systems shall be designed in order to assure that a single failure at any component of the system would not cause a loss of a safety function or system.

8.1.7 Network between any CSS Controller and its respective RIO (Remote Input/Output) Panels shall be routed by redundant physical independent routes.

8.1.8 Signals from process redundant systems and voting instruments shall be distributed in the I/O cards in a way that avoids the loss of more than one system in case of an I/O card failure.

8.1.9 Regarding adequacy to hazardous area classification for electrical/electronic equipment and instrumentation, refer to section 6.4 of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

8.1.10 All instruments, panels and equipment (if applicable) proper to be used in hazardous areas, shall have conformity certificates complying with: IEC-60079 and all its parts; *PORTARIA INMETRO Nº 115, de 21/março/2022,* and its annexes and shall be approved by Classification Society.

8.2 CENTRAL CONTROL ROOM (CCR) SYSTEMS

8.2.1 The Unit shall have a CCR with an integrated working area from which the Topside process and utilities plant, subsea production/injection systems and Hull/Marine systems shall be continuously monitored, operated and controlled, enabling the proper operation of the Unit as a whole.

8.2.2 The supervision and monitoring shall be done by navigating through HMI (human machine interface) screens showing the Topside and Hull/Marine diagrams and other fixed structures. The main components of this hardware (such as equipment, valves, detectors, process analyzers and instruments) shall be animated by displaying changes to their status, such as the opening of a valve, start-up of a pump, indication of a process variable etc.

8.2.3 The term HMI refers to the displays, computers and software that serve as an interface with CSS, specialized in processing/displaying the field data in a suitable format, leaving the tasks of data gathering to the other systems, such as CSS, CTMS, and SPCS.

8.2.4 The HMI shall have at least five primary functions:

- Provide visualization of process parameters and methods with which to control the process;
- Provide alarms summary and history, as well as indications to the operator that the process is outside limits or behaving abnormally or that the CSS has detected faults or failures;
- Provide a method to allow the operator to understand the process behavior, such as process tendency and time response (trending functionality);
- Provide reports of the Unit, such as overrides;
- Provide means to collect and register historical data.

8.2.5 The CONTRACTOR shall mirror all CCR (and ECR, if applicable) HMIs in 2 independent machines at the PETROBRAS Office (according to item 5.2), including Alarms Management System (alarms' and events' logs and statistics screens), in order to allow PETROBRAS to monitor the UNIT.

8.2.6 If the Unit is provided with a permanently manned engine control room (ECR), the engine room equipment can be controlled from the ECR and only the critical alarms and status signals repeated back to the CCR.

8.2.7 A “black box” device shall be foreseen into the CCR, in which all Topsides, subsea and Hull/Marine systems monitored data, events, audit trails and alarms of the last 60 (sixty) days shall be recorded in an easily removable data storage unit which shall be ejected and taken off the Unit in case of abandonment.

8.2.8 CONTRACTOR shall design and operate an Alarm Management System according to the standard IEC 62682, in order to ensure that:

- UNIT shall have an alarm management system that provides the operator with an adequate set of warnings against excursions beyond its safe operating limits both during normal operation and during abnormal situations (startups, shutdowns and upsets);
- Actions necessary to bring the process back to its normal state shall be defined for every safe operating limit and details shall be available to the operator. The operator shall be capable to execute such actions.

8.2.9 The alarm management system shall also minimize and where necessary suppress standing alarms, nuisance alarms, repeating alarms and alarm floods.

8.2.10 PLANT INFORMATION SYSTEM (PI System™)

8.2.10.1 During the operation phase, all main Topsides, Subsea, Turbomachinery, Main Pumps and Hull/Marine data shall be available online at PETROBRAS' PI System™-Server, with the following conditions:

- The interface between supervisory system and Plant Information System (PI System™) shall be based on OPC-UA (Open Platform Communications Unified Architecture) (provided that the supervisory system is based on Windows®);
- The interface between the supervisory system and OPC shall be hosted in a dedicated server in the supervisory system layer or in the supervisory system workstation, if it is Native OPC Client-Server. (By CONTRACTOR);
- OPC-PI System™ drivers with store and forward mechanism shall be hosted in a computer on the Automation network and shall communicate through DMZ (demilitarized zone) firewalls installed in Telecommunications Room. (By CONTRACTOR);
- Both supervisory system-OPC and OPC-PI System™ interfaces shall be installed in redundancy, including hardware and licenses. (By CONTRACTOR);
- PI System™-Server software shall also run in DMZ (PI System™-Server will be located in onshore DMZ). (By PETROBRAS);
- The data to be stored in PI System™ will be defined by PETROBRAS during the Detail Engineering Design Phase;
- If CONTRACTOR needs to use a different protocol for the communication between supervisory system and PI System™, PETROBRAS shall be consulted for acceptance, the licenses and configuration, if the protocol is accepted, shall be provided by CONTRACTOR;
- Information and network security mechanisms between owner supervision and operation system and PI System™ shall be installed and configured by CONTRACTOR.

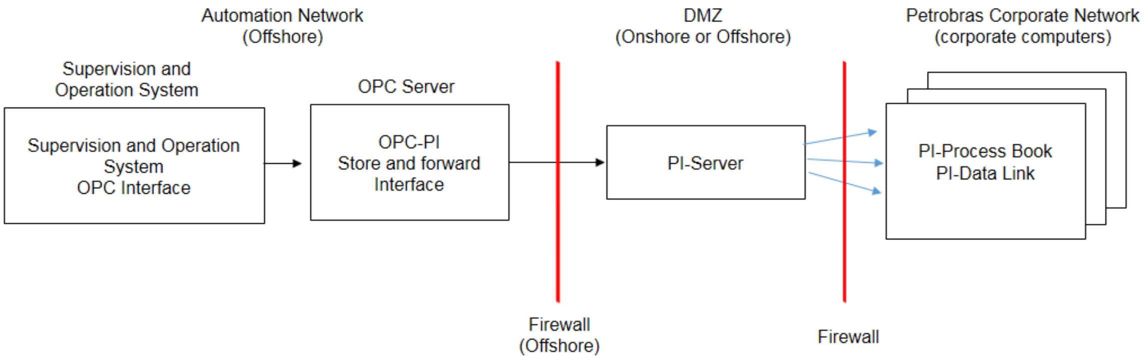


Figure 8.2.10.1 – Plant Information Architecture

8.2.10.2 For details of Telecommunications infrastructure, see I-ET-0600.00-5510-760-PPT-569 Telecommunications Systems.

8.2.11 CONTROL NETWORK ARCHITECTURE

8.2.11.1 Network communications among the CSS Controllers shall preferentially be by a deterministic network protocol. Signals to indicate safety interlock actions between Controllers shall be fail safe.

8.2.11.2 All network levels, supervision network, control network and field network shall have diagnostics and Management System in order to indicate fault of communication at any level.

8.2.11.3 The Network Management System shall, at minimum:

- Be capable to show the installed topology;
- Have network sniffer function;
- Switch remote configuration function (such as SNMP (Simple Network Management Protocol)).

8.2.12 CYBERSECURITY

8.2.12.1 This item defines the cybersecurity minimum requirements that shall be implemented in the design of the FPSO. Additional features than those stated in this item that lead to higher security levels may be implemented.

8.2.12.2 CONTRACTOR shall implement cybersecurity actions in Automation System to guarantee availability, confidentiality and reliability of the Automation System data.

8.2.12.3 Writing in Automation System's processors and in the supervisory software from outside the Automation network shall not be allowed, unless explicitly authorized for Operation necessity. All writing and reading accesses in the Automation network shall be logged.

8.2.12.4 Different firewalls shall be provided between:

- CONTRACTOR Automation network and PETROBRAS corporate network/Onshore PETROBRAS Facilities;
- CONTRACTOR Automation network and CONTRACTOR corporate network.

8.2.12.5 CONTRACTOR shall notify Petrobras any cyber security incident in Automation environment and any change or discontinuity in cybersecurity requirements.

8.2.12.6 CONTRACTOR shall perform one or more workshops to address cybersecurity requirements with PETROBRAS attendance. The agenda and topics to be addressed on these workshops shall be mutually agreed between CONTRACTOR and PETROBRAS. The actions and outcomes from these workshops shall be shared with PETROBRAS.

8.2.12.7 CONTRACTOR shall follow IEC 62443 – all parts. Additionally, the following requirements shall be evidenced:

8.2.12.7.1 CONTRACTOR shall implement all System Requirements (SR´s) related to Security Level 1 in accordance with IEC 62443-3-3, plus the specific System Requirements below:

- SR 1.1 RE 2 – Multifactor authentication for untrusted networks (related to Security Level 3);
- SR 3.2 RE 2 – Central management and reporting for malicious code protection (related to Security Level 3);
- SR 5.1 RE 2 – Independence from non-control system networks (related to Security Level 3);
- SR 6.2 – Continuous monitoring (related to Security Level 3);
- SR 7.3 RE 1 – Backup verification (related to Security Level 2.

8.2.12.7.2 CONTRACTOR shall implement a patch management program in accordance with IEC 62443-2-3.

8.2.12.7.3 CONTRACTOR shall implement a vulnerability management process in accordance with IEC 62443-3-2 and IEC 62443-2-1.

8.2.12.7.4 CONTRACTOR shall implement an incident response process in accordance with IEC 62443-2-1.

8.3 CONTROL & SAFETY SYSTEM (CSS)

8.3.1 The Unit shall be equipped with fully automated control system, named Control & Safety System (CSS), to provide both control and safeguarding functions according to SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

8.3.2 A number of dedicated CSS controllers (redundant CPUs/processor modules in a fully hot stand-by scheme), shall be foreseen for the following functions:

a) Process Control System (PCS), for Unit systems remote controlling and monitoring. Regulatory control (PID), monitoring, remote actuation, control transmitters data acquisition and process alarms shall be carried out by this system;

b) Process Shutdown System (PSD), for carrying out overall Unit safety and safeguarding preventive automatic and manual actions. The purpose of this system is to prevent escalation of abnormal conditions into a major hazardous event and to limit the extent and duration of any such events that do occur;

c) Fire & Gas/ESD System (FGS/ESD), for carrying out overall Unit safety mitigation automatic actions mainly due to fire, flammable and toxic gas releases/leaks and explosion events. This system shall monitor continuously for the presence of a fire or gas leakage to alert personnel and allow control actions to be initiated manually or automatically to minimize the likelihood of fire or gas escalation and probability of personnel exposure.

8.3.3 PCS shall be an independent system from PSD and FGS/ESD. It is recommended that PCS, PSD and FGS/ESD be from the same vendor.

8.3.4 A single time reference shall be used for the CSS and Electrical System. The interface between CSS and the Electrical System shall be such that, in the event of a failure of the communication, the electrical loads go to a safe state.

8.3.5 Automation system commissioning shall follow IEC 62381 and its references.

8.3.6 Some equipment may be supplied as package units with their own Control and Automation System. These shall also be integrated to the Unit´s Automation & Control Architecture, and shall comply with Classification Society rules, especially regarding to the segregation between control and safeguarding functions. Fire and Gas signals of these package units shall also be integrated to the Unit Fire and Gas system.

8.4 CARGO TANK MONITORING SYSTEM (CTMS)

8.4.1 The Cargo Tank Monitoring System shall provide reliable, fast and highly accurate information on tank level and related variables (draft, pressure, etc.).

8.4.2 The CTMS shall comply with Class Society requirements.

8.5 SUBSEA PRODUCTION CONTROL SYSTEM (SPCS)

8.5.1 For Subsea Production Control System, refer to SUBSEA PRODUCTION CONTROL SYSTEM FOR FPSO (see item 1.2.1).

8.6 OFFSHORE LOADING SYSTEM

8.6.1 For Offshore Loading System, see OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

8.7 METERING

8.7.1 For Flow Metering System, refer to FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1).

8.8 CANCELLED.

8.9 CANCELLED.

8.10 CANCELLED.

8.11 CANCELLED.

8.12 MACHINERY MONITORING SYSTEM (MMS)

8.12.1 CONTRACTOR shall provide a Machinery Monitoring System for critical rotating equipment (at least for all gas compressors, electrical generators, gas and steam turbines, boiler feed water pumps, SRU Feed pumps, main water injection pumps, booster water injection pumps and sea water lift pumps) and its drivers and gearboxes/HVSD. MMS shall be integrated with the Machinery Protection System (MPS).

8.12.2 In addition to the signal available through MPS Communication, CONTRACTOR shall make available the process variable signals through the Fast Ethernet Network to perform the functions above in the Machinery Monitoring System, with acquisition interval of at least one second.

8.12.3 For a basic description, the primary function of the MMS is to perform analysis of the mechanical parameters: all machinery protection system signals, with possibility to make analysis like FFT (Fast Fourier Transform), full spectrum, Bode plot, cascade and waterfall diagrams, shaft average center line, orbit, X-Y plot and experience-based vibration analysis, and auxiliary system signals (lube, seal, etc.).

8.12.4 The Machinery Monitoring System shall have the following functions:

- Data acquisition of vibration signals from machinery sensors and bearing temperatures as a minimum;
- Data logging and event/variable recording and storing (compressed data feature to allow the access of significant values with high resolution within measurements spanning five years);
- Listing of all incoming alarms chronologically in a directory and a user-defined actions;
- Historical trending (all variables);
- Real-time measurements in order to allow diagnostics of fault detection and analysis;
- Display of equipment schematic layout;
- Measurements covering the widest possible range of machine faults.
- Real-time display of process variables such as temperatures, pressures, vibration, flows, speed, electrical measurements, valve position, tank levels, etc.; and others applicable variables for each equipment class. The CONTRACTOR shall provide access to MMS at the PETROBRAS Onshore Office through offshore DMZ (see TELECOM MASTER SPECIFICATIONS FOR FPSO

CHARTERED – item 1.2.1), in order to allow PETROBRAS to monitor the Machines. MMS and MPS shall have a dedicated Ethernet network for vibration signals, different from the network used to mirror MMS to PETROBRAS Office.

8.13 CANCELLED.

8.14 HISEP™ CONTROL AND MONITORING SYSTEM

8.14.1 The HISEP™ Control and Monitoring System comprises all Automation and Control equipment needed for the correct operation of the HISEP™ system.

8.14.2 The core of this system is the HISEP™ Master Control Station (HISEPTM MCS), which is a set of panels that is the single-point automation interface with all other HISEP™ equipment. PSD and FGS/ESD hardwired signals shall be exchanged bidirectional between the HISEP™ MCS to the CSS. Besides, the HISEP™ MCS shall make the main process variables of the HISEP™ available to the supervisory system via computer network using Modbus TCP or OPC-UA protocols (final protocol will be defined by PETROBRAS during HISEP™ installation). The HISEP™ MCSs shall have their power supplied by the UPS. The MCS may require an external connection to the Internet through the platform firewall.

8.14.3 Additionally, the CCR HMIs shall display in dedicated screens and in real-time all the variables of the HISEP™ system. If the HISEP™ supplier furnishes a dedicated Operation Workstation, this workstation shall be placed in CCR and all its interconnections with the CSS/MCS shall be supplied, installed and configured by CONTRACTOR.

8.14.4 Other A&C equipment may include the following items:

- Barrier fluid HPU (BFHPU);
- Control Fluid HPU (CFHPU);
- Electronic Power Unit;

8.14.5 This equipment is considered an integrated part of HISEP™ package and, as so, shall be supplied or endorsed by the HISEP™ manufacturer in order to preserve the warranty of the whole system.

8.14.6 Additionally, it is the MANUFACTURER scope of work:

- Provide the correct internal interconnection of all HISEP™ topsides equipment (process, electrical, automation and instrumentation connections, etc.) and with the umbilical terminal unit;
- Provide configuring, testing and internal commissioning and any other services in order for the HISEP™ system to be fully functional.

8.14.7 CONTRACTOR shall provide the correct interconnection of all HISEP™ systems (including MCS and Operation workstation) with FPSO systems (automation, electrical, pneumatic, hydraulic, etc.).

8.14.8 CONTRACTOR shall provide, configuring, testing and commissioning of the HISEP™ system integration with the CSS in order for the HISEP™ system to be fully functional in the FPSO.

8.14.9 CONTRACTOR shall provide the connections between umbilical terminal units and the umbilical.

8.14.10 CONTRACTOR shall follow all operational requirements (such as maintaining the cleanliness levels of the HISEP™ HPU hydraulic fluids) defined in item 8.5.

8.14.11 Dedicated drawers in the MCC shall be foreseen for the Barrier Fluid HPU power supply. The BFHPU shall therefore be energized by FPSOs MCC. The commands for the BFHPU shall come from the HISEP™ MCS.

8.15 OPTIMIZATION AND ADVANCED CONTROL

8.15.1 Optimization and advanced control are intended to increase production efficiency, process plant stability and safety of control loops of critical equipment. CONTRACTOR shall be responsible for providing infrastructure for optimization and advanced control:

- 1 (one) machine (server) in the platform automation network to host advanced control applications. Through this microcomputer, it shall be possible to access (read/write) all control loops running in CSS (main topsides, subsea and Hull/Marine data) via OPC protocol. PETROBRAS will provide the ADVANCED CONTROL software solution and CONTRACTOR will configure the OPC connection with the Supervisory System to access the control loops in CSS. This server shall be provided with Windows Server Operational System (latest version) and be suitable to continuously working on a 24 x 7 duty. Drivers to convert from others protocols to OPC are CONTRACTOR's scope. Minimum Hardware requirements: Processor for Server systems released on 2021 or after, 8 cores, 16 threads, at least 3,2GHz base clock (or better), 32Gb RAM and at least 500Gb free on storage, all storage shall be Solid State Drives (SSD);
- CONTRACTOR shall provide means, via supervision HMIs, allow the operator to enable (on/off) the advanced control, as well as to define its limits and setpoints;
- CONTRACTOR shall set up watchdog logic in automation (A&C) systems to take the correct actions and inform the operator when a communication fail has occurred between the computer, where advanced control is running, and the automation system of the platform;
- All the necessary intervention in automation (A&C) system for the implementation of optimization and advanced control is CONTRACTOR responsibility.

8.16 PRESSURE AND TEMPERATURE MONITORING POINTS

8.16.1 CONTRACTOR is responsible for the definition of the instrumentation required for legal compliance and stable, continuous and safe operation.

8.16.2 Pressure and temperature transmitters indicated on table 8.16.3 and 8.16.4 shall not be duplicated if this instrumentation is required for pressure and temperature correction for flow measurement as stated in FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) are mandatory.

8.16.3 CONTRACTOR shall provide at least the monitoring points indicated in Table 8.16.3 with indication in the supervisory system for energy efficiency and atmospheric emissions assessment. These monitoring points shall be available at Plant Information system, for onshore monitoring.

Table 8.16.3 – Pressure and temperature monitoring points for energy efficiency and atmospheric emissions assessment

Item	Monitoring points	Temperature	Pressure
1	Inlet and outlet hot and cold streams of the heat exchangers from the following systems:		
1.1	Oil separation and treatment	x	x
1.2	Condensate	x	x
1.3	Gas	x	x
1.4	Produced water	x	x
1.5	Cooling medium	x	x
1.6	Heating medium	x	x
1.7	Amine	x	x
1.8	Glycol (if applicable)	x	x
2	Injection water header	x	x
3	Production header	x	x
4	First separator oil outlet	x	x
5	First separator gas outlet	x	x
6	First separator water outlet	x	x
7	Recycle streams routed to first separator	x	x
8	Oil transference pump discharge (from the process plant to the cargo tanks)	x	x
9	Gas Export Line	x	x
10	Fuel gas total	x	x
11	Produced water disposal	x	
12	Seawater disposal from cooling system	x	
13	Inlet and outlet of flue gas and heating medium streams from each WHRU	x	
14	Turbine intake air and flue gas chimney exit	x	
15	Inlet and outlet of Main Seawater Injection Pump	x	x
16	Diesel engine - fuel	x	x

17	Diesel engines - flue gas	x	
18	Diesel engines - inlet and outlet cooling water	x	
19	Sulphate removal reject	x	
20	Ultrafiltration reject	x	
21	Reverse Osmosis reject	x	

8.16.4 CONTRACTOR shall provide the instrumentation listed on table 8.16.4.

Table 8.16.4 – Pressure and temperature monitoring points for operational purposes

Item	Monitoring points	Type
1	Downstream and upstream of shutdown valves at water injection pumps discharge	Pressure
2	Bearing and motor of main water injection pump	Temperature
3	Upstream and downstream of each choke valve	Pressure and Temperature
4	Topsides water injection lines	Pressure
5	Each molecular sieve bed (if applicable)	Pressure
6	TEG absorber column packing (if applicable)	Pressure
7	Each Regeneration gas heater	Temperature
8	Solid removal filters of produced water treatment	Pressure
9	HP and LP headers upstream QOV	Pressure
10	Pump discharge filters of umbilical (subsea) chemical injection	Pressure
11	Each chemical injection point	Pressure
12	Sea cooling water overboard discharge	Temperature
13	Cargo tanks	Pressure
14	Critical rotating equipment (at least all gas compressors, turbogenerators, main water injection pumps, booster water injection pumps and sea water lift pumps) and its drivers and gearboxes/HVSD	Pressure and Temperature
15	Printed Circuit Heat Exchanger (PCHE) core	Pressure
16	Gas inlet strainer of PCHE	Pressure
17	Cooling medium inlet strainer of PCHE	Pressure
18	Top of injection/service risers	Temperature
19	Downstream of each service choke valve	Pressure
20	fuel gas individual consumers (e.g. gas-turbines, flare, boilers, etc)	Pressure and Temperature

8.17 FLOW MONITORING POINTS

8.17.1 CONTRACTOR is responsable for the definition of the instrumentation required for legal compliance and stable, continuous and safe operation.

8.17.2 Flow monitoring transmitters indicated on table 8.17.3 and 8.17.4 shall not be duplicated if this instrumentation is required on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM FOR LEASED UNITS (see item 1.2.1) are mandatory.

8.17.3 CONTRACTOR shall provide at least the monitoring points indicated in Table 8.17.3 with indication in the supervisory system for energy efficiency and atmospheric emissions assessment. These monitoring points shall be available at Plant Information system, for onshore monitoring.

Table 8.17.3 – Flow monitoring points for energy efficiency and atmospheric emissions assessment

Item	Monitoring points
1	Main Gas Compressor suction
2	Export Gas Compressor suction
3	VRU suction
4	Produced water flotation gas
5	Gas from TEG Flash Drum (if applicable)
6	Stripping Gas for TEG Regenaration (if applicable)
7	Gas from Amine Flash Drum
8	Sour gas from amine regeneration
9	All recycle streams routed to 1st production separator
10	Produced water from 1st production separator
11	Ultrafiltration reject
12	Sulphate removal reject
13	Reverse Osmosis reject
14	Main Injection Water Pump suction
15	Cooling water for each turbogenerator
16	Cooling water for each motogenerator
17	Sea cooling water to overboard
18	Sea water to fresh water maker
19	Generated fresh water
20	Inert gas
21	Diesel for each turbogenerator
22	Diesel for each motogenerator

8.17.4 CONTRACTOR shall provide the instrumentation listed on table 8.17.4.

Table 8.17.4 – Flow monitoring points for operational purposes

Item	Monitoring points
1	Service pump

2	Each gas-lift riser, including the production satellite wells
3	Deviated rich TEG flow (if applicable)
4	Lean TEG flow (if applicable)
5	Stripping gas flow of TEG Regeneration Reboiler (if applicable)
6	Stripping gas flow of Stahl Column (if applicable)
7	Each source of purge gas
8	Each chemical injection point
9	Critical rotating equipment (at least all gas compressors, turbogenerators, main water injection pumps, booster water injection pumps and sea water lift pumps) and its drivers and gearboxes/HVSD
10	fuel gas individual consumers (e.g. gas-turbines, flare, boilers, etc)

9 ELECTRICAL SYSTEM

9.1 GENERAL

9.1.1 The electrical system design and installation shall comply with IEC 61892 series. Additionally, the requirements defined below shall be mandatory.

9.1.2 The electrical design shall be signed by a legally qualified electrician (PLH), according to NR-10. An ART (*Anotação de Responsabilidade Técnica*) shall be issued by a PLH with this information clearly stated.

9.2 GENERATION POWER MANAGEMENT SYSTEM

9.2.1 Apart from the usual generation Unit controls (frequency, voltage control and turbine controllers), an independent generation control shall be supplied in order to maintain full simultaneous control of all generators of the FPSO. This controller shall be hereinafter called PMS (Power Management System).

9.2.2 A Power Management System (PMS) shall be provided, including functions of main generation voltage control, main generation frequency control, load shedding, load sharing and permission of starting for high demand loads and maximum turbogenerator demand.

9.2.3 To prevent total or partial loss of power, the load shedding shall command fast selective tripping of pre-determined HV consumers, in the event of main generation overload (sudden or gradual) and main generation under frequency, to prevent total or partial loss of power.

9.2.4 PMS GENERAL REQUIREMENTS

9.2.4.1 The system shall be type approved by Class Societies.

9.2.4.2 The PMS shall at least comprise generator paralleling control, load sharing, peak shaving, automatic load shedding, load import/export control and protection.

9.2.4.3 The load shedding function shall allow temporary overload of main generation due to starting of large motors and transformers.

9.2.4.4 The load sharing function shall be capable to share active power demand evenly (in proportion of their capacities) among the main generators running, or to set adjustable fixed active power to keep one generator with variable active power, according to the demand variation.

9.3 GENERATORS

9.3.1 MAIN GENERATORS GENERAL REQUIREMENTS

9.3.1.1 The power generation system shall be designed considering operational cases defined on section 2.

9.3.1.2 Each power generation package consists of a synchronous alternator driven by dual fuel gas turbine, designed to operate on fuel gas (normal) or on Diesel fuel (no fuel gas available). Dry Low Emission Turbines (DLE) are not accepted for aero-derivative gas turbine type.

9.3.1.3 For main power generation based on gas turbines, the auxiliary and the emergency generator shall be capable independently to start-up the main generator, assuming dead-ship condition.

9.3.1.4 Main turbogenerator packager shall be the gas turbine OEM (original equipment manufacturer).

9.3.1.5 CONTRACTOR may propose Combined Cycle system for main power generation. Combined cycle configuration shall be based on gas turbines and steam turbines. For details about combined cycle system, see item 9.10.

9.3.2 MAIN GENERATOR TURBINE REQUIREMENTS

9.3.2.1 CONTRACTOR is requested to present the following on the technical proposal submission in order to evidence power generation compliance to GTD:

X(KW) = [Turbine ISO output power at 15 degrees Celsius temperature](KW) * [N-1] generators / [Z] + Steam turbine driven generator power (kW) * [M];

Y(KW) = [maximum electrical demand from electrical load balance calculation report] (KW) * [Z];

X(KW) shall be greater or equal than Y (KW);

[N] = total number of main turbogenerators sets installed;

[M] = total number of main steam turbine generator sets running, if any;

[Z] = derate factor (see table 9.3.2.1)

Table 9.3.2.1: “Z” Factor by Model

[Z]= 1.25	[Z] = 1.33
BHGE Baker Hughes GE: LM2500+G4; SIEMENS: SGT-A35 (34 MW ISO)	BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM6000 PC/PG SAC; SIEMENS: SGT-A05, SGT-A65 SAC (WLE DRY), SGT-100, SGT-600; SOLAR: SATURN, CENTAUR 50, TAURUS 60, MARS100, TITAN 130, TITAN 250.

NOTE 1: PETROBRAS considers that CONTRACTOR will built-in design contingencies into the maximum expected electrical demand. PETROBRAS consider those contingencies (margins) as a CONTRACTOR internal issue. However, all contingencies (margins) applied to all gas compressors shall be clearly stated including all losses and degradations applied to calculate the maximum power on the compressor´s driver shaft.

NOTE 2: The generators packages on duty shall be designed at least to supply the maximum electrical load at 30 degrees Celsius (maximum ambient temperatures to be considered for design purpose).

NOTE 3: [Z] factor value is the minimum required for main generators design.

NOTE 4: In case of power generation with combined cycle, CONTRACTOR shall inform during tender period the additional pressure drop on the gas turbine exhaust gas (anything above 250 mm H2O for exhaust pressure loss) according to the proposed combined cycle configuration. Such additional pressure loss, if any, shall be included in Z factor and shall be clearly stated along with its effects on the turbine output.

9.3.2.2 The main generators shall be capable to immediately restart at any time after a shutdown event. Restriction of the turbine restart due to mechanical locking of the gas generator (GG) is not acceptable. Forced lockout time is not acceptable.

9.3.2.3 For acceptable vendor list for Gas Turbines for Main Generators, see item 19.

9.3.3 MAIN GENERATOR ELECTRICAL REQUIREMENTS

9.3.3.1 The configuration of the main generator packages shall consider one generator in stand-by condition, for all operational modes defined on section 2, with [N-1] generators running.

NOTE: “N” is the total number of main generators installed in the FPSO.

9.3.3.2 For direct on-line starting the largest motor, it shall be considered maximum 2 main generators running, to keep transient voltage drop within tolerable limit of +/- 20% (voltage excursions - sum of transient and steady state deviation - on switchboards and distribution panels which electrical system and consumers in general shall withstand).

NOTE: The use of alternative starting solutions is allowed, i.e.: Soft-starters, Soft-Starter-VSDs, and VSD or other.

9.3.3.3 CONTRACTOR shall consider stand-by compressor start-up without turn off the running compressor during load transfer.

9.3.4 ESSENTIAL/AUXILIARY GENERATOR

9.3.4.1 For auxiliary generator package, CONTRACTOR shall use new equipment.

9.3.4.2 Auxiliary generators can be used to complement main power generation during offloading operations; in this case, one standby auxiliary generator is required.

9.3.4.3 Auxiliary generator shall have a dedicated starting system independent from the emergency generator.

9.3.5 EMERGENCY GENERATOR

9.3.5.1 For emergency generator package, CONTRACTOR shall use new equipment.

9.3.5.2 Emergency generator shall be dimensioned to feed simultaneously all loads indicated in the SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1), IMO MODU CODE and required by C.S., for at least 18 hours.

9.3.5.3 Emergency and auxiliary generators shall have a quick-closing fuel valve shall be a normally-open, “energize to close” coil. A manual acting closing device shall be provided to close the fuel valve, outside the emergency and auxiliary generator rooms, in case of fire inside.

9.3.5.4 The starting sources for Emergency Generator shall not be shared with any other generator.

9.4 DISTRIBUTION SYSTEM

9.4.1 POWER DISTRIBUTION

9.4.1.1 The HV, LV and UPS distribution system shall be designed with required redundancy, so that a single failure in any equipment, circuit or bus section does not impair the whole system and neither reduce the production/processing capacity of the Unit.

9.4.1.2 For main generation systems, the main bus shall be subdivided in at least two parts which shall be normally connected by a tie circuit breaker.

9.4.1.3 The earthing and detection methods shall comply with Chapter 6 of IEC 61892-2 (System Earthing) requirements and the CS rules, as applicable.

9.4.2 HIGH/MEDIUM VOLTAGE SYSTEM

9.4.2.1 For Medium Voltage generation and distribution systems, the high resistance earthing shall be adopted with instantaneous selective tripping in the event of earth fault.

9.4.3 LOW VOLTAGE SYSTEM

9.4.3.1 The Low Voltage power distribution system shall be of secondary-selective type, with main bus subdivided in at least two parts which shall be normally connected by a tie circuit breaker; each bus part shall normally be fed from secondary of duplicated and fully redundant HV/LV transformers with tie circuit breaker open.

9.4.3.2 Low voltage distribution system shall be divided into different groups and switchboards:

- Normal Process Plant loads;
- Normal Utilities/Ship Service loads;
- Essential loads.

9.4.4 DEDICATED VDC SYSTEM

9.4.4.1 In case CONTRACTOR opts for VDC systems (e.g. 24 VDC) for control and starting of Emergency Generator and Fire water pumps, the following requirements shall be met:

- VDC system shall be dedicated;
- VDC system shall be powered by essential busbars;
- VDC system shall have its own battery bank;
- VDC system shall be installed as close as possible to their loads.

9.5 ELECTRICAL EQUIPMENT

9.5.1 GENERAL REQUIREMENTS

9.5.1.1 Electric panels shall have the front and rear floor covered by insulating rubber matting complying with ASTM D-178-01 requirements for Type II – ABC (ozone, fire and oil resistant) and minimum Class 0 (tested for 5kV) for panels with rated voltage up to 690V and minimum Class 1 (tested for 10kV) for panels with rated voltage above 690V.

9.5.2 POWER TRANSFORMERS

9.5.2.1 Each power transformer shall be dimensioned to feed 100% of the maximum switchboard load demand, with no forced ventilation, on a contingency condition with the duplicated redundant unit out of service.

9.5.2.2 For dry-type power transformers, the Fire Behavior Class shall be F1, according to defined IEC 60076.

9.5.3 VARIABLE SPEED DRIVERS

9.5.3.1 VSD-FC shall be designed, manufactured, and tested according to IEC 61800.

9.5.3.2 Manufacturer is responsible for detailed electrical design and engineering within the VSD and shall perform all functions required to interface with the design of electrical system, as well as guarantee the control and monitoring from Control Panel.

Note: When driving compressor systems, Compressor OEM (Original Equipment Manufacturer) shall assume unit responsibility and shall assure that all vendors comply with the requirements stated herein this document including VSD. Therefore, Compressor Vendor is responsible for the design, development, engineering, coordination, procurement, fabrication, assembly, test and shall guarantee overall performance (fully functional and operable) of complete compressor package.

9.5.3.3 For VSD-FCs feeding motors installed in hazardous areas Zone 1 or Zone 2 or installed in safe external area but kept in operation during shutdown conditions, shall be certified as a unit association (motor-VSD-protective device) as required by IEC 60079-14.

Note: Alternatives foreseen in IEC 60079-14 for this certification (as a unit association) are acceptable.

9.5.3.4 MEDIUM VOLTAGE VSDS

9.5.3.4.1 Medium Voltage VSD-FC shall be supplied with internal electric arc monitor device able to send a signal for instantaneous opening of the feeding panel circuit breaker to shut down the converter.

9.5.3.4.2 Safety requirements for VSD-FC shall comply with IEC 62477-1 and IEC 62477-2.

9.5.3.4.3 If VSD-FC has arc withstand capability, it shall comply with IEC 62271-200.

9.5.3.4.4 Medium Voltage VSD-FC harmonics shall comply with maximum values defined in IEEE Std. 519.

9.5.3.4.5 The minimum efficiency for the VSD-FC system including, i.e., VSD-FC, power transformers, cooling auxiliary devices, control and protection devices and accessories shall be: 96.0% efficiency at 100% rated load.

9.5.3.4.6 The minimum power factor at the VSD-FC set input with rated voltage and frequency shall be: 0.95 lag, with tolerance -0%, at 100% rated load.

9.5.3.4.7 A dV/dt filter or sine wave filter shall be provided whenever required by the motor insulation limits, considering the effects of the connection cables.

9.5.3.4.8 VSD-FC shall comply with emission and immunity EMC (Electromagnetic Compatibility) and RFI (Radio Frequency Interference) requirements according to IEC 61800.

9.5.3.4.9 VSD-FC shall have the protection functions defined in IEC 61800.

9.5.3.4.10 For Medium Voltage VSD driving compressor systems the following requirements apply:

9.5.3.4.10.1 The proposed equipment shall be field proven and have satisfactory operation in floating offshore units.

9.5.3.4.10.2 Transformer requirements for VSD:

- Transformer rating shall follow IEC 61378 or IEEE C57.18.10
- Insulation: class F with temperature rise plus ambient temperature under the limits of class B (all windings) or class H with temperature rise plus ambient temperature under the limits of class F (all windings).

- Two RTD, platinum resistance temperature detectors type (PT100Ω @ 0ºC) per winding or thermostats (see 4.3); These RTDs shall be in contact with the hottest temperature parts of the windings.

- VSC-FC Input Transformer Temperature Rise Tests shall be repeated during String Tests.

9.5.3.4.10.3 Transformers and Drives Cooling systems and controls tests shall be included as defined in IEC 61800.

9.5.3.4.10.4 Tests shall follow IEC 61800. All routine test, special tests and string tests (full load) shall be witnessed by PETROBRAS. These tests procedures and approval criteria shall demonstrate the unit's performance and reliability. During the execution phase, CONTRACTOR shall provide all test reports.

9.6 UNINTERRUPTIBLE POWER SUPPLY (UPS) SYSTEM - AC AND DC

9.6.1 GENERAL

9.6.1.1 UPS source of power may be provided by AC or DC UPS.

9.6.1.2 UPS shall be arranged and dimensioned to feed simultaneously all loads indicated in the SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1), IMO MODU CODE, and required by C.S., and corresponding autonomy time.

9.6.1.3 UPS log report shall be recordable, retrievable and available for PETROBRAS as requested, providing comprehensive information on the equipment status and diagnostic information.

9.6.2 UPS FOR AUTOMATION/INSTRUMENTATION SYSTEM

9.6.2.1 UPS source of power may be provided by AC or DC UPS.

9.6.2.2 The UPS system for Automation shall be comprised by two redundant and electrically separated units, “A” and “B”, each of them sized for supplying all loads (2 x 100%), operating isolated.

9.6.2.3 Each UPS, if AC, shall be provided with dedicated by-pass transformer, with automatic transfer through static switches.

9.6.2.4 Each distribution switchgear shall have option to be fed either from UPS A or UPS B. Therefore, all switchgears shall have circuit breakers facilities to transfer the UPS supply from UPS A to UPS B (or the other way round, from UPS B to UPS A).

9.6.2.5 The distribution switchgears shall have full capacity interconnecting circuit breakers for transfer all connected loads to and from redundant UPS, keeping the loads operating (without temporary black-out).

9.6.2.6 UPS output voltage shall be isolated from earth. Ground fault detection with local and remote alarm at CCR shall be provided; means for troubleshooting and locating ground fault as portable clamp meter shall be provided without interrupting services.

9.7 LIGHTING

9.7.1 Design of external lighting and illumination system shall avoid the disturbance on seawater, meaning that CONTRACTOR shall avoid directing the lighting to the sea. Outdoors lighting fixtures shall be preferentially directed to internal areas of the Unit, in order to not affect/impact marine life. CONTRACTOR shall consider that only specific lighting systems required by Brazilian and international regulations, Class and Flag requirements and Unit safe operation shall be directed to overboard in direction to seawater area.

9.7.2 The emergency lighting UPS system shall be redundant (2x100%).

9.8 LIGHTNING PROTECTION

9.8.1 A Lightning Protection Study shall be carried out according to NFPA 780 - Standard for the Installation of Lightning Protection Systems, mainly chapters 4 and 7. Elevation views of protected zones shall be shown, considering the rolling spheres graphical method with sphere radius of 30 meters. Special regard shall be given to high structures (flare stack, telecom tower and flare booms) as well as to packages and structures containing flammable vapors, gases and liquids.

9.9 ELECTRICAL STUDIES

9.9.1 CONTRACTOR shall present to PETROBRAS, the following electrical studies:

- Main and Emergency Generation electrical load balance;
- Load Flow calculation report;
- Short-circuit calculation report;
- Voltage drops due to motor starting calculation report;
- Transient stability calculation report;
- Harmonic analysis calculation report;
- Protection coordination and selectivity calculation report;
- Arc fault incident energy calculation report;
- UPS and battery bank sizing report;

- Grounding Fault Analysis;
- Lightning Protection Study.

9.10 COMBINED CYCLE MINIMUM REQUIREMENTS

9.10.1 CONTRACTOR shall provide stand-by equipment, ready to operate, to guarantee no process capacity reduction nor degradation of the oil, gas and water specification occur.

9.10.2 For combined cycle configuration, the stand-by generator unit shall be gas turbine driven.

9.10.3 Steam turbine generator rated power shall not be greater than gas turbine generator rated power.

9.10.4 Steam turbine generator (STG) shall be driven by a condensing-type, special-purpose steam turbine with controlled extraction, in accordance with API STD 612. Lube and control oil system shall be according to API STD 614 for special purpose applications.

9.10.5 Centrifugal pumps shall be provided in accordance with API 610.

9.10.5.1 Boiler feedwater pumps shall be barrel-type (BB-5), electric motor driven, fitted with variable speed drives (VSD).

9.10.6 If main power generation is based on a combined cycle, a Reliability, Availability and Maintainability (RAM) analysis as described in AVAILABILITY AND MAINTAINABILITY (RAM) ANALYSIS REQUIREMENTS FOR LEASED UNITS WITH COMBINED CYCLE GENERATION (see item 1.2.1) shall be provided. The effects of Combined Cycle subsystems in the oil production shall be considered.

9.10.7 The combined cycle power plant shall be capable of providing the required heat demand to the process and the required power demand to the electrical grid (in accordance with operational cases defined on chapter 2) without disturbing the turbomachinery redundancy philosophy of the entire system, as per item 9.3.2.

9.10.8 Condenser(s) shall comply with HEI-2629 - STANDARDS FOR STEAM SURFACE CONDENSERS (Heat Exchanger Institute). Condenser tubes shall be made of full titanium material (other parts in contact with sea water shall also be in titanium).

9.10.9 Full condensate recovery (start-up venting, blowdown, drain etc.) is required.

9.10.10 The Combined Cycle Power Plant shall be provided with a dedicated online analytical instrumentation system for automatic water quality monitoring and chemicals dosing control. Sample points and additional analytical equipment for any required or recommended offline lab analysis shall also be provided.

9.10.11 VENDOR LIST

9.10.11.1 For Vendor List for combined cycle main equipment, refer to item 19.

9.10.11.2 Vendor list for other equipment (condenser, balance of plant (BOP) system, heat exchanger etc.) shall be provided in the technical proposal during tender period. It shall include equipment operating in similar conditions in three floating units for at least three years.

10 EQUIPMENT

10.1 NOISE AND VIBRATION

10.1.1 CONTRACTOR shall conduct Noise and Vibration Study including process areas, marine areas and accommodations to evaluate working environment and implement mitigating measures whenever required. Specifically for compression and generation areas and whenever possible, Noise and Vibration study shall be based on existing similar equipment and projects.

10.1.2 NOISE

10.1.2.1 Noise limits shall be in accordance with the Brazilian Regulations (NRs), CS rules and guidelines requirements for FPSO and / or MODU where applicable.

10.1.2.2 Equipment operating at high noise levels shall be acoustically treated using hoods, silencers, filters or other noise control system to meet the requirements.

10.1.2.3 After completion of services, if noise levels exceed the specified limits, CONTRACTOR may be required to carry out additional improvements in order to insulate individual noise sources. Such remedial measures can be, for example, the installation of AVMs (Anti-Vibration Mounts), foundations for smaller equipment and additional insulation for limited areas.

10.1.3 VIBRATION

10.1.3.1 CONTRACTOR shall carry out structural and main equipment vibration measurements during commissioning and sea trials in order to verify acceptable levels of vibration, according to NRs, CS rules and guidelines requirements for FPSO and / or MODU where applicable.

10.1.3.2 CONTRACTOR shall rectify the stiffening of equipment and/or the equipment itself, if vibrations are clearly in excess of the recommendations of the above-mentioned standards.

10.2 HOISTING AND HANDLING SYSTEMS

10.2.1 CONTRACTOR shall submit to PETROBRAS for comments a detailed procedure for equipment maintenance that includes their removal/disassembly from any part of the Unit to allow the installation of a new one. The procedure shall include facilities to allow offshore maintenance of the Unit, without affecting the production/processing capacity of the Unit.

10.2.2 Special attention shall be given to the area necessary for hoisting, handling and maintenance of the main generators, gas compressors, seawater lift pumps and diving equipment that are composed by large pieces with large weights.

10.2.3 CRANES

10.2.3.1 Cranes shall comply with API-2C - Offshore Pedestal Mounted Cranes or BS EN 13852-1 Cranes – Offshore Cranes Part 1: General Purpose Offshore Cranes for load and personnel lifting.

10.2.3.2 Cranes shall be classified by CS and shall comply with Brazilian Government Regulations Rules (NRs).

10.2.3.3 Crane capacities shall be compatible with equipment parts to be removed/disassembled (e.g. main generator rotor, heat exchanger tube bundles, diving equipment, etc.) and to transfer material/equipment to/from supply vessels to the Unit. Crane outreaches are measured outboard from the Unit's side shell.

10.2.3.4 In this option, as the risers shall come up on the Unit's Portside, this side shall not be used for any supply boat operations. All cranes shall be located on the Starboard side.

10.2.3.5 At least two cranes are required, Aft (AFT) Starboard and Forward (FWD) Starboard, built to operate under the following conditions:

- Loading/unloading from/to a supply vessel with an outreach able to transship at a distance of 28 m from FPSO's side at capacities defined on item 10.2.3.6;
- The whip hoisting system shall be able to lift 15,000 kg (minimum) with any boom angle;
- Transportation of personnel to/from the supply vessels.

10.2.3.6 The minimum loading/unloading capacity of one crane shall be 25,000 kg and the minimum for the other shall be 15,000 kg.

10.2.3.7 All above mentioned capacities are net lift capacities. Vessel motions and dynamic loads shall also be considered to properly design each crane.

10.2.3.8 CONTRACTOR shall provide means of transporting supplies/goods/spares from a lay-down area to the galley store, machineries spaces, warehouses, etc. (i.e., aft spaces/compartments).

10.3 HEAT EXCHANGERS

10.3.1 CONTRACTOR shall comply with all requirements and recommendations for the design of heat exchangers and pressure protection systems according to the internal failures scenarios as per API 521 item 4.4.14, especially where large pressure difference is observed (e.g. 7000 kPa or more), where dynamic analysis are recommended in addition to the steady state approach, and where the low pressure side is liquid-full and the high-pressure side contains a gas or a fluid that flashes across the rupture.

10.3.2 GASKET PLATE HEAT EXCHANGER

10.3.2.1 Gasket Plate Heat Exchangers, if considered by CONTRACTOR, shall be in accordance with API STD 667 – PLATE AND FRAME HEAT EXCHANGERS, and be capable to withstand pressure surges (dynamic pressure variations) due to process and control fluctuations. For cyclic services, fatigue design shall be in accordance with ASME BPVC Section VIII, Division 2.

10.3.3 PRINTED CIRCUIT HEAT EXCHANGER (PCHE)

10.3.3.1 PCHE will only be accepted for gas coolers in gas compression systems. If CONTRACTOR decides to use PCHE (Printed Circuit Heat Exchanger), one additional PCHE per compression stage stored onshore (capital spare) and ready for installation shall be provided and the commissioning, operation and maintenance procedure shall be defined by PCHE vendor. An integral T-type (or similar) strainer shall be supplied on the gas inlet and a separate Duplex in line cleanable strainer shall be supplied for the cooling medium side, and the strainer aperture for both cases shall be advised by manufacturer. All the cooling medium control valves shall guarantee the minimum flow rate to the PCHE (typically around 20%), rudder stop valves are recommended. In addition, the pressure drop across the PCHE (core) and also the pressure drop across the strainers shall be individually and remotely monitored for both streams.

10.3.3.2 A side stream filtration (polishing) system shall be included and all measures necessary to guarantee the high quality and cleanliness of the cooling water, as recommended by PCHE manufacturer. The cooling medium operating pressure shall be higher than its vapor pressure at the maximum exchanger process inlet temperature, to prevent boiling in low flow or turndown conditions, and higher than the sea water pressure, to prevent sea water ingress to the closed loop in case of any leaks in the sea water cooler.

10.3.4 SHELL AND TUBE HEAT EXCHANGER

10.3.4.1 Process system shell and tubes heat exchanger shall be in accordance with API 660 and ASME BPVC Section VIII, Division 1 standards.

10.4 PIPING

10.4.1 Piping and valves design, materials fabrication, assembly, erection, inspection and testing shall comply with ASME B31.3 and CS rules. Piping system layout, design, structural and fatigue analyses are required. Special attention shall be taken, but not limited to, well production lines, vents/drains of hydrocarbon system and other lines subjected to vibration (e.g. compression/pump systems), including small line diameters and instrument connections. Regarding such subject the compliance to NORSOK L-002 is required.

10.4.2 The use of long-bolt (wafer) type valves for services which contain flammable or combustible fluids shall not be acceptable. Lug and flanged types are acceptable.

11 TELECOMMUNICATIONS

11.1 GENERAL

11.1.1 The Unit's telecommunications shall comply with the TELECOM MASTER SPECIFICATIONS FOR FPSO CHARTERED document (see item 1.2.1).

12 STRUCTURAL DESIGN

12.1 GENERAL

12.1.1 Besides the CS load requirements for the operation of the Unit at the site, CONTRACTOR shall also design the Unit to withstand all construction loads and the environmental loads during transportation from construction/conversion shipyard to Brazil. For decommissioning purpose (including risers pull-out), the design shall ensure that in the end of the leased contract, the Unit shall have enough strength to be transported or towed to outside Brazilian waters.

12.1.2 Current revision of the CS rules shall be used to check and design the structures (hull and topsides), reinforcements and complementary structures. CONTRACTOR shall use net scantlings that are obtained deducting corrosion margins (as presented in item 12.2.7) from final scantlings or "as-built" scantlings in case of new building. "Final scantlings" means the plate thickness measured at the beginning of the conversion or after plate replacement.

12.2 CONVERSION SURVEY (IF APPLICABLE)

12.2.1 The hull assessment shall be submitted to a third party for reviewing and validation. This third party shall be a CS, other than the one that is classing the Unit. For acceptable CSs see item 1.3.4.

12.2.2 The hull shall be fully inspected according to CS requirements. Regardless of those CS requirements, as the Unit shall maintain continuous offshore operation during its whole operational lifetime with no dry-docking. All damaged areas, cracks of any nature, and all defective structural pieces, including welds and all warped areas, shall be replaced or restored to fit conversion specifications.

12.2.3 The Unit shall be surveyed prior to the installation of any new structure. The survey report shall inform all items that do not match the original design. Special attention shall be paid to the following items:

- Structure dimensions- girders, beams, stiffeners and plates;
- Out of tolerance imperfections of structural elements;
- Changes in the material specifications;
- Corrosion of structural elements.

12.2.4 Ships that have been involved in explosion, grounding damage, lay-up (3 years or more) and/or relevant collision incident during their operational life shall not be utilized for conversion.

12.2.5 Both ultrasonic gauging report and the reassessment study shall be submitted to CS for approval and to PETROBRAS for information. Also, the pitting map for the inner surface of cargo, slop, ballast, produced water and oil offspec tanks bottom plates shall be submitted for PETROBRAS information. In case any cargo tank has been converted to Diesel Storage Tank, this requirement is also applicable.

12.2.6 Further inspections (to be made by a third party) may be required by PETROBRAS during the engineering design phase, as part of the Survey Report.

12.2.7 PLATE REPLACEMENT CRITERIA

12.2.7.1 The design philosophy shall consider that no hot work will be done, due to plating/structural replacement, during the Unit’s operational lifetime.

12.2.7.2 Specification of hull steel renewal at conversion is based on the requirement that no part of the hull will fall under substantial corrosion during the contract period.

12.2.7.3 Hull steel renewal shall consider both local corrosion (pitting and grooving) and overall corrosion.

12.2.7.4 For overall corrosion of plating and stiffeners, renewal thickness at conversion is defined such that the substantial corrosion margin will not be reached within the FPSO life, taking into account anticipated corrosion losses during the FPSO life. The substantial corrosion margin is defined as 75% of the allowable corrosion margin as specified in the inspection criteria of the rules.

12.2.7.5 When re-assessment is performed, the FPSO required gross thickness (TR) is defined as the required thickness for use as FPSO without reduction for corrosion, based on the environmental site-specific design parameters, even in the case that the re-assessed thickness is lower than the original “as-built” thickness.

12.2.7.6 As a minimum criterion, the following procedure shall be adopted to determine the steel renewal thickness at conversion:

$T_{measured} \leq T_R * (1 - 0.75 * R_L) + M \rightarrow$ Element shall be renewed;

$T_{measured}$ – Structural element thickness – based on the Thickness Reading Report;

M – XX,X years corrosion margin;

T_R – rule required gross thickness – to be defined by the Reassessment Study;

R_L – rule allowed corrosion percentage according to Classification Society rules.

12.2.7.7 The following table shows the corrosion margin values (M) to be used for XX years of operation (Contract period) for different uncoated structural elements (“F” factor is XXX (M / 20 years)):

Table 12.2.6.7: Corrosion Margin Values

LOCATION	ITEM	CORROSION MARGIN (mm)	
		Cargo Tank	Ballast Tank(1)
LONGITUDINAL ELEMENTS	Deck plating	1.3 x F	2.0 x F
	Deck longitudinals	1.3 x F	2.0 x F
	Side shell plating	1.0 x F	1.5 x F
	Side shell longitudinals	1.0 x F	2.0 x F
	Longitudinal bulkheads plating	1.0 x F	1.5 x F
	Longitudinal bulkheads longitudinals	1.0 x F	2.0 x F
	Bottom shell plating	1.4 x F	1.5 x F
	Bottom shell longitudinals	1.0 x F	2.0 x F
TRANSVERSE WEB FRAMES	Deck transverse web plating	1.5 x F	2.0 x F
	Bottom transverse web plating	1.0 x F	2.0 x F
	Side shell transverse web plating	1.0 x F	2.0 x F
	Long. bhd. transverse web plating	1.0 x F	2.0 x F
TRANSVERSE BULKHEADS	Plating	1.0 x F	1.5 x F
	Vertical stiffener (web)	1.0 x F	1.5 x F
	Horizontal stringer web plating	1.6 x F	2.0 x F
	Vertical girder plating	1.0 x F	1.5 x F
SWASH BULKHEADS	Web plating	1.0 x F	1.5 x F
	Horizontal stringer web plating	1.6 x F	1.6 x F
	Vertical girder plating	1.0 x F	1.5 x F

NOTE 1: Slop tanks, off-spec tanks and settling tanks (if applicable) shall consider same corrosion margins as ballast tanks.

12.2.7.8 By means of coating, the start of corrosion will be postponed. Therefore, a corrosion postponement can be considered, if CONTRACTOR ensures application of painting scheme with guarantee not lesser than 10 years. As so, the corrosion margins given in the table above can be de-rated, due to the referred corrosion postponement effect, for structural elements that are fully painted with NOVOLAC coating. Alternative solutions to NOVOLAC may be accepted by PETROBRAS.

The reduction on the required corrosion margins in case of coated steel structural elements can be 5 years/XX,XX years (XX% reduction) on the corrosion margins given in the table above.

12.2.7.9 For pitting inspection/acceptance bottom plating shall be fully inspected after being properly blasted. The following plating renewal criteria shall be considered:

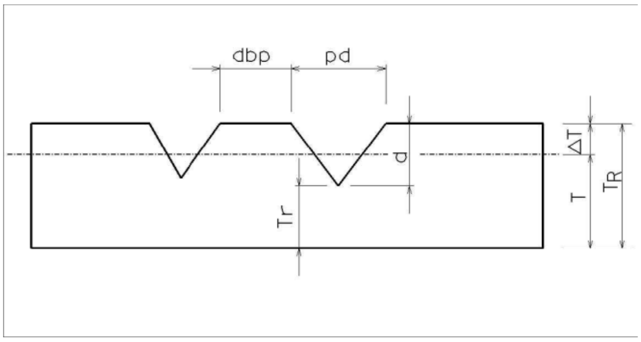


Figure 12.2.6.9: Plating Renewal Criteria

1 - If in the inspected region d < 0,15 . TR: Plate to be treated and painted;

2 - If in the inspected region 0,15 . TR < d < TR /3: See note below;

3 - If in the inspected region d > TR /3: Plate to be renewed.

NOTE: Additional criteria shall be considered for those regions related to item 2 above:

- If pd > 200 mm ⇒ plate renewing;
- If pd ≤ 200 mm and either:
  - dbp < 75 mm ⇒ plate renewing
  - dbp ≥ 75 mm and cpfd ≤ 80 mm Þ plate renewing
  - dbp ≥ 75 mm and cpfd > 80 mm and tr < 6 mm or to TR/3 Þ plate renewing

where: pd - pitting diameter

dbp - distance between pittings

cpfd - continuous pitting weld filling distance

tr - residual plate thickness below pitting

to - original plate thickness

REMARK: Cpfd is the minimum continuous weld bead necessary to fill up a pit.

12.3 MATERIALS

12.3.1 To prevent the lamellar tearing effect, steel with Z quality (strength through the thickness) shall be used in places where plate stress occurs through thickness, such as fairlead connections, riser balcony connections, crane pedestal connection, etc. Special details may be adopted to avoid stress in the transversal direction of steel plate.

12.3.2 Double plates under the cargo pumps suction lines, drop lines, sounding pipes and ullage pipes inside the cargo tanks, ballast tanks, diesel tanks, oil and water offspec tanks, fresh water tanks, etc. shall be welded in order to prevent erosion corrosion on structure. Alternative design solutions shall be submitted for PETROBRAS approval.

12.4 HULL

12.4.1 The following alternatives shall be adopted for new build hull:

a) Double side, with, at least, three longitudinal bulkheads;

b) Double hull, without any hydrocarbon piping system routed inside the double bottom and/or void spaces.

12.4.2 In case of converted hull, the double hull alternative, without any hydrocarbon piping system routed inside the double bottom and/or void spaces, shall be adopted.

12.4.3 CONTRACTOR shall comply with MARPOL Regulation 19 requirements.

12.4.4 In lieu of a risk analysis and/or a drifting analysis that defines the scenarios for vessel collision structural analyses, side shell structure at supply vessel approaching area shall withstand an impact energy (collision accidental load) imposed by a 9,000-MT displacement supply vessel, plus added mass, with speed of 2 m/s, for the worst cases of sideways, bow and stern impact scenarios, without causing the rupture of FPSOs cargo tank longitudinal bulkhead and without compromising the global structure. Supply vessel approaching area shall comprise the following region of the side shell: + 30 meters and -30 meters of each crane position, and 3.5 meters above maximum draft and -1.5 meters below minimum draft.

12.4.5 Side shell structure shall be designed at the same area to withstand an impact energy imposed by the same 9,000-MT displacement supply vessel, plus added mass, at 0.5 m/s for the worst cases of sideways, bow and stern impact scenarios, associated with normal operational conditions, without any rupture to the side shell structure.

12.4.6 Criteria and methodology shall follow NORSOK N-003 and N-004.

12.4.7 The referred area shall preferably have elastomeric fenders fixed to side shell by steel beams, in order to prevent contact between supply boat and the Unit’s side shell plate. The fenders and their foundations shall be designed (dimensioned and spaced) to absorb the collision energy for normal operation conditions of supply vessel. In case of using floating fenders, at least 3 (three) shall be considered in each supply vessel approaching area.

12.4.8 Other external equipment/structures/piping (e.g. caissons for seawater uptake) connected to side shell at the supply vessel approaching area shall be protected by specific steel structure.

12.4.9 CONTRACTOR shall provide welded doubler plates in line with the suction and discharge of each tank. Insert plates with increased thickness is also acceptable alternative. If CONTRATOR decides to provide suction bilge boxes on the tank bottom then plates shall also be designed with increased thickness.

12.4.10 TURRET AND CARGO TANK INTERFACE (NOT APPLICABLE)

12.4.10.1 Not applicable.

12.4.11 RISER BALCONY AND CARGO TANK INTERFACE (SPREAD MOORING OPTION)

12.4.11.1 CONTRACTOR shall perform a finite element analysis at the balcony/hull interface region to assess the structural strength and fatigue life. This analysis shall be submitted to CS for approval.

12.4.12 BALCONIES AND AFT STRUCTURE

12.4.12.1 Fairlead support structures, riser balconies, aft hull structures and other attached structures subject to wave slamming loads shall be analyzed considering the probability of occurrence and the corresponding load. Significance of effects on onboard comfort and on hull stresses are also to be addressed.

12.4.12.2 Sufficiently inclined flat plates at the bottom of each of these structures shall be employed in order to minimize wave slamming, and, in consequence, whipping hull girder effects.

12.4.12.3 Slamming loads can be calculated using CFD software in association with model test results and/or potential hydrodynamic simulations. Alternatively, the simplified approach as described in DNV-RP-C205 – “Environmental Conditions and Environmental Loads” may be used.

12.4.12.4 Fatigue calculations shall also include the slamming loads with the corresponding probability of occurrence.

12.4.13 CATHODIC PROTECTION AND PAINTING

12.4.13.1 The cathodic protection (CP) system, painting specification and corrosion protection shall be part of the philosophy to allow the Unit to operate continuously during its operational lifetime without any production interruption. Therefore, design shall clearly identify those requirements.

12.4.13.2 Galvanic anode CP system shall be used for internal of tanks. Fresh water tanks shall have a different solution in order to avoid water contamination.

12.4.13.3 For external hull, impressed current cathodic protection systems is the preferred solution. The potential range to be adopted as a cathodic protection criterion for carbon steel structures shall be from -900 mV to -1000 mV, measured to the silver/silver chloride (Ag/AgCl sea water) reference electrode. Submerged defective parts replacement shall be feasible via diving operation. Additionally, galvanic anode CP may be accepted for external hull and limited areas with complex geometry. In this case, CONTRACTOR shall design the system to comply with design life requirement.

12.4.13.4 Special attention shall be given to chain pipes and other similar underwater structures to allow maintenance, inspection and replacement with no dry-docking/shutdown and to avoid problems caused by corrosion and marine growth.

12.4.13.5 Bottom cargo tank plating and structures shall be fully painted up to 2.0 meters of vertical structures or maximum water level, whichever is greater. Top cargo tank plating and structures shall be fully painted at least 2.0 meters from top. Painting specification shall consider the design life as stated in item 1.2.2.

12.4.13.6 Zinc anodes shall be adopted in ballast tanks if the “anode installation height X anode gross weight” is greater than 28 kgf x m and the maximum operation temperature is less or equal to 50ºC.

12.4.13.7 Cargo and slop tanks bottom shall be provided with anodes. These galvanic anodes shall be placed at the bottom of the tank.

12.4.13.8 Produced Water Tanks, Slop Tanks, Off-spec tanks (if applicable) and Settling Tank (if applicable) shall be entirely painted with NOVOLAC coating considering design life as stated in item 1.1 herein. Alternative solutions to NOVOLAC may be accepted by PETROBRAS. Anodes shall also be provided to protect the entire tank.

12.4.13.9 CONTRACTOR shall provide an anti-fouling painting scheme for the external hull, encompassing bottom plate and side shell plate up to transit draft (maximum foreseen draft during transit phase from yards and final location). The anti-fouling painting scheme shall follow chapter 3 of NORMAM 20 requirements and IMO Resolution MEPC.207(62) - Guidelines for the Control and Management of Ships’ Biofouling to Minimize the Transfer of Invasive Aquatic Species requirements.

12.4.13.10Coating of conversion hulls

12.4.13.10.1 Coated areas structural tanks and external hull shall be fully abrasive blasted to Sa 2 ½, roughness between 50-100 micrometers prior coating application.

12.4.13.11Holiday detector shall be applied on 100% of bottom plate surface in way of cargo and ballast tanks. Holiday test to be carried out only after finishing all tank internal services as piping works, outfitting, instrumentation installation and scaffolding removal.

12.4.13.12Coating of cargo tanks must comply with IMO Resolution MSC.288(87) Performance Standard for Protective Coatings for Cargo Oil Tanks of Crude Oil Tankers (PSPC). Ballast tanks coating must comply with IMO RESOLUTION MSC.215(82) - Performance Standard for Protective Coatings for Dedicated

Seawater Ballast Tanks in All Types of Ships and Double-Side Skin Spaces of Bulk Carriers.

12.4.14 CARGO AND BALLAST TANKS STRUCTURAL INSPECTION

12.4.14.1 All tanks access arrangements shall comply with IMO Recommendations A 272 (VIII) and A 330 (IX).

12.4.14.2 CONTRACTOR shall submit to PETROBRAS and CS an inspection plan of the cargo, ballast tanks or any other structural compartments evidencing that the Unit enables safe inspection inside all tanks. This plan shall be based on the Fatigue Analysis.

12.4.14.3 Means shall be provided to allow a safe “free-for-fire” certificate with minimum disturbance of the Unit’s operation. In addition, cargo piping shall be installed with devices to reduce the risk of any accidents during inspection and “hot” services (e.g.: devices to avoid valves or expansion joints leakage).

12.4.15 HULL EXTERNAL INSPECTION

12.4.15.1 CONTRACTOR shall provide facilities for the installation of the temporary diving support equipment and for the diving operation itself, considering that the entire hull shall be visually inspected, as required by CS.

12.4.15.2 CONTRACTOR shall ensure the UNIT is designed to enable 100% in-service hull survey without any need of diving activities. In-service underwater Hull Class surveys and inspections shall be fully performed by ROV. In addition, the following requirements shall be complied with:

- Hull appendices structures (e.g sea chest, lower riser balcony, fairleads, bilge-keel, etc.) shall be non-inspectable during unit design life.
- Contractor shall provide docking points in the hull to enable under water ROV activities (e.g sea chest, bilge-keel, etc).
- The diving stations shall provide the facilities required for operations with electric mini-ROVs for UWILD (Underwater Inspection in Lieu of Dry-Docking), mooring and SURF (Subsea Umbilicals, Risers, and Flowlines) inspections to the extent possible.
- All hull frames shall be identified through double plates and paintings in contrasting color on the following locations:
    - vessel keel and both port and starboard sides in order to facilitate orientation of the ROVs;
    - side shell on both port and starboard sides close to main deck, above operational maximum draft.

12.4.15.2.1 During execution phase, CONTRACTOR shall demonstrate the requirements are being complied with.

12.5 TOPSIDE STRUCTURES

12.5.1 Green Water occurrence and the effects on the main deck and topside structures of FPSO shall be considered on the design, according to motion analysis results.

12.5.2 The structures and their foundations shall be designed according to CS requirements in order to withstand the worst of the following:

- Motions and accelerations associated with DOC and DEC design condition (item 13.6.3);
- All CS requirements, including accidental and towing condition.

NOTE: All safety systems and life-saving systems, including emergency equipment and vessel abandonment equipment, shall continue to operate while under the worst of the conditions listed above in this item.

12.5.3 When wave slamming loads on hull as those identified in item 12.4.12 are significant and may affect the dynamic response of a topside structure, then, its natural frequencies shall be kept away from hull girder natural frequencies a minimum of 20% difference for full range of operational drafts (light loading up to full loading conditions) and in transient condition, in order to avoid large dynamic amplification. CONTRACTOR shall perform integrated analyses for most susceptible structures, that is, slender structures and other potentially affected structures, e.g. hull/flare tower model, including dynamic effects, to evaluate the flare tower integrity under dynamic hull deflections, for both strength and fatigue, similarly for the other structures.

12.5.4 When, otherwise, those impact loads are not significant for these structures, then the difference between their natural frequencies and those of hull girder shall still be a minimum of 10%.

12.6 FATIGUE ASSESSMENT REQUIREMENTS

12.6.1 CONTRACTOR shall obtain Class Certificate for a fatigue design life equal to the design life defined in item 1.2.2.1.

12.6.2 Fatigue life and hull substantial corrosion criteria used during the design shall comply with the CS requirements and Structure and Naval Design requirements, in order to allow continuous offshore operation during its contract period, with no dry-docking in a shipyard. In addition, the Unit shall be fitted with facilities that enable any maintenance required during the operational lifetime as well as the surveys required by the CS, Port Administration, or Flag Statutory requirements without affecting the production/processing capacity of the Unit.

12.6.3 The fatigue analysis shall be submitted to a third party for reviewing and validation. This third party shall be a CS, other than the one that is classifying the Unit. For acceptable CSs see item 1.3.4

12.6.4 Fatigue Damage calculation for the support structures, foundations, etc., shall be carried out in accordance with the CS rules.

12.6.5 CONTRACTOR shall use the waves, wind and current for fatigue analysis given in the annex METOCEAN DATA (see item 1.2.1). In this document, it is important to note that the specific direction reference for wind, wave and current can be different among them.

12.6.6 For converted hull, the fatigue assessment shall also consider the early fatigue effects in the hull during the early operation of the vessel before the hull conversion.

13 NAVAL DESIGN

13.1 GENERAL

13.1.1 The Unit shall have the following main naval characteristics:

13.1.2 Ship-shaped or barge-shaped unit, with a minimum storage capacity, i.e. minimum volume of oil available, in the cargo tanks, to be offloaded, of 1,450,000 bbl of crude oil. The amount of oil considered as permanent ballast and a residual tank volume of least 2% for each tank shall be added to this value. Stability criteria and structural constraints shall also be considered.

In addition, the 1,450,000 bbl of oil for offloading shall be available when:

a) the two largest tanks are isolated for inspection and repair;

b) the slop tanks, oil offspec tanks and the produced water tanks shall be excluded from the volume of 1,450,000 barrels of oil.

To calculate the “volume of oil available to be offloaded”, CONTRACTOR shall proceed as follows:

1) One condition approved by the Classification Society of maximum loading of oil shall be included in the “Trim and Stability booklet”; This condition shall include the exclusions defined above.

2) One condition of minimum loading safe operational condition approved by the Classification Society shall be included in the “Trim and Stability booklet”;

3) The “volume of oil available to be offloaded” is to be calculated as follows:

(Volume of oil available to be offloaded) = (Oil capacity in the maximum loading condition) – (Oil Capacity in the minimum loading safe operational condition) – Volume of Slop Tanks (if applicable) – Volume of the Produced Water Tanks (if applicable) – Volume of the two largest cargo tanks (98% full) – Volume of oil offspec tank

4) The volume of oil available to be offloaded shall be equal or greater than 1,450,000 bbl

13.2 WEIGHT CONTROL PROCEDURES

13.2.1 It is CONTRACTOR's responsibility to evaluate the Unit's weight and Center of Gravity Coordinates during design, installation and operational phases, according to the design and CS requirements.

13.3 STABILITY ANALYSIS

13.3.1 The Unit shall comply with the latest CS rules, MARPOL Annex I, MODU Code and International Load Line Convention, regarding intact and damage stability.

13.3.2 The distribution of static weights and vertical reactions imposed by the Spread Mooring and Riser System on the FPU shall be calculated for the purpose of evaluating the Unit trim and stability conditions.

13.3.3 PETROBRAS shall receive the FPSO model (latest version) used for stability analysis in *.IGS format including hull, tanks and compartments (different file extensions may be agreed with PETROBRAS).

13.4 MAXIMUM OFFLOADING OPERATIONAL CONDITION

13.4.1 For maximum offloading operational condition, see OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

13.5 BEAM SEA CONDITION (Applicable only for TURRET)

13.5.1 Not applicable.

13.6 MOTION ANALYSIS

13.6.1 GENERAL

13.6.1.1 The most stringent criteria between the GTD and CS requirements shall be considered.

13.6.1.2 Motion analysis results, regarding displacements, velocities and accelerations, shall be used for the analysis of the following items:

- Process plant structural design;
- Fairlead and riser support structure/hull interface design (Spread-Mooring);
- Flare boom / tower structural design;
- Vent tower structural design;
- Helideck structural design;
- Crane foundation structural design;

- Equipment operational limit assessment;
- Offloading operational limit assessment;
- Pull-in / pull-out operational limit assessment.

13.6.2 RAO – RESPONSE AMPLITUDE OPERATOR

13.6.2.1 CONTRACTOR shall issue to PETROBRAS the RAO (Response Amplitude Operator) curves and tables with their corresponding phase angles, for Unit's 6 (six) degrees of freedom.

13.6.2.2 For each degree of freedom and selected draughts, respective RAO curves shall be informed together with natural periods and linearized viscous damping, when applicable, as for Roll motion for instance. The viscous damping coefficients shall be submitted to PETROBRAS for comments. Model tests shall be used to validate the CONTRACTOR proposal. In addition, the Model Test Report shall be provided for PETROBAS for information.

13.6.2.3 Roll RAO curves shall be computed considering viscous damping varying according to the significant wave heights as follows:

- Hs < 2.5m (irregular waves contour curves);
- 2.5 < Hs < 4 (irregular waves contour curves);
- Hs > 4 (irregular waves contour curves).

13.6.2.4 The RAO curves shall be computed also considering the following:

- At least five loading conditions: minimum loaded, 40% loaded, 60% loaded, 80% loaded and fully loaded. The roll viscous damping shall be derived for each draught.
- The mooring lines and risers shall be considered only as weight items to compose the loading condition and no dynamic effect shall be included in the RAO analysis.
- Regular wave frequencies ranging from 0,16 to 3,0 rad/sec.
- The number of calculated frequency components shall be at least 60.
- Around natural frequency peaks (in the Roll and Heave RAO amplitude curves, the regular wave frequency discretization in the curves shall correspond to 0,1s steps within a range of ± 1,0 s around natural period value.
- Regular wave incidences ranging from 0 to 360 degrees with 7,5 degrees increments, being 0 degree value the "aft", 90 degrees value the "starboard", 180 degrees the "bow".
- RAO curves shall be referred to the C.O.G. (Center of Gravity of the Unit) for each draught. Thus, the C.O.G shall be informed with the RAO curves, apart from respective radius of gyrations about longitudinal, transversal and vertical axes, all of them calculated at C.O.G.
- The waves considered for the roll damping estimation shall be the beam sea condition (irregular waves) that causes the higher motions (higher Hs or wave peak

period: Tp equal to the natural period of the roll motion for each specific draft). All roll damping estimation shall be done with no current.

13.6.2.5 The RAO curves will be used on the analysis of forces and the stresses acting on the risers, mooring lines and secondary structures. The reference system and direction conventions shall be included in the Motion Analysis report. The expression that needs to be employed to generate displacements, velocities and accelerations time series shall be also published by CONTRACTOR.

13.6.2.6 All numerical output data (RAO, curves and tables, added mass coefficients, potential damping coefficients, wave exciting forces and full quadratic transfer functions) shall be released in Microsoft Excel file and *.txt format by CONTRACTOR (different file extensions may be agreed with PETROBRAS). The RAO shall be released to PETROBRAS 9 months after LOI (Letter of Intent).

13.6.2.7 For fatigue analyses, the time percentages of each operational draft shall be informed in Motion Analysis Report.

13.6.3 MOTIONS AND ACCELERATIONS DESIGN CONDITIONS

13.6.3.1 For displacements and accelerations responses, short term statistics shall be evaluated for the DEC (design extreme conditions – 100 year return period waves) and DOC (design operational condition – 1year return period waves) according to wave contour plots distribution available in METOCEAN DATA (see item 1.2.1). The most probable maximum responses shall be appraised on the COG of the FPSO and at additional evaluation points that are required for structural sizing as well. The distribution of the points to be evaluated in this analysis shall be in accordance with CS requirements.

13.6.3.2 Unit's displacements and accelerations responses shall be demonstrated by the CONTRACTOR through calculations, including input information such as METOCEAN DATA (see item 1.2.1) and the Unit's 1st and 2nd order motions (RAOs and QTFs), considering the Unit at free-floating condition (without any mooring lines or risers contribution in terms of stiffness and damping).

13.6.3.3 For Motion Analysis, extreme sea states (Hs x Tp contour plots distributions for each incidence direction and return periods) that are specific for Unit's final offshore location shall be taken from METOCEAN DATA (see item 1.2.1).

13.6.3.4 CONTRACTOR shall design and install a bilge keel in the hull as following:

i. CONTRACTOR shall present calculations in order to back-up the bilge keel width and length definition. This shall be submitted to PETROBRAS for comments.

ii. Regardless the calculations in item (i), the minimum width of the bilge-keel shall be 1,5m.

iii. Under DOC conditions, the Unit's single-amplitude roll motion shall not exceed 8 degrees, while under DEC conditions the Unit's single-amplitude roll motion shall not exceed 15 degrees. The roll motion single-amplitude values shall be demonstrated during the model tests to be carried out by CONTRACTOR.

iv. Single-amplitude vertical motion at any riser support location shall not exceed 10,5 m (displacement) and 2,2 m/s² (acceleration) while under DEC conditions.

13.6.3.5 The Unit shall be designed to operate normally up to DEC condition. To "operate normally" means a state in which all systems and processes on the Unit can be started or kept running without tripping alarms or safety shut-down or endangering equipment and personnel involved. This includes the oil collecting system, utility systems, vessel systems, oil transfer to/from cargo tanks. In addition, process facilities shall be designed to ensure the efficiency of separation and treatment and transfer of oil, gas and water.

13.6.3.6 In addition, the Unit shall be verified for environmental conditions along specified route between construction site and offshore final location in Brazil, during sail-away phase, and, on specified route between the Brazilian offshore location and elsewhere outside Brazilian waters, after Unit decommissioning, at the end of the Contract.

13.6.3.7 If the CONTRACTOR decides to use a wave spreading formulation, it shall be used spreading parameters prescribed in METOCEAN DATA document (see item 1.2.1). The decision to use or not use a wave spreading formulation is CONTRACTOR's responsibility.

13.6.4 MODEL TESTS

13.6.4.1 Seakeeping model tests are required during the engineering design phase.

13.6.4.2 In order to calibrate numerical models and predict Unit's motions and non-linear effects such as roll viscous damping mainly provided by bilge keel (RAOs), green water, and wave slamming occurrences with their mitigation options and induced loads, second-order effects (QTFs) CONTRACTOR shall submit the model test matrix to PETROBRAS for comments, carrying out model test program based on agreed matrix.

13.6.4.3 For Roll natural periods beyond 17 seconds, considering all operational draught range, second-order effects for rolling motions must be addressed in model test scope.

13.6.4.4 Wave basin Unit's model scale shall be between 1:70 and 1:100, in order to obtain adequate model dimensions associated with sufficiently accurate results.

14 MOORING

14.1 GENERAL

14.1.1 The Unit's Maximum Design Condition shall comply with the SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see 1.2.1).

14.2 MOORING SYSTEM DESIGN PREMISES

14.2.1 The Unit's Mooring System shall be designed to withstand extreme environmental combinations of waves, wind and currents at any draught ranging from slightly loaded to fully loaded conditions, in accordance with requirements from CS and ISO 19901-7, and shall consider all design condition defined in SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see 1.2.1). Under these conditions, the Unit's Mooring System shall demonstrate its adequate station keeping performance according to limits and constraints stated in that document.

14.2.2 In terms of environmental combinations (simultaneous wind, waves and current loads), CONTRACTOR shall comply with CS standards associated with specific field METOCEAN DATA (see item 1.2.1).

14.3 WIND AND CURRENT DRAG COEFFICIENTS

14.3.1 For Mooring System Design purposes wind and current drag coefficients shall comply with CS requirements. If necessary and agreed with CS, wind and current drag coefficients can be obtained from Wind Tunnel Tests, with model scale 1:200. In this case, Wind Tunnel Test Report shall be provided for PETROBRAS for information.

14.3.2 The coefficients shall be given from 0 to 360 degrees incidence directions, stepped by 15 degrees, for three distinct draughts (slightly loaded, intermediate loaded and fully loaded), for both Wind and Current Drag coefficients achievement. The coefficients shall be reported in Mooring Analysis Report.

14.3.3 OCIMF (Oil Companies International Marine Forum) standards shall be followed either in reference system or non-dimensional coefficients representation.

14.4 POLYESTER ROPE STIFFNESS MODEL

14.4.1 In Mooring Analysis Report, a detailed description on polyester ropes' stiffness model shall be provided, together with related references.

14.5 MOORING FIXED POINTS

14.5.1 PETROBRAS will be responsible for design, installation of the mooring fixed points (torpedo piles). CONTRACTOR shall assume that the anchor points will support the maximum loads mentioned in document SPREAD MOORING AND RISER SYSTEM REQUIREMENTS, item 6.2.

14.6 SOIL DATA

14.6.1 Mooring system design shall comply with bathymetry chart (stratigraphy and soil profile) of the Unit's installation site.

14.6.2 During the detailed design phase, PETROBRAS will inform the "fine bathymetry map" for the intended location of the Unit´s mooring fixed point.

15 SUBSEA SYSTEMS

15.1 GENERAL

15.1.1 The riser balcony of the Unit shall be designed on the Portside, with guide tubes or receptacles and a support for the upper balcony installed on the Hull upper side. PETROBRAS highlights this is a preliminary plan. It can be changed up to Kick-off Meeting.

15.1.2 CONTRACTOR shall consider:

- Production, gas transfer and water/gas injection risers will be rigid, during the lifetime of the FPSO;
- Service/Gas lift risers will be flexible, during all operational lifetime of Unit.

15.1.3 The flexible risers can come from portside and/or starboard side of Unit. For rigid riser CONTRACTOR shall consider that up to four positions, that will always be grouped together side by side, can come from starboard, and it will be confirmed at Kick-off meeting.

15.1.4 The riser balcony of the Unit shall be designed in order to connect the flexible and/or rigid risers listed in Table 15.1.4.

Table 15.1.4 - Risers Details

FPSO	Risers (NOTE 1)	Function	Total	Comments
Oil Production and Gas Injection PAG (P1) (NOTE 6)	8"	Oil Production/Gas Injection	1	The production/gas injection riser will be rigid (8" ID).
Oil Production (P2 to P11)	8"	Oil Production	10	The production risers will be rigid (8" ID).
	4" ID	Gas Lift	11	Gas lift risers will be flexible (4" ID).
WAG Injection Wells (I1 to I7) (NOTE 2)	6" or 6.5" ID	Water/Gas Injection A	5	The injection risers will be rigid (6" or 6.5" ID). Unit shall be prepared that both alternatives and diameters can be implemented during lifetime of FPSO. They may inject water or gas alternately at any time. This slot can be connected to satellite wells or subsea interconnected pair of wells.
	6" or 6.5" ID	Water/Gas injection B	5	The injection risers will be rigid (6" or 6.5" ID). Unit shall be prepared that both alternatives and diameters can be implemented during lifetime of FPSO. They may inject water or gas alternately at any time. This slot can be connected to satellite wells or subsea interconnected pair of wells.
	6" or 6.5" ID	Water/Gas injection	2	The injection risers will be rigid (6" or 6.5" ID). Unit shall be prepared that both alternatives and diameters can be implemented during lifetime of FPSO. They may inject water or gas alternately at any time. This slot can be connected to satellite wells or subsea interconnected pair of wells.
	4" ID	WAG Service Line	3	Service risers will be flexible (4"). One service riser is exclusive for HISEP™.
Umbilicals	UEH	Control/Power Supply	11	Unit shall be prepared to receive STU (Steel Tube Umbilicals. This slot may also be used to import electric power to Unit from external sources.
Fiber Optic	CO	Control	1	For Platform communication
PRM Cable (NOTE 4)	CO	Control	1	For PRM communication

		TOTAL	50	-

NOTE 1: The sequence, functions and diameters of each riser slot will be defined at the project kick-off meeting together with the subsea layout.

NOTE 2: Each injection slot may inject water or gas alternately and independently. Positions I1 to I5 may be connected to a subsea interconnected pair of wells, as detailed in Figure 2.6.22. Positions I6 and I7 may be connected to satellite wells.

NOTE 3: One of the injection slots could be used to connect a gas transfer line, it will be defined at the kick-off meeting, in this case one of the umbilicals will be used to control subsea emergency shutdown valves (SESDV) (DHCS - Direct Hydraulic Control System).

NOTE 4: The information about this line is detailed at the item **Erro! Fonte de referência não encontrada.**.

NOTE 5: More details related to the interface between risers and HISEP™ system, see item 2.11.

NOTE 6: Topsides interconnections and protections shall consider that position P1 may switch function to gas injection after some years of production. Gas injection will be through production riser. Removable spools shall be used to switch interconnections from production to gas injection function. During execution phase, PETROBRAS will provide Subsea Risk Assessment recommendations.

15.1.5 Flexible risers:

- Positions P1, P2, P3, P4, P5, P6, P7, P8, P9, P10 and P-11 - one Gas Lift / Flexible service line (4” ID) for each well: 1 x 11 = 11 slots are required;
- Positions I6, I7 and HISEP™ Service Line - one flexible service, water / gas injection (4” ID) riser for each well: 1 x 3 = 3 slots are required;
- Control/Power Supply Umbilicals: 11 slots are required;
- One Optical cable for data transmission: 1 slot is required;
- One Optical cable for PRM data acquisition: 1 slot is required.

15.1.6 Rigid risers:

- Position P1 – one production/gas injection (8”ID) for each position: 1 slot is required;
- Positions P2, P3, P4, P5, P6, P7, P8, P9, P10 and P11 - one production (8” ID) for each position: 1 x 10 = 10 slots are required;
- Positions I1A/I1B, I2A/I2B, I3A/I3B, I4A/I4B, I5A/I5B, I6 and I7 - two water/gas injection (6’’ or 6.5” ID) for each interconnected pair of wells (Slot A + Slot B) + one water/gas injection riser (6’’ or 6.5” ID) for I6 + one gas injection riser (6’’ or 6.5” ID) for I7: 10 + 1 + 1 = 12 slots are required.

15.2 RISERS CHARACTERISTICS

15.2.1 CONTRACTOR shall provide supports for flexible and Rigid risers that may be connected to the Unit in accordance with SPREAD MOORING AND RISER SYSTEM REQUIREMENTS (see 1.2.1).

15.2.2 CONTRACTOR shall consider the following to protect the risers regarding pressure and temperature:

Table 15.2.2A - Pressure for Risers Protection

Subsea Line	Design Pressure (kPa(a))	Leak Test Pressure (kPa(a)) (1,2)	Max. Process Operating Pressure (kPa(a))	Gas Service Operating Pressure (kPa(a))	Max. Well Service Operating Pressure (kPa(a))
Production Line	36,500	41,900	31,000		33,000
HISEP™ Production Line	52,600(14)	55,255	31,000		33,000
Gas Lift/Production Service Line	36,500	41,900	25,000	Pig Operation Mode Min. 4,500	33,000
Gas Lift/Production Service Line (for P1 and P8)	38,500	44,500	25,000	Pig Operation Mode Min. 4,500	33,000
WAG Service Line (for I6)	38,500	44,500		Pig Operation Mode Min. 4,500	33,000
WAG Service Line	60,500	66,550		Pig Operation Mode Min. 4,500	31,000
HISEP™ Service Line	60,500	69,900		Pig Operation Mode Min. 4,500	33,000
WAG & Gas Injection Line	60,500	69,900	55,000	Pig Operation Mode Min. 4,500	33,000
Umbilical Line	69,000		51,750		

Table 15.2.2B - Temperature for Risers Protection

Subsea Line	Temperature (°C)			
	Max. Design	Min. Design	Operating	HH to close respective BSDV
Production Line/ HISEP™ Production Line	108	-30	15 to 95 (Production) Ambient temperature to 85 (Well service operations w/Diesel)	XX
Gas Lift/Service Line	95	-20	40	XX
Water Injection Line	65	3	40	XX
Gas Injection Line	65	-30	40	XX

NOTE 1: During the leak test an overpressure of 4% above the leak test pressure for all risers may be requested by PETROBRAS.

NOTE 2: A separate low capacity (fresh water, 2.5 m^3/h with 100% re-circulation), high pressure pump shall also be provided to achieve the required pressure up to 72,700 kPa(g) for leak test all risers: production, water injection, lift gas and gas injection risers after hook-up. Piping and accessories design shall consider the presence of sea water. A portable and/or movable skid pump is acceptable. The pump shall be permanently onboard.

NOTE 3: The required leak test pressures are related to riser test. Topsides piping and accessories may not be designed considering the riser leak test pressure. The conceptual design shall be submitted to PETROBRAS for comments/information.

NOTE 4: Facilities to allow the leak test of the risers using rented service pumps shall be provided.

NOTE 5: During execution phase PETROBRAS will confirm to CONTRACTOR the pressure and temperature requirement for riser protection. Temperature at top of injection/service risers shall be monitored.

NOTE 6: The selection of relief devices to protect the risers against overpressure during service pump operation shall take into consideration: (i) operating conditions defined on item 2.6; (ii) each riser required design pressure as per Table 15.2.2A; (iii) maximum overpressure (full open condition) of 10% of relief device set pressure.

NOTE 7: The selection of relief devices on the discharge of Main/Injection Compressors and Water Injection Pumps shall also take into consideration each riser required design pressure as per Table 15.2.2A.

NOTE 8: Facilities to monitor the pressure and depressurize risers during leak test operation shall be provided.

NOTE 9: The leak test for rigid lines shall obey the maximum pressures from table Table 15.2.2A.

NOTE 10: A PSHH (Pressure Switch High High) and PSLL (Pressure Switch Low Low) shall be installed downstream of each gas injection choke valve and interlocked with the respective injection gas riser BSDV valve. The PSLL downstream of each gas injection choke valve shall also be interlocked with the respective Christmas tree. The set points will be informed during the project execution phase and updated during operational phase.

NOTE 11: A PSLL shall be installed downstream of each service choke valve and interlocked with the service pump when operating in this mode. Additionally, PSLL shall be interlocked with the respective gas lift riser BSDV valve when operating in gas lift mode. The set points will be informed during the project execution phase and updated during operational phase.

NOTE 12: The Unit shall have specific devices to monitor pressure on topsides gas lift/ service lines paired with P1, P8 and I6 in order to detect undesired flow from gas injection subsea lines to subsea service lines during gas injection. (OBS: Service line from P8 may be temporarily paired with a satellite injection well).

NOTE 13: For P1 (PAG), during the production phase, the pressure and temperature riser protection parameters of Production Lines should be considered and, during the Gas Injection phase, the pressure and temperature riser protection parameters of Injection Lines should be considered.

NOTE 14: The riser's design pressure is 50,179kPa(a), however, the riser is designed to withstand the maximum incidental pressure of 52,600 kPa(a).

15.3 RISERS INSTALLATION AND DE-INSTALLATION PROCEDURES

15.3.1 The Unit's Risers Installation and De-installation Procedures shall comply with the SPREAD MOORING AND RISER SYSTEM REQUIREMENTS document (see item 1.2.1).

15.4 RISER HANGOFF AND PULL-IN SYSTEMS

15.4.1 CONTRACTOR shall refer to the Annex documents (see 1.2.1):

- SPREAD MOORING AND RISERS SYSTEM REQUIREMENTS;
- RISERS TOP INTERFACE LOADS ANALYSIS;
- DIVERLESS BELL MOUTH SUPPLY SPECIFICATION;
- DIVERLESS BELL MOUTH PART LIST DRAWINGS;

- CONICLE RECEPTACLE “TYPE B”.

15.5 RISER MONITORING SYSTEM

15.5.1 RIGID RISER MONITORING SYSTEM (RRMS)

15.5.1.1 For RRMS, see RIGID RISER MONITORING SYSTEM (RRMS) – FPU SCOPE (see item 1.2.1).

15.5.2 MODA RISER MONITORING SYSTEM (MODA)

15.5.2.1 For MODA, see MODA RISER MONITORING SYSTEM – FPU SCOPE (SPREAD MOORING) – see item 1.2.1.

15.5.3 ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM

15.5.3.1 The annulus of every flexible riser connected to the Floating Production Unit shall be vented to a safe area.

15.5.3.2 CONTRACTOR shall design, provide and operate the Annulus Pressure Monitoring and Relief System, as detailed on the technical specification "Annulus Pressure Monitoring and Relief System" (I-ET-3010.00-5529-812-PAZ-001) in order to:

- Guarantee a safe release on board for the permeated gas in the flexible riser annulus;
- Monitor, detect and control any abnormal pressure build up that may - for example - damage the flexible risers.

15.5.3.3 This specification allows some variations of the Annulus Pressure Monitoring and Relief System. For this project the (XXX type) shall be used by the CONTRACTOR and the (XXX type) shall be applied to all flexible risers, except for (YYY).

15.5.3.4 CONTRACTOR shall provide the annulus pressure monitoring and relief system, to guarantee a safe release for the gas permeated in the annulus space of flexible risers and to detect any pressure build up that may damage the risers.

15.5.3.5 CONTRACTOR shall perform detailed engineering of this system (including piping, valves, pressure sensors, supervisory integration, etc.).

15.5.3.6 This system shall be applied to all flexible risers (production risers, injection risers (gas or water) and service risers (gas lift) of all wells).

15.5.3.7 Additional information is presented in the Technical Specification ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM (see item 1.2.1).

15.6 ENV – METOCEAN DATA GATHERING AND TRANSMISSION SYSTEM

15.6.1 For ENV, see METOCEAN DATA ACQUISITION SYSTEM REQUIREMENTS (see item 1.2.1).

15.7 POS - POSITIONING SYSTEM FOR MOORING OPERATION AND OFFSET DIAGRAM

15.7.1 For POS, see POSITIONING AND NAVIGATION SYSTEMS (item 1.2.1).

15.8 PRM – PERMANENT RESERVOIR MONITORING SYSTEM

15.8.1 For PRM, see PERMANENT RESERVOIR MONITORING SYSTEM – SPREAD MOORING - FPSO SCOPE (see item 1.2.1).

16 MARINE SYSTEMS AND HULL UTILITY SYSTEMS

16.1 GENERAL

16.1.1 In case of conversion, CONTRACTOR shall adopt the so called “all new” philosophy for marine and utility systems. This means that all existent marine and utility system shall be fully removed (including, but not limited to, rudder, shaft, main engine and auxiliary propulsion systems, marine boiler, former cargo pumps, etc.) or replaced by brand new item (such as but not limited to equipment, piping, cable, panels, valves, HVAC). This also includes the items inside accommodation. Exception can be made for former tanker anchor windlass.

16.1.2 CONTRACTOR shall provide an emergency anchoring system in accordance to CS`s and Brazilian Naval Authorities requirements. This system shall be similar to the anchoring system required for a ship of similar size under the CS’s normal “Steel Vessel Rules” and is intended for use in shallow coastal waters and harbors.

16.2 CARGO OIL SYSTEM, CRUDE OIL WASHING SYSTEM, BALLAST SYSTEM, INERT GAS SYSTEM AND HYDROCARBON GAS BLANKETING SYSTEM

16.2.1 The Cargo Oil System, Crude Oil Washing System, Ballast System and Inert Gas and Cargo Tanks Venting System shall follow the requirements of SOLAS and CS rules, guidelines and requirements.

16.2.2 In addition to Inert Gas System for tank blanketing, Hydrocarbon (HC) Gas Blanketing System shall be installed to reduce emissions to the atmosphere.

16.2.2.1 HC Gas Blanketing System shall operate in cargo tanks, slop and structural process tanks (e.g produced water tanks, oil off-spec tanks, settling tanks, etc.). Structural process tanks are the tanks installed in the hull cargo area, dedicated to the process plant.

16.2.2.2 For Hydrocarbon Gas Blanketing system minimum requirements, refer to section 10.2 of SAFETY GUIDELINES FOR OFFSHORE PRODUCTION UNITS (see item 1.2.1).

16.2.3 Crude Oil Washing System shall have a dedicated heater using Unit heat medium.

16.2.4 The FPSO shall not have any pump room. In case of conversion, the former pump room shall be converted in void space and shall not have any equipment, piping and other accessories.

NOTE: The fluid transfer system dedicated to cargo, ballast, slop, produced water, off-spec and settling tanks (if applicable) shall be based on submerged type pumps.

16.2.5 Independent Inert gas, purge gas and vent gas headers shall be provided for cargo tanks.

16.2.6 Inert gas generator system shall be fed by a dual fuel system, burning preferably fuel gas and alternatively marine Diesel oil. Oxygen content shall be measured with indication in the supervisory system.

16.2.7 The Ballast System shall comply with all Brazilian Administration requirements.

16.2.8 .Scrape water (displacement water eventually settling out of stabilized crude oil in cargo storage tanks) shall be sent to the oil offspec tank instead of the slop tank.

16.2.9 HC Gas Blanketing System gas recovery compressors shall be either liquid-ring compressors (as per API Std. 681) or screw compressors (as per API Std. 619). Configuration shall be N+1.

16.3 OIL TRANSFER SYSTEM

16.3.1 The oil from the storage tanks will be exported to a shuttle tanker, according to the document OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see 1.2.1).

16.3.2 Oil Transfer System with individual submerged pumps (deep-well) in each tank shall comply with the following requirements:

- A longitudinal header shall be installed on the main deck and branches provided with manual valves and blind flanges for the connection of the portable cargo pump to every and each tank. For further details, cargo portable pumps supplier standards shall be used. CONTRACTOR shall include cargo portable pump and accessories in the mechanical handling study.
- Submerged hydraulic or electrical driven pumps on main deck for each cargo and each slop tank.

16.3.3 CONTRACTOR shall limit exported oil temperature through export hoses, from a minimum of 35ºC to a maximum of 55ºC, to comply with shuttle tankers requirements.

16.3.4 CONTRACTOR shall provide arrangements and facilities to allow proper flushing of the offloading system (including the offloading hose), which will be performed immediately after every cargo transfer (offloading) as follows:

- The Unit shall allow pumping both seawater and slop water through the offloading hose from the Unit to the shuttle tanker.
- After the oil offloading being performed, the shuttle tanker will pump the water back to the Unit at a flowrate of at most 3000 m³/h. Therefore, the Unit shall not have any constraint, such as non-return valves at the hose reel that may jeopardize the seawater pump-back operation from shuttle tanker to FPSO.
- Additionally, Unit shall be capable to perform final flushing of the offloading hose on a “closed circuit mode”. The close circuit mode means the offloading hose will be reeled and stored onboard the Unit.

16.3.5 The offloading system, including the hose reel, shall be designed considering the operation with Suezmax shuttle tankers, as described in document OFFSHORE LOADING SYSTEM REQUIREMENTS and OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS (see item 1.2.1).

16.3.6 CONTRACTOR shall provide means to store the NSV (North Sea Valve) in an area with secondary containment in order to avoid possibility of oil spills overboard.

16.4 HULL UTILITIES

16.4.1 In addition to the Unit Utilities detailed on section 3 of this GTD, Hull utilities mainly dedicated to the Hull Marine Systems are herein detailed: Fresh Water and Potable Water System, Filling Stations, Diesel Oil System and Sewage.

16.4.2 FRESH AND POTABLE WATER SYSTEM

16.4.2.1 Water maker units shall be installed to generate sufficient fresh and potable water for the Unit’s consumption.

16.4.2.2 The fresh and potable water aboard shall comply with Ordinance Anexo XX da Portaria De Consolidação Nº 5, de setembro de 2017 (Consolidação das normas sobre as ações e os serviços de saúde do Sistema Único de Saúde)and ANVISA RDC 72/2009. Chlorination Unit is required. Special attention shall be given to the quality parameters as well as cleanness requirements, tanks and distribution lines disinfection, analysis routine and the separate storage of water for human consumption of distinct sources. Material selection for Piping (upstream and within accommodation) shall avoid corrosion particles and contaminants in potable water.

16.4.2.3 CONTRACTOR shall provide sampling points in accordance with *Portaria GM/MS Nº 888, 4/maio/2021*.

16.4.2.4 Power consumption of fresh water maker unit shall be registered on unit supervisory system.

16.4.3 FILLING STATIONS

16.4.3.1 Despite the Unit being prepared to generate fresh and potable water, a minimum of 2 (two) filling connections (one for water and another for Diesel) shall be installed at each bunkering station. The bunkering stations to be located at Starboard side of the Unit near each aft and forward cranes respectively. The bunkering stations shall be located as close as possible to the supply boat mooring area and allow quick operation. Piping shall be at least 4” diameter.

16.4.3.2 The bunkering stations shall be provided with separate hoses, connections and valves for Diesel and fresh water, so that both stations are full time available to allow quick and immediate operation, in compliance with the following:

16.4.3.2.1 Connections:

- Type EVER-TITE® quick connect-disconnect couplers for Diesel and freshwater hoses;
- Filling station end: swaged-on male NPT carbon steel nipple + female thread/male adapter + female coupler/female straight pipe thread (connected to the filling station piping);
- Supply-boat end: swaged-on male NPT carbon steel nipple + female straight pipe thread/female coupler.

16.4.3.2.2 Hoses:

- All hoses shall be 120m length and with 4” diameter;
- The hose sections of Diesel hoses shall be connected by non-leakage couplings. WECO wing union type SHU and similar are not allowed. One connection between the Diesel hoses sections shall be of Safety Break-Away Coupling type to prevent pull-away accidents and avoiding sea contamination;
- 150 psi working pressure;
- Cover: black, weather, ozone and oil resistant high-quality chloroprene rubber;
- Reinforcement layers: synthetic textile yarns;
- Tube: black, smooth fuel/oil resistant high-quality nitrile rubber;
- Temperature range: -30 to +80 ºC;
- Lifting clamps shall be provided at hose ends;
- Hoses shall float (self-floating hoses or with floating devices);
- Diesel oil hoses located at FPSO filling stations shall have dry disconnect female coupling type for end connection manufactured according to NATO STAGNA 3756 for operations with the supply vessel. In addition, FPSO shall provide, as a loose

item, one adaptor to connect in a CAMLOK tank end of the supply vessel (old fleet vessels);

- A drip-pan shall be installed to collect any leakage from all bunkering station connections with manually operated drainage valve located at the pan bottom;
- CONTRACTOR shall comply with Ordinance MS Nº 2914/2011 and present evidence of harmlessness of the materials used in freshwater bunkering hose.

16.4.4 DIESEL SYSTEM

16.4.4.1 The Diesel system shall be designed in order to supply, besides all other consumption requirements, feed the well service pump operations (e.g. to push pigs, and subsea system clean flowlines (see item 2.6).

16.4.4.2 For details of bunkering station connections see item 16.4.3.

16.4.4.3 Diesel oil shall be filtered and on-line metered before being sent to the storage tank.

16.4.4.4 A minimum configuration of 2x100% is required for Diesel pumps dedicated for well service which shall be designed in order to guarantee the required flowrate of the well service pump (as per item 2.6). The Diesel pumps shall have filter upstream and recycle for flow control to avoid frequent start/stop.

16.4.4.5 The Diesel oil storage tank volume shall have enough capacity to provide Diesel oil to be used as fuel for 7 (seven) days continuously plus 5,000 m^3 for subsea lines flushing.

16.4.4.6 PETROBRAS will provide Diesel oil in accordance with ANP requisition. DMA (*Diesel Marítimo TIPO A*) shall be considered for turbogenerator projects.

16.4.5 SEWAGE SYSTEM

16.4.5.1 Unit shall have a sewage treatment unit in compliance with MARPOL, and IBAMA requirements specially but not limited to the “Resoluções CONAMA” and the “NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11”. Sampling point shall be provided according to item 2.9.

16.4.5.2 Both grey and black waters shall be previously treated and metered before discharged to sea.

16.4.5.3 The FPSO is not allowed to discard sewage (black and grey waters) overboard without treatment even during the sewage treatment unit maintenance period. CONTRACTOR shall submit to PETROBRAS a plan that allows the FPSO continuous operation without any impact.

16.4.5.4 The sewage treatment unit shall be capable to treat at least 250 liters/person/day.

16.4.6 TANKS REQUIREMENTS

16.4.6.1 Online Gas Sampling System shall be provided in ballast tanks and void spaces adjacent to cargo/slop tanks, according to the requirements of FSS Code (International Code for Fire Safety Systems).

16.4.6.2 Permanent means to connect a contingency hose for inert gas shall also be provided for each ballast tank and void spaces adjacent to cargo tanks.

16.4.6.3 It shall be possible to recirculate the slop tank fluids passing through a heat exchanger, with sample points in the return line. It is acceptable to use Crude Oil Washing System heater (item 16.2.2).

16.4.7 SLOP DISCHARGE TREATMENT

16.4.7.1 To complement gravitational separation in the slop tanks, the Unit shall have a separate water treatment system using centrifuge (2x100%), in order to treat the oily water prior to discharge. This water treatment system shall have a by-pass and the minimum and maximum flow to each centrifuge shall be 50 m^3/h and 100 m^3/h, respectively. Alternative configuration shall be submitted for PETROBRAS approval provided that dynamic equipment be 2x100%.

16.4.7.2 Water discharge from slop tanks shall be measured and monitored for TOG, as followed:

- 2x100% online TOG analyzer;
- TOG analyzer with an IMO MEPC 107(49) certification, to attend MARPOL 73/78;
- Automatic cleaning system of acoustic (ultrasonic) type and manual sampling devices shall be provided;
- Logics shall also be implemented so that the overboard discharge is interrupted if the slop water downstream treatment system is out of specification. The water out of specification shall be returned to slop tank;
- The discharge point shall have a redundant flow meter (2x100%).

17 ENVIRONMENT IMPACT STUDIES AND LICENSING

17.1 GENERAL

17.1.1 PETROBRAS will engage third party for Environmental Studies, in which case CONTRACTOR shall take part in the assessment, provide all necessary information and comply with recommendations.

17.1.2 CONTRATOR shall provide a report with information requested by PETROBRAS during FPSO licensing process.

17.1.3 This report shall include the following items:

a) Table with the FPSO characteristics including FPSO name, mooring type, length, molded breadth, depth, molded depth, light weight, maximum draft, flare height, total FPSO storage capacity, fuel gas and Diesel consumption list, crane capacities, power generation (main, auxiliary, emergency) rating, sewage treatment system capacity and technology, living quarters capacity, helideck specification, life saving equipment;

b) Hull description;

c) Tank capacity plan including each tank material specification and specific requirements e.g. painting;

d) Inert gas system description;

e) Ballast system description;

f) Description of the Fluid processing plant (oil, gas, produced water and injected water);

g) Simplified process block diagram containing produced oil, produced water, produced gas and sea water treatment; gas export and reinjection; seawater and produced water injection;

h) Diagram (for each process: oil treatment, gas treatment, produced water treatment and sea water treatment for injection) containing main equipment as separators, scrubbers, heat exchangers, compressors and pumps;

i) Table with pressure, temperature, flow rate and contaminant content (water cut for liquid systems, CO_2, H_2S and water for gas systems) for inlet and outlets of each main process equipment as separators, heat exchangers, compressors and pumps;

j) Cooling sea water overboard characteristics such as discharge maximum flow rate, temperature, internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;

k) Cooling water closed loop system description, including pumping configuration and flow rate;

l) Industrial water supply system description including type of treatment, suction depth, flow rate and consumers list;

m) Potable water system description including type of treatment and flow rate;

n) Simplified diagram of industrial and potable water treatment;

o) Power generation description including capacities of main, auxiliary, uninterruptible and emergency systems, as well as fuel consumption for each generator considering all fuel sources;

p) Cranes description including length and capacity;

q) Flare and vent systems description including flow rate capacities, and stack height;

r) Topsides and Subsea Chemical injection system description including a table expected chemical, dosage rate, injection points, and storage capacity.

17.2 EFFLUENTS

17.2.1 CONTRACTOR shall provide details about effluent treatment and discharge on sea are required to support plume dispersion included in environmental studies:

a) Sulphate removal/ Ultrafiltration/ Reverse Osmosis reject flow rate, composition, discharge temperature, density (measured or calculated), pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;

b) Sulphate removal/ Ultrafiltration/ Reverse Osmosis membranes cleaning procedure description including expected frequency and the duration of each step, waste water overboard description containing composition, pH, discharge volume, temperature and duration, density, salinity, chemical concentration, flow rate, pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;

c) Produced water system description, oil content, sample connections, measurement points, interlock between measurement and discharge, reprocessing philosophy description, discharge flow rate, temperature, density (measured or calculated), pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;

d) Drainage system description, estimate of volume generated monthly, composition, oil content, measurement points, interlock between measurement and discharge, reprocessing philosophy description, discharge flow rate, pipe internal diameter, direction and position in relationship to sea water surface. The draft variation due to FPSO load shall be informed;

e) Simplified scheme containing all drainage systems (topsides and marine);

f) Sewage treatment system description, including Oil and Grease and Biochemical Oxygen Demand (BOD) removal capacity, considering the expected POB in all the FPSO's lifecycle.

17.3 ATMOSPHERIC EMISSIONS

17.3.1 CONTRACTOR shall provide:

a) Annual quantification (volume) per type of fuel used for the design cases (Table 2.2.2.3);

b) Characteristics and composition (up to C10+ in case of gas) of fuel, volume and type of fuel used by emitting sources. In case of fuel gas with different CO_2 contents, normal and the highest concentration must be used. For dual fuel generators the quantification must be done for each fuel;

c) Quantification of fugitive emission sources from equipment and piping handling fluid with methane content equal or higher than 20% in weight and/or handling non stabilized liquid hydrocarbon. The sources to be considered shall be, but not limited to, valve stem, valve flanges, pumps seals, drains, vents, etc.;

17.3.2 A description of Unit Commissioning Procedure, including the volume of gas flaring , fuel (diesel and gas) consumption and estimated time for commissioning of each system.

17.4 WASTE MANAGEMENT

17.4.1 CONTRACTOR shall provide solid residues characterization, residue class, disposal destination, annual mass generation including change out process materials (molecular sieve, CO2 membranes cartridges, sulphate removal membranes cartridges, etc.), sewage sludge, oil tank sludge, slop tank sludge, flotation cell unit sludge, ordinary garbage, nursery garbage, dangerous residues, food debris, oily residues, chemicals, etc.

18 PETROBRAS LOGOTYPE

18.1 GENERAL

18.1.1 CONTRACTOR shall paint PETROBRAS logo type in the following Unit places:

- Funnel (both sides);
- Port side and Starboard in visible area;
- Front wall of the accommodation block.

19 VENDOR LIST

19.1 GENERAL

19.1.1 Vendor list defined for the equipment below shall be followed. The selection of proper equipment among supplier's portfolio is under CONTRACTOR responsibility.

19.1.1.1 Water Injection Pumps

- Sulzer;
- Flowserve;
- Nuovo Pignone;
- FRAMO.

19.1.1.2 Molecular Sieve Solid Bed (Zeolite)

- CECA;
- UOP (Honeywell);
- ZEOCHEM L.L.C;
- Axens;
- Grace GmbH.

19.1.1.3 Moisture Analyzer

- Ametek;
- Spectrasensors.

19.1.1.4 Membranes for CO2 Removal Unit

- Cameron;
- UOP;
- Air Liquide;
- Evonik;
- MTR.

19.1.1.5 Rotary compressor for Vapor Recovery Unit API 619:

- Kobelco;
- MAN;
- HOWDEN.

19.1.1.6 Centrifugal Compressors API 617:

- BH;
- Hitachi;
- MAN;
- Mitsubishi;
- Siemens/ Dresser-Rand;

19.1.1.7 Cancelled.

19.1.1.8 Submerged Sea water Lift Pumps (Electric)

- FRAMO;
- EUREKA with Hayward-Tyler submerged electric motors.

19.1.1.9 Fire Water Pumping Unit

19.1.1.9.1 Diesel-Hydraulic package

- Sulzer;
- FRAMO.

19.1.1.9.2 Diesel-Electric package

- FRAMO;
- EUREKA with Hayward-Tyler submerged electric motors

19.1.1.10 Aero-derivative or light industrial gas turbine API 616 for offshore environment (Main Generators):

- Baker Hughes: LM 2000, LM2500, LM2500+, LM2500+G4, LM6000 PC/PG;
- SIEMENS: SGT-A35 (up to 34MW ISO), SGT-100, SGT-600, SGT-750 (No propane, only diesel startup system);
- SOLAR: SATURN, CENTAUR, TAURUS 60, MARS100, TITAN 130, TITAN 250.

19.1.1.11 Flare flow meter:

- Fluenta;
- Baker Hughes;

19.1.1.12 Variable Speed Drives (VSD) (> 5MW):

- ABB;
- GE;
- Innomotics;
- TMEIC;
- WEG.

19.1.1.13 Cancelled.

19.1.1.14 Boiler Feed Water Pump:

- BH;
- Flowserve;
- Sulzer.

19.1.1.15 OTSG:

- BIH;
- NEM;
- IST/PROPAK.

19.1.1.16 Steam Turbine:

- BH;
- Siemens;
- Peter Brotherhood.

19.1.2 Vendor List does not exempt CONTRACTOR from its responsibilities for events caused by the selection of equipment among suppliers' portfolio or equipment malfunction or defect.