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INDEX OF REVISIONS

REV.	DESCRIPTION AND/OR REVISED SHEETS
0	Original
A	Updates in Table 1 concerning Pigging Readiness Requirement since FPSO Project may use concept of sharing Pig Launchers
B	Update in the document information confidentiality level from “Confidential” to “Internal” to comply with its correct classification according to DI-1PBR-00337
C	Updates regarding subsea rigid lines diameters, Gas Transfer subsea line material and de-watering requirements for Gas Transfer and Gas Export lines

	REV. 0	REV. A	REV. B	REV. C	REV. D	REV. E	REV. F	REV. G	REV. H
DATE	28/02/2025	24/04/2025	14/05/2025	30/09/2025					
DESIGN	DEEIT	DEEIT	DEEIT	DEEIT					
EXECUTION	C5D3	C5D3	C5D3	C5D3					
CHECK	BG3P	BG3P	BG3P	BG3P					
APPROVAL	U44G	U44G	U44G	AKRZ					

INDEX

1 OBJECTIVE

The objective of this document is to provide general preliminary information on subsea operations planned for the Búzios 12 FPSO. Detailed operational procedures will be issued by BUYER at a later stage, providing specific requirements. Other operations not described in this document may also be proposed and discussed with SELLER during execution and operational phases.

2 GLOSSARY

BSDV: Boarding Shutdown Valve

Bullheading: Fluid injection from FPSO to well

CEU: Cryogenic Expansion Unit – N_2 Cylinders

CRA: Corrosion Resistant Alloy

DHSV: Down Hole Safety Valve (installed in the tubing)

EHU: Electro-Hydraulic Umbilical

Flushing: Displacement of subsea fluids

FPSO: Floating Production Storage and Offloading Platform

GTD: General Technical Description

HMXO: Hydrate Mitigation Cross-over

HRE: Hydrate Removal Equipment

ID: Inner Diameter

OD: Outer Diameter

ROV: Remotely Operated Vehicle

SDU: Subsea Distribution Unit

SESDV: Subsea Emergency Shutdown Valve (installed at subsea flowline)

Soaking: Displacement of the inventory of subsea fluids with solvents

WAG: Water Alternating Gas

WCT: Wet Christmas Tree (also referred to as Subsea Tree in the document)

3 INTRODUCTION

For general information about FPSO, see FPSO General Technical Description I-ET-3010.2K-1200-941-P4X-001. For subsea risers' design pressures and temperatures, see GTD.

The operations described in this document may require ROV support (with proper tools), foam pigs, volume estimation of injected fluids (diesel or dead oil, water, and hydrate inhibitor), pressure, temperature, valve status monitoring and record. ROV support will be provided by BUYER as required for the subsea operations.

There will be 3 kinds of production/injection positions on the FPSO:

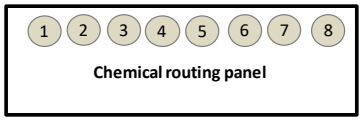
- Oil Production Positions (Riser Balcony slots from P1 to P8);
- Water and Gas (WAG) Injection Positions (Riser Balcony slots from WAG1A/B to WAG5A/B);
- Oil Production Positions or WAG Injection Positions (Riser Balcony slots from PWAG1 to PWAG5).

Additionally, there will be 2 kinds of gas transfer and export positions on the FPSO:

- Gas Transfer Positions (Riser Balcony slots GT1 and GT2);
- Gas Export Position.

Pull-in and pull-out activities may be required for every slot on the balcony during production life. These activities will be planned and discussed with the SELLER.

Figure 1 illustrates valves and chemical injection points at a generic well. It is important to note that valves provide communication between production and service lines (in the Subsea Tree). This communication is used in several operations, such as flushing and pigging. For specific production wells, subsea equipment identified as HMXO (Hydrate Mitigation Cross Over) may also provide hydraulic communication between production and service lines, as described in item 3.1.2. Please refer to FPSO GTD for further information about subsea control systems.



HOSE/TUBE	INJECTION POINT
1	IQ3 (well A)
2	IQ4 (well A)
3	IQ2/IQ5 (well A)
4	IQ1 (wells A & B)
5	IQ1A (wells A & B)
6	IQ2/IQ5 (well B)
7	IQ4 (well B)
8	IQ3 (well B)

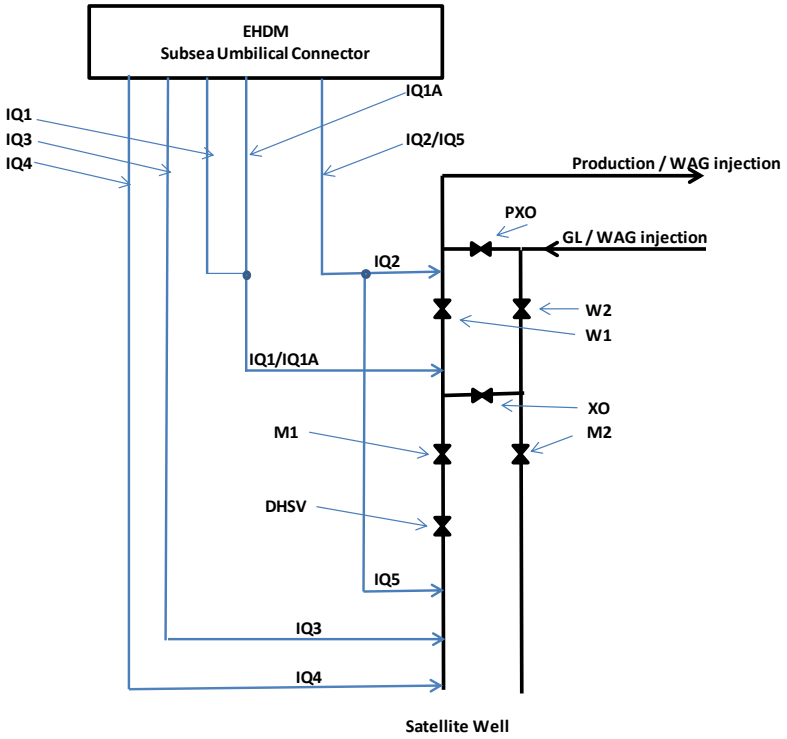


Figure 1: Subsea tree diagram (vales and chemical injection point) for generic well

As described in FPSO GTD, in “Chemical Injection” Section, each position (Production, Production/WAG or WAG injection) may have up to 8 tubes/hoses connected to its chemical routing panel. The IQ1 injection point (linked to hose/tube 4) and the IQ1A injection point (linked to hose/tube 5) are connected subsea and merge into the IQ1/IQ1A point shown on Figure 1.

Special Operations are possible from every FPSO production/injection slot (Production, Service, Production/WAG or WAG injection) using service boats through connections to the FPSO. During these operations, selected fluids will be pumped from the service boat to the FPSO, to a connection located at the discharge of the well service pumps. I-ET-3000.00-1210-010-1DO-001 presents the types of fluids that may be used for these special operations.

Autonomous Special Operations are also possible from every FPSO production slots (Production and Production/WAG injection) without the support of a dedicated stimulation vessel. During these operations, concentrated chemicals are diluted in line with desulfated and deaerated water provided by the FPSO, via countercurrent injection, and the resulting solution is injected in the wells. I-ET-3000.00-1210-010-1DO-001 presents the concentrated products (e.g., formic acid, acetic acid, hydrochloric acid

solutions and solvents solutions) that may be used for these autonomous special operations.

Diesel volume for flushing operations depends on subsea layout, yet to be confirmed, and operating conditions (up to a limit volume stated in GTD). Each cleaning operation, for decommissioning, requires a significant amount of sea water that can surpass 3,000 m³ per operation.

3.1 Subsea system description – Production Positions

3.1.1 Satellite Production Wells (P1 to P8 Positions)

The production wells will be tied back to the FPSO through flexible and/or rigid flowlines and risers. Either flexible (6'' ID or 8'' ID) or rigid lines (with 8.625'' OD, 9.625'' OD or 10.75'' OD, with respective internal diameters to be informed in later stage by BUYER) may be employed for the production well, and one type of service lines (4" ID flexible) may be employed. Service line purposes include flushing with diesel or dead oil (or a mixture of both, in any proportion), pigging, depressurization (one or two sided), soaking, removing liquids from subsea system (service gas), gas lift (when applicable), bullheading and special operations (by service boat or by the FPSO) like scale removal/inhibition.

Figure 2 and Figure 3 present typical conditions for Production Positions.

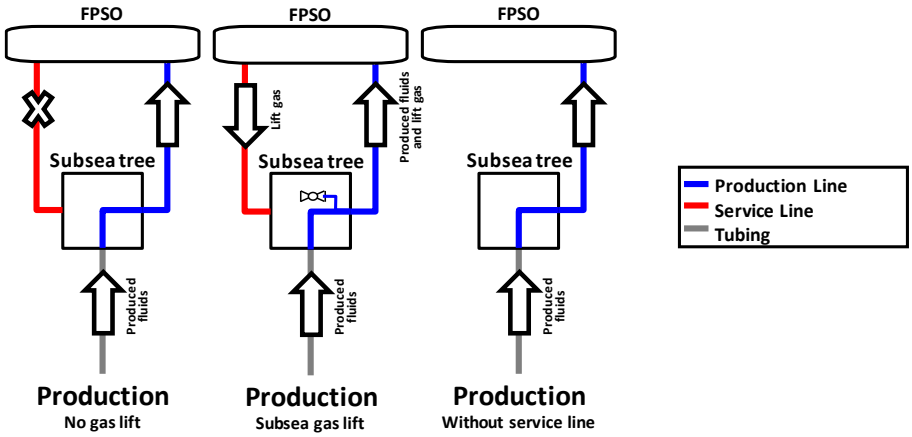


Figure 2: Subsea scheme for typical conditions (production scenarios)

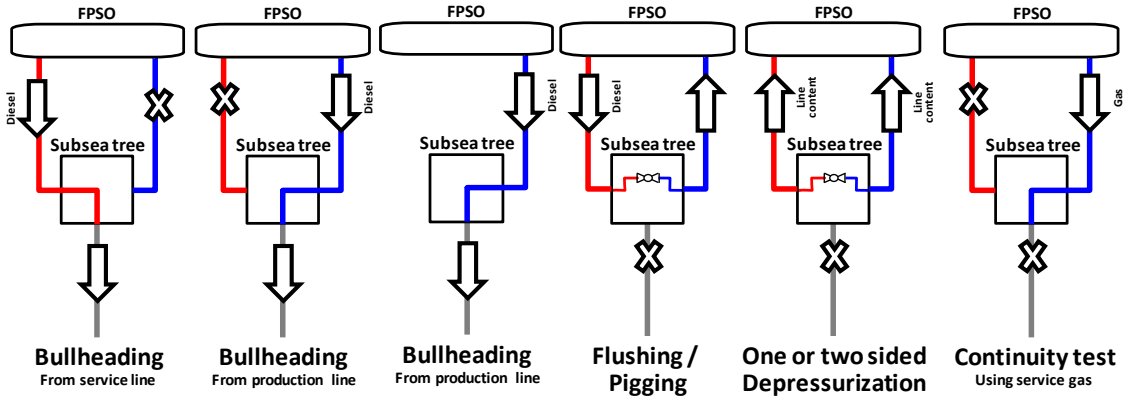


Figure 3: Subsea scheme for typical conditions

Continuity test shown in Figure 3 may be made using either Service gas or Nitrogen (Nitrogen Generation Unit to be placed on topsides by BUYER). In this operation, production riser top is filled with gas (Service or Nitrogen), leading to increases in flowline pressures that help in confirming valve status at subsea equipment. A permanent connection is required for continuity test with Service gas, while a temporary connection is acceptable for Nitrogen.

3.1.2 Satellite production well with subsea valves connecting service line with production line (HMXO – Hydrate Mitigation Cross Over)

This configuration is similar to item 3.1.1 and all the planned operations for that scenario are also applicable. Any Production or Production/WAG Well may include a subsea equipment identified as HMXO (Hydrate Mitigation Cross Over). The HMXO equipment provides hydraulic communication between the production and service lines for satellite wells at the riser base or other hydrate-prone sections of subsea flowlines. This specialized junction enables flushing, chemical injection or depressurization operations across the production system during planned shutdowns or emergency hydrate remediation scenario. Additionally, the HMXO may serve as a pathway for artificial lift operations, allowing lift gas to flow through the crossover equipment instead of requiring downhole gas lift valves, thus providing operational flexibility for production enhancement.

Quantity and position of wells with HMXO will be determined in later stages of the Project, depending mainly on final wells mesh arrangement and subsea layout. Production wells in this configuration consider the expected operations in Figure 4. Assuming the HMXO will be connected to the FPSO by an umbilical line and may be remotely operated, this umbilical line that is connected to the HMXO comprises at least

a chemical injection line for injecting hydrate inhibitor, electrical signal for pressure measurements at the equipment and hydraulic control lines for remote operation of HMXO valves.

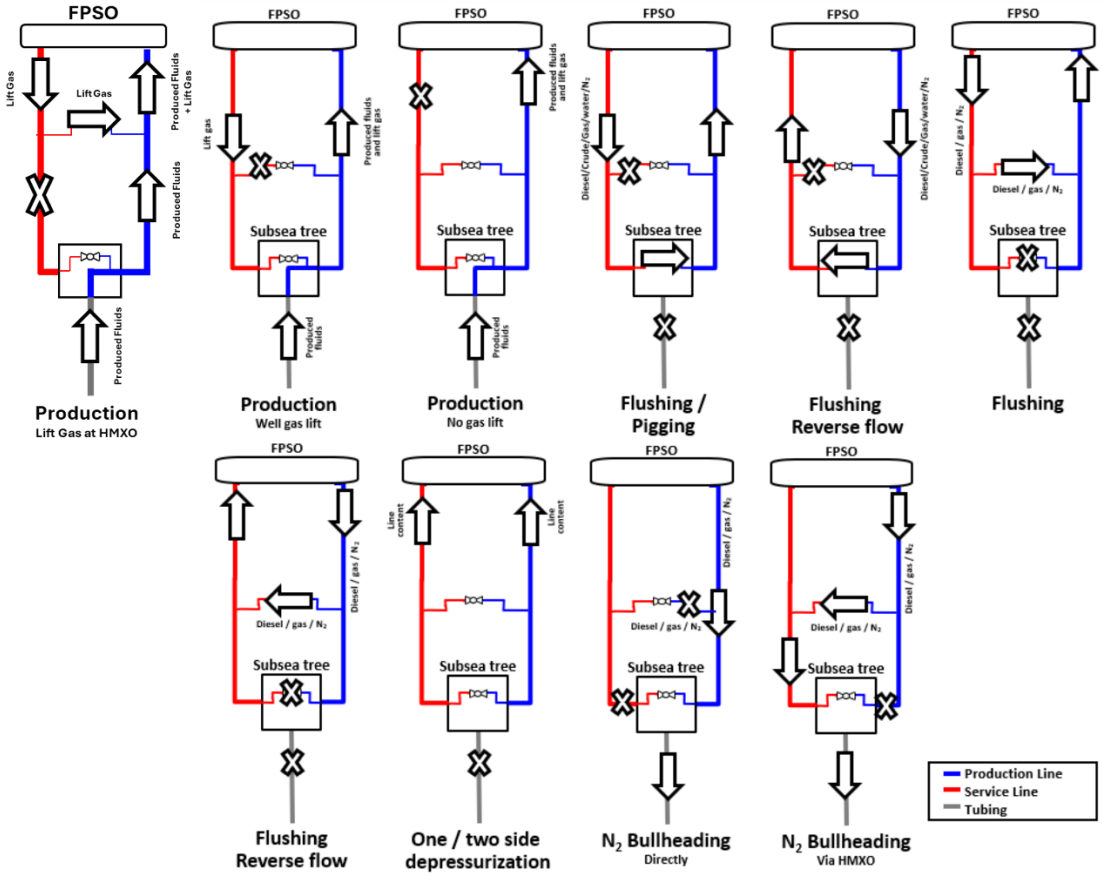


Figure 4: Subsea scheme for satellite wells with HMXO valves

For ordinary flushing operations, diesel, dead oil or a mixture of both fluids may be displaced by the well service pump. Additional flushing operations may be performed by using gas from gas lift / export header, by using water by well service pump, or by using N_2 provided by an external unit (Nitrogen Generation Unit to be placed on topsides by BUYER) to be temporarily connected to piping on topsides.

Additionally, for the wells equipped with HMXO, bullheading operations may be performed through the service line with N_2 during hydrate dissociation operations. Note that greater pressures in the topsides piping and equipment are required in such operation with N_2 when compared with a bullheading operation performed with diesel. The system shall be designed accordingly for the wells equipped with HMXO.

3.2 Subsea system description – WAG Injection Positions

Either flexible (6'' ID or 8'' ID) or rigid lines (with 8.625'' OD, 9.625'' OD or 10.75'' OD, with respective internal diameters to be informed in later stage by BUYER) may be employed for the WAG injection positions. These injection wells can be tied back to the production unit through one or two lines. Every WAG injection slot on the FPSO shall inject water and gas alternately and independently. Two injection wells (slot A and slot B) may be connected through a circulation jumper. This results in 3 alternatives for the injection well tie-back, as shown on Figure 5 to Figure 8:

- Alternative 1 (Figure 5): One-line tie-back for gas injection or water injection;
- Alternative 2 (Figure 6 and Figure 7): Two-line tie-back for gas and/or water injection (one line per well), using a circulation jumper to interconnect two injection wells (e.g., wells WAG1A and WAG1B);
- Alternative 3 (Figure 8): Two-line tie-back for single water injection and/or gas injection.

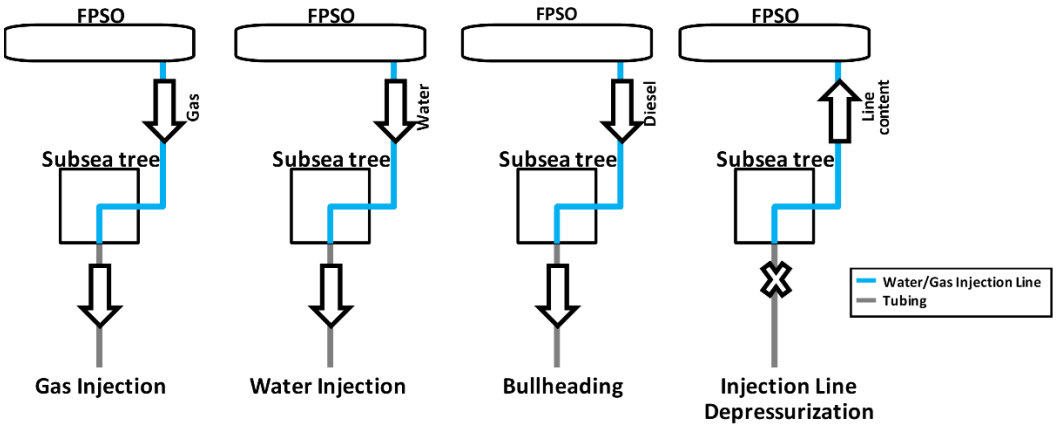


Figure 5: Subsea scheme for typical injection conditions (Alternative 1)

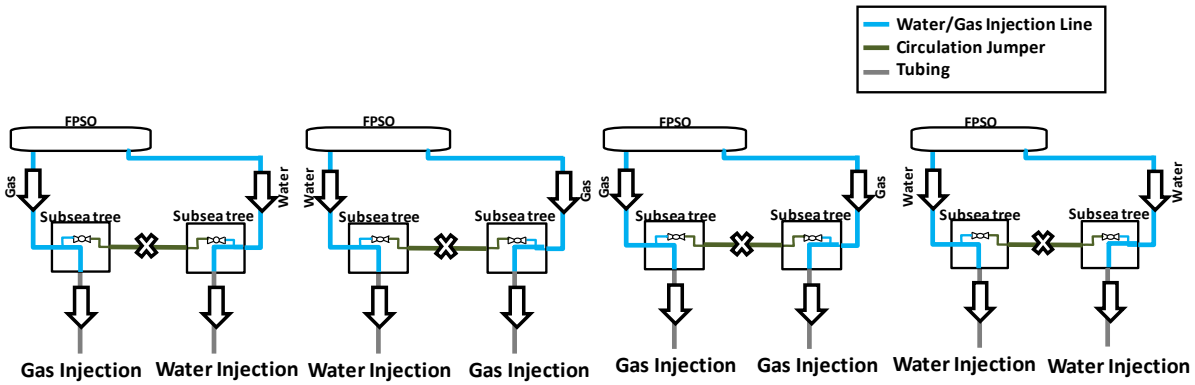


Figure 6: Subsea scheme for typical injection conditions (Alternative 2, operational injection scenarios)

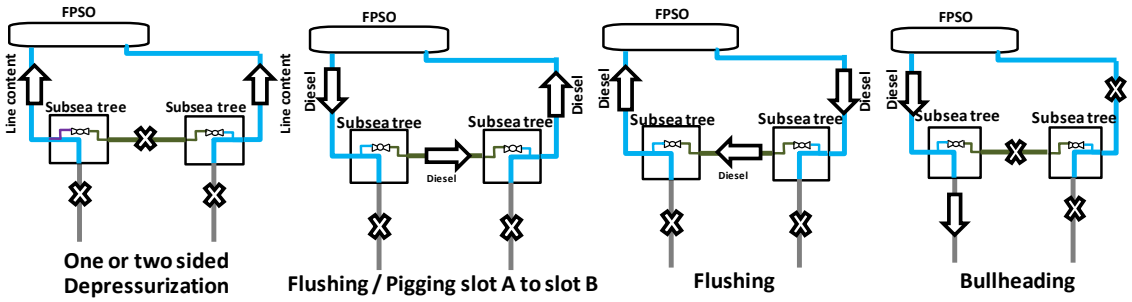


Figure 7: Subsea scheme for typical injection conditions (Alternative 2)

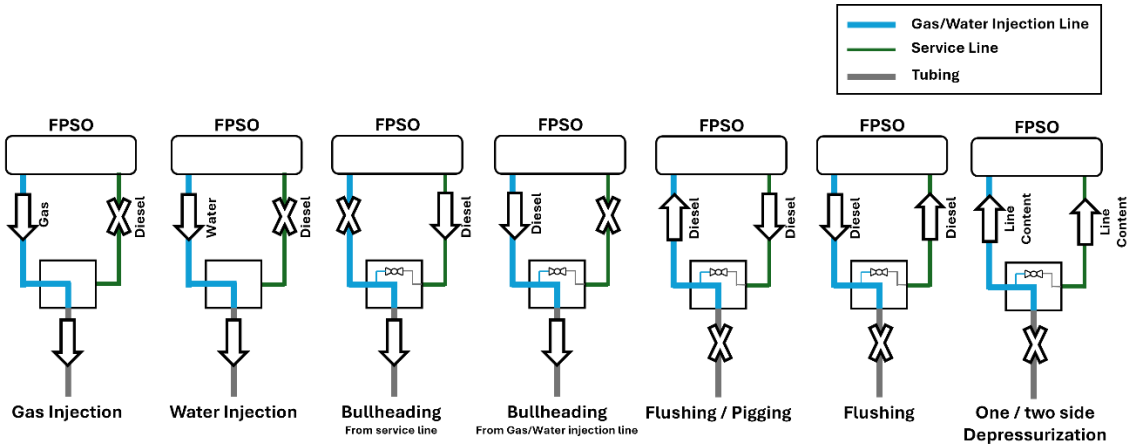


Figure 8: Subsea scheme for typical injection conditions (Alternative 3)

BUYER highlights that water injection may be performed using a subsea line with design pressure of a water injection line or of a WAG injection line (refer to GTD). Topsides design shall consider both possibilities.

3.3 Subsea system description – Production / Water and Gas Injection Positions

Some positions on the FPSO have the feasibility to be tied back to both production or water and gas injection wells. The function of these positions may be changed by BUYER during production life, from production to water and gas injection and vice-versa. These positions are referred in the FPSO GTD as Production/WAG Positions.

When the position operates as Satellite Oil Production Position the wells will be tied back to the FPSO through flexible or rigid flowlines and risers. Either flexible (6'' ID or 8'' ID) or rigid lines (with 8.625'' OD, 9.625'' OD or 10.75'' OD, with respective internal diameters to be informed in later stage by BUYER) may be employed for the production well and one type of service line may be employed (4" ID flexible). Service line purpose includes replacing produced fluid by diesel or dead oil (or a mixture of both fluids, in any proportion), pigging, depressurization (one or two sided), soaking, removing liquids from subsea system (service gas), gas lift (when applicable), bullheading and special operations (by service boat or by the FPSO) like scale removal/inhibition.

Figure 9 and Figure 10 present typical conditions when operating as Production Positions.

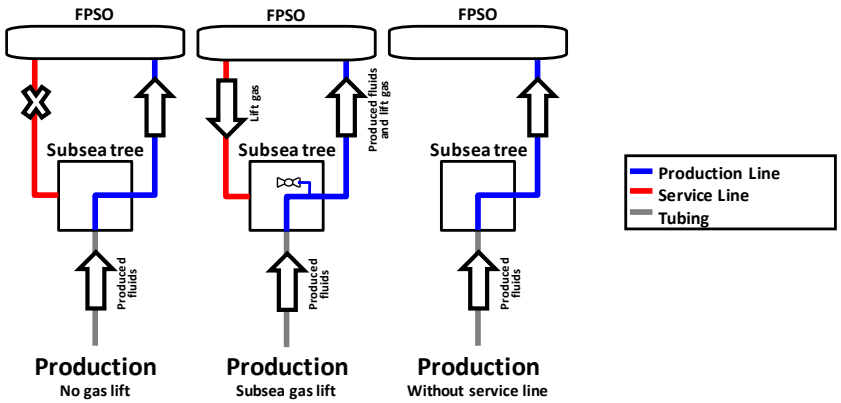


Figure 9: Subsea scheme for operation as production position.

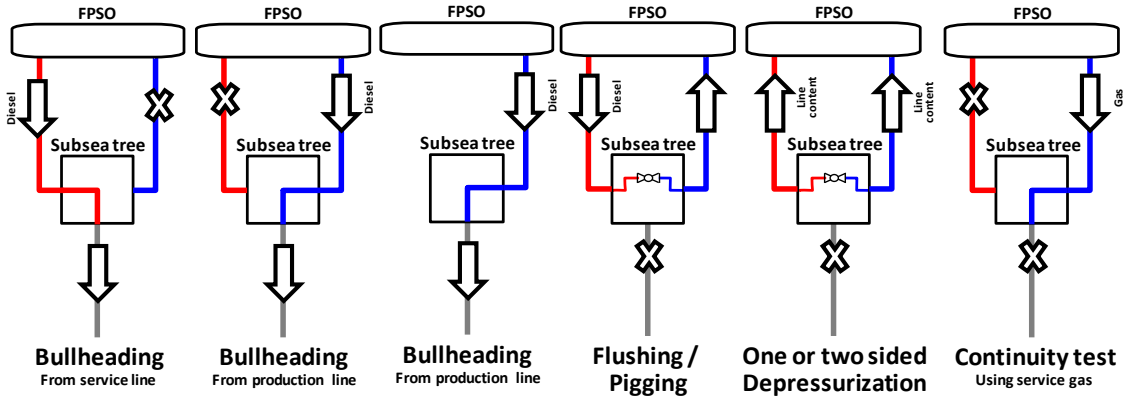


Figure 10: Subsea scheme for operation as production position.

When operating as Water and Gas Injection Position the wells will also be tied back to the FPSO through flexible or rigid flowlines and risers. Three different configurations may be employed, as shown on Figure 11:

i) Satellite WAG wells with one WAG injection line (6'' ID or 8" ID for flexible lines, or 8.625'' OD, , 9.625'' OD or 10.75'' OD for rigid lines) and one service line (4" ID flexible), as in Figure 11;

ii) Satellite water wells with one water injection line (6'' ID or 8" ID for flexible lines, or 8.625'' OD, , 9.625'' OD or 10.75'' OD for rigid lines) with or without one service line (4" ID rigid or flexible), as in Figure 12;

iii) Satellite gas wells with one gas injection line (6'' ID or 8" ID for flexible lines, or 8.625'' OD, , 9.625'' OD or 10.75'' OD for rigid lines), as in Figure 12;

Service line purpose includes replacing injection fluid by diesel or dead oil, bullheading and special operations like acid stimulation of reservoir. Special operations may also be done through water and gas injection lines.

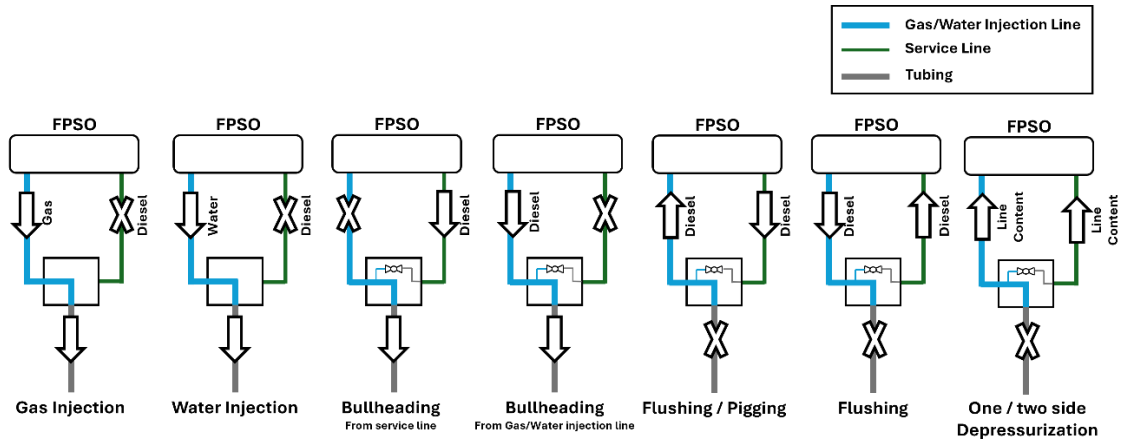


Figure 11: Subsea scheme for operation as injection position (WAG injection line)

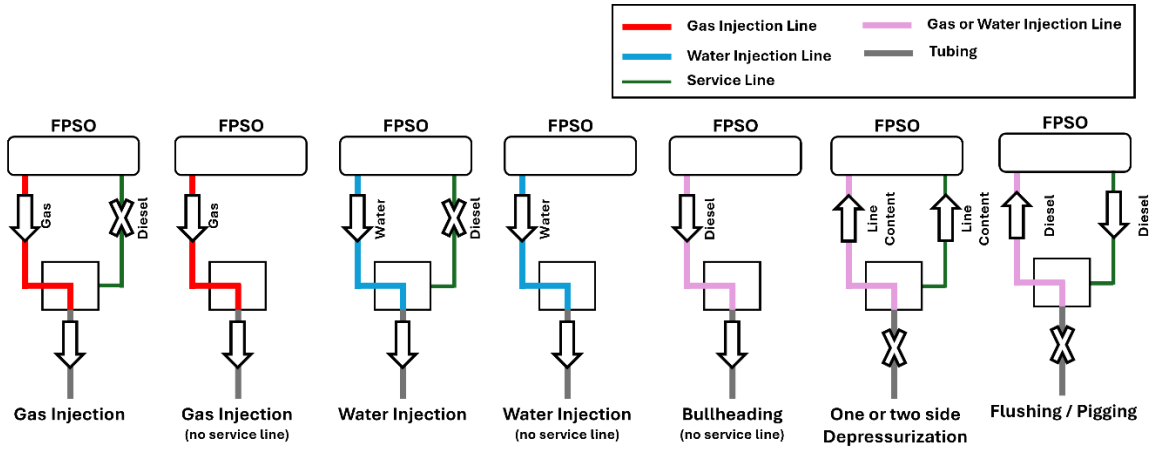


Figure 12: Subsea scheme for operation as injection position (Water or Gas injection line, with or without service line)

Before changing the function of the position (production to injection and vice-versa), the subsea system may be decommissioned, the risers and flowlines may be replaced, tested for leaks and commissioned according to the procedures listed in this document.

3.4 Subsea system description – Gas Transfer Position

The Gas Transfer positions at the Riser Balcony of Búzios 12 FPSO may be connected to other FPSOs in Búzios field (in platforms with no gas exportation, such as FPSO Almirante Tamandaré, P-80, P-82, or P-83), using rigid lines, in order to transfer gas with high CO_2 content (above 20% in molar fraction). Thus, from Búzios 12 FPSO perspective, the Gas Transfer is similar to a gas producing well with a specified range of water and contaminants content, and a limited gas flowrate.

Expected operations for the Gas Transfer lines are presented in Figure 13, including: (i) conventional gas transfer from other Búzios FPSO (indicated as “Búzios X”)

to Búzios 12 FPSO; (ii) one or two side depressurization; and (iii) flushing/pigging operations. Gas transfer operation may require continuous hydrate inhibitor injection or continuous corrosion inhibitor injection at the Gas Transfer origin (indicated as “Búzios X”). Additionally, preferred operations consider that Búzios 12 FPSO shall be prepared to received pigging and flushing fluids from Gas Transfer line.

Gas Transfer lines shall consider a slug catcher at Búzios 12 FPSO in order to handle potential liquid slugs due to hydrate inhibitor injection or corrosion inhibitor injection at “Búzios X” FPSO, liquid condensate formed in normal operation or liquid received from pigging operations. For handling higher liquid volumes, that may occur at depressurization operations or due to other causes, Gas Transfer line shall be aligned to test separator.

Gas Transfer lines will have one or two subsea emergency shutdown valves (ESDVs), to be confirmed during detailed design.

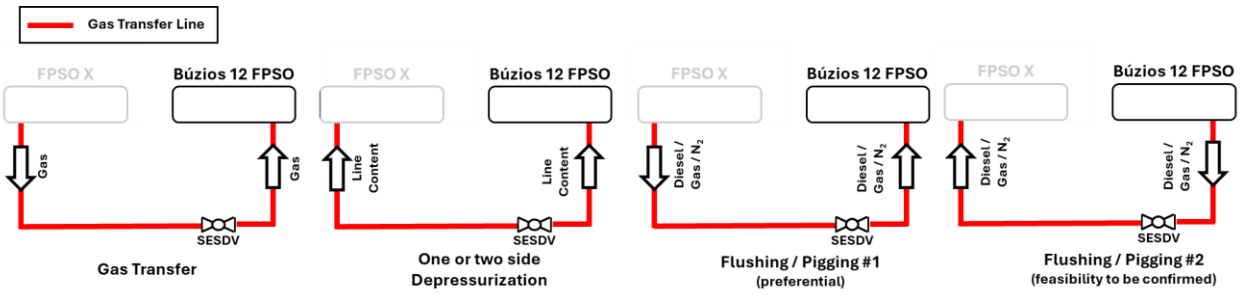


Figure 13: Subsea scheme for Gas Transfer positions

4 SUBSEA COMMISSIONING

Subsea commissioning activities include leak tests of production, service and injection lines, as well as Gas Transfer and Gas Export lines; umbilical leak test and content replacement for chemical injection; dewatering of production, service and injection lines; potential dewatering of Gas Transfer/Gas Export lines; subsea tree leak and functional tests; hydrate prevention procedure; DHSV equalization and opening.

4.1 Leak Test of Production, Service, Water and Gas Injection Lines

First, it is necessary to verify the subsea valves status (at subsea tree) with ROV support. It is necessary to verify the functionality of service pump, leak test pump and hydrate inhibitor injection pumps (high flow rate). Furthermore, subsea control and monitoring systems must be previously commissioned.

To execute the leak tests (production, service and injection lines), the lines need to be fully filled with water (service pump should preferentially be used). The final pressure adjustment has to be done using the leak test pump. After the stabilization period, pressure must be monitored nearby the riser connection for several hours with the system isolated. At any moment, if the pressure drops more than the acceptable, the system needs to be pressurized again and the tests restarted from the stabilization period. After test acceptance, the system is depressurized taking care not to exceed the maximum depressurization rate for risers (see GTD).

4.2 Leak Test of Gas Transfer and Gas Export Lines

SELLER shall follow the requirements for Gas Export and Gas Transfer riser pre-commissioning stated at the GTD, which include space on deck to receive and store a provisional Pig Launcher/receiver (PLR) and other temporary equipment from a vessel to the Unit.

The base case considers that Gas Transfer and Gas Export lines will be connected to FPSO filled with nitrogen. The gas pipeline will be pressurized with NGU or CEU (supplied by BUYER) and the nitrogen Leak test will be performed. After the stabilization period, pressure must be monitored near the riser connection for several hours with the system isolated. With the approval of the leak test, depressurize the pipeline through the FPSO until pressure equalization with the pressure of the gas pipeline flow network in

operation (for the gas export line) or the minimum operational pressure expected upstream of the Gas Transfer choke line (for the Gas Transfer line).

In case the Gas Transfer and Gas Export lines are not delivered filled with nitrogen, they may be delivered filled with water (with or without chemicals) and the leak test of such lines may be performed with water. In this scenario, the lines need to be fully filled with water (service pump should preferentially be used) and the final pressure adjustment must be done using the leak test pump.

4.2.1 Dewatering of Subsea Gas Transfer/Gas Export Lines

In case the Gas Transfer and Gas Export lines are delivered filled with water, the FPSO shall provide alignments from the Gas Transfer/Gas Export lines to a tank or to the sea in order to allow the dewatering of the lines. After line depressurization, dewatering of the Gas Transfer/Gas Export lines is done using foam pigs displaced by inert gas.

In this dewatering process, Búzios 12 FPSO may receive water with chemicals (such as Biocide and oxygen scavenger) and shall be prepared to align this fluid to an offspec tank. For the pig operation, the FPSO is expected to receive MEG-gel and it is SELLER responsibility to receive and store this MEG-gel.

4.3 Dewatering of Subsea Production/Injection Lines

For dewatering of the production loop (subsea lines and equipment of a production well), it is necessary to verify that subsea tree valves are correctly set up, the service and production lines are depressurized and the production line is aligned to a pig receiver. Dewatering of the production loop is done using foam pigs displaced by diesel (free of water) through the production loop. During pigging/flushing, manipulation of subsea tree valves is required. BSW of the returned fluids needs to be monitored. Diesel is circulated from service line to production line (flushing) until BSW requirement is met (as defined by BUYER). Fluids returned shall be collected in the test separator.

For the injection Alternative 1 (Figure 5), flushing is not possible. Before injecting gas, water will be displaced by diesel using the well service pump (bullheading). Time and volumes will be detailed by BUYER during the operational phase. When the first fluid to be injected is water, water present in the injection line will be displaced by treated injection water, using the water injection pumps (see start-up procedures in Section 5).

The dewatering procedure for Alternative 2 or 3 (Figure 6, Figure 7 and Figure 8) is similar to the one described for production loop. Diesel is circulated from one water/gas injection line (Slot A) to the other water/gas injection line (Slot B) (see GTD) through the circulation jumper or subsea tree. This procedure may be carried out with foam pigs. Fluids returned shall be collected in the test separator.

4.4 Subsea Tree Valves Functional Test

ROV support is necessary for subsea tree valves functional test. Hydrate inhibitor injection in different subsea tree injection points may be required by BUYER during this operation.

4.5 DHSV Equalization and Opening

DHSV valve requires equalization of downstream and upstream pressures before opening. For this operation, both hydrate inhibitor and/or low flowrate service pumps and/or leak test pump may be used, injecting through EHU hoses, production, or service lines (see Figure 14). Pressures at the subsea systems and flow rates must be monitored during this operation.

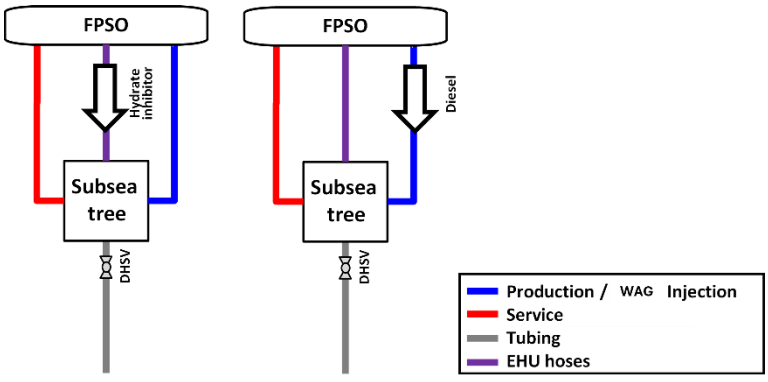


Figure 14: Usual subsea schemes for DHSV equalization

5 START-UP

5.1 Production Start-up

After confirmation that subsea tree valves and production BSDV are tested and operational, production choke valve shall be opened following BUYER Operational Procedures. Service gas or Nitrogen (using a Nitrogen Generation Unit to be placed on topsides by BUYER) may be used in this condition. The FPSO shall be prepared to receive completion fluids from the production well. Please see I-ET-3000.00-1210-010-1DO-001 for further information about completion fluids.

5.2 Injection Start-up

During start-up, water or gas injection flowrates and system pressures must be controlled mainly to avoid bottom hole pressures over a limit (normally related to reservoir fracture pressure). Hydrate inhibitor may be injected from topsides and/or at subsea tree at any moment, hydrate inhibitor injection will not occur during continuous injection of water or gas. If the injection line is filled with diesel, it will be displaced into the well by injected fluid (water or gas). Before switching injection fluid, from water to gas or vice versa, it is necessary to perform procedures to be defined by BUYER, similar to those described in section 4.3.

5.3 Gas Transfer and Gas Export Start-up

During start-up, Gas Transfer flowrate and system pressure and temperate shall be controlled using Topsides choke to avoid hydrate envelope (mainly due to reduced temperatures related to riser depressurization and choke pressure reduction). Hydrate inhibitor and hot diesel may be used at the Gas Transfer arrival at Búzios 12 FPSO to prevent hydrate formation.

During start-up, Gas Export line may be used to import gas in order to perform: (i) FPSO start-up with import gas to Export/Gas Lift Compressor for Wells kick-off; or (ii) FPSO start-up with import gas to Fuel Gas System.

6 CONTINUOUS OPERATION

During continuous operation, chemicals may be continuously injected through umbilicals, in production wells, as requested by BUYER. The chemical injection system has flexibility to allow the alignment of each injection pump through more than one umbilical (see GTD, “Chemical Injection” Section).

For production wells, monitoring of solids production as well as fluid properties (e.g. gas-oil ratio, composition) and operational conditions (pressure and temperature) are required in order to ensure operation within designed ranges. Special attention should be given to gas-oil ratio of production wells due to its relevance to reservoir/production management. In addition, pigging may be frequently required for deposits removal.

H_2O content in lift gas, Gas Transfer lines and injection gas shall be monitored and limited, as specified in GTD. H_2S content for the production fluid (merged fluid from producing wells and Gas Transfer line), producing wells and the Gas Transfer line shall be monitored and limited, as specified in GTD. Injection well pressures shall be monitored to avoid surpassing limits to be specified by BUYER, regarding to reservoir fracture pressure or subsea system specification.

Batches of non-reactive chemical tracers may be added into individual injection wells in gas or water streams when required by BUYER. Operational procedures must ensure non-stop injection for a few days following the injection of tracer slug to allow tracer to move into reservoir away from well and avoid injection shutdowns to prevent any backflow to the well.

Gas Transfer line may consider continuous injection of hydrate inhibitor or corrosion inhibitor at the other end (“FPSO X” in Figure 13), besides the potential injection of hydrate inhibitor or hot diesel at Búzios 12 FPSO facilities. Gas Transfer operational conditions shall avoid free water in Gas Transfer line in order to prevent excessive consumption of corrosion margin in subsea line (since the Gas Transfer line does not consider an internal CRA coating and adopts a corrosion margin).

If possible, Gas Transfer preferred operation shall consider reducing the pressure drop at Búzios 12 FPSO Gas Transfer choke to a minimum due to the temperature decrease related to Joule-Thompson effect (besides the already relevant temperature

reduction caused by gas depressurization at the arrival riser) and monitor temperature at Búzios 12 FPSO arrival.

Instrumented pig operations are expected for corrosion management of the Gas Transfer line (besides conventional cleaning pig operations), since it does not present a CRA internal coating but considers a corrosion allowance instead. It is recommended to perform an instrumented pig inspection after the first year of Gas Transfer operation. Additional instrumented pig operations on the Gas Transfer line shall follow BUYER's integrity management plan.

Choke valves (particularly for production and water injection) must be able to operate continuously in a wide range of pressure conditions, as specified in GTD.

7 SHUTDOWN

Flow Assurance related operations after planned or unplanned shutdowns vary depending on a series of parameters, including production and injection conditions, results from lab tests and simulations, lessons learned, production restart forecast, among others. For production, most of these possibilities are covered in the following sections based on the service line condition before shutdowns.

These operations may not be necessary immediately after a shutdown. During some shutdowns, especially short ones, they may not be required. Nevertheless, FPSO must be prepared to take all the described actions as soon as possible after a shutdown. In particular, FPSO shall be prepared to perform fluid (diesel, crude oil or mixture of both) injection by the well service system in up to two risers (more details in Section 12).

Subsea chemical injection, especially hydrate inhibitor, and service pump availability is required for all described conditions.

7.1 Production Position

7.1.1 Gas filled service line – depressurized

In this condition, many operations may be performed: production line depressurization, diesel or dead oil flushing (with or without pigs), diesel or dead oil bullheading, soaking, production line and service line communication (provided by subsea tree valves), topsides hydrate inhibitor injection (in direction to risers).

7.1.2 Gas filled service line – pressurized

This condition represents the use of lift gas for artificial lift and lead to similar operations as the previous condition. In addition to the operations described in section 7.1.1, service line depressurization is first required.

During a two-sided depressurization to prevent or to remove hydrates, a small volume of produced fluids from the reservoir may flow from the subsea tree through the service line to the topsides. These operations are not expected to be frequent and will occur during the depressurization of service lines. Flushing of topside piping may be needed after these operations to avoid corrosion.

7.1.3 Diesel filled service line

This condition may require production line depressurization, diesel or dead oil flushing (with or without pigs), diesel or dead oil bullheading, soaking, topsides hydrate inhibitor injection (towards risers).

7.2 Production / Water and Gas Injection Position

7.2.1 Gas-filled service line – depressurized

In this condition, many operations may be performed: production line depressurization, diesel or dead oil flushing (with or without pigs), diesel or dead oil bullheading, soaking, production line and service line communication (provided by subsea tree valves), topsides hydrate inhibitor injection (in direction to risers).

7.2.2 Gas-filled service line – pressurized

This condition represents the use of lift gas for artificial lift and lead to similar operations as the previous condition. In addition to the operations described in section 7.1.1, service line must be previously depressurized.

During a two-sided depressurization to prevent or to remove hydrates, a small volume of produced fluids from the reservoir may flow from the subsea tree through the service line to the topsides. These operations are not expected to be frequent and will occur during the depressurization of service lines. Flushing of topside piping may be needed after these operations to avoid corrosion.

7.2.3 Diesel-filled service line

This condition may require production line depressurization, diesel or dead oil flushing (with or without pigs), diesel or dead oil bullheading, soaking and/or topsides hydrate inhibitor injection (in direction to risers).

7.2.4 Water being injected

In this condition water is being injected through WAG or water injection line. Following the shutdown, injection line depressurization may be required. Other operations may be necessary such as diesel or dead oil flushing, diesel or dead oil bullheading and/or hydrate inhibitor injection.

7.2.5 Gas being injected

In this condition gas is being injected through WAG or gas injection line. Following the shutdown, injection line depressurization may be required. Other operations may be necessary such as diesel or dead oil flushing, diesel or dead oil bullheading and/or hydrate inhibitor injection.

7.3 WAG Injection Position

7.3.1 Gas being injected

In this condition gas is being injected through WAG injection line. Following the shutdown, injection line depressurization may be required. Other operations may be necessary such as diesel or dead oil flushing (possible for Alternatives 2 and 3), diesel or dead oil bullheading and/or hydrate inhibitor injection.

7.3.2 Water being injected

In this condition water is being injected through WAG injection line. Following the shutdown, injection line depressurization may be required. Other operations may be necessary such as diesel or dead oil flushing (possible for Alternatives 2 and 3), diesel or dead oil bullheading and/or hydrate inhibitor injection.

7.4 Gas Transfer Position

In this condition gas with high CO_2 content is being transferred from Búzios “X” FPSO to Búzios 12 FPSO (Figure 13) through the Gas Transfer. Following the shutdown, Gas Transfer depressurization may be required. Other operations may be necessary such as flushing or hydrate inhibitor injection.

8 SUBSEA LINES DECOMMISSIONING

Sea water needs to be flushed in order to clean the subsea lines before pull-out (see fluid inventory in Section 3 for estimates in water volumes). The following information shall be used as a reference. During the operational phase, decommissioning steps shall be detailed.

8.1 Production Positions

After production interruption, perform subsea system depressurization. Circulate diesel or dead oil through the production loop (subsea tree valves). Circulate water through production loop until required cleanliness (as defined by BUYER) is obtained. Pigs may be launched during these operations.

8.2 Production / Water and Gas injection Positions

8.2.1 Production Loop

After production interruption, perform subsea system depressurization. Circulate diesel or dead oil through the production loop (subsea tree valves). Circulate water through production loop until required cleanliness (as defined by BUYER) is obtained. Pigs may be launched during these operations.

8.2.2 Water Injection Loop

After injection interruption, perform subsea system depressurization. Batch and/or continuous injection of hydrate inhibitor at subsea christmas tree may be required during this operation.

8.2.3 Gas Injection Loop

After injection interruption, perform subsea system depressurization, fill injection line with diesel or dead oil removing gas from the line. Diesel and seawater shall be injected until required cleanliness (as defined by BUYER during operational phase) is obtained. Batch and/or continuous injection of hydrate inhibitor at subsea christmas tree may be required during this operation.

8.2.4 Water and Gas Injection Loop

After injection interruption, perform subsea system depressurization. Flushing operations using diesel or dead oil may be required. Circulate water through injection loop until required cleanliness is obtained. Batch and/or continuous injection of hydrate

inhibitor at subsea Christmas tree may be required during this operation. Pigs can be launched during these operations.

8.3 WAG injection Positions

8.3.1 Alternative 1

After injection interruption, perform subsea system depressurization. If water is the injection fluid, no further operation is required. For gas injection, injection line must be filled with diesel or dead oil, removing gas from the line. Then, diesel and seawater shall be injected until required cleanliness (as defined by BUYER during operation phase) is obtained. Batch and/or continuous injection of hydrate inhibitor at subsea Christmas tree may be required during this operation.

8.3.2 Alternative 2 and Alternative 3

After injection interruption, perform subsea system depressurization. Flushing operations using diesel or dead oil may be required. Circulate water through injection loop until required cleanliness is obtained. Batch and/or continuous injection of hydrate inhibitor from topsides and/or at subsea Christmas tree may be required. Pigs may be launched during these operations.

8.4 Gas Transfer Positions

After Gas Transfer interruption, perform line depressurization, fill subsea line with diesel or dead oil removing gas from the line. Diesel and seawater shall be injected until required cleanliness (as defined by BUYER during operational phase) is obtained. Batch and/or continuous injection of hydrate inhibitor at Búzios “X” FPSO (Figure 13) or Búzios 12 FPSO may be required during this operation.

9 SPECIAL OPERATIONS

In addition to the usual operations described above, it is also possible to employ special purpose boats alongside the FPSO to perform so-called special operations. Figure 15 shows a schematic view of a typical squeeze. The operation may be fulfilled by any of the flowlines, not at the same time.

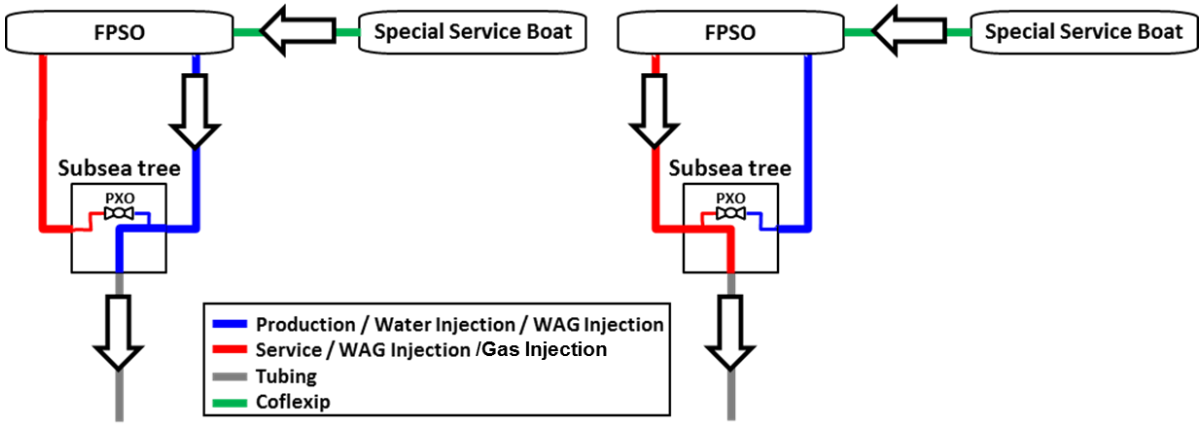


Figure 15: Typical scheme for Special Operations

10 AUTONOMOUS SPECIAL OPERATION

Autonomous special operations consist of performing chemical treatments for the removal or inhibition of scaling (squeeze) in production wells, without the support of a dedicated stimulation vessel (as in Section 9). The chemicals are sent to the platform in concentrated form, and the production facilities are used for inline dilution with de-sulfated and de-aerated seawater, via countercurrent injection prior to application in the well.

The platform facilities must allow for redirecting de-sulfated and de-aerated water from the injection system to the well service system, as well as provide an adaptation point for injecting the concentrated chemicals, which will be diluted inline before application in the well.

The following additional equipment may be temporarily loaded specifically for each operation and does not need to remain permanently on the platform: containers for concentrated chemicals (5,000 liters), chemical injection pumps with a flow rate of 5 to 15 liters per minute, a triplex pump with a flow rate of 20 to 300 liters per minute, lines, connections, and a manifold. The set of non-resident equipment may vary depending on the operation, but previous experience suggests the need for approximately 140 m² of total deck area and a total weight of 40 tons. The heaviest individual piece of equipment in this set may weigh up to 17 tons and occupy an area of 7 m².

In this area, it is necessary to provide electrical, pneumatic, and diesel power to supply the equipment brought on board for the operation.

The chemicals intended for this operation are non-diluted formulations of the fluids described in reference I-ET-3000.00-1210-010-1DO-001.

11 HYDRATE REMOVAL OPERATIONS AND HYDRATE REMOVAL EQUIPMENT

The occurrence of hydrate blockage may have several causes, such as: low temperature of the liquid in flow, delay or troubles during hydrate prevention procedures, excessive humidity in the lift gas, failure in subsea valve operations, etc.

The hydrate dissociation operation in the subsea system basically depends on the location of the block and the pressure and temperature condition of the stream.

For blockages in the lift gas, gas transfer and exported gas lines, the dissociation is generally achieved by depressurizing the line to atmospheric pressure.

For production lines, one may usually have the following blocking locations and the usual dissociation operations: (i) at the subsea tree (WCT); (ii) at the production or service flowlines; and (iii) at the production or service risers. Depending on the location, after lines depressurization hydrate removal operations may circulate (hot or cold) diesel or potentially natural gas or nitrogen may be used, as for BUYER' request. Diesel injection may be performed simultaneously in up to two risers. For specific lines in Búzios 12 FPSO there may also be a subsea equipment identified as HMXO (operations described in 3.1.2) for helping hydrate prevention and dissociation in more critical subsea lines.

Other hydrate scenarios may occur with the need for specific procedures for each case, such as the use of Hydrate Removal Equipment (HRE) detailed in Section 11.1. At any occurrence of hydrate blockages, BUYER will define, together with the SELLER, the best procedure option for its dissociation.

11.1 Hydrate Removal Equipment (HRE)

In case of no success in removing hydrate blockage by conventional means, a Hydrate Removal Equipment may be mobilized to be inserted into the production line to help hydrate dissociation, which may be performed, for example, by removing liquid from the riser. FPSO shall provide the facilities informed in 11.1.1 to allow the use of hydrate removal technologies.

11.1.1 Hydrate Removal Equipment Minimum Requirements

a) FPSO shall provide a direct vertical access in the closing spool to allow the insertion of the equipment (hydrate removal technologies), see Figure 16. This direct vertical access' internal diameter is equal to the ID of the subsea lines (which is to be confirmed with BUYER);

Figure 16: Vertical access in spool for allowing the insertion of hydrate removal equipment into subsea lines

b) Direct vertical access must have a closing mechanism that allows the PIG to pass through when not in use, see Figure 17. Alternatively, a spare spool for instrumented pigs can be used;

Figure 17: Branch closure to allow PIG passage

c) FPSO shall provide means for moving the hydrate removal equipment to the direct vertical access described in Figure 16;

d) The vertical branch must have flanges and pressure class compatible with the rest of the piping;

e) There shall be preferably no curved sections between the direct vertical access and the subsea line. In case they cannot be avoided, curved section from the HRE access point to the riser shall be minimized and limited to 45º bends;

f) It is necessary to provide electrical, pneumatic, and diesel power to supply the equipment brought on board for the operation.

11.1.2 Hydrate Removal Equipment General Operation

The installation, assembly, disassembly of the Hydrate Removal Equipment procedures to perform a hydrate removal operation will be released by BUYER at proper time, and the following contains the essential content after this step is completed and the equipment is ready to be used.

The decision to perform the operation with HRE indicates that several previous procedures for dissociating the hydrate have been carried out and failed. Most likely, the hydrate did not dissociate due to hydrostatic pressure from the fluid column in the production (or service) riser.

Although other Hydrate Removal Equipment and technologies may be based on different principles of operation, the following description will cover a specific HRE principle based on "discharging" the fluids accumulated in the production or service riser, using N_2 for this purpose. The unit shall consider the following actions after installation of all equipment for coiled tubing on the existing tie-in over the riser:

1) Open the tie-in valves to access the riser in Figure 16;

2) Open the SDV and make alignment to the test separator, passing through the pig receiver;

3) Control the HRE laying and inject nitrogen, controlling pressure and flowrate:

4) Check the arrival of fluid in the test separator;

5) Monitor WCT or manifold pressure changes (indicative of Hydrate dissociation);

6) When the hydrate dissociation is noticed the operation will be completed;

The liquid that was accumulated in the riser will be expelled and shall be aligned to the test separator. This fluid will basically consist of oil, produced water, diesel, MEG, alcohol, gas, nitrogen and dissociated hydrate. There is the possibility of receiving hydrate block. This possibility requires attention, due to the risks involved, and is the reason why it is mandatory to align the well via the pig receiver before proceeding to the test separator.

Due to the time-varying of the composition of the recovered gases (basically the mixture of N_2 and natural petroleum gas) there may be a risk of extinguishing the flare pilot. Detailed operation procedure shall take it into account.

Other Hydrate Removal Equipment principles include inserting a part of the HRE into the line, close to the blockage and injecting fluids such as MEG, ethanol or NGU.

12 WELL SERVICE SYSTEM OPERATIONAL CONDITIONS

All the requirement of operational conditions during bullheading/flushing/pigging operations, described in GTD, must be respected and limited by subsea lines design pressures. The pressurization of diesel or dead oil injection should be controlled in order comply with the maximum pressurization rate allowed for the subsea lines (as per GTD requirement for flexible risers).

12.1 Production line bullheading

Bullheading in production lines may be done during commissioning, after shutdowns or for decommissioning.

12.2 Flushing with diesel, dead oil or a mixture of both fluids

Required pumping pressure may vary from zero (no flow or initially gas-filled subsea lines) up to maximum pressure requirements. For service pump flowrate and pressure ranges, see GTD.

12.3 WAG well bullheading

This operation is the design case for the service pump maximum pressure. For an early life scenario, with high reservoir pressures, bullheading in WAG wells at the maximum discharge pressure of the service pump may be necessary.

12.4 Flowline Service Operation Readiness Requirements

In order to minimize hydrate formation risks, immediate readiness is required for some flowline service operations, especially after shutdowns (refer to item 7). The readiness requirements in Table 1 should be taken into account when defining well piping arrangement.

Table 1 – Readiness requirements for flowline service operations

Position	Function	Bull heading / Equalization	Flushing	Pigging	Leak test
P1 to P8 / PWAG1 to PWAG5	Production	Readiness required	Planned operation	Planned operation	Planned operation
P1 to P8 / PWAG1 to PWAG5	Gas Lift	Readiness required	Readiness required	Planned operation	Planned operation
WAG1A/B to WAG5A/B / PWAG1 to PWAG5	Water Injection	Readiness required	Planned operation	Planned operation	Planned operation
WAG1A/B to WAG5A/B / PWAG1 to PWAG5	Gas Injection	Planned operation	Planned operation	Planned operation	Planned operation

For reference sake, Production / Gas Lift functions, immediate readiness is required for flushing from Gas Lift riser to Production riser, but not required for flushing from Production riser to Gas Lift riser. This immediate readiness also requires the FPSO to allow simultaneous fluid (e.g., Diesel, crude oil or mixture of both) injection at a minimum of 2 service line risers at a time, with the respective flowrate measurement of injected fluid in each riser, as per GTD. 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 carry out a risk assessment and provide a human reliability study to detail the proposed operation for providing a simultaneous fluid (e.g., Diesel, crude oil or mixture of both) injection from the well service system at a minimum of 2 service line risers.

13 REFERENCES

I-ET-3010.2K-1200-941-P4X-001: GENERAL TECHNICAL DESCRIPTION - BOT

I-ET-3000.00-1210-010-1DO-001: FLUIDS FOR SPECIAL OPERATIONS

I-ET-3D10.12-1350-274-PX9-001: RISER SYSTEM REQUIREMENTS – BÚZIOS 12

I-ET-3010.00-1200-200-P4X-012: TECHNICAL SPECIFICATION FOR HARD PIPE FOR BOT CONTRACTS