# 9 PRODUCTION AND EXPORT SYSTEMS

This chapter presents Husky Oil's proposed approach for production and export systems for the White Rose development.

The section covers the following topics:

- production systems considered;
- steel FPSO;
- subsea facilities;
- export system; and
- system efficiency.

## 9.1 Production Systems Considered

Husky Oil has carried out a concept selection study to identify the potential alternatives for developing the White Rose oilfield.

All production facility concepts for the White Rose oilfield were evaluated, based on:

- economics;
- flexibility;
- feasibility;
- deliverability; and
- Canada-Newfoundland benefits.

Eight production concepts were analyzed. They were:

- steel ship-shaped FPSO facility;
- concrete FPSO facility;
- steel semi-submersible facility with and without integral storage;
- concrete semi-submersible facility;
- concrete GBS;
- disconnectable concrete TLP;
- concrete barrier wall with FPU; and
- steel FPDSO facility.

A two-stage screening process was used to evaluate the concepts.

The first stage involved qualitative screening whereby options that were either undeveloped or clearly failed to satisfy primary technical criteria were identified.

As a result of analysis at this stage, the disconnectable concrete TLP, concrete barrier wall with FPU, and steel FPDSO were not carried forward because they either did not meet Husky Oil's technical requirements or were prototypes with no operating history in harsh-environment offshore locations.

The second stage screening process used a number of economic indicators to assess the five remaining options carried forward for detailed evaluation. These comprised Net NPV, ROR and PVPI.

These remaining five options (steel FPSO facility, concrete FPSO facility, steel semi-submersible facility with and without integral storage, concrete semi-submersible facility, and concrete GBS) were further analyzed with respect to construction time, capital costs, concept maturity, concept deliverability, and risk considerations (Figures 9.1-1 and 9.1-2).

### 9.1.1 Preferred Production System

The concept selection study concluded that the preferred option for the White Rose oilfield development should be based on a steel FPSO facility, together with subsea wells located in glory holes, similar to that selected for the Terra Nova Development.

The FPSO concept is a floating, production, storage and offloading ship-shaped vessel. Production facilities are mounted on raised supports above the vessel deck. Reservoir fluids pass from subsea production wells, via flowlines and risers, up into the turret and then to the production facilities. Produced oil is stored in the vessel cargo tanks and periodically offloaded on to a shuttle tanker via a loading hose.

The FPSO will be ice-strengthened. It will be moored using a geo-stationary turret, which is anchored to the seabed. The turret mooring will be disconnectable so that the FPSO can move to avoid potential iceberg threat. The functional characteristics of the turret will be similar to Terra Nova. The vessel will rotate (“weather vane”) around the turret to take up a position of least resistance to the weather with the bow heading into the prevailing wind and waves.

**Figure 9.1–1 Construction Costs and Time for the Five Production Options**

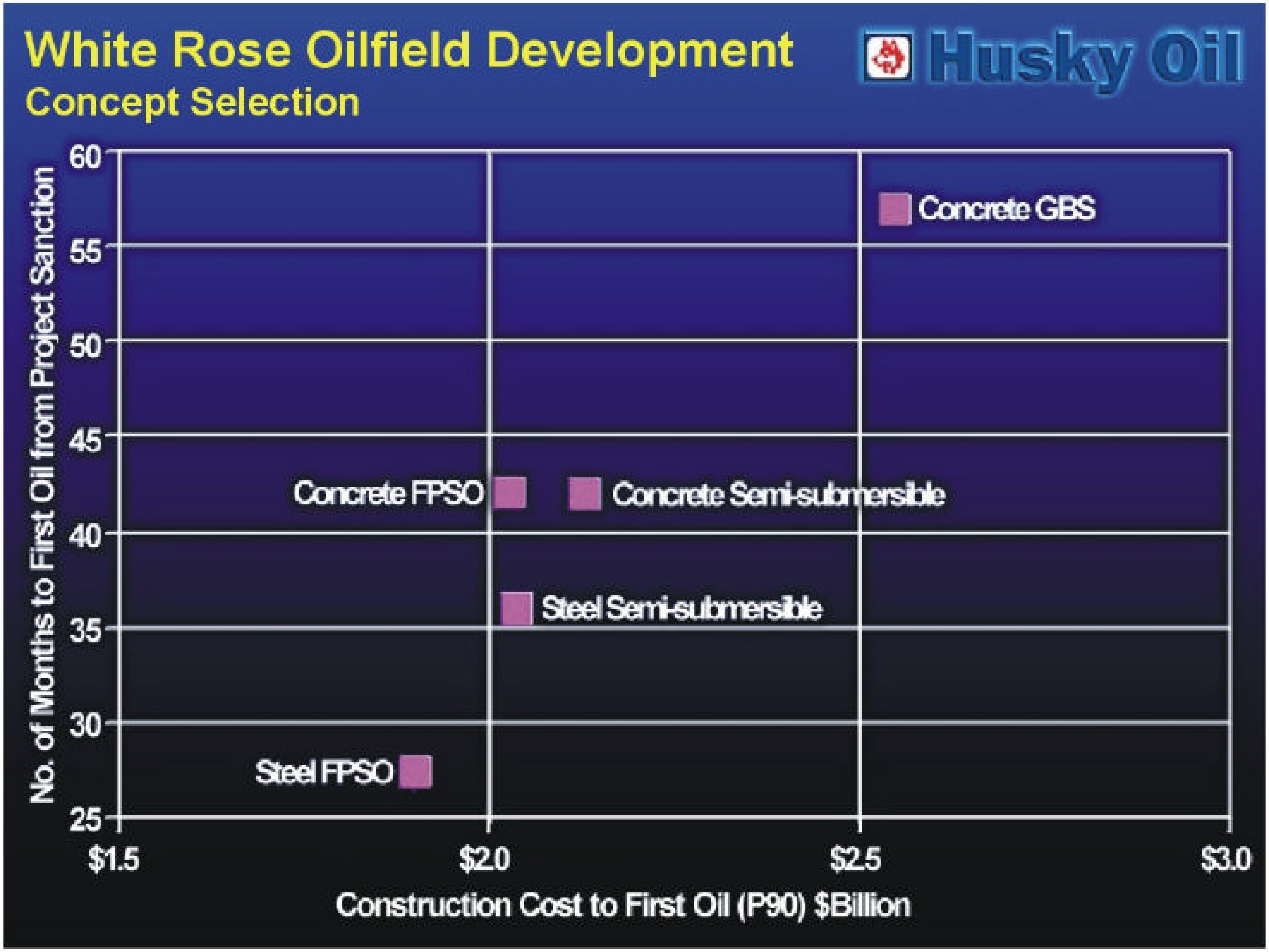
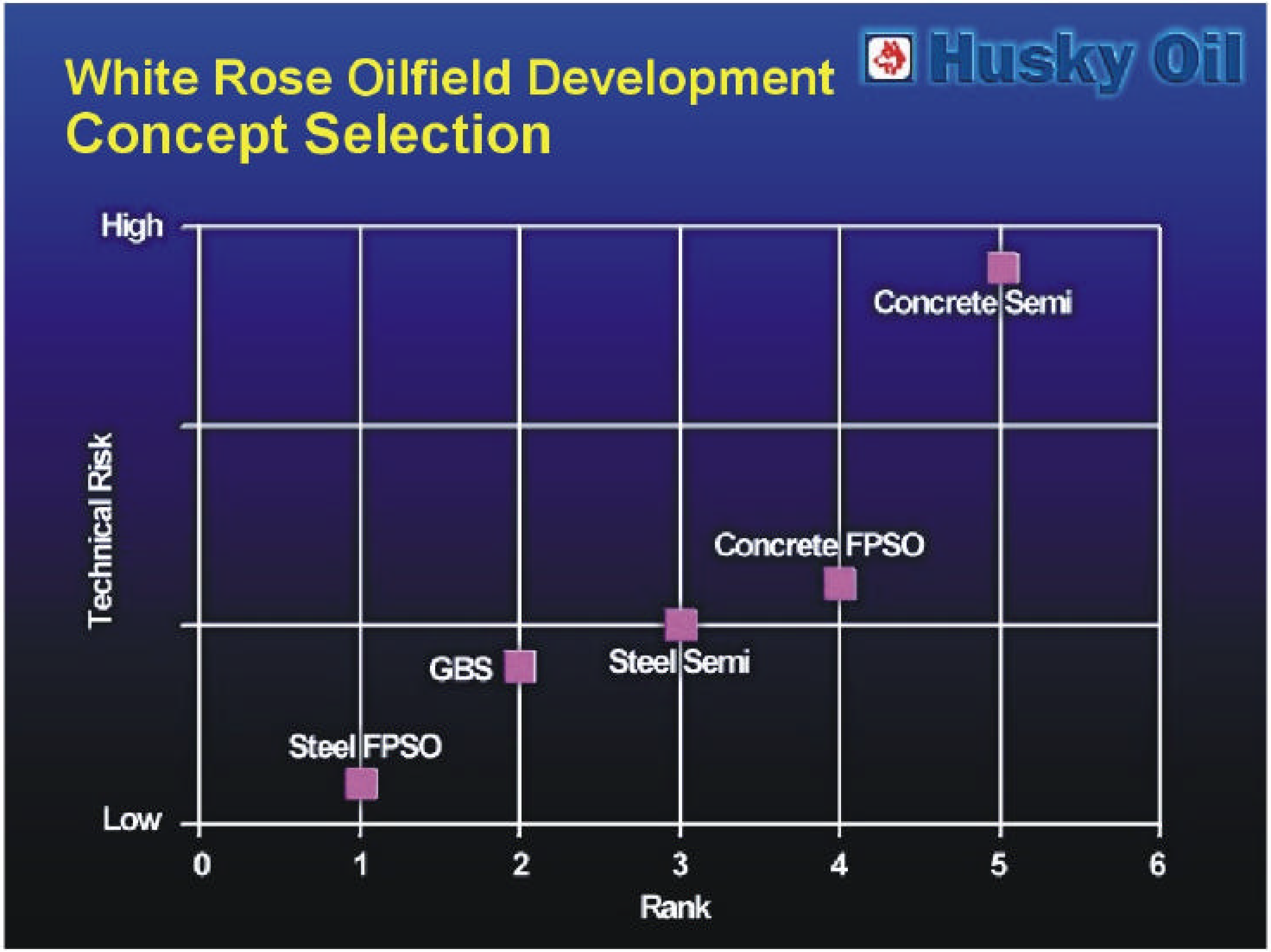


**Figure 9.1–2 Relative Technical Risk for the Five Production Options**

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Key factors which contributed to the selection of the steel FPSO as the preferred development option included the following:

- it is the most economically feasible way to develop the White Rose oilfield, taking into account feasibility, flexibility, deliverability, economic attributes, risk and safety, and Canada-Newfoundland benefits [Refer to Table 14.4-1 in Chapter 14];
- it has commercial and technical flexibility that is well suited to a complex field such as White Rose with technical challenges and reservoir uncertainties;
- it has a proven track record in harsh environments, with 20 units installed, or in construction, in the last eight years;
- it can produce both oil and gas in sequential development;
- it has flexibility to tie in future fields;
- it offers the shortest time to First Oil, thereby enhancing economics; and
- it poses less of a challenge at decommissioning than a bottom-founded structure.

The following further attributes apply to the steel FPSO option:

- it will provide an opportunity for continuous employment and a growing industrial base for the Province;
- it will provide on a competitive basis the opportunity to develop the current capabilities of the Newfoundland workforce.
- it will increase competitive opportunities for the shipyard in Marystown;
- it will increase opportunities for facilities providing expertise in engineering, subsea and topside fabrication, drilling and supply services on a competitive global basis;
- it will establish and consolidate a proven and leading exportable technology in the Province for future developments off the East Coast of Canada and abroad; and
- it will enable expertise and industry within the Province to keep pace with the trend in offshore oil and gas development throughout the world.

The subsea wells will be located in glory holes dredged to a maximum of 11 m below the seafloor to provide protection to the wellheads against iceberg scour. Caisson wells will also be considered.

The FPSO will be positioned between glory holes and will receive product via flexible flowlines that deliver reservoir fluids through the turret located near the bow of the vessel. Stabilized oil will be exported to a shuttle tanker at the stern of the FPSO, via a flexible loading hose. Produced gas will be re-injected into the formation, through the turret, via dedicated flowlines.

The processing requirements will most likely be based upon a single train and will not require any unconventional facilities. The oil will be stabilized in a conventional separation train and de-watered in an electrostatic coalescer. The gas will be compressed for reinjection in a multi-stage compression train.

The subsea wells will be located in up to four glory holes strategically located in the reservoir. The wells will be drilled and completed by a conventional drilling semi-submersible, with up to eight to ten wells drilled prior to commencing production and additional wells drilled thereafter up to a total of 18 to 25.

It is anticipated that the wells will be either cluster wells or drilled through a template structure (or other appropriate subsea system). Manifold skids will be used either to co-mingle produced fluids or to distribute injection fluids. A template solution may minimize the subsea facilities envelope, hence minimizing glory hole size. Each glory hole would have two or more templates.

It is anticipated that flowlines and risers will convey the produced and injection fluids to and from the FPSO and subsea templates. An electro-hydraulic umbilical to each manifold will convey the required hydraulic fluid, chemicals, power and communication signals necessary to operate the christmas tree valves and monitor downhole and tree-mounted instrumentation.

This system was selected as top preference based on life of project cost and first equal on time to First Oil [For costs, refer to Table 14.4-1 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

Full descriptions of the preferred production systems are provided in Sections 9.2 to 9.4.

### 9.1.2 Alternative Systems

The physical characteristics of the other four alternative systems evaluated are briefly described in the following sections.

#### 9.1.2.1 Concrete Floating Production Storage, Offloading Facility

This concept essentially comprises a concrete barge outfitted for production, storage and offloading in a similar fashion to the steel FPSO. Due to displacement considerations, its plan area is necessarily larger than the equivalent steel FPSO. It has the ability to disconnect if required by extreme conditions or icebergs.

The concrete FPSO was assessed to be inferior to the steel FPSO in respect of feasibility because there are no existing units currently in operation, thereby increasing uncertainty and risk and because the construction scale is so large, requiring extension to Bull Arm if this yard were the preferred construction facility.

A concrete FPSO is marginally more flexible than a steel FPSO because the vessel size has to be large to support its own self weight, and this size provides additional deck space.

With respect to deliverability, the concrete FPSO was considered to be inferior to the steel FPSO because of the likelihood of limited construction competition for the concrete hull and the lack of industry experience on the required scale.

This system was evaluated as second preference on life of project cost and third equal on time to First Oil. [For costs, refer to Table 14.4-2 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

#### 9.1.2.2 Steel Semi-Submersible Facility With and Without Integral Storage.

The semi-submersible concept comprises a floating hull form with four surface-piercing columns connected by sub-surface pontoons. Production facilities are mounted on the semi deck. The subsea facilities are similar to the FPSO. The semi-submersible is anchored to the seabed by fixed catenary chain and wire moorings and does not "weather vane". The flexible risers are fixed to a porch(s) on the semi-submersible hull. In the event of iceberg threat, the porch(s) would be disconnected, the risers lowered and the semi moved aside using thrusters mounted on the pontoons.

A total of six semi-submersible options were evaluated; the base case option comprised a production unit with the oil offloaded to a FSU moored permanently in the field and located a short distance from the semi. Oil is exported via shuttle tanker in a similar manner to the FPSO option. The alternatives comprised:

- Alternative 1 removed the FSU but included two loading buoys and an extra shuttle tanker with one always connected; this is a so-called 'dynamic storage' arrangement;
- Alternative 2 included drilling capability as well as production facilities;
- Alternative 3 included well intervention capability as well as production facilities;
- Alternative 4 was similar to Alternative 2, but with the addition of oil storage; and
- Alternative 5 was similar to the base case but assumed the conversion of an existing drilling semi-submersible.

This option was assessed as being similar to the concrete semi-submersible in respect of flexibility but having a higher ranking in respect of feasibility and deliverability. This was largely because there is so much operational experience, with nearly 40 production units in operation world-wide.

This system was evaluated as third preference on life of project cost and second on time to First Oil. [For costs, refer to Table 14.4-3 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

The principal reason for selecting the steel FPSO in preference to the steel semi-submersible was forecast life-cycle cost, the steel semi-submersible cost being some $190 million more than the steel FPSO. [Refer to capital and operating cost data presented in Chapter 14.] A steel semi-submersible may become a technical and commercially viable option if the final depletion plan indicates a lower then expected production rate.

#### 9.1.2.3 Concrete Semi-Submersible Facility With and Without Integral Storage.

This concept is similar to the steel semi-submersible concept except that the material of construction is concrete.

The same six options as described above for the steel semi-submersible were also evaluated for the concrete semi-submersible.

The only concrete semi-submersible in existence is the Troll B structure, installed in the North Sea in 1995. The semi-submersible is a production facility, without drilling or storage, with a design capacity of 27,000 $m^3$/d. This structure is very large compared with steel production semi-submersible counterparts, with a plan area approximately 40 percent greater, a wave area more than 200 percent greater and a displacement more than 300 percent greater. A concrete semi-submersible for White Rose would be smaller than Troll B but would still be significantly larger than a steel semi-submersible, leading to significantly higher mooring costs.

A further disadvantage of the concrete semi-submersible concept is the lack of a disconnection design. Although feasible, this would take an additional amount of design development. Another significant uncertainty is the need, or otherwise, for an independent means of propulsion in the event of disconnect. This system was evaluated as fourth preference on life of project cost and third equal on time to First Oil. [For costs, refer to Table 14.4-4 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

#### 9.1.2.4 Concrete Gravity Base Structure

The GBS concept is conceptually similar to that used on the Hibernia oilfield, although reduced in complexity and design. The structure rests on the seabed and is designed to resist the forces imposed by iceberg and other environmental loads. The topside facilities include drilling equipment, as well as the process plant, with all wells drilled and maintained from the platform. Oil is stored within the base structure and offloaded via a subsea pipeline to a loading buoy located a short distance from the GBS.

The concrete GBS is jointly top ranked in respect of feasibility.

A significant challenge for the concrete GBS is considered to be deliverability where the concept is ranked lowest of the top five options.

This system was evaluated as last preference on life of project cost and last on time to First Oil. It also indicated a negative return on investment to the Owner. [For costs, refer to Table 14.4-5 in Chapter 14; for time to First Oil, refer to Table 9.1-1 in Section 9.1.3.]

The concrete GBS was ultimately discounted as an option on the following grounds:

- it is not economically viable for a field of the size of White Rose;
- of all options considered, it compares the most unfavourably with the steel FPSO option on cost and deliverability;
- it requires a long lead time;
- it presents problems for decommissioning and abandonment, and is not practical for relocation for further service at another site;
- there are insufficient oil reserves proven in the field to justify its use, and there is a high degree of uncertainty about the extent of further gas reserves yet to be proven;
- its forecast life-cycle cost is some $507 million more than the steel FPSO option; and
- with a forecast negative return on investment, it is an option which owners will not be able to implement based on commercial and business considerations.

### 9.1.3 Time to First Oil for Options Considered

The time to First Oil for each of the options considered is shown in Table 9.1-1.

**Table 9.1-1 Time to First Oil for Options Considered**

| Option | Months to First Oil | Wells to First Oil | Ramp-up Period (months) |
|---|---|---|---|
| Steel FPSO | 36 | 10 | 0 |
| Concrete FPSO | 42 | 10 | 0 |
| Steel Semi-submersible | 36 | 10 | 0 |
| Concrete Semi-submersible | 42 | 10 | 0 |
| Concrete GBS | 57 | 4 | 12 |

Except for the GBS, all cases assume up to 10 wells to be pre-drilled to First Oil and a production ramp-up period is not required. For the GBS, it is assumed that one well can be drilled from the GBS before the structure is operational at 48 months. It is further assumed that an additional three wells will be drilled and First Oil will occur at 57 months. It will not be until 12 months later that a total of eight wells will be available on the GBS and full production capacity is achieved. The estimated schedule for the FPSO for White Rose is 36 months from Contract Award to First Oil. This assessment is based upon experience from Terra Nova and benchmarked data for North Sea FPSOs, with due allowance for size and complexity factors. A steel semi-submersible is also tied with the steel FPSO in reaching First Oil in 36 months, while a concrete semi-submersible and concrete FPSO are tied at 42 months to First Oil. An early First Oil date is important in maintaining the financial viability of the White Rose project, which has significant less reserves than the other projects currently on the Grand Banks.

## 9.2 Steel Floating Production, Storage Offloading Facility

### 9.2.1 Vessel

#### 9.2.1.1 Vessel Size

The FPSO hull will be approximately 200 to 300 m in length, and will support a topsides process plant. Its conceptual layout is shown in Figure 9.2-1.

#### 9.2.1.2 Vessel Standard

The vessel will be ice-strengthened as necessary and the hull should be capable of accepting the following ice criteria:

- 100,000 t iceberg at 0.5 m/s;
- pack ice, 0.3 m thick; and
- 5/10 (50 percent) ice cover.

Vessel classification will be in accordance with Section 8.2.

The vessel will have a storage capacity commensurate with throughput, and offloading frequency. Typically this will be between 111,000 to 135,000 $m^3$.

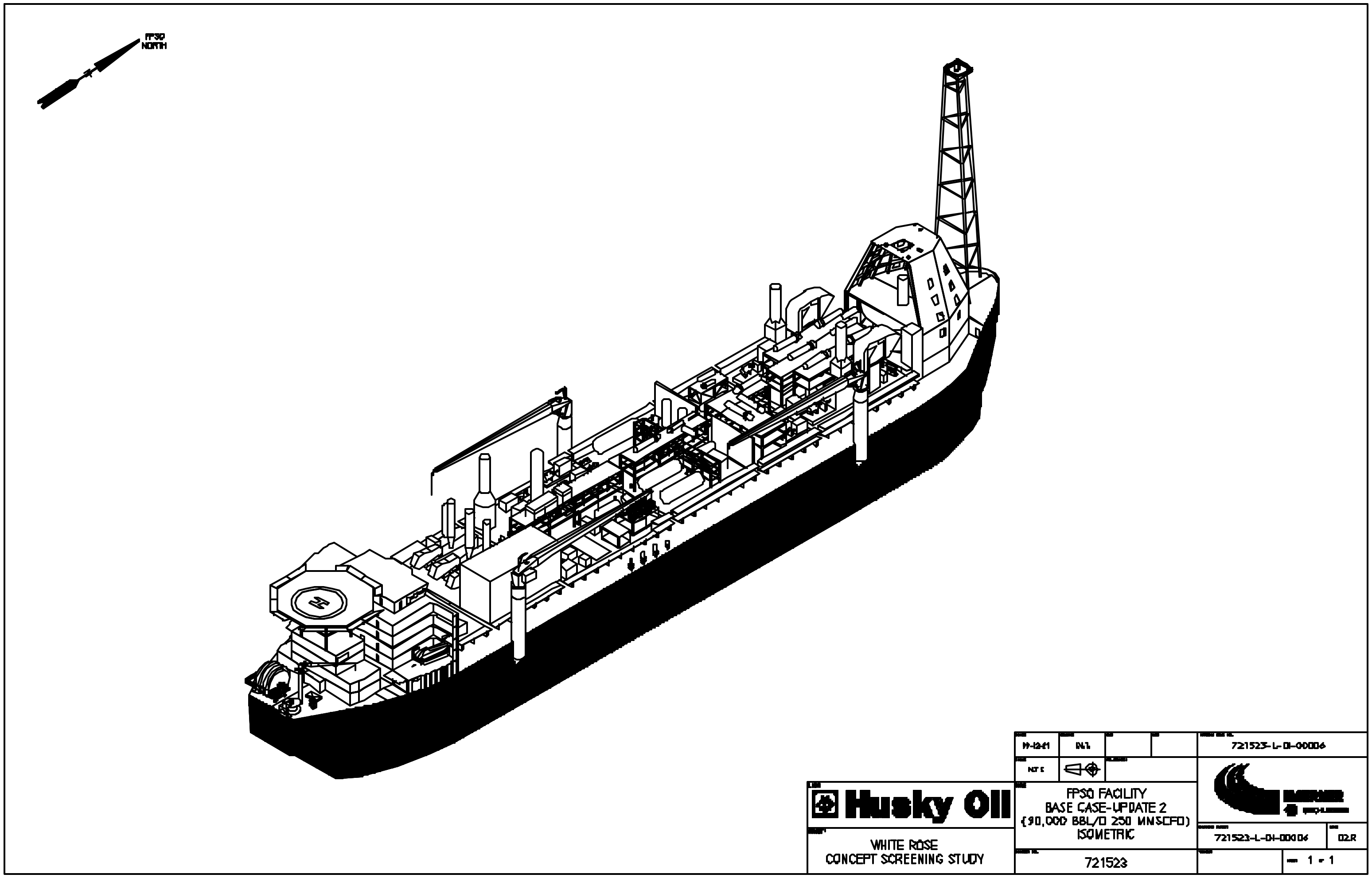
The vessel will incorporate a double hull construction and will have a segregated ballast system.

The layout of tanks will be such as to maximize storage while maintaining sufficient ballast capacity.

#### 9.2.1.3 Structural Design Requirements

In addition to the ice-strengthening detailed above, the FPSO will be designed for the demands of Grand Banks operation and to withstand (as a minimum) the loads and motions imposed by the following:

**Figure 9.2–1 FPSO Facility - Isometric**



- the 100-year return period, extreme environmental conditions for the full range of FPSO operational draft, heel and trim;
- transit conditions from fabrication and assembly locations to offshore location; and
- sloshing within the tanks.

Due to the extreme environmental conditions of the Grand Banks, particular attention will be paid to hull ultimate strength and fatigue life.

#### 9.2.1.4 General Design Requirements

The following design goals are considered the minimum requirements to obtain safe and effective vessel operation over the life of the field:

- the vessel and moorings will be designed in accordance with Lloyds Register's Guidance Notes for Structural and Mooring Aspects of Ship Type FSU and FPSO Units at a Fixed Location or equivalent;
- the main detail design features of the FPSO hull will be designed so that in-service inspection and maintenance can be undertaken;
- the hull will be designed to efficiently integrate the support requirements for the topsides facilities and all other main deck structures and equipment;
- the hull will be designed to consider possible operational impacts from supply boats. The structural response will be designed to be compatible with the safety case for the vessel;
- vessel motions will be central to the safe and efficient operation of the vessel and be such as to have no significant adverse effect on availability for production;
- vessel intact and damage stability will comply with certification authority requirements, MARPOL 1973/78 Regulation 25, and IMO Resolutions A562 & A206;
- vessel will have adequate propulsion for manoeuvring to avoid icebergs after disconnection of mooring and riser lines;
- corrosion protection will be provided for steel hull and turret for the full design life;
- the toughness and strength of the material in the hull will be compatible with the anticipated operating temperatures and stresses;
- fatigue will be fully addressed during hull design and testing;
- topsides modules/pre-assembled units (PAUs)/skids will be located at such an elevation as to avoid green water on the deck of the vessel. This will be verified by model testing. Equipment below the level of the modules/PAUs/skids will be provided with protection from the occurrence of green water; and
- full model testing program will be completed.

#### 9.2.1.5 Marine Systems

Marine systems integrated within the hull will include the following:

- cargo handling;
- ballast;
- propulsion;
- bilge;
- hull power distribution;
- fire and gas detection;
- fire fighting for pump room, machinery spaces and accommodation;
- inert gas;
- gas freeing;
- crude oil washing system/tank cleaning;
- tank gauging;
- ballast tank gas detection;
- steam heating of cargo tanks;
- hydraulic control system for remotely actuated valves;
- diesel;
- fresh water and potable water; and
- sewage treatment.

The cargo control console, ballast controls and a monitoring/alarm system for all marine systems will be located in the FPSO Central Control Room.

In addition to the above, the cargo tanks will be fitted with a pressure monitoring system capable of detecting pressures abnormally high or low relative to atmospheric that may endanger the vessel. This system will provide both visual and audible alarms in the FPSO Central Control Room.

Some vessel utility systems have to remain active during production shutdown. The extent of hull and topsides integration will be fully addressed with respect to both shutdown philosophy and electrical isolation.

#### 9.2.1.6 Safety Equipment

The vessel will be provided with a minimum of 200 percent capacity in persons on board in lifeboats and 200 percent capacity in life rafts. Lifeboats and life rafts will be located close to the temporary refuge and on both sides of the vessel. Additional lifeboat(s) and life rafts will be provided at other suitable locations on the vessel. All safety equipment will meet international marine requirements and Canadian regulations. A secondary muster point will be provided.

#### 9.2.1.7 Accommodation

Accommodations will be either at the stern or at the bow of the vessel. The skids containing oil and gas will be located furthest away from the accommodations as is possible. Typical staffing levels will range from between 45 to 50 steady state crew, to between 80 to 85 with start up resources. The accommodation requirement for the FPSO will be addressed and will consider the requirements for normal operation and also offshore hook-up and commissioning and maintenance operations. Utilities, such as the galley and mess, food storage areas, change rooms and laundry, potable water and sewage treatment will be sized accordingly. Other facilities provided will include office, recreational, sick bay, and entertainment amenities.

#### 9.2.1.8 Helicopter Operations

The FPSO will be capable of accommodating an Aerospatiale Super-Puma, EH101 or equivalent helicopter. The helideck will be designed to comply with governing legislation and for 1.5 x Super-Puma overall length (19.7 m). The helideck structure will be capable of accepting loads from the EH101 helicopter. Refuelling facilities will be installed.

#### 9.2.1.9 Mechanical Handling

Offshore rated cranes of sufficient type and number will be provided to allow safe and efficient re-supply, operation and maintenance of the FPSO.

Arrangements will be made for the safe and easy handling of provisions to the galley storage spaces, and handling of equipment between the process and utility areas on deck and the workshop and stores areas.

### 9.2.2 Topside Facilities

A preliminary schematic diagram of the oil and gas process system is shown in Figure 9.2-2.

The White Rose production facilities will be designed to produce 12,000 to 18,000 $m^3$/day of stabilized crude oil for shuttle tanker transportation. The gas handling facilities will be designed to process 3 to 7 $10^6 m^3$/day of gas. The production facilities will handle 15,000 to 30,000 $m^3$/day of produced water. The facilities will handle all the oil, gas and water produced.

The topside facilities will primarily be on a horizontal plane raised above the vessel deck. It is envisaged that the topsides will be configured in modules, PAUs or skids, the number and size of which will be determined.

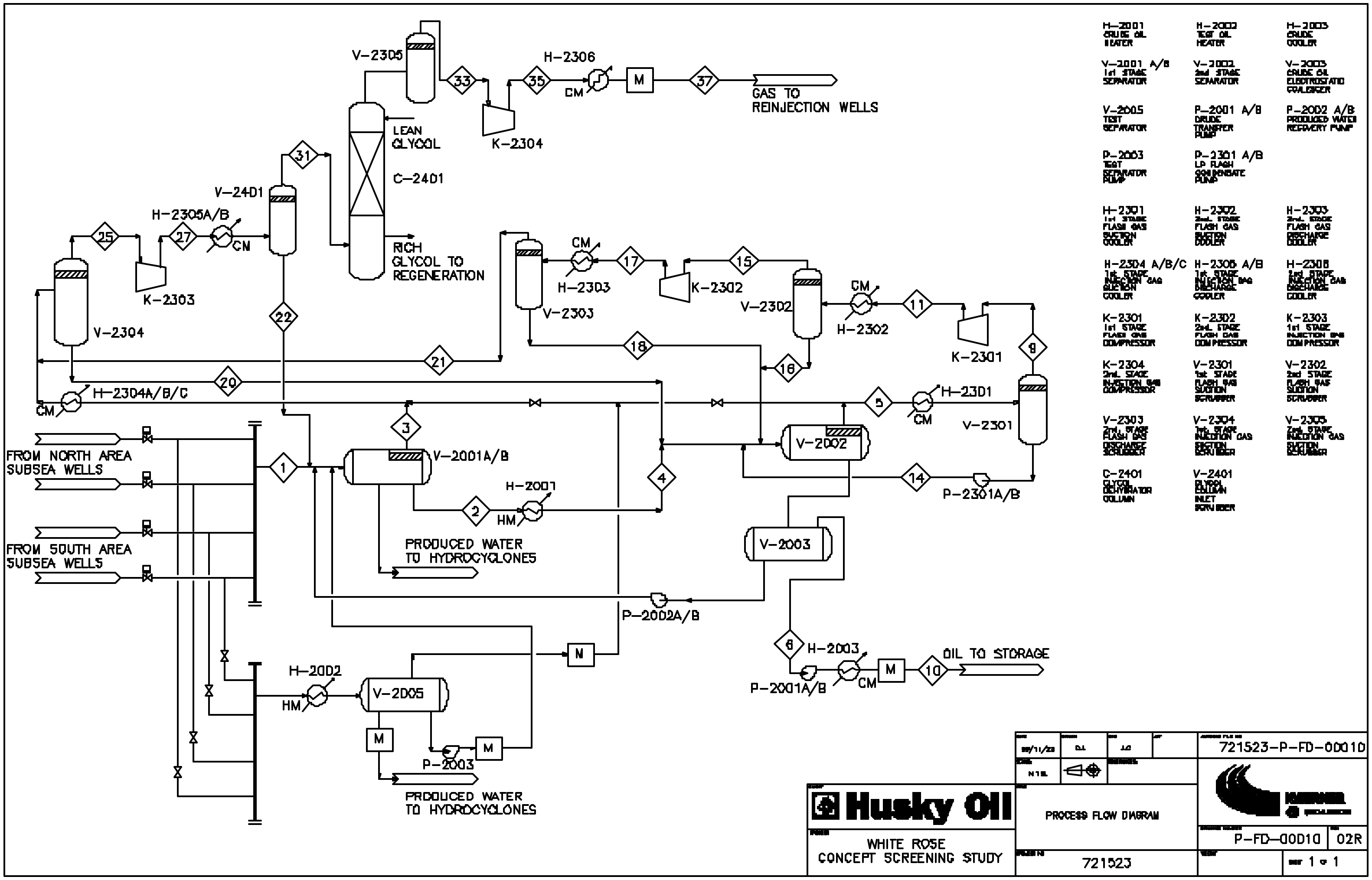
The configuration and layout of the modules/PAUs/skids will be determined giving consideration to Canadian/Newfoundland fabrication capability, safety, operability, maintainability, constructability, construction sequence, schedule, installation, hook-up and commissioning. The precommissioning and functional testing of the modules/PAUs/skids will be maximized prior to departure from the fabrication site to the at-shore hook-up and commissioning site.

The main topside facilities are expected to consist of the following:

- production from subsea wells;
- two stage oil stabilization;
- crude heating using a fired heater;
- oil dewatering using an electrostatic coalescer;
- test separation;
- produced water clean-up using hydrocyclones;
- a single train of two stage flash gas compression driven by electric motors;
- a single train of two stage gas injection compression, each stage driven by a gas turbine;
- gas dehydration by glycol contact;
- process cooling using a closed circuit cooling medium system;
- power generation using gas turbines; and
- flaring for emergencies only.

As discussed in Section 9.3, the crude oil will be stored in the FPSO tanks and offloaded to a tanker by a flexible hose. The offloading facilities will be located at the stern of the FPSO and incorporate a fiscal metering system as an integrated package. The offloading hose will be of an appropriate length, circumference and specification. Storage facilities will be provided for the hose when not in use.

## Figure 9.2–2 Process Flow Diagram



Design of the storage facilities and offloading system will ensure the crude oil remains above a temperature that will avoid problems associated with wax.

#### 9.2.2.1 Pigging

The topside facilities will include provision for launching and receiving operational pigs. The facilities will be configured so that pigs can be launched down and received from all production and production/test risers entering the turret.

#### 9.2.2.2 Layout

The initial topsides layout is shown in Figure 9.2-3. It may also be viewed isometrically in Figure 9.2-1.

The topsides layout is to be reviewed and is subject to change during the detailed design process.

The equipment will be arranged in skids. Each process or utility subsystem will be largely self-contained within a skid so that hook-up may be minimised and to enable a maximum degree of at-shore commissioning.

It is anticipated that the layout will be based around a central piperack (sections of the piperack are fabricated on each skid) and hook-up between skids will be at the piperack only.

### 9.2.3 Process Utility Support Systems

The following topsides utilities systems will be required to support the process systems.

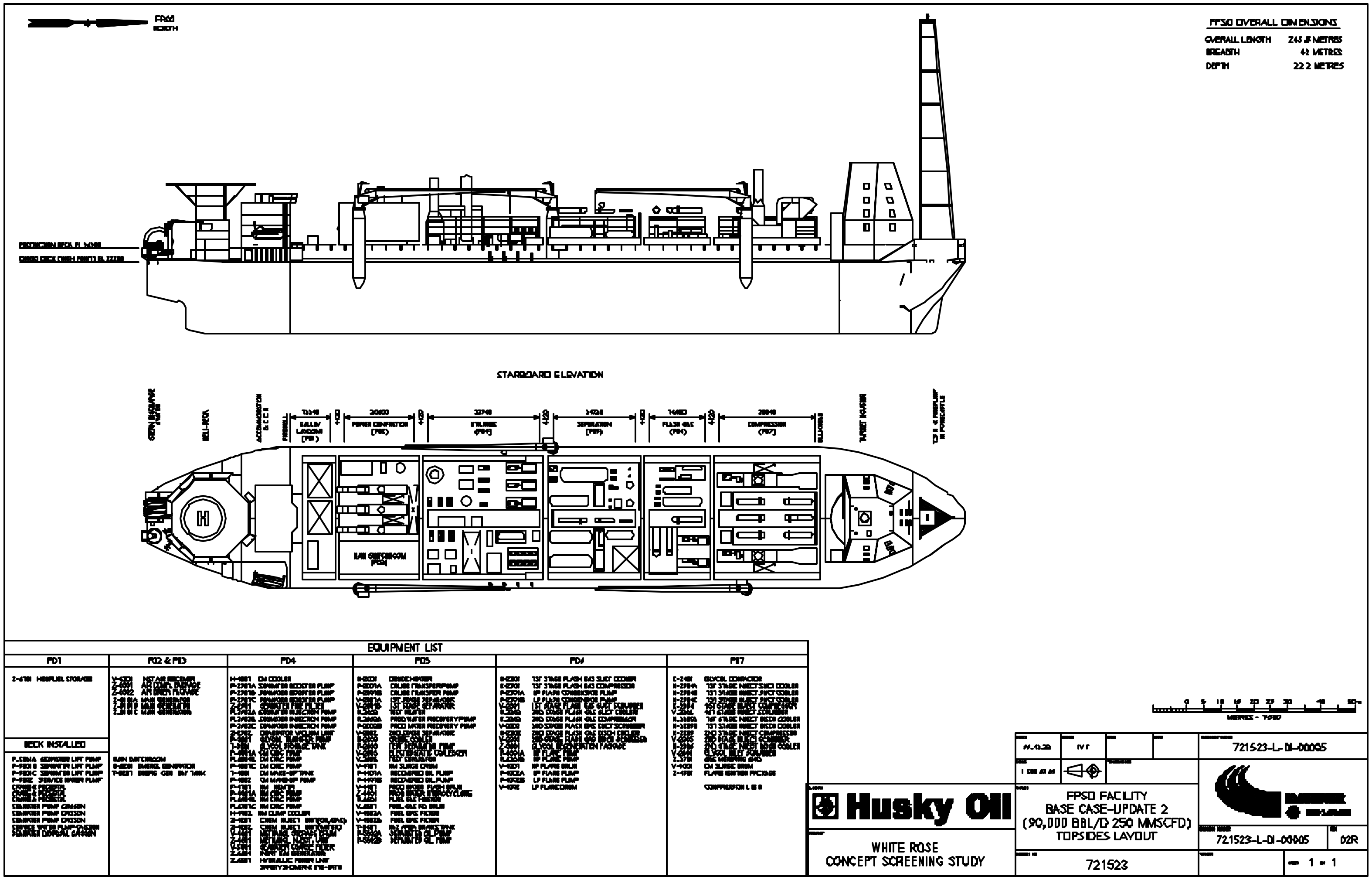
#### 9.2.3.1 Produced Water Treatment

All produced water will be treated prior to disposal overboard. All produced water disposed of overboard will meet the requirements of the 1996 Offshore Waste Treatment Guidelines (NEB, C-NOBP and C-NSOPB 1996). This primarily requires produced water to be treated to reduce oil concentrations of dispersed oil to the following levels:

- 40 mg/L or less as averaged over a 30-day period; and
- 80 mg/L or less over any 48-hour period.

The feasibility of using produced water to meet Husky Oil's water injection requirements will be investigated during the detailed design process, as well as the feasibility of reinjecting all produced water rather than discharging overboard.

**Figure 9.2–3 Topsides Layout**



Water injection requirements will be met by treating and injecting seawater. Facilities for deoxygenating, filtering and preventing bacterial growth will be included in the topsides.

#### 9.2.3.2 Cooling Medium

The cooling medium system is shown on the system utility flow diagram (Figure 9.2-4).

A cooling medium system, whereby the cooling medium is circulated in a closed loop and is itself cooled by seawater, is proposed for the present evaluations.

A tri-ethylene glycol/water solution is proposed for the cooling medium. The cooling medium will be cooled in a plate exchanger.

#### 9.2.3.3 Heating Medium

Heating medium will be required for the crude heater and the test heater. The possible requirement for production heating to prevent wax formation in the separators will be quantified following confirmation of the wax formation temperature.

#### 9.2.3.4 Seawater Lift

Seawater will be required for injection into the reservoir to maintain reservoir pressure and also to cool the cooling medium. The seawater system is shown on the seawater system utility flow diagram (Figure 9.2-5).

It is anticipated that seawater will be lifted by three lift pumps (two operating and one spare).

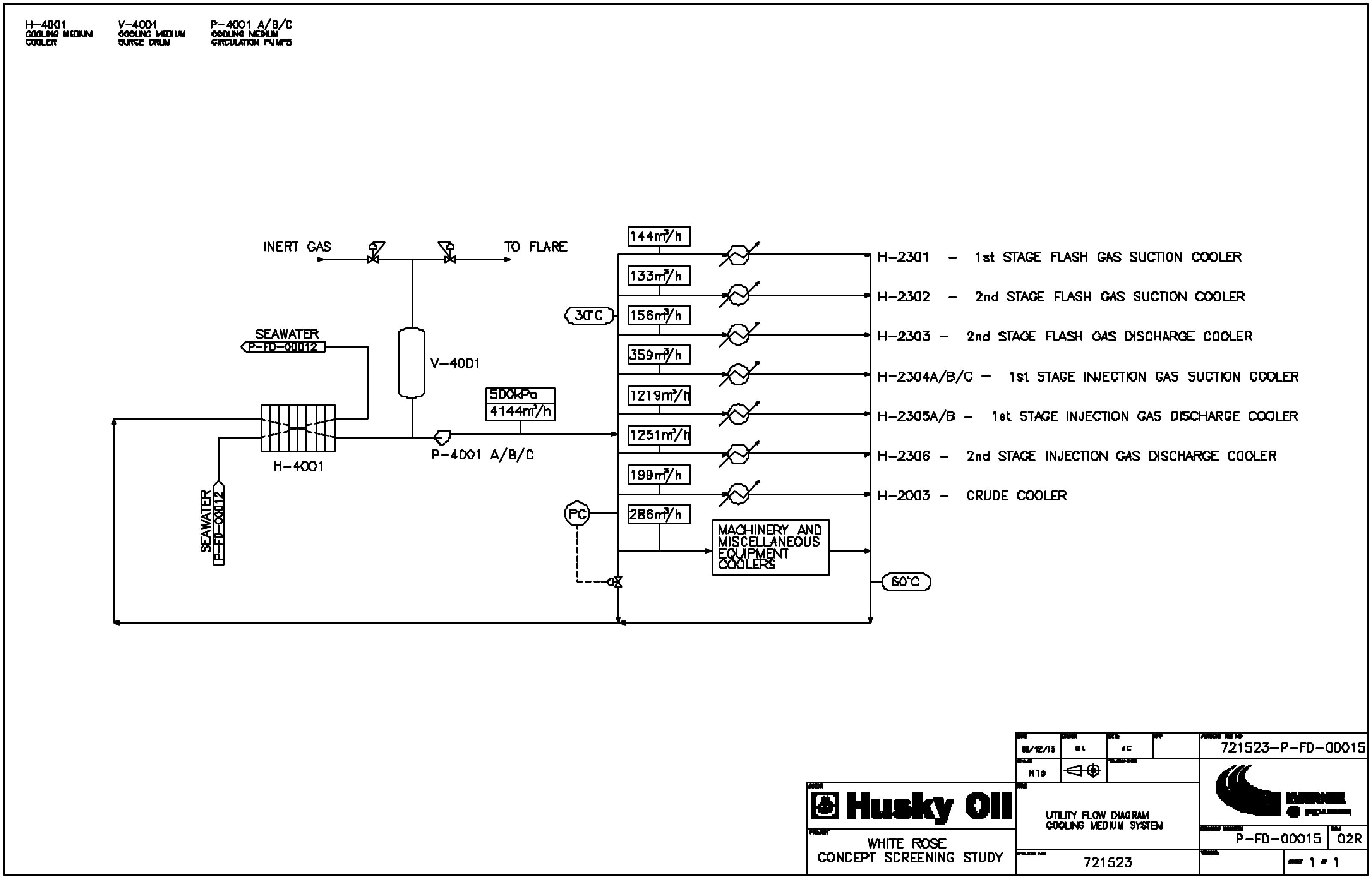
It is anticipated that the seawater will be filtered to approximately 100 micron in coarse filters and dosed with sodium hypochlorite to prevent marine growth. The hypochlorite will be generated by electrolysis of seawater.

#### 9.2.3.5 Seawater Injection System

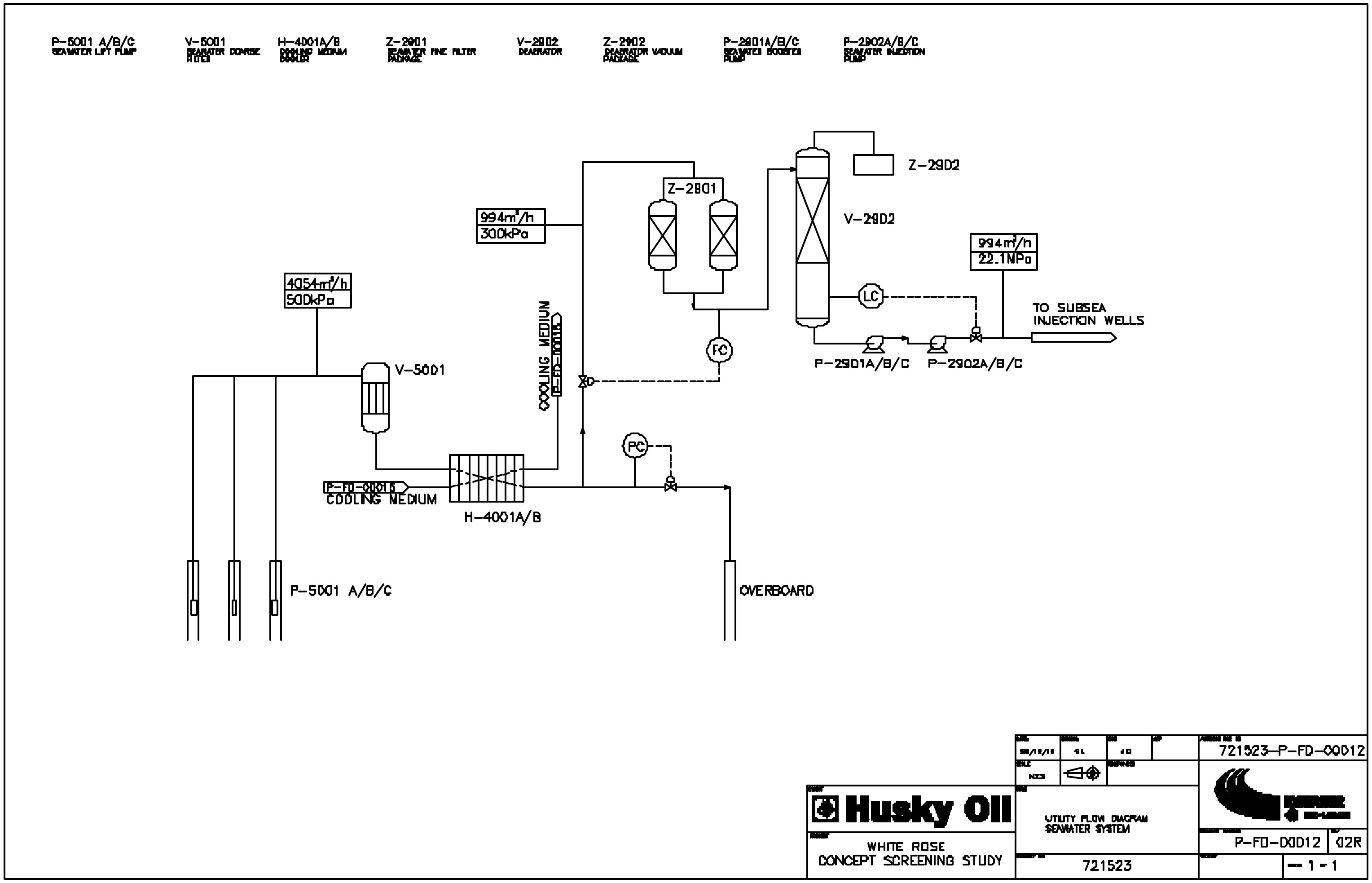
Initial plans are to use filtered seawater. Final filtration levels will be determined once the reservoir filtration requirements have been determined.

It is expected that the seawater will be de-aerated prior to injection to prevent corrosion in the injection wells and possibly the injection water flowline.

## Figure 9.2–4 Utility Flow Diagram – Cooling Medium System



## Figure 9.2–5 Utility Flow Diagram – Seawater System



The de-aeration system will be either the conventional vacuum de-aeration type or a catalytic system. This will be evaluated at a later stage in the project development.

#### 9.2.3.6 Fuel Gas

Fuel gas will be required for the gas turbine driven injection compressor drivers (if electrical drivers not chosen), for the main power generators, inert gas system and for the heating medium fired heater and steam boilers. Small quantities are used for flushing, blanketing, flare pilots etc.

It is anticipated that fuel gas will be taken from the discharge of the first stage injection gas compressor, filtered, heated and then let down to the fuel gas system pressure (assumed to be 3,000 kPa, depending on turbine selection). The fuel gas knockout drum will act as an accumulator to allow the main generator turbines to change to diesel fuel if fuel gas pressure is lost.

#### 9.2.3.7 Flare and Vent System

There will normally be no continuous flaring. The largest continuous flaring load is likely to be the flash gas which may be flared at start up, and which will be within the flaring consent limits if the flash gas compression system fails.

Flaring will normally only occur during non-steady state or emergency conditions. The largest relief load will be the gas injection compressor blocked discharge when 7 $10^6$ $m^3/d$ may have to be flared.

During design, measures will be evaluated to reduce atmospheric emissions wherever possible. The use of fuel gas and reinjection of produced gas are two of the means that will be employed. Further discussion of air emission strategies may be found in the EIS (Comprehensive Study Part One).

#### 9.2.3.8 Drain Systems

The vessel will be provided with three separate drain systems to handle the three different types of fluid. The hazardous drainage liquids from process equipment and piping will be carried in closed drains for recycling through the second-stage separator and produced water treatment system. Water subject to contamination from hydrocarbons around equipment will be collected in open drains and conveyed to the oily water sump tank. Other routine drainage from precipitation or washdown operations will be collected in open drains and discharged overboard in accordance with 1996 Offshore Waste Treatment Guidelines (NEB, C-NOPB and C-NSOPB 1996).

#### 9.2.3.9 Oily Water Treatment

In the case of open drains for areas around, or containing, process equipment, the liquids will be collected and piped into an oily water sump tank. Oil will be skimmed from these sumps and pumped into a reclaimed oil sump. The clear water remaining will be discharged overboard in accordance with 1996 Offshore Waste Treatment Guidelines (NEB, C-NOPB and C-NSOPB 1996). Closed drain liquids will be routed to a closed drain flash drum. Oil from the closed drain flash tank will be routed to the reclaimed oil sump. The oil accumulated in the reclaimed oil sump will be pumped to the inlet of the medium pressure production separator.

#### 9.2.3.10 Chemical Injection

The following chemicals may be required for normal production operations:

- methanol;
- corrosion inhibitor;
- demulsifier;
- wax inhibitor;
- scale inhibitor;
- oxygen scavenger;
- antifoam;
- biocide;
- asphaltine inhibitors;
- hypochlorite;
- polyelectrolyte; and
- hydrogen sulphide scavengers.

Chemical injection requirements will be determined during the design phase and adjusted based on actual production performance.

#### 9.2.3.11 Potable and Service Water

Potable water will be primarily supplied from supply boats. Freshwater generators will be installed for the back-up provision of potable water. Regular service water for washdown services will be seawater provided by a service water system.

#### 9.2.3.12 Fire Water

Fire protection for the facility will be provided by a fire water system. The system will be designed such that it will incorporate appropriate back-up means of operation. A water fog system will be provided for the protection of vessel machinery spaces.

#### 9.2.3.13 Nitrogen

A nitrogen system will be provided for flushing and inerting purposes.

#### 9.2.3.14 Jet Fuel

Helicopter fuel storage and pumping facilities will be installed.

#### 9.2.3.15 Diesel

To maintain operability of systems during shutdown periods, a diesel storage and distribution system will be provided for supply of fuel to the back-up power generation system.

#### 9.2.3.16 Compressed Air

Utility air and air for instrument operation will be provided by a compressed air system.

#### 9.2.3.17 Inert Gas

Gas blanket requirements for crude oil storage tanks will be met by installing an inert gas system.

#### 9.2.3.18 Hydraulic Power

Hydraulic power may be provided by the installation of a central hydraulic storage, pumping and distribution system. This will provide high pressure hydraulic fluid to all points where such service is required.

#### 9.2.3.19 De-icing

If required, de-icing of the superstructure will be accomplished by heat tracing and steaming facilities. Chemicals may be used for de-icing in certain circumstances.

### 9.2.4 Safety and Control Systems

Personnel safety will be paramount in the design of the facilities. This will apply to layout, construction and the provision of safety systems, which will include:

- emergency shutdown valves;
- flare and blowdown;
- hazardous drain system;
- fire and gas detection;
- active and passive fire protection; and
- personnel escape routes, temporary safe refuge and evacuation.

A safety shutdown system will be implemented for the protection of personnel, environment and equipment from accidental or aberrant operating conditions. This will isolate equipment or systems which may be detrimental to safety in the abnormal operating condition that has arisen. Several shutdown levels corresponding to various conditions are foreseen. Examples are as follows:

- Level 1: Abandon Platform Shutdown;
- Level 2: Emergency Shutdown;
- Level 3: Process Shutdown;
- Level 4: Partial Process Shutdown; and
- Level 5: Unit Shutdown.

The system will include the control and process shutdown system, the fire and gas system and the emergency shutdown system. These will operate separately, but will have common supervisory operators via an integrated, network-based system. The operator consoles will be located in the central control room, alongside other control packages.

It is anticipated that twin escape routes will be provided below the process deck. Three sides of these will be protected by walls, while the outboard side will be partially open. Temporary safe refuge areas will be provided and evacuation plans will be prepared.

In the event that an unsafe condition develops, the safety shutdown condition will be communicated by audio-visual alarms in the central control room and throughout the facility.

Safety valve actuators will be for use exclusively in safety shutdown conditions. They will not be used in routine operations. Emergency shutdown valves will be provided subsea and on the inlet manifold above the riser connectors to ensure isolation of the process facility.

Depressurization of the topside facilities and vessel systems will be done manually for all safety shutdown levels, except for Level 1 where depressurization will occur automatically.

The various areas will be classified in accordance with codes and regulations that will serve as a basis for the selection of electrical equipment and the control of ignition sources.

For further description of safety and control systems planned for the operation, refer to Volume 5 (Safety Plan and Concept Safety Assessment).

#### 9.2.5 Power Generation

The generators will be sized to meet the electrical loads of the FPSO vessel, both for normal and emergency operation. They will be dual-fuelled, able to function on produced gas or diesel. As well, for security, there will be provision for further diesel-driven power generation for emergency.

It is anticipated that a power generation capacity of 15 MW will be required to service the electrical needs of all onboard equipment, except for the FPSO's systems and crude offloading. It is expected that the latter will be supplied by the FPSO's electrical systems.

The electrical load is assumed to be supplied by turbine driven generators.

### 9.3 Subsea Facilities

The subsea facilities for White Rose will include all equipment necessary for the safe and efficient operation and control of the subsea wells and transportation of production and injection fluids between the wells and the FPSO. Anticipated operations include but are not limited to:

- steady state production with and without gas lift;
- steady state water and gas injection;
- planned and emergency shutdown;
- start-up after shut down with and without gas lift;
- SCSSV leak off tests;
- hydrate, scale and wax inhibition;
- well intervention and workover;
- well treatments (for example, squeeze);
- production and gas lift choke replacement;
- subsea control module replacement;
- tie-in future facilities and possible future prospects;
- flushing and round-trip pigging;
- emergency intervention/repair activities;

- ability to flush lines in case of iceberg encroachment;
- temporary and final field abandonment; and
- controlled and emergency disconnect of the spider buoy from the FPSO.

The subsea facilities include all wellhead completion equipment, trees, manifolding, flowlines, umbilicals, risers, seabed structures, control systems and all interfaces required to control and operate the facilities and associated test, installation, inspection and maintenance equipment. Wellhead equipment, trees and manifolding structures (templates or clusters) will be located in open glory holes for iceberg protection.

In general, the subsea facilities will be designed for diverless installation, operation, inspection and maintenance, and will be based on field-proven designs wherever possible. Technology development will only be undertaken where there is a clear economic justification to do so and where the schedule allows this. New designs will be subject to comprehensive qualification testing.

The subsea facilities will be configured to allow production well testing to be performed by routing individual wells through a test flowline to the test separator on the FPSO. Whenever well testing is not ongoing, the test line will continue to be used for production to mitigate wax formation in the line. Facilities will also be provided to permit round trip pigging of the production and test lines from the FPSO.

As a minimum, metal to metal sealing will be used for all surfaces with potential for sustained exposure to well fluids.

It is anticipated that remotely operated choke valves will be included for the production, gas lift, gas injection and water injection wells. The potential requirement for back-flowing of the injection wells needs to be addressed.

The overall availability target for the subsea facilities must be compatible with the overall availability target set for the whole facility.

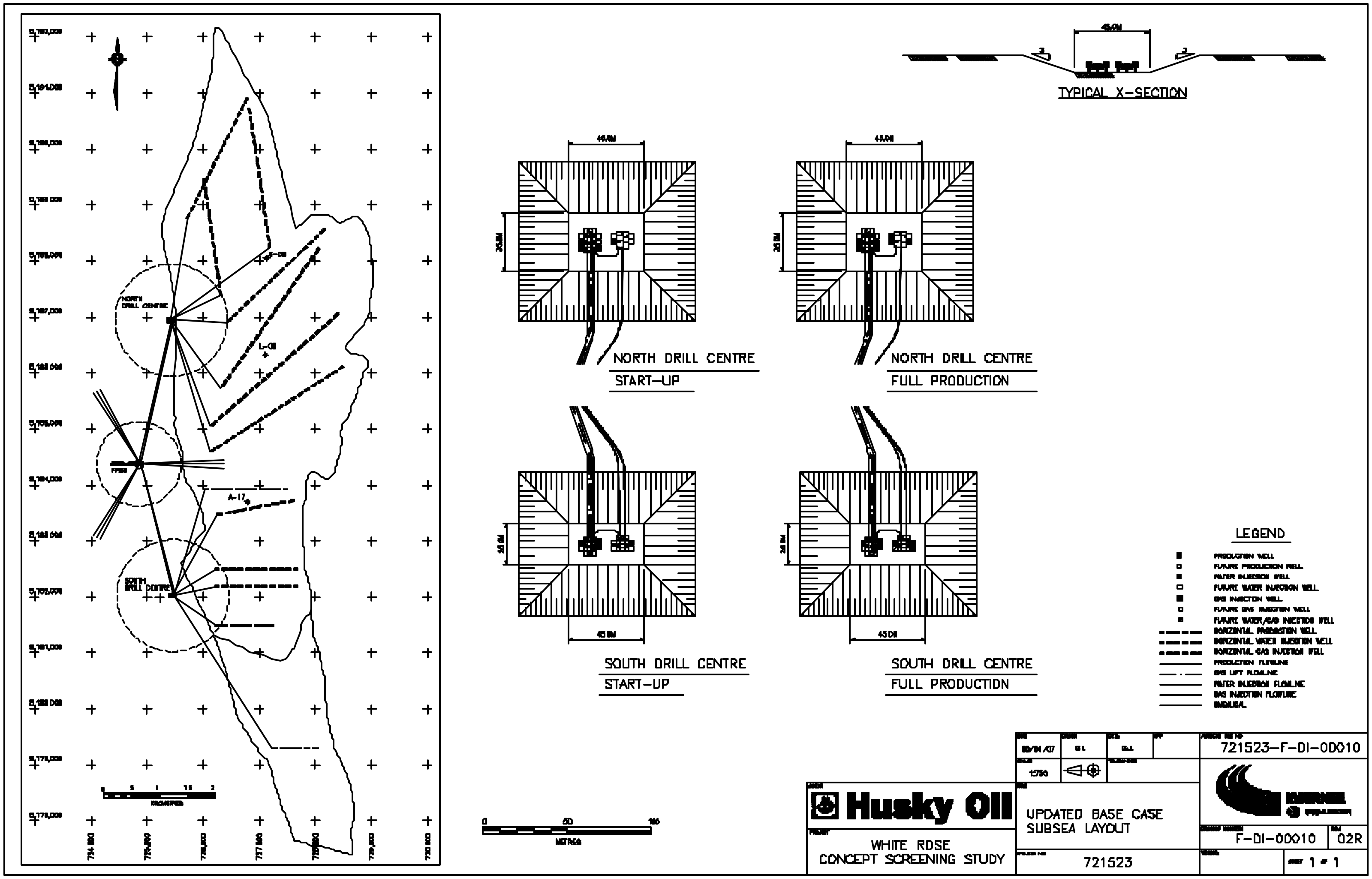
A possible layout of the subsea facilities is shown in Figure 9.3-1.

### 9.3.1 Manifold Systems

The subsea facilities will provide a means to co-mingle the flow from the subsea wells via a manifold. The manifold will be retrievable independently of the trees and provide sufficient flexibility to satisfy the operational requirements and also possible future expansion requirements.

Valving will be incorporated to allow for remote switching of flow between test and production headers.

Figure 9.3–1 Subsea Layout



Isolation will be incorporated into the design so that intervention on one tree or its choke valve(s) will not impede the normal operation of other wells connected to the same production/test/gas lift/injection header. In addition, where a tree connection is not used, provision will be made for installation of a pressure cap, which may remain exposed over extended periods.

Where the manifold foundation also comprises the well foundation in the form of a template, the template will be designed to be installed by the MODU in a safe manner, preferably through the moonpool.

To facilitate round trip pigging operations, a remotely actuated valve will be placed between test and production headers.

#### 9.3.2 Chemical Injection

Provision will be incorporated in the subsea facilities and subsurface for the injection of chemicals. Isolation for ports where chemical is injected into the production stream will be in accordance with API 17D. At least one of the barriers will be a remotely operated valve. The provision for metering the injection of chemicals will be addressed.

#### 9.3.3 Subsea Completion System

It is currently envisaged that the subsea completion system will be designed around the use of vertical or horizontal christmas trees and a 476 mm wellhead. These wellheads may be used either in a glory hole or using a caisson system.

Two types of christmas trees are required:

- production with gas lift capability; and
- injection (water and gas).

The use of common subassemblies across tree designs will be adopted.

The requirement for reverse flowing of the injection trees has yet to be addressed.

Two independent and tested barriers will be available in order to prevent discharge from the well.

The completion system will be designed to be normally deployed through a conventional rotary table and moonpool. The completion system will include an installation/workover control system.

### 9.3.4 Subsea Control System

The subsea control system is presently expected to be an open loop, multiplexed electro-hydraulic system. The system will feature both subsea and FPSO located equipment. The level and location of the FPSO equipment will depend on overall field facility control philosophy, topsides equipment layout and turret design.

The subsea and FPSO located control equipment will be connected via electo-hydraulic control umbilicals (see Section 9.3.5).

The control system will be designed to supply sufficient hydraulic fluid (high pressure (HP) and low pressure (LP)) to control the remotely operated valves on the manifolds and christmas trees at all drill centres. Consideration will also be given to possible future expansion requirements. In selection of a control fluid, particular attention will be given to the ambient environmental conditions discussed in Section 8.3.1. The system will also be designed to request, assimilate and transmit data from downhole, tree and manifold mounted instrumentation as required.

All subsea located equipment that is retrievable will be done by remotely operated vehicle (ROV) without the requirement for divers.

### 9.3.5 Subsea Control Umbilicals

The control umbilicals will be designed and manufactured to an appropriate industry standard with particular reference to API 17E.

They will convey HP and LP hydraulic fluids and chemical injection fluids and provide electrical cable paths from the FPSO to the subsea facilities. The requirement for spare cores within the umbilical is yet to be addressed.

The umbilicals will be fully compatible with the intended service duties (pressure, temperatures, control and chemical injection fluids, voltages and currents) without degradation for the design life. The umbilicals will also cater to any specific downhole or tree service operations as required.

Wherever possible, umbilicals will be a single continuous length. If this is not possible, the number of midline connections will be kept to a minimum.

The umbilicals will be comprised of static sections which will remain stable on the seabed under all operational and environmental loadings, and dynamic sections which will be designed to be compatible with the design of the dynamic risers and FPSO mooring lines.

#### 9.3.6 Flowlines and Risers

The flowlines and risers for White Rose will be designed to an applicable industry standard (API 17J). They will provide an unobstructed flow conduit between the subsea facilities and the FPSO and will be fully compatible with the intended service duty for the entire design life. Appropriate valving will be installed subsea to control flows in both normal and emergency situations.

Design of the flowlines and risers will ensure that no maintenance is required during the design life, other than external inspection using an ROV and damage repair and operational pigging. Flowlines will be designed to be stable on the seabed and risers designed to be compatible with the mooring lines and dynamic umbilicals. In addition, the risers will not be allowed to touch the seabed or break the sea surface other than is intended by design.

#### 9.3.7 Insulation Requirements

The subsea facilities, including flowlines, will be insulated as required to meet the minimum arrival temperature at the top of the riser. This temperature will be the optimum temperature to satisfy both wax and hydrate formation criteria. Additionally, the selected hydrate and wax prevention strategy will be taken into account in order to ensure a safe and good practice in operation of the subsea system for both regular production and well testing scenarios. Insulation will also be designed to provide a minimum reasonable period for repair and restart in the event of an unplanned shut down, to minimize gelling of the crude in the lines.

#### 9.3.8 Subsea Tie-in and Connection Systems

Initial field installation tie-ins and connections may be by either diver or diverless methods. Any connections that are required to be broken for maintenance and repair subsequent to initial installation will be by diverless methods. The final choice of tie-in and connection method will be made with due regard to safety, economic and feasibility considerations.

#### 9.3.9 Iceberg Protection

The White Rose oilfield is subject to scouring icebergs and the design of the subsea facilities will consider the following:

- the location of wellheads, christmas trees and manifolds in glory holes, with the top of the equipment a minimum of 2 to 3 m below the seabed level. This does not apply to components not critical to the integrity of the well;
- flowline trenching;
- rock backfilling;

- requirement for overtrawlability;
- design loads from fishing activities resulting from fishermen accidentally entering the safety zone;
- transfer of loads from icebergs to flowlines and umbilicals to ensure that well integrity is not compromised;
- design loads of snag and dropped objects; and
- flowline weak link technology.

In addition, the following inherent safety features will be built into the design of the subsea facilities:

- all subsea systems will be designed to be fail-safe (that is, all hydraulically operated isolation valves will automatically close if hydraulic power is lost); and
- any abnormal operating conditions resulting from control system damage, which endangers the safe operation of the subsea facilities, will trigger an automatic system shutdown.

### 9.3.10 Cathodic Protection

The subsea facilities will be protected from seawater corrosion for the life of the field by use of sacrificial anodes. Design of the protection system will be in accordance with an appropriate standard, for example DNV RP B401, but due consideration will be given to local conditions and regulatory requirements.

### 9.3.11 Interfaces

The following key interfaces will be addressed during the FEED phase:

- well construction:
  - MODU characteristics and operations,
  - drilling and completion activities,
  - logistics,
  - potential for carrying out installations from MODU, and
  - number of wells, glory holes and drill centres;
- FPSO mooring and turret
  - subsea layout will comply with the layout of the FPSO and mooring system,
  - dynamic riser configuration will be based on results of mooring design,
  - number and type of swivel paths; and
- topsides
  - identification of requirements for chemicals, electrical & hydraulic power, control & process interfaces,
  - integration of subsea control system with topsides control system, and
  - maximum pressures, temperatures and flow rates of production and injection fluids.

### 9.3.12 Oil Spill and Leak Protection

The goal in the design and operation of all subsea facilities will be to ensure that any possible iceberg impact will result in no pollution. The ice management system, described in Section 11.3, will be in operation, and continuous monitoring of iceberg locations, drifts and forecast trajectories will be maintained during the iceberg season.

Provision will be made in the design for subsea oil production lines to be shut down and flushed, and for the FPSO to be disconnected from the subsea facilities, in the event that a scouring iceberg enters the area.

Flowlines may be trenched to reduce the risk from scouring icebergs, improve the thermodynamic characteristics, or provide on-bottom stability.

## 9.4 Export System

### 9.4.1 Offloading System

It is envisaged that the offloading facilities will be located at the stern of the FPSO and incorporate a fiscal metering system as an integrated package. The offloading hose will be of an appropriate length, circumference and specification. Storage facilities will be provided for the hose when not in use.

Design of the storage facilities and offloading system will ensure the crude remains above a temperature that will avoid problems associated with wax, including an appropriate safety margin.

The offloading system and offloading rate will be designed with regard to the environmental conditions in the field, such that the availability of the facility is not compromised by weather limitations which inhibit shuttle tanker connection or cause disconnection.

The offloading system will include a mooring hawser complete with messenger line, and all equipment necessary for handling and storing of the hawser. The tension in the hawser will be monitored continually while the shuttle tanker is connected and emergency disconnect will be provided.

Telemetry and communication systems necessary for both the safe approach/mooring of the shuttle tanker and control of the offloading operation will be provided on the FPSO.

### 9.4.2 Shuttle Tankers

Shuttle tankers will be used for exporting White Rose crude to markets in Eastern North America, the U.S. Gulf Coast or to a transshipment facility, such as the one currently operating at Whiffen Head.

Depending on the distance to market and on the volumes of crude to be exported, one to three tankers will be required. They will be sized appropriately for the transportation requirements and will be designed according to current relevant codes and standards, with due consideration of East Coast environmental conditions. They will be bow-loading and capable of connecting to the FPSO offloading system in significant wave heights of 5 m.

## 9.5 System Efficiency

The White Rose facility is expected to have a system efficiency in the range of 90 to 94 percent. This is consistent with experience on similar operating facilities in the North Sea and elsewhere.