

BAY DU NORD

Engineering reference atlas

Public design reconstruction | June 2026 concept

Research library prepared 22 September 2026

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Read the evidence correctly

Published tags, counts and functions do not establish exact equipment geometry. Rendered representations are not dimensioned fabrication drawings.

Keep separate

The proposed coordinate table and schematic connection lengths do not fully reconcile. Concept options, future tiebacks and foundation alternatives must remain explicitly labelled.

Build boundary

Suitable for a source-linked public-design reconstruction. Not an as-built digital twin, hydraulic simulator, mooring analysis or installation model.

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Proposed locations of the FPSO and subsea templates, along with their approximate water depths, are detailed in Table 1.2 [5] and illustrated in Figure 1.1. These locations are subject to change during the FEED and detailed design phases.

Table 1.2 Proposed FPSO and Template Locations, and Approximate Water Depths

Infrastructure	Water Depth (approximate)	Longitude	Latitude
Proposed location - FPSO	1,161 m	46° 31' 29.99" W	47° 55' 48.76" N
Proposed location - Bay du Nord North template	1,168 m	46° 26' 12.52" W	47° 57' 03.66" N
Proposed location - Bay du Nord South template	1,170 m	46° 26' 12.07" W	47° 56' 12.65" N
Proposed location - Cambriol template	621 m	46° 58' 49.73" W	47° 51' 04.81" N
Datum: NAD83 (CSRS)			

1.1.4 Project Proponents

The Project proponents have varying participating interests in the six SDLs as identified in Table 1.3. A licence unitization for the Bay du Nord and Cambriol fields will be in place prior to the Final Investment Decision (FID).

Table 1.3 Overview of Licences

Field	Licence	Ownership
Bay du Nord	SDL 1055	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)
Cambriol	SDL 1060	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)
Deferred Development - Cappahayden	SDL 1059	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)
Deferred Development - Harpoon	SDL 1058	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)
Deferred Development - Baccalieu	SDL 1056 and SDL 1057	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)

1.1.5 Project Need and Justification

The Project will be a major contributor to the economic development of NL as the province's fifth major offshore oilfield development project. The Project is set to deliver lasting value to NL's offshore industry, generating sustained opportunities in subsea fabrication, supply chain development, skilled labour, and long-term operations and maintenance. With a projected multi-billion-dollar spend, the Project will inject substantial capital into the province, stimulate Gross Domestic Product (GDP) growth, and generate long-term employment across sectors. The Project will activate local supply chains—from fabrication and marine services to technology and logistics—creating sustained business activity and confidence. For the business community, the Project represents not just opportunity, but economic momentum that can be felt province-wide. The SEIS [6] and Benefits Plan [7] outline the Project's contribution to a sustainable economic development within NL.

Given the known resources and the extensive remaining prospectivity as described herein (Section 1.2 Subsurface), over the life of the Project Equinor anticipates the development of one of the largest subsea infrastructure projects in its history. This activity represents opportunities to develop a local centre of excellence in subsea construction and installation and long-term economic activity for both onshore and marine industries. During the operational phase, there will be employment opportunities in areas such as logistics, engineering and technical support, drilling and production, and marine transportation and support services (e.g., helicopters, supply vessels, shuttle tankers, etc.). Opportunities during the construction and operational phases will continue to develop the capabilities of NL companies and individuals working on the Project and thereby contribute to the provincial ambition for a globally competitive offshore industry.

Table 11.15 Overview of Current Design Basis

Concept Item	Details (subject to change during FEED and detailed design phases)
Estimated Recoverable Reserves	Approximately 429 MBO
Distance from Shore	Approximately 475 km (FPSO)
Water Depth	Bay du Nord - 1,168 m Cambriol - 621 m
Production Life	20 years
Drainage Strategy	Bay du Nord – Water-Alternating-Gas (WAG), template-based and riser base gas lift Cambriol – WI, riser base gas lift
Drilling and Well	Well count total – 16 (production, WI, WAG) ² Standard well type concepts
Subsea Umbilicals, Risers, and Flowlines (SURF)	Number of templates: 3 x 6-slot Number of risers: 8 flexible risers, 2 dynamic umbilicals, 1 power cable, 4 spare slots in turret Flowlines: Production, WI, and Gas Injection (GI) Number of static umbilicals: 3 Subsea cooler: 1 Subsea Power Distribution Unit (SPDU): 1 Subsea Distribution Units (SDU): 2 Riser bases: 2
Main Facilities Concept	FPSO: Ship-shaped Accommodation: Up to 120 person capacity Turret: Disconnectable Offtake to shuttle tankers Oil capacity: 160 kbbbl/sd design plateau production Target oil capacity (debottlenecked): 175 kbbbl/sd ³ Gas handling capacity: 5.0 MSm ³ /sd Liquid capacity: 40,000 Sm ³ /sd ³ Water injection capacity: 40,000 Sm ³ /sd ³
Operations	Equinor is accountable for overall field operations, including SURF and Drilling & Well. FPSO contractor is responsible for FPSO operations and maintenance.

Well fluids information from the reservoir is described in Section 6.2.2 Fluid Properties and Fluid Models.

Table 11.16 summarizes the sales specification for oil.

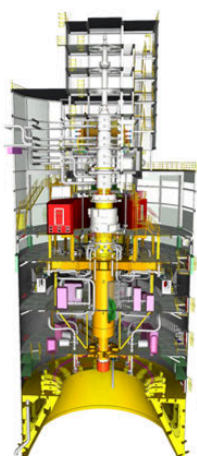
As Project design progresses, the flow rates and capacities will be further optimized. In addition, during the operational phase, an optimization/debottlenecking process will be in place to capture potential incremental capacity gain during the asset life.

Table 11.16 Sales Specification for Oil

Parameter	Oil
C ₄ -	Max. C ₄ - content of 2.5 wt% in the stabilized crude, with an operational flexibility to increase this to 4.5 wt% within given Reid Vapour Pressure (RVP) limitations during the production phase
True Vapour Pressure (TVP) (bubble point pressure)	< 1.0 bara @ 40°C
RVP	RVP as defined and measured according to ASTM-D323 latest revision shall be less than 0.54 bara at 100° F (37.8°C) RVP requirement refers a storage temperature of maximum 40°C and an AP-42 TVP of 0.75 bara
Minimum oil storage/offloading temperature	20°C
Basic Sediments and Water (BS&W)	Max. 0.5 vol%, no stable emulsions
Salt	Max. 200 mg/l
Oxygenates (Monoethylene Glycol [MEG], Triethylene Glycol [TEG])	Max. 10 ppm wt

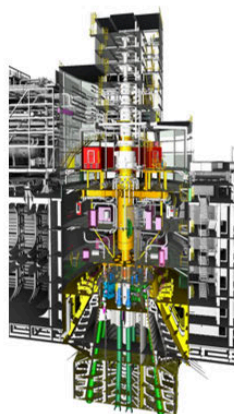
There will be 15 slots in the turret. All production lines and umbilicals will be routed through the centre turret structure of the STP system. Fluid, utilities, and power/signals will be connected and distributed on the geostationary platform decks above the top of the STP disconnectable buoy. A turret local equipment room will house control and power system cabinets on an upper geostationary deck. The turret local equipment room will have a protected overpressure ventilation system and fire/blast ratings in accordance with the fire and explosion risk analysis. Figure 12.1 provides an overview of the STP system.

STP shipboard system



Swivel system module
Geostationary module
STP compartment module (integrated in hull)
Mating cone module (integrated in hull)

STP system – cross section



STP subsea system

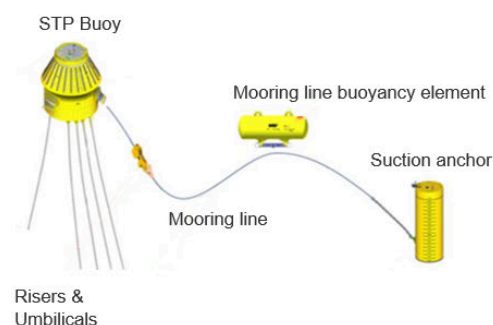


Figure 12.1 Submerged Turret Production System Overview

Mooring lines, risers, umbilicals, and power cables are connected to the STP disconnectable buoy. The STP disconnectable buoy will be locked to the FPSO by locking mechanisms which can be released simultaneously in case of disconnection, or individually during inspection testing.

12.1.2.3 Mooring System

The mooring system will provide position keeping within specified allowable offsets. The mooring system is designed according to Class rules.

The mooring system will comprise of 15 mooring lines configured in three clusters, where each cluster consists of five mooring lines. Each mooring line will consist of a lower chain segment towards the suction anchor, followed by a long polyester rope, a mooring line buoyancy element, and two polyester rope segments towards the STP buoy. These are divided by chain segments with a mooring line re-tensioner in between to adjust mooring line lengths. The mooring system will be equipped with a mooring line monitoring system.

12.1.2.4 Fluid, Power, and Signals Transfer System

The fluid transfer system provides transfer of fluids between risers/umbilicals and the topsides systems. This includes transfer of production fluids from wells, as well as injection water, injection gas and hydraulics and chemicals to subsea. Power and signals will be transferred via dedicated swivels and distributed in the turret local equipment room towards internal turret consumers and subsea. The fluid transfer system will consist of three main areas – the shipstationary piping, the swivel stack and the geostationary piping arrangement (including connectors). The geostationary piping arrangement will be connected to the top of the buoy and provide fluid transfer from the risers to the swivel section, and will include valve and pigging arrangements. The swivel stack will consist of several modules dedicated for each service.

12.1.2.5 Disconnection and Reconnection System

The disconnection system is designed to safely disconnect the FPSO from the STP disconnectable buoy. It supports both planned and emergency disconnection and can be operated fully automatically.

The disconnection and reconnection system consists of several sub-systems, including pull-in system, connectors and control system. The pull-in system will be used for the initial hookup of the STP buoy to the FPSO and for

The SPS comprises of the following:

- Two 6-slot template structures for the Bay du Nord Field;
- One 6-slot template structure for the Cambriol Field;
- Umbilical system with Subsea Distribution Unit (SDU) for the Bay du Nord Field;
- Umbilical system with SDU for the Cambriol Field;
- Passive subsea cooler for production fluid at the Cambriol Field;
- Power cable for Electrically Heat-Traced Flowline (EHTF) production flowlines for the Cambriol Field; and
- Flowline and riser system for production, gas injection, gas lift, water injection, and riser/template-based gas lift.

The Project fields are connected to the FPSO through rigid and flexible flowlines, and a flexible riser system, with diverless tie-ins to riser bases and manifolds installed in the templates. The proposed Project SPS layout is as illustrated in Figure 12.7.

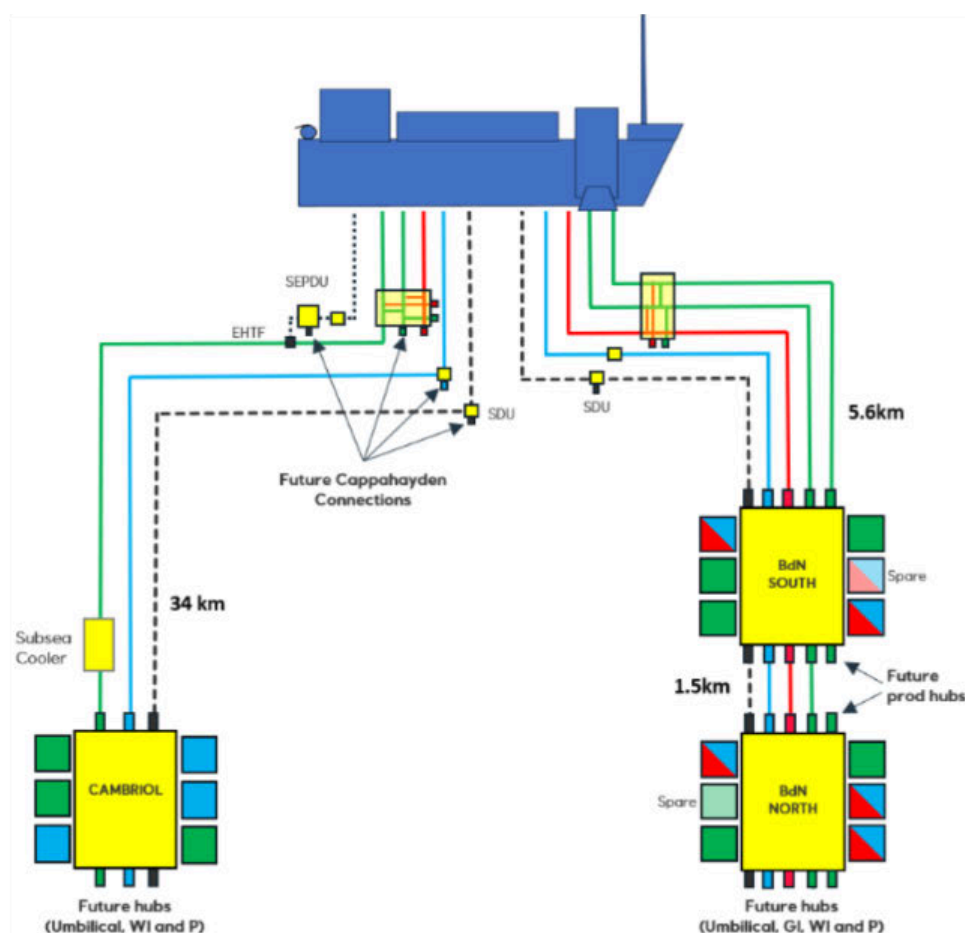


Figure 12.7 Proposed Subsea Production System Layout

The SPS will be designed to minimize the need for adhoc maintenance and repair. Thus, fault tolerance, robustness and regularity analysis will support the design with regards to redundancy. The SPS design allows for suitable Inspection, Maintenance and Repair (IMR).

The SPS design allows for simultaneous drilling and production with respect to barrier philosophy. Interface between template and the wellhead will take into consideration the expected drilling loads.

The SPS structures are designed with consideration of the anticipated installation loads as well as for the in-place operation and upset conditions.

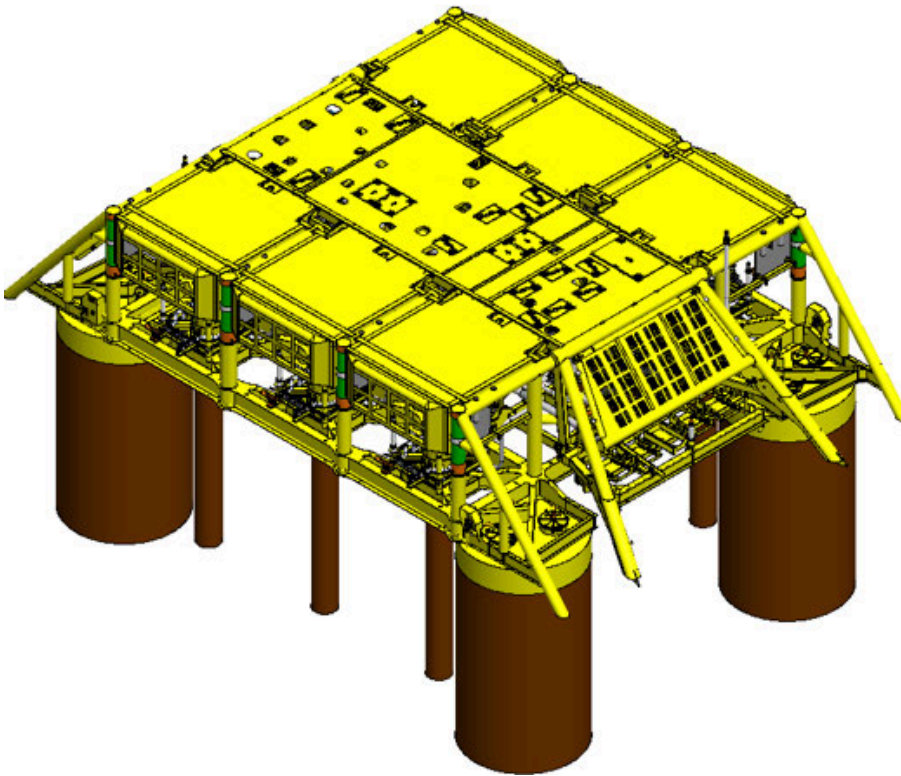


Figure 12.8 Template Structure Representation

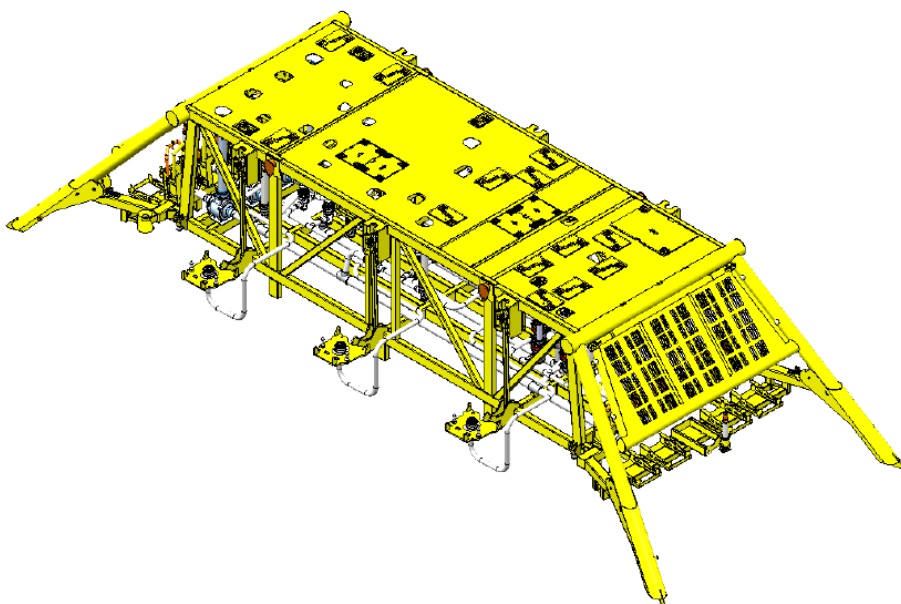


Figure 12.9 Manifold Structure Representation

12.2.3 Wellhead System

The subsea wellhead system will be a standard 15,000 psi (1,035 bar) working pressure wellhead system based on standard configuration utilized in Equinor.

The wellhead system will be designed to accommodate the expected wellbore temperatures, pressures, loads and service conditions that it may be exposed to over its lifetime. The design will take into account optimization for enhanced wellhead fatigue performance.

The wellhead system (Figure 12.10) will include a conductor housing, wellhead housing, casing hangers and packoff seal assemblies.

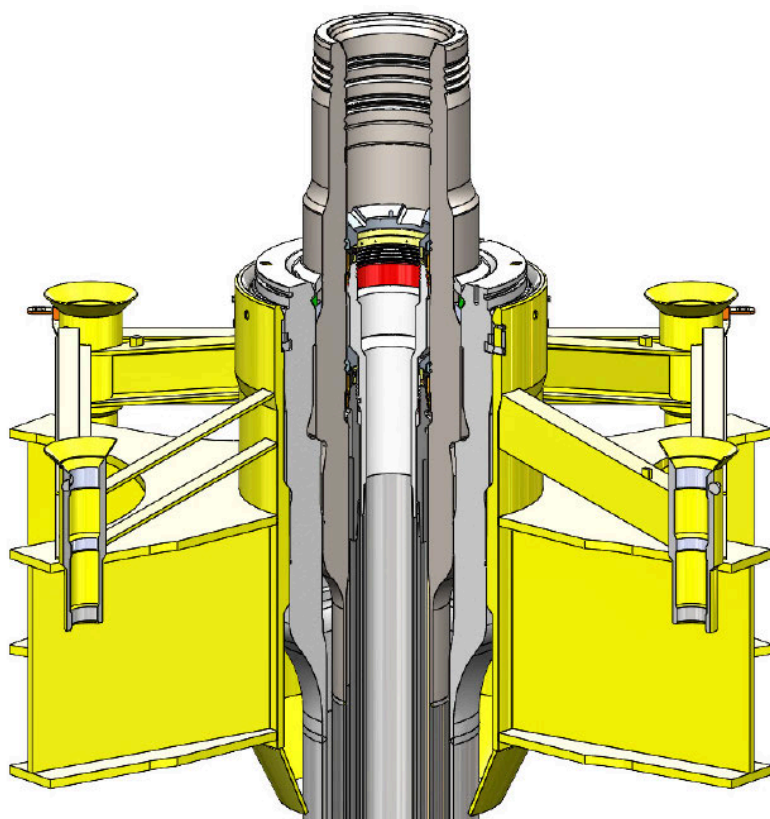


Figure 12.10 Typical Wellhead System

The conductor housing will interface with the planned conductor system to form the basic foundation for the well. It interfaces the template structure and provides a landing profile for the wellhead housing. It is designed to accommodate loads transferred from the wellhead housing for the entire life of field which includes drilling, production and workover modes.

The wellhead housing lands and locks inside the conductor housing. The wellhead housing will interface with the planned surface casing. The wellhead housing provides a landing, locking, and sealing preparations for the subsequently run casing hangers and tubing hanger. The wellhead housing includes a mandrel interface at the top for connection of the BOP or VXT, as applicable. The interface is designed with due consideration to wellhead fatigue performance.

The wellhead system is configured to accommodate two casing hangers which will interface with the associated casing strings. Each casing hanger will be locked in place by a packoff and will provide a seal toward the relevant annulus.

12.2.4 XT System

The VXT solution will be based on the Equinor standard electric-hydraulic 7" (VXT) (Figure 12.11) with modifications as required for the Project's water depths and relevant operating temperatures. Project specific elements, including configuration (injector/producer), will be located inside the retrievable/interchangeable Flow Control Module (FCM). The VXT system will be designed to accommodate the expected temperatures, pressures, loads and service conditions that it may be exposed to over its lifetime.

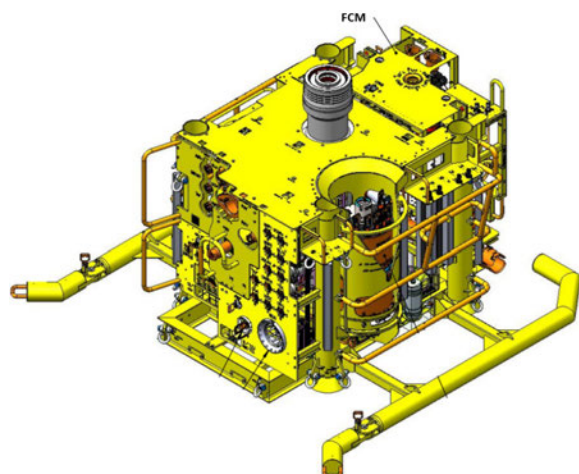


Figure 12.11 7" VXT with Retrievable FCM

The VXT features both remote operated and manual valves, isolating, and directing flow to and from the wellbore. It has a hydraulic connector to the manifold and a hydraulic connector to the wellhead. The VXT system includes a retrievable FCM which connects to the VXT through a multi-bore hub and clamp connector.

The following configurations are expected to be utilized for the development:

- Production;
- Water injection; and
- WAG injection

There will be chemical injection points both in the VXT and in the FCM. Pressure and temperature sensors will monitor tubing pressure and annulus pressure.

The FCM will typically contain components such as a flow-meter, a production or injection choke, pressure and temperature transducers, Chemical Injection Throttle Valves (CITV) and an acoustic sand detector.

Control of VXT system is achieved by means of a Subsea Control Module (SCM) and associated controls equipment. Metered chemical injection is provided into the production / injection flow and regulated by means of a retrievable CITV.

Downhole temperature and pressure monitoring will be facilitated through a retrievable downhole interface unit mounted on the VXT.

ROV access for all VXT valves is available via the panel located on the front of the VXT.

The VXT top connection (tree re-entry hub) provide a means for re-entering the well with well intervention equipment. It consists of an industry-standard mandrel, similar to the wellhead housing, and connects to the XT cap or well intervention well control equipment, as required.

The XT cap interfaces and locks to the tree re-entry hub. It provides a secondary pressure containing barrier to the production and annulus bores of the VXT. The Tubing Hanger (TH) is installed in the wellhead and interfaces with the VXT via a series of hydraulic and electrical stabs. The TH interfaces with both the production and annulus bore of the VXT.

The tubing hanger will also include an annulus isolation valve which eliminates need for wireline well intervention operation to set an annulus isolation device during the initial completion operation. The TH will be equipped to supply hydraulic pressure via the completion control lines for operation of downhole valves such as the Surface Controlled Subsurface Safety Valve (SCSSV). The TH includes a profile for a wireline installable plug in the production bore. It also includes a connection at the bottom to interface with the completion tubing.

12.2.5 Riser Base System

The riser base system includes two units, one for the Bay du Nord Field and one for the Cambriol Field, both located within the anticipated safety zones, eliminating the need for trawl protection. The riser bases serve as connection hubs for dynamic risers, flowlines, and utilities.

Each riser base is designed with flexible foundation options, including mudmat and suction anchor solutions, depending on installation requirements. They are equipped with production and gas lift headers, allowing for flushing via a crossover line. Subsea leak detection capabilities will also be integrated (see Section 12.2.11 Subsea Leak Detection).

Key functionality of the rise base system:

- Dual production headers with crossover capability;
- Gas injection header and distribution to both production headers; and
- Provisions for future production and/or gas injection tie-ins.

The riser bases are presented in Figure 12.12.

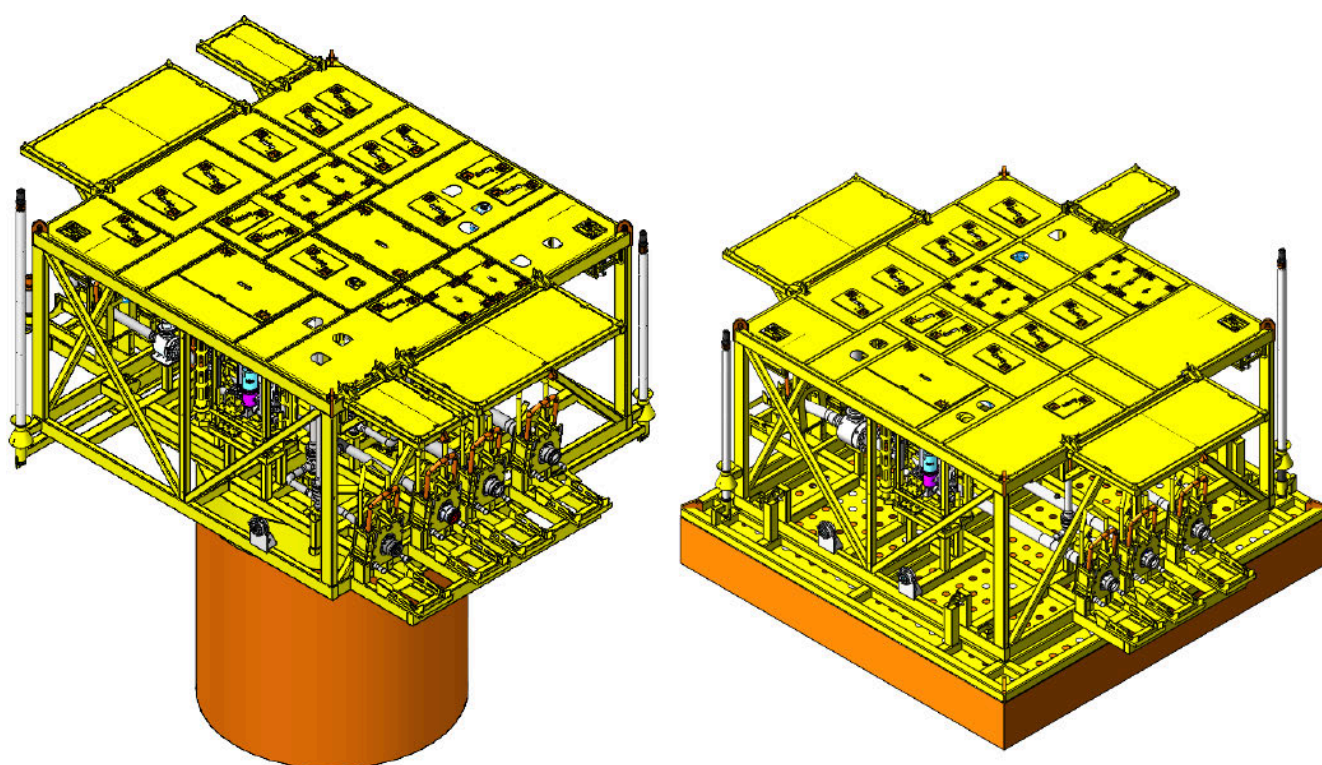


Figure 12.12 Riser Bases with Foundations

12.2.6 Subsea Cooling

Subsea cooling will be necessary for the Cambriol well fluids. A passive subsea process cooler will be installed downstream of the Cambriol template, to ensure that the temperature will be within the design limitations before entering the production flowline, riser, and turret systems.

The cooling station features two cooler modules placed in series. They are within a protective structure that includes a foundation supported by four suction anchors. Cold seawater in external contact with the cooler piping passively cools production fluids directly from the wells, eliminating the need for upstream separation or treatment. The cooler modules are retrievable for maintenance and include passive cooling capacity, instrumentation, valves, a hot-stab connection for interventions, and a control system. Small bore piping and valves allow for the injection of MEG to inhibit and displace the cooler modules. The cooling station also has a main bypass line and valve, allowing production to bypass the cooler modules when cooling is unnecessary and can help facilitate operations such as well clean-up or flowline pigging.

Figure 12.13 and presents the preliminary subsea cooler for the Cambriol Field.

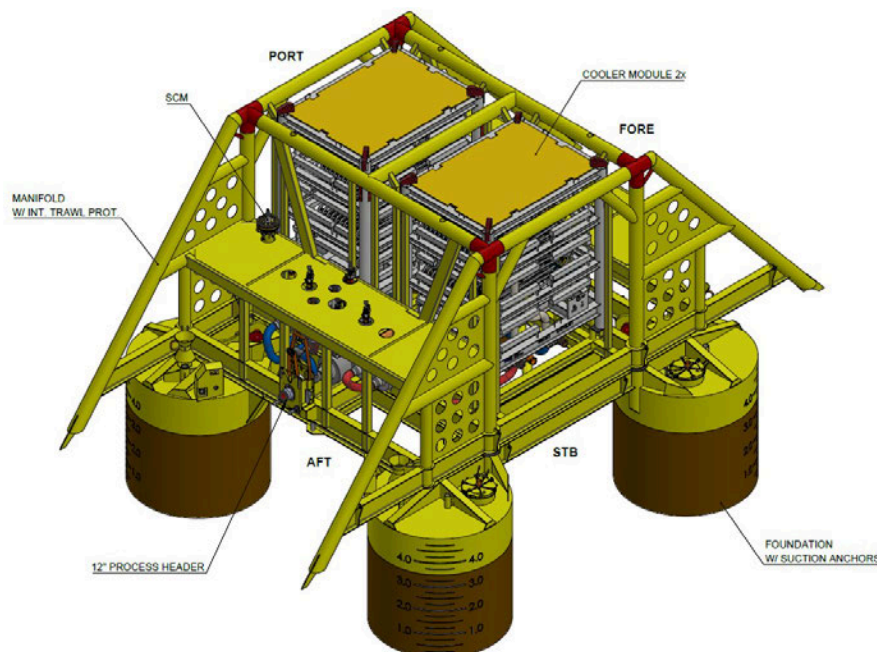


Figure 12.13 Subsea Cooler Station

12.2.7 Subsea Production Control System

The subsea production control system is based on a proven electro-hydraulic design, utilizing actuators for manifold and riser base valves in an open-loop configuration. Hydraulic fluid used in the open-loop system will be screened for use and will be reflected in the Project's Environmental Protection Plan (EPP).

The system is designed to support up to 36 wells and interfaces with the FPSO via a standardized Subsea Control Unit (SCU). Topsides control and monitoring are managed through hard-wired signals and serial communication.

Power and communication are supplied from topsides equipment and distributed via dynamic and static umbilicals. These are routed through Umbilical Termination Heads (UTHs) and connected to manifolds and riser bases using electrical and optical flying leads. Distribution continues locally or is capped for future use.

Hydraulic fluids and chemicals are delivered from the topsides Hydraulic Power Unit (HPU) through the umbilical system to the subsea infrastructure. Manifolds distribute these fluids to valves and instrumentation, and include pass-through lines for future expansion via multibore hubs.

Key topsides equipment includes:

- Electrical Power Unit (EPU);
- Subsea Gateway (SG);
- Third Party Server Unit (TPSU);
- Remote Operator Station (ROS);

- Communication Distribution Unit (CDU);
- SCU; and
- HPU.

Two Downhole Interface Units (DIUs) are also provided to all subsea VXTs for communication with downhole instrumentation.

The control system interfaces with various subsea sensors and electrically actuated valves, including gas-lift valves, chokes, isolation valves, chemical injection valves, and pressure sensors.

A layout of the control system is shown in Figure 12.14.

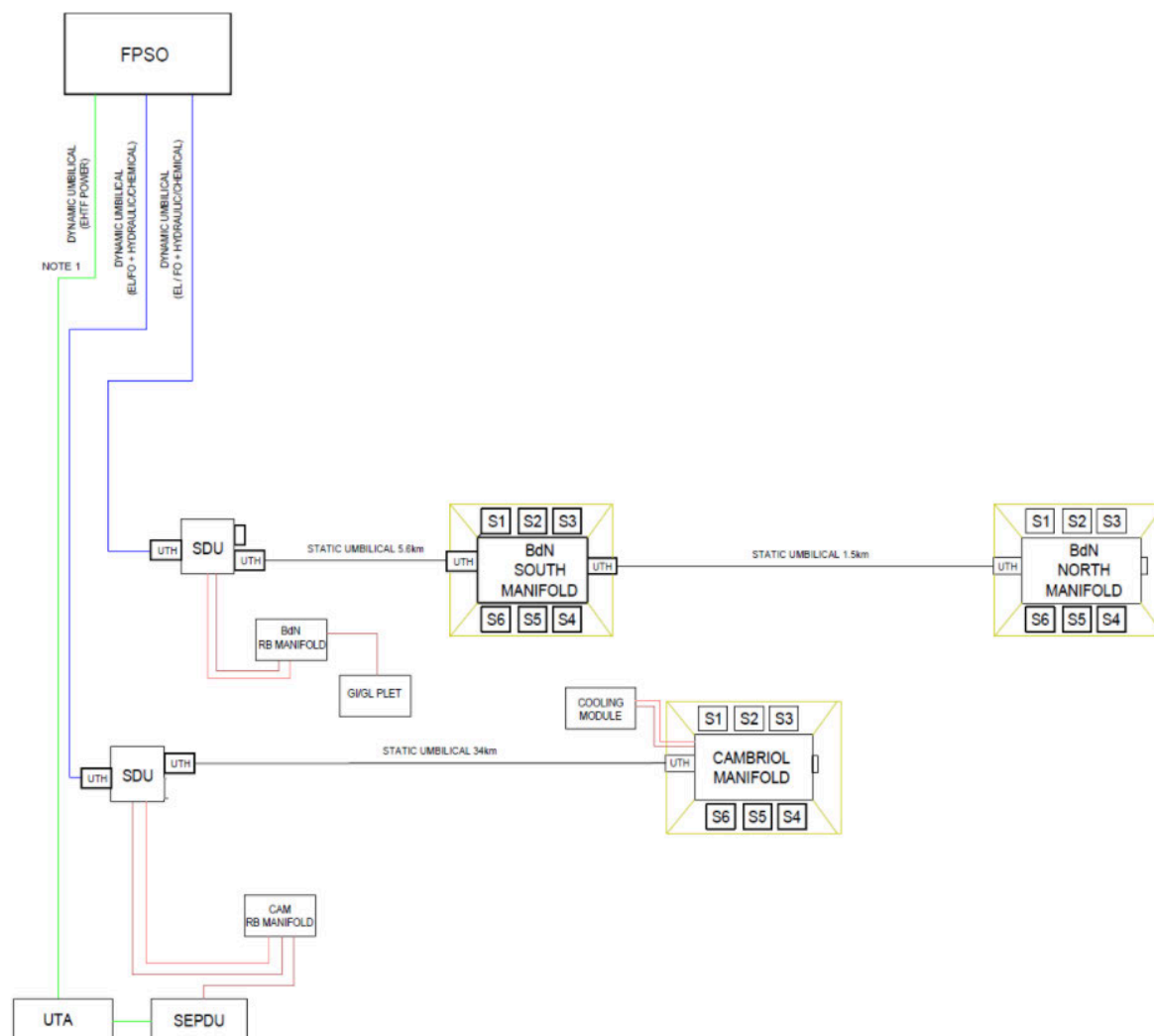


Figure 12.14 Control System Top Assembly

12.2.8 Power and Umbilical System

The base case umbilical system includes:

- Two dynamic umbilicals connecting the FPSO to the riser bases for control and chemical supply;
- Three static umbilicals connecting the riser bases to subsea templates, carrying chemicals, hydraulics, power, and communications; and
- A dynamic power cable from the FPSO to the power Umbilical Termination Assembly (UTA), with further connections to the Subsea Equipment and Production Distribution Unit (SEPDU) and EHTF flowline via electrical flying leads.

At the topsides, the dynamic riser umbilicals will be terminated with a pull-in head consisting of segmented elements to contain the end termination arrangements for electrical power, fibre optic, and hydraulic/chemical fluid lines within the umbilical.

For the Cambriol Field, the SEPDU manages power distribution, monitoring, and control of subsea equipment. It includes a subsea transformer to adapt transmission voltage for EHTF operations and a Subsea Switch Module (SSM) for control and monitoring.

12.2.9 Riser System

Eight risers are currently planned to be applied in the Project; all sizes are preliminary and will be further assessed during FEED:

- Two medium pressure production risers to Bay du Nord;
- One medium pressure gas injection/gas lift riser to Bay du Nord;
- One medium pressure water injection riser to Bay du Nord;
- Two high pressure production risers to Cambriol;
- One high pressure gas injection/gas lift riser to Cambriol; and
- One high pressure water injection riser to Cambriol.

The flexible riser concept has been developed for high pressure, deepwater, and harsh environment condition of the Project. A preliminary configuration for the flexible riser system for the Project is shown in Figure 12.15. The flexible risers will utilize tethered wave configuration with sag and hog of the riser positioned at higher elevation in order to reduce the tension at the turret. The hog and sag elevations have been checked for disconnection depth of the turret buoy.

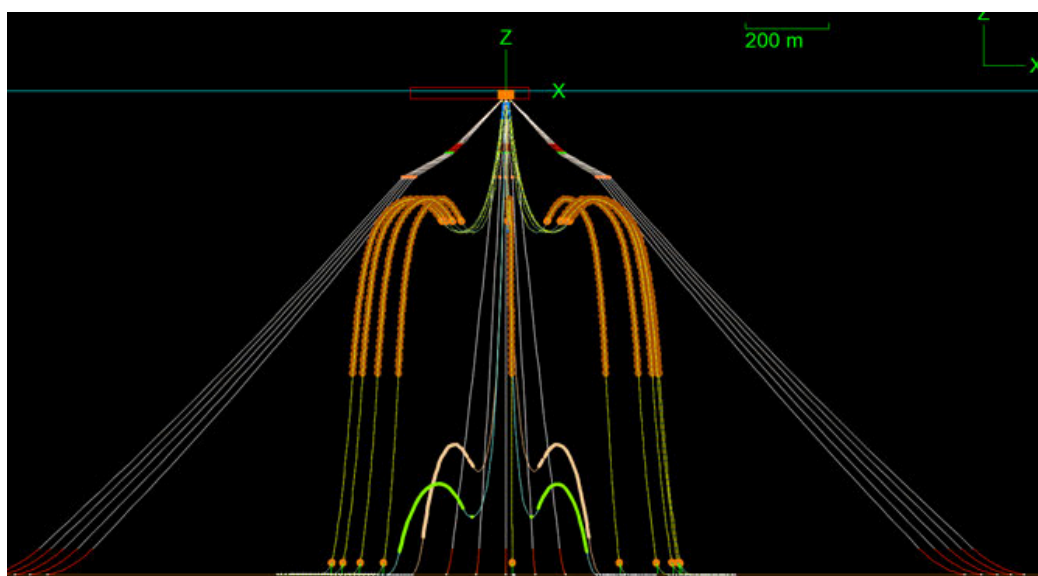


Figure 12.15 Flexible Riser System - General Configuration

The initial cross section of the flexible risers (Figure 12.16) has been defined in order to ensure sufficient fatigue life throughout the field lifetime. Each flexible riser will be made up of multiple sections, and each section will be connected using mid-line connections.



Figure 12.16 Flexible Riser System - Initial Cross Section

The risers will be connected to the FPSO/turret through guide tubes with a bend stiffener connector connected at the lower part of the guide tube. Typical bend stiffener is shown in Figure 12.17.



Figure 12.17 Flexible Riser System - Bend Stiffener

Distributed buoyancy modules (Figure 12.18) are installed to achieve the desired tethered wave configuration. The modules consist of two main components, namely the clamp and the buoyancy elements. The purpose of the clamp is to axially secure the buoyancy element to the riser and will be designed to ensure that axial capacity is maintained throughout the design life of the system. The buoyancy elements will be designed as two half-shells installed over the internal clamp and will be secured in place using an external strapping system.

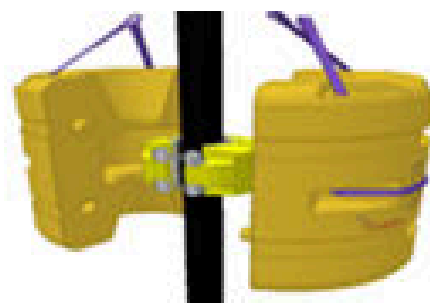


Figure 12.18 Buoyancy Module

The riser and mooring system have been designed to maintain full integrity in both the connected condition, where the buoy is connected to the FPSO, and in the disconnected condition, where the buoy reaches an equilibrium position at a lower water depth. The design also considers all intermediate phases, including buoy disconnection

The Bay du Nord Project comprises development of the Bay du Nord and Cambriol fields. A number of exploration wells have been drilled. Together with multiple seismic surveys this provides a comprehensive dataset over the project area. The current development concept for the fields has approximately 420 MMbbl of light oil produced through 16 subsea wells (8 producers and 8 injectors) to an FPSO shipshape vessel, with offtake to shuttle tankers.

2.2. Facility Development

The Base Case development scenario is a shipshape FPSO with tandem offloading and a disconnectable buoy system with flexible risers and a combination of rigid and flexible flowlines. The design life of the facilities and wells is such that they facilitate 20 years of production. The design life of different elements are to be detailed further in the next phase based on cost benefit considerations towards production profile and future prospects.



Figure 2-2 Bay du Nord FPSO

With the current topside nameplate production rate of 160 000 bbls/day, the crude oil storage capacity is dimensioned for the FPSO hull size and is approximately 1.2 million barrels. The turret is located at the forward end of the vessel and the FPSO shall have a (quick) disconnectable buoy system complete with mooring and riser system to allow the FPSO to leave the location typically in low probability safety-related situations, such as iceberg threats over a certain collision energy level or ice thickness over a certain threshold level.

2.2.1. Operations

The Bay du Nord operating environment is harsh and remote; some 475km offshore Newfoundland in the North Atlantic Ocean. The operating challenges in this environment include:

- Distance from shore and 250 km from the closest facility offshore Newfoundland
- Icebergs and pack ice may be present in the operating area in the spring / early summer
- Hurricanes are often experienced during the fall months
- Severe fog in the spring and summer provide logistical challenges with helicopter personnel transport
- Severe and frequent storms occur during the fall and winter months.

- Produced Water management
- Drill cuttings management, and
- Energy consumption and emissions
- Waste management and Pollution Prevention

These environmental aspects are not discussed further in the CSA.

2.4. Hull and Living Quarters

2.4.1. General Concept

The FPSO hull and LQ is designed by the experienced FPSO Contractor BW Offshore.

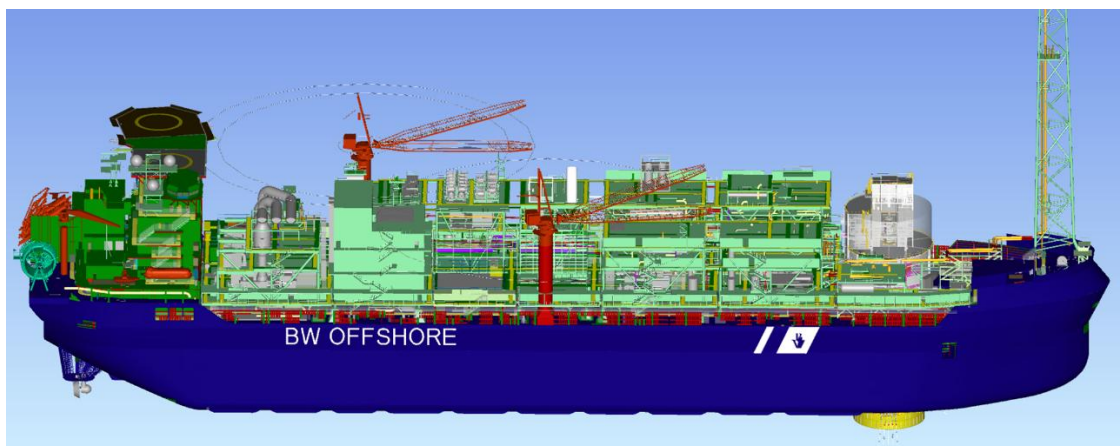


Figure 2-3 View of FPSO (Starboard side)

All the “extraordinary” physical environmental, geographical and metocean features for the location have been considered and have influenced the design of the hull to a large degree:

- Helideck located aft over the port side. This helicopter deck location improves availability of the helicopter deck significantly compared to a forward located helideck. It also improves flight safety compared to forward mounted helicopter decks as wind direction during landing and sight/reference lines are optimal.
- LQ located aft. This improves comfort for crew (reduced accelerations), reduces green sea and slamming issues in the LQ area, reduces collision risk to personnel, improves natural weathervaning and reduces power consumption. It is also easier to achieve aft trim and thus ballast amount may be reduced in fully loaded conditions.
- Turret location is somewhat further forward on the vessel. This improves natural weathervaning capability in some weather combinations, improves layout and improves fabrication installation with regards to structural details around turret.
- Disconnectable unit. This requires that the vessel is equipped to sail as a ship, including navigation bridge, power, propulsion, marine crew, anchor and mooring equipment.
- The hull is ice strengthened to resist sea ice and smaller icebergs up to the established design limits.

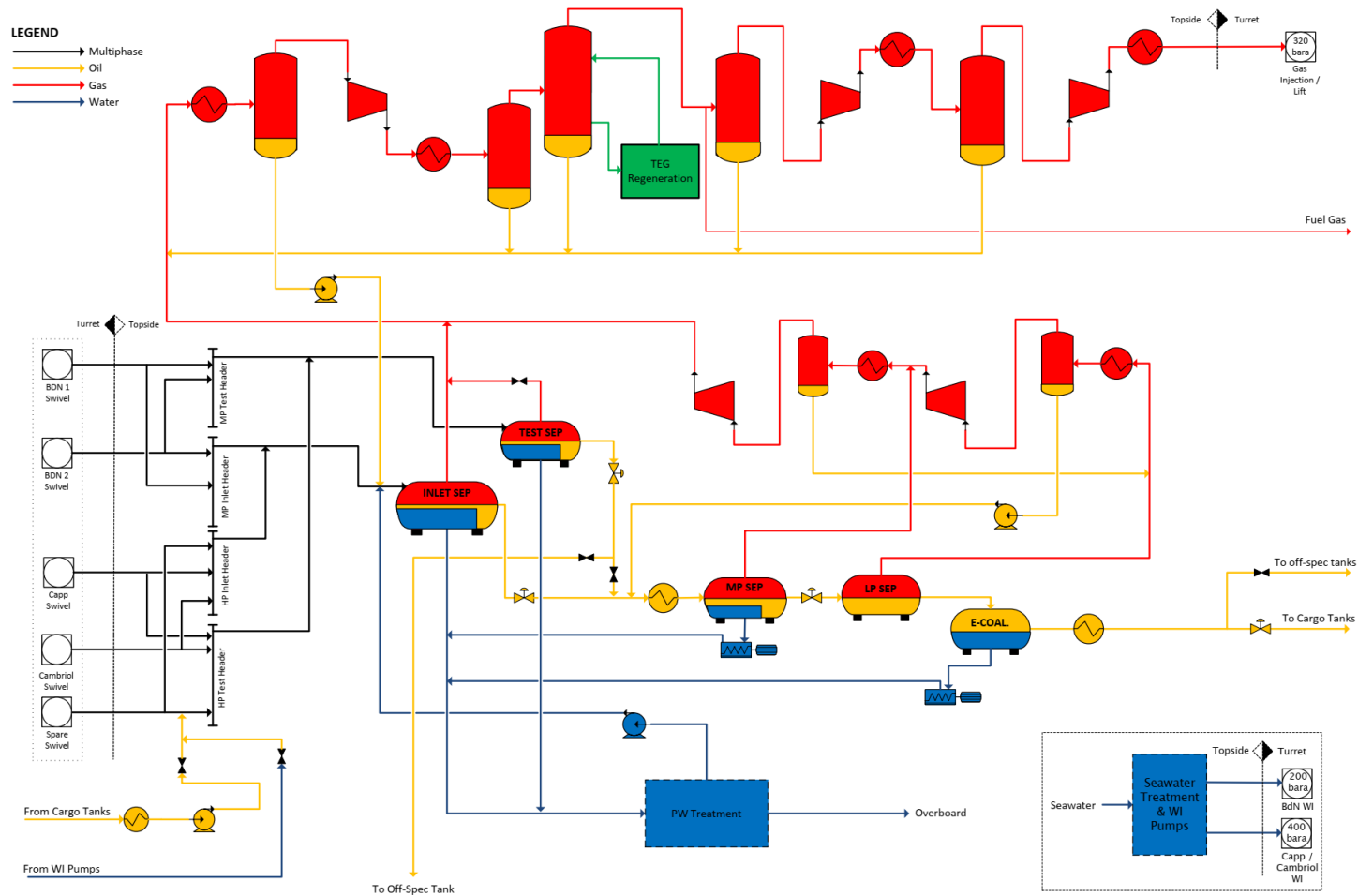


Figure 2-4 Bay du Nord Process Flow Diagram

2.5.2. Technical and Process Safety

2.5.2.1. Layout Arrangement

The FPSO will be arranged with a forward turret which is enclosed and mechanically ventilated up to the process deck but naturally ventilated above that level. The Topsides process and utility decks will be installed on an elevated deck level above the vessel cargo tank deck, with up to three deck levels across the Process & Utility area. Level 1 of the process deck shall be a continuous plated deck to act as a barrier between main deck and topside. The mezzanine and upper decks of topsides are grated except where liquid secondary containment is needed.

The accommodation module is located at the aft of the FPSO along with the offloading hose reel for oil export to the shuttle tanker. The FPSO will weathervane on the turret and thruster assisted heading control will also be provided. The FPSO layout is based around an inherently safe design approach, with higher pressure gas or large un-stabilized oil inventories located at the forward end of the FPSO Topsides, as far as possible from the accommodation.

The helideck is located on the port side, and the current proposed location for W2W gangway landings include suitable locations aft on the port and starboard sides. A protected escape route runs from the forecandle (bow) area to the e-House / Power Gen modules on the starboard side, and from M10 to M41 on the port side. The protected escape route has a roof and wall towards the process area, with door openings to allow for escape from the process areas. The primary purpose of the protected escape route is to shield the escape route against radiation and explosion loads from process incidents. Additionally, shielding the escape route from smoke is another benefit of the protected escape route in small/medium fire scenarios.

Figure 2-5 shows the Bay du Nord layout for the topsides concept being considered.

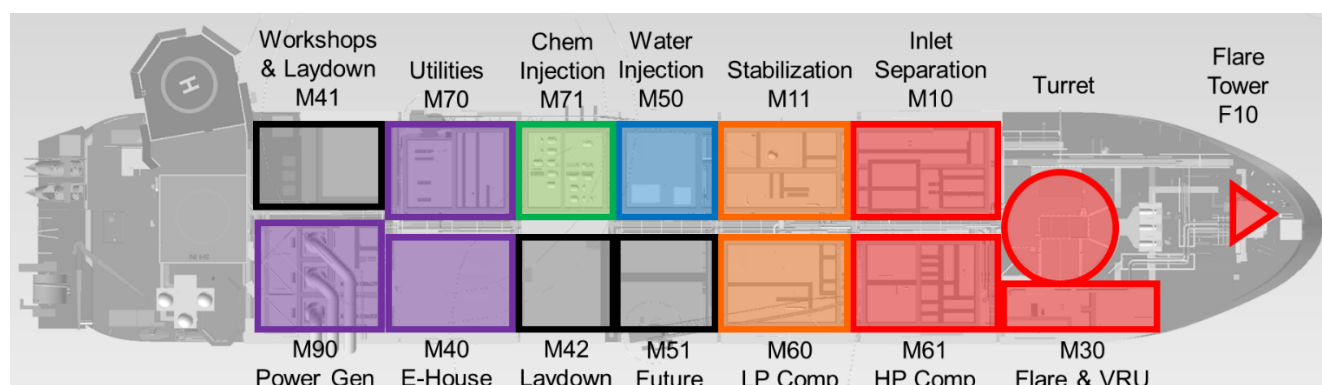


Figure 2-5 Bay du Nord FPSO Layout

The separation system is located port forward on the FPSO in M10 and M11, with the test separator, inlet separator and electrostatic coalescer expected to be on Level 1 (L1) of the Process Deck level and the MP Separator and LP separator expected to be on Level 2 (L2). The Process Deck (L1) is assumed to be plated, with sealed inter-module gaps, and decks L2 and L3 are generally grated, with containment to catch potential liquid releases as required.

The gas compression system is also located towards the forward end of the FPSO, on the Starboard side of M60 and M61. The higher-pressure reinjection compressor package is positioned at the forward end of compression (M61), whereas the lower pressure compressor packages and fuel gas skid are located at the aft end of compression (M60).

2.5.7. Layout and Piping

The overall layout of the FPSO has the offloading and the LQ facilities at the aft end of the vessel with the main laydown areas in front of the LQ (M41) and between the E-House and Water Injection (M42). The turret and the flare tower are located at the forward end of the FPSO. The topside area consists of a utility area, future area, and a process area.

The area allocated to the topside facilities measures approximately 170 x 52 meters.

The process deck (Level 1) is elevated 5.5 meters above the centre line cargo deck and is designed to remain intact in the event of a hydrocarbon fire. The Level 2 process deck is located 10 meters above the process deck, and Level 3 process deck is 6 m above Level 2 on the Port Processing modules and 8 m above Level 2 on the Starboard Processing modules.

The topside has been arranged with a series of modules and pancakes located on either side of a central pipe rack. This arrangement allows for a flexible construction program with the module sizes designed to be comfortably within the lifting capacity of the proposed installation cranes. Larger modules may be arranged to minimize hook-up, if site cranes have sufficient capacity. The main mechanical handling transit route is located at the topside facilities centrally under the pipe rack.

2.5.8. Material Handling

The governing principle for material handling for equipment maintenance of the topside modules is that normal maintenance shall not require the use of the offshore cranes over process modules. Forklift transport along the main transport route is the main means of transporting equipment from modules to workshops or to laydown area for further lifting to shore. Local lifting equipment is provided to remove valves, PSVs or filter cartridges out of the line onto trolleys for transport to goods lift or down to the main transport route.

If major pieces of equipment need to be removed, the offshore cranes will be used, as the process will be shut down and depressurized in such cases. In these circumstances lifting over depressurized process equipment will be allowed.

Containers for galley and laundry will be handled by the offshore crane located at Port side. The material handling between galley laydown area and galley will be carried out by deck trolley.

Similarly tote tanks for chemicals are lifted directly onto tote tank storage above the chemical injection package (level 3).

The turret compartment is provided with hatches providing a vertical lifting corridor. Items will be moved on the relevant decks to this shaft and lifted out of the turret onto the laydown area provided at the port side of the turret on the process deck.

2.6. Subsea Production System

The Subsea Production System (SPS) is defined as the following equipment:

- wellhead
- Xmas tree (XMT)
- flow control module (FCM)
- manifold
- protection structure
- subsea control system
- umbilical containing control and chemical lines

Table 4-1 Bay du Nord Topsides Failure Cases, Masses & Volumes and Operating Conditions

Failure Case Description	Event ID	Physical Properties of Inventory - Mass					Modelling Parameters - Oil		Modelling Parameters - Gas	
		Total Oil Mass in Inventory (kg)	Maximum Oil Mass Released (kg)	Total Free Gas Mass (kg)	Total Flash Gas Mass (kg)	Total Gas Released (kg)	Oil Density (kg/m ³)	Vessel Pressure (barg)	Operating P (Bara)	Operating T (°C)
BdN Production Flowline 1 and 2 (ESV to XSV) - Two Phase Release at Turret Lower Deck	P01-M-TRTL	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at Piperack	P01-M-PRK	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P01-M-M10L1	28,215	29,853	119	3,123	3,242	-	-	15	70
MP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P01-M-TRTU	28,215	29,853	119	3,123	3,242	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at Turret Upper Deck	P02-M-TRTU	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at Piperack	P02-M-PRK	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Inlet and Test Manifolds - Two Phase Release at M10 Process Deck Level 1	P02-M-M10L1	31,381	31,381	125	3,474	3,599	-	-	15	70
HP Spare, Cambriol and Circulation Production Flowline (ESV to XSV) - Two Phase Release at Turret Lower Deck	P02-M-TRTL	31,381	31,381	125	3,474	3,599	-	-	15	70
Test Separator (20-VA-1004) - Two Phase Release at M10 Process Deck Level 1	P03-M-M10L1	53,346	49,427	2,616	4,863	7,479	-	-	15	67
Test Separator (20-VA-1004) - Gas Release at M10 Process Deck Level 1	P03-G-M10L1	53,346	49,427	2,616	4,863	7,479	-	-	15	67
Test Separator (20-VA-1004) - Liquid Release at M10 Process Deck Level 1	P03-L-M10L1	53,346	49,427	2,616	4,863	7,479	788	15	-	-
Inlet Separator (20-VA-1001) - Two Phase Release at M10 Process Deck Level 1	P04-M-M10L1	59,185	55,469	3,064	5,389	8,453	-	-	15	70
Inlet Separator (20-VA-1001) - Gas Release at M10 Process Deck Level 1	P04-G-M10L1	59,185	55,469	3,064	5,389	8,453	-	-	15	67
Inlet Separator (20-VA-1001) - Gas Release at Piperack	P04-G-PRK	59,185	55,469	3,064	5,389	8,453	-	-	15	67
Inlet Separator (20-VA-1001) - Liquid Release at M10 Process Deck Level 1	P04-L-M10L1	59,185	55,469	3,064	5,389	8,453	788	15	-	-
LP Separator (20-VA-1002) - Two Phase Release at M11 Process Deck Level 2	P05-M-M11L2	80,334	77,175	380	3,149	3,529	-	-	2.5	61
LP Separator (20-VA-1002) - Gas Release at M11 Process Deck Level 2	P05-G-M11L2	80,334	77,175	380	3,149	3,529	-	-	1.3	86
LP Separator (20-VA-1002) - Liquid Release at M11 Process Deck Level 2	P05-L-M11L2	80,334	77,175	380	3,149	3,529	792	1.5	-	-
1st Stage LP Compressor Scrubber Pumps (23-PA-6001A/B) - Two Phase Release at M60 Process Deck Level 1	P05-M-M60L1	80,334	77,175	380	3,149	3,529	-	-	1.5	86
Electrostatic Coalescer (20-VI-1003) & Oil Booster Pump (20-PA-1001A/B) & Crude Oil Coolers (20-HB-1002A/B) - Liquid Release at M11 Process Deck Level 1	P06-L-M11L1	198,473	198,473	-	4,933	4,933	792	1.5	-	-
Crude Oil Loading Header - Liquid Release at M11 Process Deck Level 1	P07-L-M11L1	23,199	23,199	-	571	571	840	0	-	-
Crude Oil Loading Header - Liquid Release at Piperack	P07-L-PRK	23,199	23,199	-	571	571	840	0	-	-
Crude Oil Loading Header - Liquid Release on Hull	P07-L-HULL	23,199	23,199	-	571	571	840	0	-	-
Cargo Tank - Liquid Release on Hull	P08-L-HULL	9,284,805	9,284,805	-	-	-	840	0	-	-
Off-Spec Fluid Tank - Liquid Release on Hull	P09-L-HULL	9,285,812	9,285,812	-	25	25	840	0	-	-
Off-Spec Fluid Tank - Liquid Release at Piperack	P09-L-PRK	1,007	1,007	-	25	25	840	0	-	-
Crude Oil Transfer Header - Liquid Release on Hull	P10-L-HULL	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release at Piperack	P10-L-PRK	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release at M10 Process Deck Level 1	P10-L-M10L1	11,528	11,528	-	284	284	840	14	-	-
Crude Oil Offloading Header - Liquid Release on Hull	P11-L-HULL	15,454	15,454	-	380	380	840	14	-	-
Crude Oil Offloading Reel - Liquid Release on Hull	P12-L-HULL	4,194	4,194	-	103	103	840	14	-	-
Crude Oil Offloading Reel - Liquid Release at Offloading Reel	P12-L-OFF	4,194	4,194	-	103	103	840	14	-	-
COT Gas Blanketing - Gas Release on Hull	P13-G-HULL	-	-	13	-	13	-	-	0	78
COT Gas Blanketing - Gas Release at Piperack	P13-G-PRK	-	-	13	-	13	-	-	0	78
COT Gas Blanketing - Gas Release at M30 Process Deck Level 1	P13-G-M30L1	-	-	13	-	13	-	-	0	78
1st Stage LP Gas Compression Suction Cooler (23-HB-6001) - Two Phase Release at M60 Process Deck Level 2	P14-M-M60L2	6,686	6,686	222	-0	222	-	-	0.8	30
1st Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P14-G-M60L1	6,686	6,686	222	-0	222	-	-	0.7	30
1st Stage LP Gas Suction Scrubber (23-VG-6001) - Liquid Release at M60 Process Deck Level 1	P14-L-M60L1	6,686	6,686	222	-0	222	677	0.8	-	-
1st Stage Recompression to Flare KO Drum (43-VD-3001) - Gas Release at Piperack	P14-G-PRK	6,686	6,686	222	-0	222	-	-	5	86
2nd Stage LP Gas Compression Suction Cooler (23-HB-6002) - Two Phase Release at M60 Process Deck Level 2	P15-M-M60L2	3,004	3,004	229	-	229	-	-	4	30
2nd Stage LP Gas Compression - Gas Release at M60 Process Deck Level 1	P15-G-M60L1	3,004	3,004	229	-	229	-	-	6	30
2nd Stage LP Gas Compressor Suction Scrubber (23-VG-6002) - Liquid Release at M60 Process Deck Level 1	P15-L-M60L1	3,004	3,004	229	-	229	593	4	-	-

* Note that the inventory reported for the Cargo Tank and Off-spec fluid tank events (P8-L-HULL and P9-L-HULL) is conservatively assumed to be the entire full inventory of a storage tank

Failure Case Description	Event ID	Physical Properties of Inventory - Mass					Modelling Parameters - Oil		Modelling Parameters - Gas	
		Total Oil Mass in Inventory (kg)	Maximum Oil Mass Released (kg)	Total Free Gas Mass (kg)	Total Flash Gas Mass (kg)	Total Gas Released (kg)	Oil Density (kg/m ³)	Vessel Pressure (barg)	Operating P (Barg)	Operating T (°C)
MP Gas Compression - Gas Release at Piperack	P16-G-PRK	8,139	8,139	1,192	870	2,062	-	-	49	30
MP Gas Compression Suction Cooler (23-HA-6003) - Two Phase Release at M60 Process Deck Level 2	P16-M-M60L2	8,139	8,139	1,192	870	2,062	-	-	13	30
MP Gas Compression - Gas Release at M60 Process Deck Level 1	P16-G-M60L1	8,139	8,139	1,192	870	2,062	-	-	49	30
MP Gas Compression Suction Scrubber (23-VG-6003) - Liquid Release at M60 Process Deck Level 1	P16-L-M60L1	8,139	8,139	1,192	870	2,062	622	13	-	-
Gas Dehydration Inlet Cooler (24-HG-6601) - Two Phase Release at M60 Process Deck Level 2	P17-M-M60L2	3,050	3,050	5,014	-	5,014	-	-	49	35
Gas Dehydration System - Two Phase Release at Piperack	P17-M-PRK	3,050	3,050	5,014	-	5,014	-	-	49	35
Gas Dehydration Inlet Scrubber (24-VG-6601) - Two Phase Release at M61 Process Deck Level 1	P17-M-M61L1	3,050	3,050	5,014	-	5,014	-	-	50	35
Gas Dehydration Inlet Scrubber (24-VG-6001) & TEG Contactor (24-VB-6602) & 1st Stage HP Gas Compressor Suction Scrubber (23-VG-6004) - Gas Release at M61 Process Deck Level 1	P17-G-M61L1	3,050	3,050	5,014	-	5,014	-	-	77	35
Gas Dehydration & 1st Stage HP Gas Compression - Gas Release at Piperack	P17-G-PRK	3,050	3,050	5,014	-	5,014	-	-	77	35
Gas Dehydration Inlet Scrubber (24-VG-6601) - Liquid Release at M61 Process Deck Level 1	P17-L-M61L1	3,050	3,050	5,014	-	5,014	470	49	-	-
1st Stage HP Gas Compressor Discharge Cooler (23-HG-6004) at M61 Process Deck Level 2	P17-G-M61L2	-	-	1,683	-	1,683	-	-	77	35
2nd Stage HP Gas Compressor & Suction Scrubber (23-VG-6005) - Gas Release at M61 Process Deck Level 1	P18-G-M61L1	-	-	5,626	-	5,626	-	-	194	30
1st & 2nd Stage HP Gas Compressor Discharge Coolers (23-HG-6004 & 23-HG-6005) - Gas Release at M61 Process Deck Level 2	P18-G-M61L2	-	-	5,626	-	5,626	-	-	194	30
HP Gas Compression / Injection Pipework - Gas Release at M61 Process Deck Level 2	P19-G-M61L2	-	-	1,683	-	1,683	-	-	319	60
HP Gas Compression / Injection Pipework - Gas Release at Piperack	P19-G-PRK	-	-	1,683	-	1,683	-	-	319	60
HP Gas Compression / Injection Pipework and Flowlines - Gas Release at Turret Upper Deck	P19-G-TRTU	-	-	1,683	-	1,683	-	-	319	60
Gas Injection/Lift 1 BDN & Gas Lift 2 Cambriol/Circulation Flowline (XSV to ESV) - Gas Release at Turret Lower Deck	P19-G-TRTL	-	-	1,683	-	1,683	-	-	319	60
Fuel Gas System - Gas Release	P20-G-M61L1	3,301	3,301	1,511	1,250	2,761	-	-	48	34
Fuel Gas System - Liquid Release	P20-L-M61L1	3,301	3,301	1,511	1,250	2,761	473	48	-	-
Fuel Gas Superheaters, Metering Skid & Filter Package - Gas Release	P20-G-M61L2	3,301	3,301	1,511	1,250	2,761	-	-	48	34
Fuel Gas to Turbines - Gas Release	P21-G-M61L2	-	-	218	-	218	-	-	46	63
Fuel Gas to Turbines - Gas Release	P21-G-PRK	-	-	218	-	218	-	-	46	63
Fuel Gas to Turbines - Gas Release	P21-G-M90L1	-	-	218	-	218	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-M61L2	-	-	49	-	49	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-PRK	-	-	49	-	49	-	-	46	63
LP Fuel Gas to Consumers - Gas Release	P22-G-M11L2	-	-	49	-	49	-	-	46	63
Reject Vessel (44-VD-1003) - Two Phase Release at M11 Process Deck Level 3	P23-M-M11L3	2,722	2,722	11	-	11	-	-	0	86
Reject Vessel (44-VD-1003) - Gas Release at M11 Process Deck Level 3	P23-G-M11L3	2,722	2,722	11	-	11	-	-	0	86
Reject Vessel (44-VD-1003) - Liquid Release at M11 Process Deck Level 3	P23-L-M11L3	2,722	2,722	11	-	11	804	0	-	-
VOC Compression - Gas Release at Piperack	P24-G-PRK	-	-	1	-	1	-	-	1.5	146
VOC Compression - Gas Release at M30 Process Deck Level 1	P24-G-M30L1	-	-	1	-	1	-	-	1.5	146
Pig receiver - Two Phase Release at Turret Lower Deck	P25-M-TRTL	1,719	1,719	7	190	197	-	-	15	70
Pig launcher - Two Phase Release at Turret Lower Deck	P26-M-TRTL	1,719	1,719	7	190	197	-	-	15	70
BdN Production Riser 1 Subsea	R01-G-SS	247,758	247,758	987	27,424	28,411	-	-	15	70
BdN Production Riser 2 Subsea	R02-G-SS	247,758	247,758	987	27,424	28,411	-	-	15	70
Cambriol Riser Subsea	R05-G-SS	756,999	756,999	3,016	83,792	86,808	-	-	15	70
Gas Injection/Gas Lift Riser Subsea	R06-G-SS	-	-	58,059	-	58,059	-	-	324	60
Helifuel Skid - Liquid Release	H01-L-HELI	-	-	-	-	-	841	10	-	-
MP Separator - Two Phase Release at Piperack	P35-M-PRK	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Two Phase Release at M11 Process Deck Level 2	P35-M-M11L2	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Gas Release at M11 Process Deck Level 2	P35-G-M11L2	25,326	25,326	24	1,205	1,230	-	-	4.5	61
MP Separator - Liquid Release at M11 Process Deck Level 2	P35-L-M11L2	25,326	25,326	24	1,205	1,230	796	4.5	-	-

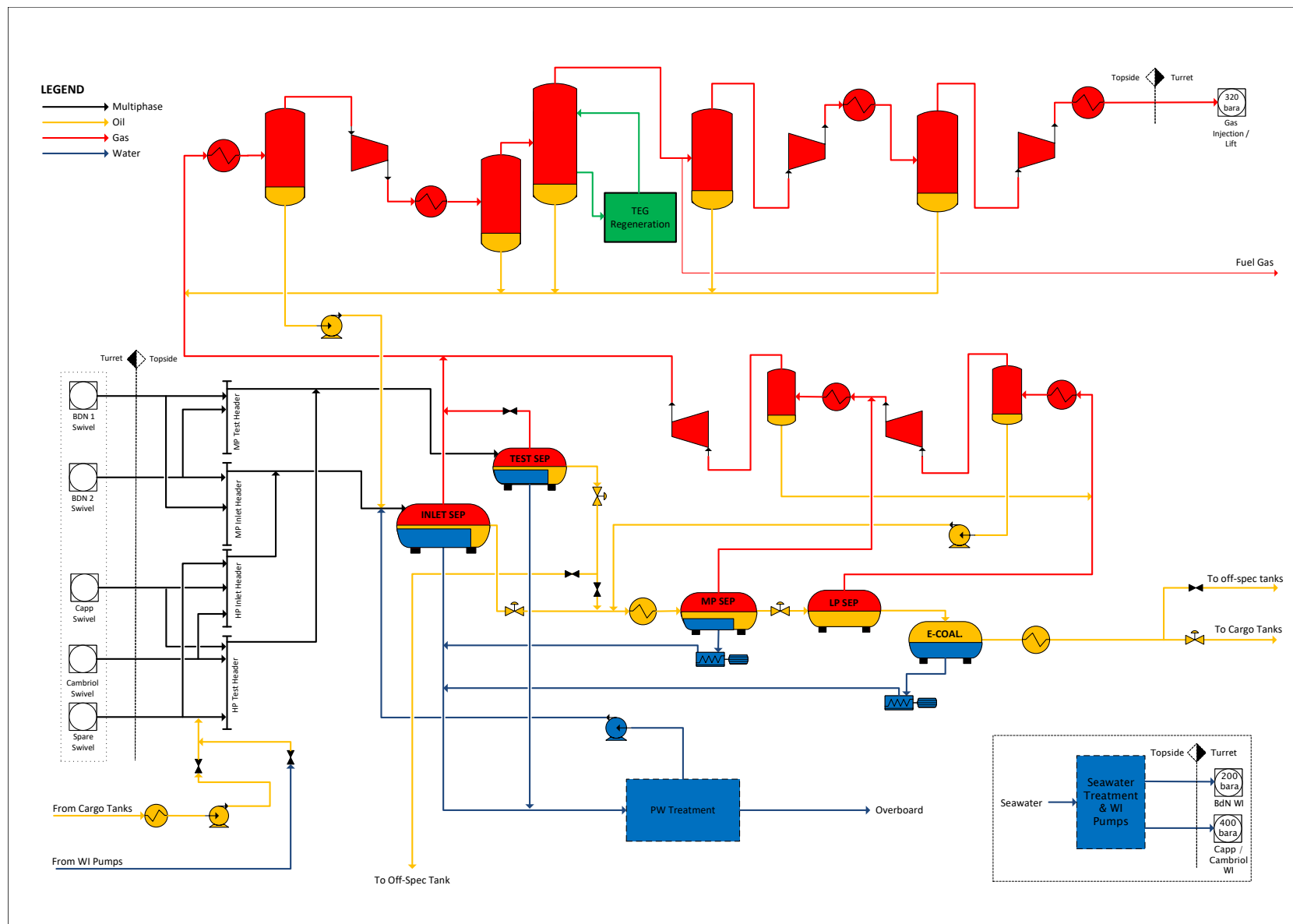


Figure 12.2 Preliminary Oil and Gas Processing System

further in two stages up to a pressure of approximately 325 barg. The gas compression system is configured as a single-train arrangement. Finally, the gas is injected into the Bay du Nord field to maintain reservoir pressure and also used for gas lift to both fields when required.

The preliminary design of the gas systems is shown in Figure 12.3.

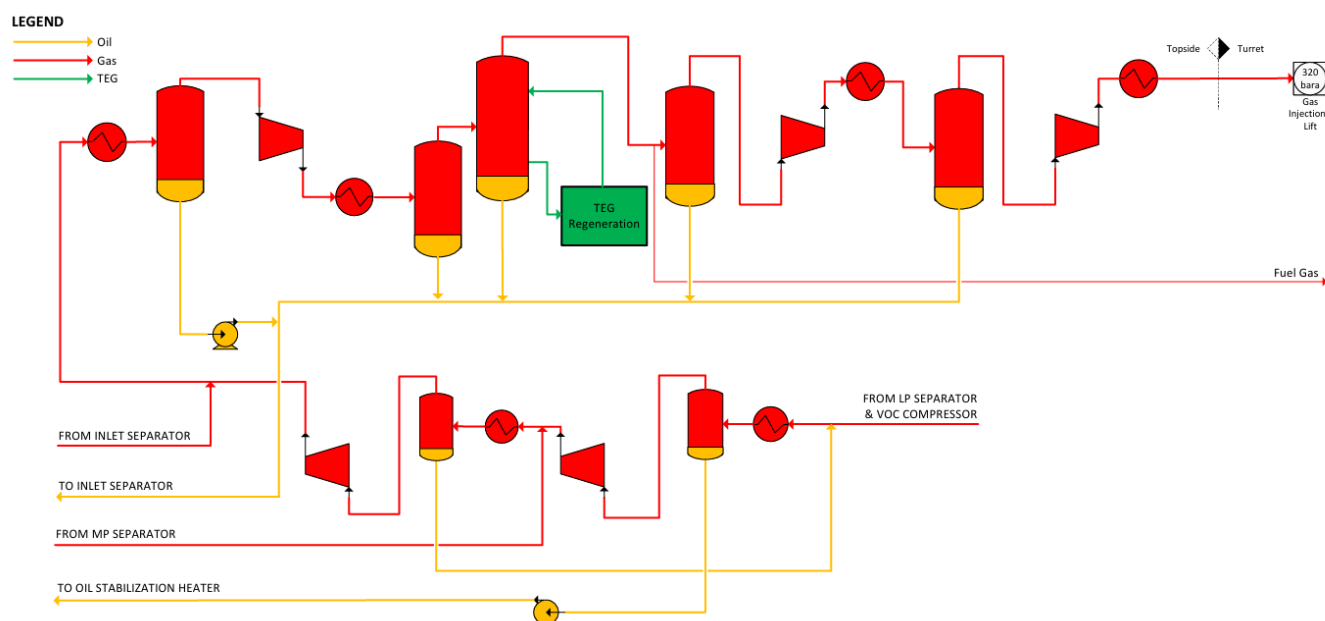


Figure 12.3 Preliminary Gas Systems

12.1.3.6 Fuel Gas and Flaring Systems

The fuel gas system provides treated gas for use as fuel by gas turbines for power generation and for other users. Fuel gas is routed from downstream the gas dehydration unit, scrubbed, and filtered to meet the turbine generator supplier specifications.

The flare and vent systems will collect and recover or safely dispose of hydrocarbon gases and liquids from the gas and oil-processing systems and produced water treatment. These gases are captured from process venting/flaring, relief, and blow-down/de-pressurization.

The FPSO flare system consists of two sub-systems, which are independent of each other: a closed flare system and an atmospheric vent system.

The closed flare system is comprised of:

- Two flare knock-out drums (one HP and one LP);
- Flare gas metering;
- Two flare tips (one HP and one LP);
- Atmospheric vent header (from cargo system);
- Vapour recovery unit; and
- Two independent ignition systems.

It is divided into two sub-flare systems: a High Pressure (HP) flare system receiving flaring from HP sources and a Low Pressure (LP) flare system receiving flaring from LP sources. There will be no routine flaring from the production process and flare tips will be designed as high-efficiency units. During start up, shutdown, well clean-up activities, and during upset process conditions, depressurization of process segments may be required for safety reasons, and gas will be sent to the flare.

In a relieving scenario, pressure in the flare drum will rise, and at a specified set point, the control valve will open to the flare tip. If the pressure continues to rise, the Fast Opening Valve (FOV) will open towards the flare tip. If the

FOV fails, a parallel-installed mechanical device at a higher set point will open. The flare tip will be ignited by two different methods of ignition: a primary and a secondary system. Flare pilots are provided for flare ignition using fuel gas as a primary source and will be lit on demand only.

The system will also include a Volatile Organic Compound (VOC) compressor package, which collects gas from the LP flare system, and increases the pressure to match that of the suction pressure of the LP compressor, where it is routed to for further processing. The VOC compressor package also recovers the low-pressure fuel gas used in the cargo oil tanks for blanketing (see Section 12.1.1.10 Crude Oil Storage and Export).

The preliminary design of the closed flare system and VOC compressor package is shown in Figure 12.4.

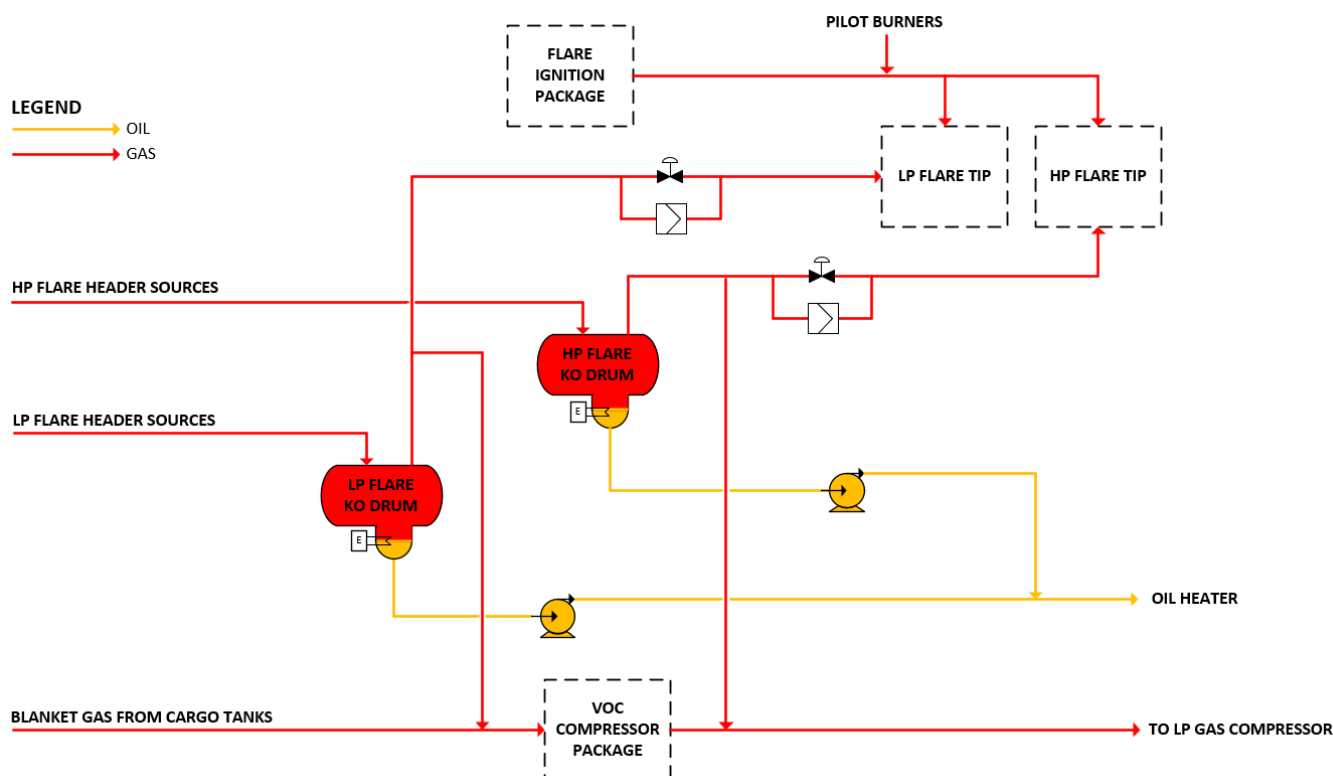


Figure 12.4 Preliminary Flaring System

The atmospheric vent system is comprised of an atmospheric vent header and a maintenance header, which are routed to a safe location and dispersed partway up the flare tower.

12.1.3.7 Produced Water Treatment System

A multi-stage water treatment process will be selected for produced water.

The current design routes produced water from the inlet separator, test separator, second stage separator, and electrostatic coalescer to a centralized produced water collection vessel. Oil separated in the vessel and flashed gas are returned to the production system. From the collection vessel, produced water is routed to hydrocyclones, which remove oil from water, and reject oil is returned to the production system via the collection vessel. The produced water is further treated using fuel gas to facilitate flotation in Compact Flotation Units (CFUs) and is then cooled prior to the treated water being discharged to sea. When produced water is discharged to sea, it will be released from below the bottom of the hull. Recovering flash gas via the VOC compressor from the discharge caisson is under evaluation. Off-specification water can be routed to designated cargo tanks for further handling/reprocessing. The preliminary design of the produced water treatment system is shown in Figure 12.5. The use of a multi-stage water treatment process will meet discharge limits. See Section 7.5.2 Water Management Strategy and the *Produced Water Management Strategy* [57] for additional information.

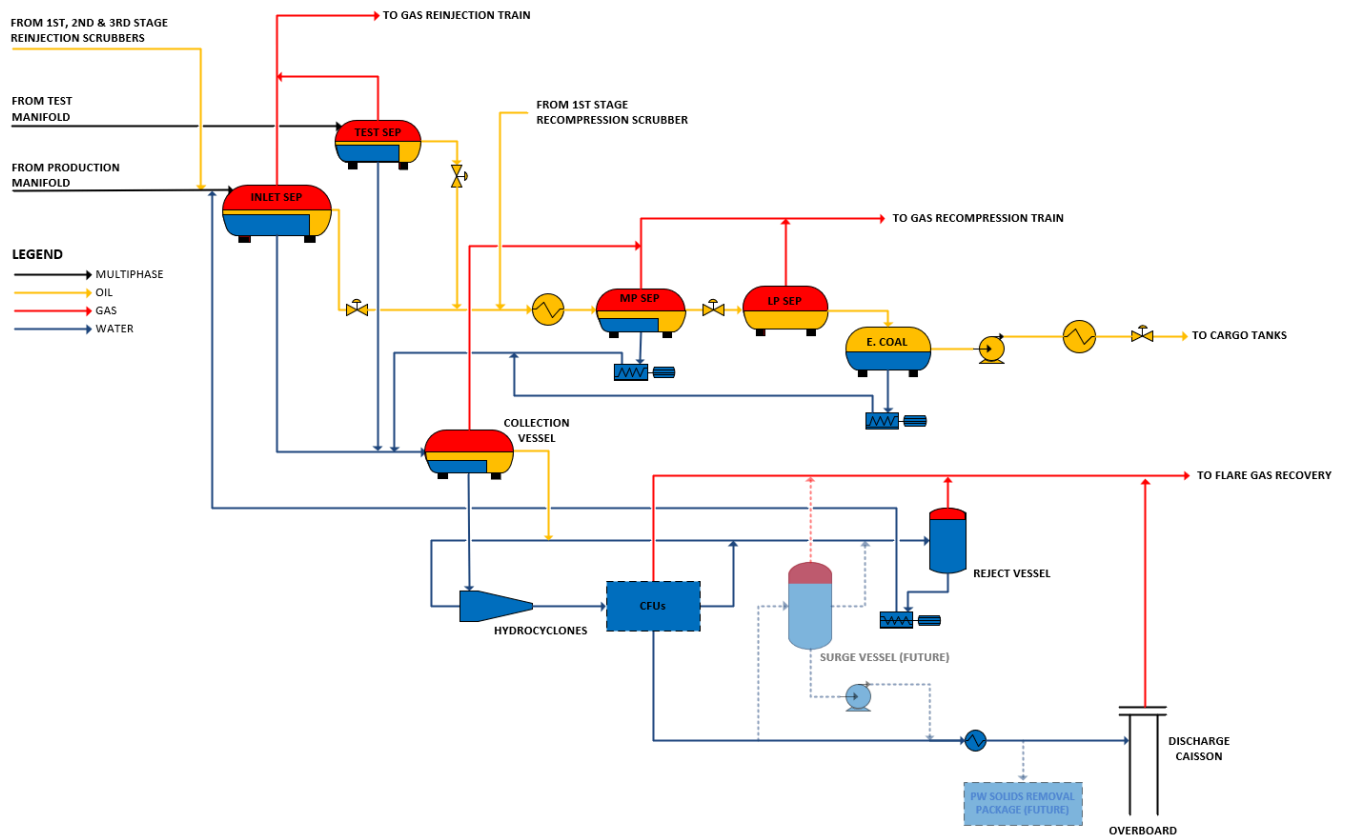


Figure 12.5 Preliminary Produced Water Treatment System

12.1.3.11 Power Generation

The current design for the main power generation system is comprised of three Gas Turbine Generators (GTGs), with Waste Heat Recovery Units (WHRUs) to supply heat to the heating medium system by extracting heat from the exhaust, located on the topsides. All three GTGs will have dual fuel capability, allowing operation on either natural gas or diesel. A schematic of the preliminary GTG and WHRU system is shown in Figure 12.6.

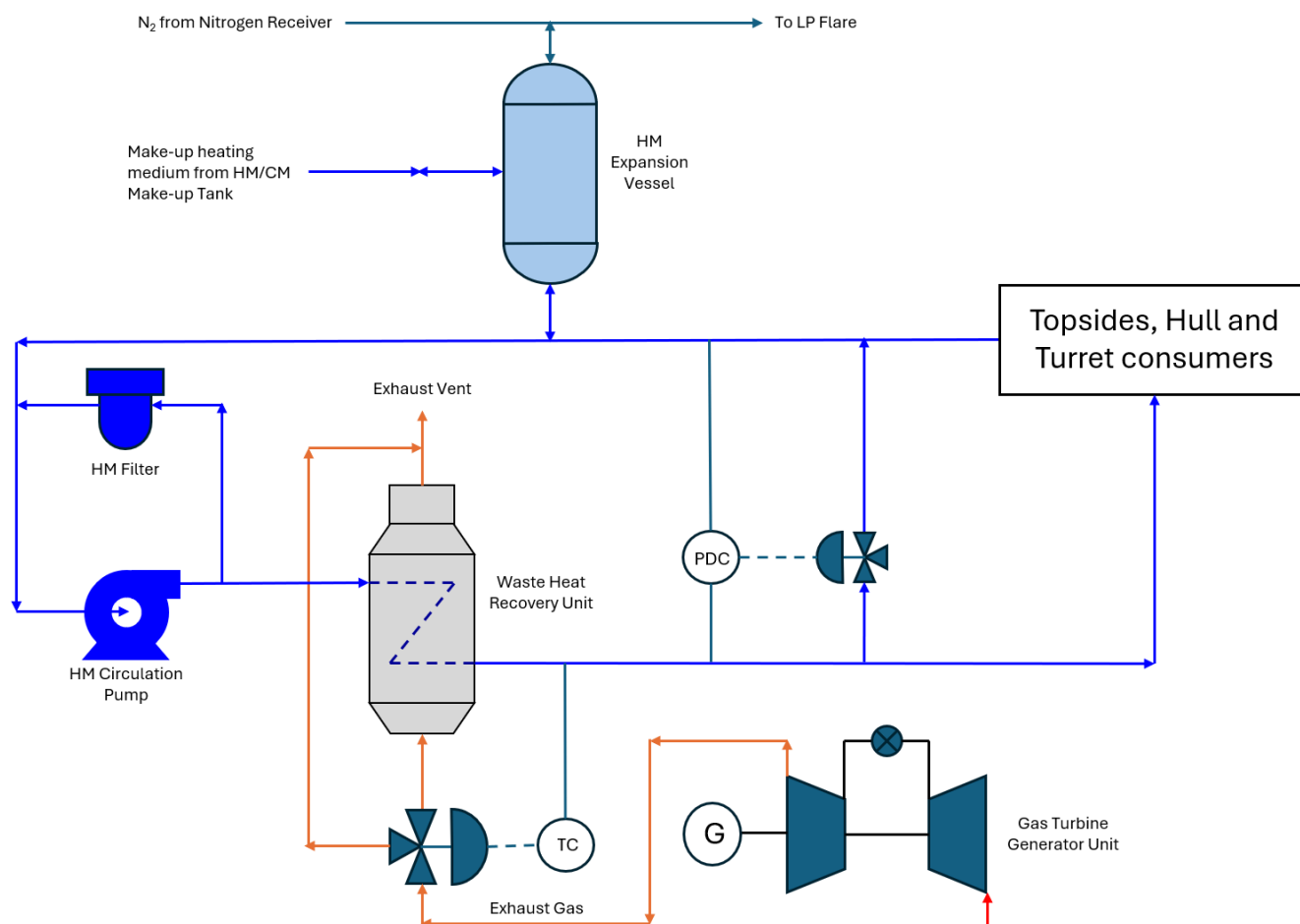


Figure 12.6 Preliminary GTG and WHRU System

In addition, the FPSO is planned to be equipped with two essential generators (reciprocating diesel engines), each capable of supplying approximately 8-9 MW of power, and one 2-2.5 MW reciprocating diesel engine as the emergency generator. The essential and emergency generators are located in the hull.

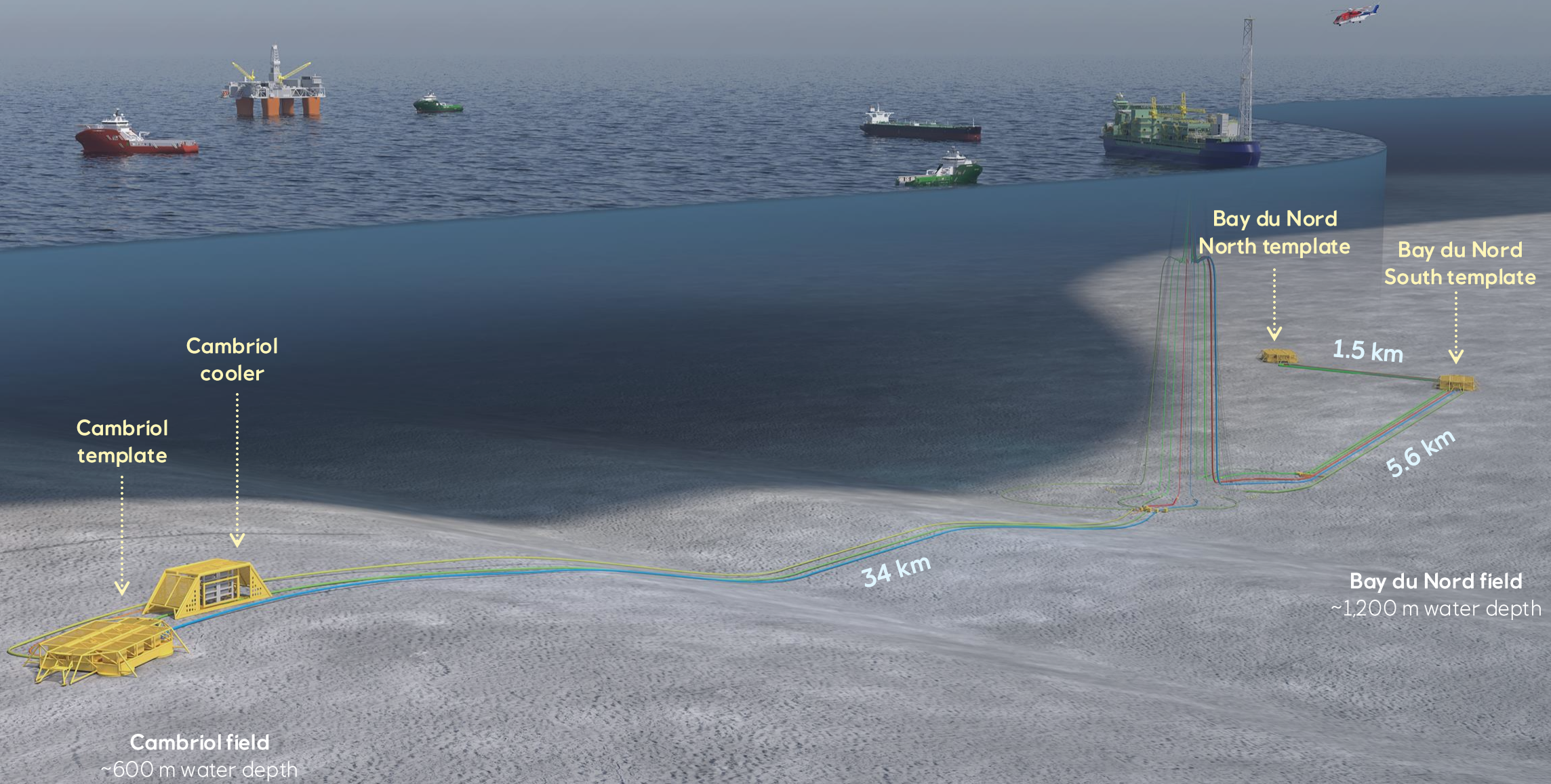
12.1.3.12 Fluid Measurement, Sampling, and Allocation

In consideration of the *Measurement Guideline* [58], separate Metering Philosophies for subsea [69] and the FPSO [70] will be issued to the C-NLOER.

Oil export, oil to storage, fuel gas, flare gas, gas to injection and gas lift, produced water, water to injection, produced water discharged to sea, test separator gas, test separator oil, and test separator water will be measured in consideration of the *Measurement Guidelines*. There is no gas export from the field.

The oil export metering system will have a planned capacity of 8000 m³/h. The system is currently planned with a single duty meter plus a single master meter configuration. The master meter will also be back-up for the duty meter in case of failure. Pressure and temperature instruments are duplicated in each of the metering runs. The master meter will be calibrated in an onshore facility at required intervals.

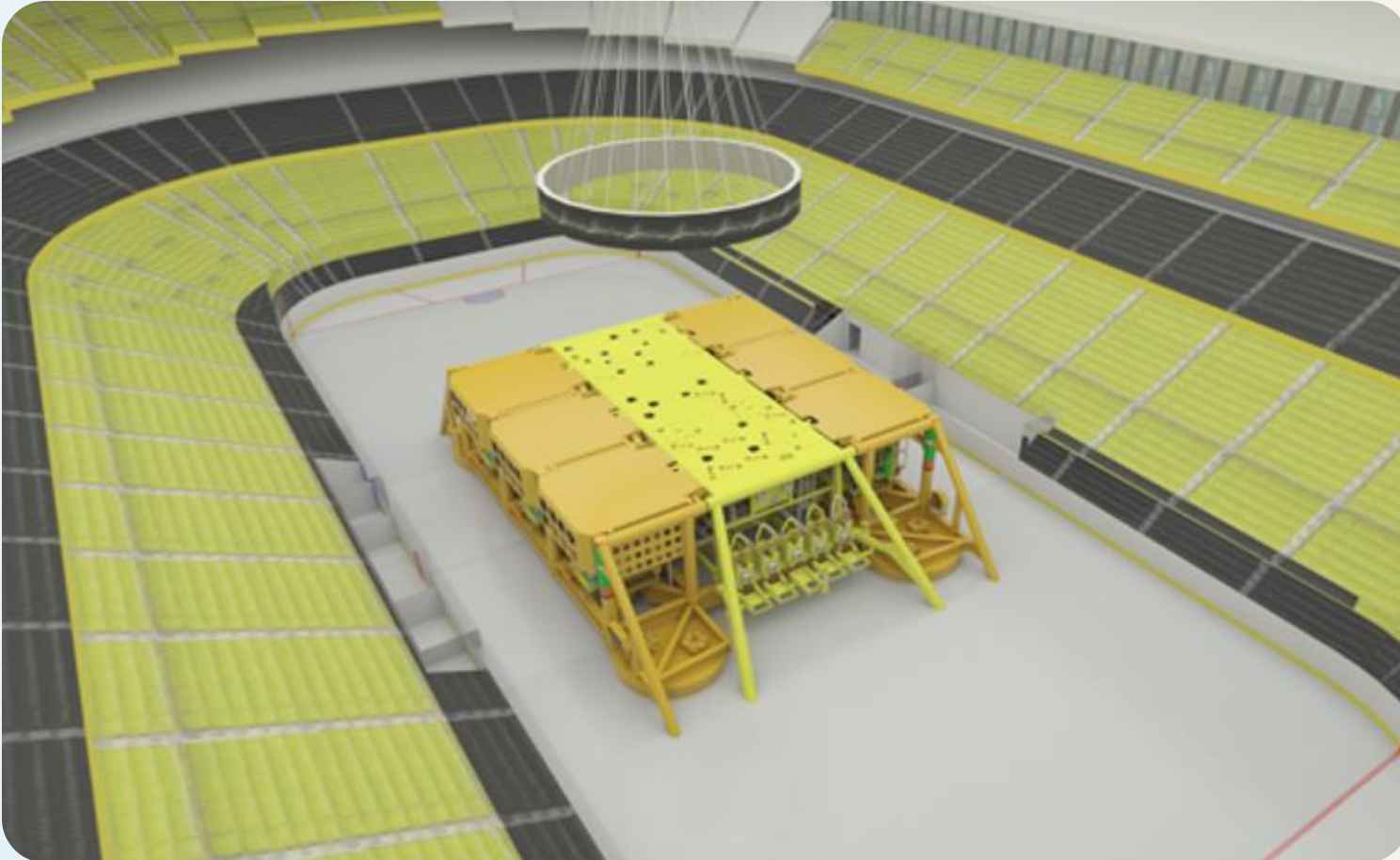
The design is based on the premise that the fields will be unitized. Therefore, there will not be any allocation of production between fields with different ownerships.





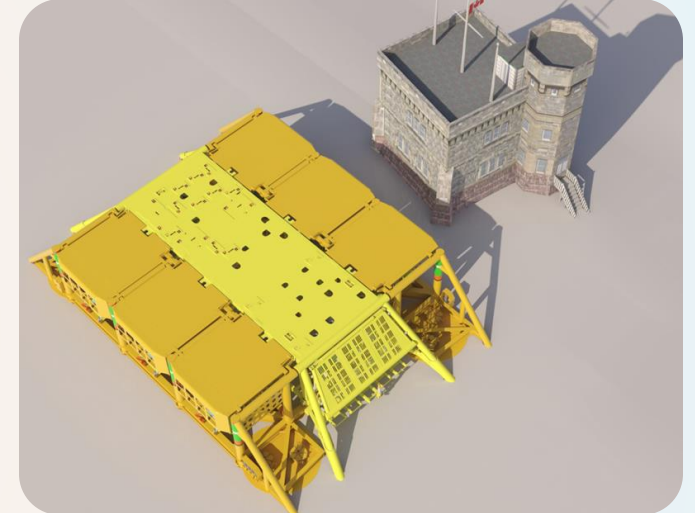


MARY BROWN'S CENTRE



Credit: Subsea Integration Alliance (SIA)

CABOT TOWER AT SIGNAL HILL



Credit: Subsea Integration Alliance (SIA)