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2 PROJECT DESCRIPTION

This Chapter describes the attributes of the Project and discusses the review of Project alternatives that lead to the preferred development strategy from construction through operations to decommissioning and abandonment. The Project schedule is also provided.

2.1 Project Need and Justification

The Hebron Project will be a major contributor to the economic development of Newfoundland and Labrador, as well as to Canada. The Hebron Project will be Newfoundland and Labrador's fourth offshore oilfield development project. As such, it will build on and contribute to the multi-phase offshore petroleum industry in the province. In particular, the Project will provide substantial benefit through diversity programs, employment and training opportunities, business opportunities for the local service and supply community, and research and development opportunities, further expanding the Province's industrial capabilities.

In 2008, the Project Proponents and the Province signed a Benefits Agreement. Through this Agreement, the Hebron Project has made significant commitments to the people and government of the Province for engineering work, diversity programs, education and training, research and development, and construction and fabrication in the Province.

The Project has committed to providing significant person-hours of work in Newfoundland and Labrador during the six-year design, fabrication and construction phase, including local Project management, front-end engineering and design (FEED), detailed design and construction of the Gravity Base Structure (GBS), with additional employment during construction of Topsides modules.

During the operations phase, there will be employment opportunities in areas such as logistics, engineering and technical support, drilling and production, marine support vessels (helicopters, supply vessels, tankers), catering, and similar onshore support. These opportunities during construction and operations will further develop the capabilities of Newfoundland and Labrador companies and individuals working on the Project, and thereby enable local companies and individuals to develop capabilities to compete internationally on future opportunities.

Throughout its operations, the Project will also contribute substantial revenues to the provincial government through corporate taxes and royalty payments. If approved, the Hebron Project will extend the life of the offshore oil and gas industry in Newfoundland and Labrador. It represents an important next step in the development of a sustainable offshore oil and gas industry in Newfoundland and Labrador.

2.2 The Hebron Asset

The Hebron Asset is composed of four reservoir intervals organized into several normal fault-bounded fault blocks. The central horst block is the Hebron field, and the down-dropped fault blocks to the northeast are the West Ben Nevis and Ben Nevis fields. The down-dropped fault block to the southwest forms the Southwest Graben (Figure 2-1). The four stratigraphic units are the Late Jurassic Jeanne d'Arc formation, the Early Cretaceous Hibernia formation, the Early Cretaceous Avalon formation and Early Cretaceous Ben Nevis formation.

The four vertically stacked reservoirs and multiple fault blocks contribute to the complexity of the multiple hydrocarbon columns with different contacts at the Hebron Asset. To simplify communication, the Hebron Asset is currently divided into five major pools (although other hydrocarbon-bearing pools beyond these exist). The pools, shown in Figure 2-1, are defined as follows:

- Pool 1: Hebron Field, Ben Nevis Reservoir, including the fault block penetrated by the D-94 and M-04 wells and the fault block penetrated by the I-13 well
- Pool 2: West Ben Nevis Field, Ben Nevis Reservoir, penetrated by the B-75 well
- Pool 3: West Ben Nevis Field, Avalon Reservoir, encountered in the B-75 well and the Ben Nevis Field, Ben Nevis Reservoir, encountered in the L-55 and I-45 wells
- Pool 4: Hebron Field, Jeanne d'Arc Reservoir, including the isolated B, D, G and H hydrocarbon-bearing sands, encountered in the I-13 and M-04 wells
- Pool 5: Hebron Field, Hibernia Reservoir, encountered in the I-13 and M-04 wells

The Ben Nevis Reservoir within the Hebron Field (Pool 1) is the core of the Hebron Project, and is anticipated to produce approximately 80 percent of the Hebron Project's crude oil. However, the 20 API crude in this reservoir presents production challenges, as the viscosity can be 10 to 20 times higher than that of water.

The Jeanne d'Arc and Hibernia Reservoirs within the Hebron Field (Pools 4 and 5) are also part of the Hebron Project. Relative to the Hebron-Ben Nevis Pool, the Jeanne d'Arc and Hibernia Reservoirs have higher oil quality but decreased reservoir quality consistent with deeper burial and cementation. The Jeanne d'Arc Formation has lower reservoir quality than the Jeanne d'Arc Formation of the Terra Nova Field, just as the Hibernia Formation at Hebron has lower reservoir quality than the Hibernia Formation of the Hibernia Field.

A depletion strategy for each of the reservoirs in the Hebron Project Area has been formulated. The depletion strategy balances economic value, risk mitigation and overall development flexibility to allow the reservoirs to be effectively managed over the life of the field. All reservoirs within the Hebron Asset are being evaluated with respect to risked production performance.

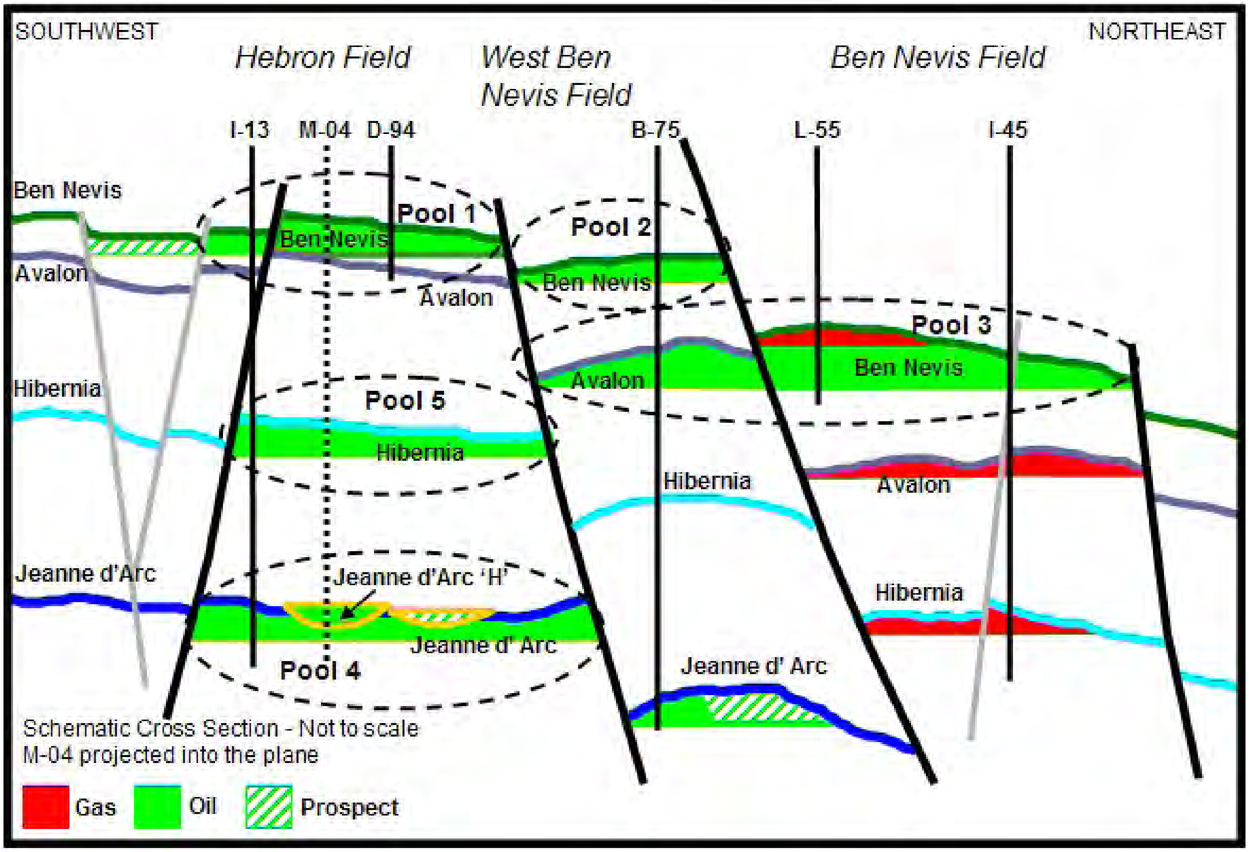


Figure 2-1 Schematic Cross-section across the Hebron Asset

The initial development phase consists of developing oil resources from the Ben Nevis, Hibernia and Jeanne d'Arc H and B Reservoirs within the Hebron Field, and gas storage in either the Ben Nevis Reservoir of the Hebron Field or in the Ben Nevis Reservoir of the West Ben Nevis Field. Water injection is planned as the primary drive mechanism for the Hebron Field to improve overall oil recovery. Forecasted cumulative oil recovery for the initial development phase after 30 years of producing life ranges from 87 Mm^3 (548 MBO) to 140 Mm^3 (883 MBO) from an anticipated 41 wells.

In addition to the initial development phase, there is opportunity for the development of additional pools in the Hebron Project Area, depending on the results of further drilling, production performance (of wells from the initial development), studies, possible delineation wells, additional seismic data or some combination of these. In anticipation of potential expansion development, the GBS will be designed to include 52 well slots. To maximize resource development, slots may later be reclaimed for re-use. Expansion development could also occur via sub-sea tie back(s) from seafloor drill centres. The platform will have space available for future installation of production facilities and J-tubes and/or risers to allow for such future expansion. For example, the Ben Nevis Reservoir in the Ben Nevis Field is being evaluated as a potential future subsea development that would tie back to the planned Hebron Platform.

Oil in the principal Ben Nevis Reservoir of Hebron Field contains a relatively low amount of associated gas. Even so, it is anticipated that during a portion of this field's productive life, the level of gas production will temporarily exceed the amount of gas that can be beneficially used in facilitating oil production. An integrated plan is being developed to ensure both efficient use of produced gas and a means of storing and conserving gas during temporary periods of surplus gas production. Later in field life, the gas production rate is expected to decrease in conjunction with a natural decline in oil production as water cut increases, and the gas previously stored may need to be withdrawn in order to provide fuel for platform operations. The gas management plan will take into account a number of considerations, including:

- Use of associated gas in applying artificial lift to oil producing wells
- Fuel requirements are expected to vary with time
- Down-time gas flaring (not continuous)
- Prospective subsurface location(s) for storing any temporary surplus of produced gas
- Potential need to withdraw gas that has previously been stored in order to provide fuel for platform operations
- Potential for using gas in any enhanced oil recovery method in the Hebron Offshore Project Area, should such a method be deemed technically and commercially viable
- Potential for future commercial gas production

2.3 Alternatives to the Proposed Project

As required under Section 16(2)(b) of the *Canadian Environmental Assessment Act* (CEAA), project alternatives must be considered for a comprehensive study-level of assessment. There are no economically or technically viable alternatives to the Project.

The significance of each of the environmental effects, including accidental events, proceeding with the Project is assessed in Chapters 6 to 12 of this Comprehensive Study Report (CSR).

2.4 Alternative Means of Carrying out the Project: Concept Selection

2.4.1 Alternative Means of Offshore Development

The selection of the preferred concept for development of the Hebron Project included consideration of environmental effects, safety, capital and operating cost, reliability, energy efficiency, constructability, and schedule for construction. Four potential concepts were considered in detail:

- Subsea wells tied back to Hibernia Platform
- Floating Production, Storage and Offloading (FPSO) facility in combination with subsea wellheads (wet tree), manifolds, pipelines and risers

- FPSO in combination with wellhead gravity base structure (WHGBS)
- GBS (with or without pre-drill alternative)

2.4.1.1 Tieback to Hibernia

In this concept (Figure 2-2), subsea wells would be drilled by a mobile offshore drilling unit (MODU) over the life of the Hebron field. Subsea equipment, including metering facilities, would be installed in two excavated drill centres, one for the Ben Nevis horizon wells and another for the Hibernia and Jeanne d'Arc wells. The produced fluids would be delivered to the Hibernia Platform (31.5 km to the north) from the excavated drill centres by two insulated, subsea, multi-phase, production lines using multiphase pumps.

The production lines would have round-trip pigging capability. The power for the multiphase pumps would be supplied by two independent power cables from the Hibernia Platform. Two umbilicals would control the subsea wells and isolation valves. Gas lift would be delivered from the Hibernia Platform to the subsea wells. Injection water would be supplied from the Hibernia Platform via a water injection line. All the flow lines, power cables and umbilicals would be installed in trenches to protect them from iceberg scour. Modifications to the separation, compression, power generation and water injection systems on the Hibernia Platform would be required.

2.4.1.2 FPSO with Subsea Wellheads

A FPSO with subsea satellite wells concept would entail subsea wells being drilled using a MODU (Figure 2-3). Subsea wells would be located in excavated drill centres to protect them from iceberg scour. Production fluids would be transferred to a FPSO via flowlines and flexible risers.

The FPSO would be double-hulled and double-bottomed, with appropriate storage capacity for crude oil, thrusters (for heading control), and would house the oil treatment, gas compression, gas lift, water injection and utility equipment, including power generation. It would also include quarters to house operations and maintenance personnel. The FPSO would stay on station by means of an internal, disconnectable turret anchored to the sea floor. In the event of an encroaching iceberg or dense pack ice, the FPSO would be able to disconnect and depart from the field. Stabilized crude oil would be stored in the FPSO prior to tandem loading onto ice-strengthened tankers for shipment to market or to the Newfoundland Transshipment Terminal.

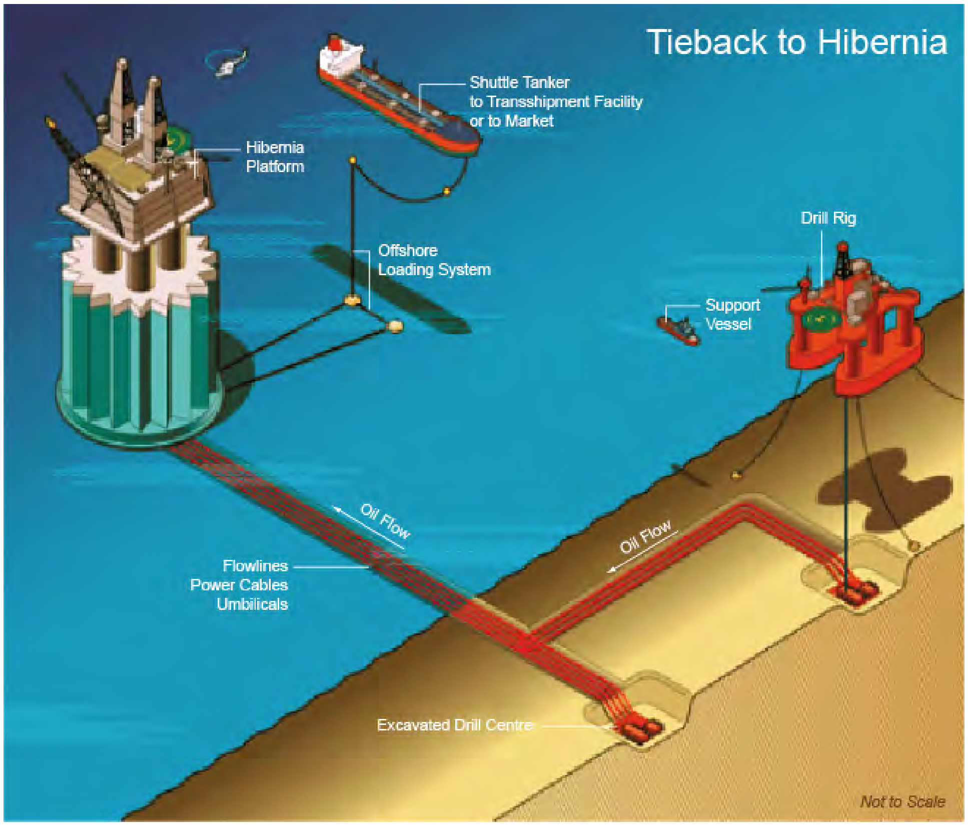


Figure 2-2 Tieback to Hibernia

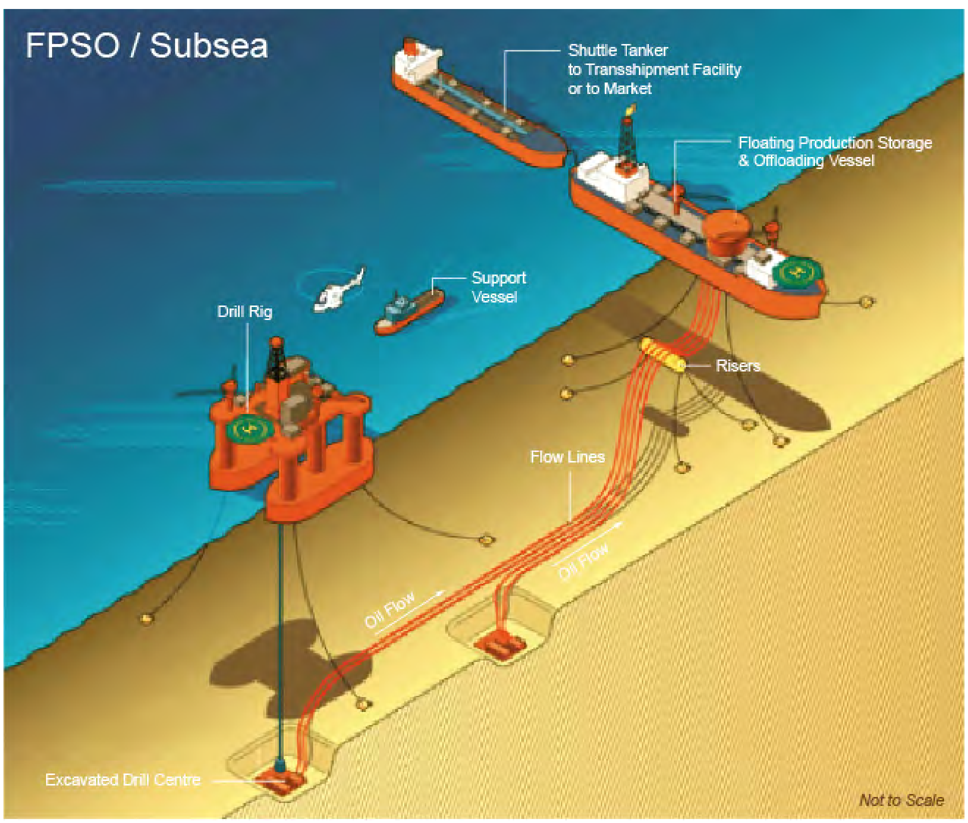


Figure 2-3 Floating Production, Storage and Offloading Facility and Subsea Infrastructure

2.4.1.3 FPSO with Wellhead Gravity Base Structure

This concept requires wells to be drilled from a concrete mono-tower WHGBS using a MODU in a tender assist mode (Figure 2-4). All wells (producers and injectors) would be drilled from the WHGBS. The WHGBS would be constructed and installed approximately two years prior to FPSO completion to enable pre-drilling and, hence, improved production ramp-up.

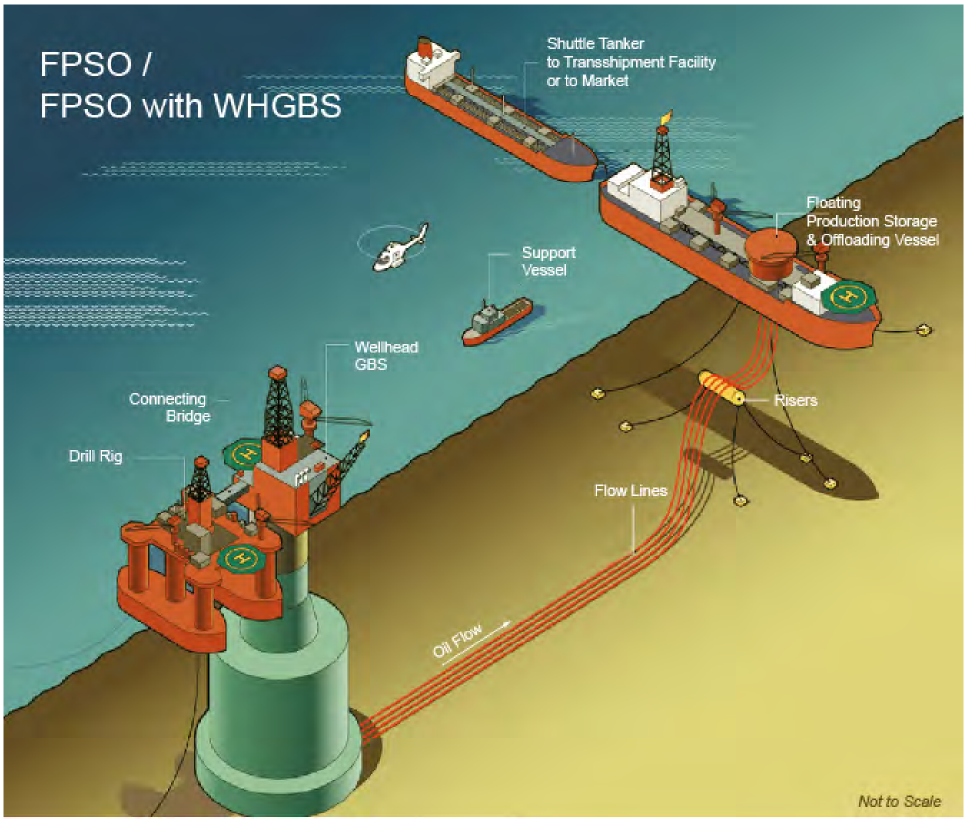


Figure 2-4 Floating Production, Storage and Offloading Facility with Wellhead Gravity Base Structure

The WHGBS would be configured with minimal topsides processing functionality to reduce the numbers of personnel on the structure. WHGBS process equipment would be limited to manifolding and well testing via multiphase meters. Utility systems, notably those involving rotating equipment, would be limited. Trenched pipelines, with riser base manifolding, would be used to tie the WHGBS to the FPSO. Injection water, gas lift and power to the WHGBS would be supplied by the FPSO. Oil export would be undertaken with ice-strengthened shuttle tankers loading in tandem off the stern of the FPSO.

2.4.1.4 Gravity Base Structure

The stand-alone GBS production facilities concept is similar to Hibernia and includes a concrete GBS with associated topsides (Figure 2-5). The GBS and topsides would be constructed separately and then mated at an inshore site prior to towing and installing the Platform at the Hebron site.

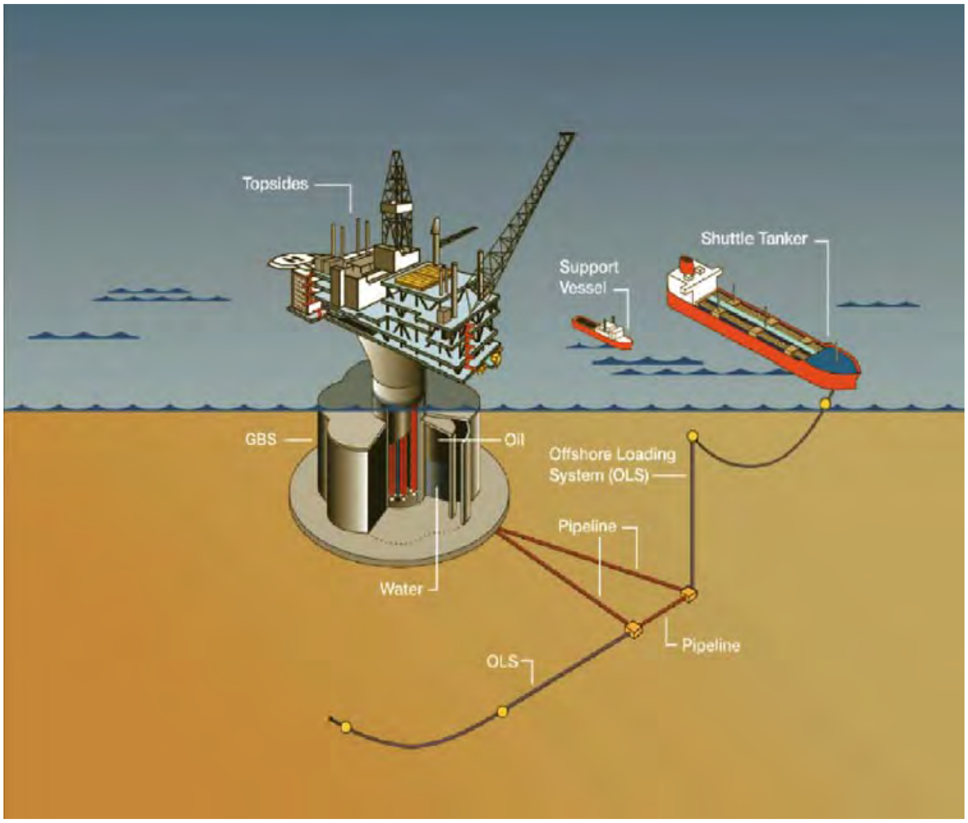


Figure 2-5 Stand-alone Gravity Base Structure Preliminary Development Layout

All wells (producers and injectors) would be drilled by the platform rig. Treated oil would be stored in the Hebron Platform prior to custody transfer metering and subsequent shipment. An offshore loading system (OLS), complete with a looped pipeline and two separate loading points, would be installed to offload the oil onto tankers for transport.

Pre-Drill Alternative

Within the stand-alone GBS option, consideration has been given to a pre-drill alternative, where some wells would be drilled prior to the arrival of the platform, through a pre-drill template.

With the pre-drill alternative, a MODU would be used to drill and partially complete the pre-start-up wells prior to the installation of the Hebron Platform. However, an excavated drill centre would not be constructed for the pre-drill option; the platform cannot be installed over an excavated drill centre. Rather, the well heads would remain, unprotected, above the sea floor until the platform was installed over the well heads. Drill cuttings, both water-based and non-aqueous fluid (NAF) based, would be processed and discharged overboard in accordance with Offshore Waste Treatment Guidelines (OWTG) (NEB *et al*., 2010).

Once the pre-drill has been completed, the platform is installed by floating the platform structure over the template, and lowering the platform to the seafloor. The pre-drilled wells would be connected to the platform topsides and then completed from the platform. The remaining wells would then be drilled by the platform rig in parallel with operations.

2.4.2 Alternative Means for Nearshore Construction

Construction of a drydock at a new greenfield site would have resulted in a measurable increase in the consumption of raw materials, fuel, energy, resources and resulted in higher environmental risks and greater environmental effects associated with the necessary dredging of a new graving dock and construction of required supporting infrastructure. Therefore, refurbishment of the existing Bull Arm Site was determined to be the preferred option for the site at which to construct the GBS, as well as Topsides integration work, hook-up and commissioning activities.

2.5 Preferred Concept: Hebron Project

The Project Proponents, using a concept selection strategy, evaluated the alternative modes of development, and determined that the preferred concept is to develop the Hebron Asset using a stand-alone concrete GBS (no pre-drill option) and topsides, and an OLS. No other option provides technical and economic certainty. Based on current Project requirements, the GBS (no pre-drill) is the only technologically and economically feasible option with comparable environmental effects, as illustrated in Table 2-1.

Table 2-1 Summary of Analysis of Alternate Means of Carrying Out the Project Showing Determination of Risk

Alternative Considered	Technical Feasibility	Economic Feasibility	Environmental Effects
Subsea tieback to Hibernia			
Subsea tieback to FPSO			
FPSO with WHGBS			
Stand-alone GBS (with pre-drill)			
Stand-alone GBS (no pre-drill)			
High - red; Medium - yellow; Low - green			

Neither FEED nor detailed design for the Topsides and GBS have been completed. However, the main criteria upon which the detailed design will be based are provided in Section 2.6.

2.6 Hebron Project Concept and Design

2.6.1 Hebron Project Concept

The GBS for the Hebron Project will be a post-tensioned reinforced concrete structure designed to withstand impacts from sea ice and icebergs, and the meteorological and oceanographic conditions at the Hebron Project Area. It will accommodate up to 52 well slots with J-tubes and/or risers for potential future expansion.

The GBS will be designed to store approximately 190,000 m^3 (1.2 Mbbl) of crude oil in multiple separate storage compartments. It will have a single main shaft supporting the topsides and will encompass all wells to be drilled from the platform. The GBS will be designed for an in-service life of 50 or more years. The Topsides facilities will include the following modules:

- Drilling Support Module (DSM)
- Drilling Equipment Set
- Flare Boom
- Utilities and Processing Module (UPM)
- Living Quarters, including helideck and lifeboat stations

A schematic of a typical GBS and Topsides layout are provided in Figures 2-6 and 2-7, respectively.

Production facilities will have the capacity to handle the requirements of drilling and production of crude oil, storage and export, gas management, water injection, and the management of produced water, for a production life of 30 or more years.

The Hebron Project will include an OLS to offload crude oil onto tankers for transfer to the Newfoundland Transshipment Terminal or directly to market. The currently planned OLS system, as shown in Figure 2-5, consists of two main offshore pipelines running from the GBS to separate riser bases (Pipe Line End Manifolds with an interconnecting offshore pipeline connecting the two pipe line end manifolds. OLS bases may be anchored to the seabed by piles, or other suitable means, to provide a stable connection for the OLS risers. Rock dumping, or other suitable insulation material, may be required for off-loading line protection and insulation.

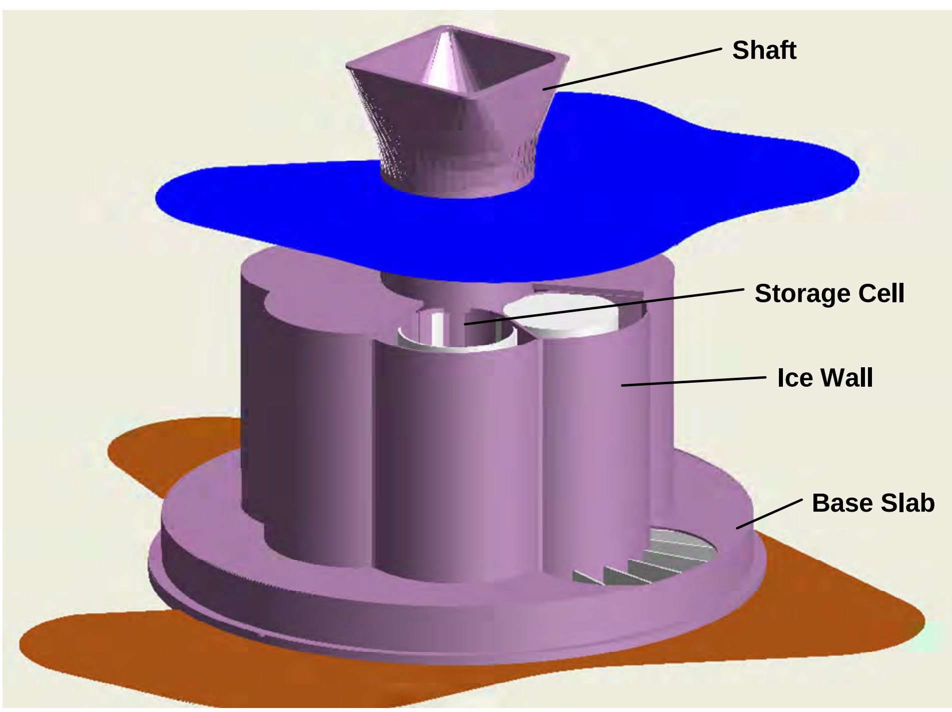


Figure 2-6 Schematic of Gravity Base Structure

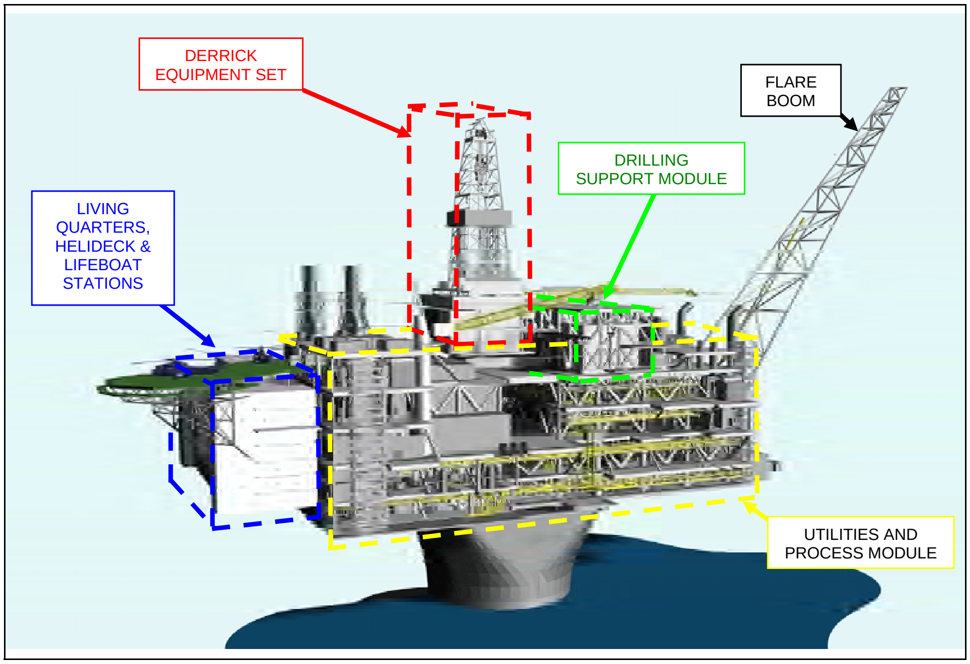


Figure 2-7 Schematic of Topsides

The closed loop arrangement is planned to allow round-trip intelligent pigging and flushing operations through the pipelines and pipe line end manifolds if an iceberg threatens the loading facilities.

During loading, the riser will be connected to the dynamically-positioned, bow-loading shuttle tanker.

A Direct Offloading system for cargo transfer from GBS to tankers is being studied as an alternative to the OLS. If the Direct Offloading option is selected, the system will likely consist of a hose reel integrated with the topsides, extending from the northeast side of the topsides structure, together with an approximately 340 m long, 508 mm (20") diameter marine hose with buoyancy elements. The hose will remain on the reel between offloadings and, during offloading, will be connected to a dynamically positioned, bow-loading shuttle tanker. During offloading, the tanker will maintain its position in a safe zone approximately 250 m from the Platform using its thrusters. The hose connecting the Platform storage tanks with the tanker storage tanks will take a "Lazy-W" configuration in the water (see Figures 2-8 and 2-9). The hose ends enter the water almost vertically and the intermediate hose sections float at approximately mid-water column height at an approximate water depth of 38 m. No subsea equipment is required for Direct Offloading.

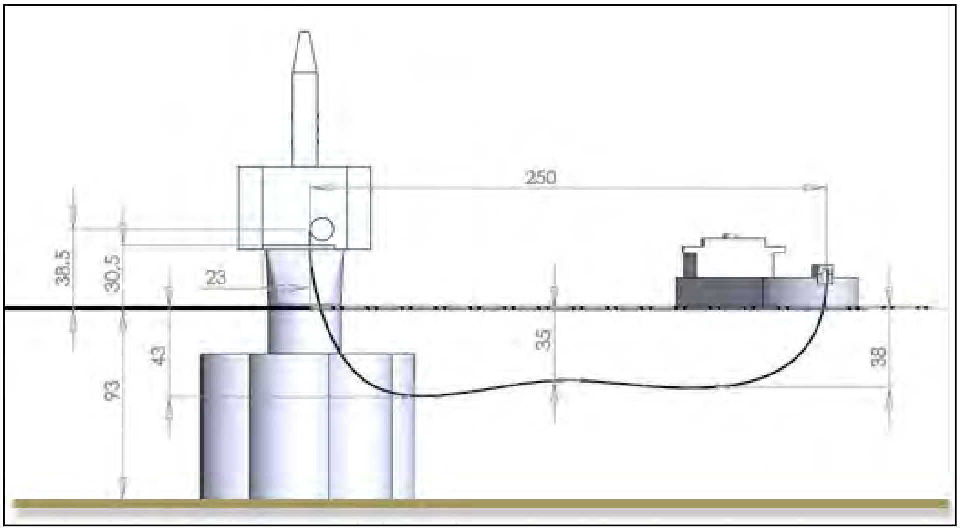


Figure 2-8 Configuration of Offloading Hose

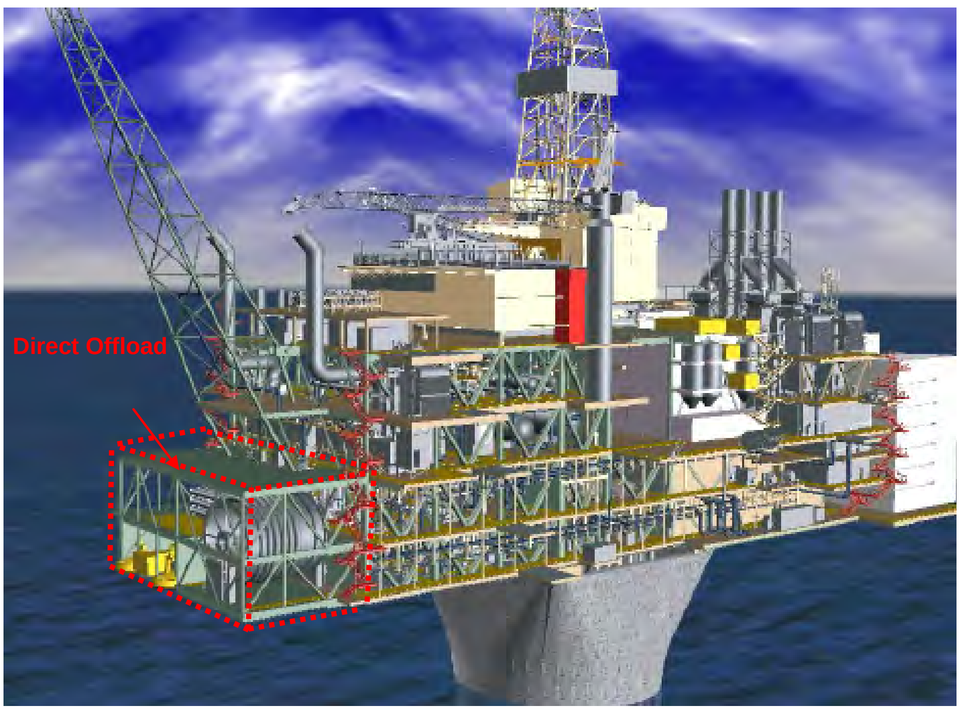


Figure 2-9 Platform Location of Direct Offloading Equipment

2.6.2 Hebron Project Design Criteria

An overview of the Hebron GBS and Topsides design criteria is provided in the following paragraphs. The following design criteria are based on current estimated project requirements. However, during FEED and detailed design and engineering, some of these elements may be modified. The following description provides for ranges in design criteria to allow for any modifications to project design.

The Hebron production facilities will have the capacity to handle the predicted life-of-field production stream for 30 plus years. Based on the current initial development phase, it is expected the facility will be designed to accommodate an estimated production rate of 23,900 m^3/day of oil (150 kbd). It is anticipated that, with de-bottlenecking and production optimization post-start-up, that the total capacity of the facility could potentially be raised to 28,600 m^3/day (180 kbd). The produced water system will be designed to process and discharge up to 56,000 m^3/day (approximately 350 kbd) of produced water and inject up to 74,000 m^3/day (470 kbd) of water. Gas handling of up to 8,500 km^3/day (300 MSCFD) will be required to accommodate gas re-injection and artificial lift gas.

An overview of the design basis for the Hebron Project is provided in Table 2-2. These design rates may change as the reservoir depletion strategy and initial development phase are finalized. The design basis values listed are representative of peak production. The environmental assessment will, therefore, use the upper limit of these ranges in its effects assessment.

Table 2-2 Hebron Project Attributes

Project Component	Attribute
Platform Location	46°32'64344' N; 48°29'88379' W
Life of Field	Greater than 30 years
Well Slots	Up to 52
Measured Well Depths	2,300 to 6,500 m measured depth
Topsides Design Basis Summary	
Preliminary Topsides Weight	30,000 to 44,000 tonnes
Crude Oil Production	23,900 to 28,600 m^3/d (approximately 150 to kbd)
Water Production	31,800 to 56,000 m^3/d (approximately 200 to 350 kbd)
Water Injection	43,000 to 74,000 m^3/d (approximately 270 to 470 kbd)
Gas Handling (includes associated gas and gas-lift gas)	6,000 to 8,500 km^3/d (approximately 215 to 300 MSCFD)
GBS Notional Design Metrics	
Concrete GBS Structure	Reinforced concrete with post tensioning
Overall Height (seabed to top of central shaft)	Approximately 120 to 130 m (394 to 427 ft)
Foundation Diameter	122 to 133 m (400 to 436 ft)
Caisson Diameter	100 to 110 m (328 to 361 ft)
Shaft internal diameter	Approximately 33 t m (108 ft)
GBS Dry Weight	300,000 to 340,000 tonnes
Solid Ballasting	50,000 to 100,000 tonnes
Concrete Volume	115,000 to 126,000 m^3 (150,300 to 164,700 cubic yards)
Reinforcing Steel	33,000 to 50,000 tonnes
Post Tensioning Steel	3,700 to 5,000 tonnes
Topsides Support during tow-out	Up to 44,500 tonnes
Base Storage	7 storage cells Approximately 190,000 m^3 (1.2 M bbl)
Life Expectancy of GBS	Approximately 50 years

Project Component	Attribute
Potential Field Expansion	J-tubes and spare well slots (approximately 6 to 15) Future options may include reclamation of slots and over 70 wells in total through platform and sub-sea wells
Water Quality	
Produced Water Handling (*Offshore Waste Treatment Guidelines*) (OWTG) (National Energy Board *et al.*, 2010)	≤30 mg/L 30-day average; ≤60 mg/L 24-hour average
Storage Displacement water (oil content – OWTG)	≤15 mg/L
Ballast / Bilge Water (oil content – OWTG)	≤15 mg/L
Deck (open) Drainage (oil content – OWTG)	≤15 mg/L
Well Treatment Fluids	≤30 mg/L; strongly acidic fluids should be treated with neutralizing agent to a pH of at least 5.0 prior to discharge
Cooling Water	As approved by Chief Conservation Officer
Desalination Brine	No discharge limit
Fire Control Systems Test Water	No discharge limit
Sewage and Food Waste	Macerated to ≤6 mm
Water-based Drill Solids	No discharge limit
NAF-based Solids	Re-injected where possible; if not, ≤ 6.9 g/100 g on wet solids
Offshore Loading System	
OLS Location	Approximately 2 km north-northeast of platform
Transfer Rate	Up to 8,000 m^3/h (50,312 bbls/hour)
Off-loading line length (each)	2 km (approximate) (6,560 ft)
Interconnecting off-loading line Length	500 m (approximate) (3,280 ft)
Export vessels	Anticipated use of existing shuttle tankers

2.6.3 Gravity Base Structure Systems

The GBS will be designed to have temporary and permanent mechanical systems installed as follows:

- Up to 52 well slots and associated conductor guides and J-tubes and/or risers
- Two shale chutes, routed down the inside of the structure, maintaining a sufficient angle so cuttings run down the chute and are deposited beyond the outer storage cell walls
- Seven crude oil storage compartments, including associated booster pump(s) to lift the oil for offloading, and level monitoring equipment
- Seawater systems including storage displacement water, cooling water and firewater, will likely include:
  - a large-diameter caisson for return of seawater to the marine environment
  - separate lift pumps to supply the firewater and seawater systems; firewater pumps will be segregated to ensure that no single point of failure can cause loss of firewater supply
  - storage displacement water from the crude oil storage compartments will pass through a buffer cell before horizontal discharge

- Corrosion protection system to protect metal elements against corrosion and biological growth where seawater is present. The discharge from the hypochlorite system will be treated in accordance with the Offshore Waste Treatment Guidelines (OWTG) (National Energy Board (NEB) et al. 2010)
- A separate sewage disposal line may route water from the sewage treatment unit to the marine environment. Merits of combined disposal will be addressed during detailed engineering design work. Sewage will be discharged overboard in accordance with the OWTG (NEB *et al.* 2010)
- Systems to minimize the occurrence of flammable gases and flammable or combustible liquids entering the shaft and allowance for removing any accumulations of gas
- Fire and gas detection system
- Control and monitoring systems including instrumentation to control crude oil levels, monitor corrosion systems and monitor foundation integrity
- Cooling system to ensure proper temperature maintenance of the GBS shaft over the life of the project
- Grounding / Earthing System including cables running through the GBS

2.6.4 Topsides Systems

- The Topsides will include all equipment required for the drilling, processing and power generation for the Hebron Project

2.6.4.1 Drilling Facilities

Based on preliminary design work, drilling facilities on-board the Hebron Platform will consist of the following systems:

- Mechanical drilling systems, including drawworks and pipehandling
- Well-control system consisting of a blowout preventer (BOP) stack, complete with diverter assembly, hydraulic control system, kill and choke manifold, trip tank, atmospheric separator (de-gasser)
- Bulk material and storage system, including storage tanks and surge tanks for dry bulk materials
- Mud storage, mixing and high pressure system, including liquid storage tanks, mixing equipment, and mixing, transfer, pre-charge and high-pressure mud pumps
- Mud return and reconditioning system, including shaker distribution box, shale shakers, degassers, centrifuges / dryers and associated tanks and pumps
- Onboard gravel pack equipment
- Cementing system, including a dual high-pressure pump unit, a batch mixing unit and a liquid additive system
- Driller's cabin containing drilling controls as well as monitoring capabilities for all drilling, pipe handling, mud handling and cement handling operations
- Cuttings re-injection system for NAF-based muds and cuttings. NAF-based muds and cuttings will be re-injected into the subsurface via a re-injection well. There will be no NAF-based cuttings treatment on the

platform. The cuttings re-injection system will be designed with dual redundancy; there will be a minimum of two wells for re-injection. All water-based drill muds and cuttings will be discharged overboard, as per the OWTG (NEB *et al.* 2010). There will be two shale chutes for water-based cuttings discharge

Water-based mud (WBM) cuttings are currently planned to be used on the first three hole sections of the Hebron wellbores.

For the first hole section (conductor section), it is planned to return the WBM cuttings to the GBS shaft. Soil strengths immediately below the GBS base slab are anticipated to be very weak and unable to sustain the additional hydrostatic load that would be introduced should the cuttings be returned to the Drilling Support Module (DSM) for re-injection. It is anticipated the DSM will be ±50 m above mean sea level. The returning fluid column would exert this equivalent hydrostatic head on the soils in the conductor hole section. Based on operational experience at ExxonMobil operations, it is anticipated this would result in significant fluid losses while drilling, subsequently creating a hole enlargement. This would pose potential risk to subsequent cementing operations of the conductor, overall well integrity and, potentially, stability of the soils beneath the base slab.

Similarly, the second hole section (surface casing) is anticipated to encounter weak sands and soils. It is currently planned to return these cuttings to the lower levels of the Platform, where they will be routed to the shale chutes for overboard discharge. Attempting to route the returns to the higher elevation of the cuttings re-injection system would introduce hydrostatic head that could also result in hole enlargement and risk to wellbore integrity.

The third hole section (intermediate casing) will also be drilled with WBM systems. However, the geologic intervals to be penetrated typically return cuttings that tend to be tacky in texture and result in large masses, or clumps, of cuttings, that can best be defined as 'sticky'. These masses are not well suited to cuttings re-injection as they require large surface systems to dissolve the cuttings prior to routing to subsurface injection.

Finally, at the current Project stage, analysis has been performed to identify candidate subsurface zones for cuttings re-injection. Modelling is currently planned to be completed to ensure containment can be maintained for the NAF-based mud drill cuttings and avoid out of zone fracture. Injection of large volumes of WBM cuttings potentially poses a risk for out-of-zone fracture and the subsequent loss of containment of NAF materials. Thus, the proposed plan of water-based discharge provides a balanced approach that minimizes overall risk of environmental damage.

The anticipated drill cuttings management information is shown in Table 2-3. The estimated cuttings volume per chute is approximately 4,453 m^3. Cuttings from the 838 mm hole section will be deposited inside the GBS shaft. The growth of anaerobic bacteria and the resulting production of hydrogen sulphide could be potential health issues in addition to being corrosive to facilities. Anaerobic bacteria require very low or no oxygen in their environment in order to survive and grow. The GBS shaft for Hebron will be designed with a passive seawater circulation system using natural convection. Cold seawater will enter from the bottom of the shaft and warmer water will exit at the top of the shaft, with direct discharge to the ocean. The constant replenishment of fresh seawater (containing dissolved oxygen) will minimize the possibility for developing the anaerobic conditions suitable for growth of anaerobic bacteria, thereby minimizing the growth of anaerobic bacteria action in the GBS without the need for to add biocides. This circulation system design will account for drill cuttings that may be discharged at the shaft bottom.

Table 2-3 Estimate of Drill Cuttings Volumes

Hole Size (mm)	Start Depth (m)	End Depth (m)	Hole Length (m)	Volume per Well (m^3)
838 (33 in)	135	300	165	91
660 (26 in)	300	500	200	171
432 (17 in)	500	2,300	1,800	260

Cuttings from the 660 mm hole section will be returned to the surface and routed overboard via the shale chutes. Cuttings from the 432 mm hole section will be drilled with water-based drilling mud and will be discharged overboard.

2.6.4.2 Process Systems

The main function of the production facility will be to stabilize the produced crude by separating out the water and gas from the oil, sending the crude oil to storage, and treating and managing the separated gas and water and associated components such as sand. The following is a list of the main systems employed in the process and utilities during crude oil processing.

- Three-stage separation system: While a three-stage separation system is presently envisaged, alternative processes will be reviewed during FEED

  The high-pressure separator will receive the fluids from Hibernia and Jeanne d'Arc Pools, where the gas will be separated out. The liquids will be mixed with the fluids from the Ben Nevis Reservoir fluids prior to entering the medium-pressure separator, which separates out the water and the gas. The oil will then flow to the low-pressure separator, where additional gas will be released. From the low-pressure separator, the oil will flow to the coalescers, where more water will be removed such that it meets its oil-in-water sales specification. To achieve effective separation between oil and water, fluids will be heated prior to entering the medium-pressure and low-pressure separators. Water from the medium-pressure and low-pressure separators and coalescers will be routed through additional treatment equipment to remove residual oil prior to being discharged overboard. Discharged water will be in adherence with the OWTG (NEB *et al.* 2010). Gas from the high-pressure, medium-pressure and low-pressure separators will be compressed, dehydrated, re-circulated for gas lift, used for fuel for platform operations or injected into a gas storage reservoir for conservation purposes. The final separation and compression system will be configured during detailed design

- Water Injection system: filtered, de-aerated and treated seawater will be metered and injected into the reservoir to maintain reservoir pressure to maximize oil recovery
- Current design includes the provision for overboard disposal of produced water, following treatment in accordance with the OWTG (NEB *et al.* 2010). Produced water will be discharged from a single point source below the summer thermocline at an approximate 50 m water depth. Water treatment technology was evaluated, and Compact Flotation Units (CFUs) were identified as the most advanced proven water treatment technologies available on the market for offshore application. The Hebron produced water treatment system includes CFUs in addition to hydrocyclones operating in series. The heavy, API 20 Hebron crude is expected to be difficult to separate from produced water. Thus, both hydrocyclones and CFUs are expected to be necessary to meet OWTG 2010 guidelines. EMCP is investigating various treatment options to reduce oil in water content for produced water, and is analyzing the feasibility of injecting produced water into the subsurface
- Vent and flare system: The Hebron flare system design is not yet complete. The flare system will implement a design that uses appropriate, available, proven technology to minimize smoke production. The system will be designed for pressure relief to prevent over-pressurization of equipment during process upset conditions. The flare will dispose of associated gas from the low pressure separator when the low pressure compressor is down for maintenance, during process upsets such as for brief periods after a medium pressure / high pressure (MP/HP) compressor trip, during emergency depressurization or other emergency events and during well tests. Small amounts of fuel gas will be continuously used for flare pilots and flare head purging. In the event of an emergency, gas from pressurized systems will be routed to the flare system. A flare knock-out drum will drop-out the liquids from the stream to be flared. This knock-out drum will be sized to remove liquids from the stream to be flared. Other systems operating at or near atmospheric pressure will be vented via an atmospheric vent header, located on the flare tower
- Design definition of utility systems, such as atmospheric tanks, is not well developed at this conceptual engineering phase. Definition will increase as engineering progresses. However, the low pressure atmospheric tanks that will be vented generally contain low vapour pressure sources (*e.g.*, diesel, methanol) or non-hydrocarbon sources (*e.g.*, glycol, fresh water, drill water, potable water. Most venting will occur during tank transfers and tank breathing. Vented volumes are expected to be minimal
- Oily water treatment: pressurized (closed) and open-to-atmosphere (open) drain systems will be used to collect fluids drained from equipment and run-off from the platform deck. The closed system will include separation and pressure reduction equipment to separate oil, gas and water. Oil will be recycled back into the process stream, gas will be vented to the flare

system and water will be treated prior to being discharged in accordance with OWTG (NEB *et al.* 2010). The open drain system will also separate oil using a recycle separation system, and water will be discharged overboard in accordance with OWTG (NEB *et al.* 2010)

- Chemical injection: chemical injection requirement details will be determined during the FEED phase and adjusted based on actual performance. EMCP will implement a chemical management system in accordance with the *Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands* (NEB *et al.* 2009). All chemicals will be screened according to the protocols established in the chemical management system. Typical chemical injection requirements for offshore oil and gas production facilities are:
  - Scale Inhibitor
  - Asphalthene Inhibitor
  - Defoamer
  - Biocide
  - Flocculant
  - Methanol
  - Corrosion Inhibitor
  - Oxygen Scavenger
  - Demulsifier
  - Pour Point Depressants
  - Drag Reducing Agents
  - Viscosity Reducing Agents
  - Wax Inhibitors
- Seawater lift: seawater will be required for injection into the reservoir to maintain reservoir pressure and to remove heat from the cooling medium. Seawater will be filtered and sodium hypochlorite will be added to prevent biological growth in the cooling water pipe
- Power generation: although subject to final design, EMCP plans to install four turbine-driven main generators (at least two of which will have dual-fueled capability), each capable of producing up to approximately 30 megawatts (MW) for a 4 x 33 percent configuration, as well as separate emergency and essential diesel generators
- Fuel gas: process gas will be taken from the gas compression stream for use as fuel gas. A diesel fuel system will provide backup in periods of process facilities shutdown and at initial start-up until gas compression is operable
- Process cooling: a closed loop cooling system is planned
- Crude oil offloading and metering system where crude oil will be lifted, pumped to full pressure and metered through a custody transfer quality metering system prior to being offloaded to shuttle tankers via the OLS
- Potable and service water: potable and freshwater generators are planned for the production of potable and service water
- Fire suppression systems: fire and gas detection and emergency shutdown systems will be installed to notify personnel and automatically

respond to emergency situations. A combination of area seawater deluge, local vessel seawater spray, pressurized hose reels, fire monitors, foam systems and portable fire extinguishers will provide active fire suppression to the process areas of the platform. Active fire protection systems for the living quarters, utility, machinery, and electrical spaces may include sprinkler systems, foam systems, pressurized hose reels, portable fire extinguishers, water mist systems and inert gas systems. Passive fire protection may include fire and blast walls and decks and coatings on certain structural members and vessels

- Escape, evacuation, and rescue facilities: Escape routes to the fire-protected temporary safe refuge and lifeboat muster areas will be included in the platform layout per regulation. Evacuation facilities including lifeboats, life rafts and immersion suits will be provided per regulation. Rescue capability will be managed by platform support vessels and training of platform personnel
- Jet fuel storage: a jet fuel bulk storage and pumping system will be installed to provide refuelling capability for the helicopters servicing the installation
- Diesel fuel storage: a diesel fuel bulk storage, treating, and distribution system will be installed to provide fuel for power generation, as required (*i.e.*, during start-up, shutdown periods)
- Hydraulic power: a central hydraulic fluid storage, pumping and distribution system may be installed to provide high pressure hydraulic fluid
- Heating, Ventilating and Air Conditioning: a heating and cooling system will be installed for heating, ventilating and air conditioning systems

2.6.4.3 Produced Water Management

Introduction

The management of water during Hebron production operations will be one of the most technically complex and challenging operations for an offshore production facility. Produced water discharge rates from the Hebron Platform are estimated at up to 56,000 m^3/d. The management of such high water volumes requires extensive equipment and associated piping which contributes significantly to topsides weight and costs as well as operational complexity.

As part of its overall water management strategy the operator is investigating the feasibility of injecting produced water mixed with seawater, into the reservoir for pressure maintenance. A mix of seawater and produced water is required, as the volumes of produced water are insufficient to maintain reservoir pressure.

EMCP has completed its initial assessment of produced water re-injection (PWRI) into the producing formations and has concluded there are unacceptable risks associated with initiating PWRI until factors associated with these risks are better known. Initial assessment indicates that PWRI into the producing formations for pressure maintenance purposes may be technically feasible, if technical risks can be reduced through further data acquisition and studies post start-up. ExxonMobil is committed to adopting PWRI once it is demonstrated that the risks and costs are manageable.

Preliminary studies identified several potential risks to adopting PWRI:

- Souring potential is up to 50 percent greater than with injecting seawater only due to temperature and the presence of volatile fatty acids (VFAs)
- WRI could result in greater than predicted increases in injection pressure (potentially beyond pressure limits)
- Fracture containment could be compromised with increasing use of produced water
- Scaling potential is increased when injecting produced water into the formation

Confirming that these risks are manageable requires additional data that can only be obtained and analyzed post start-up and after several years of operation. For example, VFA content is highly variable across reservoirs and more produced water samples are required. Further, only a very small number of formation water samples are currently available – more are needed to draw firm conclusions.

The operator examined the potential to inject produced water (including partial re-injection) into dedicated disposal reservoir(s). Based on a this evaluation, suitable reservoir capacity to accept the produced water was limited. The cumulative volume of water produced in 30 years is approximately 366 million m^3. Over-pressuring of the disposal formation would also be a significant risk. With regard to partial re-injection, such an approach would require a duplication of the pumping facilities and associated piping currently required for seawater injection, additional well slots, and increased power generation capacity. The topsides design includes approximately 100 MW of power generation. Adding separate pumping facilities would require an increase in power generation of approximately 25 percent, and thereby increase the emissions. Produced water injection into dedicated reservoirs would exacerbate the weight, cost and operational challenges already inherent in offshore processing of a heavy crude. The added pumps and power generation equipment, as well as the use of well slots for additional dedicated injection wells, is not technically feasible, economically viable, nor environmentally sound.

Produced Water Management Strategy

Hebron will initially operate with marine discharge of produced water at start-up. As more wells come on-line and production data and experience is gathered, further testing on rock properties and produced water / seawater / reservoir compatibility will be carried out as additional core samples and produced water become available. Hebron will switch to PWRI for routine operations, once testing and studies (post-start-up) demonstrate that the risk and impacts of PWRI are understood and acceptable. When PWRI is adopted, the facility will maintain flexibility for marine discharge during unplanned events (*e.g.*, equipment failure) or planned maintenance. In addition, it will be necessary to preserve the option to return to marine discharge if unexpected complications arise with PWRI (*e.g.*, loss of oil recovery, reservoir souring, scaling, plugging).

In the base design, the water injection system is designed to inject at the predicted pressures required for PWRI. The Topsides facilities include space and connections for the future installation of the low pressure incremental equipment required to route produced water into the water injection system.

Produced Water Re-injection Feasibility Studies

Large volumes of seawater will be needed for pressure maintenance and the design team investigated if produced water could be used to satisfy a portion of those needs. Several risks arise when mixing produced water with seawater and injecting into a producing formation that need to be well understood before committing to produced water re-injection:

- Compatibility of seawater and produced water with each other and the reservoir
- Potential to "plug" the formation
- Potential for injection pressures to increase with produced water / seawater mix compared to seawater only injection
- Potential for bacterial contamination of the producing formation

The proceeding sections summarize the studies completed to date, and further work to be completed.

Injectivity

Water injectivity (the ability to inject water into the producing formation) can be impaired over time by injecting produced water with higher concentrations of suspended solids and even relatively low concentrations of oil-in-water. Both of these would increase the risk of plugging pore throats in the near-well region where the injected water first enters the formation. In turn, such plugging may accelerate the rate of fracture growth and extend fractures beyond desired boundaries, leading to a potential loss of conformance and thereby reduced effectiveness in supporting reservoir pressure.

Thermal effects of PWRI may also influence water injectivity since PWRI is likely to raise the injected water temperature (compared to seawater-only) and thus increase the fracture extension pressure, leading to a reduction in injectivity index.

An injectivity study was conducted to assess the required injection pressure to achieve fracture injection for all potential injection wells in Hebron and how the injection requirements may change PWRI versus seawater injection.

The injectivity study found that PWRI is technically feasible from an injectivity standpoint; however, there are several vulnerabilities that require additional operational data to confirm. A key area of risk is that fracture pressure will increase through time with PWRI, and increasing fracture pressures can lead to a greater risk for loss of fracture containment during injection.

Scaling

Both seawater and produced water are a complex solution of dissolved components (many types of "salts"). Upon mixing, the positive and negative ions in each must reach a new balance and sometimes they combine to form a solid that precipitates out of solution. Some of these chemical reactions take time to occur and precipitation can occur during injection process, as pressure and temperature changes take place. The rock fractures and pore spaces can then get plugged by these solids and hinder or prevent future injection.

The only way to obtain a clear answer on the compatibility of Hebron produced water with seawater from the Grand Banks is to mix the two waters in a laboratory study and observe what happens under different temperature and pressure conditions. Such a definitive study cannot be done as yet, since there are no production wells available to sample. The produced water at the Hebron Platform will be a mix of produced water from several different reservoirs and, therefore, is not presently available for study.

However, the Project does have small samples of what is now "aged" water produced from individual reservoirs. These samples were obtained during production testing of individual wells from individual reservoirs in the late 1990s. These are now considered "aged" samples and, although ionic composition is the same, the potential loss of volatile organics and possible changes in organic composition could alter ionic reactions when mixed with seawater. Using these samples, the Project has proceeded with a small-scale study to obtain a preliminary understanding regarding the compatibility of the two waters.

The results of this small-scale study suggest with low certainty that mixing produced water and seawater is possible. However, further investigation is required, using samples of Hebron produced water from actual production wells, to confirm and validate these preliminary compatibility test results.

Souring (bacterial contamination)

In the oil producing reservoir, bacteria are present. Hydrogen sulphides (H_2S) act as an energy source and VFAs are the nutrient source. An increase in growth of bacteria could result in a plugging of the formation, or souring of the reservoir. Levels of souring are dependent upon VFA concentration in formation water.

An initial study of Pool 1 (Ben Nevis reservoir) souring susceptibility was conducted in 2005, using a range of levels of souring nutrients (VFAs) in formation water. Pool 1 predictions indicate potential for substantial total-wellstream mass of H_2S, and that the sulphide content forecast for mixed produced water / seawater injection is up to 50 percent higher than that for seawater-only injection.

PWRI is likely to increase the souring susceptibility of Pool 1 *verses* seawater only injection; however, further studies are required to determine the effects and extent of souring from PWRI and if mitigations are available to control bacterial contamination, and prevent reservoir souring.

Disposal Reservoir

An evaluation was made to identify non-producing subsurface formations that could potentially serve as repositories for produced water. Ideally, such formations would be relatively thick and laterally continuous with high capacity for accepting a large volume of fluid, and would provide minimal potential for migration of injected fluid into other formations, or for entering subsurface faults that are conductive in character.

Screening of wireline well logs and mud logs revealed only one prospective non-producing formation that would merit quantitative analysis of its potential water storage capacity. A unit of porcelaneous mudstone (also known as the Tilton Member) exists in the Paleocene section approximately 300 m above the top of the Ben Nevis formation in the Hebron initial development area, and this unit was subjected to preliminary investigation as a possible storage compartment for Hebron produced water. Screening-level calculations were performed to estimate the thickness trend, average net-to-gross, average porosity and, subsequently, the net pore volume of this formation within the Hebron Unit boundary.

Results indicated that the porcelaneous mudstone unit is predicted to have far too little storage capacity to accept the forecasted volume of produced water over the life of the Hebron Project (an estimated 366 million m^3 plus additional produced water if future expansions are developed).

A screening assessment of the implications for topside facilities design indicated a requirement for additional dedicated pumping facilities and associated piping, additional well slots, and increased power generation capacity. This would exacerbate the weight, cost and operational challenges already inherent in offshore processing of a heavy crude and result in increased carbon dioxide emissions (approximately 150,000 tonnes of carbon dioxide equivalents) released into the atmosphere annually (4.5 million tonnes over 30 years).

The overall conclusion of the Project's evaluation is that disposal of produced water into Hebron non-producing formation(s) is not feasible when considering technical and economic factors. The operator's preferred approach is re-injection into the producing formation when all operational, technical, environmental, regulatory compliance, and economic factors are considered.

Plan for Completing further Produced Water Re-injection Feasibility Assessment

In order to complete an assessment of PWRI and ensure all risks are understood, additional formation water samples are required. This can only be completed post start-up and analyses will include measuring produced water compositions for each distinct hydrocarbon resource and determining the degree of intra-reservoir variability in water compositions. Produced water from a few geographically-distributed wells is likely to provide the highest-confidence data.

Further testing of produced water is required to confirm the scaling tendency / severity of seawater / produced water for both in-situ reservoir conditions and for operating conditions of wells / facilities. The concentration of VFA nutrients in produced water is needed for better forecasting of souring behaviour and additional measurements of variability will aid in characterizing the effects of mixed produced water / seawater.

Further testing is also required on the reservoir rock properties, and some fresh core material will be acquired in select new wells to enable lab displacement measurements of mixed-produced water- / seawater-waterflooding.

Topsides Facilities

The Hebron Topsides facilities include the best commercially proven water treatment technology and equipment for offshore applications. Heavy oil separation challenges warrant a robust produced water treatment system that includes hydrocyclones, CFUs, and degassing drum.

In addition, Hebron will include Vessel Internal Electrostatic Coalsescer technology, which minimizes emulsion layer thickness and creates a better defined oil / water interface, helping to mitigate oil carry-under from separators to the produced water treating system.

Pre-investment has been made in the water injections system to allow for PWRI to be initiated at a later date. Design elements include:

- System designed to inject at predicted pressures required for PWRI
- Inclusion of manifolds to blend produced water with seawater make-up
- Injection pump seals designed for the fine particles in produced water (a specialist application)
- Include space and connections for the future installation of the low pressure incremental equipment required to route produced water into the water injection system (*i.e.*, low pressure booster pumps and filters)

Summary

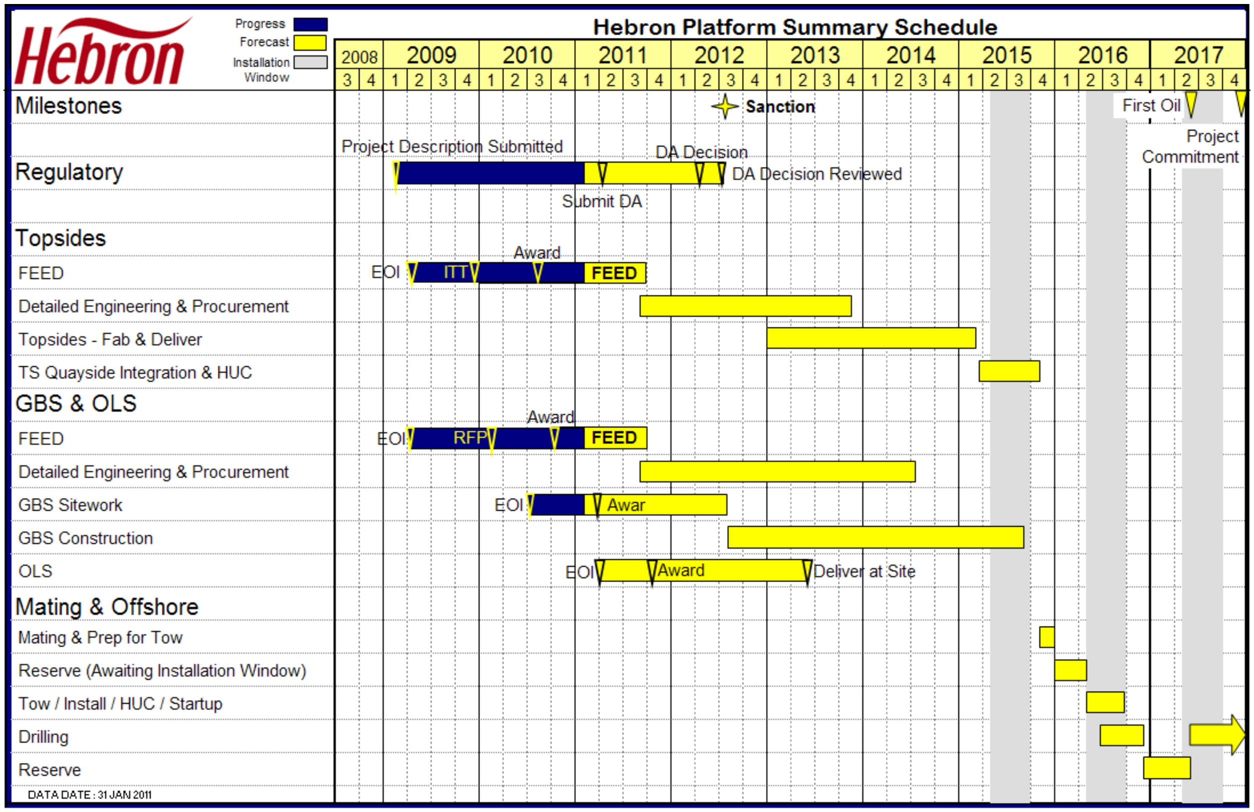
ExxonMobil is committed to adopting PWRI for routine operations once it is demonstrated that the associated risks are acceptable.

The Produced Water management strategy will be to operate with marine discharge of produced water at start-up using the best proven treatment technology available today. Hebron will switch to PWRI for routine operations, if testing and studies demonstrate that the risk and impacts of PWRI are understood and acceptable. The option will be preserved to return to marine discharge if unexpected complications arise with PWRI (*e.g.*, loss of oil recovery, reservoir souring, scaling, plugging).

The Hebron water injection system will be designed to inject at predicted pressures required for PWRI, and include pre-investment for potential establishment of PWRI (space and connections for additional PWRI equipment). A post-start-up study and testing plan will be developed to address uncertainties.

2.7 Project Schedule

The overall project development schedule is presented in Figure 2-10. The Hebron Project is committed to achieving first oil prior to the end of 2017.



Notes:

* DA - Development Application includes Development Plan, Benefits Plan, CSR, Socio-economic Impact Statement and other supporting documents as determined by the C-NLOPB

** This is the initial development schedule (base case) and does not include additional drilling / development for future developments

Figure 2-10 Hebron Project Development Schedule

2.8 Hebron Project: Construction and Installation

All shore-based construction activities are planned to take place (as far as practical) at established existing facilities in Bull Arm, Trinity Bay, or elsewhere in Newfoundland and Labrador at existing facilities. No new onshore facilities are planned; however, some of those existing facilities at the Bull Arm or other sites may need to be refurbished or expanded.

The Bull Arm Site will be used for the following activities: GBS construction, fabrication of selected Topsides modules, integration of all Topsides modules, mating of integrated Topsides with the GBS, and hook-up and commissioning of the mated platform. Site preparation activities at Bull Arm will be required in order to ready the site for GBS construction and Topsides fabrication and integration. Various repairs and upgrades will be required to make the marine site suitable for construction and fabrication of Hebron Platform components. Some of the major work anticipated includes re-establishment of the bund wall and drydock, replacement of concrete batch plant and dredging of tow-out channel and blasting, if needed. Early works activities are scheduled to commence in 2011. The construction of the GBS is scheduled to commence 2012.

An estimate of the duration of activities associated with the GBS construction, Topsides fabrication, Topsides integration, tow-out and commissioning offshore is provided in Table 2-4. The following project durations are estimated timeframes. Some of the activities may occur concurrent with, or overlap with, other project activities.

Table 2-4 Hebron Estimated Maximum Project Durations

Activity	Estimated Duration
Drydock Preparation and Bund Wall Construction	6 to 18 months
GBS ‘Dry’ Construction	12 to 18 months
GBS ‘Wet’ Construction	12 to 18 months
Topsides Fabrication	18 to 24 months
Topsides ‘Dry’ Integration	7 to 12 months
Topsides ‘Wet’ Mating	1 to 2 months
Hook-up and Commissioning activities following mating (but prior to tow to field)	1 to 2 months
Tow to Site	10 to 14 days
Facility Installation	3 to 6 months
OLS Installation	3 to 6 months
Final Hook-up and Commissioning	3 to 9 months

2.8.1 Great Mosquito Cove: Drydock Construction

The existing Bull Arm drydock in Great Mosquito Cove will be re-established prior to starting construction of the GBS. The current concept is to construct a rock-fill dike (or bund wall) with a centre impermeable core comprised of a cement slurry across the cove to form the wall of the basin. It will be protected on the outside faces by a layer of crushed rock (*e.g.*, quarried conglomerates and sandstones). It is estimated that the bund wall may be up to 500 m in length, and the area of the drydock at approximately 35,000 to 40,000 m^2. Exact configurations and designs will be determined during FEED.

Once the bund wall is in place, the drydock will be de-watered and the access roads rebuilt or replaced and the construction support infrastructure (offices, cranes, laydown areas) put in place. Additional infrastructure outside of the drydock itself will also be either refurbished or built to support GBS construction.

A list of potential marine activities and potential emissions and discharges, associated with the construction of the drydock is provided in Table 2-5.

Table 2-5 Potential Activities and Potential Discharges / Emissions / Wastes during Construction in the Drydock

Potential Activities	Potential Environmental Interactions / Discharges / Emissions / Wastes
Bund Wall Construction (*e.g.*, sheet / pile driving, infilling)	• Air emissions • Bilge / ballast water • Onshore site runoff • Disposal / discharge of stormwater, potable water, fire water, and industrial water) • Elevated suspended solids • Substrate disturbance • Loss of subtidal habitat and organisms • Potential localized water column contamination • Sedimentation • Solid, construction, hazardous, domestic and sanitary waste disposal • Lights • Noise (including underwater) • Potential physical impacts (*e.g.*, blasting)
Inwater Blasting	
Dewater Drydock / Prep Drydock Area	
Concrete Production (floating batch plant)	
Vessel Traffic (*e.g.*, supply, tug support, tow, diving support, barge, passenger ferry to / from deepwater site)	
Lighting	
Air Emissions	
Safety Zone	
Surveys (*e.g.*, geophysical, geological, geotechnical, environmental, Remotely Operated Vehicle (ROV), diving)	
Removal of Bund wall and Disposal (blasting, dredging / ocean disposal)	
Tow-out of GBS to Bull Arm deepwater site	
Dredging of Bund Wall and Possibly Sections of Tow-out Route to deepwater site (may require at-sea disposal)[A]	
GBS Ballasting and De-ballasting (seawater only)	
[A] Pending requirements determined by bathymetry survey	

Bund wall design and selection of construction methods are ongoing. Alternative construction methods are being considered that may eliminate or reduce underwater blasting and dredging during construction.

Dredging and ocean disposal of the dredged spoils and/or bund wall may be required in association with the partial removal of the bund wall and to ensure adequate depth for navigation and tow-out of the GBS to the deepwater site. Dredging of shallow areas near the Topsides pier identified by detailed bathymetry, may be required, depending on the vessels chartered for load-out of the Topsides.

The disposal area in Great Mosquito Cove is unknown at this time. Work is ongoing to identify an area that has the least potential for habitat disturbance and that can accommodate the volume of spoils to be disposed. Based on preliminary review of the bathymetry and fish habitat information for Great Mosquito Cove, a likely candidate area is located at approximately 40 to 45 m water depth on the south side of Great Mosquito Cove. EMCP will consult with DFO and other federal authorities regarding the selection of the spoils disposal area. In addition, Transport Canada requirements regarding navigability of water channels will be included in the selection process.

2.8.2 Gravity Base Structure Construction at Drydock

GBS 'dry' construction in the drydock may include: skirts; base slab including mechanical outfitting and cantilevered base slab roof; and conventional and slip forming of the cantilever walls including the storage cell walls and ice walls with mechanical outfitting. Construction will continue to a height sufficient to allow floatout from the drydock and to maintain floating stability throughout. Once the drydock is flooded, the bund wall will be removed, and the partially constructed GBS will be towed to the deepwater site.

The first stage in the construction of the GBS is the installation of the skirts. The GBS base slab will be underlain by concrete or steel partitions, called skirts. The purpose of the skirts is to assist with sliding resistance of the GBS and to provide a containment system for the grout materials to be installed when the Hebron Platform is positioned offshore. The skirts may be prefabricated outside of the drydock and transported to the basin.

Construction of the base slab will begin once the skirts are positioned. Post tensioning ducts, anchors and other embedments will be installed simultaneously with rebar as the concrete work proceeds. Conventional methods will be used to construct the base slab.

The reinforced concrete walls above the base slab, including the ice walls, and crude oil storage tanks will be built by slipforming. Slipforming is a process of continually pouring high-strength concrete, reinforced with steel (rebar), into a form or mould that moves vertically with the assistance of hydraulic or screw jacks. The jacks are spaced at equal intervals to lift the form gradually, at a predetermined rate. In the case of a GBS, where a cavity is required in the concrete structure, inner and outer forms are used to create the cavity and concrete walls. Inside the walls, rebar is tied together vertically and horizontally to reinforce the concrete walls as they are poured. Post tensioning ducts are also placed in the forms and this reinforcement is tensioned after the concrete has reached sufficient strength. As the form rises, the section of previously poured concrete hardens and acts as support; strong enough to withstand the weight of the concrete being poured on top of it. Pouring is continued until the desired height is reached.

Some of the activities involved in slipforming include the following:

- Placing and compacting concrete in controlled layers
- Placing reinforcement, post tensioning ducts and anchors
- Installation of embedded mechanical outfitting items (*e.g.*, pipe penetrations, instrumentation)
- Installation of embedment plates and block outs, sleeves / manholes
- Repairing deficient concrete surfaces
- Curing of cast concrete
- Dimensional control / verification and as-built measuring
- Civil and mechanical quality control

In the drydock, skirts will be installed; base slab, including mechanical outfitting and cantilevered base slab roof will be completed, and the storage cell walls and ice walls will be constructed. Mechanical and marine outfitting will proceed in the lower levels of the GBS, with installation of permanent and temporary access systems, ballasting systems, grouting systems, safety systems, electrical and instrumentation systems, corrosion protection, and structures for marine towing and mooring. Once the walls are complete, the conductor frames will be lifted and placed in the GBS.

Once the base slab, cantilever and lower portions of the walls of the GBS are constructed, the casting basin will be cleared of infrastructure and filled with seawater to the level of Great Mosquito Cove. The bund wall will be removed (likely by clamshell dredge or dragline and extracting the sheet piles) to allow passage of the GBS out of the basin. The GBS will be towed out and moored at the deepwater site where construction will continue.

Some of the steps involved in the construction of a typical GBS are illustrated in Figure 2-11.

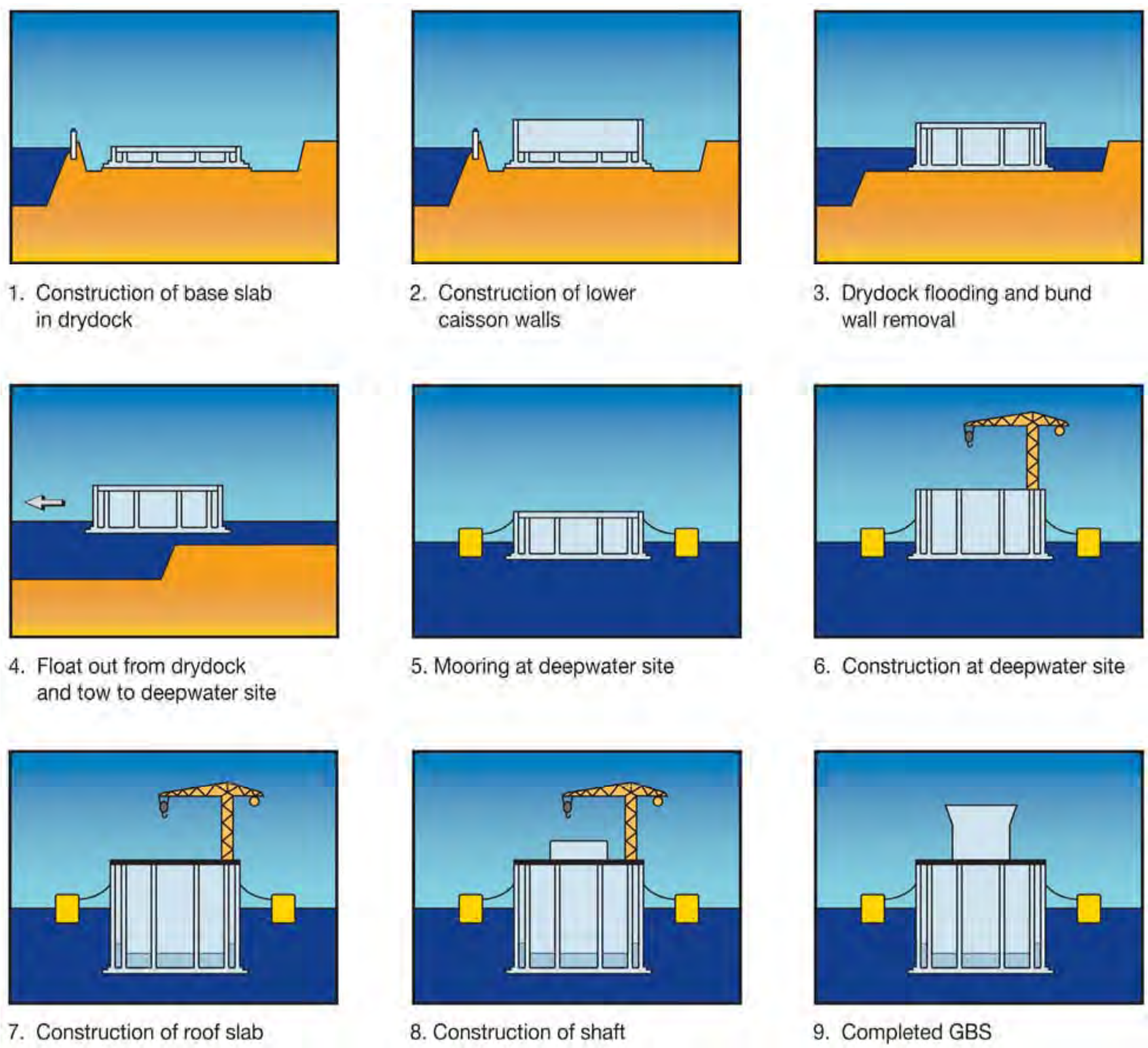


Figure 2-11 Schematic of Building a Gravity Base Structure

2.8.3 Deepwater Site Construction

Once moored at the deepwater site, slip forming of the storage cell walls and ice walls and mechanical completions continue to full caisson height. The Roof slab is constructed and slip forming and conventional construction of the remainder of the shaft continues to full height of GBS.

Construction of the caisson walls and the centre shaft walls by slip-forming, will be completed once the GBS is secured at the deepwater site in Bull Arm. It is anticipated that existing deepwater moorings will be used; however, additional moorings may be required. The requirement for additional moorings will be determined at the FEED stage. If additional moorings are required at the deepwater site, they will likely be constructed on land. The Hebron Project will consult with Transport Canada and DFO, and other federal authorities as may be required, regarding additional moorings at Bull Arm. The Environmental Protection Plan for Bull Arm (EMCP, 2011) includes mitigation measures for any land-based construction.

At the Topsides pier, temporary underwater moorings (or anchors) may be required to position the heavy lift vessel for Topsides tow-out. Details regarding the requirement for moorings, or the type of moorings that may be required are unknown at this time, as the Project is in the early stages of Project design. However, the Hebron HADD Strategy addresses all potential activities at Bull Arm, and any effects on fish habitat at this site, will be included in the fish habitat compensation plan, if warranted.

The GBS construction process will be similar to the slip-forming completed in the drydock and will require a number of support barges. The height of the walls will be extended to full height, requiring a floating concrete batch-plant, work barges and other support vessels on-site. Once the caisson walls reach full height and mechanical outfitting of the caisson is complete, a concrete roof slab will be constructed. The roof slab will be followed by construction of the centre support shaft. This shaft will support the Topsides facility.

The pier in Back Cove, which is the site of the ferry terminal to transport workers to the GBS in the deepwater site, may require upgrading. The details regarding the upgrades are unknown at this time, but likely will include a temporary replacement of the pier. As more information becomes available during FEED, EMCP will consult with DFO regarding construction activities. Design changes or mitigations will be considered to reduce potential impacts to the stream that flows into the cove. Currently proposed upgrades are anticipated to remain within the footprint of the original dock structure.

Support and transport barges are required at the floating construction site. One or two barges will be used to locate construction offices, tool cribs and other support buildings. Another barge will carry the floating concrete batch plant. Lastly, a series of transport barges will be used to ferry cement, aggregate, reinforcing bars, steel embedment and mechanical outfitting to the deepwater site. These barges will be moored to each other and to the structure with a series of attachment points which progressively move up the structure as it is built. Tugs will move transport barges to and from the deepwater site. Ferries or large crew boats will be used to transfer personnel from shore to the deepwater site and back. A water supply floating pipe will be installed, from shore to the deepwater site. An underwater cable will provide electricity and communications.

The floating concrete batch plant will be designed to prevent release of untreated washwater and spoiled concrete into the environment. Washwater will be retained and directed to settling basins.

Once the vertical walls of the caisson are constructed, the permanent solid ballast will be placed. A portion of the ballast may be placed between the external ice wall and internal oil storage tank walls and another portion may go into the bottom of the storage cells themselves. Solid ballast is brought to the site on bulk carrier barges. A series of conveyors or a pumping system is then used to transfer and drop the ballast into the cells. In the storage cells, the material will be levelled and capped with a non-structural slab of concrete. Once complete, the ballasted GBS will undergo submergence testing and be prepared for mating with the Topsides.

A list of potential marine activities at the deep water construction site and associated emissions and discharges is provided in Table 2-6.

Table 2-6 Potential Activities and Potential Discharges / Emissions / Waste during Construction at the Deepwater Site

<table>
<tr><th>Potential Activities</th><th>Potential Environmental Interactions / Discharges / Emissions / Wastes</th></tr>
<tr><td>Re-establish Moorings at Bull Arm deepwater site
Potential construction of new moorings, likely on-land</td><td rowspan="15">• Air emissions
• Bilge / ballast water
• Deck drainage
• Disposal / discharge of stormwater, potable water, fire water, industrial water
• Suspended solids
• Noise (including underwater)
• Sedimentation
• Discharges associated with floating batch plant
• Solid, construction, hazardous, domestic and sanitary waste disposal
• Substrate disturbance
• Lights
• Discharges associated with hook-up and commissioning</td></tr>
<tr><td>Ballasting and/or Deballasting of GBS</td></tr>
<tr><td>Surveys (e.g., geophysical, geological, geotechnical, environmental, ROV, diving)</td></tr>
<tr><td>Power Generation</td></tr>
<tr><td>Slipforming (operation of floating batch plant)</td></tr>
<tr><td>Re-fueling of Vessels and/or Generators and other Equipment</td></tr>
<tr><td>Upgrade Ferry Terminal in Back Cove (to transport workers to the GBS in the deepwater site)</td></tr>
<tr><td>Operation of Passenger Ferries, Supply, Support, Standby, Mooring and Tow Vessels / Barges / ROVs and Possibly Helicopter during Commissioning of Helideck</td></tr>
<tr><td>Mating of Topsides and GBS</td></tr>
<tr><td>Hook-up and Commissoning of Topsides</td></tr>
<tr><td>Mechanical Outfitting and Commissioning of GBS</td></tr>
<tr><td>Tow Platform (GBS and Topsides) to Offshore Location (clearance dredging may be needed based on outcome of future studies)</td></tr>
<tr><td>Lighting</td></tr>
<tr><td>Air Emissions</td></tr>
<tr><td>Safety Zone</td></tr>
</table>

2.8.4 Topsides Fabrication and Assembly

It is intended that the helideck, lifeboat stations and flare boom will be constructed in Newfoundland and Labrador. Other modules will be constructed in Newfoundland and Labrador, subject to capacity and resource considerations. The UPM will be competitively bid internationally.

The Topsides design is based on the concept of an integrated deck (the UPM). The UPM reduces the amount of inter-module piping, electrical and instrumentation connections and maximizes the extent of pre-commissioning while at the fabrication site. Typical equipment and/or facilities in the UPM may include processing and utilities systems, switchgear, instrument rooms, and workshops. Space will be provided on the integrated deck for the installation of the remaining Topsides modules.

All modules will be assembled and integrated at Bull Arm on the Topsides integration pier. The various steps in Topsides assembly, integration and tow-out for mating are shown in Figure 2-12.

2.8.5 Topsides Mating and Commissioning

All modules are received, assembled and integrated on the assembly pier at Bull Arm. The use of an integrated UPM design will minimize the extent of physical hook-up needed during integration with the other modules. It is anticipated that individual modules will have considerable commissioning accomplished prior to integration.

Prior to mating, the completed GBS will be ballasted using a combination of solid ballast and seawater to the required depth while maintaining a freeboard. The Topsides will be floated on barges to the GBS in catamaran formation. Once positioned, the GBS will be de-ballasted until connection is made with the Topsides. Hook-up and commissioning will continue after mating.

It is expected that Topsides fabrication will take approximately 30 months at a number of different fabrication facilities, with assembly and integration of all modules accomplished at the Bull Arm Topsides integration pier. Hook-up, commissioning and tow-out to field preparations continue over the one to two months following mating.

2.8.6 Offshore Site Preparation

Ship-based environmental and engineering surveys may be required prior to offshore installation of the platform. Geophysical, geological and geotechnical surveys may require the use of seismic, multibeam, echosounder, sidescan sonar, and or subbottom profiler techniques and equipment. Pending further engineering and design, all of these surveys may not be required and some may occur during other Project stages.

Environmental surveys may include meteorology, oceanography, fish and sediment sample collection, habitat surveys by ROV and iceberg surveys.

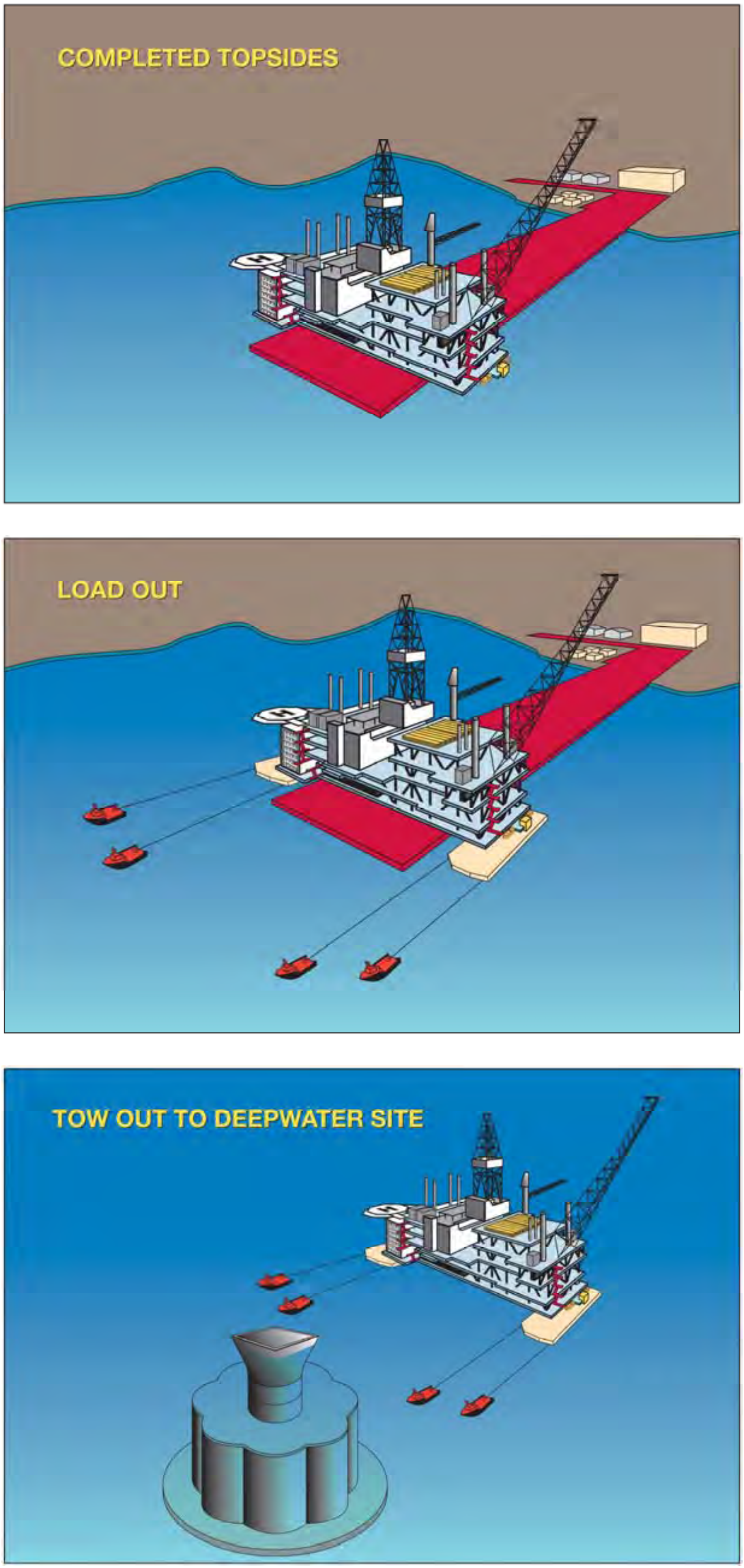


Figure 2-12 Example of Hebron Topsides Integration onto Gravity Base Structure

2.8.7 Platform Tow-out and Offshore Installation

The completed Hebron Platform (GBS and Topsides) will be towed to the permanent site, 340 km offshore. The weather window for tow out from the deepwater site to the Hebron field is ideally from May through September. For tow-out, the GBS will be de-ballasted to maintain a required freeboard.

After de-ballasting the GBS to ensure the necessary under keel clearance, the Hebron Platform will be released from its moorings at the deepwater site and the tow will begin using first class towing vessels (high performance tugs) in a similar configuration to that used for Hibernia tow-out. During towing, there will be tugs running ahead of the platform, with other tugs following for back up, if needed. The tow of the platform to site is anticipated to take between 10 and 14 days.

The Hebron Platform will be set in place on site on the Grand Banks. Skirt penetration into the seabed may be assisted by a skirt evacuation system to assist with release of entrapped air and water in the skirt compartments. Additional seawater ballast will be added to the platform. Grouting around the base of the Hebron Platform may be required to increase uniformity in foundation bearing pressure and increasing the platform stability *in situ*. Final hook-up and commissioning may take between three to nine months.

Potential activities that may be associated with offshore site preparation, tow-out, and installation of the platform and potential environmental interactions are listed in Table 2-7.

Table 2-7 Potential Activities and Potential Discharges / Emissions / Wastes during Hebron Platform Tow-out and Installation

<table>
<tr><th>Potential Activities</th><th>Potential Environmental Interactions / Discharges / Emissions / Wastes</th></tr>
<tr><td>Clearance Surveys (e.g., geohazard, sidescan sonar, diving, ROV, prior to installation of platform, OLS, potential excavated drill centres in the future)</td><td rowspan="16">• Air emissions
• Bilge / Ballast water
• Deck drainage
• Disposal / discharge of stormwater, potable water, fire water, cooling water and industrial water
• Elevated suspended solids
• Marine / underwater noise
• Potential loss of benthic habitat and organisms
• Potential substrate disturbance
• Potential water column effects
• Fish habitat disturbance
• Sedimentation
• Lights
• Discharges associated with hook-up and commissioning</td></tr>
<tr><td>Installation of Temporary Moorings</td></tr>
<tr><td>Tow-out / Offshore Installation</td></tr>
<tr><td>Possible Clearance Dredging</td></tr>
<tr><td>Seafloor Levelling for Platform Installation</td></tr>
<tr><td>Placement of Platform at Offshore Site Location</td></tr>
<tr><td>Underbase Grouting</td></tr>
<tr><td>Possible Offshore Solid Ballasting</td></tr>
<tr><td>Placement of Rock Scour Protection on Seafloor around Final Platform Location</td></tr>
<tr><td>Operation of Helicopters, Supply, Support, Standby and Tow Vessels / Barges</td></tr>
<tr><td>Hook-up, Production Testing and Commissioning</td></tr>
<tr><td>Hydrostatic Testing (OLS and offloading lines)</td></tr>
<tr><td>Possible Flaring during Production Testing</td></tr>
<tr><td>Lighting</td></tr>
<tr><td>Air Emissions</td></tr>
<tr><td>Safety Zone</td></tr>
</table>

2.8.8 Offshore Loading System Construction and Installation

The OLS off-loading lines and risers will be placed at their location, approximately 2 km from the platform, either before or after Platform installation. Methods to be used for the installation of the OLS will depend on the final design of the OLS. It is anticipated that the OLS off-loading lines will be placed using conventional pipe lay techniques; trenching or burial is not anticipated. OLS bases may be anchored to the seabed by piles, or other suitable means, to provide a stable connection for the OLS risers. Rock dumping and/or concrete mattress pads may be required for insulation and stability. Support vessels (diving, supply vessels) will likely be required.

Potential activities that may be associated with OLS, construction and installation and potential environmental interactions are listed in Table 2-8.

Table 2-8 Potential Activities and Potential Discharges / Emissions / Wastes during Offshore Loading System Construction and Installation

Potential Activities	Potential Environmental Interactions / Discharges / Emissions / Wastes
Clearance Surveys (*e.g.*, sidescan sonar, diving, ROV) prior to Installation of Platform, OLS	• Air emissions • Bilge / Ballast water • Elevated suspended solids • Marine / underwater noise • Potential loss of benthic habitat and organisms • Potential substrate disturbance • Potential water column contamination • Sedimentation • Solid, construction, hazardous, domestic and sanitary waste disposal • Lights
Operation of Helicopters, Supply, Support, Standby and Tow Vessels / Barges or Specialized Pipe-lay Vessel	
Anchor OLS Bases to Seabed by Piles	
Installation of OLS (may may be trenched to protect offloading flowlines; may be installed using diving vessels)	
Placement of Insulation / Stabilization (rock or concrete mattress pads) on the Seafloor over the OLS Offloading Lines	
Install OLS Riser	
Install Tie-ins to Platform	
Integration Testing Programs between the OLS Risers and OLS Bases and between the OLS Risers and Tanker Loading Equipment	
Hydrostatic Testing (OLS and pipelines)	
Possible Use of Corrosion Inhibitors or Biocides (OLS or flowlines)	
Lighting	
Air Emissions	
Safety Zone	

2.9 Hebron Project Operations

The Hebron Project operations will be managed by EMCP as Operator, employing both Company and third-party services. The Project will be managed and operational decisions will be made from offices in St. John’s, Newfoundland and Labrador.

2.9.1 Production Operations and Maintenance

Potential activities that may be associated with production operation and maintenance activities and potential environmental interactions are listed in Table 2-9.

Table 2-9 Potential Activities and Potential Discharges / Emissions / Wastes during Production

Potential Activities	Potential Environmental Interactions / Discharges / Emissions / Wastes
Operation of the Platform and OLS	• Air emissions • Bilge / ballast water • Changes to water quality in receiving environment • Deck drainage • Disposal / discharge of stormwater, potable water, fire water, cooling water, and industrial water • Drilling fluids and cuttings (WBM / synthetic-based mud (SBM)) disposal • Produced water discharge • Seawater / Firewater • Storage Displacement Water Discharges • Well treatment fluids Elevated TSS levels • Noise (including underwater noise) • Possible substrate disturbance • Possible loss of fish habitat • Lights • Safety zone
Maintenance Activities	
Power Generation and Flaring	
Normal Platform and OLS Operational Activities	
Operation of Seawater Systems (cooling, firewater)	
Operation of Oil Storage / Storage Displacement Water System	
Water Requirements (potable water, fire water, cooling water and industrial water)	
Waste Generated (domestic waste, construction waste, hazardous, sanitary waste)[A]	
Operation of Produced Water Treatment / Disposal System[B]	
Corrosion Protection System	
Use of Corrosion Inhibitors or Biocides (*e.g.,* hypochlorite)[C]	
Grey Water and Black Disposal	
Chemical / Fuel Management and Storage	
Operation of Helicoptors, Supply, Support, Standby and Tow Vessels / Barges / ROVs	
Offloading of Produced Crude	
Well Workovers (*e.g.*, drilling, completing, testing)	
Preparation and Storage of Drilling Fluids	
Managment of Drilling Fluids and Cuttings (reconditioning, discharge or injection)[D]	
Management and Storage of BOP Fluids and Well Treatment Fluids	
Cementing and Completing Wells	
Operation of Possible Disposal Well(s)	
Oil Processing Systems	
Seawater Injection System (to maintain reservoir pressure)	
Gas Injection Systems	
Artificial Lift (gas lift, electric submersible pumps or a combination)	
Oily Water Treatment[E]	
Produced sand management[F]	
Vent and Flare System[G]	
Diving Activities	

A Hazardous and non-hazardous wastes will be managed to avoid interactions with the marine environment

B Produced water will be discharged in accordance with OWTG

C The Operator will evaluate the use of biocides other than chlorine. The discharge from the hypochlorite system will be treated to meet a limit approved by the C-NLOPB's Chief Conservation Officer

D WBM cuttings will be discharged overboard in accordance with the OWTG; SBM cuttings will be re-injected into a designated well bore

E Operational discharges will be treated prior to being discharged overboard in accordance with OWTG

F Current drilling designs are focused on the prevention of produced sand to Topsides (downhole sand control). Produced fines are expected. Topsides sand management will be focused on the handling of these fines. In the unlikely event of failure of the downhole sand control system, management of the produced sand will be required (singular event)

G Small amounts of fuel gas will be used for flare pilots and may also be used to sweep the flare system piping or burn excess gas

2.9.2 Operational Support

The onshore organization will include engineering, technical support, Safety, Security, Health and Environment, logistics, financial and administrative personnel. Onshore support for docking, warehouse space, helicopter operations and product transshipment will be carried out at existing worksites in Newfoundland and Labrador. The Hebron Project will look to optimize existing operations at EMCP, through the sharing of resources, contracts, where feasible.

2.9.3 Logistics and Other Support

Four key areas of logistical support required during the operation and maintenance of the Project are shorebase support, personnel movements, vessel support and ice management. Where practical, the Operator will consider possible synergies with existing Grand Banks operators. The Project will also be supported by Oil Spill Response personnel.

Shorebase Support: Marine shorebase and warehouse facilities using existing facilities in St. John's and surrounding areas capable of providing Project support activities will be used. Existing port facilities are capable of servicing multiple operations, including wharfage, office space, crane support, bulk storage, consumable (fuel, water) storage and delivery capability.

Personnel Movements: Helicopters will be the primary method to transfer personnel between St. John's and the offshore platform. Personnel may also be transferred using supply vessels, when required (*i.e.*, weather or other logistical delays). The Operator will consider and discuss possible shared services with other Grand Banks operators with a view to optimizing the fleet configurations of all operations and providing the safest and most efficient and effective service. There were 280 crew change flights during Hibernia operations in 2008.

Vessel Support: Supply and stand-by vessels will be required to service the operational needs of the platform and drilling units in the Hebron Field. Supply vessels may also be required to conduct components of the Environmental Effects Monitoring (EEM) program and for oil spill response support, training and exercising. The Operator will consider and discuss possible synergies with other Grand Banks operators, where practical, with a view to optimizing the fleet configurations of all operations and providing the safest and most efficient and effective service. As with current operations, vessels associated with the Hebron Project will operate within established shipping corridors between St. John's and the Offshore Project Area. As an estimate of vessel frequency that may apply to the Hebron Project, there were 122 vessel sailings from St. John's to Hibernia in 2008.

Ice Management: The Grand Banks Ice Management Plan has been developed by existing operators and the Hebron Project is expected to participate in this program. Reliable systems for the detection, monitoring and management of icebergs and pack ice, including towing techniques, have been developed for the Grand Banks area.

2.9.4 Communications

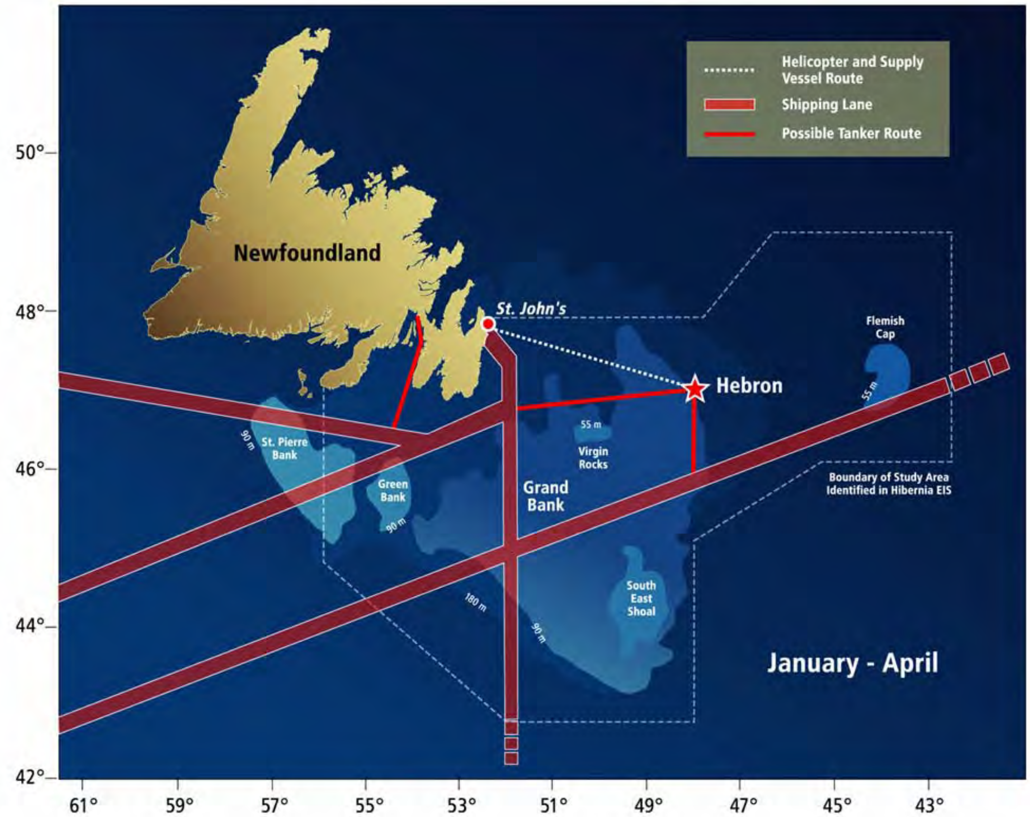
Offshore telecommunications systems to support the Hebron Project may include the following systems:

- Private Automatic Branch Exchange and emergency telephone systems
- Public Address and General Alarm system
- Radio systems – platform trunked, marine, aeronautical
- Radio console system
- Radio antenna tower
- C-Band Satellite system
- Inmarsat A satellite terminal
- GMDSS system
- Lifeboat radio systems
- Racon
- Crane radio system
- Metocean / Ice Management Radar Monitoring system
- Collision-avoidance Radar / navigational
- Differential GPS system
- Tanker telemetry system
- Closed Circuit Television
- Inter- / Intra-platform telephone system
- Microwave radio to Hibernia
- Inter- / Intra-platform LAN / WAN data communications network
- Entertainment system
- Security system
- Telemed system
- Additional telecommunication systems, which may be required, will be investigated during FEED and detailed design

These systems must operate and be suitable for a remote installation in all weather and atmospheric conditions anticipated on the Grand Banks. The systems must be fully available and operable during both steady state conditions and during all platform emergencies and power outages. Uninterruptible power supplies must be incorporated as required, in order to achieve this requirement. The applicable onshore components must also incorporate the same availability and operability standards.

2.9.5 Shipping / Transportation

Crude oil from the Hebron Platform will be transported to the Newfoundland Transshipment Terminal or direct to market. Assuming a peak production of 24,000 m^3/day, it is estimated that Hebron will require one tanker loading every six days, for a total of approximately 60 tanker loadings per year. Based on these estimates, it is anticipated that the existing tanker fleet (three tankers) currently servicing Hibernia and Terra Nova will be used; no additional tankers are anticipated to be required. Tankers will use existing international shipping lanes (as shown in Figure 2-13 and established shipping lanes when transitting to the transshipment facility in Placentia Bay.



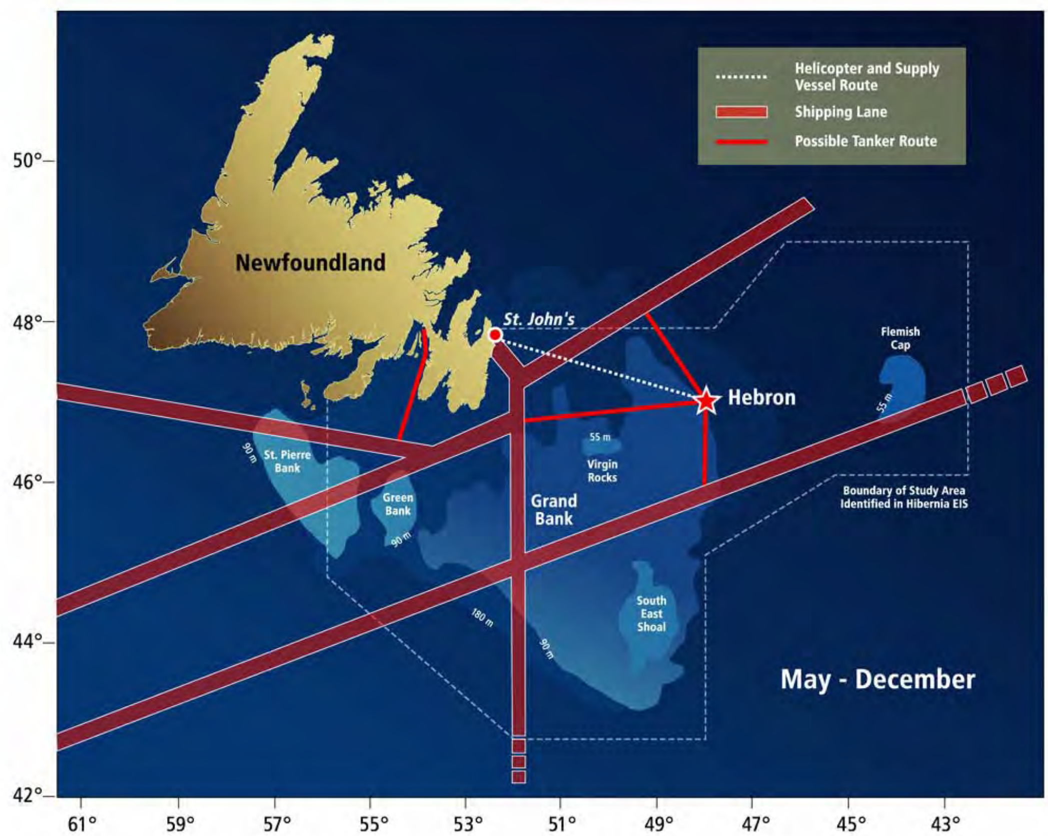


Figure 2-13 Transportation Routes Relevant to the Hebron Field

2.9.6 Surveys and Field Work

2.9.6.1 Seismic Surveys

Seismic surveys are a technique used to map rock layers and properties with sound propagation and related echo mapping (includes seismic mapping). The goal of a seismic survey is to develop an image of the subsurface geology and of the features where hydrocarbon reserves could accumulate *(i.e.*, subsurface strata and structures).

Seismic surveys are undertaken by a specialized vessel towing a submerged, compressed air-driven gun (sound source) array to produce short bursts of sound energy. The acoustic pressure pulse travels into the seafloor and reflects off various seafloor layers. Hydrophone assemblies are towed as streamers behind a vessel to record the reflected sound waves.

There can be between six to ten streamers towed in typical 3D surveys. Typically, one streamer is towed in a 2D survey. Each streamer contains a dense array of hydrophone groups that collect and pass to recorders echoes of sound from reflecting layers. The depths of the reflecting layers are calculated from the time taken for the sound to reach the hydrophones via the reflector; this is known as the two-way travel time. Positional and signal return-time data are collected over a grid pattern and analyzed to develop an image of the geological layering beneath the seabed, allowing potential hydrocarbon traps to be identified. A 2D survey typically covers a larger area than a 3D survey, which tows more streamers over a finer grid pattern than a 2D survey. Typical seismic surveys are able to map rock layers over 10 km deep (CEF 1998).

Seismic airguns release most of the acoustic energy focused in a vertically downward direction. The noise associated with airguns can range between approximately 215 and 235 dB re 1 µPa-m for a single airgun and approximately 235 to 260 dB re 1 µPa-m for arrays (Richardson *et al.* 1995). Source levels off to the sides of the array in the horizontal are generally lower.

The arrays and hydrophones are usually towed several metres below the sea surface. A typical seismic survey lasts several weeks and covers a range of approximately 555 to 1,110 km. The ship towing the array is typically 60 to 90 m long and moves through the water at speeds usually in the range of 8 to 10 km/h (4.5 to 5.5 knots).

In general, the frequency output of an airgun depends on its volume: larger airguns generate lower-frequency impulses. However, due to the pulsive nature of the source, airguns inevitably generate sound energy at higher frequencies, above 200 Hz, although the energy output at these frequencies is substantially less than at low frequencies.

2.9.6.2 Geohazard Surveys

Well site or geohazard surveys may be used to identify and avoid unstable areas (*e.g.*, shallow gas deposits) or hazards (*e.g.*, shipwrecks) prior to drilling. The well site survey may use a combination of video and a small acoustic array and/or sonar over the well location. Although a variety of seismic sources may be used for such a wellsite / geohazard survey, a typical source is a 160 cu. in. four-gun ladder array of sleeveguns with an estimated source level of 238 dB re 1μPa @ 1m (zero to peak) towed at a depth of 3 m. This equates to 244 dB re 1μPa @ 1m (peak to peak).

2.9.6.3 Geotechnical Surveys

Geotechnical programs are those surveys involving the measurement of physical properties of the seabed and soil. Seabed surveys using geophysical and geotechnical methods are used to determine the nature of the seafloor and underlying sediments. These surveys assist in the positioning of wells, pipelines and production facilities.

Substrate properties often need to be characterized prior to installation of any equipment on the substrate (such as the Platform and flowlines). Geotechnical investigations primarily involve the physical collection of sediment samples, and may also include collection of geophysical data (*i.e.*, side-scan sonar), as described in Section 2.9.6.1. Methods to collect sediment samples include drilled boreholes and grab samples. Boreholes are drilled at each of the potential site to a specified depth, which is program specific and depends on data requirements.

Due to the shallow nature of most boreholes, they are usually entirely in soils (unconsolidated sands, silts, and clays) and will not penetrate hydrocarbon-bearing formations. Cuttings will be expelled at the seafloor. Approximately 1 m^3 cuttings is typically generated per borehole.

2.9.6.4 Vertical Seismic Profiling Surveys

VSP may be also conducted as part of the drilling and production activities using an airgun array. VSPs are a collection of well bore measurements (seismograms) recorded by geophones inside the wellbore using sound sources at the surface near the well. A VSP is used to correlate well data with surface seismic data, to obtain images of higher resolution than surface seismic images and to collect data ahead of the drill bit. The array is similar to that employed by 2D or 3D seismic surveys, but is typically smaller and deployed in a smaller area over a shorter time period, often only 12 to 36 hours, but occasionally up to several days. An airgun similar to that employed for surface seismic collection is used as the seismic source.

An imaging toolstring is run in the wellbore and is anchored at successive points as required to cover the entire recording depth. With a zero-offset VSP, a seismic source array is deployed over the side of the drilling platform. The source is activated (typically three to five times) to create a sonic wave that is picked up by geophones in the toolstring.

Typically, only one zero-offset VSP is conducted on each well when total depth has been reached. An operator may elect to conduct two zero-offset VSPs per well, when the intermediate and lower hole sections have been drilled. An operator may also elect to conduct a walkaway VSP concurrent to the intermediate hole section zero-offset VSP. A walkaway VSP is a type of

VSP in which the source is moved to progressively farther offset at the surface and receivers are held in a fixed location, effectively providing a mini-2D seismic line that can be of higher resolution than surface seismic data and provides more continuous coverage than an offset VSP. 3D walkaways, using a surface grid of source positions, provide 3D images in areas where the surface seismic data do not provide an adequate image due to near-surface effects or surface obstructions. If a walkaway VSP is used, the two source arrays would not be activated concurrently.

2.9.6.5 Environmental Surveys

Environmental surveys are those surveys involving the study of physical, chemical and biological elements of the site. They may involve collection of data on ice and icebergs, weather, biota, sediments or water. Methods of data collection include direct observation, onsite weather station, core or surficial sediment sample collection, or fish sampling by various methods. Environmental surveys also include environmental effects monitoring programs.

2.10 Decommissioning and Abandonment

The Operator will decommission and abandon the Hebron production facility according to regulatory requirements in place at the time of end of Project life. The Hebron Platform infrastructure will be decommissioned and the wells will be plugged and abandoned. The Hebron Platform structure will be designed for removal at the end of its useful life.

2.11 Potential Expansion Opportunities

Future development of resources is anticipated within the four Significant Discovery Licenses, and/or on adjacent land that may be acquired by Project Proponents. These expansion developments may be produced from the platform or through tie-back using subsea flowlines. Such developments may require the addition of one or more excavated (s) within the Project Area. J-tubes and/or risers will be incorporated into the GBS design to accommodate this tie-back option. The excavated drill centres would be situated within the Hebron Project Area as required over the duration of the Project.

For any excavated drill centre that may be constructed, final locations will be adjusted based upon future engineering, seismic, geotechnical and geohazard investigations. The conceptual well and flowline configurations described below are tentative and subject to further review before the final design is determined. These possible expansion developments may involve, but are not limited to, the following activities:

- Construction, installation, operation, maintenance, modification, abandonment and decommissioning of up to four excavated drill centres (up to approximately 70 m x 70 m x 10 m in size) that contain the equipment necessary to support the extraction of petroleum resources:

  - Each of the excavated drill centres could contain a number of injection or production wells
  - Would be excavated using proven construction methods for the Grand Banks
  - Excavated drill centre dredge spoils disposal in one or more approved areas

- Construction, installation, protection, operation, maintenance, modification, abandonment and decommissioning of subsea flowlines / umbilicals and associated equipment (inclusive of water, gas and oil flowlines) tied back to the Hebron Platform:
  - This includes any associated seabed trenching, excavation, covering and/or soil deposition
  - Concrete mattresses positioned over the flowlines near the platform may be installed by a diving support vessel or another vessel of opportunity
  - Well tie-ins may be performed by an installation vessel and/or a MODU (with ROV support) during the subsea construction program
  - Trees, templates, and manifolds would be installed by installation vessel, whereas pipeline-to-manifold tie-ins may be made by divers and/or ROV
- Possible requirement for additional topsides equipment located on the Hebron Platform to provide additional process capacity
- Drilling, completion and workovers of subsea wells; may be undertaken from one or more MODUs
- Geophysical (seismic (2D/3D/4D), geohazard / wellsite, VSP) surveys and/or geotechnical investigations
- Supporting activities including ROV surveys and Diving Programs and operation of support craft associated with the above activities including but not limited to vessels for excavated drill centre excavation, offshore drilling platforms, supply vessels, standby vessels and helicopters

It is anticipated that the excavated drill centres will be constructed using proved methods and will be of similar design to those already in-place on the Grand Banks. Each of the excavated drill centres could contain a number of injection or production wells. The installation of subsea infrastructure would be by installation vessel, divers, and/or ROV. If required, concrete mattresses will be positioned over the flowlines near the Hebron Platform may be installed by a diving support vessel or another vessel as appropriate. Measures to protect flowlines from iceberg scour will be identified and implemented where required.