PETROBRAS	**TECHNICAL SPECIFICATION**	Nº: I-ET-3010.2K-1200-941-P4X-001	
	CLIENT: BÚZIOS	SHEET 1 of 170	
	JOB: FPSO BÚZIOS 12	--	
	AREA: CAMPO DE BÚZIOS		
SRGE	TITLE: **GENERAL TECHNICAL DESCRIPTION - BOT**	INTERNAL	
		ESUP/PIES	

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DATE	FEB/02/25	MAR/10/25	MAY/12/25	OCT/02/25					
DESIGN	ESUP	ESUP	ESUP	ESUP					
EXECUTION	CXGA	CXGA	CXGA	CXGA					
CHECK	UQK9 / NRWK	UP8W / NRWK	NRWK / UP3L	B5QO / NRWK					
APPROVAL	UP8W	CQC4	UP8W / U40V	NS5Z / UP3L					

SUMMARY

1 GENERAL

1.1 INTRODUCTION

1.1.1 The intent of this specification and documents referenced hereinafter is to provide the SELLER with general information of intended service and requirements for the design, construction, 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 Agreement. 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 Previdência), Flag Administration, International Maritime Organization (IMO) and applicable rules and laws) shall be complied with. In addition, SELLER shall comply with BUYER 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 BUYER’s technical requirements, BUYER 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 SELLER from contractual responsibilities. SELLER 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 reviewed 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 “SELLER responsibility” or “SELLER’s responsibilities” means that the SELLER will design, supply, install, operate and maintain according to the Agreement provisions.

1.1.6 BUYER “approval” or "comments" on the documents shall not exempt SELLER 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 BUYER, at their sole discretion, have the right to reject any detail of the Unit’s design.

1.1.8 SELLER 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. SELLER 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 SELLER 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 SELLER and BUYER. The actions and outcomes from these workshops shall be shared with BUYER.

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-3A26.00-1000-941-PPC-001	G	METOCEAN DATA
2	I-ET-3D10.12-1350-274-PX9-001	B	RISER SYSTEM REQUIREMENTS
3	I-ET-3010.00-1500-274-PLR-001	F	RISERS TOP INTERFACE LOADS ANALYSIS
4	I-ET-3010.2K-1200-813-P4X-001	B	FLOW METERING SYSTEM – BOT
5	I-ET-3010.00-5400-947-P4X-012	E	SAFETY GUIDELINES FOR BOT OFFSHORE PRODUCTION UNITS
6	I-ET-3010.00-1359-960-PY5-001	X	OFFSHORE LOADING SYSTEM REQUIREMENTS
7	I-ET-3010.00-1300-279-PX9-001	B	UNIFIED DIVERLESS SUPPORT TUBE (TSUDL) - GENERAL REQUIREMENTS
8	I-LI-3010.00-1300-270-P56-001	E	TSUDL Part List
9	I-ET-3010.2K-1357-962-PX9-001	B	SPREAD MOORING SYSTEM REQUIREMENTS
10	I-ET-3D10.12-1500-800-PEK-001	0	SUBSEA PRODUCTION CONTROL SYSTEM FOR FPSO
11	I-ET-0600.00-5510-760-PPT-601	E	TELECOM MASTER SPECIFICATIONS FOR BOT UNITS
12	I-ET-3010.2K-5521-931-PEA-001	0	METOCEAN DATA ACQUISITION SYSTEM REQUIREMENTS
13	I-ET-3000.00-5139-800-PEK-004	A	HYDRAULIC POWER UNIT FOR SUBSEA EQUIPMENT WITH MULTIPLEXED ELECTROHYDRAULIC AND DIRECT HYDRAULIC CONTROL SYSTEM (OWNED FLOATING PRODUCTION UNIT)
14	I-ET-3010.00-1200-200-P4X-012	0	TECHNICAL SPECIFICATION FOR HARD PIPE – BOT CONTRACTS
15	N/A	-	N/A

16	I-MD-3D10.12-1500-274-PX9-001	0	RISER AND HULL INTERFACE
17	I-ET-3010.00-5529-812-PAZ-001	H	ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM
18	I-ET-3010.2K-1200-940-1DN-001	C	PRELIMINARY SUBSEA OPERATION PHILOSOPHY
19	I-DE-3D10.12-1500-941-P56-001	0	RISER SUPPORTS ARRANGEMENT CONCEPTUAL DESIGN - FPSO BALCONY (NOTE 1)
20	I-ET-3010.2K-5530-850-PEA-001	0	POSITIONING AND NAVIGATION SYSTEMS REQUIREMENTS
21	I-ET-3010.00-5529-854-PX9-001	0	MODA RISER MONITORING SYSTEM – FPU SCOPE (SPREAD MOORING)
22	I-ET-3010.00-1300-279-PX9-002	B	DIVERLESS BELL MOUTH (BSDL) - GENERAL REQUIREMENTS
23	I-LI-3010.00-1300-279-PPC-350	I	BSDL-SI Part List
24	I-ET-3000.00-1210-010-1DO-001	0	FLUIDS FOR SPECIAL OPERATIONS
25	I-ET-3010.00-5529-854-PX9-002	0	RIGID RISER MONITORING SYSTEM (RRMS) – FPU SCOPE
26	I-ET-3010.00-5524-854-PX9-001	0	MONITORING SYSTEM FOR SUBSEA EMERGENCY SHUT-DOWN VALVE (SESDV) – FPU SCOPE
27	I-MD-3D10.12-5520-850-PX9-001	A	MD - SUBSEA MONITORING SYSTEM FOR FPSO BUZIOS 12
28	I-RL-3A00.00-1000-941-PPC-001	A	DURATION OF EXTREME CURRENT PROFILES AND CLUSTERS OF SIMULTANEOUS METOCEAN CONDITIONS
29	I-ET-3010.2K-1200-600-1DN-001	B	PIG FACILITIES FOR BUZIOS 12
30	I-ET-3010.00-1359-940-P4X-001	C	OFFSHORE LOADING EQUIPMENT DESIGN REQUIREMENTS
31	I-ET-3010.00-1200-901-P4X-001	D	AVAILABILITY AND MAINTENABILITY (RAM) ANALYSIS REQUIREMENTS – BOT-BOOT
32	I-LI-3D10.12-5139-800-PEK-002	0	LIST OF CONSUMERS FOR SUBSEA HPU OF THE BUZIOS 12 PROJECT
33	I-ET-3010.00-5139-172-PX9-001	0	PORTABLE UMBILICAL PRESSURIZATION SYSTEM (PUPS)
34	I-ET-3000.00-1519-29B-PZ9-012	0	TOPSIDE ARRANGEMENT AND INTERFACES WITH SUBSEA UMBILICAL SYSTEMS
35	I-ET-3010.2K-1200-941-P4X-002	0	ADDITIONAL REQUIREMENTS FOR BOT UNITS
36	I-ET-3010.00-1200-000-P61-002	0	OPERATIONAL MODES BOT
37	N/A	-	N/A
38	I-ET-3010.00-5412-98G-P4X-001	E	FLARE RADIATION STUDY
39	I-ET-0600.00-5510-760-PPT-603	0	TELECOM MASTER SPECIFICATIONS FOR SANTOS BASIN MALHA OPTICA PROJECT EQUIPMENT

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

1.2.2 GENERAL DESCRIPTION

1.2.2.1 The Unit design life shall be at least 30 years. During the Agreement 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 circa 1,960 meters, in accordance with SPREAD MOORING SYSTEM REQUIREMENTS and RISER SYSTEM REQUIREMENTS.

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

1.2.2.4 Produced gas shall be compressed, dehydrated, treated, and used as a fuel gas and for lifting oil production. Remaining gas will be exported through a gas pipeline to BUYER gas pipeline system or reinjected in the reservoir. Produced water may 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	31,800 Sm^3/d
Total Maximum Oil	28,600 Sm^3/d
Total Produced Water	23,850 Sm^3/d
Total De-Sulphated Sea Water Injection	54,850 Sm^3/d
Total Gas Handling, including lift gas, treatment and compression	12,000,000 Sm^3/d (1)

NOTE 1: Gas flow rate at the inlet of Main compression. The gas coming from internal recycles shall be added to define the total main gas compression/treatment capacity.

1.2.2.5 SELLER shall consider the SUBSEA LAYOUT documents and refer to ITEM 15.

1.2.2.6 Not Applicable.

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 1,360,000 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, exportation and/or 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);
- Gas compression plant comprising high-pressure centrifugal compressors driven by electric motor or gas turbine;
- Accommodation for normal operation crew, maintenance technicians required for contracted performance and for BUYER representatives. The unit's design accommodation shall be sized for a minimum of 180 People On Board (POB), considering the required personnel to accomplish the BUYER's operation, maintenance and asset integrity management plans for concepts with no or one turbocompressor driven service. For concepts with two or more compression services driven by turbocompressors, the unit's design accommodation shall be sized considering the corresponding increase of the Operations and Maintenance activities.
- Facilities to connect risers for oil production, gas-lift, gas export/import, gas transfer, water/gas injection and control umbilical;
- Cargo handling systems, including cranes, monorails, rail cars, etc;
- Helideck;
- Telecommunication facilities.

For additional requirements, see document ADDITIONAL REQUIREMENTS FOR BOT UNITS (see item 1.2.1).

1.3 CLASSIFICATION

1.3.1 SELLER shall contract a single CS to follow and approve the whole FPSO project comprising the design, construction, installation on site and operation;

1.3.2 The CS shall also consider all construction loads and the environmental loads during transportation from construction shipyard to Brazil. 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 SELLER's scope of work. SELLER's scope shall cover down to the last flanged connection in all risers.

1.3.7 During construction and operational phase, SELLER shall provide, whenever requested by BUYER, 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 °C and 101.3 kPa(a);
- Nm^3 @ 20 °C and 101.325 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 SELLER 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 ITEM 13).

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

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

2.1.5 SELLER 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 SELLER shall implement piping arrangement in order 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. SELLER shall design the Unit to process oil with any blend within these properties. SELLER shall make simulations to assess the correct design parameters.

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

Table 2.2.1.2 Oil Properties

Oil Properties and contaminants		
	Well A	**Well B**
Oil API grade	27.5	28.2
Viscosity (dry – dead oil) (1)	32.2 cP @ 30 °C 21.0 cP @ 40 °C 14.5 cP @ 50 °C 10.5 cP @ 60 °C 7.9 cP @ 70 °C	22.4 cP @ 30°C 15.2 cP @ 40°C 10.9 cP @ 50°C 8.1 cP @ 60 °C 6.3 cP @ 70 °C
Wax Appearance Temperature (2, 3)	45.8 °C (1st event) 21.1 °C (2nd event)	44.7 °C (1st event) 21.1 °C (2nd event)
Foam	Yes	Yes
Sand/Solids (2,4)	(5)	(5)

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

NOTE 2: SELLER 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 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. Offline removal system is acceptable, 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 SELLER shall design the Unit with the compositions given below. SELLER shall submit to BUYER, 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

#	Well	T (NOTE 1)	Oil Sm³/d (NOTE 2)	Liquid Sm³/d	Total Gas Sm3/d	Produced Gas Sm³/d	Lift Gas Sm³/d	Transferred Gas Sm³/d	Transferred Gas Fluid	Operation Mode
1	Early Life	65	28,621	28,621	12,000,000	12,000,000	0	0	N.A.	1,2,3
2	Early Life	50	28,621	31,802	12,000,000	12,000,000	0	0	N.A.	1,2,3
3	Early Life Blend	50	28,621	31,802	9,300,000	9,300,000	0	0	N.A.	1,2,3
4	Early Life	45	3,720	3,720	900,000	900,000	0	0	N.A.	3
5	Low CO2	35	4,864	4,864	900,000	900,000	0	0	N.A.	3
6	Mid Life	35	1,250	1,250	900,000	900,000	0	0	N.A.	3
7	Mid Life	75	28,621	28,621	12,000,000	10,000,000	0	2,000,000	GT30	1,2,3
8	Mid Life	60	19,081	31,802	12,000,000	10,000,000	0	2,000,000	GT30	1,2,3
9	Mid Life	65	15,000	31,802	12,000,000	8,000,000	2,000,000	2,000,000	GT30	1,2,3
10	Late Life	90	11,500	28,621	9,500,000	7,500,000	0	2,000,000	GT40	1,2,3
11	Late Life	55	7,950	31,802	11,000,000	7,000,000	2,000,000	2,000,000	GT40	1,2,3
12	Late Life	90	8,052	31,802	9,500,000	9,000,000	0	500,000	GT40	1,2,3
13	High CO2	90	9,655	31,802	9,300,000	9,300,000	0	0	GT40	1,2,3
14	High CO2	90	9,655	31,802	12,000,000	12,000,000	0	0	GT40	2,3
15	Highest CO2	90	3,541	31,802	7,000,000	4,500,000	2,000,000	500,000	GT50	3
16	Highest CO2	90	3,934	31,802	7,000,000	5,000,000	2,000,000	0	GT50	3

NOTE 1: Operational temperature for the blend downstream of production choke valve. During the production the blend temperature can vary from 35°C to 90°C.

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

NOTE 3: Gas Flow rate at inlet Main Gas Compressor. Any recirculation of gas streams shall be added onto this Gas Flow Rate.

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 BUYER will provide to SELLER the pressure, temperature and flow rate conditions (steady flow and well start-up) to size production choke valves.

NOTE 7: During project execution phase BUYER will provide to SELLER the pressure, temperature and flow rate conditions to size gas export control valve and lift gas, water injection and gas injection choke valves.

NOTE 8: The shut-in pressure at top production riser is 41,000 kPa(a) for the oil production wells.

NOTE 9: The normal pressure range upstream of production choke valve is 2,500 to 31,000 kPa(a) for the oil production wells. Under some conditions, e.g. intermittent flow, pressure can achieve lower values.

NOTE 10: H_2S concentrations are informed in Table 2.2.2.4.

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

NOTE 12: Liquid flowrate refers to oil/condensate and water.

NOTE 13: Some wells are susceptible to slugging. SELLER shall provide anti-slugging automatic control system, actuating on the choke valves for each production riser. SELLER shall submit anti-slugging control system design for BUYER approval. Anti-slugging control system parameters shall be approved by BUYER during operating phase. BUYER will define the applicable wells at its sole discretion during operating phase.

NOTE 14: For Operation modes refer to I-ET-3010.00-1200-000-P61-002 – OPERATIONAL MODES BOT.

2.2.2.4 Tables 2.2.2.4 and 2.3.5.1 shall be used for the fluid composition.

Table 2.2.2.4: Well Fluid Composition

	Early Life	Low CO_2	Early Life Blend	Mid Life	Late Life	High CO_2	Highest CO_2
CO2	17.57	2.26	15.96	27.12	36.62	41.77	56.12
N2	0.24	0	0.24	0.24	0.29	0.24	0.24
C1	44.42	48.47	49.00	48.12	44.46	39.87	27.08
C2	6.59	9.01	6.93	6.27	5.64	5.2	4.56
C3	4.49	6.18	4.72	4.27	3.62	3.1	3.11
iC4	0.76	1.02	0.80	0.72	0.55	0.48	0.53
nC4	1.81	2.67	1.90	1.72	1.3	1.13	1.25
iC5	0.56	0.83	0.59	0.53	0.37	0.32	0.39
nC5	0.93	1.34	0.98	0.89	0.54	0.48	0.64
C6	1.25	1.58	1.09	0.63	0.49	0.46	0.38
Benzene	0.43	0.51	0.37	0.22	0.17	0.16	0.13
C7	1.03	1.23	0.90	0.52	0.42	0.40	0.32
Toluene	0.05	0.06	0.05	0.03	0.02	0.02	0.02
C8	1.93	2.14	1.68	0.97	0.55	0.60	0.59
Ethyl-Benzene	0.09	0.09	0.08	0.04	0.02	0.03	0.03
Meta and Para Xylene	0.30	0.31	0.26	0.15	0.07	0.09	0.09
Ortho Xylene	0.08	0.09	0.07	0.04	0.02	0.02	0.03
C9	1.22	1.29	1.07	0.61	0.30	0.35	0.38
C10	1.43	1.62	1.25	0.72	0.37	0.42	0.44
C11	1.22	1.31	1.06	0.61	0.31	0.36	0.37
C12	1.11	1.14	0.97	0.56	0.28	0.33	0.34
C13	1.12	1.23	0.88	0.48	0.28	0.34	0.31
C14	0.94	1.04	0.74	0.40	0.25	0.31	0.26
C15	0.91	1.09	0.72	0.39	0.23	0.28	0.25
C16	0.71	0.83	0.56	0.30	0.2	0.23	0.20
C17	0.57	0.73	0.45	0.24	0.15	0.17	0.16
C18	0.63	0.63	0.50	0.27	0.17	0.18	0.17
C19	0.55	0.68	0.43	0.24	0.15	0.16	0.15
Well A C20+(3)	7.05	0	0	2.66	2.16	2.52	1.55
Well B C20+ (3)	0	10.62	5.73	0	0	0	0
H_2S (ppmv)	120	120	120	120	170	170	170

Note 1: If there is any process streams (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 streams with H_2S and define or estimate their concentration in ppm and provide control actions.

Note 3: Properties of the Pseudo-components are as follows:

Pseudo-component	Well A C20+	Well B C20+
Density (kg/m³)	957,2	938,1
MW	570	468

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 heaters, three-phase test separators, pumps and other related items).

Table 2.2.3.1a: Tests Separators Capacities

CHARACTERISTICS	NOTE	VALUE
Oil production wells		
Oil Flow rate	Maximum	8,000 Sm³/d
	Minimum, for accuracy of measurement purpose	100 Sm³/d
Gas Flow rate	Maximum	3,500,000 Sm³/d
	Minimum	100,000 Sm³/d
Water cut	For accuracy of measurement purpose	0 to 95%
Arrival temperature downstream choke valve	-	20 °C to 95 °C

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: SELLER shall design well test system using the following design cases. Test heater shall be designed to increase temperature from 20°C to 40°C for these cases.

Table 2.2.3.1b: Scenarios for Well Test Header

Fluid	Oil Flowrate (Sm³/d)	Liquid Flowrate (Sm³/d)	Gas Flowrate (Sm³/d)
Early Life	8,000	8,000	1,930,000
Early Life	5,000	5,000	1,200,000
Early Life	1,100	1,100	275,000
Low CO_2	8,000	8,000	1,480,000
Low CO_2	5,000	5,000	925,000
Low CO_2	1,500	1,500	275,000
Mid Life	8,000	8,000	2,950,000
Mid Life	750	1,250	275,000
Late Life	3,100	3,100	3,500,000
High CO_2	3,750	3,750	3,500,000

NOTE 3: The well test system shall be able to operate with one or more well within the capacities informed on table 2.2.3.1a. Operation with more than one well is the one where the wells in trunkline or wells with subsea manifold are aligned to the test separator.

NOTE 4: Transferred gas may also be sent to test separator.

2.2.3.2 Oil Wells test separator shall be able to operate from low pressure up to the Free Water KO Drum normal operating Pressure of 2,500 kPa(a). During low pressure operations, expected for well kick-off purpose, produced gas from Oil Wells test separator may be routed to flare and liquids routed to further lower pressure separation stages.

2.2.3.3 Test separators shall be sized for the maximum liquid and gas flow with the normal operating pressure of 2,500 kPa(a).

2.2.3.4 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. The Unit shall be responsible to reprocessing completion fluids and special operations fluids.

2.2.3.5 Test separator will also receive fluids during subsea commissioning. These fluids are a mixture of diesel and inhibited water, which typically contains biocide, oxygen scavenger, and fluorescein dye – to be confirmed during execution phase. These fluids shall be routed to slop tank or offspec tank in order to treat to remove excess oil-in-water to discharge to overboard and/or reprocess.

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, whichever is greater.

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

2.2.3.8 The well test heaters and well test separators may receive wax crystals.

2.2.3.9 SELLER shall provide tests heaters 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 up to 240,000 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): 34 kPa at 37.8°C. This value is intended for measurement purpose in order 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 - BOT (see item 1.2.1): 70 kPa (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: 40°C;
- 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 Methods (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: see item 15.2.2;
  - Maximum Operating Pressure at the top of the riser: see item 15.2.2;
  - Design Pressure: see item 15.2.2;
  - Maximum 5 ppmv of H_2S;
  - Maximum 3% mol CO_2;
  - Maximum H_2O content:1 ppmv;
  - Design Temperature: see item 15.2.2.

- Gas injection riser:
  - Normal gas injection temperature at the top of the riser: see item 15.2.2;
  - Maximum Operating Pressure: see item 15.2.2;
  - Design Pressure: see item 15.2.2;
  - Maximum H_2O content: 75 ppmv
  - Design Temperature: see item 15.2.2.

2.3.4 EXPORT GAS

2.3.4.1 The export gas shall meet the following specification:

- Normal exported gas temperature at the top of the riser: see item 15.2.2;
- Maximum operating pressure at the top of the riser: see item 15.2.2;
- Design pressure: see item 15.2.2;
- Design temperature: see item 15.2.2;
- Maximum 5 ppmv of H_2S;
- Maximum 3% of CO_2;
- Maximum H2O content: 1 ppmv.

2.3.4.2 Facilities shall also be provided to import gas using the gas export pipeline. The imported gas shall meet the following specification:

- Operating pressure (Note 1): from 13,000 kPa(a) up to 25,000 kPa(a);
- Operating temperature: from -6°C up to -2°C (downstream import gas valve);
- Maximum 10 ppmv of H_2S;
- Maximum 3% mol CO_2;
- Maximum H2O content: 30 ppmv.

2.3.4.2.1 The imported gas will have two main purposes:

- Provide a gas source to fuel gas, at a rate to be determined based on design proposed by SELLER;
- Provide a gas source to lift gas/service gas for start-up and flow assurance, at a flowrate of up to 700,000 Sm^3/d.

2.3.5 TRANSFERRED GAS

2.3.5.1 The Unit shall have facilities to receive gas transferred from another unit. This gas stream shall be processed to meet export and injection requirements.

2.3.5.2 The transferred gas shall meet the following specifications:

- Operating pressure (downstream transferred gas valve): from 11,000 kPa(a) up to 25,000 kPa(a);
- Operating temperature (downstream transferred gas valve): from -21°C up to 40°C;
- Maximum H_2O content: 240 ppmv at upset conditions.

2.3.5.3 A Slug Catcher or a Safety K.O. drum shall be installed for transferred gas, in order to separate any liquid carry-over. This condensate shall be sent to the gas process plant.

2.3.5.4 Composition of transferred gas is presented in Table 2.3.5.1

Table 2.3.5.1

	GT 30	GT40	GT50
CO2	30.06	40.10	49.70
N2	0.29	0.25	0.21
C1	54.53	46.47	37.99
C2	6.50	5.67	5.20
C3	4.43	3.86	3.54
iC4	0.75	0.65	0.60
nC4	1.78	1.56	1.43
iC5	0.55	0.48	0.44
nC5	0.92	0.80	0.73
C6	0.03	0.03	0.03
Benzene	0.01	0.01	0.01
C7	0.02	0.02	0.02
Toluene	0.003	0.002	0.002
C8	0.047	0.038	0.038
Ethyl-Benzene	0.002	0.002	0.002
Meta and Para Xylene	0.008	0.008	0.008
Ortho Xylene	0.002	0.002	0.002
C9	0.03	0.03	0.03
C10	0.03	0.03	0.03
H_2S (ppmv)	120	170	170

Note 1: Transferred gas may contain trace amounts of hydrate inhibitor and/or corrosion inhinitor. Unit shall be designed to handle drop out of some liquids including hydrate inhibitor, and to inject hydrate inhibitor in the gas transfer arrival line.

Nota 2: Transferred gas may contain up to 120 ppmv of H_2O.

2.4 WATER INJECTION

2.4.1 The Unit shall be able to operate continuously with only one injection well up to 10 (ten) connected wells, in accordance with table 15.1.4.

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 BUYER 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)
		Sm3/d	kPa(a)
Max Flowrate / Max Pressure	1	54,850	25,000
Max flowrate / high injectivity	2	54,850	15,000
Ramp-up 1	3	8,000	25,000
Ramp-up 2	4	11,000	20,000
Mid Life / Max Pressure	5	28,800	25,000
		19,200	20,000
Late Life / Max Pressure	7	24,000	25,000
		16,000	20,000
Min flowrate / 1 well	7	3,750	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 BUYER will provide to SELLER the pressure, temperature and flow rate conditions to size water injection choke valves.

2.4.4 Seawater to injection shall meet the following quality specification:

- Operating Pressure: See Table 2.4.3;
- Minimum operating Temperature: 40°C;
- 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 BUYER during operational lifetime);
- pH of injected water: to be daily monitored.

OBS: Design shall guarantee water injection temperature above 40°C, maximizing the use of cooling medium return to heat the injection sea water. Design shall consider temperature to stop injection of item 15.2.2.

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

- Operating Pressure: See Table 2.4.3;
- Operating Temperature: from 40°C up to 60°C;
- pH of produced water to be daily monitored;
- Produced Water quality specification (maximum values):
  - Dispersed Oil, as measured by SM5520F: 20 mg/L;
  - Content of suspended solids (TSS): 5 mg/L;
  - Particle size: 25 µm;
  - Dissolved oxygen: 10 ppb (vol) O_2;
  - Sulphate content: 55 mg/L;
  - Sulfide content: 2 mg/L;
  - Bacteria (SRB planctonic – mesophile): 50 NMP/mL;
  - Total anaerobic bacteria (TAHB planctonic): 5,000 NMP/mL.

2.4.6 Water injection riser characteristics:

- Maximum 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;
- pH of injected water: to be daily monitored.

2.4.7 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 54,850 Sm³/d of injected desulfated water. For the SRU configuration, at least three trains (3x50%) are required, however, 4x33%, 5x25%, 6x20% can also be considered. During cleaning operation no reduction in flowrate of the unit is allowed. At least three trains (3x50%) are required for the SRU' feed pumps, booster and main injection pumps. The system shall be designed considering that, during operation, BUYER may require lower injection flowrates that shall be achieved with the minimum number of injection pumps in operation.

2.4.7.1 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).

2.4.7.2 For Ultrafiltration option, design of the 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@25°C;
- 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 with SRU supplier's requirements;
- Full bypass of UF unit.

2.4.8 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 BUYER.

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

2.4.10 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.

2.4.11 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 by BUYER during execution phase. The analyzer shall have an installed stand-by instrument.

2.4.12 The produced water shall have options to be discharged overboard or reinjected in the reservoir, as shown on figure 2.4.12. It is BUYER decision to discharge overboard or reinject the produced water.

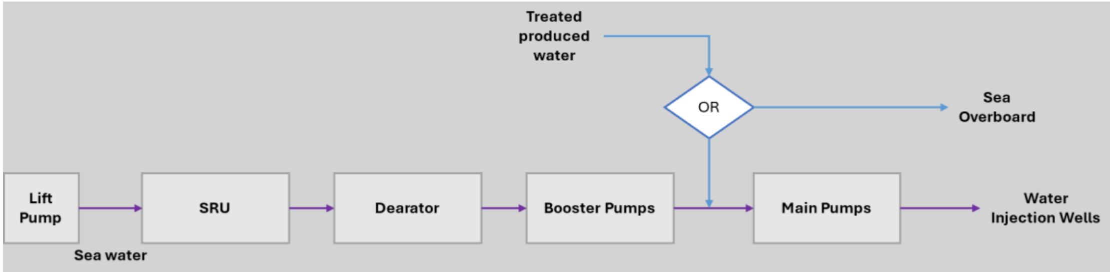

Figure 2.4.12 - Simplified Diagram for Produced Water and/or Seawater Injection

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

2.4.14 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.

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

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

2.4.17 The water injection pumps sealing system shall comply with API-682 latest edition 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.

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

2.4.19 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 (no stand-by required);
- 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 (2)	
Oil production wells	
Maximum production oil flow rate per well	8,000 Sm^3/d
Minimum production oil flow rate per well	550 Sm^3/d (1) (3)
Maximum production liquid flow rate per well	8,000 Sm^3/d
Minimum production liquid flow rate per well	550 Sm^3/d (1) (3)
Watercut from one well	0% to 95%
Maximum gas production flow rate per well	3,500,000 Sm^3/d
Maximum lift gas flow rate	2,000,000 Sm^3/d
Maximum lift gas flow rate per well	350,000 Sm^3/d
Minimum lift gas flow rate per well	100,000 Sm^3/d
Water injection wells	
Maximum water injection flow rate per well position	11,000 Sm^3/d
Minimum water injection rate per well position	500 Sm^3/d (1)
Gas injection wells	
Maximum gas injection flow rate per well position	4,500,000 Sm^3/d
Minimum gas injection flowrate per well position	250,000 Sm^3/d (1)
Gas Transfer positions	
Maximum gas transfer flow rate per position	2,000,000 Sm^3/d
Minimum gas transfer flowrate per well position	500,000 Sm^3/d (1)

NOTE 1: For measurement accuracy purposes for transient periods of production.

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

2.5.2 PROCESS DESIGN SUMMARY

Table 2.5.2: Process Design Data

Design data	
Total liquids processing capacity	31,800 Sm^3/d
Total oil processing capacity	28,600 Sm^3/d
Produced water capacity	23,850 Sm^3/d
Gas treatment & compression system (1)	12,000,000 Sm^3/d
Gas-lift pressure	25,000 kPa (a)
Maximum lift-gas capacity	2,000,000 Sm^3/d
Exported gas pressure at top of riser	25,000 kPa (a)
Gas injection pressure	50,000 kPa (a)
Total water injection capacity	54,850 Sm^3/d
Water injection pressure downstream of the choke valve	25,000 kPa (a)

Note 1: Gas flow rate at outlet of first stage separation (FWKO). The gas coming from internal recycles shall be added to define the total main gas compression/treatment capacity.

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 oil producer wells.

2.6.2 Boarding Shutdown Valves (BSDV) shall be installed in all well lines. BSDVs 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 BSDV to the base of the riser is as short as reasonably practicable. Scenarios of riser 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 at 90°C, upstream each production choke valve (in the direction of production), 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 125 m^3/h. Pigging will not use hot Diesel.

2.6.4 The Flow Metering System (FMS) flow meter of each fluid that can be connected to WAG injection 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 BUYER.

2.6.5 The Test Header and the Test Separator shall provide periodical production test for each well.

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, corrosion/scale inhibitor, acetic acid, 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 SELLER 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 position slot (production, WAG injection, gas lift/service, export) with no disturbance to the others shall also be provided. This service header may be used to perform Diesel injection (pigging operations, Diesel circulation, hot diesel circulation, bullhead operation, etc.), dead oil circulation, desulfated/deaerated water circulation, gas circulation as service gas (pigging operations) and special operations. The service header shall also have facilities to inject ethanol or monoethylene glycol (MEG) bed during pigging, commissioning, WAG fluid change-over operations.

NOTE: During project execution phase BUYER will provide/confirm to SELLER the pressure, temperature and flow rate conditions (steady flow and well start-up) to size choke valves.

2.6.10 All Gas Lift Slots shall be capable to receive (back flow from well) small amounts (up to 10 m³) 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 IWAG01A/B to IWAG05A/B position 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, desulfated/deaerated water circulation, leak test, pigging, etc.) shall be done using facilities onboard. SELLER 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 / subsea system. The Nitrogen Generator Unit (NGU) will be supplied by BUYER (approximately 3 skids of 2.6 x 6.3m demanding air, water and electricity).

2.6.13.3 Well service system requirements:

- The well service system shall be able to inject Diesel, an ethanol or MEG bed, oil from the cargo tanks, deaerated water and desulfated/deaerated water in each of the production, service, WAG injection lines.

- The service pump shall operate with Diesel, crude oil or a mixture of Diesel and crude oil. The service pump shall also operate with deaerated water and desulfated water. 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 item 2.8 (Chemical Injection Rates & Requirements, Product: Gas hydrate inhibitor: ethanol or MEG for oil production wells (subsea)).
- The well service system shall be able to circulate fluids in order to prevent hydrate, perform pig passage, bull heading and circulate during commissioning (dewatering) with or without pig.
- It shall be possible to inject a mixture of Diesel and crude oil in any proportion, it is under SELLER responsibility to provide proper facilities to measure and control the mixture. The crude oil to be injected shall be metered with dedicated operational 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/crude oil service tank/vessel shall be installed at topsides for well service system operations (including Diesel and crude 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/crude oil service tank/vessel shall be 30 m³. If an atmospheric tank is used for this purpose, 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 25 to 250 m^3/h of Diesel, oil, and deaerated/desulfated water at maximum discharge pressure up to 32,000 kPa(a). The service pump shall be positive displacement type according to API 674. 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, SELLER 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 3x125 m³/h 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).
- Service pump system shall allow simultaneous fluid (e.g., Diesel or crude oil) injection at a minimum of 2 service line risers at a time, with the respective flowrate measurement of injected fluid in each riser. Implemented solution may consider service header division, however, in such case SELLER shall evaluate the feasibility of quick alignment (e.g., by remotely operated valves) of any service header to any service line. SELLER shall also perform human reliability analysis, with BUYER participation, to evaluate the task of diesel injection into all production risers, two at a time, in order to provide design and operational measures to prevent

process safety events, such as liquid hydrocarbon release to the sea from the Unit or from the subsea system.

- A second set of 2 x 50% pumps are required for the low flow rate operations with a total flow rate of 4 m^3/h of diesel or desulphated/deaerated water at maximum operational discharge pressure of 32,000 kPa(a). Flow control is not required. The system shall be also able to perform pressurization after production stop, pressurization to equalize WCT valves pressure and pressurization to equalize DHSV.
- The service pumps shall be tested for the rated flow during commissioning.
- The well service system shall be ready to be aligned, without the need to reassemble any piping element (e.g. removable spool, spectacle blind etc.), as per readiness requirements described in PRELIMINARY SUBSEA OPERATION PHILOSOPHY.
- SELLER shall consider Well Service pump operating continuously as an input for load balance calculation.
- Each well shall be capable to operate from 2 to 250 m^3/h.

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 paired line. In this case, an automatic action shall be activated to isolate pressure source.
- SELLER 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) at the top of each riser.

2.6.13.5 Special operations requirements:

- The Unit shall be prepared to perform autonomous special operation such as acid squeeze, scale removal and prevention by chemical bullhead into production wells. For this operation, rented diesel motor driven pump and chemical tanks shall be placed at laydown area and connected to downstream well service pump. Chemicals shall be pumped together with deaerated and desulfated water from well service system. Refer to PRELIMINARY SUBSEA OPERATION PHILOSOPHY for a description of facilities needed for autonomous special operations.
- 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, SELLER 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 SELLER 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 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 SELLER shall guarantee the performance of pigging operation regarding service fluid flowrate control.

2.6.15 BUYER is responsible to supply pigs during operational lifetime.

2.6.16 The gas-lift header shall allow individual injection to each service/gas-lift riser. SELLER 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 service/gas-lift riser, including connection to service slots in satellite wells, connections to service slots in PWAG wells, and connections from service header to WAG slots. 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, service/gas lift, and WAG injection with no production disturbance. These facilities shall allow:

a) Depressurization of all oil production risers within two hours (it shall consider the proposed subsea arrangement issued by BUYER) in order to avoid hydrate blockage. In this case, the depressurization may be routed to FWKO Drum, then Oil Test Separator, then flare system to accomplish total depressurization within 2 hours. SELLER shall consider as maximum subsea riser volume 510 m³ (one well) and initial conditions 36,000 kPa(a) and 20 °C (to be confirmed in KoM);

b) Depressurization of each service/gas lift riser within one hour and thirty minutes (it shall consider the proposed subsea arrangement issued by BUYER), not exceeding 12 hours for depressurization of all production gas lift risers. SELLER shall consider as maximum subsea riser volume 250 m³ (one well) and initial conditions 32,000 kPa(a) and 20 °C (to be confirmed in KoM);

d) Depressurization of gas export riser with no time constraint. SELLER shall consider as maximum subsea riser volume 1000 m³ and initial conditions 25,000 kPa(a) and 20 °C (to be confirmed in KoM);

Depressurization of GAS TRANSFER riser with no time constraint. SELLER shall consider as maximum subsea riser volume 1000 m³ and initial conditions 25,000 kPa(a) and 20 °C (to be confirmed in KoM);

e) Control and monitoring the depressurization of production, gas lift, gas transfer, gas export and WAG injection risers at a rate up to 8 bar/min, according to operational procedure to be defined by BUYER. Risers are designed for a maximum depressurization rate of 80 bar/min.

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

NOTE 2: For depressurization of a single production well or a single WAG (injection well, the design shall consider the depressurization through the test separator or 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 SELLER 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 item 7.

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

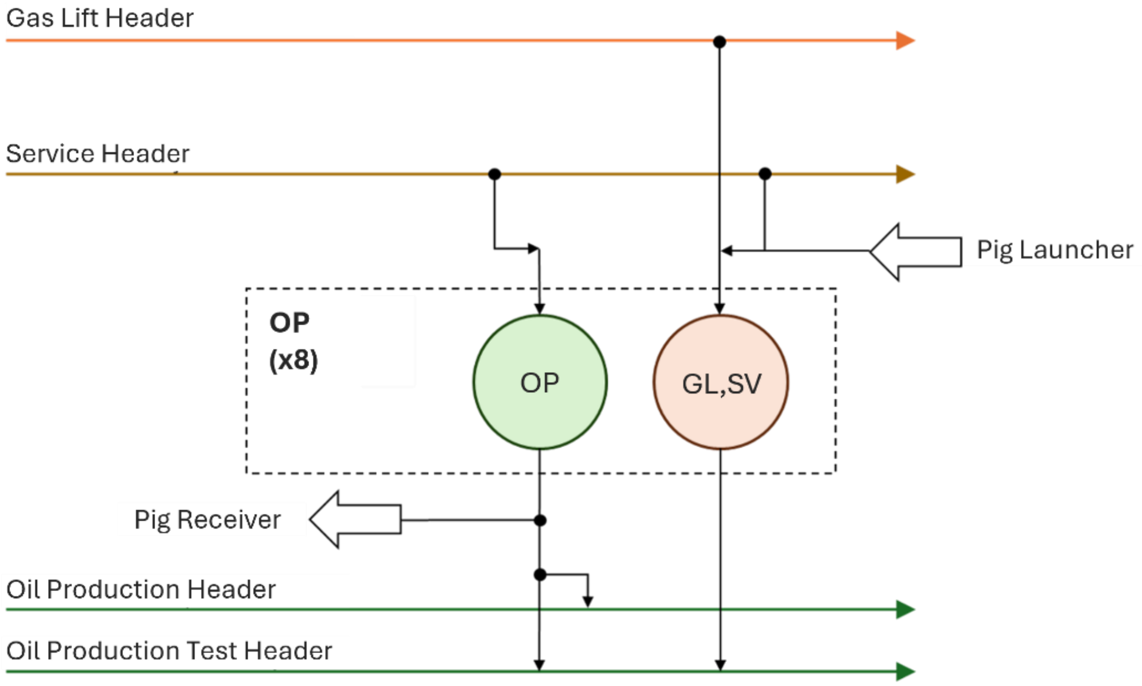

Figure 2.6.22a - Wells Piping Arrangement (Oil Production Bundles)

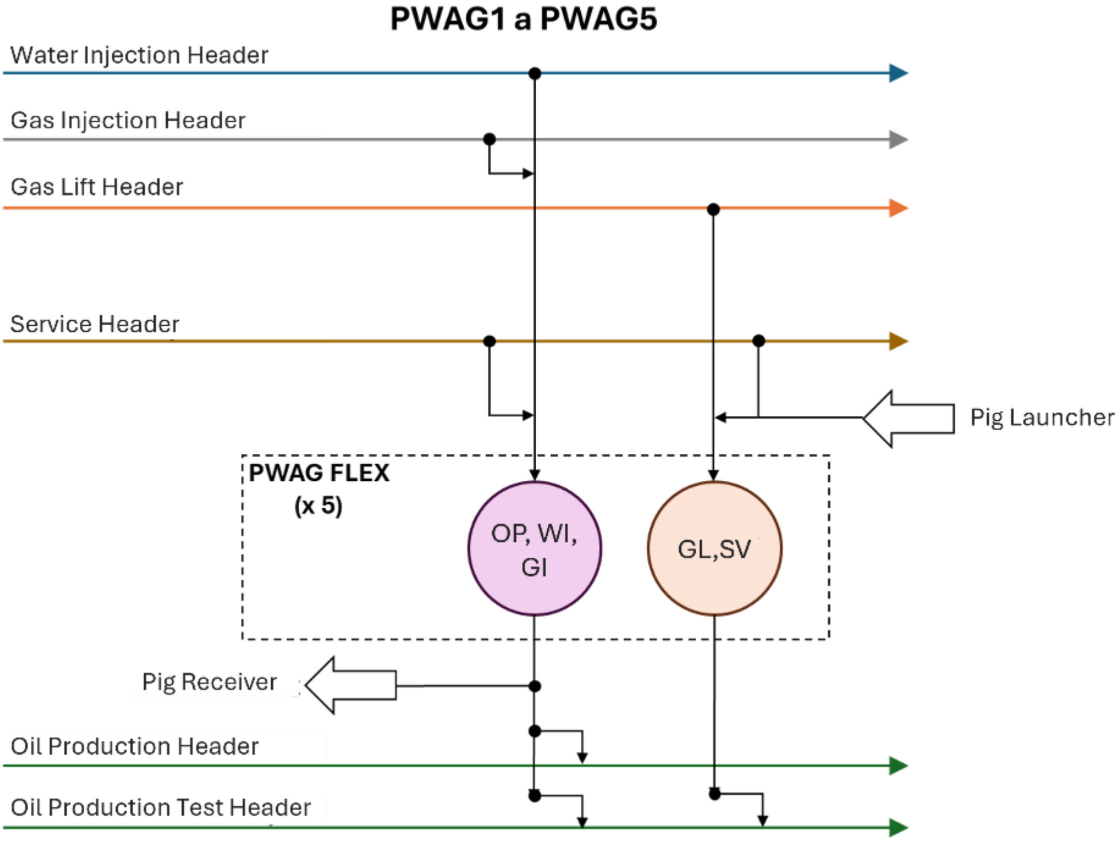

Figure 2.6.22b - Wells Piping Arrangement (PWAG Bundles)

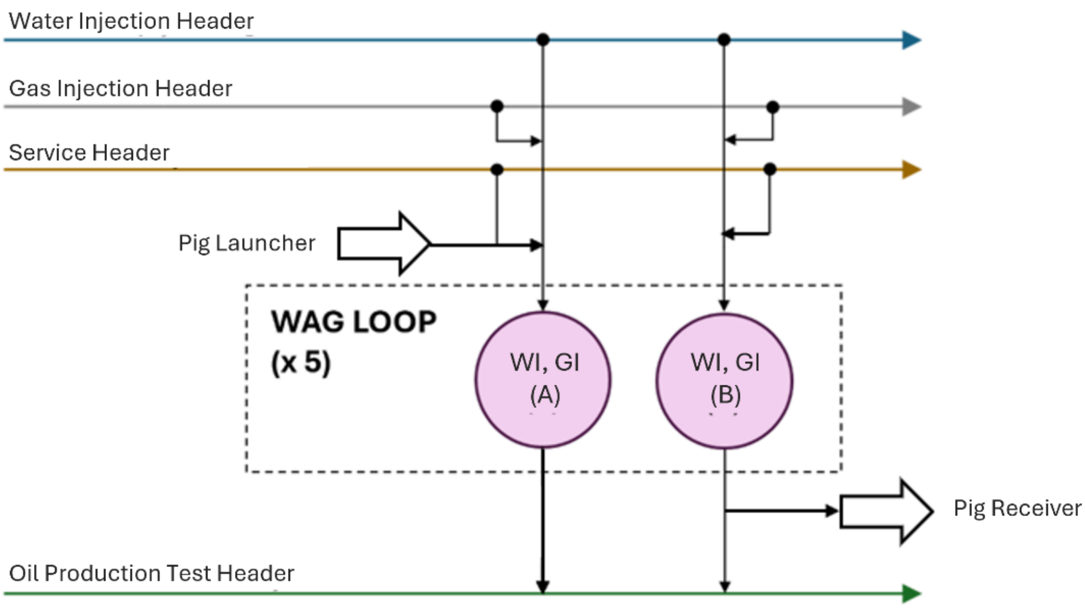

Figure 2.6.22c - Wells Piping Arrangement (WAG Injection Bundles)

NOTE 1: Positions IWAG01 to IWAG05 shall receive independent lines from Water injection header and Gas injection header for each injection slot.

NOTE 2: Positions IWAG01 to IWAG05 will be subsea interconnected pair of wells (slot A/B). These slots may inject water, gas alternately and independently.

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

2.6.24 SELLER shall provide the following facilities to allow the use of hydrate removal technologies (e.g. Annelida and Flexicoil) according to PRELIMINARY SUBSEA OPERATION PHILOSOPHY (see item 1.2.1). Details of the necessary facilities will be discussed during execution phase, including but not limited to:

- Weight and space requirements;
- Material handling requirements;
- Utility consumption such as diesel and air supply;
- Human power required;
- Measures to prevent well blowout to be implemented.

2.7 PROCESS FACILITIES

2.7.1 SEPARATION AND TREATMENT

2.7.1.1 The oil processing shall be constituted of a stage of three-phase separator, pre-heater of produced liquid (using the heat recovered from the processed oil), oil heater, degasser, electrostatic pre-treater, degasser for RVP/TVP specification, electrostatic treater and oil cooler as shown in Figure 2.7.1.17. One test separator shall also be installed.

2.7.1.2 The producing oil wells will flow to the production header. From there oil is sent directly to a first stage three-phase separation at the Free Water KO Drum (FWKO), operating at 2,500 kPa(a). The separator shall be able to separate gas from oil and water, routing the gas to the gas compressors (via KO Drum) and water to Produced Water system. SELLER shall consider that oil outlet stream contains up to 40% of water.

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

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

2.7.1.5 Production heater shall be shell and tube type and shall be provided with removable bundle. Plate type heat exchangers are not accepted for this service.

2.7.1.6 In order to help removing salt deposits and to help pre-treater performance during low BSW production period, SELLER shall provide a dilution water injection upstream Oil Heater and produced water recirculation from electrostatic treater to upstream Oil/Oil Pre-Heater. SELLER shall consider oil or produced water recirculation from electrostatic pre-treater and produced water from electrostatic treater to upstream FWKO. If required, the water/oil recirculation shall also be used in order to keep the FWKO inlet temperature at 40°C. The heating system shall be sized considering the flexibility of recirculating water, oil or no recirculation, even at lower arriving temperatures. SELLER shall consider oil recirculation to size Main Gas Compressor and VRU flowrates.

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

2.7.1.8 The design shall include ability to inject H_2S scavenger into the cargo pumps header or upstream offloading metering skid, to be used in case treated oil does not meet H_2S spec.

2.7.1.9 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, SELLER shall comply with "*Resolução CNEN NN 6.02", "Resolução CNEN 215/17" and "Anexo D – SMS – Segurança, Meio Ambiente e Saúde Ocupacional*".

2.7.1.10 The treated oil from the electrostatic treater is cooled in the oil/oil pre-heater and in the oil cooler to reach the temperature of 40°C. SELLER might propose higher storage temperature to guarantee the minimum offload temperature of item 16.3.3, for BUYER approval. A TVP value at storage temperature higher than defined in item 2.3.1.1 or separation temperature higher than 99°C will not be accepted. 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 m³. Alignments of offspec tanks to cargo tanks or directly to offloading shall be avoided, as per FLOW METERING SYSTEM – BOT (see item 1.2.1).

2.7.1.11 Oil processing and produced water plant heat exchangers, heaters and coolers shall be designed to guarantee high availability in the oil and produced water treatment; shall be provided with by-pass lines and with facilities to allow chemical cleaning. Electrostatic treaters shall be provided with by-pass lines with positive isolation, to allow continued degassing while the treaters are offline. SELLER shall provide spare heat exchanger for oil/oil pre-heater, production heater and oil cooler. Spare exchangers shall be installed and ready to operate.

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

2.7.1.13 SELLER shall consider slug volume (Normal Liquid Level (NLL) to Level Alarm High (LAH) of the vessel) in the FWKO Separator and Test Separators design (30.0 m^3 for FWKO Separator, and 10.0 m^3 for Test separators). The FWKO, and Test Separators design shall consider wax crystals dispersed in oil phase.

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

2.7.1.15 BUYER highlights that in scaling and salt precipitation, including $CaCO_3$, $BaSO_4$, $SrSO_4$, 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.

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

2.7.1.17 The Figure 2.7.1.17 present simplified proposed flow diagram of the Oil Processing scheme.

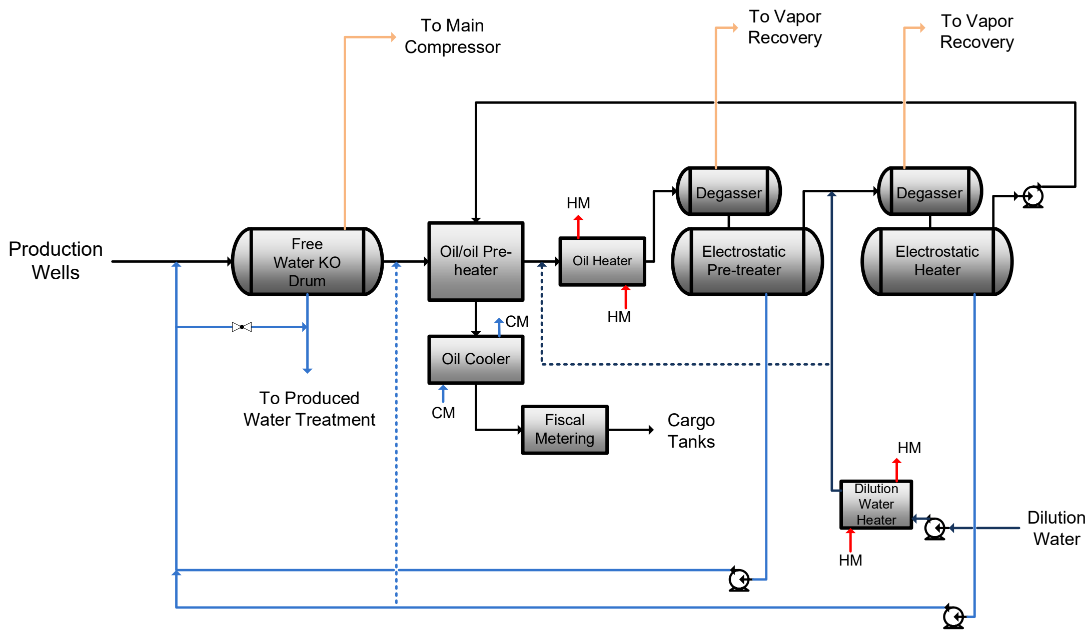

Figure 2.7.1.17 – Oil Processing Scheme

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:

- transport to shore, through a gas pipeline;
- reservoir injection;
- fuel gas;
- lift gas for the producing wells.

2.7.3.1.2 The export gas pipeline operating pressure range in topside outlet is up to 25,000 kPa (a).

2.7.3.1.3 Proper device Control shall be installed at the Export Gas Compressors discharge header to guarantee the required lift gas pressure level of 25,000 kPa (a), and send the excess gas to the export pipeline.

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 SELLER shall install online Chromatographic Analysis for hydrocarbon (up to C9+), CO_2 and N_2 and also water content) to the following streams, as a minimum and in addition to the requirements from FLOW METERING SYSTEM – BOT (see item 1.2.1):

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

2.7.3.1.6 SELLER shall provide online water and H_2S content on the following streams, as a minimum:

- Import/Export 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 be designed according to Figure 2.7.3.3.1.

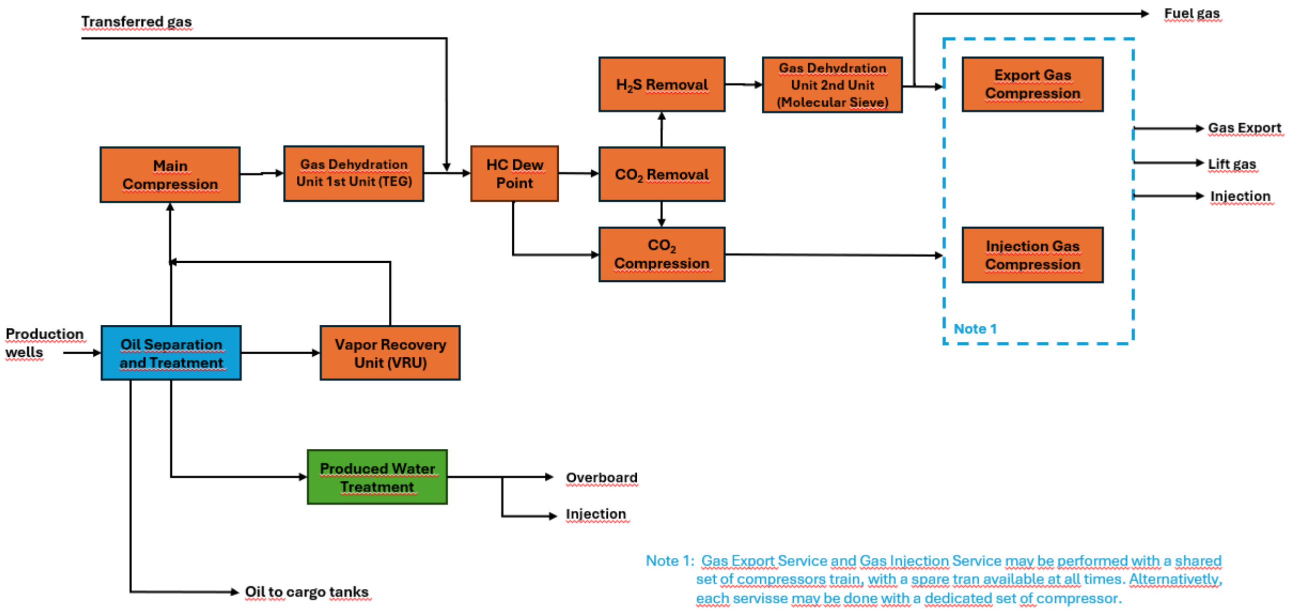

Figure 2.7.3.3.1 – Process Plant Overview

2.7.3.3.2 The gas treatment and compression system shall take into account all design cases on Table 2.2.2.3 and shall be able to operate in three (3) different modes, as follows:

2.7.3.3.3 **MODE 1**: Treated Gas export and CO_2 stream injection.

2.7.3.3.4 During this operation mode, up to all produced gas is treated for CO_2, H_2S and water for export and/or use as lift gas. Permeate from Membrane Unit is reinjected into reservoir.

2.7.3.3.5 The required specification for export or lift gas shall be as item 2.3.4.

2.7.3.3.6 **MODE 2**: Part of produced gas is treated.

2.7.3.3.7 During this mode operation, only a portion of the produced gas is treated for export, use as fuel gas and/or lift gas. Excess produced gas is by-passed around the CO_2/H_2S removal units and is reinjected into the reservoir.

2.7.3.3.8 **MODE 3:** Membrane by-pass and Gas Reinjection.

2.7.3.3.9 During this operation mode, produced gas treated for use as fuel gas and lift gas as determined by BUYER. Balance gas flowrate is reinjected into reservoir.

2.7.3.4 DEHYDRATION(S) UNIT(S)

2.7.3.4.1 The processing plant base case presented in Figure 2.7.3.3.1 requires two separate Gas Dehydration Units. Requirements of the design of these units are as follows:

GDU 1st Unit:

- Inlet gas specification = as least 2400 ppmv H_2O;
- Inlet gas H_2S content = according to design cases;
- Inlet pressure = according to Main Compressor discharge pressure (minus head loss);
- Outlet gas specification = 42 ppmv H_2O.

GDU 2nd Unit:

- Inlet gas specification = saturated
- Inlet gas H_2S content = up to 10 ppmv;
- Inlet pressure = according to Main Compressor discharge pressure (minus head loss);
- Outlet gas specification = 1 ppmv H_2O.

2.7.3.4.2 Specific requirements for each acceptable solution for the Dehydration Units are presented in the following sections.

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 H_2S. The Molecular Sieve shall be resistant to the expected CO_2 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 ∆P 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 5°C 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. SELLER 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 SELLER decides to send regeneration gas back to Main Compressor, this machine capacity shall be increased to accommodate this additional flow.

2.7.3.4.2.1.11 SELLER 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 SELLER 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 SELLER 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. SELLER 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 SELLER 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: SELLER shall design the vessels with insulation.

NOTE 2: SELLER 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 SELLER shall install proper online instrumentation and analysis devices to determine H_2O 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 Moisture Analyzer, see item 19.1.1.5.

2.7.3.4.2.1.19 For Acceptable vendor list for Molecular Sieve Solid Bed (Zeolite), see item 19.1.1.3.

2.7.3.4.2.1.20 SELLER shall provide the molecular sieves for the first fill-up and Molecular Sieve replacement needed during operation.

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 40°C. SELLER 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. SELLER 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 SELLER shall provide two level meters for the scrubber and two for each section of the coalescer filter. In each vessel, SELLER 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 SELLER 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 5°C 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 10°C 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 $1 m^3/h/m^2$ 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 H_2S content shall be considered and heat and mass balance for the unit shall include concentration on regeneration gas and recirculating H_2S destination.

2.7.3.4.2.2.20 Chemical injection skid(s) for pH control and antifoaming shall be provided. SELLER shall provide all chemical products required for effective operation of the TEG Unit.

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 204°C.

2.7.3.4.2.2.22 SELLER 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 SELLER 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 SELLER shall install proper online instrumentation and analysis devices to determine H_2O content in the gas dehydration outlet stream. Analyzer shall be installed downstream of absorber, upstream CO_2 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 SELLER 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 H_2O Dew point vs. Temperature at Various TEG Concentrations”. These results will be used to mediate divergences about measured values. SELLER 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. SELLER 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 Moisture Analyzer, see item 19.1.1.5.

2.7.3.4.2.2.33 Minimum Requirements for TEG Units Suppliers:

- Proven experience on offshore TEG units design with 6 MM Sm^3/d gas capacity;
- Proven experience on onshore or offshore TEG units design to dehydrate the gas with minimum 30% mol CO_2 content. These units shall be in operation.

2.7.3.4.2.2.34 SELLER shall provide the TEG for the first fill-up, TEG fill-ups needed during operation and TEG make-up due to operational losses.

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 for turning 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 CO_2 MEMBRANE PRE-TREATMENT OR HYDROCARBON DEWPOINT UNIT (HCDP UNIT)

2.7.3.5.1 The required outlet gas hydrocarbon dew point is defined by the supplier of the CO_2 removal membranes and may be omitted if the supplier provides performance guarantee. 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 CO_2 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 CO_2 Separation Membrane Unit.

2.7.3.5.6 The liquid outlet from the vessels of the CO_2 membrane pre-treatment shall be routed to an oil plant stage, CO_2 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: to be determined by process simulations;
- Maximum outlet gas CO_2 content = 3% mol;
- Outlet gas H_2S content = according to membrane performance;
- Permeate CO_2 stream H_2S content = according to membrane performance;
- Permeate stream = 400 kPa(a) to 800 kPa(a);
- Minimum retentate flow: According to reference in Table 2.7.3.6 from process design cases shown in Table 2.2.2.3.

Table 2.7.3.6 – Expected Minimum Retentate Flow

Design Case	Produced Gas (Sm³/d)	CO2 Content (%)	Minimum Treated Gas (1)
Case 1	12,000,000	23.0	7,300,000
Case 7	12,000,000	30.0	6,400,000
Case 13	9,300,000	45.0	3,800,000
Case 15	7,000,000	60.0	1,900,000

(1) Treated Gas is the full amount of the retentate gas downstream the Membrane Unit. In this value is considered: Export Gas, Fuel Gas and/or Lift Gas.

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 SELLER shall install proper online real time analysis devices to determine CO_2 and H_2S 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 SELLER shall guarantee use of fuel gas by consumers when the CO_2 removal unit is not operational and fuel gas CO_2 content is bellow or equal to 45%. 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 BUYER.

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

2.7.3.7 H_2S REMOVAL AMINE UNIT

2.7.3.7.1 The H_2S Removal Amine Unit shall be designed according to the following:

- Minimum design Capacity = according to process simulations, and at least 7,300,000 Sm³/d;
- Inlet pressure: to be simulated
- Inlet H_2S: up to 170 ppmv, according to design cases
- Inlet CO_2: up to 3% mol
- Turndown: the unit shall be designed to continuous operation for any flow rate between 5% and 100% of the design capacity, considering all design cases.
- Maximum outlet gas H_2S content = 5 ppmv.

2.7.3.7.2 A proper amine shall be selected taking into account the inlet composition and required specification for H_2S in the outlet gas.

2.7.3.7.3 The H2S removal Unit shall be designed in accordance with API RP 945 – Avoiding Environmental Cracking in Amine Units.

2.7.3.7.4 SELLER shall provide the amine for the first fill-up of H_2S removal system, amine fill-ups needed during operation and amine make-up due to operational losses. SELLER shall provide all chemical products required for effective operation of the H_2S Removal Amine Unit.

2.7.3.7.5 A scrubber (1 x 100%) and a coalescer filter (2 x 100%) upstream the H_2S Removal Amine 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).

2.7.3.7.6 For the scrubber vessel design, as a minimum, SELLER shall provide:

- at least 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 inlet zone.
    - Mesh or Vane device to separate large liquid droplets, drain it 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.

2.7.3.7.7 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.

2.7.3.7.8 The coalescer filters shall have differential pressure transmitter (PDT).

2.7.3.7.9 The scrubber vessel and the coalescer filter shall have independent level control loops (LIT, LIC and LV).

2.7.3.7.10 The level meters shall have at least three side connections to avoid measurement errors in case of two liquid phases.

2.7.3.7.11 The amine contactor(s) and amine stripper shall use packing. The liquid distributor shall be tubular type or similar. PDTs shall be installed around the packings.

2.7.3.7.12 The amine contactor (s) shall have a bucket to eventually separate condensed hydrocarbons.

2.7.3.7.13 It shall be provided an amine contactor(s) by-pass in order to allow the lean amine circulation during start-up.

2.7.3.7.14 A by-pass around the amine contactor(s) shall be provided for lean amine to allow circulation during start-up.

2.7.3.7.15 Temperature of lean amine entering the top of the amine contactor shall be controlled at 5°C above inlet gas temperature.

2.7.3.7.16 All heaters shall use hot water (as heating medium) or electrical resistors. In case of electrical resistors at reboiler heating system compliance to item ELECTRICAL REQUIREMENTS FOR HEATING SYSTEMS is mandatory.

2.7.3.7.17 In case of venting the sour gas from the amine regeneration a dedicated vent shall be provided for this stream. The height and the location shall be based on dispersion calculation supported by CFD analysis. In case of vent trap installed, the drainage shall be sent to reflux drum. If no vent trap installed the line shall not have low points.

2.7.3.7.18 In case of flaring the sour gas, the minimum requirements shall be complied with:

- Appropriate dispersion of SOx and H_2S shall be guaranteed in case of ignited and non-ignited;
- Dedicated piping for the sour gas stream;
- The flare design shall be designed for all expected sour gas conditions (composition, pressure, etc.).

2.7.3.7.19 The amine flash drum shall be a three-phase horizontal separator, to separate amine hydrocarbon and gas, with dedicated level control loops (LIT, LIC, LV) for each liquid phase.

2.7.3.7.20 Amine tank or vessels with connections to atmospheric vent shall be equipped with nitrogen or other inert gas blanketing system.

2.7.3.7.21 Flow meter (transmitter) in the lean amine inlet of the contactor(s) shall be provided.

2.7.3.7.22 2 x 100% Cartridge filters shall be provided for 100% of amine flow. Activated carbon filter and a secondary cartridge filter, with a by-pass, shall be provided for 20% of amine flow.

2.7.3.7.23 The unit shall have online H_2S/CO_2 content analyzer downstream of the amine contactor and upstream of Amine unit. The analyzers shall be calibrated with certificate issue in accordance with the manufacturer's specifications at least annually.

2.7.3.7.24 All facilities (tanks, pump, instrumentation, etc.) for chemicals injection shall be provided.

2.7.3.7.25 The regeneration system shall be design in order to avoid oxygen entrance during a shutdown/cooling-condensation of the steam inside de tower.

2.7.3.7.26 The H2S Removal Amine Unit shall also be designed taking into account the minimum temperature that occurs during the depressurizing condition of unit to the flare system.

2.7.3.7.27 For plate heat exchangers, consider hydrocarbon presence in order to specify the equipment. Furthermore, a spare equipment or spare plates and gaskets on board are required.

2.7.3.7.28 The off spec treated gas shall be deviated to flare through a pressure control valve installed on downstream the unit. The gas is considered offspec when H2S is higher than 5 ppmv or amine flow is lower than amine plant design specification.

2.7.3.7.29 Continuous gas released in the Amine Flash Drum is to be returned to the process as vapor recovered in order to avoid hydrocarbon flaring.

2.7.3.7.30 The make-up water shall have the following quality parameters, as a minimum, or more restrictive parameters according to the amine plant design specification:

- Total Hardness (Ca & Mg) < 50 ppmw max
- Chlorides < 2 ppmw max
- Sodium < 3 ppmw max
- Potassium < 3 ppmw max
- Iron < 10 ppmw max

2.7.3.7.31 H_2S Removal Amine Unit equipment shall comply with the following minimum requirements as spare philosophy:

- Pumps: N+1 (one stand-by);
- Filters: N+1 (one stand-by); except Amine Carbon Filter and its associated cartridge downstream filter which shall be 1 x 100%;
- Lean/Rich Amine Exchanger (2 x 100%);
- Amine Stripper Reboiler (2 x 50%).

2.7.3.8 VAPOR RECOVERY UNIT (VRU)

2.7.3.8.1 The Vapor Recovery Units (VRU) shall be dry screw compressor type according to API 619 or centrifugal compressor type according to API 617.

2.7.3.8.2 Vapor Recovery Unit shall be supplied as complete package by the compressor Original Equipment Manufacturer (OEM). Package means main equipment train (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).

2.7.3.8.3 The shaft seals shall be of self-acting bi-directional 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.

2.7.3.8.4 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:

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

2.7.3.8.4.2 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, SELLER is required to demonstrate.

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

2.7.3.8.4.4 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.

2.7.3.8.4.5 Alternate seal gas supply shall maintain the minimum sealing gas conditions required by DGS Manufacturer and API Std. 692, 20°C 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 (SELLER is required to demonstrate).

2.7.3.8.4.6 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.

2.7.3.8.5 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.

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

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

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

2.7.3.8.9 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 420,000 Sm^3/d and the capacity of the 2nd stage shall not be lower than 960,000 Sm^3/d.

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

2.7.3.8.11 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).

2.7.3.8.12 For acceptable vendor list for Rotary Compressor for Vapor Recovery Unit API 619 and for Centrifugal Compressor Unit API 617, see item 19.1.1.7.

2.7.3.9 CENTRIFUGAL GAS COMPRESSORS

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

2.7.3.9.2 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).

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

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

2.7.3.9.5 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 the Main Compressor, 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.

2.7.3.9.6 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.

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

2.7.3.9.8 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.

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

2.7.3.9.10 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. SELLER shall consider one antisurge recycle line for each stage. Overall recycle line shall not be accepted. Additionally, SELLER should also provide cooled recycle, nevertheless a hot recycle in a secondary recycle line shall be provided.

2.7.3.9.11 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.

2.7.3.9.12 The compressor packages shall have their own Control and Automation System. All data shall be available to BUYER (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.

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

2.7.3.9.14 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.

2.7.3.9.15 Extraction/injection gas stream from/into a compressor casing (except for sealing or balance line) is not acceptable.

2.7.3.9.16 SELLER 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). Compressor shall be designed to be capable of restarting from a pressurized condition at suction pressure as minimum. An operational XV valve (different from BDV) shall be used automatically to reduce the system pressure.

2.7.3.9.17 SELLER shall consider the molecular weight range corresponding to all design cases.

2.7.3.9.18 SELLER 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 BUYER. During these tests, shop driver may be used.

2.7.3.9.19 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 2.7.3.9.20.2.

2.7.3.9.20 MAIN GAS COMPRESSOR

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

- Inlet pressure = 2,200 kPa(a) (estimated, depends on previous pressure drop);
- Discharge pressure range = to be defined by SELLER;
- A stand-by unit is required as follows: 2x100% or 3x50% or 4x33%.

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

2.7.3.9.20.3 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.

2.7.3.9.21 EXPORT GAS COMPRESSORS

2.7.3.9.21.1 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 = to be defined by SELLER;
- Discharge pressure = 25,000 kPa(a) at the top of the lift gas risers;
- Normal operating temperature downstream discharge cooler (due to riser limitation): 40-55°C;
- A stand-by unit is required as follows 2x100% or 3x50% or 4x33%.

2.7.3.9.21.2 For Export Gas Compressors, the condensate from inlet, inter-stage and final coolers vessels shall be routed to second stage oil plant. It shall not be sent to slop or drain system.

2.7.3.9.21.3 Gas Lift extraction point shall be downstream Export Gas Compressor.

2.7.3.9.22 CO_2 COMPRESSORS

2.7.3.9.22.1 The CO2 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 = to be defined by SELLER;
- Discharge pressure = according to Injection compressor suction pressure
- A stand-by unit is required as follows 2x100% or 3x50% or 4x33%.

2.7.3.9.22.2 For CO2 Compressors, the condensate from inlet, inter-stage and final coolers vessels shall be routed to second stage oil plant. It shall not be sent to slop or drain system.

2.7.3.9.23 INJECTION GAS COMPRESSORS

2.7.3.9.23.1 The injection gas compression system shall be designed as follows:

- Capacity and gas composition = according to process simulations for all design cases and Operation Modes;
- Inlet pressure = according to process simulations for all design cases and Operation Modes;
- Discharge pressure = 50,000 kPa(a) at the top of gas risers;
- Normal operating temperature downstream discharge cooler= 40°C;

- A stand-by unit is required as follows 2x100% or 3x50% or 4x33% for Mode 1. No stand-by Injection Compressor unit is required for Mode 3.

2.7.3.9.23.2 For Injection Compressors, the condensate from inlet, inter-stage and final coolers vessels shall be routed to second stage oil plant. It shall not be sent to slop or drain system.

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

2.7.3.9.24 CENTRIFUGAL COMPRESSOR DRIVERS

2.7.3.9.24.1 Compressors shall be driven by electric motors or gas turbines.

2.7.3.9.24.2 For speed variation with electric motor, only solutions with Hydraulic Variable Speed Drives (HVSD) or Variable Frequency Drives (VFD) are acceptable. Soft starters are acceptable as well as Variable Frequency Drivers (VFD) working as soft starters. Dry Low Emission Turbines (DLE) are not accepted for aero-derivative gas turbine type.

2.7.3.9.24.3 For electric motors, the available power shall be at least 12% higher than compressor greatest power required (including gear and coupling losses) indicated in the supplier data set.

2.7.3.9.24.4 For acceptable vendor list for Gas Compressor API 617 and Gas Turbines, see item 19.1.1.7.

2.7.3.9.24.5 Gas compression services that may be driven by a gas turbine are CO2 compressor, Export Compressor, Booster/Injection compressor and Main Compressors. Gas turbine driver is not accepted for VRU, if centrifugal. The gas turbine driver for compressor services shall be dual fuel type, designed to operate on fuel gas or on Diesel fuel.

2.7.3.9.24.6 The gas turbine SITE Power (30°C as site air intake temperature) shall be higher than compressor greatest power required (including gear and coupling losses) indicated in the supplier data sheet. SELLER shall apply a factor (this factor shall be indicated and detailed in Technical Proposal) taking into consideration the following, as minimum:

- Efficiency loss due to ageing of the turbine;
- Efficiency loss due to fouling of the turbine;
- Efficiency loss due to intake and exhaust losses (with or without WHRU, when applicable);
- Gearbox efficiency;
- Centrifugal Compressor mechanical losses.

NOTE 1: The factor proposal shall be based on SELLER's recent FPSO designs, and shall also include 15% of temperature derating (ISO to SITE temperature);

NOTE 2: If it can be demonstrated that the vendor-specific temperature derating factor is less than 15%, SELLER may use the vendor informed factor but shall apply, at least, a surplus of 9% for the overall efficiencies and losses as described in this GTD Item.

2.7.3.10 OTHER REQUIREMENTS

2.7.3.10.1 Utilities (including power generation system) shall be designed considering at least the capacity of 12,000,000 Sm³/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.

2.7.3.11 GAS EXPORT RISER PRE-COMMISSIONING

2.7.3.11.1 Pre-commissioning of the gas export pipeline shall occur after pull-in of riser and subsea ESDV's control umbilical and after hardpiping assembly. The pre-commissioning activity will be BUYER's scope of work (performed by pipeline installer).

2.7.3.11.2 The gas export riser pre-commissioning procedure and responsibilities are presented in RISER SYSTEM REQUIREMENTS (see item 1.2.1).

2.7.3.11.3 SELLER shall provide space on deck (estimated area with dimensions of 10m x 10m near gas export risers region) to receive and storage the provisional Pig launcher/receiver (PLR) and other equipment (piping/hoses, storage tanks, manifolds, chokes, silencer and valves) from a vessel to the Unit and subsequent internal handling to enable it to be assembled on the "dry" extremity of the respective hard pipe. This temporary set of equipment (provided by pipeline installer) will be used for the water discharge, MEG recovery/storage, N_2 discharge (all under internal pressure) and pig receiving.

2.7.3.11.4 SELLER shall be responsible for the hardpiping and temporary pig receiver assembly necessary to perform the gas export riser pre-commissioning, with pipeline installer support.

2.7.3.11.5 The pipeline installer personnel shall be responsible for all the provisional equipment assemblies, and SELLER shall be responsible for the permanent hardpiping assembly necessary to perform the gas export riser pre-commissioning.

2.7.3.11.6 Provision shall be available for the necessary support to operations during the gas export riser pre-commissioning (Compressed air, water and electricity) on board the FPSO.

2.7.3.11.7 SELLER is responsible for scaffolding supply and assembly when necessary to complete the scope of work.

2.7.3.11.8 Riser water content (filtered seawater without chemicals or potable water) will be discharged into the sea through hoses (supplied by pipeline installer) installed into the PLR and routed from the upper balcony to the sea.

2.7.3.11.9 MEG used for pipeline drying will be recovered by pipeline installer and will be returned together with the provided temporary equipment.

2.7.3.11.10 SELLER shall be prepared to handle properly the residual inert gas (99% pure nitrogen) used during pre-commissioning and sent it to a safe location.

2.7.3.11.11 CANCELLED.

2.7.3.12 OTHER RISERS PRE-COMMISSIONING

2.7.3.12.1 SELLER is responsible for diver assistance of pre-commissioning activities (underwater PLR operation, PLR disassembly and handling, etc).

2.7.3.12.2 Details about riser pre-commissioning procedure may be found in RISER SYSTEM REQUIREMENTS (refer to 1.2.1).

2.7.3.12.3 All items in section 2.7.3.11 are applicable to the pre-commissioning of the GAS TRANSFER RISER.

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.

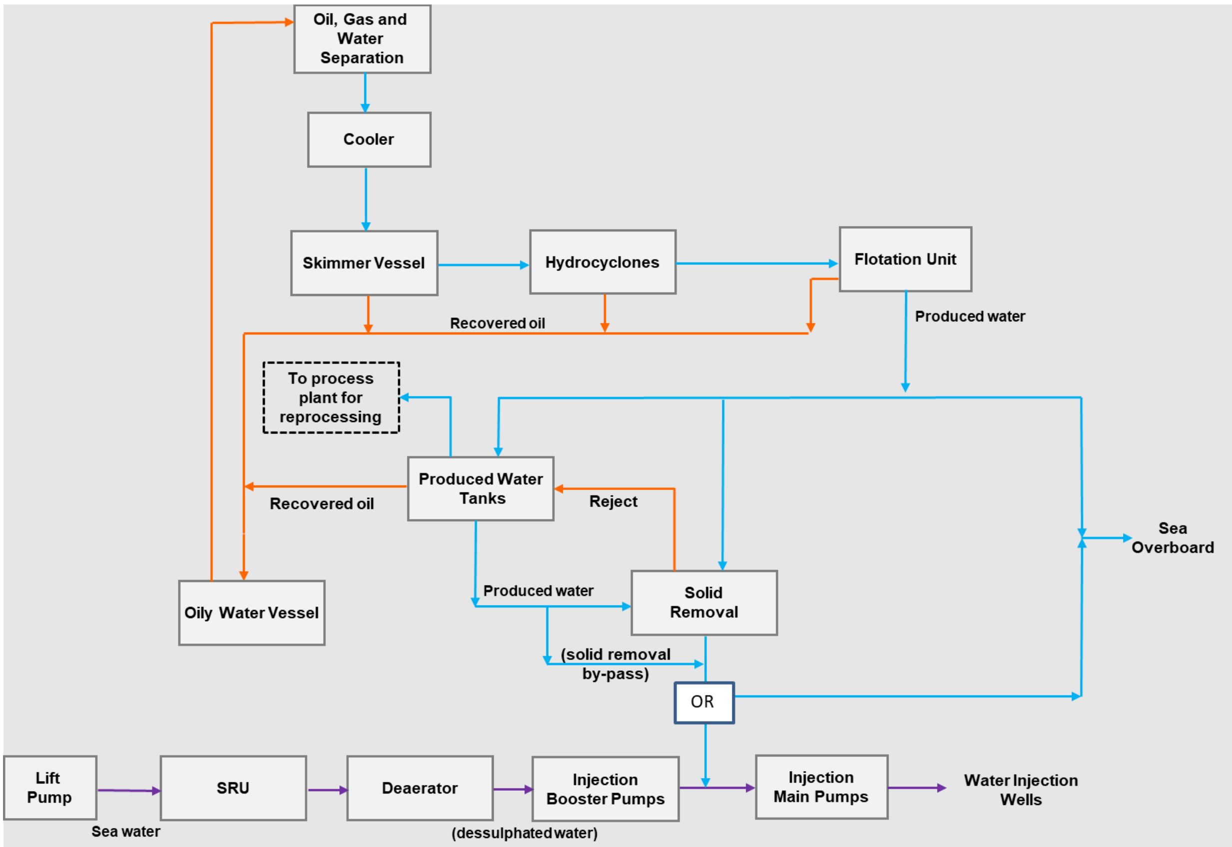

Figure 2.7.4.1 - Simplified Diagram for Produced Water Treatment, Reinjection and Seawater Injection

2.7.4.2 Alternative configuration shall be submitted for BUYER 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. SELLER shall provide means to rout Treated Produced Water to one of the following destinations:

- Overboard, if all applicable specifications are met;

- Produced Water Tank for additional polishing or to be routed back to process plant for reprocessing;
- As an option, SELLER may also provide a booster pump to route produced water directly to 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). The produced water from Flotation Unit may be routed directly to Solid Removal Unit in case of it meets the specifications of item 2.4.5.

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, SELLER 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/cm³;
- Average particle size (d50): 30 μm;
- Maximum particle size at water outlet (d98) 25 μm.

2.7.4.11 The system shall consider that desulfated 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 desulfated 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 flotation 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 SELLER 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. The volume of each tank shall be at least 10,000 m³. One of these Produced Water tanks shall be capable of receiving 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% considering produced water flowrate defined in Table 1.2.2.4 (2 x 11,925 m^3/d), per tank.

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

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. SELLER shall be responsible for managing residual disposal. Different configuration for the solid removal reject routing shall be submitted to BUYER approval.

2.7.4.16.3 The minimum requirements for filtration are summarized below.

- The configuration shall consider at least 3x50%, considering produced water flowrate defined in Table 1.2.2.4 (3 x 11,925 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 SELLER'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 drafts 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 -100°C 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 3,500,000 Sm^3/d. Process disposal streams like regeneration and flash gas from TEG Treatment 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. SELLER shall route the gas to production plant or to the gas processing plant in order to minimize gas flaring and its consequences.

2.7.5.4 SELLER shall submit to BUYER 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 the 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 SELLER shall submit to BUYER 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 and API 537 shall be followed to determine radiation levels limits during emergency and continuous flaring. SELLER shall also conduct dispersion analysis during flare snuffing scenarios and noise level studies for the determination of the flare stack height. SELLER shall also perform a flare radiation study as per FLARE RADIATION STUDY TECHNICAL SPECIFICATION.

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 SELLER 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 (Destruction Efficiency >99% and 98% conversion to CO_2) to guarantee low HC emissions to atmosphere;
- Operational flaring scenarios be evaluated to guarantee flame stability and quality, especially for the lowest expected flowrates, adopting staged flare or variable slot tip. Concern is excessive radiation and damage to flare structure in staged flare designs, if selected;
- 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 liquid-ring compressors (as per API

Std. 681), screw compressors (as per API Std. 619) or ejector. If the ejector option is considered, the motive fluid type and its supply characteristics shall be clearly specified during the proposal stage to ensure reliable and continuous operation. Any unavailability of the recovery system due to failure or insufficiency of the motive fluid supply will not be accepted under any circumstances.

2.7.5.9.5 As a minimum, SELLER shall design the FGRS with an overall capacity of 75,000 Sm³/d in a 2x50% configuration. If the FGRS is used to recover continuous process streams outlined in 2.7.5.3, these flowrates shall be added to this capacity. 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 CO_2 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 SELLER shall provide point(s) for nitrogen purge. In case of staged systems, it shall be 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 SELLER 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 CO_2

2.7.5.11.1 CONTRACTOR may evaluate the use of alternative design for emergency disposal of rich CO_2 stream, such as header segregation and venting. CONTRACTOR shall also evaluate if CO_2 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 CO_2 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 CO_2 flowrate during the depressurization and relief of gas streams containing CO_2 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 CO_2 presence and accumulation;
- For the cases where potential for CO_2 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 CO_2 solid, showing relief and CO_2 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:

- H_2S scavenger for subsea;
- H_2S scavenger for Topside;
- 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;
- Biocide for Slop Tank, Off-spec Tanks and Cargo Tanks, Produced Water Tanks;
- Acetic Acid;
- Oxygen scavenger;
- All the manufacturer recommended chemicals for TEG Treatment Unit. As a minimum SELLER shall consider:
    - pH stabilizer;
    - Antifoam;
- All the manufacturer recommended chemicals for the Sulphate Removal Unit and Ultrafiltration Unit. As a minimum SELLER 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 20 days of normal consumption, calculated by using 100% 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 levels 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. Tank vents for flammable and combustible products shall be equipped with flame arrestors.

2.8.5 Vents for flammable and combustible products shall be in accordance with API STD 2000 or NFPA 30. For vent sizing, reduction factors foreseen in API STD 2000 and NFPA 30 shall not be considered. SELLER can evaluate the use of 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 (slot, 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 and on pump suction (2x100%, 100 mesh stainless steel) shall be added. The discharge filters shall have remote differential pressure alarm for replacement. SELLER 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 BUYER during operation phase.

2.8.8 All chemical injection pumps shall have a filter upstream. Additional filter downstream injection pumps shall be provided to protect spray nozzles, where applicable. SELLER shall install stand-by pumps at all chemical units to guarantee continuous performance, except for high-volume pumps as 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 For all chemical injections (subsea and topside) SELLER shall provide a pump system to guarantee the individual flow control per point. 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. SELLER shall comply with flow meter maintenance plan recommended by the supplier. Flow meters shall be Coriolis type, transmitting online flow and density.

All subsea chemical injection points shall be protected against loss of injection flow control caused by vacuum occasionally formed in the injection line (due to U-tube phenomenon). The installation of an in-series relief valve or similar device downstream the flowmeter of each chemical injection line is an acceptable solution.

2.8.11 Each injection point shall be in the center of pipe (“quill device”). All the topside injection points in the gas shall be installed with spray nozzle to accelerate the chemical mixing. The chemical injection points should be installed far from any fiscal, allocation or custody transfer measurement system (including its respective sampling point), preferably downstream the flow meter, so as to avoid inaccuracies on the flow meters.

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

<table>
<tr><th colspan="2">PRODUCT</th><th>INJECTION RATE</th></tr>
<tr><td colspan="2">Gas hydrate inhibitor: ethanol or MEG, not continuous (subsea) (1)</td><td>Total flow rate of 7,000 L/h with at least 2 x 50% pumps configuration.
There shall be a storage of 2 (two) tanks of 65 m³ each. At any time, each of the tanks may be used for ethanol or MEG.</td></tr>
<tr><td colspan="2">Gas hydrate inhibitor: ethanol or MEG, not continuous (topsides) (2)</td><td>Topside: 1 to 200 L/h (multi head pump).
These facilities will share the same tanks used for subsea injection (not continuous).</td></tr>
<tr><td colspan="2">Scale inhibitor for topside (3, 6)</td><td>SELLER shall provide independent systems for topside and subsea scale inhibitor injection.
Topside: from 8 to 800 L/h in each injection point.
Minimum effective tank capacity: 240 m³.</td></tr>
<tr><td colspan="2">Scale inhibitor for subsea (3,5)</td><td>The injection system provided shall operate in the range of 1 to 10 L/h per injection point. More than one head pump may be required to reach the maximum injection rate.
Minimum effective tank capacity: 50 m³.</td></tr>
<tr><td rowspan="4">Shared facilities for subsea (5)</td><td>Asphaltene inhibitor</td><td rowspan="4">The injection system provided shall operate in the range of 20 to 200 L/h per well.
There shall be a total storage of 4 (four) tanks of 50 m^3
The facilities defined for this item should be able to attend the four products specified, not simultaneously.</td></tr>
<tr><td>Wax inhibitor (4)</td></tr>
<tr><td>H_2S scavenger for subsea</td></tr>
<tr><td>Scale inhibitor for subsea</td></tr>
</table>

PRODUCT	INJECTION RATE
H_2S scavenger for topsides (6)	Injection point: upstream cargo transfer pump, off spec tank, produced water tank. The injection system provided shall operate in the range of 24 to 240 L/h. There shall be a total storage of 36 m³. This product should be used just contingently and in agreement with BUYER.
Water-in-oil demulsifier for topsides (6)	The injection system shall provide 2 a 140 L/h. Minimum tank capacity: 56 m³.
Oil defoamer (6,7)	The injection system shall provide 5 a 265 L/h. Minimum tank capacity: 64 m³.
Biocide for Slop Tank, Produced Water Tank, Cargo Tanks and Off-spec Tanks (8)	Batch treatment uses 140 L/h as product flow rate. Minimum effective tank capacity: 5 m³.
Biocide for Slop Tank, Produced Water Tank, Cargo Tanks and Off-spec Tanks (8)	Batch treatment uses 140 L/h as product flow rate. Minimum effective tank capacity: 5 m³.
(SRU) Acid cleaning	Batch use (9) Tank capacity: To be defined by SELLER.
(SRU) Alkaline cleaning	Batch use (9) Tank capacity: To be defined by SELLER.
Water injection shock Biocide: DBNPA (10)	From 100 to 500 ppm twice a week for one hour, upstream SRU (downstream REDOX analyzer and upstream the cartridge filters). Tank capacity: To be defined by SELLER.
Water injection shock biocide: THPS (tetrakis hydroxymethyl phosphonium sulfate)	Batch treatment uses 100 to 1000 ppm as product flow rate twice a week for one hour, upstream and downstream deaerator, not simultaneously. Minimum effective tank capacity: 12m³, to be confirmed by SELLER.
Scale inhibitor for SRU	From 1 to 20 ppm upstream SRU. Minimum effective tank capacity: 6 m³, to be confirmed by SELLER.
Chlorine scavenger	From 1 to 30 ppm upstream SRU • Tank capacity: No additional storage required; SELLER may use the same tank mentioned for oxygen scavenger.
Oxygen scavenger	From 5 to 25 ppm upstream and downstream deaerator, not simultaneously (operational deaerator). From 100 to 200 ppm upstream and downstream deaerator (two points, one inside and another after dissolved O_2 analyzer), not simultaneously (non-operational deaerator).

PRODUCT	INJECTION RATE
	From 100 to 200 ppm upstream Solids Removal Unit. Minimum effective Tank capacity: 35m^3. To be defined by SELLER.
Oxygen scavenger for produced water	Injection point: downstream Solid Removal Unit From 1 to 40 ppm. No additional storage required, SELLER may share the storage defined for Oxygen scavenger for treated seawater.
Biofouling disperser	From 5 to 20 ppm downstream deaerator. Minimum effective Tank capacity: 16m^3.
Polyelectrolyte (11)	From 100 to 100 ppm. Minimum effective tank capacity: 60 m³
Caustic (12)	Injection capacity: 200 L/h. Effective tank capacity: 22 m³
Acetic acid (75%) (13,14)	Injection points: on production and test headers (more distant upstream) considering 100 to 1000 ppm of product based on total produced water flow rate. Minimum effective tank capacity: 224 m^3.

NOTE 1: To inhibit hydrate formation, ethanol / MEG shall be injected into the Wells Wet Christmas Trees. This injection is not planned to be continuous, however, it should be possible to inject it in up to two points at the same time. SELLER 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.

Injection points are required at the top of all risers, and on the chemical routing plates shown in Figure 2.8.15. 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. SELLER 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: Injection points are required at the topside facilities in case of water content gas out of spec.

The attachment of chemical injection device to tubing or equipment shall be via flanged connection. Retractile nozzles system (the part in contact with the fluid can be inserted and removed in operation) is required for maintenance.

SELLER shall provide the following injection points:

- Gas export pipeline;
- Gas-lift lines, individually per well;

- Gas Transfer line;
- Upstream fuel gas pressure control valve (if necessary);
- Condensate outlet of the high pressure fuel gas vessel (if necessary).

It shall be considered additional injection points, where hydrate could form, to be eventually used in the operation to remove any hydrate formed due to an abnormal operation condition.

The injection system provided shall consider 200 L/h for gas export pipeline and 100 L/h for gas-lift lines (range of 1 to 15 l/h per line) and 20 L/h for the Gas Transfer line. The minimum flow rate for each injection point shall be 1.0 (one) l/h.

NOTE 3: 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 headers, test headers, produced water outlet of FWKO, upstream of treaters and/or heat exchangers, Oil Test Separator and treaters - as close as possible to the water outlet nozzles, upstream of hydrocyclones, upstream mixing device (oil/dilution water), upstream mixing with desulfated water (reinjection scenario) and others) whenever required by BUYER. Separate systems shall be provided, as different products are injected topsides and subsea. BUYER informs that there is a high potential of scaling at topside and subsea. In the case of dosage ranges exceeding 10: 1, the SELLER must provide sets of heads / pumps of complementary ranges.

NOTE 4: Wax inhibitor chemical uses Xylene as solvent.

NOTE 5: The Unit shall be prepared to inject this product continuously subsea.

NOTE 6: The Unit shall be prepared to inject this product continuously topsides.

NOTE 7: Points of injection: production and test headers, upstream of the oil level control valve of the FWKO and upstream flash vessels.

NOTE 8: SELLER 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 9: During project execution phase, SRU cleaning procedure shall be submitted to BUYER for comments.

NOTE 10: DBNPA is a corrosive product so its injection system shall not be metallic However, titanium/hastelloy C is acceptable for use with DBNPA.

NOTE 11: Polyelectrolyte must be injected upstream of the flotation cell and the injection points must be downstream of the hydrocyclones. This product should be diluted 10 to 30 times in fresh water. The SELLER must use in-line dilution systems or pumps that allow automatic product dilution in water, without the need for a dilution tank.

NOTE 12: Points of injection: Cargo transfer pump suction.

NOTE 13: The necessary amount of acetic acid and coagulant will be provided by BUYER at no cost.

NOTE 14: Facilities defined for acetic 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 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, using the 5 m³ tank as a reference. Products of non-continuous use shall not be considered in this calculation. Products marked as “ZERO” mean that tote transfer facilities are required, but definition of total storage area may not consider these products. No stacking of tote tanks is allowed.

Table 2.8.14 – Tote Tanks Quantity for Storage Area Definition

PRODUCT	TOTE TANKS QUANTITY (reference 5m3)
H_2S scavenger for subsea	4
H_2S scavenger for topsides	7
Gas hydrate inhibitor: ethanol or MEG (1)	2
Scale inhibitor for topside	4
Scale inhibitor for subsea	18
Wax inhibitor	ZERO
Asphaltene inhibitor	10
Water-in-oil demulsifier for topsides	7
Oil defoamer	7
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	1
Water injection shock Biocide: DBNPA	1
Water injection shockbiocide: THPS(tetrakis hydroxymethyl phosphonium sulfate)	1
Scale inhibitor for SRU	2
Chlorine scavenger or Oxygen scavenger	2
Biofouling disperser	3
Polyelectrolyte	2
Acetic Acid	5
Caustic	5

2.8.15 Configuration for Chemical Routing Panels is presented in the following Figure. Detailed information of routing to umbilical tubings shall be confirmed with BUYER during engineering detailing phase. Design shall provide:

- connections to all MEG flushing of subsea chemical injection lines on topsides and subsea umbilicals;
- connection from Subsea inhibitor tank to each of the 3 (three) Low Flow Pumps;
- connection from any of the 4 (four) shared subsea chemical injection tanks to any of the Medium Range Low Pumps;

- connection from one of the shared subsea chemical injection tanks to each of the 3 (three) Low Flow Pumps.

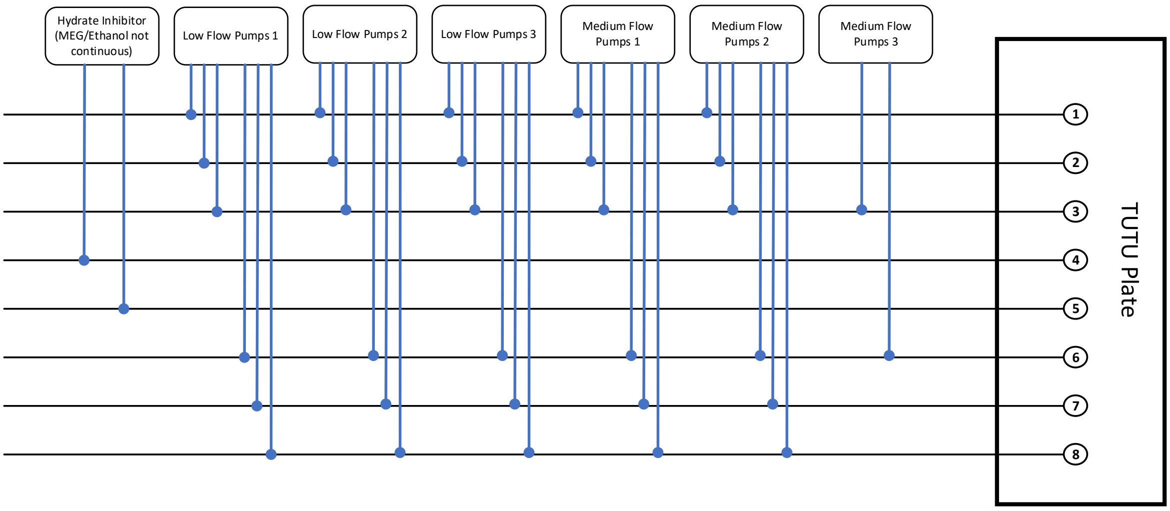

Figure 2.8.15: Chemical Routing required for each Oil Well umbilical and aggregated Injection Wells/subsea equipment.

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

2.8.16 SELLER 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 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 BUYER 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) (1)
Scale inhibitor for subsea	(2)
Scale inhibitor for subsea	(2)
Scale inhibitor for topside	(2)
H2S scavenger for subsea	(2)
H2S scavenger for topsides	(2)
Hydrate inhibitor	(3)
Asphaltene inhibitor	(2)
Wax inhibitor	(2)
Demulsifier for topside	70 m^3 (4)
Demulsifier for subsea	(2)
Oil defoamer	80 m^3 (4)
Biocide for Slop Tank, Produced Water Tank, Cargo Tanks, Settling Tanks and Off-spec Tanks	(2)
SRU Acid Cleaning	(2)
SRU Alkaline Cleaning	(2)
Water injection shock Biocide: DBNPA	(2)
Biocides for water injection	(2)
Scale inhibitor for SRU	(2)
Chemicals to be used in the Sulphate Removal Unit and Ultrafiltration Unit (if necessary)	Oxygen scavenger and chlorine scavenger - 30 m^3 (5)
Biofouling disperser	(2)
Polyelectrolyte	(2)
Caustic	(2)
Acid for produced water treatment	(2)

NOTE 1: BUYER reserves the right to conduct technical evaluation and determine the actual conditions and quantities of chemicals to be supplied. The quantities above may be revised during the operation, if SELLER presents technical evidence that supports such need and is accepted by BUYER.

NOTE 2: The maximum volume of each chemical that will be provided by BUYER at no cost will be informed during project execution phase. SELLER must use the volume or dosage requested by BUYER.

NOTE 3: The necessary amount of hydrate inhibitor necessary for cleaning the flowlines will be provided by BUYER at no cost.

NOTE 4: Based on Produced Liquids.

NOTE 5: Based on Injection Water. Refers to injection upstream SRU, upstream/downstream deaerator and Produced Water Solid Removal Unit. Other uses of Oxygen/Chlorine scavenger are SELLER responsibility.

NOTE 6: All other chemicals not mentioned for the Sulphate Removal Unit and Ultrafiltration Unit shall be supplied by SELLER.

NOTE 7: Chemical products required for Cleaning-in-Place of Water Treatment Units and Heat Exchangers shall be supplied by SELLER.

NOTE 8: Chemical products required for Utilities and potable water shall be supplied by SELLER.

2.8.18 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.

2.8.19 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.

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

2.8.21 For tote tanks dimensions, SELLER shall consider:

Table 2.8.21 – Tote Tank Dimensions

Volume (m^3)	Valve	Connection	PB	H (m)	L (m)	W (m)	Tare (kg)
1.0	Ball 2”	Screw BSP	Restricted gate	1.5	1.3	1.5	265
1.5	Ball 2”	Screw BSP	Restricted gate	1.9	1.3	1.5	440
3.0	Ball 2”	Screw BSP	Restricted gate	2.3	2.3	2.3	1500
5.0	Ball 3”	Screw BSP	Restricted gate	2.3	3.0	2.3	1700
5.2	Ball 3”	Screw BSP	Tripartite restricted gate	2.3	3.1	2.3	1700
8.5	Ball 3” TBC	Screw BSP		2.7	3.0	2.44	3100-3250

W: Width, H: Height, L: Length

2.8.22 Required pressure at top of riser and flowrates per well for the subsea chemical injection is presented in Table 2.8.22. During execution phase, BUYER will confirm these values.

Table 2.8.22 – Subsea Chemicals Requirements

Product	Injection Point	Pressure at top of riser/umbilical (bara)	Min Flow Rate (L/h)	Max Flow Rate (L/h)
Ethanol/MEG not continuous	4, 5	300	200	7000
Low Flow Pump 1	1, 2, 3, 6, 7, 8	415	1	10
Low Flow Pump 2	1, 2, 3, 6, 7, 8	415	1	10
Low Flow Pump 3	1, 2, 3, 6, 7, 8	415	1	10

Mid Range Flow Pump 1	1, 2, 3, 6, 7, 8	415	10	200
Mid Range Flow Pump 2	1, 2, 3, 6, 7, 8	415	20	200
Mid Range Flow Pump 3	3, 6	415	20	200

NOTE 1: For Production and Injection positions. Not continuous hydrate inhibitor can also be injected in other subsea equipment as manifold, PLEMs or HMXO according to the routing to be detailed.

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, SELLER 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 (1,2,3,8)	• Test and production header (upstream from the chemical injection points); • Upstream and downstream of process vessels; • Try-cocks on pre-electrostatic treater, electrostatic treater and free water separator (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)	• Upstream and downstream of process vessels; • Gas export (upstream of pig launcher and receiver); • Membrane unit: inlet gas, treated gas and CO2 rich stream (each elements cluster, as a minimum); • Fuel Gas; • High Pressure Flare gas; • Low pressure Flare gas; • Service header; • Gas lift header; • All production header lines; • Gas reinjection header; • Upstream and downstream of Dew Point Control Unit;

	• Slop and Cargo Tanks.
TEG Unit	• Lean TEG stream at the inlet of the 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.
H_2S Removal Amine Unit	• Sour gas at gas inlet of amine contactor • Sweet gas at gas outlet of amine contactor • Lean amine at inlet of amine contactor(s) • Rich amine downstream of amine flash vessel level control valve • Rich amine downstream of activated carbon filter • Sour gas upstream scrubber vessel • Sour gas - at gas outlet of regeneration tower • Sour gas - at gas outlet of Amine Flash Drum • Sweet gas downstream of KO drum in the outlet of amine contactor(s) • Reflux water to the stripper tower • Make-up water
Produced water (1,6)	• 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 desulfated 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.

NOTE 1: SELLER 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: SELLER 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 (or other updated document which substitutes or complements it) shall be complied with. For a list of all metering points and additional requirements see FLOW METERING SYSTEM - BOT (see item 1.2.1).

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

NOTE 5: SELLER 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);

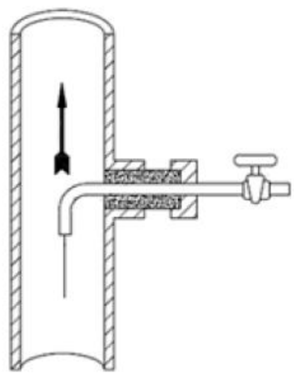

Figure 2.9.1 – Intrusive Sample Point

- 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: SELLER 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 nº 14, December 20, 1995) Annex 13 A.

NOTE 9: Additionally to the NOTE 6 requirements, this sample point shall have 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 be in compliance with *NOTA TÉCNICA CGPEG/DILIC/IBAMA Nº 01/11.*

2.10 LABORATORY

2.10.1 SELLER shall provide a laboratory on board to carry out the tests listed in Table 2.10.1a. Some tests may not be carried out on board, as defined in Table 2.10.1b.

Table 2.10.1a – Laboratory Analyses On Board

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Produced Oil	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
	H_2S content	UOP 163
	pH; two-phase oil (1)	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	RVPE	ASTM D6377
Cargo and Slop tanks	BS&W and watercut	ASTM D4007 or API MPMS 10.4; ASTM D4928; ASTM D4377
	H_2S content in oil	UOP 163
	H_2S content in water	UOP 209
	H_2S 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
	O_2 content (3)	ASTM D5543
Injection water (from sea water treatment or produced water treatment)	O2 content (3)	ASTM D5543
	SDI (Silt Density Index)	ASTM D4189
	Number of particles	SMEWW 2560 C. Light-Blockage Method
	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
	H_2S 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	H_2S 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	H_2O content (6)	ASTM 1142 and ASTM D 5454
	H_2S 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;
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 Medium Systems	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293

	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)
	O_2 content	ASTM D5543
Sewage system (8)	pH	SMEWW 4500 pH Value; ASTM E70; ASTM D1293
	Chlorine content (4)	4500-Cl G. DPD Colorimetric Method

Table 2.10.1b – Laboratory Analyses Onshore

SYSTEMS	ANALYSIS	REFERENCED DOCUMENT
Produced Oil and Condensate	PVT - shrinkage factor and gas oil ratio	BUYER Test Method (Pressurized density and flash release)
Produced and discharged water	Oil content	SMEWW 5520 B and SMEWW 5520 F
	Composition (9)	USEPA Method 300; ASTM D4327; SMEWW 4110 B; ASTM D691; ASTM D1976.
Injection water (from sea water treatment or produced water treatment)	Bacteria SBR planctonic, mesophilic and thermophilic	Standard Test Method to be defined by BUYER
	BANHT - Total Anaerobic Heterotrophic Bacteria	Standard Test Method to be defined by BUYER
	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
	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).

SELLER 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. SELLER 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 shall be able to measure at least the specification of 0,1 to 2 ppm of chlorine content.

Note 5: SELLER shall supply chromatographic analysis of any gas sampling point, under BUYER occasional demands.

Note 6: SELLER 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). SELLER shall provide portable aluminum oxide moisture sensor according to ASTM D 5454. The portable aluminum analyzer shall be able to measure H_2O content in the treated gas stream within the moisture specification range.

Note 7: Not Applicable

Note 8: The SELLER must 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.

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

2.10.3 All glassware shall 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 shall 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 shall have its own socket. For each location in the laboratory where electrical equipment will be installed, at least one additional electrical power point must be provided per type of equipment.

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

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

2.10.13 The analysis results shall be registered in appropriate software for laboratory analysis management. BUYER shall have read access to the software. The software shall, at a minimum, allow the construction of graphs as a function of time and export data to an Excel file.

2.11 ENERGY EFFICIENCY & ATMOSPHERIC EMISSIONS

2.11.1 SELLER 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 to flare pilots. Emergency conditions and safety reasons shall not be considered "routine".

2.11.2 FUGITIVE EMISSIONS

2.11.2.1 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.

2.11.2.2 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.

2.11.3 During the execution phase SELLER shall provide 18 months after Agreement signature, 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.

2.11.4 SEA WATER DUMP LINE TURBOGENERATOR (SWDLT)

2.11.4.1 SELLER shall provide a Hydraulic Power Recovery Turbine (HPRT) and electric generator installed in the sea water dump line located downstream the Classified Area cooling water heat exchangers. SELLER shall provide all necessary auxiliary systems.

2.11.4.2 The system shall be sized to maximize the average energy recovery through the Unit's operational life. The system shall be sized to allow operation with a flow at least 30% above the rated value.

2.11.4.3 SELLER shall provide a by-pass line to overboard, sized to the maximum sea water flow, allowing the Unit's uninterrupted operation in case of HPRT downtime.

2.11.4.4 The inlet flow to the HPRT shall have flow control/measurement and a shutdown valve.

2.11.4.5 SELLER shall provide hypochlorite injection line on the outlet of the HPRT to prevent marine microorganisms and bacteria.

2.11.4.6 SELLER shall carry out Torsional Critical Speed Analysis complying with the requirements and acceptance criteria of API 610.

2.11.4.7 SELLER shall carry out Lateral Rotordynamic Analysis complying with the requirements and acceptance criteria of API 610.

2.11.4.8 The system shall be designed to operate at rated flow with the Unit’s minimum draft and considering the variation of the sea wave height.

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, SELLER shall consider sea water composition in item 0 and METOCEAN DATA (see item 1.2.1). For seawater temperature, SELLER 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 SELLER 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 19.1.1.10.

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

- SELLER shall position the intake water hoses in order to not interfere with the risers during pull-in and/or final configuration.

3.2.9 Seawater Composition:

Table 0A: 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_3^{-}	101
NO_3^{-}	< 1mg/L
Cl^{-}	21,347 mg/L
SO_4^{--}	2,800 mg/L
Salinity	37.25 ppt @100m depth
Total suspended solids	3,28 mg/L
Oxygen content	7 mg/L
Turbidity	0.20 FTU
Silt density index	5.1
m-SRB	25 MPN/mL
Aerobic bacteria	7,500 MPN/mL
Facultative Bacteria	44 CFU/mL

MPN – Most Probable Number

CFU – Colony Formation Unit

Table 0B: Seawater Particle Size Distribution

PARTICLE SIZE DISTRIBUTION	
SIZE RANGE (µm)	NUMBER OF PARTICLES (part./100mL)
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.

NOTE 3: For more details on salinity, please refer to attached METOCEAN DATA FOR DESIGN OF OFFSHORE SYSTEMS.

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, Turbogenerators, 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 SELLER 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 SELLER 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.

3.4.3 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 gas turbogenerator shall be capable of running even if its corresponding steam generator is 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 SELLER 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 SELLER 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 SELLER is responsible to provide the chemical products required for combined cycle system operation.

3.5 DRAIN SYSTEMS

3.5.1 SELLER 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 SELLER shall consider streams containing poisonous substances at critical concentrations, such as, but not limited to H_2S 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 BSDVs in the production lines and gas/water 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 SELLER shall perform the material selection as oriented in ISO 21457, with the additional requirements and limitations herein stated.

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

4.2 MATERIAL SELECTION REPORT

4.2.1 SELLER shall issue a Material Selection Report for the UNIT as described in ISO 21457. This report shall 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, corrosion protection systems applied (e.g. cathodic protection, scavengers, inhibitors), as well as the efficiencies of the protection systems applied. In case of corrosion inhibitors usage, the efficiency shall be limited to a maximum of 85% for material selection purposes. Regular replacements of static equipment and process piping shall not be considered in design. These items shall be designed to have a lifetime compatible with the Unit's operational lifetime.

4.2.3 The Material Selection Report shall 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 shall include Corrosion Sensibility Studies, that shall 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, shall be included in the Material Selection Report.

4.3 SPECIAL CONSIDERATIONS ABOUT MATERIAL SELECTION

4.3.1 LOW TEMPERATURE SERVICE

4.3.1.1 SELLER shall carry out the selection of materials with due consideration for the low temperature caused by depressurization events and the compatibility of gas with non-metallic materials and high strength ferritic materials. For materials selection purposes, SELLER shall 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 SELLER shall 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. SELLER shall 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 SELLER shall 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 shall be carried out based on the fluid compositions, as described in Chapter 2 of this General Technical Description, including all 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 250 ppm_v on separated gas;
- Produced gas H_2O content: up to saturated;
- BS&W: up to 95%;
- Produced Water Chloride (Cl-1): 165,000 mg/L;
- Produced water Salinity: 240,000 mg/L;
- Inlet fluid expected pH: 4,3 (*).

(*) Acetic acid shall be injected on production and test headers.

4.3.3 H_2S SERVICE

4.3.3.1 Where H_2S 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 H_2S 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 H_2S scavengers will not, in any case, be accepted as measures to relax the requirement to use H_2S 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 H_2S removal systems malfunction. Cladding or lining shall not be considered in order to waive ISO15156 requirement of base material.

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 SELLER shall comply with the following minimum materials specifications, for the indicated portions of the topsides process facilities. Deviations from the materials specifications mentioned shall be submitted for BUYER 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 or EPDM as per ISO 18797-1. Field repair shall also be performed as per the same standard.

4.4.1.2 From the top of the hard pipe up to the three-phase 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).

c) Stainless Steel 6Mo (UNS 31254).

4.4.1.3 Heat exchangers:

- Shell: Carbon steel with Inconel 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.
  - SS 316L, 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: Carbon steel, if the cooling/heating fluid is not corrosive, Stainless Steel 316L, Super duplex stainless steel 25Cr, Duplex Stainless Steel 22Cr or Inconel 625 or 825.

4.4.1.4 Choke and adjacent lines must be compatible with depressurizing temperature during well shut-in/startup with gas segregation in the riser top. *Minimum temperature to be considered upstream the choke (from subsea systems) is at least -20°C.* Minimum temperature to be considered downstream the choke *(towards topsides)* is at least -50°C. Depressurizing temperatures may occur *for production lines,* service lines, gas import, gas or WAG injection lines, and gas export lines. The length of each line subject to -50°C temperature shall be calculated during detailed design.

4.4.1.5 Separation (including three-phase separator) 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 50°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, SS316L, 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;
- K.O. Drum & Scrubbers (downstream Gas Dehydration Unit): Carbon Steel according to item 4.3.3, with 3mm corrosion allowance as a minimum material

specification shall be considered. If necessary, corrosion resistant alloy shall be specified.

- 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 is 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:

- Fiber Reinforced Plastic (FRP);
- The use of alternative materials must take into consideration operating parameters such as temperature and chloride content;

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 Main 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 300 ppmv (or higher, as per process simulations);
- H_2O: up to saturated during commissioning.

4.4.1.11 For the VRU 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: up to 400 ppmv (or higher, as per process simulations);
- H_2O: up to saturated at all conditions.

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

- CO_2: at least 3% mol (or higher, as per process simulations);
- H_2S: at least 10 ppmv (or higher, as per process simulations);
- H_2O: saturated during commissioning.

4.4.1.13 For the Booster/Injection 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 300 ppmv (or higher, as per process simulations);
- H_2O: saturated during commissioning.

4.4.1.14 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 300 ppmv (or higher, as per process simulations);
- H_2O: saturated during commissioning.

4.4.1.15 In case of compressors that perform export and injection/booster services, the most stringent specification shall be selected.

4.4.1.16 For Dehydration / Hydrocarbon dew point adjustment unit, construction material shall be selected considering the following contents on the process:

- CO_2: at least 60% mol (or higher, as per process simulations);
- H_2S: up to 300 ppmv (or higher, as per process simulations);
- H_2O: up to saturated.

4.4.1.17 SELLER shall use materials in compliance with IOGP-JIP33 S-716 for pneumatic and hydraulic instruments and transmission lines, including its connections (junction boxes). Tubing must be electrically isolated from carbon steel supports and materials to avoid galvanic corrosion.

4.4.2 SELLER 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, SELLER 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 (as applicable);

- 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 BUYER. The analyzer shall have an installed stand-by instrument.

4.5.2.4 Gas import and Gas Export:

- Coupon at a common point at header in order to monitor subsea material;
- Non-intrusive monitoring at a common point header, 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.

4.5.2.5 Production chokes:

- Probe for erosion evaluation installed upstream of the production choke 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 to 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 BUYER highlights the following:

- Coupons positioning in horizontal section should be at 6 o'clock position and optionally at 12 o'clock position;
- Enough clearance and access shall be provided to enable the coupons exchange, with no impact to Unit operation.

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. Specific reports shall be issued in accordance with NR-17 (Ergonomics). All reports shall be issued according to the Ergonomic Work Analysis (EWA) methodology. All

recommendations raised in Ergonomics Studies and Analysis shall be validated, verified and tracked by Human Factors specialist and operational team to guarantee implementation and closure during the project;

- 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;
- SELLER shall provide a gangway station area for connecting Supply and Maintenance Units or Flotel located on the main deck, starboard side of the unit.

5.1.2 SELLER 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 item 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 exception 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 The accommodation design shall have the following cabins configuration: at least 2 (two) single bed cabins for unit’s leadership; at least 7 (seven) cabins for 2 persons each with bunk bed; and remaining cabins shall be up to 4 persons each with bunk bed.

5.2.3.1 During Operation and Maintenance Agreement period, SELLER shall provide accommodations for BUYER / partners representatives onboard as defined on Operation and Maintenance Agreement.

5.2.3.2 SELLER shall provide an office with 8 (eight) workstations and a videoconference room at the same deck level of unit’s leadership (production, marine and maintenance) for BUYER’s usage during Operation and Maintenance Agreement period. SELLER shall provide equipment and infrastructure specified herein and on I-ET-0600.00-5510-760-PPT-601 - TELECOM MASTER SPECIFICATIONS FOR BOT UNITS.

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 201 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 SELLER 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 SELLER shall define the height of the main process plant deck level as well as its layout. SELLER 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, SELLER 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 SELLER 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 SELLER's responsibility.

5.5.2 SELLER 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 222. 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 BUYER 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 designed 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, monorails, 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/cm²;
- Required Outflow: 20 Nm³/min (Approximately 2,85 m³/min, at constant pressure of 7 kgf/cm²), allowing ± 10% of tolerance.

o 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).

o Fresh water supply – one outlet for cleaning diving equipment and clothes:

- Required pressure: 1 kg/cm²;
- Required outflow: 20 l/min.

o 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 SELLER 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 BUYER during execution phase.

5.5.11 The diving stations location and handling plan shall be submitted to BUYER for comments. See also reference document 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, H160, H175) 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 223 and CAP 437. In addition, the following international/national standards shall also be complied (latest editions):

- 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 SELLER shall ensure remote access to HMS, at any time, through internet. Such access shall be available in real time to BUYER 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, SELLER 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 SELLER shall present evidence that helideck final location minimizes downtime by using computational fluid dynamics (CFD) studies, considering all the aspects mentioned above. SELLER shall submit to BUYER CFD studies for the evaluation of hot air flow and exhaust according to CAP 437, section 3.10. BUYER 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 SELLER shall paint in the helideck a codification (to be informed during execution phase) as per NORMAM 223.

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 design conditions (dry bulb temperature and coincident and wet bulb temperatures - 0,4% summer cumulative frequency of occurrence), SELLER to use ASHRAE methodology (Fundamentals Handbook - Climatic Design Information – 2013 edition).

6.1.2 The HVAC safety requirements shall comply with SAFETY GUIDELINES FOR BOT OFFSHORE PRODUCTION UNITS (see item 1.2.1).

6.2 HVAC SYSTEMS

6.2.1 HFC or non-flammable HFO refrigerant fluids shall be used. HFC Global Warming Potential (GWP) shall not exceed 1500. Non-flammable (Ashrae Safety Group A1) HFO blend refrigerant fluids shall be preferably used due to its low GWP (not exceeding 600) and HFC future phase down.

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 the 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 an independent dedicated exhaust fans and air conditioning system (maximum room internal temperature 25°C). 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 H_2 dilution as defined in IEC 61892-7.

6.3 REFRIGERATION SYSTEM (PROVISIONS)

6.3.1 HFC or non-flammable HFO refrigerant fluids shall be used. HFC Global Warming Potential (GWP) shall not exceed 1500. Non-flammable (Ashrae Safety Group A1) HFO blend refrigerant fluids shall be preferably used due to its low GWP (not exceeding 600) and HFC future phase down.

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

6.6.2 In indoor manned spaces the minimum quantity of fresh/outdoor air supply shall be not less than 40% of the total air supplied to a specific space. The fresh/outdoor air supply quantity shall not be less than 8 l/s per the number of person(s) for which the specific space is designed for (e.g., for cabins is the number of beds, for mess rooms is the number of seats, for workspaces is the number of workstations, etc.).

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 24°C), 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 24°C).

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 BUYER.

7 SAFETY

7.1 GENERAL

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

7.1.2 For acceptable vendor list for Diesel-Hydraulic Fire Water Pumping Unit, see item 19.1.1.11.

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 BOT OFFSHORE PRODUCTION UNITS (see item 1.2.1).

7.2.2 BUYER 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 SELLER 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 BUYER, provided the following:
  - Same final specifications;
  - Any different solution must be presented to BUYER.

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 SELLER, 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 times. 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, BUYER’ 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 times, 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 SELLER shall establish and apply Human Factors Engineering (HFE) guidelines as defined in IOGP Report 454: Human Factors Engineering in projects.

7.4.1.1 SELLER 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 SELLER 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:

a. Safety critical tasks;
b. Potential human errors;
c. Performance influencing factors;
d. Human error probability;
e. 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:

a. 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,
b. 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 BUYER and SELLER, BUYER team shall participate in HRA.

7.4.2.3 SELLER 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 BUYER comments.

7.4.3 SELLER 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 SELLER shall issue for BUYER 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 Closeout Report.

7.4.5 SELLER shall issue, following the Annex D of IOGP 454:

1. Task Requirements Analysis (TRA);
2. Valve Criticality Analysis (VCA);
3. Vendor Package Screening and Review (VPSR);
4. Control Room Analysis and Review (CRAR);
5. HMI Analysis and Review (HMIAR);
6. Alarm System Analysis and Review (AAR);
7. Facility/Plant Layout Design Review (DR).

7.4.6 SELLER shall fully comply with ANP NOTA TÉCNICA Nº 10/2023/SSO-CSO/SSO/ANP-RJ (or another updated documents which substitutes it).

7.4.7 SELLER shall consider well service operations detailed on PRELIMINARY SUBSEA OPERATION PHILOSOPHY as a critical task.

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:

- Central Control Room (CCR) Systems;
- Control & Safety System (CSS);
- Supervision and Operation System (SOS);
- Cargo Tank Monitoring System (CTMS);
- Subsea Production Control System (SPCS);
- Optimization and advanced control server;
- Machinery Monitoring System (MMS);
- Flow Metering System (FMS);
- Offshore Loading 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. Availability of 99% shall be considered for control process layer and 99,5% for safety and mitigation layers.

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 BOT 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: the latest revision of IEC-60079 and all its parts; *PORTARIA INMETRO Nº 115, de 21/março/2022*, and its annexes; and shall be approved by Classification Society.

8.1.11 Operational modes defined in document OPERATIONAL MODES BOT (see item 1.2.1) are mandatory for Unit design.

8.2 CENTRAL CONTROL ROOM SYSTEMS (CCR)

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. Supervisory system from Hull and Topside shall be from the same vendor.

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 SELLER shall mirror all CCR (and ECR, if applicable) HMIs in 2 independent machines at the BUYER Office (according to item 5.2), including Alarms Management System (alarms' and events' logs and statistics screens), in order to allow BUYER 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 SELLER 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 of executing 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 BUYER’ 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 SELLER).
- 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 SELLER).
- Both supervisory system-OPC and OPC-PI System™ interfaces shall be installed in redundancy, including hardware and licenses. (By SELLER).
- PI System™-Server software shall also run in DMZ (PI System™-Server will be located in onshore DMZ). (By BUYER).
- The data to be stored in PI System™ will be defined by BUYER during the Detail Engineering Design Phase.

- If SELLER needs to use a different protocol for the communication between supervisory system and PI System™, BUYER shall be consulted for acceptance, the licenses and configuration, if the protocol is accepted, shall be provided by SELLER.
- Information and network security mechanisms between owner supervision and operation system and PI System™ shall be installed and configured by SELLER.

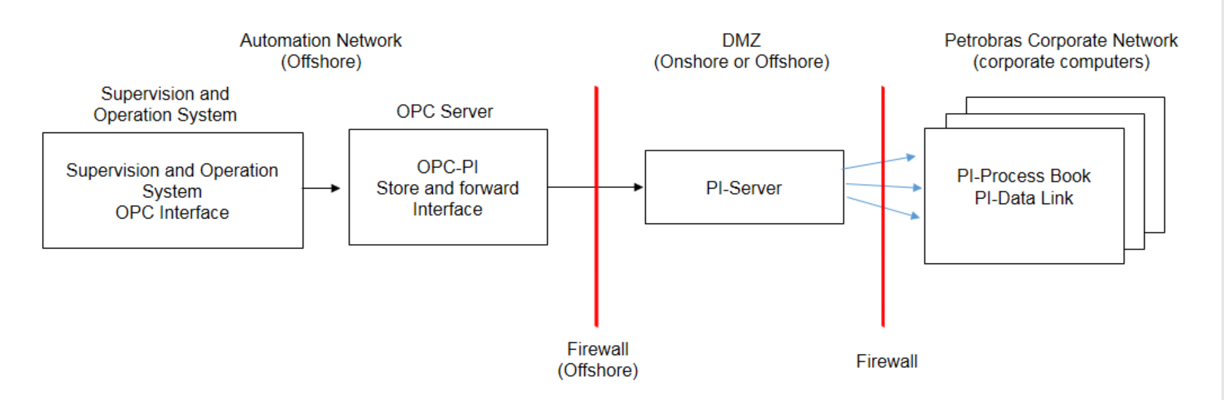

Figure 8.2.10.1 – Plant Information Architecture

8.2.10.2 For details of Telecommunications infrastructure, see TELECOM MASTER SPECIFICATIONS FOR BOT UNITS (see item 1.2.1).

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 minimum cybersecurity 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 SELLER 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:

- SELLER Automation network and PETROBRAS corporate network/Onshore PETROBRAS Facilities;
- SELLER Automation network and SELLER corporate network.

8.2.12.5 SELLER shall notify Petrobras any cyber security incident in Automation environment and any change or discontinuity in cybersecurity requirements.

8.2.12.6 SELLER 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 SELLER and PETROBRAS. The actions and outcomes from these workshops shall be shared with PETROBRAS.

8.2.12.7 SELLER shall follow IEC 62443 – all parts. Additionally, the following requirements shall be evidenced:

8.2.12.7.1 SELLER 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 SELLER shall implement a patch management program in accordance with IEC 62443-2-3.

8.2.12.7.3 SELLER shall implement a vulnerability management process in accordance with IEC 62443-3-2 and IEC 62443-2-1.

8.2.12.7.4 SELLER 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 BOT 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. All controllers (process control, safety, ESD and FGS) from Hull and Topside shall 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).

8.5.2 For specific requirements for the Subsea Emergency Shut-Down Valve, refer to MONITORING SYSTEM FOR SUBSEA EMERGENCY SHUT-DOWN VALVE (SESDV) – FPU SCOPE (see item 1.2.1). SAS Cabinet shall be supplied to acquire data from SESDV and HMXO sensors and data gathered to FPSO ICSS.

8.5.3 For subsea control umbilical interface, refer to TOPSIDE ARRANGEMENT AND INTERFACES WITH SUBSEA UMBILICAL SYSTEMS (see item 1.2.1). SESDV and HMXO direct hydraulic control rack shall be supplied and controled by FPSO ICSS.

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 - BOT (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 SELLER 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, SELLER 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 SELLER shall provide access to MMS at the PETROBRAS Onshore Office through offshore DMZ (see TELECOM MASTER SPECIFICATIONS FOR BOT UNITS – 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 CANCELLED

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. SELLER 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. BUYER will provide the ADVANCED CONTROL software solution and SELLER 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 other protocols to OPC are SELLER'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).
- SELLER 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.
- SELLER 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 SELLER responsibility.

8.16 PRESSURE AND TEMPERATURE MONITORING POINTS

8.16.1 SELLER 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 - BOT (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM - BOT (see item 1.2.1) are mandatory.

8.16.3 SELLER 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 Unit	x	x
1.8	TEG Unit	x	x
1.9	Molecular sieves	x	x
2	Injection water header	x	x
3	Production header	x	x
4	Free Water KO (FWKO) Drum oil outlet	x	x
5	Free Water KO (FWKO) Drum gas outlet	x	x
6	Free Water KO (FWKO) Drum water outlet	x	x
7	Recycle streams routed to (FWKO) 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	Total Fuel gas	x	x
11	Produced water disposal	x	
12	Seawater disposal from cooling system	x	
13	Inlet and outlet of flue (Exhaust) gas and heating medium streams from each WHRU	x	
14	Turbine intake air and flue (Exhaust) gas chimney exit	x	
15	Inlet and outlet of Main Seawater Injection Pump	x	x
16	Diesel motors - fuel	x	x
17	Diesel motors – flue gas	x	
18	Diesel motors – inlet and outlet cooling water	x	
19	Sulphate removal reject	x	
20	Ultrafiltration reject	x	
21	Reverse Osmosis reject	x	
22	Vent posts	x	x

8.16.4 SELLER shall provide at least 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	Each injection and service riser	Pressure and Temperature
3	Bearing and motor of main water injection pump	Temperature
4	Upstream and downstream of each choke valve	Pressure and Temperature
5	Topsides water injection lines	Pressure
6	Each molecular sieve bed	Pressure
7	TEG absorber column packing	Pressure
8	Each Regeneration gas heater	Temperature
9	Solid removal filters of produced water treatment (if applicable)	Pressure
10	HP and LP flare headers Among KO Drums, FGRU suction and upstream QOV	Pressure
11	Pump discharge filters of umbilical (subsea) chemical injection	Pressure
12	Each chemical injection point	Pressure
13	Sea cooling water overboard discharge	Temperature
14	Cargo tanks	Pressure
15	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
16	Printed Circuit Heat Exchanger (PCHE)	Diferential Pressure
17	Gas inlet strainer of PCHE	Diferential Pressure
18	Cooling medium inlet strainer of PCHE	Diferential Pressure
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 SELLER is responsible 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 - BOT (see item 1.2.1) or mentioned on items of GTD. Instrumentation requirements prescribed on FLOW METERING SYSTEM - BOT (see item 1.2.1) are mandatory.

8.17.3 SELLER 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 Free Water KO Drum separator
10	Produced water from Free Water KO Drum separator
11	Ultrafiltration reject (if applicable)
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 freshwater maker
19	Generated freshwater
20	Inert gas
21	Diesel for each turbogenerator
22	Diesel for each motogenerator
23	Vent posts

8.17.4 SELLER shall provide at least 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	Each injection riser

4	Deviated rich TEG flow
5	Lean TEG flow
6	Stripping fas flow of TEG Regeneration Reboiler
7	Stripping gas flow of Stahl Column (if applicable)
8	Each source of flare purge gas
9	Each chemical injection point
10	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
11	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 Total electric power demanded from the Main Generators shall met the requirements as per clause 9.3.1.5.

9.2.4 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.

9.2.5 PMS GENERAL REQUIREMENTS

9.2.5.1 The system shall be type approved by Class Societies.

9.2.5.2 The PMS shall at least comprise generator paralleling control, load sharing, peak shaving, automatic load shedding, load import/export control and protection.

9.2.5.3 The load shedding function shall allow temporary overload of main generation due to starting of large motors and transformers.

9.2.5.4 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 ITEM 2.

9.3.1.2 Each power generation package consists of a synchronous alternator driven by a gas turbine dual fuel type, 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 shall consider the requirements for the definition of the Main Power Generation System as follows:

a) Electrical power demand shall be limited to 100 MW if the following conditions are met simultaneously:

- Gas turbine generators use SAC-type gas turbines.
- Gas turbines are used as mechanical drivers (e.g., turbo compressors, turbo pumps, etc.).

b) If gas turbines are used as mechanical drivers (e.g., turbo compressors, turbo pumps, etc.) and no 100 MW electrical power limitation is applied, the following conditions shall be met simultaneously:

- Low-emission technology shall be applied.
- An atmospheric emissions monitoring system shall be provided by the gas turbine OEM (Original Equipment Manufacturer) of turbogenerator package.

- CONAMA Resolution 382/2006 and NOTE 1 (as stated below) shall be complied with, as it requires each turbine to individually comply with the limits established in Annex V of CONAMA Resolution 382/2006.

c) The all-electric concept is not subject to electrical power demand restrictions or local regulatory authority requirements for emission control and measurement, in compliance with CONAMA Resolution 501/2021.

NOTE 1: Atmospheric emissions monitoring shall be provided as follows:

- CONTRACTOR shall provide, according to local regulatory authority requirements, the following three types of monitoring: Continuous Emissions Monitoring System (CEMS), Predictive Emissions Monitoring System (PEMS), and Discontinuous Monitoring, along with all required certifications.
- Devices for sample collection shall be provided for the analysis of exhaust gas emissions and shall include, at a minimum, ladders, suitable lighting, walkways, and handrails for safe and easy personnel access to the gas turbine stack.
- All necessary means for performing the monitoring shall be provided. As an example, for CEMS, at a minimum, clear identification of measurement parameters (e.g., NOx, CO, and O_2) shall be ensured, along with a data acquisition and handling system. The system shall also include a heated sample line (per meter), a designated measurement section, ATEX classification for external components (probe and sample line), and additional protection for instrumentation (e.g., shelter).

9.3.1.6 SELLER may propose a combined cycle configuration based on gas turbines and steam turbines for power generation system. For more details about combined cycle system see item 9.10.

9.3.2 MAIN GENERATOR TURBINE REQUIREMENTS

9.3.2.1 SELLER 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).

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), SGT-750.	BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM6000 PC/PG SAC; SIEMENS: SGT-100, SGT-600; SOLAR: SATURN, CENTAUR, TAURUS 60, MARS100, TITAN 130, TITAN 250, SGT-A65 SAC (WLE DRY)

NOTE 1: BUYER considers that SELLER will built-in design contingencies into the maximum expected electrical demand. BUYER consider those contingencies (margins) as a SELLER 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, SELLER shall inform during tender period the additional pressure drop on the gas turbine exhaust gas (anything above 250 mm H_2O 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 0.

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 item 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 SELLER shall consider stand-by compressor start-up without turning off the running compressor during load transfer.

9.3.4 ESSENTIAL / AUXILIARY GENERATOR

9.3.4.1 For auxiliary generator package, SELLER 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 The auxiliary generator shall have dedicated starting system independent from the emergency generator.

9.3.5 EMERGENCY GENERATOR

9.3.5.1 For emergency generator package, SELLER shall use new equipment.

9.3.5.2 Emergency generator shall be dimensioned to feed simultaneously all loads indicated in the SAFETY GUIDELINES FOR BOT 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 into 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 into 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 SELLER 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. Complementary standards IOGP S-736 LV AC Drives (IEC) and IOGP S-747 MV AC Drives may be used.

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 motors fed by VSDs and 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 CANCELLED.

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 VSD-FC shall be arc withstand capability complying 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 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 @ 0°C) per winding or thermostats; 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. Routine, special and string tests shall be witnessed by BUYER. These tests procedures and approval criteria shall demonstrate the unit's performance and reliability. During the execution phase, SELLER shall provide all test reports.

9.6 UNINTERRUPTIBLEPOWER 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 BOT 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 BUYER 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 transferring 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 SELLER 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. SELLER 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 SELLER shall present to BUYER, the following electrical studies:

- Main and Emergency Generation electrical load balance;
- Load Flow calculation report;
- Short-circuit calculation report;
- Voltage drop 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 SELLER shall provide stand-by equipment, ready to operate, in order to guarantee no production/process capacity reduction nor degradation of the oil, gas and water specification.

9.10.2 For combined cycle configuration, the stand-by generator unit shall be gas turbine driven.

Steam Turbine Generator shall be designed to provide at least 27.1MW of electrical power.

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, the effects of Combined Cycle subsystems in the reliability KPIs shall be considered for the Reliability, Availability and Maintainability (RAM) analysis as described in RELIABILITY AVAILABILITY AND MAINTAINABILITY (RAM) ANALYSIS REQUIREMENTS - BOT/BOOT (see item 1.2.1).

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.

9.11 SEA WATER DUMP LINE TURBOGENERATOR

9.11.1 The sizing of the FPSO’s main generation power system shall not take into consideration the power generated from the SWDLT, i.e., the main generation power system shall be capable of supplying all FPSO electric loads even with the SWDLT out of service.

9.11.2 The design, installation and operation of the SWDLT system shall allow the operation of the FPSO electric power system as per IEC 61892 series.

9.11.3 The turbogenerator set shall be dynamically balanced and engineered to withstand foreseeable transient and continuous operation.

10 EQUIPMENT

10.1 NOISE AND VIBRATION

10.1.1 SELLER 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, SELLER 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 SELLER 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 SELLER 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 SELLER shall submit to BUYER 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 of 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 Starboard, this side shall not be used for any supply boat operations. All cranes shall be located on Portside.

10.2.3.5 At least two cranes are required, Aft (AFT) Portside and Forward (FWD) Portside, 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 SELLER 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 SELLER 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 SELLER, shall be in accordance with API STD 667 - PLATE AND FRAME HEAT EXCHANGERS -, and be capable of withstanding 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 SELLER 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 (without interrupting the process) 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 TEMA, API 660 and ASME BPVC Section VIII, Division 1 standards latest edition.

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. Listed valve according ASME B31.3 shall be used. Unlisted valve maybe used subjected to Petrobras approval. API 6A shall be used for valves class over 2500.

10.4.2 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.

10.4.3 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. Lug and flanged types are acceptable.

10.5 RELIABILITY, AVAILABILITY, AND MAINTAINABILITY (RAM) ANALYSIS

10.5.1 The SELLER shall perform a Reliability, Availability, and Maintainability (RAM) Analysis for all critical production systems, as described in RELIABILITY AVAILABILITY AND MAINTAINABILITY (RAM) ANALYSIS REQUIREMENTS – BOT/BOOT (see item 1.2.1).

10.5.2 The RAM Analysis shall consider all operational, maintenance, and performance aspects of the equipment, ensuring that the unit operates efficiently and continuously throughout its lifecycle.

10.5.3 The study shall be submitted for approval during the development of the project.

10.5.4 Minimum redundancies and plant equipment configuration defined on this GTD are not to be relaxed.

10.5.5 The RAM Analysis shall be updated to reflect any changes in the operational or maintenance conditions of the equipment during the Operation and Maintenance Agreement period.

10.5.6 FPU design shall ensure a minimum Project Productive Efficiency – IEP of 95% and a minimum Project Injection Efficiency – IEI of 90%.

11 TELECOMMUNICATIONS

11.1 GENERAL

11.1.1 The Unit’s telecommunications shall comply with the TELECOM MASTER SPECIFICATIONS FOR BOT UNITS document (see item 1.2.1).

11.1.2 In addition, the Unit’s telecommunications shall comply with the TELECOM MASTER SPECIFICATIONS FOR SANTOS BASIN MALHA OPTICA PROJECT EQUIPMENT requirements (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, SELLER shall also design the Unit to withstand all construction loads and the environmental loads during transportation from construction shipyard to Brazil. For decommissioning purpose (including risers pull-out), the design shall ensure that in the end of the operational life, the Unit shall have enough strength to be transported or towed to outside Brazilian waters.

12.1.2 The current revision of the CS rules shall be used to check and design the structures (hull and topsides), reinforcements and complementary structures. SELLER shall use net scantlings that are obtained deducting corrosion margins (as presented in item 12.1.3) from "as-built" scantlings in case of new building.

12.1.3 CORROSION MARGINS

12.1.3.1 The following table shows the corrosion margin values (M) to be used for 25 years of operation (operational lifetime) for different uncoated structural elements ("F" factor is 1.25 (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		

NOTE 1: Slop tanks, off-spec tanks and settling tanks (if applicable) shall consider same corrosion margins as ballast tanks.

12.2 NOT APPLICABLE

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 BUYER approval.

12.4 HULL

12.4.1 One of the following alternatives shall be adopted for new build hull:

a) Double side with single bottom, with, at least, three longitudinal bulkheads;

b) Double hull (double side and double bottom), without any hydrocarbon piping system routed inside the double bottom and/or void spaces.

12.4.2 Not applicable.

12.4.3 SELLER 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 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.

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 SELLER 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 SELLER decides to provide suction bilge boxes on the tank bottom, then plates shall also be designed with increased thickness.

12.4.10 NOT APPLICABLE

12.4.11 RISER BALCONY AND CARGO TANK INTERFACE (SPREAD MOORING OPTION)

12.4.11.1 SELLER 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. On document ADDITIONAL REQUIREMENTS FOR BOT UNITS item 2.8.2 describes the methodology that can be adopted.

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, SELLER 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 specifications shall consider the design life as stated in item 1.2.2. Alternatively, top cargo tank plating and structures painting can be replaced with a no painting system with additional corrosion margin on that region.

12.4.13.6 Zinc anodes shall be adopted 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 50°C.

12.4.13.7 Cargo tanks bottom shall be provided with anodes. These galvanic anodes shall be placed on elements close as possible to 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 stared in item 1.1 herein. Alternative solutions to NOVOLAC may be accepted by BUYER. Anodes shall also be provided to protect the entire tank.

12.4.13.9 SELLER 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 401 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.

12.4.13.10 Not applicable

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.

12.4.13.12 Coating 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 SELLER shall submit to BUYER 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 SELLER 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 SELLER 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. seachest, lower riser balcony, fairleads, bilge-keel, etc.) shall be non-inspectable during unit design life.
- SELLER shall provide docking points in the hull to enable underwater ROV activities (e.g. seachest, 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, SELLER 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 conditions.

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 CANCELED

12.5.4 CANCELED

12.6 FATIGUE ASSESSMENT REQUIREMENTS

12.6.1 SELLER 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 operational life, 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 SELLER 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.

13 NAVAL DESIGN

13.1 GENERAL

13.1.1 The Unit shall have the following main naval characteristics:

13.1.2 New built ship-shaped or new built barge-shaped unit, with a minimum storage capacity, i.e. minimum volume of oil available, in the cargo tanks, to be offloaded on both following conditions: (1) 1,360,000 bbl of crude oil when the largest tank is out of operation; and (2) 1,280,000 bbl of crude oil when two largest tanks are out of operation. 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.

(Condition 1) In addition, the 1,360,000 bbl of oil for offloading shall be available when:

a) One central tank (the largest) is isolated for inspection or repair;

b) The slop tanks, oil offspec tanks and the produced water tanks shall be excluded from the volume of 1,360,000 barrels of oil.

To calculate the “volume of oil available to be offloaded”, SELLER 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 one central cargo tank (the largest 98% full)*– Volume of oil offspec tank.

4) The volume of oil available to be offloaded shall be equal or greater than 1,360,000 bbl.

(Condition 2) In addition, the 1,280,000 bbl of oil for offloading shall be available when:

a) Two central cargo 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 1,280,000 barrels of oil.

(Condition 2) To calculate the “volume of oil available to be offloaded”, SELLER 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 two central cargo tanks (98% full) – Volume of oil offspec tank.

4) The volume of oil available to be offloaded shall be equal or greater than 1,280,000 bbl.”

13.2 WEIGHT CONTROL PROCEDURES

13.2.1 It is SELLER’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.

13.2.2 BUYER shall receive the FPSO Weight Control Report (all revisions) and a file *.XLSX with all unique items included in the report.

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 BUYER 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 BUYER).

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 SELLER shall issue to BUYER the RAO (Response Amplitude Operator) curves and tables with their corresponding phase angles, for Unit's 6 (six) degrees of freedom according to 13.6.2. When applicable, SELLER shall also provide the QTF (Quadratic Transfer Function), according to 13.6.3.

13.6.2.2 For each degree of freedom and each draught, 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 BUYER for comments. Model tests shall be used to validate the SELLER proposal. In addition, the Model Test Report shall be provided for BUYER for information.

13.6.2.3 Roll RAO curves shall be computed considering viscous damping varying in two ways: by significant wave heights and by return period as follows:

- Table 1: Hs < 2.5m (irregular waves contour curves);
- Table 2: 2.5 < Hs < 4 (irregular waves contour curves);
- Table 3: Hs > 4 (irregular waves contour curves);
- DOC;
- DEC.

13.6.2.4 Full Hs x Tp extreme single peak curves shall be considered in motion analysis as per Metocean data [see item 1.2.1].

13.6.2.5 The RAO curves shall be computed also considering the following:

- At least six loading conditions: minimum loaded, 20% 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 0,10 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 abovementioned data, apart from respective radius of gyrations about longitudinal, transversal and vertical axes, all of them calculated at C.O.G.
- The irregular waves considered for the roll damping estimation shall be the beam sea condition that causes the higher motions for each specific draft. SELLER is responsible to select the adequate waves for Model Test, analyzing all possible critical scenarios. All roll damping estimation shall be done with no current.
- In cases where roll natural period is greater than wave peak period for the beam sea direction, damping calibration shall be performed for each specific draft considering the highest Hs and the closest Tp of the wave of the adjacent directions.

13.6.2.6 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, direction and phase 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 SELLER.

13.6.2.7 All numerical output data (RAO, curves and tables, added mass coefficients, potential damping coefficients, wave exciting forces, QTF and second order roll time series) shall be released by SELLER directly in the format of the output files from WAMIT, ORCAWAVE, AQWA, MOSES, HYDROSTRAR and WADAM software’s or in Microsoft Excel file and *.txt format (different file extensions may be agreed with BUYER). The RAO shall be released to BUYER 9 months after Agreement signature.

13.6.2.8 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 – 1 year 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 SELLER 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 SELLER shall design and install a bilge keel in the hull as following:

i. SELLER shall present calculations in order to back-up the bilge keel width and length definition. This shall be submitted to BUYER 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 SELLER.

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, including motion effects from calibrated RAO and QTF as per 13.6.2 and 13.6.3.

13.6.3.5 The Unit shall be designed to operate normally up to DOC condition (10 years return period environmental condition) as a minimum. 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. For mechanical design, structural integrity and equipment in general, DOC and DEC conditions shall be used.

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 operational life.

13.6.3.7 If the SELLER 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 SELLER'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) SELLER shall submit the model test matrix to BUYER 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 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 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), SELLER 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 BUYER 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 BUYER will be responsible for design, fabrication, CS approval and installation of the mooring fixed points (torpedo piles). SELLER shall assume that the anchor points will support the maximum loads mentioned in document SPREAD MOORING 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 detail design phase, BUYER will inform the "fine bathymetry map" for the intended location of the Unit´s mooring fixed point.

15 FLEXIBLE AND RIGID RISERS

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. Regarding the riser types, sequencing and characteristics, BUYER highlights this is a preliminary plan. It can be changed up to Kick-off Meeting.

15.1.2 CANCELED

15.1.3 The flexible and rigid risers can come from portside and/or starboard side of Unit.

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	Function	Total	Comments
Oil Production (P1 to P8)	Flexible 8" or 6" ID Rigid 10,75", 9,625" or 8,625" OD	Oil Production	8	Oil production riser can be flexible or SLWR. Unit shall be prepared to both alternatives.
	Flexible 4" ID	Gas Lift / Service	8	Gas lift / service riser will be flexible
Convertible Oil Production / WAG Injection (PWAG1 to PWAG5)	Flexible 8" or 6" ID Rigid 10,75", 9,625" or 8,625" OD	Oil Production or WAG Injection	5	PWAG riser can be flexible or SLWR. Unit shall be prepared to both alternatives.
	4" ID	Gas Lift / Service	5	Gas lift / service riser will be flexible
Water Alternating Gas (WAG) Injection (IWAG01A/B to IWAG05A/B)	Flexible 6" ID Rigid 10,75", 9,625" or 8,625" OD	Water Alternating Gas (WAG) Injection (Slot A)	5	The WAG injection slot A risers can be flexible or SLWR. Unit shall be prepared that both alternatives.
	Flexible 6" ID Rigid 10,75", 9,625" or 8,625" OD	Water Alternating Gas (WAG) Injection (Slot B)	5	The WAG injection slot B risers can be flexible or SLWR. Unit shall be prepared that both alternatives.
Gas Transfer (GT1 and GT2)	Flexible 9.13" or 8" ID Rigid 11,75", 10,75", or 8,625" OD	Gas Transfer	2	The Gas Transfer risers can be flexible or SLWR. Unit shall be prepared that both alternatives.
	Control Umbilical	SESDV control	2	Umbilical can be either TPU (termo-plastic umbilicals) or STU (steel tube umbilicals). Unit shall be prepared to both alternatives.
Gas Export (EXP)	Flexible 9.13'' or 8" ID Rigid 11,75", 10,75", or 8,625" OD	Gas Export/Import	1	The Gas Export riser can be flexible or SLWR. Unit shall be prepared that both alternatives.
	Umbilical	SESDV control	1	Umbilical can be either TPU (termo-plastic umbilicals or STU (steel tube umbilicals). Unit shall be prepared to both alternatives.
Control Umbilical (UMB 01 to UMB 07)	Control Umbilical	Control Umbilical	7	Control umbilicals are going to be STU (steel tube umbilicals).
Integrated Power Umbilical (UMB 08)	Integrated Control and Power Umbilical	Power + Control	1	Umbilical can be either TPU (termo plastic umbilicals) or STU (steel tube umbilicals)
Fiber Optic (FO)	Fiber Optical Umbilical	Fiber Optic	1	Fiber Optic Cable.
		TOTAL SLOTS	**50**	

Note 1: The sequence, functions and diameters of each riser slot will be defined at the project kick-off meeting.

Note 2: Wells in subsea trunkline configuration are connected in pairs, sharing the same production, gas lift/service and/or injection lines.

Note 3: CANCELED

Note 4: Each WAG injection slot may inject water, diesel, heavy hydrocarbon rich stream (C3+) effluent from gas treatment, or gas alternately and independently. Each position IWAG01 to IWAG05 will be interconnected in pairs of wells. The pairing between these wells will be defined during kick-off meeting.

Note 5: Hard pipe, spools, supports, etc. shall be installed/furnished by SELLER in order to install the rigid risers.

Note 6: Detailed figure of wells interconnections is presented on chapter 2.6.22.

Note 7: To avoid cross contamination between the injection water and the injection gas in WAG wells, SELLER shall afford means to have temporarily positive isolation, to be provided on both Gas Injection and water injection lines. Alternatively, SELLER shall afford 2 (two) Double block and bleed isolation valves with drain and pressure alarm in between, to be provided on both Gas Injection and water injection lines.

Note 8: Where indicated, umbilicals are considered apart, so it can be shared using subsea distribution units (SDUs) or umbilical termination assemblies (UTAs), grouping up to 5 wells each. Each SDU will attend a cluster of production (OP, IWOP and GP positions) and injection wells (IWAG and WI positions). For more details, see Chapter 8.5.

Note 9: PWAG positions have the feasibility to be tied-back to both production and WAG injection wells. The function of this position can be changed by BUYER during production life, from production to water injection and vice-versa.

Note 10: Total of slots exclusive for flexible risers (bellmouths): 24 / Total of slots compatible with both flexible or rigid risers (TSUDL): 26.

Note 11: Integrated Power Umbilical (UMB 08) aims at a potential future use which requires an umbilical to provide power and/or control functions, for example, a complementary project of a subsea process and boosting system or power importation system (“*power from somewhere”* concept). Only the riser balcony slot facilities for such future use is to be considered by CONTRACTOR.

15.2 RISERS CHARACTERISTICS

15.2.1 SELLER shall provide supports for flexible and Rigid risers that may be connected to the Unit in accordance with RISER SYSTEM REQUIREMENTS (see 1.2.1).

15.2.1.1 For rigid risers, SELLER shall provide a hardpiping system to connect the top of the riser (located at the LRB) up to the URB. The hardpiping shall be designed and constructed in accordance with TECHNICAL SPECIFICATION FOR HARD PIPE – BOT CONTRACTS (see 1.2.1).

15.2.2 SELLER 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)) (1)	Leak Test Pressure (kPa(a)) (2,3,4)	Max. Process Operating Pressure (kPa(a))	Max. Shut-in Pressure (kPa(a)) (5)	Max. Well Service Operating Pressure (kPa(a))
Oil Production Line	41,000	45,100	31,000	41,000	32,000
Gas Lift/ Service Line	41,000	45,100	25,000	-	32,000
WAG Injection Line	55,000	60,500	50,000	-	32,000
Gas Export Line	27,500	TBD	25,000	-	32,000
Gas Transfer Line	41,000	45,100	25,000	41,000	32,000

Table 15.2.2B - Temperature for Risers Protection

Subsea Line	Maximum Design Temperature (°C)	Minimum Design Temperature (°C)	Temperature to stop each service (°C)	Operating Temperature (°C)
Oil Production Line	110	-20	95	35 to 90 (Production) Ambient temperature to 90 (Well service operations w/Diesel)
Gas Lift/Service Line	60	-20	55	40
WAG Injection Line	70	-20	55	40
Gas Export Line	60	-20	55	40
Gas Transfer Line	40	-20	55	-5

NOTE 1: Riser design pressure to be confirmed at the beginning of detailed design. Design pressure concept in accordance with DNVGL-ST-F101 for rigid lines and API SPEC 17J for flexible lines. It is a SELLER responsibility to evaluate compatibility among standards.

NOTE 2: Riser leak test pressure to be informed at the beginning of detailed design.

NOTE 3: During the leak test an overpressure of 4% above the leak test pressure for flexible risers may be requested by BUYER, in accordance with API SPEC 17J and API RP 17B.

NOTE 4: 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 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 5: Shut-in pressure considered to be less than relief valve fully open pressure (max accumulation pressure).

NOTE 6: 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 BUYER for comments/information.

NOTE 7: Facilities to allow the leak test of the risers using rented service pumps shall be provided.

NOTE 8: During execution phase BUYER will confirm to SELLER the pressure and temperature requirement for riser protection. Temperature at top of injection/service risers shall be monitored.

NOTE 9: 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 10: 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 11: Facilities to monitor the pressure and depressurize risers during leak test operation shall be provided.

NOTE 12: It is a SELLER responsibility to provide means to avoid pressurization higher than the defined test pressure. Pressurization tolerances shall be in accordance with DNVGL-ST-F101 and API RP 17B.

NOTE 13: 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 boarding SDV 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 14: 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 boarding SDV valve when operating in gas lift mode. The set points will be informed during the project execution phase and updated during operational phase.

NOTE 15: A PSLL shall be installed downstream of Gas Export Line choke valve and interlocked with both Gas Export Line SDV on the top and the base of the riser.

The set points shall be set according to the export flowrate and will be informed during the project execution phase and updated during operational phase.

NOTE 16: For the WAG positions, during the production phase, the pressure and temperature riser protection parameters of Production Lines shall be considered, and during the WAG injection, the pressure and temperature riser protection parameters of Injection Lines shall be considered.

NOTE 17: A separate low capacity (maximum 10 L/min), high pressure pump shall also be provided to achieve the required pressure up to 68,900 kPa(a) for leak test all subsea chemical injection lines after hook-up. A portable and/or movable skid pump is acceptable. The pump shall be permanently onboard and ready to use for either subsea chemical injection lines leak test or flow assurance procedures.

15.3 RISERS INSTALLATION AND DE-INSTALLATION PROCEDURES

15.3.1 The Unit's Risers Installation and De-installation Procedures shall comply with the RISER SYSTEM REQUIREMENTS document (see item 1.2.1).

15.4 RISER HANGOFF AND PULL-IN SYSTEMS

15.4.1 SELLER shall refer to the Annex documents (see 1.2.1):

- SPREAD MOORING SYSTEM REQUIREMENTS;
- RISER SYSTEM REQUIREMENTS;
- RISERS TOP INTERFACE LOADS ANALYSIS;
- DIVERLESS BELL MOUTH - STANDARD INTERFACE SUPPLY SPECIFICATION;
- BSDL-SI Part List;
- RISER SUPPORTS ARRANGEMENT CONCEPTUAL DESIGN - FPSO BALCONY.

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 SELLER shall design, provide and operate the Annulus Pressure Monitoring and Relief System, as detailed on the technical specification "ANNULUS PRESSURE MONITORING AND RELIEF SYSTEM" (see 1.2.1) 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 "Local Continuous Vented Type" shall be used by the SELLER. This system shall be applied to all flexible risers, except for umbilicals, electric power cables and/or fiber optic risers.

15.5.3.4 Seller 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 SELLER 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).

16 MARINE SYSTEMS AND HULL UTILITY SYSTEMS

16.1 GENERAL

16.1.1 SELLER shall provide an emergency anchoring system in accordance with 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, SELLER shall install a Hydrocarbon (HC) Gas Blanketing System 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 SAFETY GUIDELINES FOR BOT 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 headers shall be provided for HC/Inert Gas, Purge and Venting the 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 The 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 shall comprise liquid-ring compressors (as per API Std. 681), screw compressors (as per API Std. 619) or ejectors. Compressors' configuration shall be N+1. If the ejector option is considered, the motive fluid type and its supply characteristics shall be clearly specified during the proposal stage to ensure reliable and continuous operation. Any unavailability of the recovery system due to failure or insufficiency of the motive fluid supply will not be accepted under any circumstances.

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:

- Submerged hydraulic driven or deep-well electrical driven pumps for each cargo and each slop tank. If the FPSO has other structural tanks that operate under an inert gas/HC blanketing atmosphere, the submerged pumps of these tanks shall be part of the same package. In case of the failure of a submerged pump in Cargo Tank, Slop Tank, or any other structural tank operating under an inert gas/HC blanketing atmosphere, as a back-up for tank empty operation, portable cargo pumps or large capacity eductors may be considered, as specified in items 16.3.2.1, 16.3.2.2 and 16.3.2.3. If a portable cargo pump is provided, it shall meet the minimum requirements:
- Quantity: 01 (one)
- Capacity: At least 300 m^3/h
- Hydraulic oil supply / return hoses, plus Cargo Hoses
- Portable Davit with Pneumatic winch

16.3.2.1 If large capacity eductors are provided, they shall meet the minimum requirements:

- Capacity: At least 300 m^3/h;
- The system shall be designed in such a way that metered cargo, unmetered cargo, PW and slops are not mixed while operating the large capacity eductor;
- Backflushing with, PW, slop water, cargo oil or N_2 gas shall be provided in case of a plugged eductor;

16.3.2.2 Whether an eductor or portable pumps is adopted, the bidder shall meet the following requirements:

- The transfer longitudinal header shall be provided with outlets, manual valves and blind flanges for the connection of the discharge hose of the portable cargo pumps specified in item 16.3.2.1, considering that this pump can be installed in any tank with submerged pumps. SELLER shall include cargo portable pump and accessories in the mechanical handling study.
- Openings for installation/lowering of portable pumps for each tank shall be provided with clear vertical access, free of obstructions, down to the tank bottom. Additionally, the means shall be taken to allow installation and operation of portable cargo pumps without exposing the operators to the tank’s gas.

- If submerged pumps are of hydraulic driven type, outlets with manual block valve and blind flanges for pressure and return of hydraulic oil shall be provided for connection to the portable cargo pump to service all tanks.
- If submerged pumps are of electrically driven type, the handling study for the portable cargo pump installation shall consider the hydraulic skid used to operate the portable cargo pumps.

16.3.3 SELLER shall limit exported oil temperature through export hoses, from a minimum of 35°C to a maximum of 55°C, to comply with shuttle tankers requirements.

16.3.4 SELLER 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 3,000 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 SELLER 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 ITEM 0 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 SELLER 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 the Hull risers opposite 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°C;

- 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;
- SELLER shall comply with Ordinance MS Nº 2914/2011 and present evidence of harmlessness of the materials used in fresh water 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 BUYER 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 0.

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.

SELLER shall submit to BUYER 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 m3/h, respectively. Alternative configuration shall be submitted for BUYER 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 BUYER will engage third party for Environmental Studies, in which case SELLER shall take part in the assessment, provide all necessary information and comply with recommendations.

17.1.2 SELLER shall provide a report with information requested by BUYER 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) Hydrocarbon Gas Blanketing System;

f) Ballast system description;

g) Description of the Fluid processing plant (oil, gas, produced water and injected water);

h) Simplified process block diagram containing produced oil, produced water, produced gas, and sea water treatment; gas export and reinjection; seawater and produced water injection;

i) 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;

j) 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;

k) 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;

l) Cooling water closed loop system description, including pumping configuration and flow rate;

m) Industrial water supply system description including type of treatment, suction depth, flow rate and consumers list;

n) Potable water system description including type of treatment and flow rate;

o) Simplified diagram of industrial and potable water treatment;

p) Power generation description including capacities of main, auxiliary, uninterruptible and emergency systems, as well as fuel consumption for each generator considering all fuel sources;

q) Cranes description including length and capacity;

r) Flare and vent systems description including flow rate capacities, and stack height;

s) 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 SELLER 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 SELLER shall provide:

a) Annual quantification (volume) per type of fuel used for the design cases (Table 2.2.2.3);

b) The 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

d) seals, drains, vents, etc.

17.3.2 A description of the Unit's commissioning procedure must be provided, 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 SELLER shall provide solid residues characterization, residue class, disposal destination, annual mass generation including change out process materials (molecular sieve, CO_2 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 logotype in the following Unit places:

- Funnel (both sides);
- Portside and Starboard in visible area;
- Frontwall 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 SELLER responsibility.

19.1.1.1 Water Injection Pumps:

- Sulzer
- Flowserve
- Nuovo Pignone
- FRAMO

19.1.1.2 Air Compression Unit (oil free screw and centrifugal compressor). Alternate vendors are accepted according to EXHIBIT V - DIRECTIVES FOR ACQUISITIONS criteria:

- INGERSOLL-RAND (Packagers: HBR and North Sea)
- ATLAS COPCO

19.1.1.3 Molecular Sieve Solid Bed (Zeolite):

- CECA
- UOP (Honeywell)
- ZEOCHEM L.L.C
- Axens
- Grace GmbH

19.1.1.4 Membranes for CO_2 Removal Unit:

- Cameron
- UOP
- Air Liquide
- Evonik
- MTR

19.1.1.5 Moisture Analyzer:

- AMETEK
- SPECTRA SENSOR

19.1.1.6 Rotary compressor for Vapor Recovery Unit API 619:

- Kobelco
- MAN
- HOWDEN

19.1.1.7 Centrifugal Compressors API 617:

- BAKER HUGHES
- Hitachi
- MAN
- Mitsubishi
- Siemens / Dresser-Rand

19.1.1.8 Aero-derivative or light industrial gas turbine API 616 for offshore environment (Compressor Driver):

- SOLAR: SATURN, CENTAUR 50, TAURUS 60, MARS100, TITAN 130, TITAN 250
- BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM2500+G4, LM6000 PC/PG
- SIEMENS: SGT-A35 (up to 34 MWISO), SGT-100, SGT-600, SGT-750 (No propane, only diesel start up system)

19.1.1.9 Aero-derivative or light industrial Gas turbine API 616 for offshore environment:

- SOLAR: SATURN, CENTAUR, TAURUS 60, MARS100, TITAN 130, TITAN 250;
- BHGE Baker Hughes GE: LM2000, LM2500, LM2500+, LM2500+G4, LM6000 PC/PG
- SIEMENS: SGT-A35 (34 MW ISO), SGT-A65 SAC (WLE DRY), SGT-100, SGT-600, SGT-750 (No propane, only diesel start up system)

19.1.1.10 Submerged Sea water Lift Pumps (Electric):

- FRAMO
- EUREKA with Hayward-Tyler submerged electric motors

19.1.1.11 Fire Water Pumping Unit:

19.1.1.11.1 Diesel-Hydraulic Fire Water Pumping Unit:

- Sulzer
- FRAMO
- FISCHCON

19.1.1.11.2 Diesel-Electric package:

- FRAMO
- EUREKA with Hayward-Tyler submerged electric motors

19.1.1.12 Flare gas ultrasonic flow meter:

- Fluenta
- Baker Hughes

19.1.1.13 UV, UV+IR and 3IR flame/fire detector (Alternate vendors are accepted according to EXHIBIT V - DIRECTIVES FOR ACQUISITIONS criteria):

- AUTRONICA
- DET-TRONICS
- EMERSON
- MSA

19.1.1.14 Hull/Topsides CSS Programable Logic Controllers:

- ALTUS
- EMERSON (PACSystems)
- ROCKWELL
- SIEMENS

NOTE: The PLC vendor list only shall be used if the Integrated Automation and Control system is based on SCADA architecture with PLCs. The Integrated Automation and Control system can be based on DCS architecture and if this is the option, the DCS vendor list shall be used. The PLC vendor list is also not applicable to packages controllers.

19.1.1.15 Variable Speed Drives (VSD) (Medium Voltage > 5MW):

- ABB
- GE
- INNOMOTICS
- TMEIC
- WEG

19.1.1.16 Switchgear and Motor Control Center (Medium and Low Voltage):

- ABB
- GE
- SCHNEIDER
- SIEMENS
- WEG

19.1.1.17 Synchronous Generators (Medium and Low Voltage):

- ABB
- BRUSH
- GENERAL ELECTRIC
- KATO ENGINEERING
- INNOMOTICS
- WEG

19.1.1.18 Three Phase Power Transformers:

- ADELCO
- HITACHI ENERGY
- SUNTEN
- SIEMENS
- WEG

19.1.1.19 Uninterruptible Power Supply System on Alternate and Direct Current (UPS-AC and UPS-DC):

- AEG POWER SOLUTIONS
- AMETEK SOLIDSTATE CONTROLS
- BENNING
- CHLORIDE
- GUTOR

19.1.1.20 Boiler Feed Water Pump:

- BH
- Flowserve
- Sulzer

19.1.1.21 OTSG:

- BIH
- NEM Energy Group
- IST/PROPAK

19.1.1.22 Steam Turbine:

- BH
- Siemens
- Peter Brotherhood

19.1.1.23 TOPSIDES and HULL DCS (Distributed Control System):

- Honeywell (Experion PKS)
- ABB (800xA)
- Siemens (PCS7)
- Emerson (DeltaV)
- Schneider (Foxboro)

19.1.1.24 TSUDL:

- TieZhongBao
- FES
- Continental

- Hutchinson
- Oil States

19.1.2 Vendor List does not exempt SELLER from its responsibilities for events caused by the selection of equipment among suppliers’ portfolio or equipment malfunction or defect.