Hebron
ExxonMobil Canada Properties

TECHNICAL DOCUMENT

HEBRON PROJECT
Produced Water Management Strategy

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1.0 EXECUTIVE SUMMARY

From the earliest stages of the Hebron Project ExxonMobil committed to evaluating the feasibility and impact of full Produced Water Re-Injection (PWRI) into the subsurface reservoir and included that commitment in the Hebron Project Description (March 2009). This report summarizes the efforts ExxonMobil undertook to develop a comprehensive produced water management strategy to reduce or eliminate produced water discharges to the sea per the 2010 Offshore Waste Treatment Guidelines (OWTG).

Two alternatives to conventional marine discharge of produced water were identified and evaluated from technical standpoint:

- Injection into a disposal reservoir
- Reuse of produced water for pressure maintenance.

Disposal Reservoir

A dedicated produced water (PW) disposal reservoir was investigated and found not to be feasible. The cumulative volume of water produced in 30 years is approximately 366 Mm^3 and a suitable reservoir could not be identified to contain that volume. Over-pressuring of the disposal formation is a significant, unacceptable risk that the Project will not undertake.

Pressure Maintenance

Several risks associated with PWRI for reservoir pressure maintenance were identified. As explained below these risks are considered unacceptable 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.

Preliminary studies identified several potential risks to adopting PWRI:

- Souring potential is up to 50% greater as compared to injecting seawater (SW) only
- PWRI could result in greater than predicted increases in injection pressure (potentially beyond pressure limits of equipment)
- Fracture containment could be compromised with increasing use of PW
- Scaling potential is greatest when injecting PW into the formation

Additional data is needed to confirm that these risks are manageable. The additional data required can only be obtained and analyzed after sufficient water production occurs post start-up. For example, Volatile Fatty Acid (VFA) content can be highly variable across reservoirs. Currently only a small number of formation water samples have been collected from specific reservoirs. None are truly representative of the produced water that will result by producing from various reservoirs. Larger volume samples of actual water produced from the production reservoirs are needed to fully evaluate these risks.

Hebron will initially operate with marine discharge of PW at start-up. However, the Operator has incorporated into its design proven equipment that utilizes best produced water treatment practices to help ensure that oil-in water concentrations will be as low as practicable.

As more wells come on-line and production data and experience is gathered, further testing on rock properties and PW / SW / Reservoir compatibility will be carried out as additional core samples and PW become available. Hebron will switch to PW injection for routine operations if testing and studies (post start-up) demonstrate that the risks and impacts of PWRI are understood and acceptable. It is anticipated that a decision on PWRI can be reached 4-5 years after platform start-up (refer to Section 6.3). If PWRI is adopted, the facility will maintain flexibility for marine discharge during equipment failures or planned maintenance.

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

If PWRI is adopted, it will still be necessary to preserve the option to return to permanent marine discharge if unexpected complications arise with PWRI (e.g., loss of oil recovery, reservoir souring, scaling, plugging, etc.).

2.0 INTRODUCTION

This report summarizes the efforts the project took to develop a comprehensive produced water management strategy to reduce or eliminate produced water discharges to the sea as consistent with the 2010 OWTG. Two alternatives to conventional marine discharge of produced water were identified and evaluated from a technical standpoint:

- Injection into a disposal reservoir
- Reuse of produced water for pressure maintenance.

For those situations where marine discharge is the only practicable option, the Operator incorporated into its design proven equipment that utilizes best produced water treatment practices to help ensure that oil-in water concentrations would be as low as practicable.

Produced water represents the largest volume discharge stream in oil and gas production operations on most offshore platforms. Oil production operations on the Hebron platform are anticipated to generate the largest volume of produced water on a daily basis (up to 45,000 m^3) of any of the platforms off the Canadian east coast.

Large volumes of seawater will be needed for reservoir 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 (PWRI):

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

ExxonMobil Canada Properties (EMCP) conducted several studies to analyze these risks, based on the limited number of formation water samples and data available at hand. This document describes EMCP’s approach to produced water disposition and summarizes the completed studies that lead to this approach. Specifically, this document covers:

- Executive Summary and Introduction (Sections 1 & 2)
- EMCP’s Produced Water Management Strategy for Hebron (Section 3)
- Summary of the feasibility studies concluded to date (Section 4)
- An overview of the produced water facilities design (Section 5)
- Plan for assessing and executing PWRI (Section 6)
- Summary and conclusions (Section 7)

3.0 PRODUCED WATER MANAGEMENT STRATEGY

3.1 Strategy Overview

The Hebron produced water management strategy is shown in Figure 1.

Hebron will initially operate with marine discharge of PW at start-up. As more wells come on-line and production data and experience is gathered, further testing on rock properties and PW / SW / Reservoir compatibility will be carried out as additional core samples and PW become available.

Hebron will switch to PW injection for routine operations if testing and studies (post start-up) demonstrate that the risk and impacts of PWRI are understood and acceptable. If PWRI is adopted, the facility will maintain flexibility for marine discharge during equipment failures or planned maintenance.

If PWRI is adopted, it will be necessary to preserve the option to return to marine discharge permanently if unexpected complications arise with PWRI (e.g. loss of oil recovery, reservoir souring, scaling, plugging).

3.2 PW Management Criteria

PW Management requires considerations of several criteria to ensure maximum oil recovery and protect the reservoir from undue damage. Consideration of the following criteria is given in the following sections:

<u>Regulatory Criteria</u>

- Meet oil-in-water specification for marine discharge (2010 OWTG) – the ability to meet this criteria is required even if PWRI is adopted, as occasional marine discharge would still be required in the event of an equipment upset or planned maintenance
- Adopt PWRI once it is demonstrated that the associated risks are manageable
- Adopt best commercially available and proven treatment technology
- Implement continuous operational improvement on PW management

<u>Resource</u>

- Inject water (SW, PW, or a mix) to maintain reservoir pressure and maximize oil recovery
- Prevent damage to the resource or reduction in economic viability in terms of oil recovery, souring, injectability or otherwise

<u>Subsurface</u>

- Injection water cannot adversely impact subsurface assets (e.g., scaling, corrosion, plugging)

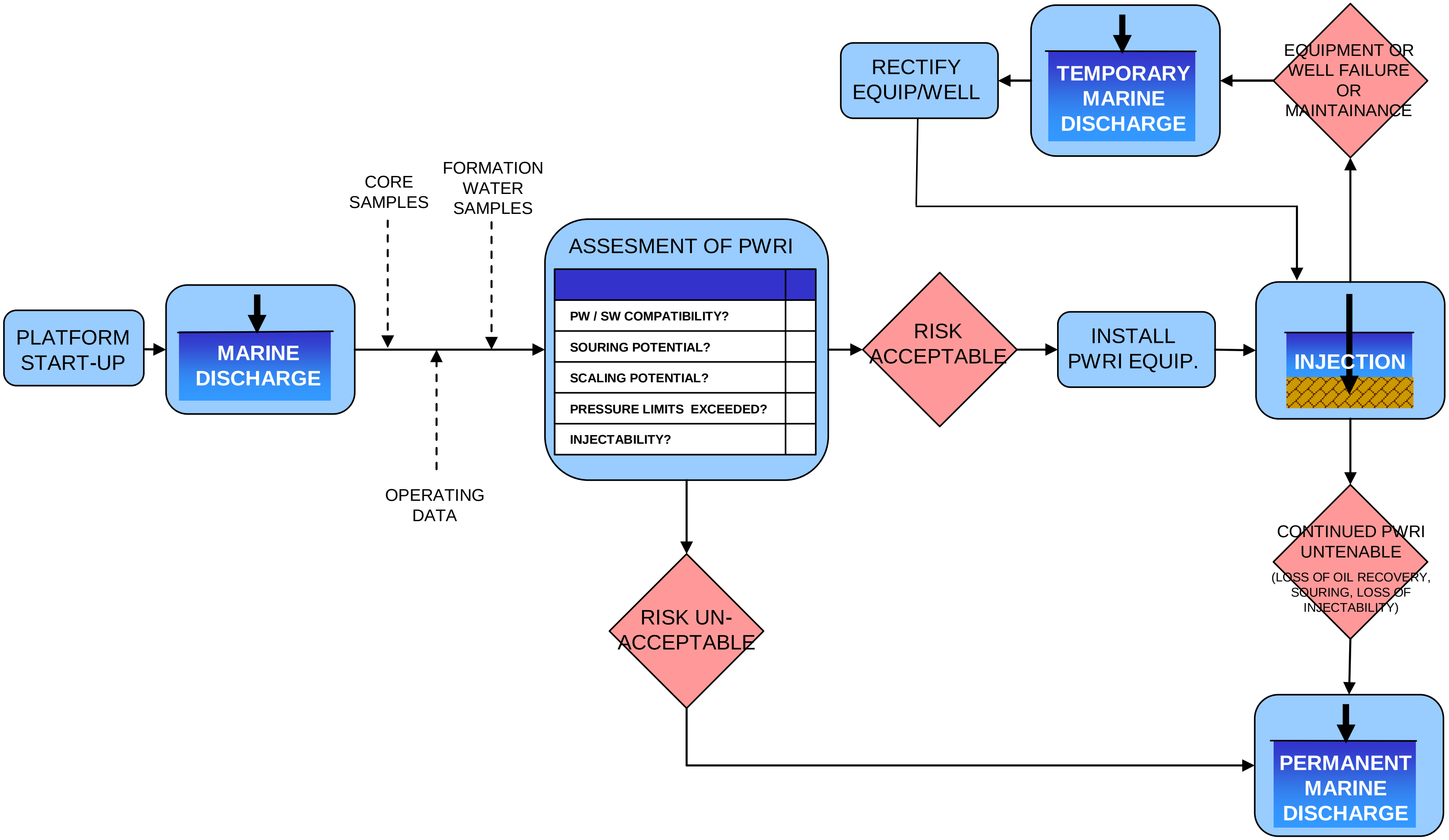

Figure 1: Hebron Produced Water Management Strategy Flow Chart

4.0 FEASIBILITY STUDIES

4.1 Introduction

Injection of PW for reservoir pressure maintenance presents several additional challenges over SW injection largely due to the fact that PW is typically warmer and contains higher concentrations of suspended solids and dissolved oil-in-water than ambient seawater. These challenges include:

- Loss of fracture containment leading to inefficient sweep conformance
- High rates of scale, corrosion, and bacterial growth
- Increased damage to surface equipment such as injection pumps due to solids loading
- More rapid injectivity decline in any unfractured zones
- Possible increased risk of souring due to increased fatty acid content in injection water providing nutrient for sulphate reducing bacteria
- Higher costs associated with increased pumping, cooling, and / or water quality requirements
- Higher costs and downtime associated with injection well workovers

Technical studies were conducted on limited available formation water samples and core data to assess potential issues regarding scaling, injectability and reservoir souring. In addition, an evaluation of PW disposal into a non-producing reservoir was carried out. Further details of these studies can be found in Appendix A and the references.

4.2 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 two prospective non-producing formations that would merit quantitative analysis of their potential water storage capacity. These prospects included an early Eocene sandstone known as the South Mara Member, and an unnamed / unpenetrated channel sand evident on seismic that incises into the top of the late-Cretaceous Petrel Member. These units were subjected to preliminary investigation as possible storage compartments 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 these sand members within the Hebron Unit boundary.

Results indicated that these sand members were predicted to have far too little combined storage capacity to accept the forecasted volume of produced water over the life of the Hebron Project (an estimated 366 Mm^3 plus additional produced water if future expansions are developed).

A screening level design of the disposal equipment required on the Topsides was developed for this option, and it was found that a PW disposal system (in addition to the water injection required for reservoir maintenance) would result in approximately 150,000 t of CO_2 equivalence of greenhouse gas warming potential being released into the atmosphere annually. The conclusion is that PW disposal is not a feasible or preferred option. Additional information regarding this option is shown in Appendix A.

4.3 Injectability

Water injectivity 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 can 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. Cooling the produced water to avoid this is impractical due to the large volumes of high-temperature water involved and the large footprint for PW coolers that would be required. Use of coolers also presents significant operational challenges with fouling and scaling reported as a common issue. Potential for scaling is discussed further in Section 4.3.

An injectivity study was conducted by ExxonMobil Upstream Research Company (URC) to assess the required injection pressure to achieve fracture injection for all potential injection wells in Hebron and how the injection requirements may change for PWRI versus SW injection (SWI) (EM URC, 2010).

The main purpose of this study was to provide the required fracture initiation (i.e. "breakdown") pressure and propagation pressure requirements for designing the water injection delivery system. The study accounted for many factors that can influence these pressure requirements such as native stress state, thermal effects, suspended solids and oil-in-water effects, well inclination and orientation effects, fluid rheology, wellbore friction effects, and effect of mixing seawater and produced water. Required breakdown and initiation pressures were calculated separately for Pool 1 and for Pools 4 / 5.

The study found that PWRI is technically feasible from an injectivity standpoint, however, there are several vulnerabilities that require additional operational data to either confirm or retire. 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. The outcome provides a technical basis for maintaining fracture-mode water injection regardless of a decision on implementing PWRI.

4.4 Scaling

Both SW and PW 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 and precipitation can occur during injection, 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 PW with SW 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 PW at the Hebron platform will ultimately be a mix of PW from multiple 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 SW.

The URC study (EM URC, 2009) assessed the potential scaling issues associated with production and injection at Hebron. Scale predictions from this study were in general agreement with those from a Flow Assurance Report by the previous Hebron Operator (Chevron), but URC predicted a higher scaling severity for carbonate and sulphate scales due to higher assessed concentrations for Ca (formation water) and SO_4 (seawater).

In producing wells, scaling predictions indicate a moderate potential for calcium carbonate scaling with production of Hebron formation water; the risk of scaling is expected to decrease with increasing fractions of seawater in the injected fluid. Mitigation through downhole injection of scale inhibitor is planned. For mixtures of formation water and SW, barium sulphate is expected to precipitate in small quantities (20 mg/L). Scale inhibitor squeeze treatments can be performed if monitoring indicates the need. Acid or EDTA treatments, or mechanical removal, are generally effective in removing accumulations of either type of scale.

During processing of producing fluids in topside facilities, severe $CaCO_3$ scaling could occur in the low-pressure separator at temperatures above 90℃. In this same temperature range, strontium sulphate and barium sulphate scale may also form.

For injection wells, $CaCO_3$ and FeS scaling risks increase with PWRI, but levels are expected to be manageable with chemical treatment if water is injected above fracture pressure.

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

4.5 Reservoir Souring

In the oil producing reservoir, indigenous sulphate-reducing bacteria (SRB) are present. When sulphates are added to the reservoir during SWI, SRB activity is stimulated and causes biogenic production of hydrogen sulphide (H_2S), a process that has been termed "reservoir souring". The rate of H_2S production is strongly dependent upon the concentration of low-chain Volatile Fatty Acids (VFAs) present in the native formation water, which serve as a metabolizable-carbon energy source. An increase in growth of bacteria could result in a plugging of the formation and / or H_2S contamination of the reservoir fluids.

Figure 2 shows the mechanism for reservoir souring. Ideal souring conditions occur at a temperature range of 35-90ºC, meaning that Pool 1 is susceptible.

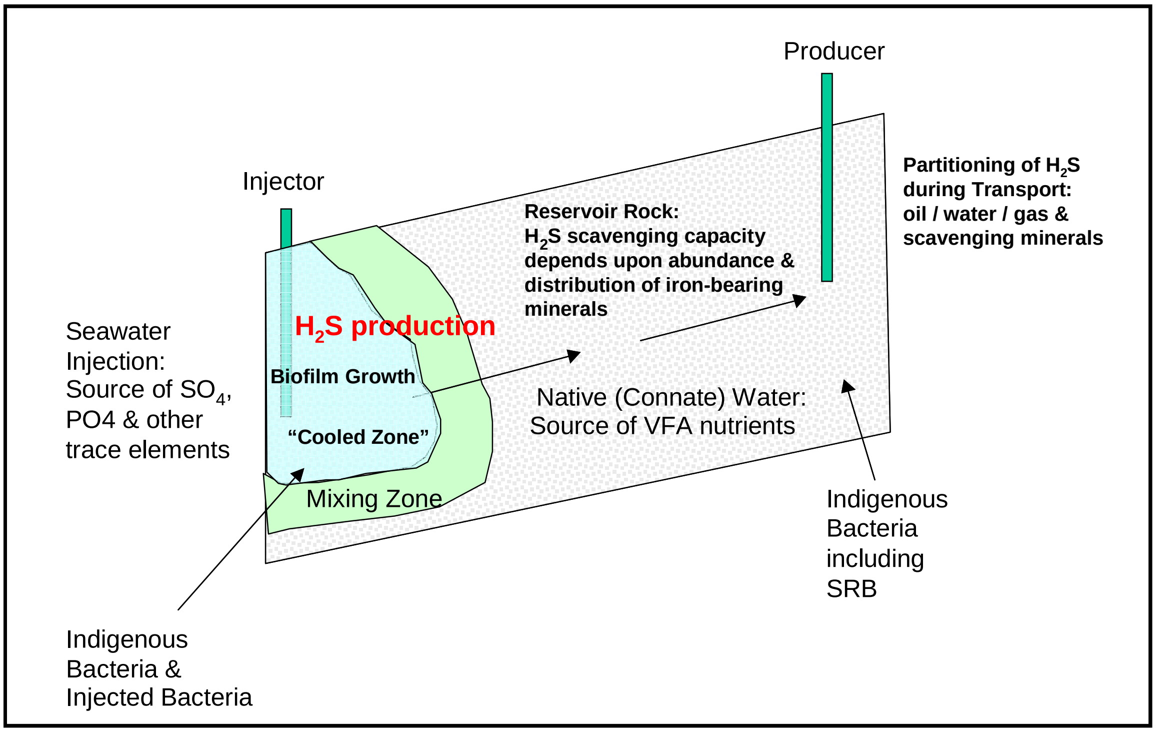

Figure 2: Reservoir souring mechanism

An initial study of Pool 1 souring susceptibility was conducted in 2005, using a range of levels of souring nutrients (VFAs) in formation water (Oil Plus, 2005). Pool 1 predictions indicate potential for significant total-wellstream mass of H_2S, and that the sulphide content forecast for mixed PW / SW injection is up to 50% higher than that for SW-only injection.

An additional study was conducted in 2010 using updated reservoir depletion plans and a VFA content of 200 mg/L based on a Pool 1 formation water sample. The simulation results predict a resulting H_2S content in associated gas in the range of 200-250 ppmv with SW only injection, and 280-300 ppmv from PWRI (Oil Plus, 2010). The simulation results also confirmed that the sulphide content forecast for mixed PW / SW injection is up to 50% higher than that for SW-only injection.

Topsides simulations completed with the reservoir souring from Pool 1 indicated H_2S concentration increase of 50% for the PW / SW injection as compared to the SWI only case in the lift gas and injection gas in year 2045 of facility life. The topsides process simulations indicate that the low associated gas production rate in late facility life in conjunction with the high lift gas rates results in accumulation of H_2S. Some of the H_2S is purged from the topsides facility in the fuel gas, produced oil, and produced water streams but not all. The Topsides facilities will be designed for sour service as per the latest revision of NACE MRO0175/ISO-15156, for all qualifying hydrocarbon systems (including wells). The impact to machinery, production, and other systems are being determined during FEED. Biocide injection into the SW is being implemented as the mitigation to control bacterial contamination, which reduced the H_2S generation rate from Pool 1 by 2/7th. Please see reference CAHE-WP-PRSIM-21-000-0003 (EMCP, 2011) for additional details of the topsides souring simulation.

5.0 TOPSIDES FACILIITES

5.1 Produced Water Treatment System

Design Basis

The PW treatment system will be designed to treat a nominal peak rate of 45,000 m^3/d of PW. The treatment specification for ocean discharge is an oil-in-water concentration not exceeding 30 mg/L on a 30-day weighted average, and not exceeding 44 mg/l on a 24-hour arithmetic average.

System Description

The Hebron PW treatment system features the following components:

- Hydrocyclones
- Compact Flotation Units (CFUs)
- Degassing drums

Hydrocyclones are the standard treatment technology employed by the current Grand Banks facilities, and have been sufficient on these facilities to meet the OWTG specifications in most operating scenarios. Hebron oil is heavier than the other installations, however, and to ensure that the OWTG specification can be met, CFU's will be installed downstream of the cyclones.

A schematic of the PW treatment system is shown in Figure 3. PW from the MP Separator is routed to the PW hydrocyclones for bulk separation of oil from water. A crossover line allows routing of oily water from the LP separator and oil / water separator directly to the PW cyclones.

The MP separator includes Vessel Internal Electrostatic Coalescer (VIEC) technology that is intended to improve level control in the MP separator by improving the definition of the oil / water interface and minimizing the thickness of the emulsion layer. In turn, this should minimize oil carry-under to the PW treating system.

The reject stream from the PW hydrocyclones is sent to the LP separator and the water fraction is sent to the CFU skid for further treatment. A bypass line is included so it is possible to send the water from the production separators directly to the CFU skid, bypassing the PW hydrocyclones.

The CFU skid consists of 3 trains of flotation units mounted on a common skid, providing a 3x33% single stage system. Future provision for an upgrade to a two-stage system with CFUs operating in series for each train is provided for if it is found to be necessary.

Low-pressure fuel gas at a ratio of approximately 0.1 m^3 gas/m^3 water is added upstream of each CFU in static gas mixers. Centrifugal forces and gas flotation contribute to enhance the oil / water separation process. Within the CFU, oil droplets coalesce into larger agglomerates as they progress through the vessel. The hydrocarbon rich phase floats to the top of the vessel then is transferred to the LP separator.

The treated water flows to the downstream PW degassing drum, for settling to reduce gas that may be entrained in the flow. Water clarifiers are proposed to be injected at a concentration of 10 – 20 ppm throughout the process and PW treating system to enhance separation.

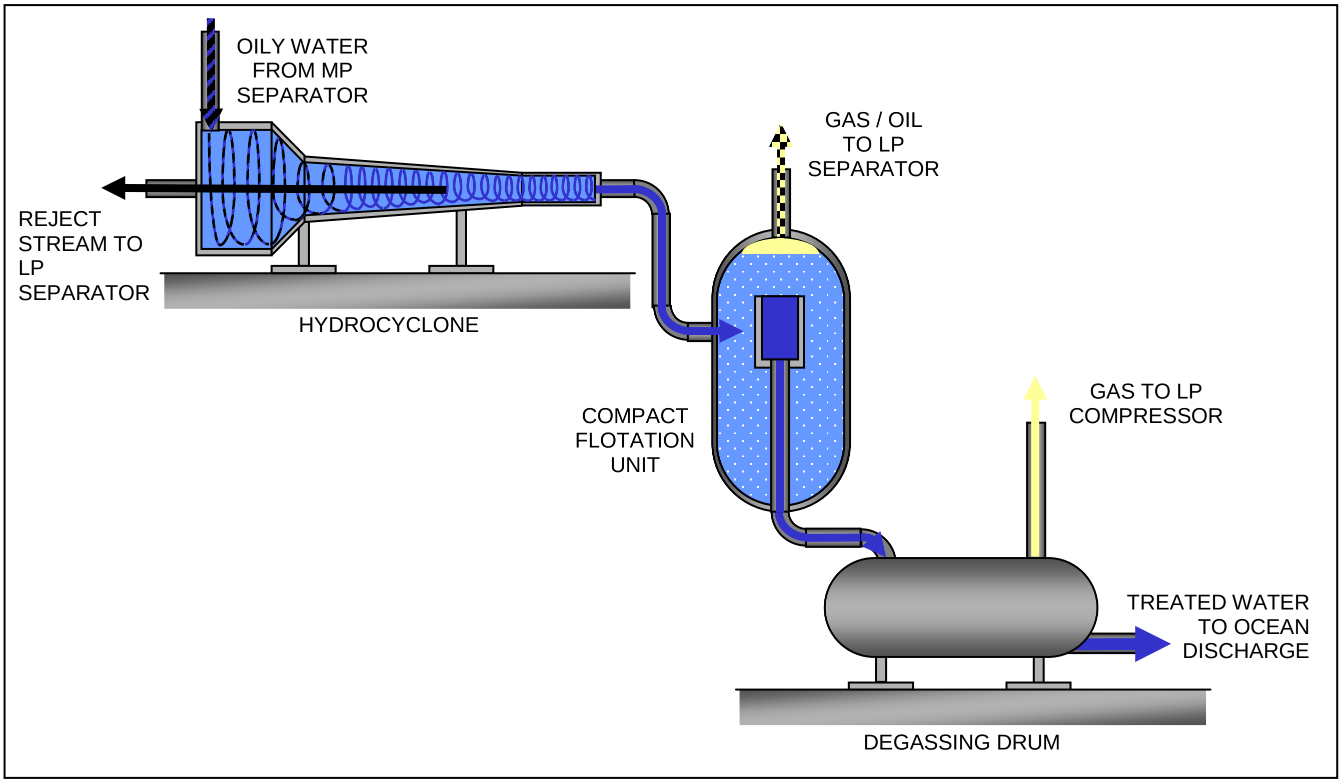

Figure 3: Schematic of Hebron PW Treatment System

The PW degassing drum operates at approximately 1.6 bara with flash gas vented to the 1st stage LP compressor suction cooler by pressure control. The oil layer is skimmed off by a weir plate and flows into the closed drain drum by gravity.

Provision for a future fuel gas sparging system in the degassing drum is included. A line for fuel gas is installed into the liquid phase of the PW degassing drum to sparge fuel gas through the water in the tank to enhance oil / water separation by gas flotation.

The treated water from the degassing drum flows under gravity to the PW caisson for ocean discharge.

System Limitations

The PW treatment system described above is designed to meet the current (2010) OWTG specifications for ocean discharge. There are several caveats that should be noted:

- PW treatment is inherently difficult to predict, and the system has been designed based on the limited information and well samples available.
- Upset conditions, and operations 'learning-curve' periods can be expected, particularly during early operations.

The hydrocyclone units specified for Hebron have greater turndown range than older units, and the liners in the units can be blanked or changed to provide further turndown for early operation when PW volumes are low.

The Hebron PW system includes the CFU technology to enhance separation. Most facilities meet the 30 mg/L oil-in-water requirement with only hydrocyclones. CFUs are the best commercially available, proven technology for produced water treatment in offshore technology. Consideration will be given for provisions to incorporate additional equipment in the future for advancements in proven treatment technology.

In addition, VIEC is being applied to enhance oil / water separation on the hydrocarbon processing side of the facility (MP separator) which should minimize oil-water carry-under to produce “cleaner” water entering the PW treatment system. Provision has also been made in the LP separator and oily-water separator to install VIEC units at a later date if required.

It is noted that both VIEC and CFU are the first application of advanced separation technology on the Grand Banks.

5.2 Water Injection System

Design Basis

The purpose of the water injection (WI) system is to provide clean water for reservoir pressure maintenance to enhance recovery of hydrocarbons from Pool 1 and Pool 4 / 5 formations. The required WI pressures (at pump discharge) are shown in the table below.

Table 1: Water Injection System Design Parameters

Water Injection Parameter	Metric Units		Oilfield Units	
	Units	Value	Units	Value
Total Water Injection Peak Rate	m^3/d	59,143	kbd	372
Peak Water Injection Rate – Pool 1	m^3/d	50,876	kbd	320
Water Injection Propagation Pressure – Pool 1	MPa	18.7	psi	2,710
Water Injection Breakdown Pressure – Pool 1	MPa	27	psi	3,920
Peak Water Injection Rate Pool 4 / 5	m^3/d	12,242	kbd	77
Water Injection Propagation Pressure Pool 4 / 5	MPa	33.6	psi	4,870
Water Injection Breakdown Pressure – Pool 4 / 5	MPa	52.8	psi	7,660
Oxygen content in Injection Water	ppb	<10	-	-
Filtration requirement	µm	<80	-	-

System Description

Water arrives at the WI booster pump manifold from the SW lift pumps and, in the case of PWRI, from the PW filters. The configuration of the WI system downstream of this point is largely independent of the use of PW / SW or SW only.

The SW or PW / SW mix is pressurised to 15 bara by the WI booster pump, to ensure enough Net Positive Suction Head (NPSH) for the WI pumps. From the booster pumps the water is further pressurized by the Pool 1 and Pool 4 / 5 WI pumps operating in parallel.

All pumps will be equipped with electrical drivers with the booster pumps being fixed speed while the Pool 1 and Pool 4 / 5 pumps will have mechanical geared coupling variable speed drives (VSDs). The VSDs will facilitate the handling of the range of operations for turndown, propagation and breakdown.

System Limitations

The WI system as described above is at the physical size limit of what can be accommodated within the platform.

5.3 Additional PWRI Equipment

System Description

In addition to the treatment and injection system described above, PWRI would require the following additional equipment, shown in Figure 4:

- Produced water filters
- Produced water pumps

The filters are required to ensure removal of fine particles that could damage the injection wells and receiving reservoir. Filters would be specified to meet 98% removal of particles larger than 80 microns. The filters would discharge into the WI booster pump manifold where it would co-mingle with SW make-up water.

Because of the system hydraulics, and platform layout, there is insufficient pressure to push the water through the filters and provide sufficient NPSH at the inlet to the WI booster pumps to prevent cavitations and pump damage. Additional pumps are required to boost the water from the discharge of the degassing drum to the pressure required for filtration.

Figure 5 shows the water injection system with potential future PWRI equipment. Table 2 shows preliminary data for the major pieces of additional equipment required for PWRI.

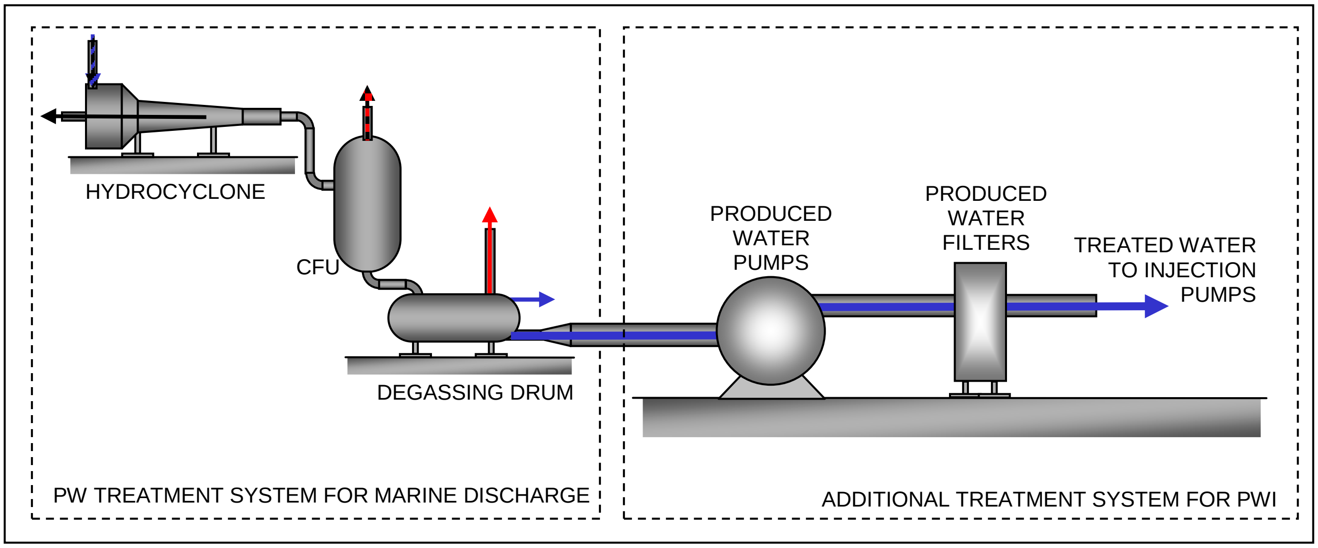

Figure 4: Schematic of additional equipment required for PWRI

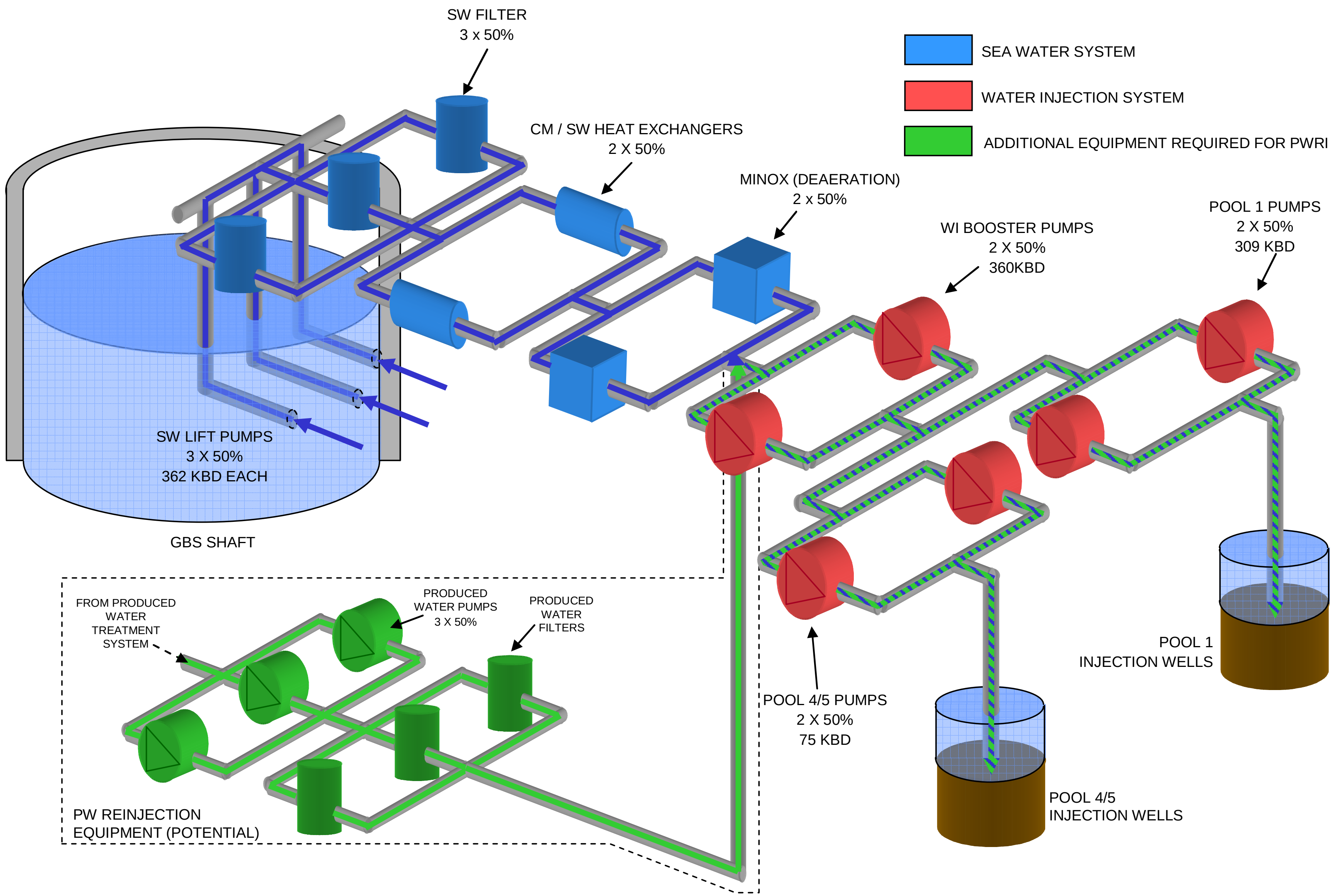

Figure 5: Schematic of injection system with potential future PWRI equipment

Table 2: Additional equipment required for PWRI

EM Tag No.	Description	Footprint [m^2]	Dry Wt [t]	Oper. Wt (t)	Des. Press. (kPa)	Flowrate (m^3/Hr)	Shaft power [kW]
VMAJ681204	PW Filter Package	3.85	4.7	6.6	1700	1941	
PBA681207	PW Pump	2.40	1.9	2.0	1700	647	96
PBA681208	PW Pump	2.40	1.9	2.0	1700	647	96
PBA681209	PW Pump	2.40	1.9	2.0	1700	647	96
	Total	**11.1**	**10.4**	**12.6**			

5.4 Pre-investment for PWRI

The Hebron facility will include a designated space for the future PWRI equipment (Figure 6). The PWRI equipment will not be procured as part of base development. This equipment will be carried through design to the end of FEED in engineering deliverables and shown as 'Future'. Equipment tag numbers have been assigned for this equipment.

Provisions in piping, manifolding, electrical design, and layout are being considered in base development so that the future PWRI equipment can be tied in at a later date with minimal disruption or shutdown to the process and utility systems.

However, the WI pump systems will be specified and designed for both SW and PW from the outset – this includes appropriate materials selection, seal design, pressure ratings, etc. Figures 6 and 7 show the pre-FEED location designated for the future PWRI equipment. The final location of the equipment may be changed when design work is completed.

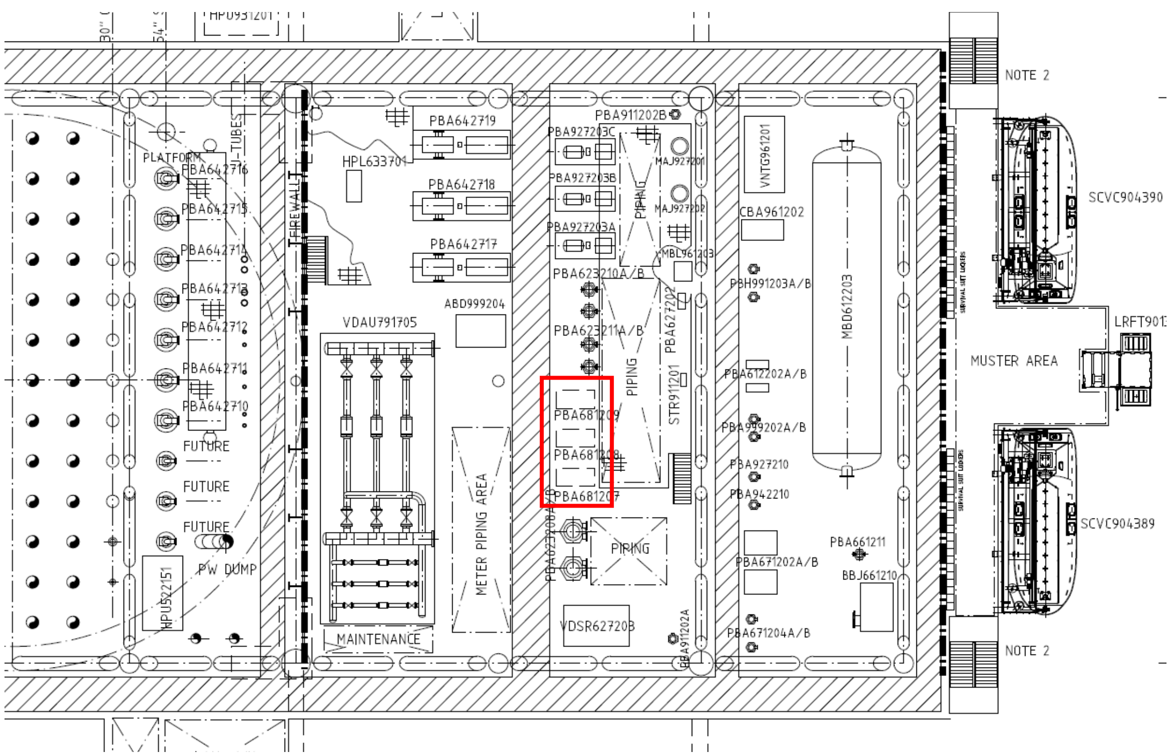

Figure 6: Hebron Cellar Deck showing space for future PW pumps and filters highlighted (pre-FEED layout)

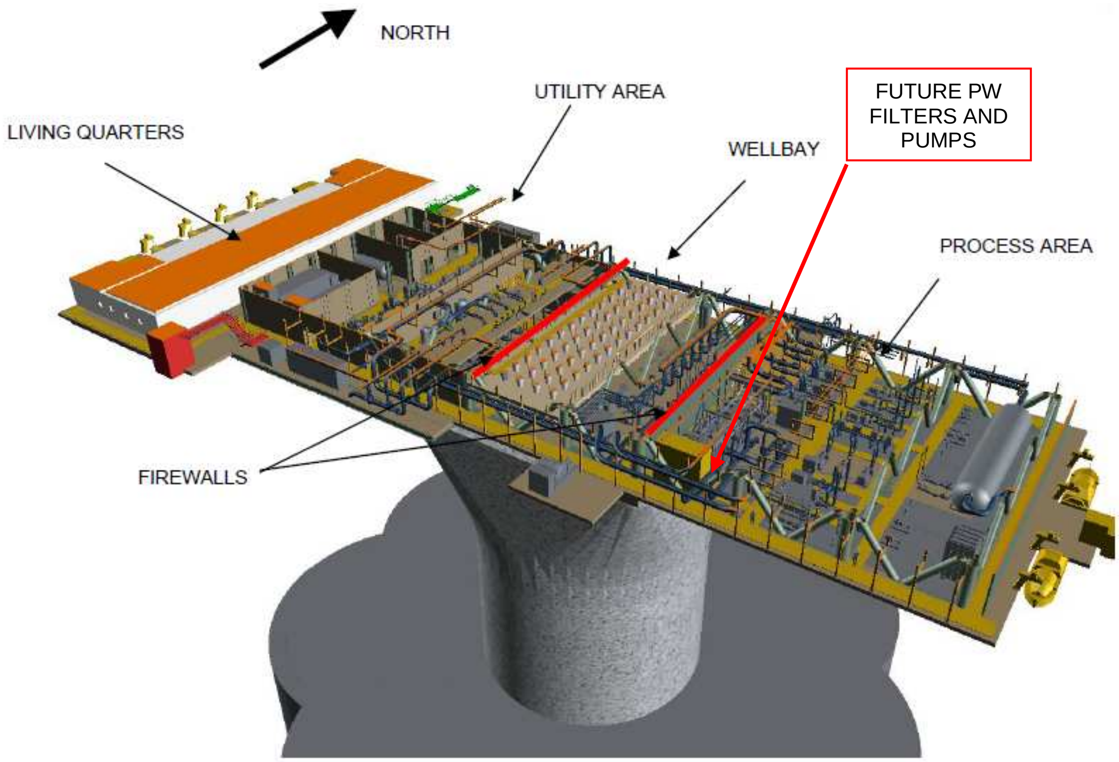

Figure 7: Model snap shot of Hebron Cellar Deck (pre-FEED layout)

5.5 Alternative Configuration – PWRI to Pool 4 only

An alternative configuration was considered that provided for PWRI to Pool 4 only, if it is found that PWRI to Pool 1 is infeasible. This would require reconfiguring the WI system, such that the common WI booster pumps no longer feed the Pool 4 / 5 injection pumps. Dedicated booster pumps for the Pool 4 / 5 injection pumps would need to be added, or potentially the PWRI pumps could be selected to serve as booster pumps.

The potential for PWRI into Pool 4 is limited. Development of Pool 4 is not planned until 6+ years into the drilling program and only 2 water injection wells are planned. Total injected volume required for Pool 4 is 32 Mm^3 versus an estimated PW volume of 366 Mm^3, meaning that 334 Mm^3, or 91% of PW would go to marine discharge in this case.

Given the small portion of PW that could be injected in this scenario and the facilities reconfigurations required, this is not a practical option.

5.6 Execution Plan for Installing PWRI Equipment

The PWRI Project would be executed by the Hebron operating company. The PWRI Project Management Team (PMT) will be provided by the Operator, and will be responsible for all phases of the project from conceptual to engineering, procurement, fabrication, installation, commissioning, and start-up through to handover to the Operations.

Engineering

During the initial design phase of Hebron, the PWRI equipment will be carried through FEED to the extent possible. Preliminary vendor data will be used to allocate space for the required equipment, and process design will include the PWRI system. 3D model studies will be used to verify adequate operating space, based on the available vendor data. This is consistent with the pre-investment plan for PWRI described in 5.4 above.

The PWRI design basis will need to be re-visited when the decision to implement PWRI approaches since operating conditions in the lapsed time frame will require a reconfirmation of the original design. The output of the design phase will include tender packages for the major equipment (pumps and filters) for the procurement and construction phases.

Procurement

Major equipment (pumps and filters) will be procured by the Operator and free-issued to the EPC contractor for assembly and installation. Other items such as minor valves, piping, cabling, structural steel supports, etc., will be procured by the EPC. Lead-time (from issue of purchase order to delivery of equipment to St. John’s) is estimated at 12 months under present market conditions.

Assembly, Fabrication and Installation

The EPC will take delivery of the major equipment and perform any assembly required. Sub-assemblies will be fabricated prior to arrival of the major equipment and then integrated onshore. The PWRI equipment will be assembled, packaged and tested to the fullest extent possible onshore prior to being taken offshore.

The PWRI equipment will be designed to be transported by supply vessel and off-loaded using platform cranes.

Commissioning

Once installed, the PWRI equipment can be commissioned without a platform shutdown although for POB (Persons on Board) and planning purposes, it may be scheduled within a shutdown. The WI system will be temporarily shutdown as the final connections are made, but the main production and drilling operations will continue during this period.

Project Schedule

Project implementation is expected to take approximately 36 months (Figure 8). FEED and procurement for the major equipment could be conducted concurrently with the future PWRI feasibility studies; such that the purchase order could be placed at the time a positive decision on PWRI is reached. This would shorten the effective implementation period to 18 months.

PWRI Equipment Installation				Year 1				Year 2				Year 3				Year 4			
Item	Description	Notes	Duration	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	Gate 1 to Gate 2		3 months																
2	Contracting - FEED / EPC	1	3 months																
3	FEED	2	9 months																
4	Procurement (major equipment)		6 months																
5	Gate 3		milestone																
5	PO Award (major equipment)		milestone																
6	Equipment delivery	3	12 months																
7	Detailed Engineering																		
8	Procurement (minor equipment)		6 months																
9	Fabrication, assembly, testing	4	6 months																
10	Installation, testing & commissioning		3 months																
11	Commence PWRI		milestone																
12	Schedule Reserve		3 months																

Notes

1 Contracting assumes FEED is executed through a standing service agreement with an NL contractor
FEED scope will include preparation of RFQ document packages for major equipment - PWRI pumps, filters and fittings.

2 Additional time needed due to Brownfield project

3 Assumes delivery from global suppliers to St. John's NL

4 Fabrication includes preparation of pipe spools, sub assemblies, supports, etc. Major equipment to be assembled, integrated and tested to the fullest extent possible prior to delivery to the platform

Figure 8: Preliminary schedule for PWRI equipment installation

6.0 PLAN FOR COMPLETING PWRI ASSESSMENT

6.1 General

As described in the preceding sections the studies conducted to date on PWRI feasibility were carried out on a limited available data set. Further studies are required to quantify the risks and technical issues associated with PWRI and to make an assessment of overall PWRI feasibility.

6.2 Additional data and studies required

Additional samples and data will be obtained post start-up as wells are developed, including:

<u>Obtain additional formation water samples</u>

- Measure produced water compositions for each distinct hydrocarbon resource
- Determine the degree of intra-reservoir variability in water compositions
- For Pool 1, produced water samples from three or more geographically-distributed wells are likely to provide the highest-confidence data

<u>Confirm scaling tendency / severity of SW / PW</u>

- For both in-situ reservoir conditions and for operating conditions of wells / facilities (suggested mixtures include 100/0, 25/75, 50/50, 75/25, 0/100)
- Standard tests:
  - Bottle tests - mixtures of SW / PW at test temperature, usually at ambient pressure
  - Tube blocking tests - mixtures of SW / PW at test temperature and pressure injected through a capillary tube. Pressure drop across tube is monitored to determine onset of scale

<u>Scale inhibitor evaluation</u>

- Appropriate scale inhibitors (4-5) should be selected and evaluated in bottle and tube blocking experiments to determine minimum inhibitor concentration (MIC) required to prevent scaling (will depend on conditions in which scaling occurs in the "standard tests"). Note that selection of scale inhibitor will need to be revisited throughout the operational life of the facility as fluid compositions change.

<u>Confirm the concentration of VFA nutrients for better forecasting of souring behavior</u>

- Additional measurements of variability in formation water VFA concentration will aid in characterizing the effects of mixed PW / SW
- For Pool 1, compositional analysis of representative water samples from three or more geographically-distributed producers should provide the necessary data

<u>Acquire some fresh core material in selected new wells</u>

- Enable lab measurements of mixed-PW / SW waterflooding
- Core flow experiments monitoring dP across core plug.

- Testing should include inhibitor at planned dosage, if needed.
- Suggested waterflood experiments could include (1) SW-only core tests as benchmarks for SW / PW mixtures; (2) one or two "representative" SW / PW mixture(s), and (3) worst-case scaling mixture of SW / PW.
- Testing should be conducted at both reservoir temperature and “cool down” temperature expected in the near-wellbore vicinity during the injection process. If damage does not occur during lower temperature test, the test temperature could be increased within the same test to evaluate reservoir temperature.
- Number of tests will depend on heterogeneity of the formation for injection. Lower permeability / higher clay content intervals will tend to be more susceptible to damage.

6.3 Schedule

Pool 1 will be developed initially and Pools 4 and 5 will not be developed until the seventh year of Hebron operations. Assessments on PWRI feasibility will be made separately for each pool due to the time difference.

Pool 1

Three producing wells will be drilled within the first 18 months after start-up, which should provide sufficient core samples for further testing. However, significant PW breakthrough that would enable representative sampling from the test separator is not expected until late in the third year of producing operations, by which time approximately 8 producer wells will be developed. Subsequently, 9 to 12 months will nominally be required to complete the testing, analysis and assess the feasibility of PWRI once sufficient data has been gathered.

A decision on the feasibility of PWRI for Pool 1 should be able to be reached within 4-5 years post start-up.

7.0 SUMMARY AND CONCLUSIONS

Hebron is designed for marine discharge of PW and ExxonMobil is committed to adopting PWRI for routine operations once it is demonstrated that the associated risks are acceptable.

The PW management strategy will be to operate with marine discharge of PW at start-up using best commercially available, proven treatment technology. 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 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 identified will be developed. Table 3 summarizes the status of PWRI criteria considered in this document.

Table 3: Summary of PWRI considerations and criteria

Consideration	Criteria	Status / Plan	
Regulatory	Meet oil-in-water specification for marine discharge (or reinjection)	✓	• Best-in-class commercial technology adopted
	Adopt PWRI once associated risks are proven acceptable	✓	• Facility design and operational programs allow for this if proven technically feasible
	Adopt best commercially available and proven treatment technology	✓	• PW treatment facilities include VIEC, hydrocyclones and Compact Floatation Units • 1st application of VIEC and CFUs in the Grand Banks
	Implement continuous operational improvement on PW management	✓	• Operational programs and planning will provide for continuous improvement
Resource	Inject water to maintain reservoir pressure and maximize oil recovery	✓	• Facilities are designed to inject the required volumes at the estimated pressure.
	Prevent damage to the resource in terms of oil recovery, souring, injectability or otherwise	?	• Cannot be confirmed at this time. • Preliminary studies indicated souring potential is up to 50% greater with PWRI. • Volatile Fatty Acid (VFA) content is highly variable across reservoirs and more samples are needed
Subsurface	Injection water cannot adversely impact subsurface assets (eg scaling, corrosion, plugging)	?	• Cannot be confirmed at this time. • Scaling potential is greatest when injecting PW into the formation. • Only a very small number of formation water samples are currently available – more are needed to draw conclusions.
Facilities	Provide facilities for treatment of PW to meet regulatory limits on oil-in-water for marine discharge	✓	• Required for PWRI and contingency marine discharge
	Provide facilities for injection of water to meet pressure maintenance requirements	?	• Cannot be confirmed at this time • Pending confirmation of injection pressure for PWRI • Pressure increases associated with PWRI may be greater than anticipated • This increases the risk of out-of-zone fracturing
	Provide for future installation of facilities specific for PWRI (ie low pressure booster pumps and filters)	✓	• Hebron facility design will allow initiation of PWRI by adding specific pieces of equipment at a later date if/when it is demonstrated associated risks are acceptable • Space and connections for this equipment are included in the base design

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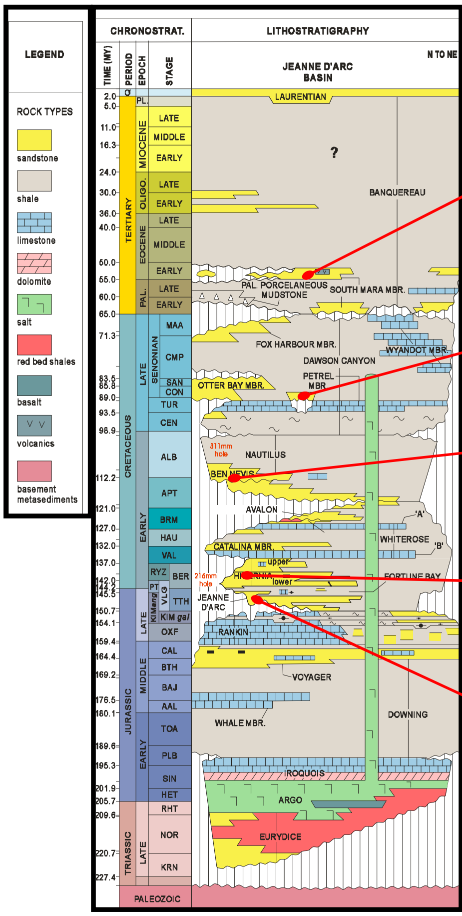
9.0 ABBREVIATIONS AND DEFINITIONS

Term	Definition
bara	Bar (atmospheric)
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
Ca	Calcium
$CaCO_3$	Calcium Carbonate
CFU	Compact Floatation Unit
EDTA	Ethylenediaminetetraacetic acid
EMCP	ExxonMobil Canada Properties
EPC	Engineering, Procurement, Construction
FEED	Front End Engineering and Design
FeS	Iron(II) Sulphide
H_2S	Hydrogen Sulphide
kbd	Thousands of barrels per day
kPa	Kilo-Pascal
kW	kilowatt
LP	Low Pressure
m^2	Square metre
m^3	Cubic metre
m^3/d	Cubic metres per day
m^3/hr	Cubic metres per hour
mg/l	Milligrams per litre
Mm^3	Million cubic metres
MP	Medium Pressure
MPa	Mega-Pascal
NPSH	Net Positive Suction Head
OWTG	Offshore Waste Treatment Guidelines
PMT	Project Management Team
POB	Persons on Board
ppb	Parts per billion
ppm	Parts per million
psi	Pounds per square inch
PW	Produced Water
PWRI	Produced Water Reinjection
SO_4	Sulphate
SW	Seawater
SWI	Seawater Injection
t	Tonnes (metric)
URC	(ExxonMobil) Upstream Research Company

Term	Definition
VFA	Volatile Fatty Acids
VIEC	Vessel Internal Electrostatic Coalescer
VSD	Variable Speed Drive
WI	Water Injection
μm	Micro-metre

APPENDIX A - DISPOSAL RESERVOIR

Figure A.1 – Sandstone reservoirs within the Hebron Unit



South Mara Mbr.
Thin, VF-C Grain, bioturbated, oil stained SS
Avg 35m gross thickness, ~75% NTG, 14-18% Ø

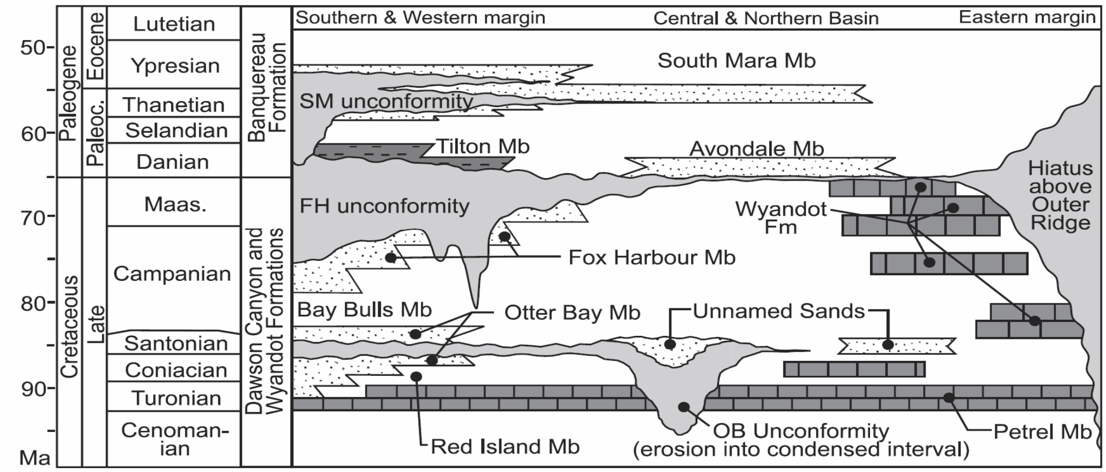
Unnamed sands within Dawson Canyon Fm
Incised into top of Petrel
Unpenetrated in Hebron unit wells, evident on seismic
Narrow, elongate channel with limited aerial extent within unit. Avg 125 m thickness, ~20% NTG, 20% Ø

Ben Nevis formation
Primary reservoir across Hebron asset
Evaluating PWRI as pressure maintenance/water flood

Hibernia formation
Secondary reservoir
HC bearing in Hebron and Ben Nevis fields,
Evaluating PWRI as pressure maintenance/water flood
Wet in West Ben Nevis fault block, limited areal extent within fault block
Lies between oil-bearing horizons above & below

Jeanne d'Arc formation
Secondary reservoir
HC bearing in Hebron and West Ben Nevis fields,
Evaluating PWRI as pressure maintenance/water flood
Unpenetrated in Ben Nevis field

Figure A.2 – Shallow Reservoirs: Potential Injection Targets



<u>Shallow Injection Target 1</u>

South Mara Sandstone Member
Distal lower-shoreface sandstone, sheet-like reservoir (15-35m thick). Thickens to south (towards Terra Nova), facies changes to mudstone to NE on Hebron lease. Net pore volume on Hebron Unit Land = 260 Mm^3 (~1633 Mbls)

<u>Shallow Injection Target 2</u>
Dawson Canyon Un-named Sandstone Member
Interpreted slope-channel complex (50-150m thick) on 3D seismic. Channel sandstones, with restricted distribution on western side of Hebron lease (channel-complex extends updip to Terra Nova and downdip off lease to north). Avondale well penetrated similar, but younger channel complex. Net pore volume on Hebron Unit Land = 73 Mm^3 (~457 Mbls)

Total pore volume for shallow reservoirs on Hebron Unit Land = 333 Mm^3 (~ 2090 Mbls)