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	JOB:		
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			ESUP/PIES

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INDEX OF REVISIONS

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1 OBJECTIVE

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

2 GLOSSARY

Bullheading: Fluids injection in the direction of the well

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

EHU: Electro-Hydraulic Umbilical

Flushing: Displacement of subsea fluids

FPSO: Floating Production Storage and Offloading Vessel

GTD: General Technical Description (see References)

ID: Inner Diameter

Inert fluid: diesel and/or stabilized oil

MEG: Monoethylene Glycol

ROV: Remotely Operated Vehicle

SDV: Shut-Down Valve (installed downstream top of riser)

Soaking: Displacement of the inventory of subsea fluids with solvents (e.g. diesel)

THI: Thermodynamic Inhibitor

WAG: Water Alternating Gas

3 INTRODUCTION

3.1 FPSO Capabilities

For information about FPSO capabilities see General Technical Description.

Some operations described in this document may require external resources such as ROV support (with proper tools), volume estimation of injected fluids (inert fluid, water, and hydrate inhibitor), record of pressure and temperature conditions and valves status, as well foam and instrumented pigs. ROV support will be provided by Petrobras as required for the subsea operations.

3.2 Subsea system description

3.2.1 Production System

The production wells will be tied-back to the FPSO through two subsea lines, a production line (8” ID) and a service line (4” ID). Service line purpose includes replacing produced fluid by an inert one, pushing fluid into the well (bullheading), pigging, depressurization (by one or two sided, depending on the case), soaking (including injection of hot diesel through production line), removing liquids from subsea system (service gas) and also gas lift (when applicable). Figure 1 shows a sketch of the use of production and service lines for these operations.

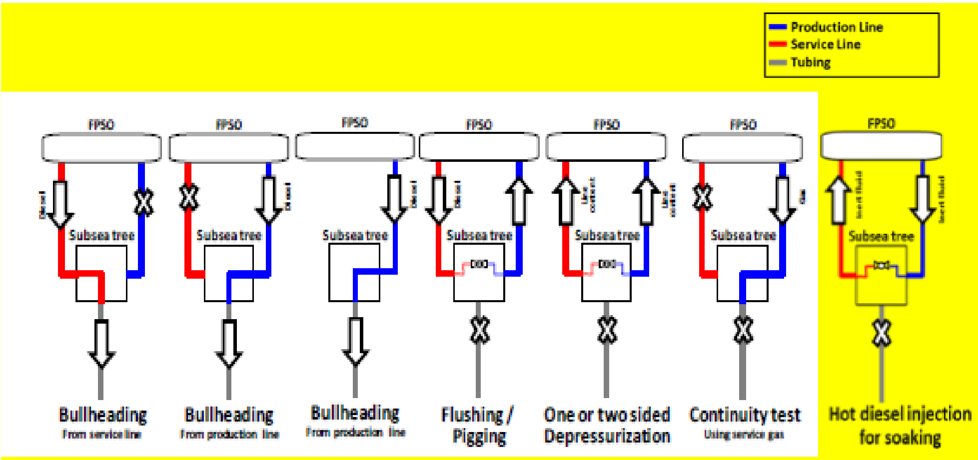

Figure 1: Subsea scheme for typical production conditions

3.2.2 Injection System

The WAG injection wells can be tied-back to the production unit through one or two lines (6”ID). Every injection slot on the FPSO shall inject water and gas (but not simultaneously in the same slot). The base case is the injection wells being tied-back to the FPSO in pairs (one injection line per well), connecting a jumper between them to allow fluid circulation through this loop. This system leads to three different operational conditions depending on the tie-back configuration at the moment of fluid injection:

- Alternative 1: One line tie-back for gas and water injection (temporary condition before the connection of second well)

- Alternative 2: One line tie-back for gas and water injection, using a circulation jumper to connect two injection wells (base case)

- Alternative 3: Two lines tie-back, one for water and gas injection and another as a service line (alternative case for one well considering an odd quantity of injection wells)

The following figures describe the expected operations for each alternative.

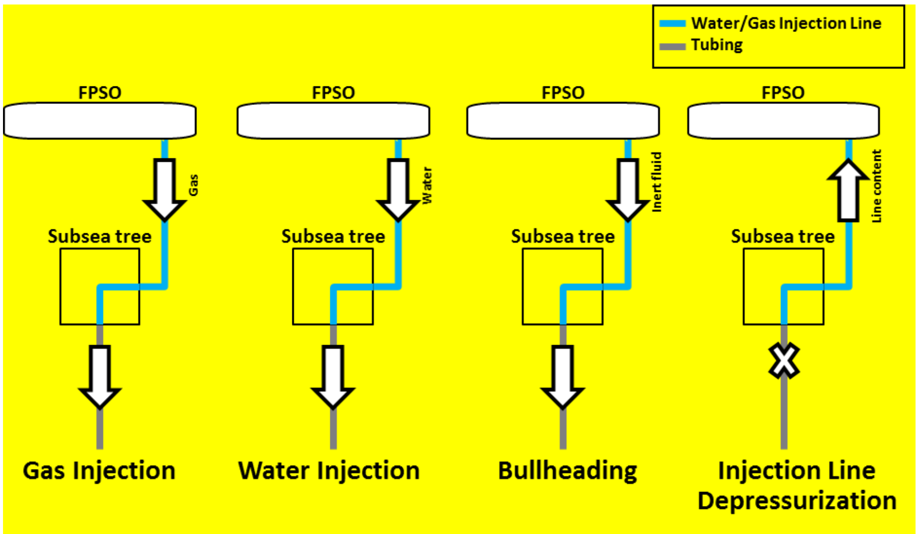

Figure 2: Subsea scheme for typical injection conditions (Alternative 1)

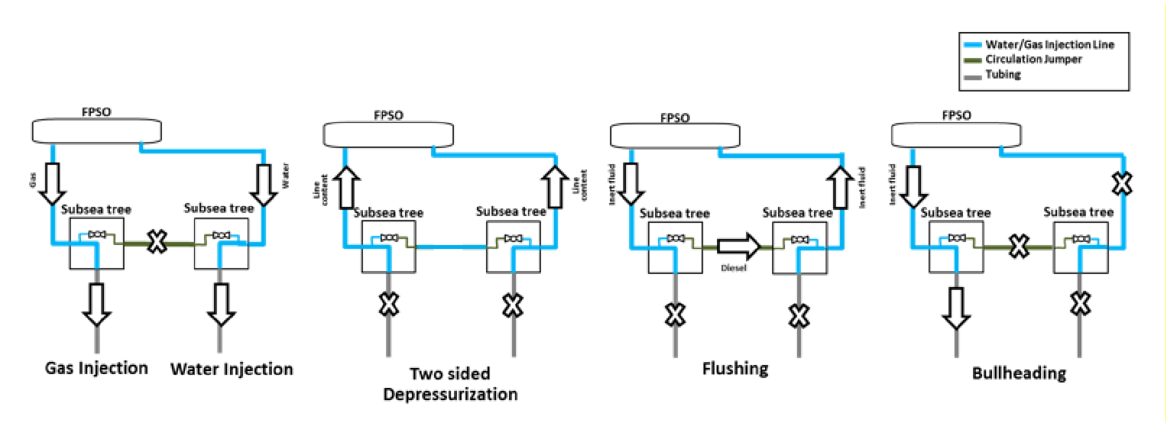

Figure 3: Subsea scheme for typical injection conditions (Alternative 2)

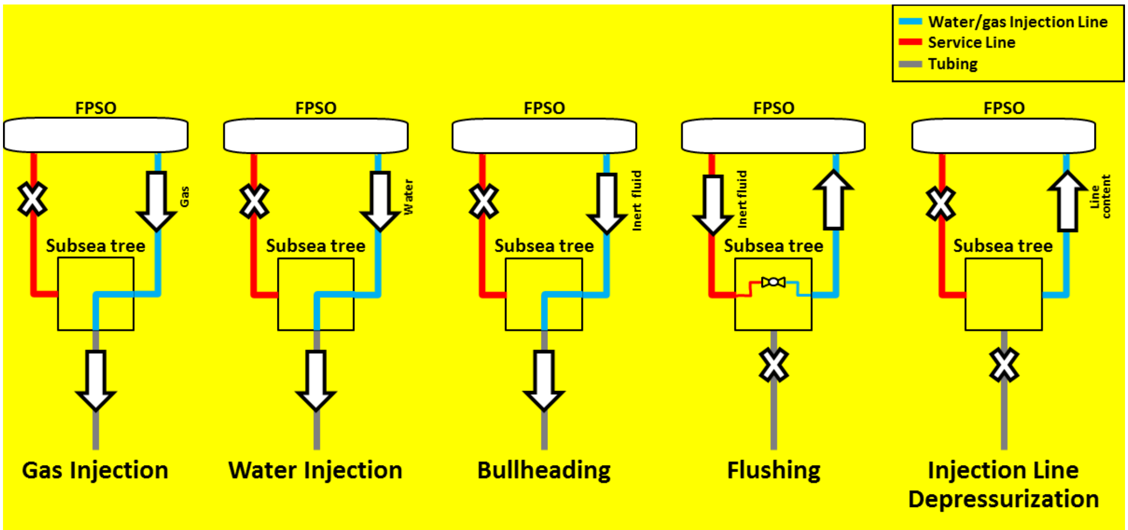

Figure 4: Subsea scheme for typical injection conditions (Alternative 3)

3.2.3 General Features

Special operations for flow assurance purposes (such as wax, hydrate, scale or asphaltene remediation) are possible from every FPSO slot (production, service, water/gas injection), using service boats through connections to the FPSO, in order to inject the required fluid. Depending on the issue, the fluid can be an acid, a solvent or have any other property to solve the problem, off course respecting all material specification for FPSO, risers and flowlines. During these operations, the selected fluids will be pumped from the service boat to the FPSO, to a connection located at the discharge of the well service pumps. For information about types of fluids that can be used for the special operations, see the document Fluids for Special Operations (I-ET-3000.00-1210-010-P8J-001).

Inert fluid volume for flushing operations in production and WAG injection loops depends on subsea layout, yet to be confirmed, and operating conditions. Estimated volume range for these operations is between 100 and 400 m³ per loop. These volumes can be significantly larger for commissioning operations, up to 1400 m³ of inert fluid. Each cleaning operation, for decommissioning, requires an important amount of sea water that can surpass 2000 m³ per loop.

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

The Figure 5 shows the subsea tree schematic view for both production and WAG injection wells. It is important to note that valves provide communication between production and service lines (or injection lines – Alternative 2 and 3). This communication is used in various operations, such as flushing and pigging. Please refer to FPSO GTD for further information about subsea control systems.

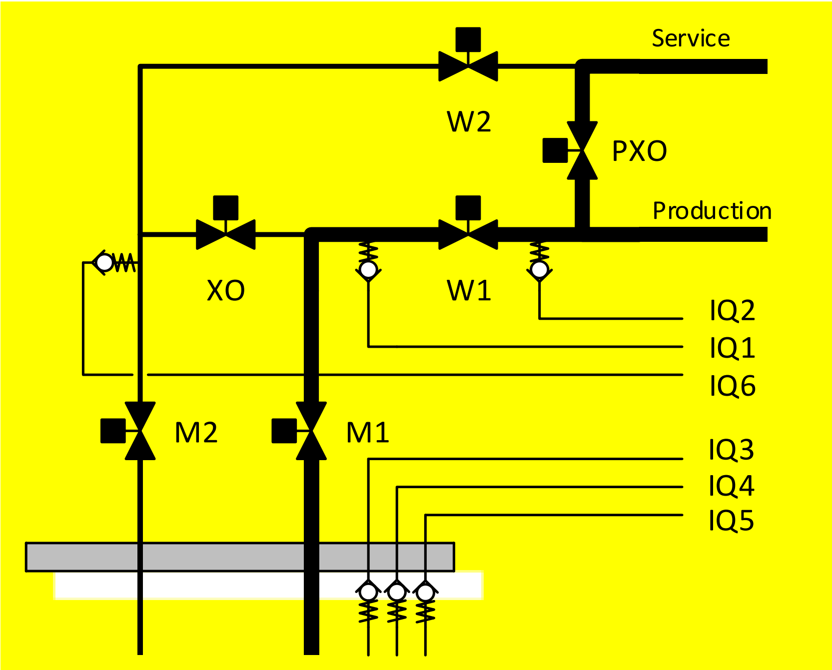

Figure 5: Subsea tree schematic view

4 SUBSEA COMMISSIONING

The subsea commissioning activities include hydrostatic test of rigid lines, leak tests of production, service and injection lines; umbilical leak test and content replacement for chemical injection; dewatering of production, service and injection lines; subsea tree leak and functional tests; hydrate prevention procedure; DHSV equalization and opening.

4.1 Hydrostatic Test of Rigid Lines

The hydrostatic test should be realized just after the installation of the subsea rigid lines, the objective of this test is to guarantee the integrity of the rigid pipelines. Each line PLET should be installed with a test cape sealing the PLET Hub. The installation vessel should realize the hydrostatic test with 1.5x the rigid line design pressure, the test should be realized according to DNVGL-ST-F101.

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

The first step is to verify the subsea valves status (at subsea tree) with ROV support. It is also necessary to verify the functionality of service pump, the leak test pump and the hydrate inhibitor injection pumps (high flow rate), make sure that the water fraction of the inert fluid and hydrate inhibitor to be used in operations is as close to zero as possible and subsea control and signals acquisition system are 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 for several hours with the system isolated. At any moment, if the pressure drops more than the acceptable (typically around 1% of the starting pressure), the system needs to be pressurized again and the tests restarted from the stabilization period. After test acceptance, the system is depressurized with care not to exceed the maximum depressurization rate for lines (see GTD).

4.3 Subsea chemical lines commissioning

For the leak test of chemical injection lines, the procedure is similar to the one described above, but employing hydrate inhibitor injection pumps. After test acceptance, the system is depressurized and flushed with MEG to eliminate any residual water present in injection system. For further information about subsea chemicals, see GTD.

4.4 Dewatering of Subsea Lines

For dewatering of the production loop, 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. The dewatering of the production loop is done using foam pigs displaced by inert fluid (free of water) through the production loop. During this flushing, the operation of subsea tree valves is required. The monitoring of water cut of returning fluids collected at the pig receiver is needed and the operation shall last until the amount of water falls to low values, typically below 2% or after flowing three times the total system volume at least.

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

The dewatering procedure for Alternatives 2 or 3 is similar to the one described for production loop. The inert fluid is circulated from one water/gas injection line to the other water/gas injection line through the circulation jumper or subsea tree, respectively. This procedure may be carried out with foam pigs. Returning fluids may be collected from the test separator.

4.5 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 during this operation.

4.6 DHSV Equalization and Opening

DHSV valve requires equalization of downstream and upstream pressures before opening. For this operation, hydrate inhibitor, service pumps and leak-test pump may be used, injecting through EHU hoses, production or service lines (see Figure 6). Pressures at the subsea systems and flow rates must be monitored during this operation.

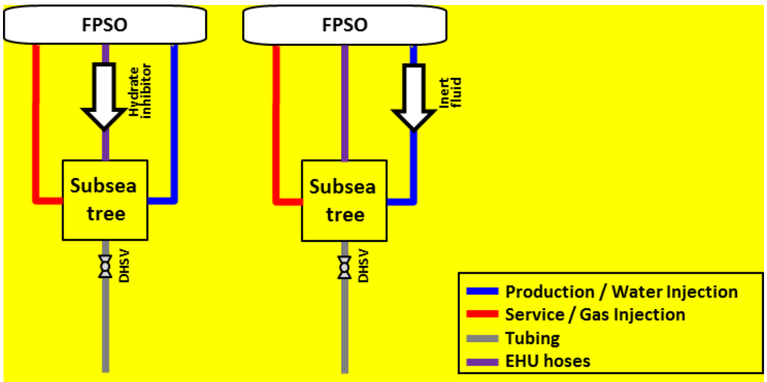

Figure 6: Usual subsea schemes for DHSV equalization

5 START-UP

5.1 Production Start-up

Before the first start-up, all production and injection equipments shall have been fully commissioned and tested.

After checking that subsea tree valves and production SDV are working properly, the production choke valve can be opened following Petrobras Operational Procedures. If the well does not flow naturally, Lift gas or Nitrogen (in this case using a Nitrogen Generation Unit to be placed by Petrobras on topsides) may be used in this condition, allowing a soft start-up of the topside facilities and protecting downhole equipments. The FPSO shall be prepared to receive completion fluids from the production well. Please see annex 12 for more information about completion fluids.

After shutdown, when the water content increases, the fluid inventory of the production pipeline shall be displaced by diesel before the well reopenning. It may be necessary to equalize the pressure between the subsea valves before its opening. Diesel or MEG injection may be considered.

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. If the injection line is filled with inert fluid, 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 similar to described in dewatering section above.

6 CONTINUOUS OPERATION

During continuous operation, chemicals may be continuously injected through umbilicals. The chemical injection system has flexibility to allow the alignment of each injection pump through more than one umbilical. A cleanliness level of NAS 6 is required for chemicals to allow the functionality of the chemical injection system.

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.

Pigging may be frequently required for deposits removal. The pig is launched through the service line down to the subsea tree and there it passes to the production line by the pig crossover valve – that has to be open. The pig can be pushed to the tree by dead oil, diesel or gas. In any case, the flowrate must be controlled for the pig do not exceed velocity limit of 3 m/s. After passing by the tree the crossover valve can be closed and pig flows back to platform with production stream.

Gas injection is paramount for the project, since all produced gas (except for consumption) must be re-injected in the reservoir. In other words, gas injection restrictions can lead to production losses.

Injection wells' pressures shall be monitored to avoid surpassing limits to be specified by PETROBRAS, regarding to reservoir fracture pressure or subsea system specification.

Slugs of non-reactive chemical tracers will need to be added into the individual injection wells in the gas or water phase approximately once every 1-3 years. The injected volumes may be up to 5000 Sm^3 of gas or 10 Sm^3 of water mixed with tracer. The injection would be done during continuous operation of the wells and can be scheduled during injection ramp up or during plateau injection phase. Water and gas chemical injection hand pumps/compressors rated at appropriate pressure would be needed as well as appropriate connections on flowlines to the injectors. 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 into well.

7 SHUT-DOWN

Flow Assurance related operations after planned or unplanned shut-downs 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. Therefore, the procedures definition will be done by the engineers in charge of flow assurance monitoring during pre-operation and operation phases. For production system, these possibilities are covered, in general, in the following sections based on the service line condition before shut-downs.

Some of these operations may not be necessary to be performed just after the well shut-in. During some shut-downs, 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 well shut-in, in order to minimize the risks of hydrate formation along the subsea equipment.

Subsea chemical injection availability, especially hydrate inhibitor, is required for all described conditions. Please refer to section 3.2 for estimates in inert fluid volume to beemployed.

7.1 Production Well

With the exception of situations in which there is no need of any operation after the well shut-in, the well depressurization must start in four hours from the shut-in moment and all the wells shall be near atmospheric pressure at the end of the operation, respecting the maximum depressurization rate in order to keep the flowing temperatures inside the designed range for flexibles. The wells can remain in this condition as long it is needed.

In case of planned shutdowns or that unplanned which takes longer than the designed, prior to restart the hydrocarbon production, fluids inside the flowlines must be replaced by an inert fluid, such as diesel or dead oil. To help prevent hydrate it is recommended to inject THI (MEG or ethanol) into subsea tree and the nearest 100 m of flowline. The same applies to any other subsea equipment that has connection to an inhibitor hose or umbilical.

7.1.1 Gas filled service line – depressurized

In this condition, many operations can be performed: production line depressurization, inert fluid flushing (with or without pigs), inert fluid bullheading, soaking, production line and service line communication (provide for subsea tree valves), topsides hydrate inhibitor injection (in direction to risers). When not being used for these operations, the service line must be maintained at 30 bar. If necessary due to line manufacturing issues, this line may be kept at pressures as low as 1 atm.

7.1.2 Gas filled service line – pressurized

This condition represents the use of lift gas for artificial lift and leads 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 (up to 10 m³) may flow from the subsea tree through the service line to the topsides. A connection between service lines at topsides is required to handle this liquid flowrate. These operations are not expected to be frequent and will last for the duration of the depressurization of the service lines. Flushing of topside piping may be performed after these operations to avoid corrosion.

7.1.3 Inert fluid filled service line

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

7.2 Injection Well

The injection fluid exchange (either water to gas or vice versa) must be done with care because if they get in contact with each other it is almost certain that will form hydrate.

So, after stopping the injection, the system must be depressurized. The following step is flood the subsea tree with MEG. After that, an inert fluid, preferably diesel, is circulated to replace water or gas, not only in the riser and flowline, but also in the well by means of bullheading.

7.2.1 Gas being injected

In this condition, gas is being injected through water/gas injection line. Following the shut-down, nothing needs to be done, except in case of injected gas out of specification (wet gas), when the flowline depressurization is mandatory. Other operations may be necessary such as inert fluid flushing (possible for Alternatives 2 and 3), inert fluid bullheading and/or hydrate inhibitor injection.

7.2.2 Water being injected

In this condition, water is being injected through water/gas injection line. Following the shut-down, it is paramount avoid any gas entering the system, including backflow from reservoir. Some operations may be necessary such as inert fluid flushing (possible for Alternatives 2 and 3), inert fluid bullheading and/or hydrate inhibitor injection.

8 SUBSEA LINES DECOMMISSIONING

Sea water needs to be circulated along all the systems in order to clean the lines before pull-out (see fluid inventory in section 3.2 for estimates in water volumes). The following sections describe briefly the decommissioning steps.

8.1 Production System

After production interruption, perform subsea system depressurization. Circulate inert fluid through the production loop (subsea tree valves). Circulate water through production loop until required cleanliness is obtained. Pigs can be launched during these operations.

8.2 Injection System

8.2.1 Alternative 1

After injection interruption, perform subsea system depressurization. If water is the injection fluid, no further operation is required. For gas injection, fill injection line with inert fluid removing gas from the line. Bullhead inert fluid and seawater (required volumes to be defined). Batch and/or continuous injection of hydrate inhibitor at subsea tree may be required during this operation.

8.2.2 Alternatives 2 and 3

Perform subsea system depressurization after injection interruption. Flushing operations using inert fluid 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 tree may be required. Pigs can be launched during these operations.

9 SPECIAL OPERATIONS

In addition to the usual operations described above, it is also possible to employ special purpose boats alongside of the FPSO to perform so-called special operations. For instance, Figure 7 shows a schematic view of a typical squeeze operation using xylene. Please refer to FPSO GTD and I-ET-3000.00-1210-010-P8J-001 for further information about fluids expected to be employed in similar configurations.

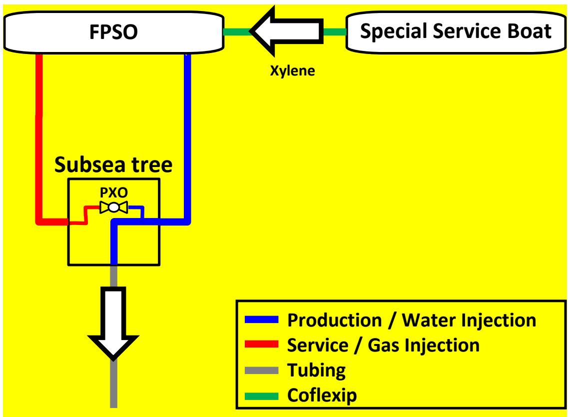

Figure 7: Typical scheme for Special Operations

It is noteworthy that these fluids injected will then be produced as well is restarted.

10 HISEP™ GENERAL OPERATION MODES

In the Project there may be a subsea separator system named HISEP™. This equipment is connected to three wells, being one injector and two producers. After HISEP™ installation, these wells will be connected to HISEP™ and lines from HISEP™ will be connected to the FPSO. In this document it is shown the general operation modes. More detailed information about how it will be operated will later be provided in a separated document.

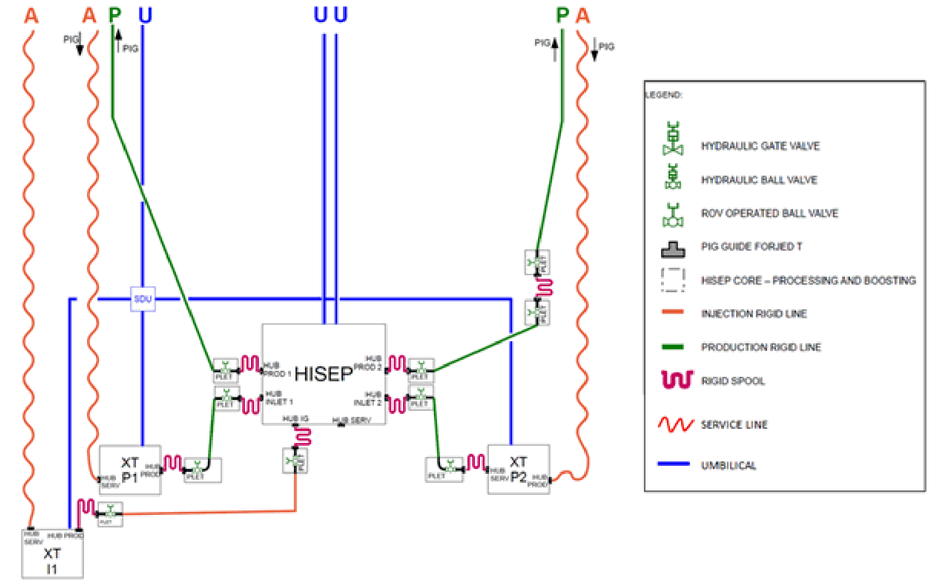

Figure 8: HISEP™ and its connections to FPSO

Concerning HISEP™, lines connected to the FPSO are the following:

1. HISEP™ - FPSO: two production lines;

   two umbilicals;

2. X-tree1 - FPSO: one service line for producer P1;
3. X-tree2 - FPSO: one service line for producer P2;
4. X-tree3 - FPSO: one service line for injector IG.

Note: umbilical linked to SDU is not considered part of HISEP™ connections. This umbilical will be installed regardless HISEP™ installation.

Each producer well will produce through HISEP™. We can distinguish the following scenarios:

1. Two wells producing through HISEP™:

   a. separation of flow from two wells being performed in HISEP™

      - only one production line from HISEP™ to FPSO being used for the separated liquid fraction;

- ➢ production line is aligned to the 2nd separation stage of the oil processing plant.

b. separation of flow from one well being performed in HISEP™; the other well being produced without separation in HISEP™, via bypass

- ➢ one production line from HISEP™ to FPSO being used for the separated liquid fraction; the other production line from HISEP™ to FPSO being used for non-separated stream (as a normal production well);
- ➢ separated stream is aligned to the 2nd separation stage of the oil processing plant;
- ➢ non-separated stream is aligned to the 1st separation stage of the oil processing plant or the test separator.

c. without separation in HISEP™, each well producing through one production line from HISEP™ to FPSO, via bypasses

- ➢ both production lines from HISEP™ to FPSO being used for the non-separated liquid fraction (as normal production wells);
- ➢ both non-separated stream is aligned to the 1st separation stage of the oil processing plant or the test separator (the both streams may not be aligned to test separator at the same time).

d. without separation in HISEP™, both wells producing through only one production line from HISEP™ to FPSO

- ➢ production line is aligned to the 1st separation stage of the oil processing plant.

2. One well producing through HISEP™:

a. separation being performed in HISEP™

- only one production line from HISEP™ to FPSO being used for the separated liquid fraction;
- separated stream is aligned to the 2nd separation stage of the oil processing plant.

b. without separation in HISEP™

- only one production line from HISEP™ to FPSO being used for the non-separated stream (as a normal production well);
- non-separated stream is aligned to the 1st separation stage of the oil processing plant or the test separator.

When one of the production lines is not being used with production purpose, it will normally be kept filled with diesel.

For bi-lateral depressurizing purposes, the service line between FPSO and X-tree is depressurized and the line connecting the X-tree to HISEP™ is aligned to one of the production lines between HISEP™ and FPSO, which will also be depressurized. This is true for injector or producers.

Therefore, production lines between HISEP™ and FPSO and service lines may be exposed to pressures as high as the subsea HISEP™ pump's shut-off pressure. In this case, the resulting pressure at FPSO of these lines is expected to be higher than the shut-in pressure of a normal producer satellite well.

Pigging may be performed in producing and injection lines. The path followed by the PIG is the following:

1. Service line connected to one X-tree;
2. PIG cross-over;
3. HISEP™;
4. Production line between HISEP™ and FPSO.

11 REFERENCES

I-ET-XXXX.XX-1200-941-P4X-001: GENERAL TECHNICAL DESCRIPTION

I-ET-3000.00-1210-010-P8J-001: Fluids for special operations

12 ANNEX

12.1 Completion fluids

12.1.1 BRINES:

Type I: Brine weight: 9.8 ppg, with the following composition:

- Sodium Chloride: 26.3% mass;
- Surfactant: 0.4% volume - ethylene oxide condensates and quaternary ammoniumsalts;
- Oxygen Scavenger: 200 ppm - Sodium Bisulfite or Sodium Erythorbate;
- Biocide; 200 ppm – Glutaraldehyde.

Type II (eventually): Calcium chloride brine may be needed, with a maximum weight of 11ppg, with the following composition:

- Calcium Chloride: 34% mass;
- Surfactant: 0.4% volume - ethylene oxide condensates and quaternaryammonium salts;
- Oxygen Scavenger: 200 ppm - Sodium Bisulfite or Sodium Erythorbate;
- Biocide; 200 ppm – Glutaraldehyde.

12.1.2 SPENT ACID:

Spent Acid: (from 200 to 1500 bbl), with the following composition:

- Calcium Chloride at 15% mass concentration @ pH from 5 to 6;
- Surfactant: 0.4% - ethylene oxide condensates and quaternary ammonium salts.