STUDY REPORT

NEIA NOIA and Oil Company of Newfoundland

Feasibility of the Electrification of FPSO Vessels Offshore Newfoundland and Labrador, Canada

Study Report

Document No.: 90001-20L01-E-SY-00001-001
Revision No.: IFI

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1 Executive Summary

Aker Solutions is a market leader in both offshore greenfield and offshore brownfield electrification of oil and gas facilities through studies and projects in Norway, Scotland, Gulf of Mexico, Australia and Brazil. We have taken the learnings from these activities and applied it to potential developments offshore Newfoundland and Labrador.

Figure 1-1 Power from shore utilizing a subsea transformer for voltage stepdown and power distribution

1.1 Recommended Approach

Our analysis indicates that electrifying new floating developments in these locations is challenging, but feasible. These developments would be amongst the furthest from shore and deepest water electrification projects carried out to date. The most appropriate technology for these locations is low frequency AC distribution with subsea transformers acting as distribution points to the FPSO. The diagrams below are a representation of the preferred LFAC approaches:

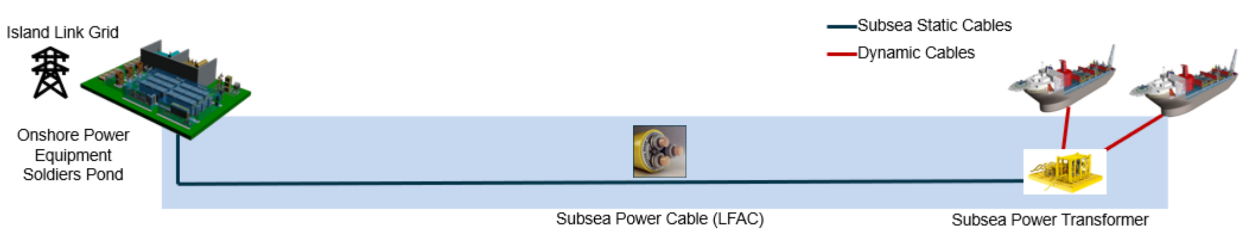


Figure 1-2: Representation of a LFAC power from shore transmission system for 2xFPSOs

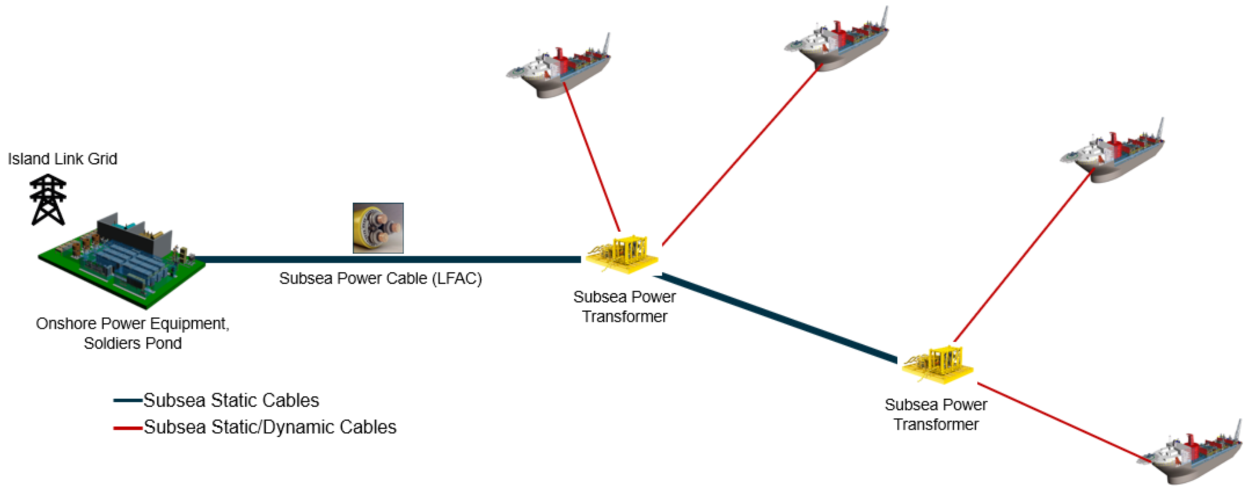


Figure 1-3: Representation of a LFAC power from shore transmission system for 4xFPSOs

The most common approach to date for long distance power transmission is a High Voltage Direct Current system. HVDC is not recommended in this case due to technology gaps associated with a lack of dynamic (flexible) power cable risers needed for use in the water depths at this location, and the lack of connectors suitable for the iceberg prone environment off Newfoundland and Labrador, where disconnection of the facility may be required – furthermore for ship-shaped FPSOs (as currently used at both Terra Nova and WhiteRose fields) there is an additional challenge in that HVDC swivel technology is still in its infancy meaning that additional development and technical qualification programs would be required for the power interface between the vessel and the turret/mooring point.

In place of HVDC we recommend the use of a Low Frequency AC transmission and distribution system. The key building blocks in this system are currently qualified or scheduled to be qualified within the next year, will have better availability and even longer in service life based on a five and ten year look ahead. Further, this transmission technology will require less onboard space, reduced weight, and offer more flexibility in electrical system design of the FPSO because major equipment, such as a gas compressor, can utilize the incoming 20Hz power and smaller converters and transformers can feed the remaining equipment as necessary. This will lead to reductions in regular maintenance, and increases in system uptime as the system does not require the maintenance or downtime associated with main power generation by onboard rotating machines.

This system would require an onshore connection to the power grid and equipment to step down the voltage between 132kV and 145kV for subsea transmission. It also requires a subsea cable connected to a subsea transformer for distribution to multiple FPSOs, and to step down the power from the transmission voltage to 50-66kV, for use on each FPSO. It would also require dynamic cables from the sea bed to the FPSO, and will require the use of an electrical swivel if a ship-shaped FPSO concept is selected.

1.2 Costs and Schedule

The estimated order of magnitude cost of an LFAC distribution system, excluding project related engineering and management. Other expenses such as owner's cost, insurance, and contingency/growth must be added based on owner's execution model and internal norm expectations. Prices are in CAD and are based on historical pricing estimates out of Europe. It should be noted that with the use of local contractors and suppliers, estimates may be reduced.

Scenario	Cost (Million CAD)	Comment
2x45MW-65MW FPSO Labrador South	$1,333*	Cable/installation is 85% of project cost
2x45MW-65MW FPSO Soldiers Pond	$1,302*	Cable/installation is 87% of project cost
4x50MW FPSO Soldiers Pond	$1,586*	Cable/installation is 83% of project cost

Table 1-1: Cost overview

***an element of trenching is included in the cable lay cost, but needs to be further defined and refined based on seabed survey and route selection**

In all cases, we have assumed a single power transmission line to offshore, and thus no redundant power feed. If a redundant supply is required, then placing it next to the primary cable would not provide an effective backup against external cable damage, as both cables would likely be damaged by the same event. A diverse secondary route would be required for true redundancy, however this would significantly increase project costs through increased cable and installation costs. Our experience in electrification projects in other jurisdictions indicate that there are design considerations that enable a single cable solution to be highly reliable over the life of the project.

A sample schedule based on engineering and equipment lead-times indicates a 4 year project life to achieve power from shore.

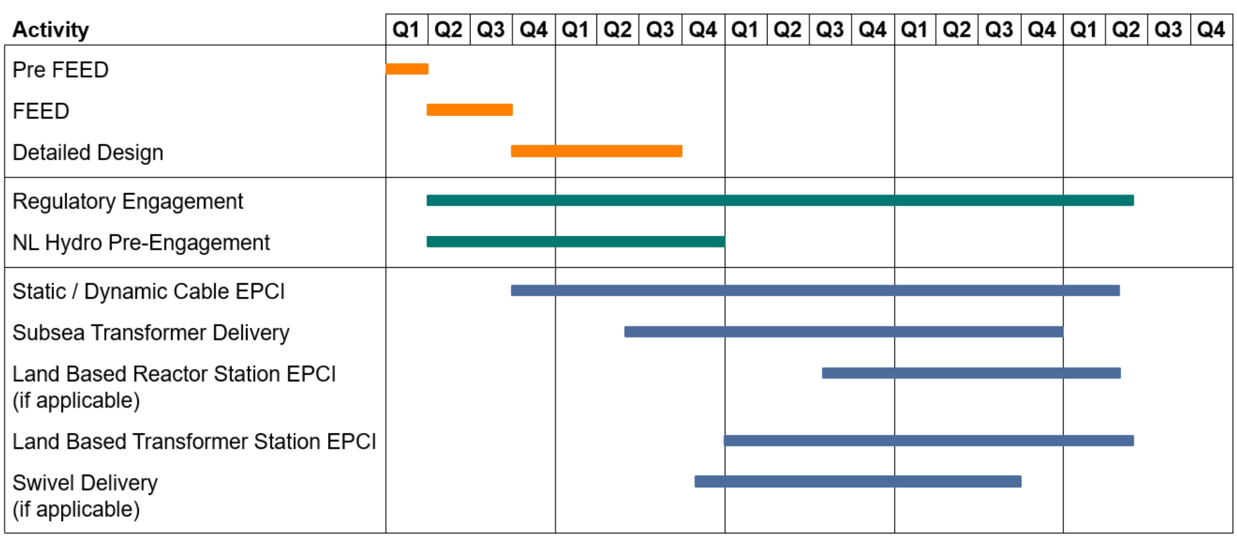


Figure 1-4: Sample execution schedule based on lead times

1.3 Routing

Our work with C-CORE has identified feasible cable routings from the Soldiers Pond substation to the West Orphan Basin and from Muskrat Falls distribution network to the Labrador offshore that minimise the risk of ice interaction and power interruptions. The risk of interaction is highest for the Labrador Sea location with a return period more frequent than 1 in 1000 years even for buried cables. The following is a summary of cable routes assessed.

Route	Burial Depth	Iceberg contact return period
Labrador to Labrador Offshore	Unburied	25 years (Note 1)
	2m	699 years
Soldiers Pond to Orphan Basin via Conception Bay	Unburied	123 years (Note 2)
	2m	1226 years
Soldiers Pond to Orphan Basin via Trinity Bay	Unburied	475 years (Note 3)
	2m	3795 years

Table 1-2: Iceberg contact return period

Note 1: 24km of route is exposed to iceberg risks – note that pack ice close to shore has not been assessed in this review.

Note 2: approximately 50% of the risk occurs in the first 5 km of this route, therefore it may be possible to further reduce risks by extending the shore crossing 5 km into the bay – however 110 km is exposed to iceberg risk.

Note 3: Trinity Bay is the landing point for major transatlantic fibre optic communication cables, hence is considered as an alternative to Conception Bay route. Only 12.4 km of this route is exposed to iceberg risk and would require trenching.

The recommendation would be to consider routing power to the Orphan Basin via Trinity Bay. This has the lowest risk of iceberg contact, and the requirements for trenching are significantly reduced vs Conception Bay, however this would require further study regarding the point of interconnection to the electrical grid.

Power to the Labrador Offshore has a higher risk of interruption due to iceberg contact, and would require at least 24 km of trenching to protect the line.

1.4 FPSO Considerations

Ship-shaped FPSOs are traditionally used in the Newfoundland and Labrador offshore due to their motion characteristics oil storage capacity, and ease to disconnect in the event of weather, ice, or iceberg incident. A ship-shaped FPSO can rotate and weathervane around an anchored, geostationary turret in order to reduce loads from changing sea and winds, however this motion requires that an electrical swivel be installed in the turret so that dynamic power cables from the seabed are not affected by the twists and strains caused by this rotation. The turret, along with all of the process and electrical swivels required, introduces cost and complexity to a ship-shaped FPSO design, however it does give a ship-shaped FPSO the ability to disconnected and manoeuvre from potential harm of icebergs and ice, and then subsequently reconnect once threat has passed. Such swivels are not required on geostationary FPSOs, only ship-shaped.

To our knowledge there are no field proven geostationary FPSO designs that have the ability to disconnect and reconnect from their moorings and process lines to avoid sea ice. While analysis of environmental conditions on the use of a ship-shaped FPSO versus a geostationary FPSO are outside of the scope of this study, the environmental and ice conditions offshore Newfoundland and Labrador certainly could make it a necessity to be able to disconnect and move from the path of danger, making this an important area for subsequent study.

2 Definitions and Acronyms

AC	Alternating Current
AFE	Active Front End
BH	Baker Hughes
CAD	Canadian Dollars
CIGRE	International Council on Large Electric Systems
CNLOPB	Canada Newfoundland & Labrador Offshore Petroleum Board
DC	Direct Current
DFE	Diode Front End
DM	Dry Mate
DNV-GL	Det Norske Veritas - Germanischer Lloyd
EPCI	Engineering, Procurement, Construction, Installation
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
HVDC	High Voltage Direct Current
LFAC	Low Frequency Alternating Current
NEIA	Newfoundland and Labrador Environmental Industry Association
NOIA	Newfoundland and Labrador Oil and Gas Association
PfS	Power From Shore
POI	Point of Interconnection
Pre-FEED	Pre-Front End Engineering and Design
SOLAS	Safety Of Life At Sea
TBD	To Be Determined
TRL	Technology Readiness Level
VSD/VFD	Variable Speed/Frequency Drive
WM	Wet Mate

Table **2-1**: Acronyms

3 Project Description

Offshore platforms typically generate electricity by burning fossil fuels to run onboard gas turbines and/or diesel-powered generating units. An alternative is to supply offshore installations with electricity from the mainland using a power cable transmission system. There are many benefits to utilizing power-from-shore including reduced CO_2 emissions, increased efficiency due to increased uptime of power system, increased safety due to reduction in possible sources of ignition and reduced planned maintenance, and lower operating costs. Power can be connected from shore via alternating current (AC) or direct current (DC). For distances longer than 150 km, high voltage direct current (HVDC) has historically been used. The power transmission losses of the entire string do however always need to be considered in an overall perspective.

Power from shore is widely used offshore Norway where sixteen fields constituting 45% of the countries' oil and gas production will be connected to shore by 2023 by both HVDC and AC cables. Similar to Newfoundland and Labrador, Norway's electrical grid is predominantly powered by low GHG emitting hydroelectric power. This project aims to apply lessons learned from the Norwegian power from shore experience to future developments in the more challenging offshore environment of Newfoundland and Labrador.

Offshore developments in Norway are typically in 100-400m water depth, and generally within 150km of shore, whereas the potential development areas identified in this scope are in iceberg prone locations more than 400km offshore and in water depths greater than 1200m. This water depth leads to floating solutions that have to be readily able to disconnect in the event of a potential iceberg impact. The only FPSO currently powered from shore in Norway is the permanently moored circular Goliat FPSO located in 400m of water and 100km offshore, in an area that is not prone to icebergs.

Two potential greenfield power from shore development scenarios have been identified; a development in the West Orphan Basin with a point of interconnection (POI) at the Soldiers Pond station, and a potential development in the Labrador Sea with a POI at the Muskrat Falls generating station (See Figure 3-1: Potential Power From Shore Development Areas).

NEIA, NOIA, and their partner the Oil and Gas Corporation, requested a pre-front- engineering and design (Pre-FEED) level of analysis on identifying challenges that will arise from electrifying green field FPSOs for the potential developments identified. This will include recommendations for specific equipment and design criteria that should be implemented for these scenarios.

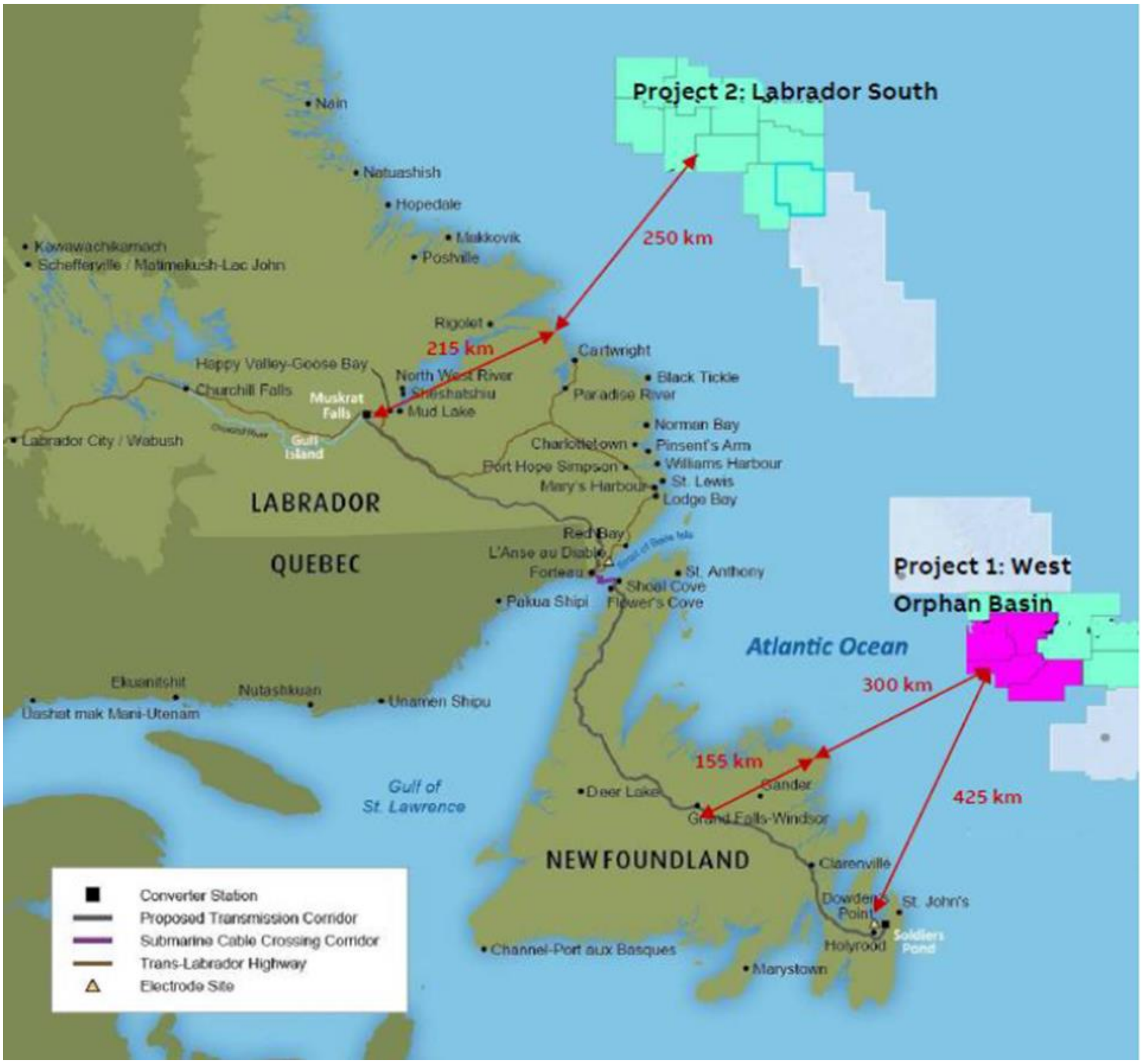


Figure 3-1: Potential Power From Shore Development Areas

4 Introduction

NEIA has requested that Aker Solutions investigate four specific activities that are crucial to understanding the challenges to electrifying floating facilities, specifically FPSOs. This study addresses the points outlined in the scope and provides insight into possible solutions and recommendations that deal with the unique challenges presented by the environmental characteristics of the offshore in Newfoundland and Labrador.

Offshore and subsea electrification projects are being carried out all over the world. Norway, UK, Qatar, the Emirates, Saudi Arabia, Africa, China, Azerbaijan, Australia, and in the Gulf of Mexico are examples of the other regions where power from shore has been installed or being considered for installation. The two Canadian regions addressed in this study provide unique challenges when evaluating the prospect of powering from shore. First, the selected sites are among the most distant from shore when considering electrification of oil and gas facilities, second, the water depths in those regions are among the deepest being considered at this time, and third, the study of the effects of icebergs on equipment and vessels in the region is a unique assessment when considering power from shore to FPSO vessels.

The objective of this study is to complete an assessment of the four specific question areas and deliver indicative costs and schedule implications as outlined in the following scopes;

4.1 Scope 1 – FPSO Electrification and Power Transfer Projects

Summarize current and planned projects for electrification of FPSO's including the electrification of subsea equipment. This will include identifying the distance from shore, power requirements, voltages and the solutions that were applied to these projects. This will also include a high-level summary of the supply chain capabilities and competencies required for such projects.

The assessment provided for this scope leverages previous industry assessments, as well as customer and vendor contacts to create a detailed list of known, current, and planned projects and their specifications for electrification of FPSOs as well as summaries for supply chain capabilities and competencies.

4.2 Scope 2 – FPSO Electrification Challenges

Review the technical challenges associated with the electrification of FPSO's including the ability to disconnect from a power source in the event of a potential impact from an iceberg.

As outlined in the introduction, electrification of FPSOs in these regions brings additional challenges and complexities not generally seen in other jurisdictions. Not only are there water depth considerations, but there are iceberg and sea ice related disconnection and cable routing / protection issues. The assessment for this scope provides commentary on the technical challenges associated with the location.

4.3 Scope 3 – Power Transmission Challenges

Review the state of offshore power transmission technology which specifically addresses the distances to potential developments offshore NL.

To address this scope element Aker Solutions utilized our inhouse record of major offshore power transmission projects and studies conducted. Initially this record was based around powering subsea equipment, however this has evolved to include longer distance power supply projects including both electrification of oil and gas developments, but also offshore wind power developments.

We were able to combine this database of projects with our experience of previous electrification projects to define the current state of the art of technology and identify critical gaps associated with the applications specified.

Further, this scope also includes an assessment of the potential for iceberg collision, as well as an assessment of seafloor scour data examining, at a high level, the need of trenching for cable protection.

4.3.1 Scope 4 – Turret Based vs Geostationary FPSOs

Review, compare and contrast the technical readiness for power transmission though a turret based FPSO vs that of a geostationary FPSO. Highlight how transformers can enable high voltage transfer from shore while delivering lower voltage through the turret. Identify how this would be different for a geostationary/cylindrical FPSO.

This assessment includes a review of current and future turret and swivel technology to contrast the turret / swivel based ship shaped FPSOs with geostationary circular vessels. Aker's experience with power transfer to subsea pumping and compression projects has been used to deliver specific solutions tailored to this location.

4.3.2 Scope 5 – 4x50MW FPSOs Soldiers Pond to West Orphan Basin

Per client request, make recommendations on a 4x50MW FPSO case for the Soldiers Pond to West Orphan Basin route.

This scope builds upon the analysis that has been completed to identify a feasible power from shore concept and addresses a number of specific questions related to timeline and regulatory hurdles.

5 Design basis and Assumptions

The following table outlines the design basis and assumptions that have been used for analysis.

Design Basis Item	Details	Comments
Labrador South Location	Lat: 55 17'7.4985"N Long: 54 36'45.9506"W	Provided by client
West Orphan Basin Location	Lat: 50 20'20.6916"N Long: 49 49'54.6230"W	Provided by client
Electrical Load	2x45MW with peak loads at 2x65MW. 4x50MW peak load. Study based on power for future greenfield FPSOs.	Provided by client
Distance – Labrador South Basin	Subsea: 250km Land: 215km	Provided by client
Distance – West Orphan	Subsea: 425km Land: 8km	Provided by client
Water depth – West Orphan Basin	1250m at given coordinates	Confirmed by C-CORE
Water depth – Labrador South	1550m at given coordinates	Confirmed by C-CORE
Onshore power connection – Soldier's Pond	±350kV DC, 230kV AC	Coordination required with Utility
Onshore power connection – Muskrat Falls	±350kV DC, 315kV AC	Coordination required with Utility
AC power from shore, with reactor	132kV, 60Hz	Higher voltages may be considered
LFAC power from shore	132kV, 20Hz	Higher voltages may be considered
HVDC power from shore	±45kV, ±80kV	Higher voltages may be recommended

Table 5-1: Design Basis and Assumptions

The following is a reference to Technical Readiness Levels as defined by API 17N:

B.10.4.2 TRL

TRL is a measure of the extent to which an item of equipment is qualified for a particular application.

Eight TRLs have been defined ranging from a minimum of TRL 0 to TRL 7 as follows.

— TRL 0—Basic Research: Basic R&D paper concept;

— TRL 1—Concept Selection: Proof of concept as a paper study or R&D experiments;

— TRL 2—Concept Demonstration: Experimental proof of concept using physical model tests;

— TRL 3—Prototype Development: System function, performance, and reliability tested;

— TRL 4—Product Validation: Pre-production system validated and environment tested;

— TRL 5—System Integration Testing: Production system interface tested;

— TRL 6—System Installed: Production system installed and tested;

— TRL7—System Operation: Production system field proven.

Figure 5-1: Technical Readiness Levels (API 17N)

6 Scope 1 – FPSO Electrification And Power Transfer Projects

6.1 Management Summary

Summarize current and planned projects for electrification of FPSO's including the electrification of subsea equipment. This will include identifying the distance from shore, power requirements, voltages and the solutions that were applied to these projects. Also include a high-level summary of the supply chain capabilities and competencies required for such projects.

Historically power transfer offshore has been focused on electrification of subsea equipment such as pumps and compressors installed on the seabed, and large offshore wind power developments, however as oil operators move to reduce operational costs and shift towards greener operations, power from shore is becoming an attractive technology that has the potential to greatly reduce the environmental footprint associated with extracting and processing oil and gas.

Fixed platforms in shallow water are generally easiest to electrify due to simpler interfaces, and being closer to shore, and have lead the way in terms of power from shore. To date there have been a limited number of floating facilities powered from shore - only one Norwegian FPSO is currently powered from shore. The Goliat facility is a circular geostationary FPSO (buoy shaped) located in the southern Barents Sea in 400m of water. Gjøa, a semi production facility, is also powered from shore. Electrification of new and existing floating facilities are currently being investigated.

Technology required to support long distance deep water power transfer is continually developing, however due to the cost and relatively new market there is currently a limited number of suppliers with qualified equipment.

Key power transfer projects are identified in Figure 6-2, and technology / equipment suppliers identified in Table 6-2.

Figure 6-1: Goliat FPSO (Vår Energi)

6.2 Offshore Electrification Projects

The graphic below identifies projects that have been installed or are being studied as candidates for power from shore, and outlines the power technology and electrical parameters to achieve reliable power transfer.

The projects are placed based on their distance from shore and the technology that is required for power distribution. Distribution is broken down into AC and DC categories with the diagram showing AC augmentations, such as reactive compensation or low frequency conversion to extend distances, and HVDC for projects that exceed the typical reach for AC power systems. Our regions of focus currently fall off the extents of the chart (circled in green) because these sites are among the longer distances that are being considered at this time. One goal of this report is to assess transmission technologies to determine a recommended option to power from shore. Power transfer over this distance was originally assumed to be only feasible via HVDC transmission, however three power transmission options (AC, HVDC, and LFAC) will be assessed and discussed in scope.

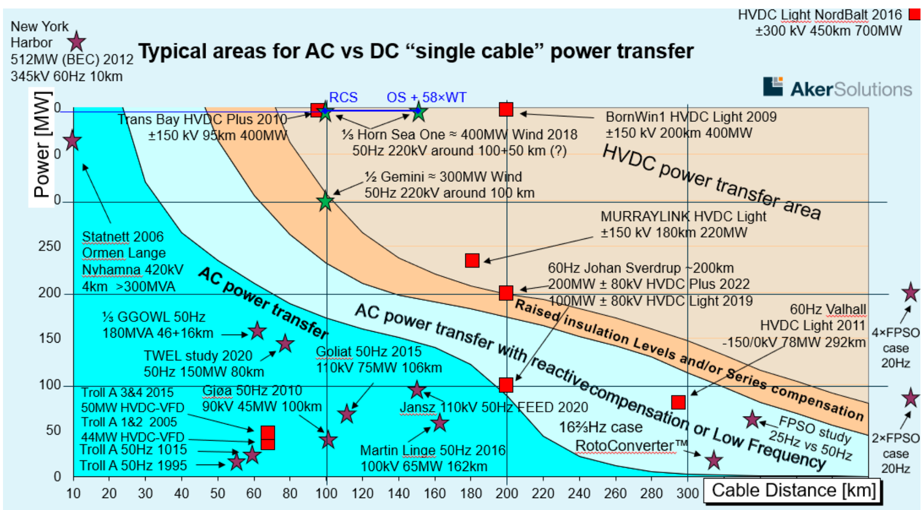


Figure 6-2: Subsea electrification project transmission technologies, loads, and distances

Further to this, the following are known FPSO or floating equipment power from shore projects that are in service or are currently being studied:

<Some data redacted from public report>

Project	Distance(km)	Depth(m)	Equipment	Technology	Load(MW)	Status
Goliat	106	420	Geostationary FPSO	110+ kV, 50Hz	75	In service
<Undisclosed>	>300	>1000	Floater	TBD	50+	Study
Labrador South	465	1550	TBD FPSO	132kV, 20Hz	2x45 (65)	Feasibility
West Orphan	425	1250	TBD FPSO	132kV, 20Hz	2x45 (65)	Feasibility
West Orphan	425	1250	TBD FPSO	145kV, 20Hz	4x50	Feasibility
<Undisclosed>	>250	>200	Fixed	HVDC	80+	Study
<Undisclosed>	>100	>900	Power Floater	AC	30+	Pilot
Gjøa	100	360	Semi-submersible	90kV, 50Hz	50	In service
Jansz-IO	145	1350	Power floater	110kV, 50Hz	90+	FEED
<Undisclosed>	>150	>300	Floater	TBD	35+	Study
<Undisclosed>	>150	>300	Floater	TBD	TBD	Study
<Undisclosed>	>200	>300	Floater	TBD	TBD	Study
<Undisclosed>	>200	>300	Floater	TBD	TBD	Study
<Undisclosed>	>200	>300	<Undisclosed>	TBD	TBD	Study
<Undisclosed>	<Undisclosed>	TBD	<Undisclosed>	HVDC	200+	Feasibility
<Undisclosed>	<Undisclosed>	TBD	<Undisclosed>	HVDC	100+	FEED
<Undisclosed>	<Undisclosed>	TBD	<Undisclosed>	LFAC	50+	Feasibility

Table 6-1: FPSO and Floating Equipment Power from Shore Projects

6.3 Supply Chain Capabilities and Competencies

There are limited vendors that can provide services and equipment to achieve reliable power from shore given the water depth and distance from shore in our regions of focus. The following is a high level overview of services and equipment providers that are developing, qualifying, and or selling equipment that is suitable for these specified LFAC transmission scenarios. It should be noted that there is a large push in the industry related to offshore electrification and windfarm projects, so many of these vendors may be experiencing high demand for these types of products and services.

Scope	Key Suppliers
Onshore/Offshore Power Equipment (Transformers / converters)	ABB GE Siemens Eaton
Subsea Cables Static	Aker NKT Nexans Prysmian
Subsea Cables Dynamic	Aker NKT Nexans Prysmian
High Voltage Swivels	Focal SBM

Table 6-2: Key Equipment Suppliers

6.3.1 Onshore and Topsides Equipment

Equipment such as transformers, converters, switchgear, and drives are typical to any power substation or standard FPSO project and would have similar lead times and availabilities. We would anticipate significant involvement of NL Hydro/Nalcor in onshore equipment specification and the use of their suppliers and subcontractors for onshore work.

6.3.2 Subsea Cables and Equipment Installation

Typically, subsea cable vendors provide a full suite of EPCI services. They will provide cable engineering services, manufacturing/procurement of cable, and installation of subsea cable and associated subsea equipment. There are few vendors that provide this service and their availability depends on what cable projects are in the pipeline worldwide. Engagement of these vendor for services and the cable laying vessels may need to be completed 2-4 years in advance of the installation date, making this typically the longest lead time in an offshore electrification project. Further, costs for these services and cables make up the majority of cost on a power from shore project such as the ones being evaluated.

A recent example of an extensive subsea cable installation in the Newfoundland region is the Maritime Link project. Over the course of four years, Nexans completed the engineering, fabrication, installation, and testing of a pair of 170km long HVDC cables between Newfoundland and Nova Scotia.
(https://norwaytoday.info/news/nexans-delivers-subsea-cables/)

6.3.3 Subsea Transformer Vendors

Multiple subsea transformer vendors offer engineering and design services. Recent projects show that it can take up to two years from initial engagement to delivery and installation of a subsea transformer. It should be noted that some designs may require qualification programs in order to complete certification for acceptable use. This time and cost will need to be built into the project budget and schedule. As such, vendor discussions around equipment selection should be held early on in the project. Further information about subsea transformers can be found in Scope 3 of this study.

6.3.4 Swivel Vendors

Two swivel providers can provide acceptable swivels for this project. SBM, and MOOG Focal. Each of these vendors has a number of swivel designs that are in various stages of development and application. Lead times for swivels are in the range of 1.5+ years, and it should be noted that some swivel designs may require qualification programs in order to complete certification for acceptable use. Further information on available swivels can be found in Scope 3 of this study.

6.3.5 Dynamic Cables

Dynamic cable vendors for the 1250-1500m depths required are very limited at this time. Recent updates to CIGRE guideline for power systems allow for the use of wet design cables at voltages that are suitable for power from shore applications. Wet design cables have reduced armoring and are typically lighter than dry design dynamic cables. This reduces the strain on the cable induced by excessive depths. Currently Aker Solutions and Prysmian have qualified cables suitable for these depths but more dynamic cable solutions will likely be available on the five and ten year horizon. Lead times on cables of this type depend on manufacturing demand so venders should be engaged in the same timeframe for the static subsea cable.

6.3.6 Supply Chain Matrix

This table outlines a sample supply chain matrix for critical parts of the project and includes a sample of vendors that can carry out the project:

Item	Project Management	Engineering definition	Procurement	Equipment Design	Transport	Installation	Commissioning	Operation
Onshore Substation including converter, switchgear	A	B	B	G	B	B	B	A
Terrestrial Cable	A	B	B	D	B	B	B	A
Land based reactor station	A	B	B	G	B	B	B	A
Subsea Cable	A	C	C	D	D	D	D	A
Subsea Transformer	A	C	C	E	C	E	C	A
Dynamic Cable	A	C	C	D	C	C	C	A
Swivel	A	C	C	F	C	C	C	A
Offshore Converters, Switchgear, and Drives	A	C	C	G	C	C	C	A

	Contractor Role	Example Contractors
A	Operator	FPSO Operator
B	Onshore EPC Scope	GJ Cahill, Pennecon, etc (Local EPCI group)
C	Offshore EPC Scope	Aker Solutions, KBR, Wood, Worley Parsons likely partnered with offshore construction specialist such as TechnipFMC, Saipem, McDermott, etc
D	Cable Vendor	Prysmian, Nexans, NKT, Aker Solutions
E	Subsea Transformer Vendor	ABB, Siemens, EPC by Aker Solutions
F	Swivel Vendor	Focal, SBB
G	Switch Gear (onshore/offshore)	ABB, GE, Siemens

Figure 6-3: Supply Chain Matrix with sample vendors

The above model assumes that offshore electrification is part of the overall FPSO project and onshore is executed in a separate contract to maximize opportunities for local contracts, and that the operator runs the onshore portion. Realistically, onshore operation it would likely be shared between operator and the Utility.

6.4 Stakeholders

Key stakeholders in these projects should be engaged early and regularly throughout the project. Input and support from these stakeholders will ensure that all sides are considered as the project proceeds.

- Government of Newfoundland
- Communities in the area of the onshore transmission route
- Fish Harvesters
- EPC contractors and associated workforce/unions
- Nalcor/NL Hydro (depending on the controlling authority)

Nalcor/NL Hydro are a critical interface and must be included early in the process to ensure onshore protection, reliability, and prioritization are properly addressed and included in the design.

6.5 Permitting, Regulations, and Coordination

Permitting, regulations, and coordination must be considered when assessing projects of this type and magnitude. While further study and preparation in these area is required, there are some high level areas that can have significant impact on scheduling and sanctioning of such projects.

An overall environmental assessment must be carried out for these projects. That assessment would include the subsea power transmission system. This would take into account the entire route of the transmission system from the land based portion to the final connection at an FPSO and would consider the elements of the submarine cable, trenching, shore crossing, and would consider, among other things, the relationship of the cable route with both recreational and commercial fishing, trawling, or other marine activities in the area.

Coordination with the Utility is also be required, and notice of up to two years may be necessary for this type of project to provide time to prepare assessments, designs, and any possible new standards that may be required to support the project. The Utility will need information from PRE-FEED design phases to understand required capacity, and overall loads, and will need to be first engaged at the FEED stage, as Stability, Protection Coordination, Prioritization, and Metering studies will be required.

Engagement with the Canada-Newfoundland & Labrador Offshore Petroleum Board (CNLOPB) and with a certifying authority body such as DNV-GL or Lloyd's Register as an example, will be necessary throughout the entire process.

6.6 Sample Project Timeline

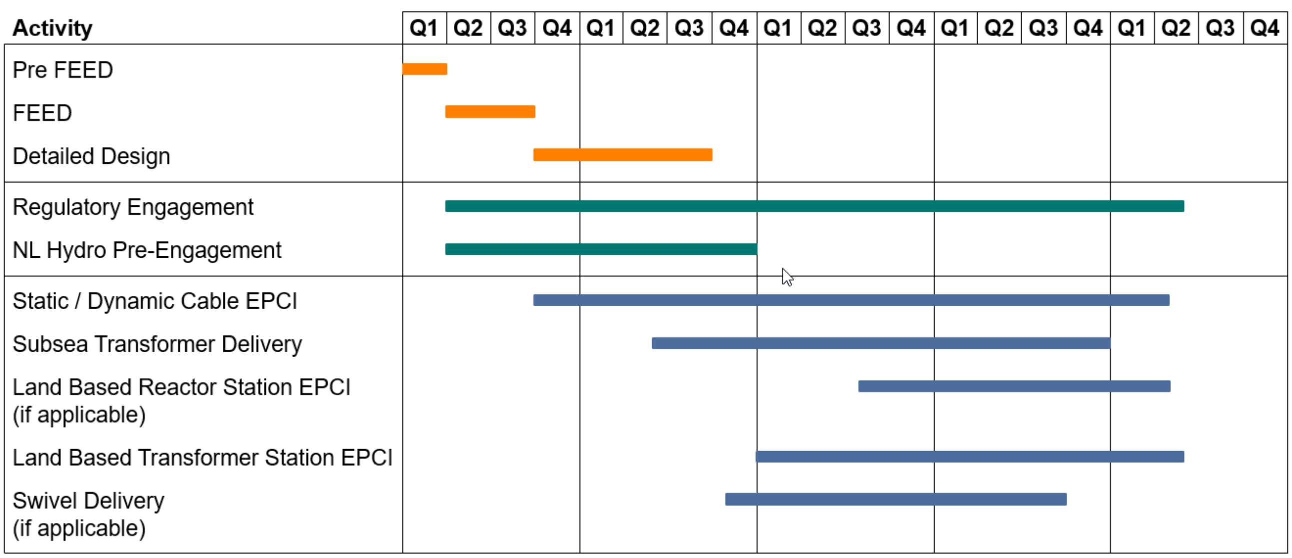


Figure 6-4: Sample execution schedule based on lead times

7 Scope 2 - FPSO Electrification Challenges

7.1 Management Summary

Review the technical challenges associated with the electrification of FPSO's including the ability to disconnect from a power source in the event of a potential impact from an iceberg.

Various options exist for electrification of FPSOs, they can be powered by High Voltage DC systems, traditional AC systems, or low frequency AC systems. Each of these options has its own challenges, in addition to which there are general challenges associated with powering an FPSO in this location. Key challenges are outlined in the following sections but can be summarized as;

HVDC Challenges:

- High Voltage DC (HVDC) systems require a large offshore DC-AC converter installed on the host platform (1500 m^2 & up to 12m high)
- Lack of qualified HVDC dynamic cable required to accommodate the motion of a floating vessel in this water depth.
- HVDC swivels to transfer power onto ship shaped FPSOs are still in the early qualification phases and will require time and cost to fully qualify

Traditional AC Challenges:

- Traditional AC transmission over this distance would have significant power losses – this can be overcome by use of multiple subsea reactors but this adds complexity and cost.

LFAC Challenges:

- LFAC requires a high voltage transmission to the FPSO which necessitates the use of a subsea transformer to step down voltage to an adequate level for connection to a swivel on the FPSO.

General Challenges:

- Facilities must be capable of disconnecting in the event of iceberg approach and readily reconnecting following departure of the iceberg. High voltage connectors are essential to this functionality and are currently only available for AC in subsea environments.
- The majority of ice hazards are associated with shallow water portions of the routes – primarily close to shore. Shore crossings for cables in Newfoundland are rocky and will require tunnel bores to cross between onshore and offshore, those in Labrador may be accommodated by a trench and fill approach.
- At water depths greater than 250m the risk of icebergs grounding and impacting the cable is significantly reduced – Cable lengths exposed to potential scour are as follows: 25km for the Labrador route, 110km of the Conception Bay Route, and 12km of the Trinity Bay route.

Schematics of HVDC and LFAC transmission to ship shaped FPSOs are provided below identifying the location of the critical components in the system.

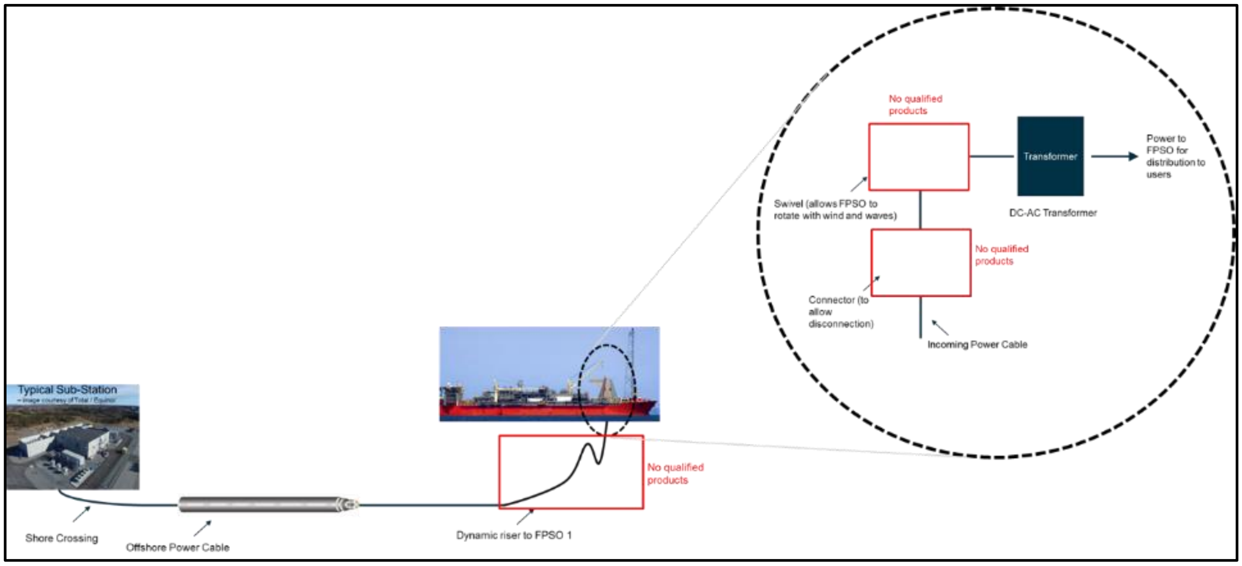


Figure 7-1: HVDC Power Supply to Ship Shaped FPSO

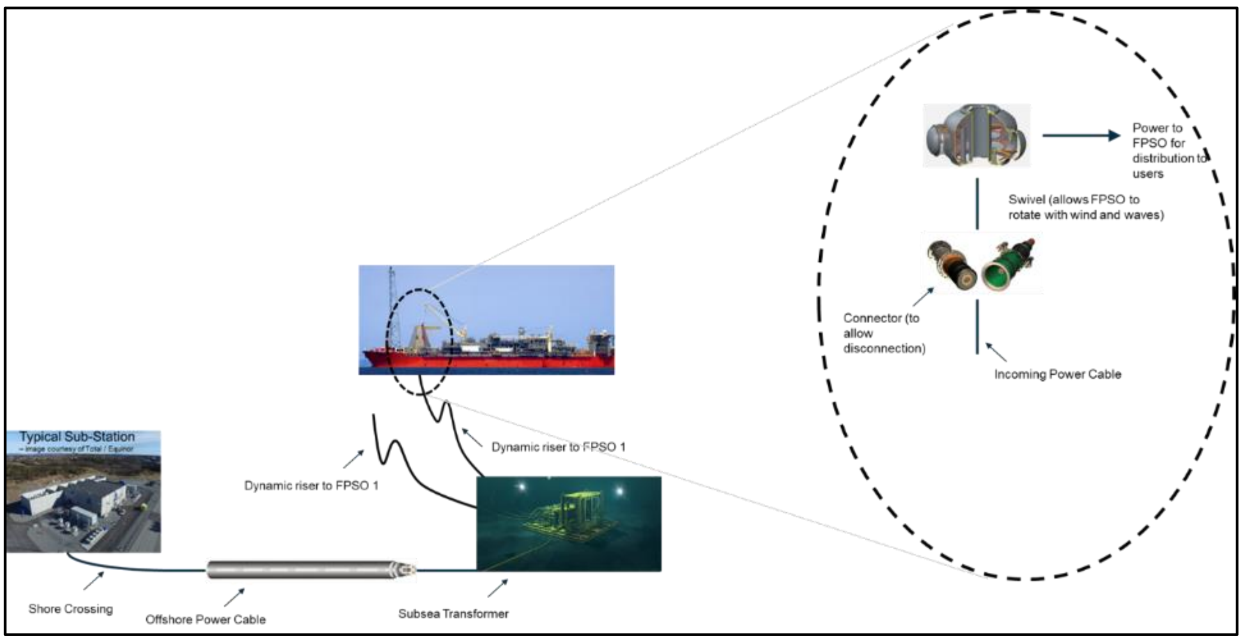


Figure 7-2: Low Frequency AC Power Supply to Ship Shaped FPSO

7.2 Assessment

Three options have been assessed as potential solutions for power from shore. AC transmission with reactor compensation, High Voltage DC Transmission, and Low Frequency AC transmission.

7.2.1 AC with Reactor Compensation Challenges

The biggest issue with this transmission method is that the distance from shore to the FPSO exceeds the practical capabilities of the equipment. At this distance this transmission method would experience excessive power losses that do not make it a reasonable candidate for transmission. Multiple subsea reactors could be installed to help lower losses, however this adds complexity and cost to the system by introducing more points of potential failure and extra cable lays to accommodate installation of multiple subsea reactors. Series capacitors could perhaps have been one path towards improved remote end voltage level stability but introduce a risk of sub-harmonic resonance phenomena. For this reason we have not studied this option further.

7.2.2 HVDC Challenges

HVDC has a number of challenges when transmitting to floating installations offshore. One major issue is the required size of the offshore DC-AC converter. Since there is no subsea converter/transformer solution the converter and full-voltage transformer must be housed in the topsides of the FPSO. HVDC converter stations can be on the order of 25mx12mx12m (or more depending on the HVDC-Link voltage level) which takes up a substantial amount of space that is at a premium on FPSO facilities. Further, this conversion equipment also adds significant weight to the facility.

For floating vessels, a dynamic cable is required to travel from the sea floor to the FPSO. This cable needs to withstand the forces of the ocean currents, turbulence cause by storms, and forces applied by the floating vessel. Currently there are no qualified HVDC dynamic cables that can operate in the water depth for the two regions of interest.

For ship shaped FPSOs, a swivel is needed in order to connect incoming HVDC power to accommodate the rotational, weathervane movement of the FPSO. Currently, there are three HVDC swivel concepts from two vendors, but they are not qualified and would require a qualification program in order to be certified for use. This would add cost and risk to the project.

In a phased development with multiple FPSOs, the first FPSO would be the power reception facility and must be dimensioned to convert power for all future FPSOs in the area, hence increase CAPEX for the first FPSO. This FPSO then acts as a hub for power distribution to other nearby facilities. Further, if a hub FPSO is forced to disconnect due to ice, all associated vessels would lose shore power and would have to shut down or generate power on board, meaning units would have to be designed for both power from shore and traditional generation to maintain process power, making them more expensive than a simplified power from shore model, based on a high availability of shore power.

Finally, ship shaped FPSOs require electrical quick connectors for connect and disconnect purposes. Currently there are no HVDC connectors suitable for subsea applications that can perform this function.

7.2.3 LFAC Challenges

LFAC also has a number of challenges to be overcome when transmitting power from shore at the required distance and water depth. To reduce power losses and increase voltage stability over this distance, a high transmission voltage is required. For ship shaped FPSOs, there are currently no fully qualified swivels that can accommodate high voltage power transfer. For this reason, a subsea transformer is recommended to step down the voltage to a level that can be accommodated by a qualified and service tested swivel.

Lower voltage dynamic riser cables qualified for these water depths are currently available and the use of a subsea transformer reduces the space required on the FPSO, as it reduces the sizes of the transformers onboard to step down the incoming high voltage power.

LFAC might face higher power loss when compared with HVDC. To reduce power losses a midpoint reactor can be optionally installed and a reduction in losses will offset the cost of the reactor. Further cost and complexity would be added if the reactor was installed subsea versus on land. For the Labrador South case, a land based midpoint reactor is recommended as it will offset power losses and the geography allows for suitable placement before the subsea cable continues out to sea.

7.2.4 Iceberg, Sea Ice, and Weather Challenges

There are several specific local environmental factors that create challenges for electrifying an FPSO from shore. The waters off the coast are subjected to seasonal occurrences of icebergs, sea ice, and intense waves and winds caused by winter storms or summer hurricanes. This environment necessitates that a ship powered from shore be able to disconnect from the power cable and maneuver away from potential harm.

It should be noted that both the Terra Nova and SeaRose ship-shaped FPSOs have been operating approximately 350km offshore in Newfoundland Labrador since 1999 and 2002 respectively. Both vessels have geostationary turrets moored to the sea floor via a connection to a buoy. The vessels operate in the harsh offshore conditions of Newfoundland Labrador but neither has disconnected from buoy due to ice. There have however been several planned disconnects during this period for maintenance purposes. While neither of these vessels are powered from shore, they provide good evidence that ship-shaped FPSOs with disconnect-able turret systems are a suitable design for these regions of study.

A typical ship-shaped FPSO is connected to a floating buoy that is moored to the sea floor. The buoy marshals all of the subsea process lines and the dynamic riser electrical cable and allows for a controlled attachment to an FPSO through an onboard turret. This system allows the ship shaped FPSO to disconnect from all mooring, process, and electrical connections to the seabed and move out of harm's way. Once the threat has subsided the system allows for reconnection so that power transmission and processes can resume. A planned disconnect can typically be achieved in 4 hours and rapid or emergency disconnect can occur in approximately 15 minutes. In ideal weather conditions it could typically take a minimum of 24 hours to reconnect the buoy to the turret following a disconnect. Qualified and suitable AC connectors are available for quick connect/disconnect. The mechanical details of the power riser connect/disconnect functionality is an area for further in-depth study as part of subsequent design phases.

To date, all geostationary FPSOs are permanently moored to the seabed and have no way to maneuver under their own power. Similar connectors would be required in order connect or disconnect the electrical cable for power from shore, however there would need to be extensive study to determine overall possibility and technology to connect and reconnect all of the required mooring lines required to maintain geostationary positioning and stability under all connected and disconnected conditions.

Avoidance of icebergs and problematic weather is part of a comprehensive ice and weather management and detection plan that provides ample warning time to prepare for a planned disconnect. Further information on ice impacts is found in section 7.2.8.

7.2.5 Disconnected State Challenges

When in a disconnected state (or in the event of loss of power from shore), an FPSO powered from shore will no longer be receiving primary power via the subsea transmission cable. The FPSO will therefore need the ability to generate its own power. This state must be considered when determining the overall power scheme when designing the vessel.

At a minimum, in a disconnected or unpowered state, essential power is required for life support of crew and critical systems along with power for a ship shaped FPSO to move or maneuver and maintain safety of life at sea. Therefore any FPSO would still retain hydrocarbon fueled electrical generators, but the total emissions would be significantly reduced versus a traditional unit.

7.2.6 Reliability Considerations

Various options exist for powering offshore facilities from shore.
The following table outlines power configurations that have historically been considered by operators during the design phase of the FPSO. These decision dictate the required load to be powered from shore.

		Power Generation and Distribution		
Electric and Thermal Load Requirements		**Normal power generation and distribution** **(No power from shore)**	**Electric power from shore, full electrification, electric consumers, and thermal requirements** **(Fully powered from shore)**	**Partial electrification, covering partial electric supply and/or thermal requirements** **(Partially powered from shore)**
	Source of electric power for drives and small power demands	Gas turbine driven generator set, 11kv or similar for distribution to main switchboard	Electric power from shore transferred through electrical swivel and to main switchboard	Power generation from gas turbine driven generator set and topping up by power from shore
	Source of process heating. (heating medium system)	The heating medium thermal demand provided via waste heat recovery unit recovering energy from the gas turbine exhaust	Thermal heating is based on use of electric boilers powered from the main switchboard	Thermal heating generated from gas turbine waste heat in combination with electric heating
	Implications on availability	Spare power generation included in design to provide redundancy	Reliant upon power from shore for production	Loss of power from shore may result in reduced production but will not cause shutdown.

Table 7-1: Power Generation Considerations

For the purposes of this study it is assumed that full electrification will be carried out, however FPSO load determinations will be affected by vendor decisions related to how much process power, if any, would need to be supported in a state where power from shore is unavailable.

7.2.7 Connectivity between Facilities

The basis of this study is for up to two FPSOs at each location. In other areas one vessel or platform acts as a landing station for incoming power from shore, and the second unit receives power via an undersea cable from the first facility.

In Newfoundland and Labrador waters where FPSOs may need to disconnect due to icebergs, this hub approach is not feasible as disconnection of the landing platform would cause the second unit to also shut down. For this reason under an LFAC power scenario a subsea transformer acts as a distribution point to provide separate power connections to each FPSO allowing for independent operation.

7.2.8 Water Depth Assessment and Subsea Cable Ice Risk

Water depths for Norwegian and other European offshore power from shore installations are typically in the range of 100-400m, with the deepest project under investigation being the Orman Lange power and control floater, operating in 900m of water. In the Gulf of Mexico at Cascade Chinook, power cables have been installed and are in operation at depths down to 2500m. The waters in the Labrador South region, and the West Orphan Basin region are approximately 1250-1550m deep which makes these some of the deepest power from shore projects being studied to date.

The following charts show the subsea profile for each of the cable routes studied. The threshold for iceberg scouring has been set at 250m. Further details can be found in the C-CORE ice risk analysis in Appendix A.

The analysis on the recommended route for Labrador south has revealed that 24.1km of the cable route is exposed to iceberg contact with an overall estimated scour crossing rate of 0.013/year.

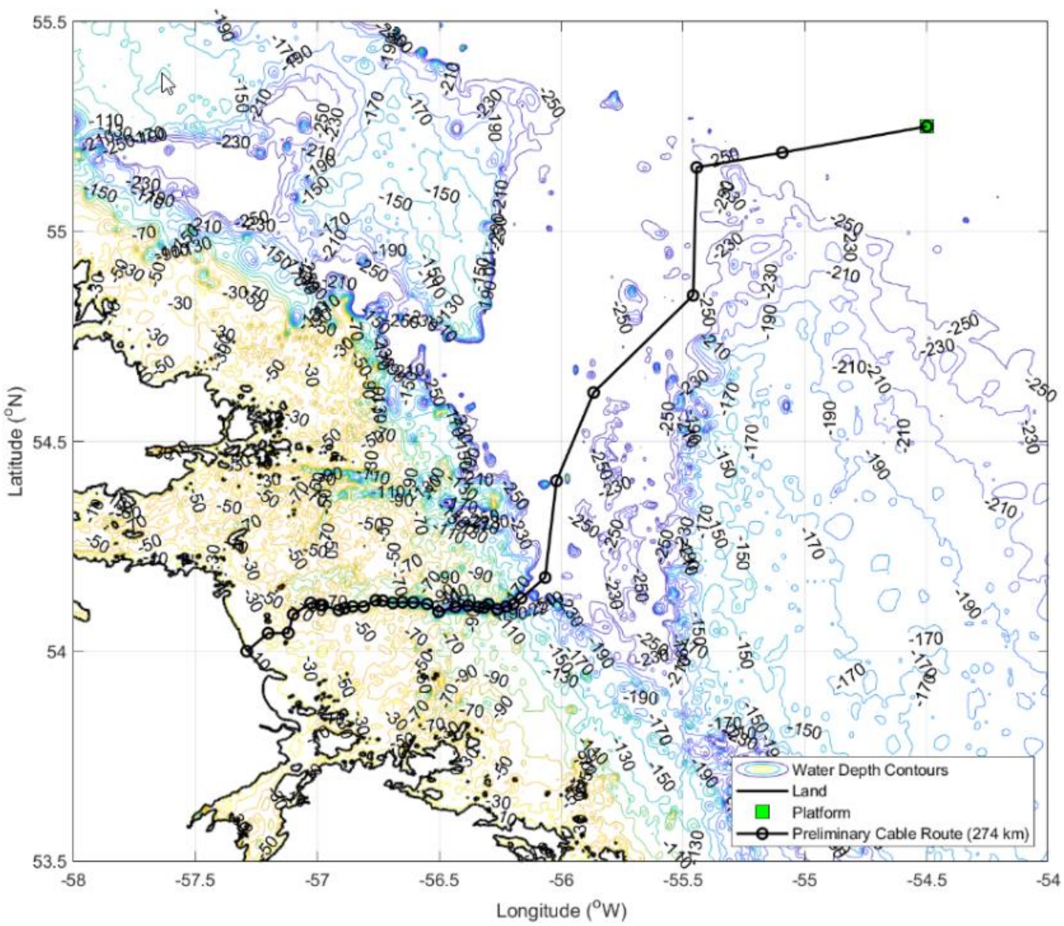


Figure 7-3: Cable Routings – Labrador South

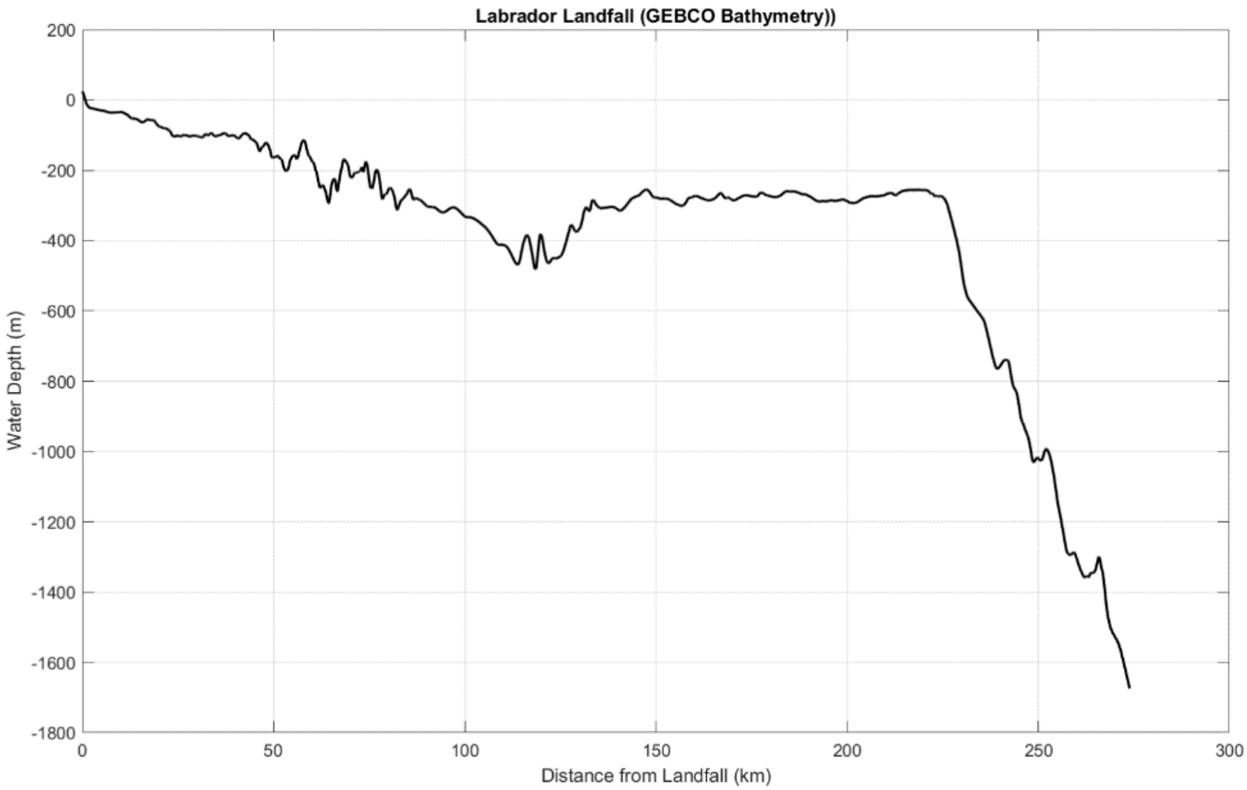


Figure 7-4: Water depth profile along Labrador South cable route

7.2.8.1 Labrador South/Lake Melville Challenges

A concern with the cable route that runs in Lake Melville is that the required cable laying vessel may not be able to enter and traverse the lake due to the physical size of the vessel and the geography of lake itself. A sample vessel from Nexans has a length of 149.9m and a width of 31m and may be too large for the lake. Smaller vessels exist, however they may have difficulty transporting the cable. The cable route through Lake Melville is a point that requires further study and input from the selected cable vendor to understand vessel logistics that would be suitable for carrying the required cable, while navigating the path through the lake.

If the provided a lake route is not feasible, a land route can be considered.

Figure 7-5: Nexans Aurora cable laying vessel (Skipsteknisk/Ulstein/Nexans)

The analysis on the recommended route for the West Orphan Basin through Conception Bay has revealed that 110km of the cable route is exposed to iceberg contact with an overall estimated scour crossing rate of 0.005/year.

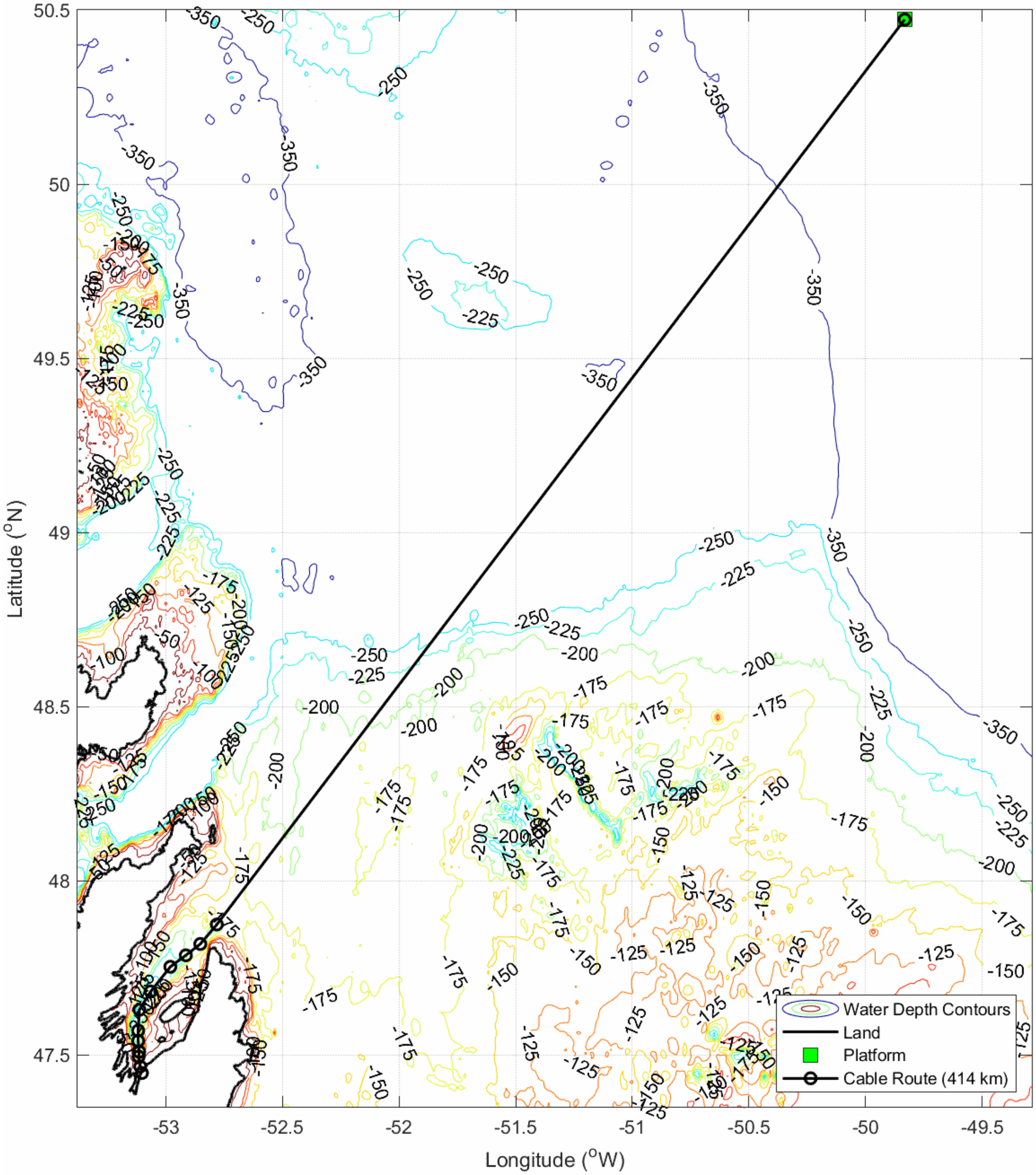


Figure 7-6: Cable Routings – West Orphan Basin via Conception Bay

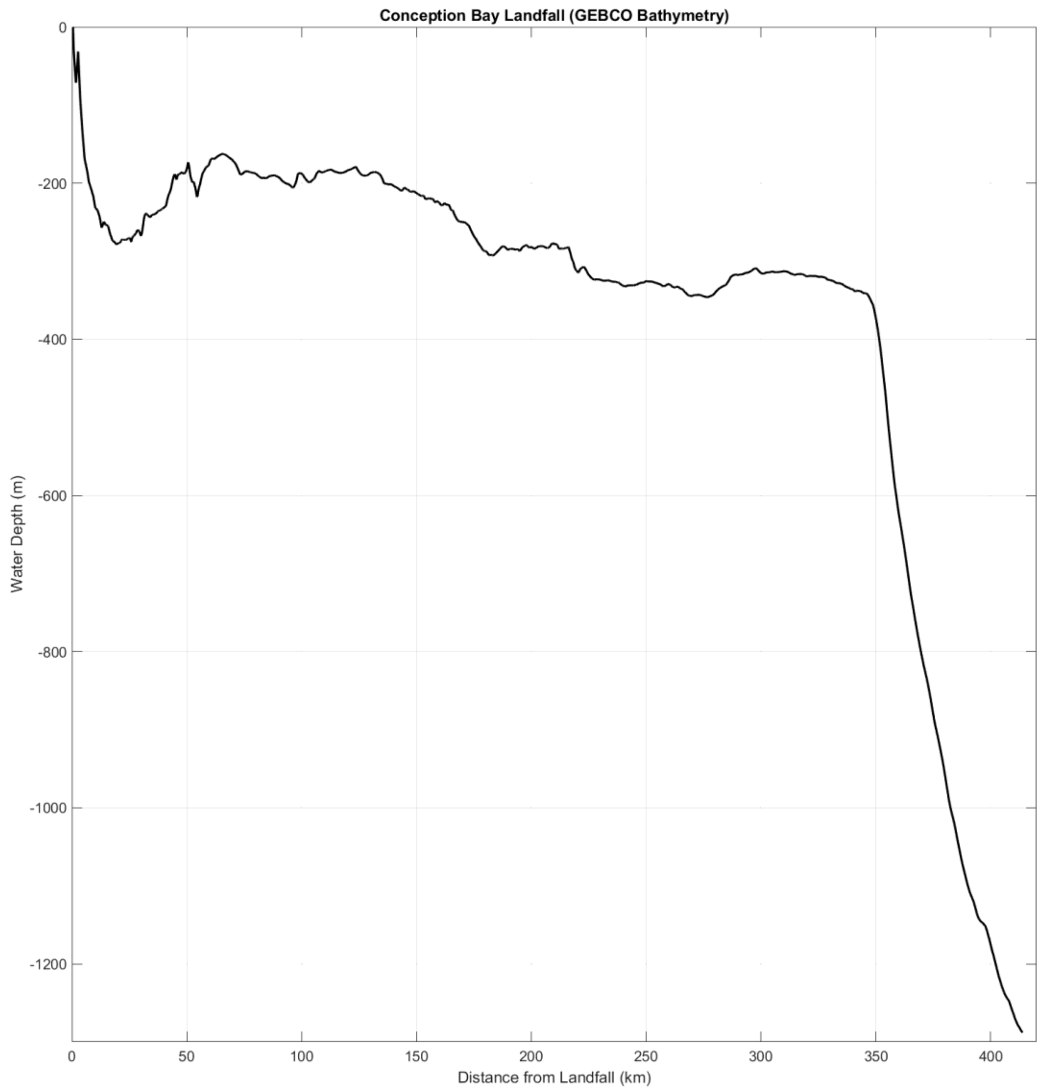


Figure 7-7: Water depth profile along West Orphan Basin cable route, Conception Bay landfall

The analysis on the alternative route for the West Orphan Basin through Trinity Bay has revealed that 12.4km of the cable route is exposed to iceberg contact with an overall estimated scour crossing rate of 0.0018/year.

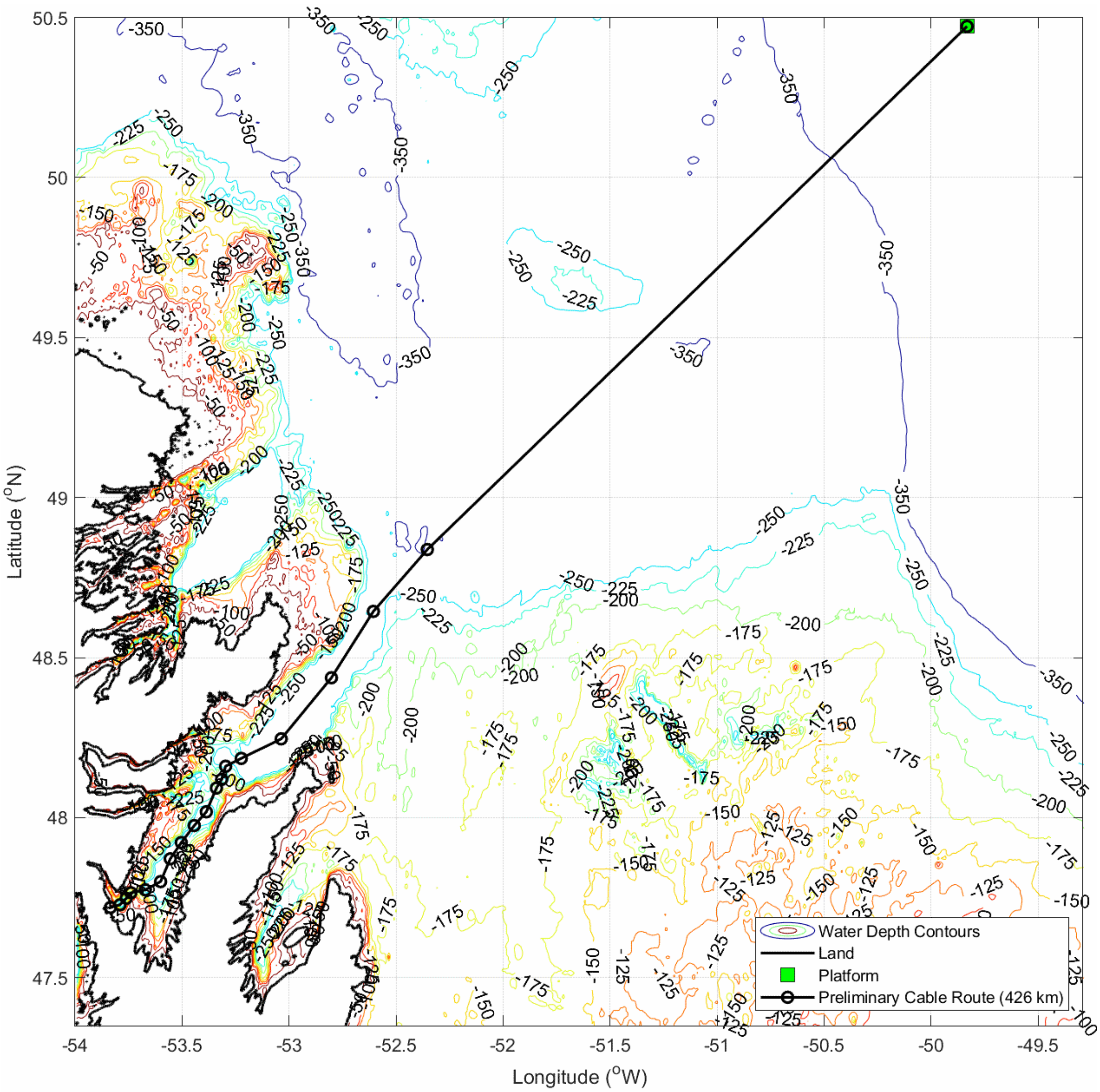


Figure 7-8: Cable Routings – West Orphan Basin via Trinity Bay

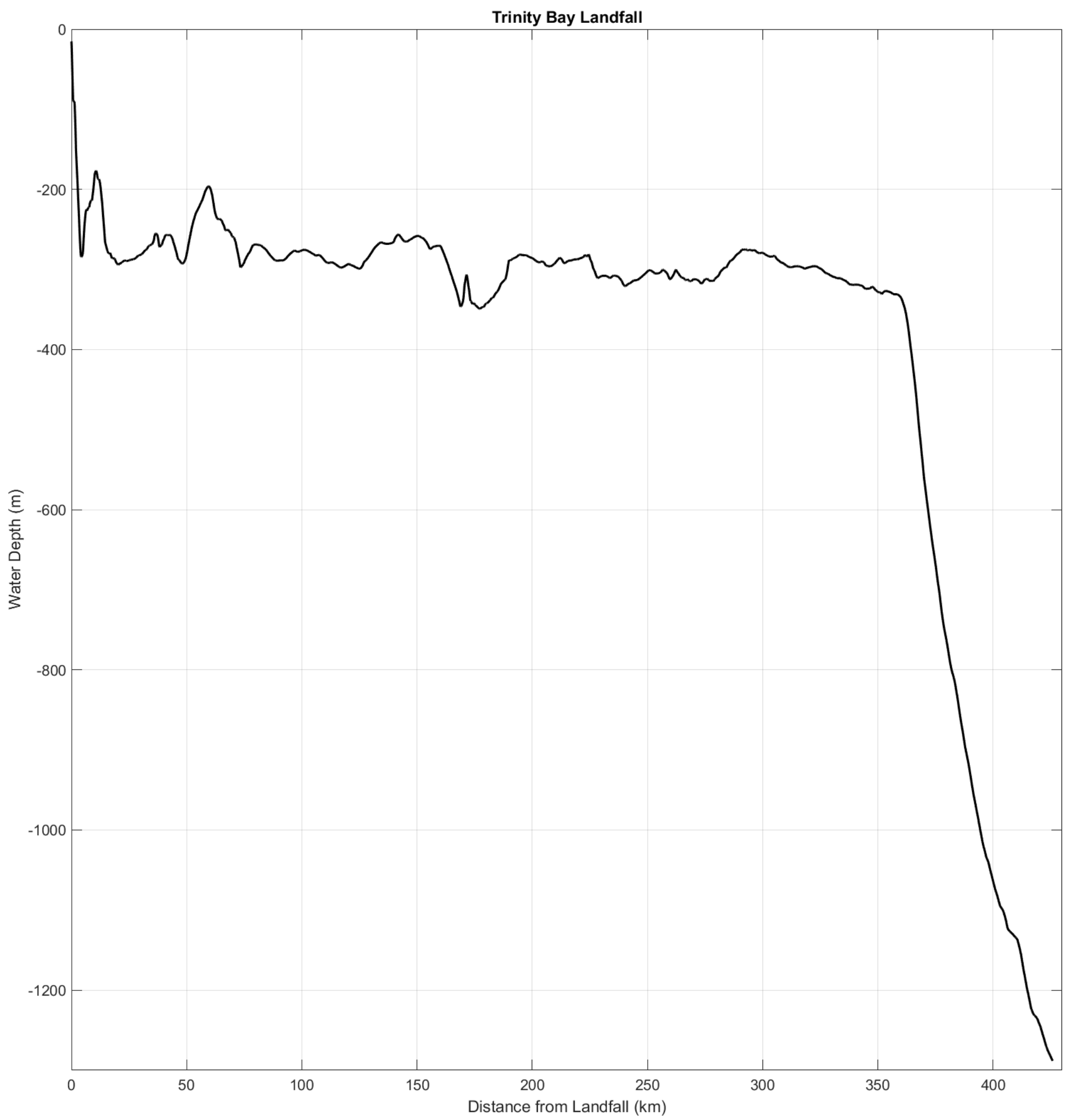


Figure 7-9: Water depth profile along West Orphan Basin cable route, Trinity Bay landfall

The alternative route through Trinity Bay is 12km longer than the conception bay route, but significantly reduces the length of cable that is exposed to iceberg contact. This has a large impact on installation costs as it would reduce the amount of trenching and/or cover protection that would be required to protect the cable along the route. Further study on this should be conducted as the point of interconnection with the electrical grid and cable route would need to be reassessed.

8 Scope 3 – Power Transmission Challenges

8.1 Management Summary

Review the state of offshore power transmission technology which specifically addresses the distances to potential developments offshore NL.

The power assessments carried out in this section are based on the subsea routes recommended by C-CORE. While the two routes are diverse, the power transmission simulation for each region of interest are similar.

- AC Transmission with Subsea Reactors, HVDC Transmission, and LFAC Transmission have been considered and each type has associated challenges. AC with subsea reactors is not a suitable technology given the distance from shore and the power losses that would be incurred. Further each subsea reactor adds an additional point of failure to the system and would require additional installation time for the cable laying vessel and an additional vessel to allow for a dry mate connection above the ocean.

- HVDC is a suitable technology for power transfer over long distances, however it presents problems for connection to ship-shaped FPSOs due to a lack of qualified HVDC swivel. Further, there is currently no HVDC subsea converter/transformer solution which means there would be no subsea distribution point for power connections to multiple FPSOs, and large transformer/converter stations would have to be installed on each FPSO, taking up valuable space. Lastly there are currently no qualified dynamic HVDC cable designs that are rated for the depths required. This would require design and qualification programs that add cost, time, and risk to a project.

- LFAC is the current recommendation for a solution when powering FPSOs from shore in these regions. The equipment for LFAC transmission is qualified, readily available, and even well tested in real world applications. LFAC also offers flexibility in design of the power distribution system on an FPSO which helps to minimize the need for relatively large transformers and converters offshore. Further LFAC offers higher uptime than HVDC as it can be designed to be left partially online (at reduced capacity) while maintenance is carried out on the system, due to the flexibility offered by multiple converters operating in parallel.

Each power from shore solution that has been considered includes a number of common building blocks. An onshore facility that houses equipment for connection to the grid, a subsea power cable, subsea equipment that facilitates delivery of power, a dynamic power cable from the subsea equipment to the FPSO, a power connection swivel required for electrical connection to ship-shaped FPSO vessels, and power connection and conditioning equipment on the FPSO vessel. The depth of water (1250m+) and distance from shore (450km+) for the regions of focus limits the equipment vendors and service providers that can meet the needs for each region. Further, the terrestrial substation and FPSO electrical equipment is standard power distribution equipment that is in service and relatively widely available. Three types of power transmission have been assessed as part of this scope.

An overview of major required equipment has been detailed to provide an understanding of the state of technology in this area of study.

8.2 Assessment

In this assessment we will review the options based on the technical feasibility of the key building blocks required to transmit power from shore.

8.2.1 Subsea Power Transmission Routes

The C-CORE study in Appendix A has recommended routes best suited for the subsea transmission cables. These routes were used as part of the design and analysis of the power transmission systems.

8.2.1.1 Subsea Power Transmission – Labrador South

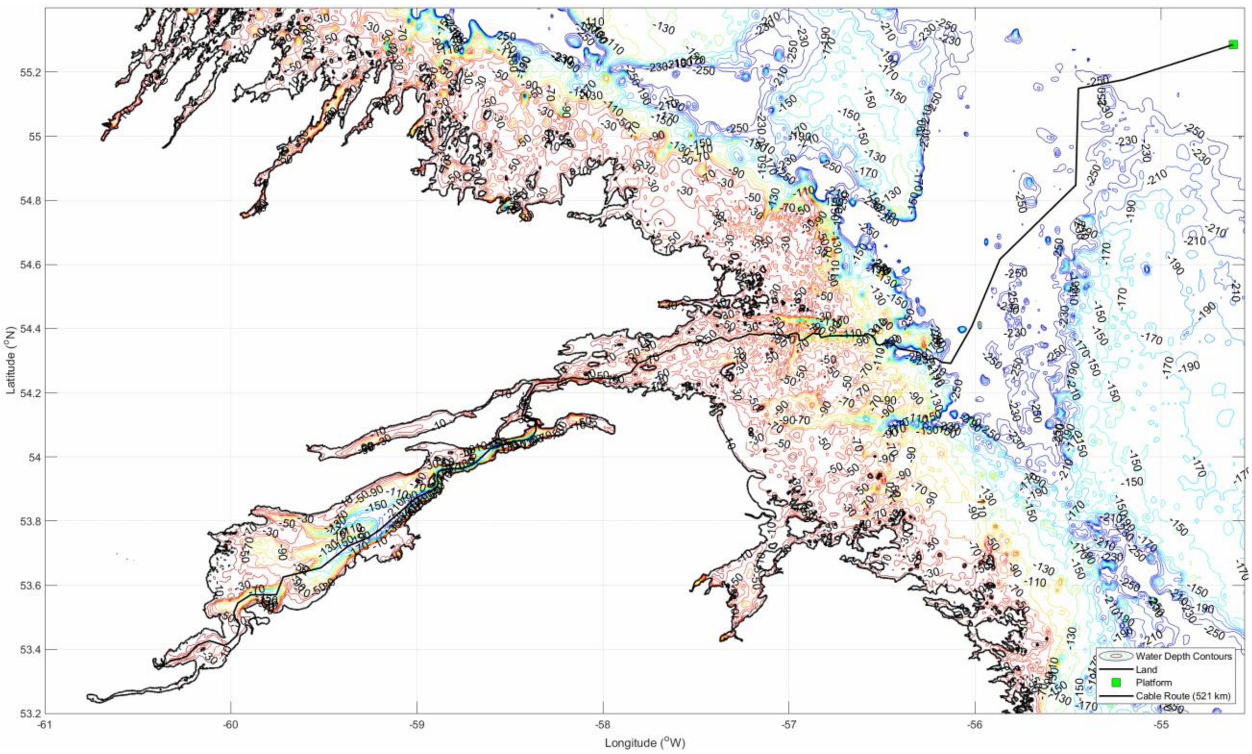


Figure 8-1: Cable route for Labrador South

When considering the route for Labrador South, the analysis is based on installing the subsea cable through Lake Melville. Based on the geography of Lake Melville, it may be difficult for a cable laying vessel to enter and install the cable. Further analysis will be required to ensure that a vessel can install the cable. Failing that, a land route may have to be considered.

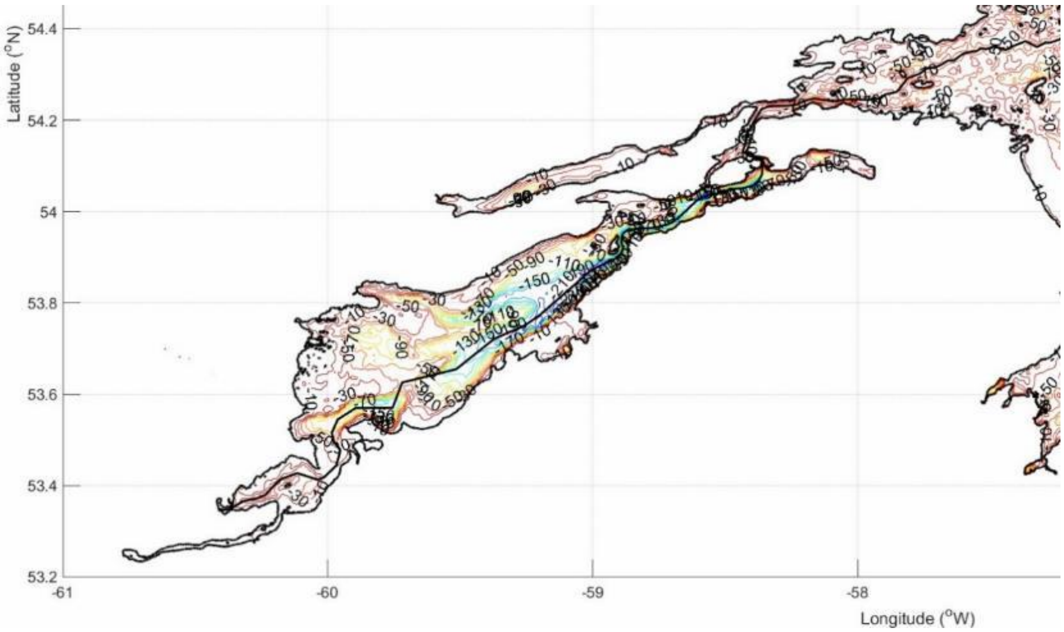


Figure 8-2: Cable route for Labrador South – Lake Melville

8.2.1.2 Subsea Power Transmission – West Orphan Basin

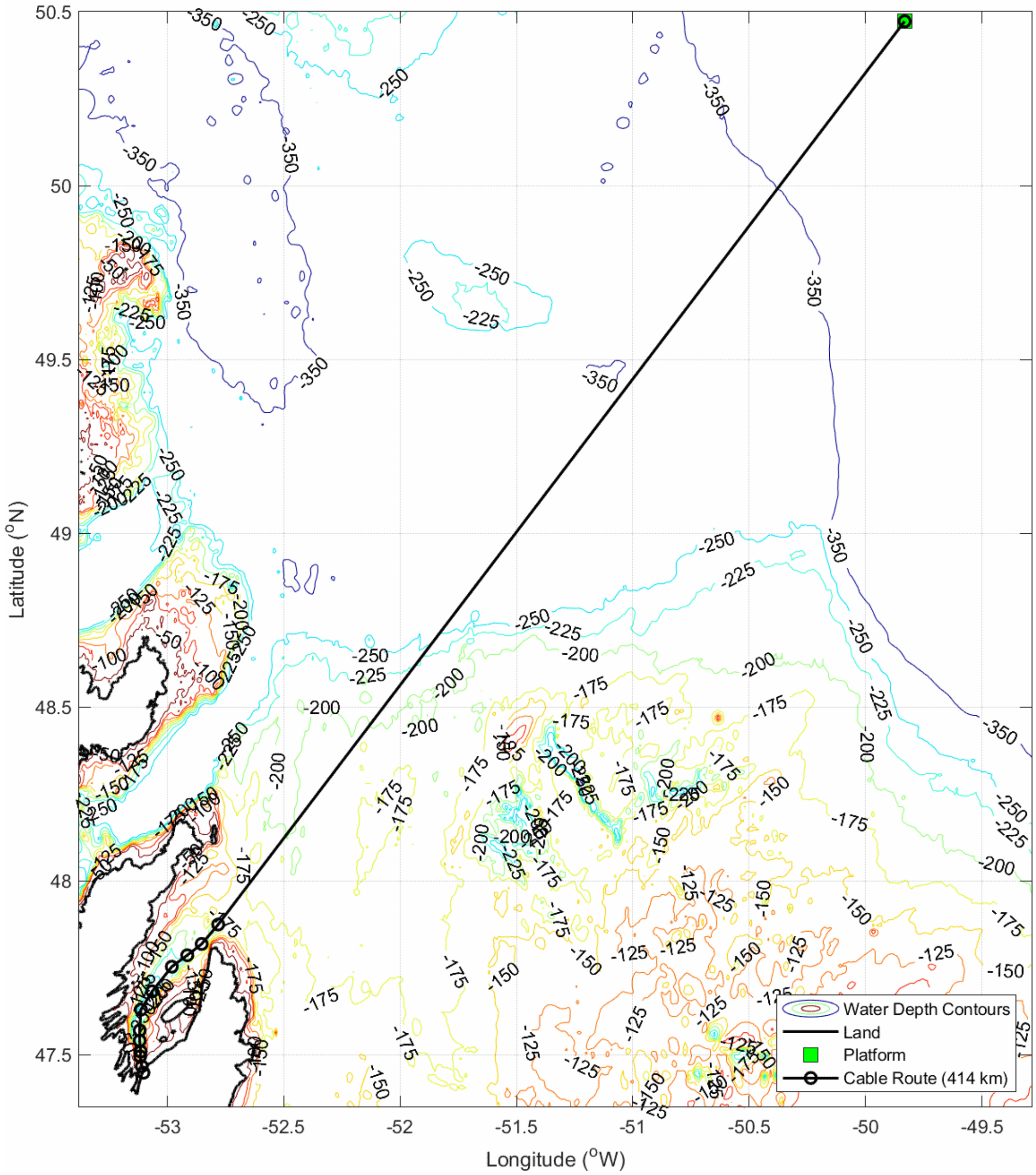


Figure 8-3: Cable route for West Orphan Basin, Conception Bay landfall

8.3 Power Transmission Systems Evaluation

The distances and water depths associated with the two regions of interest provide extremely challenging conditions when studying power from shore solutions. Developing and qualifying new equipment solutions for these harsh environments will be expensive and time consuming, and as such we have based our assessment on developing a feasible system with components that are largely qualified and even in service in the offshore industry, and identify any gaps in technology that exist. A specific focus has been placed on the recommended solution.

Further, looking out over a five year horizon there have been a number of vendors that have testing and qualification of major equipment planned, or already in progress however, in some cases there is a need for vendors to have operator commitment to fully qualify and place equipment into service. This is typically in opposition of oil and gas design methods where selected equipment is usually extensively field proven before inclusion on a project. Even so, there are some vendors pushing ahead and testing the limits of their designs and some operators who are evaluating this equipment for ongoing feasibility studies for possible project inclusion.

One primary example of a vendor that is pushing the limits is ABB. They are in the process of testing and qualifying a suite of technologies and services for subsea power transmission, distribution, and remote equipment operation at a distance of 600km and depth of 3000m. Power transmission is up to 100MW and the life is designed for 30 years of maintenance free operation. While these technologies have currently undergone shallow water tests and laboratory pressure tests to 3000 meter water depth, currently qualified to TRL4 (API) in spring 2020. ABB's goal is to move oil production to the seafloor which is a future forward way of looking at the oil and gas industry. Further details on their progress are available here after registration: https://forms.abb.com/form-29720/subsea-whitepaper.

Anecdotally, there generally appears to be a push towards studying power from shore using LFAC technologies. This could be due to the reduced complexities and more readily available qualified equipment. This evidence is not only seen in the offshore oil and gas industry, but also the offshore wind and other energy transmission industries where power is transferred to shore from offshore.

The following tables summarize the selection criteria covering technical readiness, safety/environment, complexity, and cost and schedule impacts. Using this criteria we have completed a preliminary evaluation of the power transmission options and have done a further in depth analysis of the recommended transmission system. As with any lookahead information, there are many factors that may alter this information in the future, and it is recommended that it is re-evaluated during a pre-FEED study.

Option	Technical Readiness	Safety / Environment	Complexity	Cost & Schedule
HVDC	Lack of qualified subsea equipment. Currently no qualified swivel and no dynamic cable due to water depth	Possibility for earth leak current that can be problematic if not addressed.	Large DC/AC converter required offshore requires greater footprint volume and weight	Floating hub station required, or space for HVDC converter equipment on FPSO.
AC with reactors	Offshore distance exceeds reasonable equipment capability at 60Hz	Larger impact due to the need of multiple subsea reactors	More subsea components required	Subsea reactor cost and extra campaign to lay and tie in reactors
LFAC	Subsea and terrestrial equipment has been qualified and in service.	Subsea transformer required, land reactor recommended	Only AC/AC converters required, land reactor recommended	Most qualified components and best solution ready for design
	Best Option or No major issues identified	Some issues or technology gaps being currently filled	Worst Issue or gaps unlikely to be filled in time for development	

Table 8-1: Labrador Sea 465km/1550m – Oil and Gas Development (5 year horizon)

Option	Technical Readiness	Safety / Environment	Complexity	Cost & Schedule
HVDC	Potential that HVDC swivel and dynamic cables will be qualified.	Possibility for earth leak current that can be problematic if not addressed.	Subsea converter may become available	Hub or vessel space not required topside if subsea components become available.
AC with reactors	Offshore distance exceeds reasonable equipment capability at 60Hz	Larger impact due to the need of multiple subsea reactors	More subsea components required	Subsea reactor cost and extra campaigns to lay and tie in reactors.
LFAC	More qualified and field proven equipment available	Subsea transformer required, land reactor recommended	Subsea converter may become available (already in design)	Costs reduced as more components mature and become readily available.
	Best Option or No major issues identified	Some issues or technology gaps being currently filled	Worst Issue or gaps unlikely to be filled in time for development	

Table 8-2: Labrador Sea 465km/1550m– Oil and Gas Development (10 yr horizon)

Option	Technical Readiness	Safety / Environment	Complexity	Cost & Schedule
HVDC	Lack of qualified subsea equipment. Currently no qualified swivel and no dynamic cable due to water depth	Possibility for earth leak current that can be problematic if not addressed.	Large DC/AC converter required offshore requires greater footprint volume and weight	Floating hub station required, or space for HVDC converter equipment on FPSO.
AC with reactors	Offshore distance exceeds reasonable equipment capability at 60Hz	Larger impact due to the need of multiple subsea reactors	More subsea components required	Subsea reactor cost and extra campaign to lay and tie in reactors
LFAC	Subsea and terrestrial equipment has been qualified and in service.	Subsea transformer required	Only AC/AC converters required	Most qualified components and best solution ready for design
	Best Option or No major issues identified	Some issues or technology gaps being currently filled	Worst Issue or gaps unlikely to be filled in time for development	

Table 8-3: 4x50MW West Orphan Basin 450km/1250m – Oil and Gas Development (5 yr horizon)

Option	Technical Readiness	Safety / Environment	Complexity	Cost & Schedule
HVDC	Potential that HVDC swivel and suitable dynamic cables will be qualified.	Possibility for earth leak current that can be problematic if not addressed.	Subsea converter may become available	Hub or vessel space not required if subsea components become available.
AC with reactors	Offshore distance exceeds reasonable equipment capability at 60Hz	Larger impact due to the need of multiple subsea reactors	More subsea components required	Subsea reactor cost and extra campaigns to lay and tie in reactors.
LFAC	More qualified and field proven equipment	Subsea transformer required, land reactor recommended	Subsea converter may become available (already in design)	Costs reduced as more components mature and become readily available.
	Best Option or No major issues identified	Some issues or technology gaps being currently filled	Worst Issue or gaps unlikely to be filled in time for development	

Table 8-4: 4x50MW West Orphan Basin 450km/1250m – Oil and Gas Development (10 yr horizon)

8.3.1 AC Transmission with Reactors Assessment

Previous work in the offshore oil and gas industry has indicated that subsea AC transmission tends to be more cost effective than HVDC transmission as AC transmission requires smaller and lighter equipment both at the feeding and receiving end. However there are some specific challenges with AC transmission that limit what is physically possible with the different combinations of equipment that are available. As the length of transmission increases, the power losses can become significant.

For extra-long AC cable lengths, large charging currents and impedances are introduced and lead to significant power loss. Subsea reactor stations can be installed along the cable to reduce power losses and effectively extend the transmission length for AC transmission solutions, however this transmission method remains largely outside of a possible solution for these scenarios.

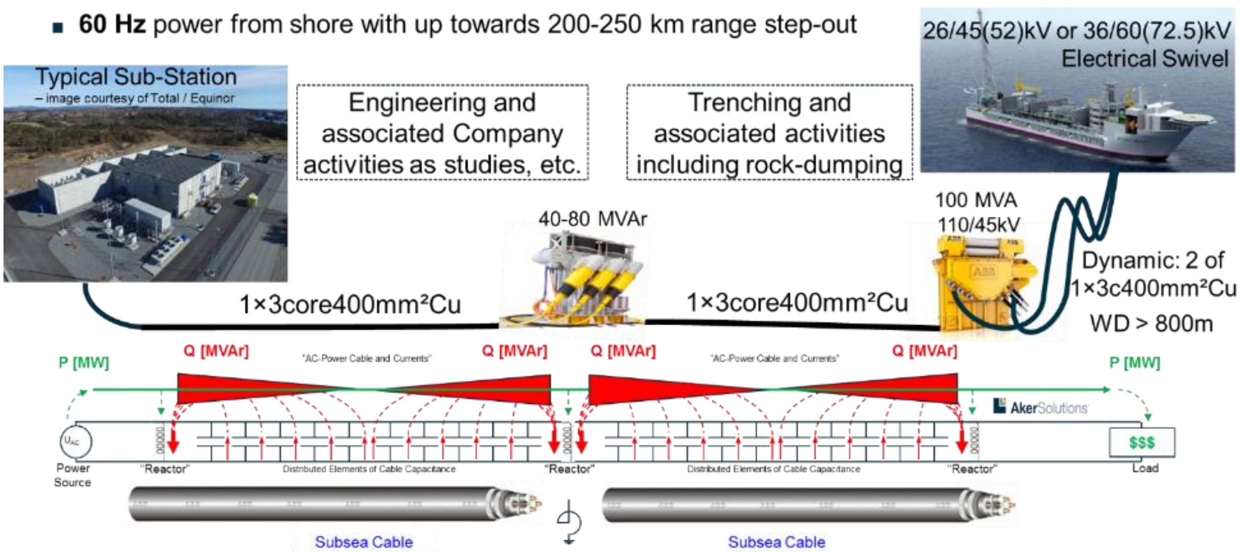


Figure 8-4: Example AC transmission with reactive compensation in the middle of the cable run (Aker Solutions)

The distances required to reach our regions of focus would require multiple subsea reactors distributed along the route. This would result in extra costs associated with purchasing and installing the equipment, add installation complexities as the subsea cable is being installed, and introduce several new points of potential failure. Additionally, a reactor/transformer can also be installed on the turret for improved stability and reduced power loss, but this leads to challenges with increased weight, and potential explosion hazards that would need to be evaluated and mitigated. For these reasons, and the overall distance required, this solution is not recommended for the scenarios of focus.

8.3.2 HVDC Transmission Assessment

The use of HVDC technologies enables very long transmission distances under certain conditions while experiencing a limited amount of power loss through the transmission system. Two configurations were considered. The first option includes a HVDC power hub that acts as a conversion and power distribution point. In the second option, the first FPSO acts as a power distribution hub to the second FPSO.

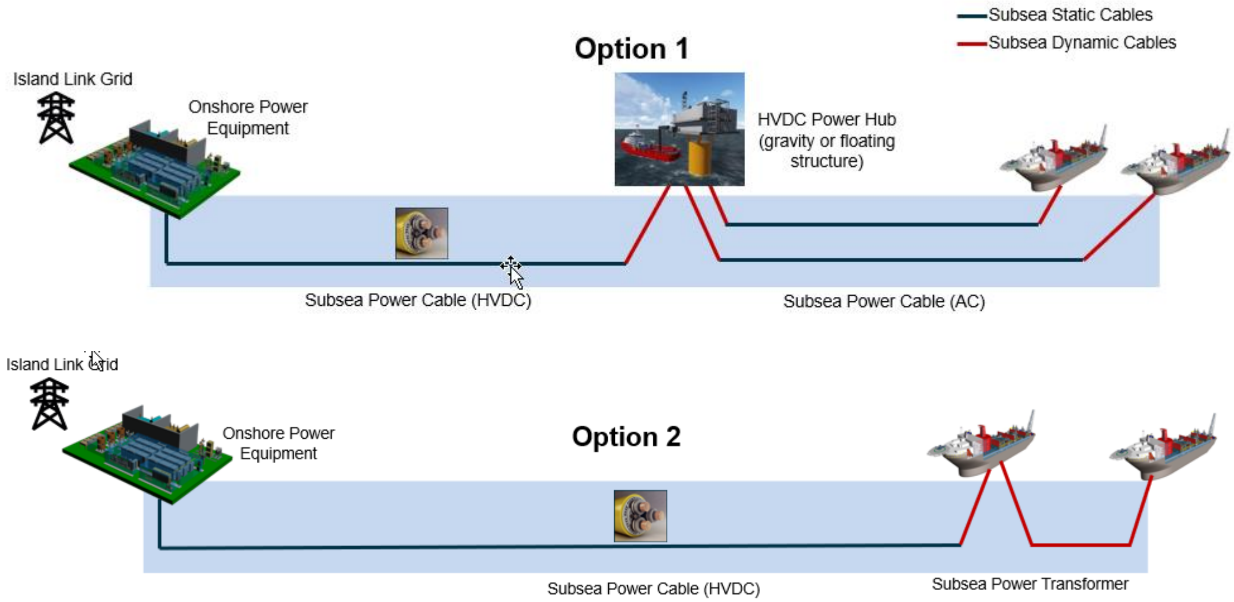


Figure 8-5: HVDC power from shore potential solutions

Transmission even at moderate DC voltages provides relatively rigid AC networks at the endpoints from a power dynamics and stability perspective. This would be beneficial for the establishment of regional AC-grid solutions out at sea as an extension of a DC based electrification hub. This solution was chosen for the area electrification of Utsirahøgda from the Johan Sverdrup field in Norway.

While HVDC provides excellent transmission characteristics under certain scenarios, it requires the use of a relatively large AC-DC converter station at the feeding end and relatively large DC-AC converter station at the receiving end, both of which will require multiple utility systems to achieve and maintain the controlled atmosphere required by the converters. I.e. air temperature, humidity, particle content, etc. Incoming HVDC power to the FPSO would necessitate large DC-AC converter equipment that would handle conversion of the full load from HVDC to 60Hz AC in order to drive large motors, and subsequent downstream busses and equipment. The additional equipment required on board an FPSO will occupy area, weight reserve, and require regular maintenance which may not be practical and will increase costs and complexity.

In more complex and larger power transfer scenarios, an offshore converter platform or semi-submersible structure has been developed to house the required conversion and transformer equipment and act as a hub to connected platforms, subsea equipment, or wind turbines. In the harsh Newfoundland or Labrador offshore environment such a hub platform requires a significant investment. This platform would also provide a single point of failure in the event of storm damage, or disconnecting for purposes of iceberg avoidance.

For the HVDC alternative, an assessment was completed considering the connection point onshore to be at a substation near Soldiers Pond in Newfoundland, where 230kV at 60 Hz is currently available. From here, DC subsea cables can be laid in similar manners as for AC directly towards the offshore target region. The cable route is long; 450+ km one way (i.e. a total cable length of around 900+ km for the DC-currents). Assuming a bipolar network configuration, the losses for a +/- 80 kV DC voltage for the 2×45 MW = 90 MW case have been assessed to be as follows, taking into account trenched/protected, and hence, thermally de-rated cables:

2×45 MW case; P = 90 MW offshore	2×65 MW case; P = 130 MW offshore
Subsea Cable: 2×800mm²Cu +/- 80 kV	Subsea Cable: 2×1200mm²Cu +/- 80 kV
Losses: Approx. 11.4 MW including HVDC-aux.	Losses: Approx. 17.0 MW including HVDC-aux.

Table 8-5: High level assessment of HVDC transmission losses for offshore of Newfoundland load cases

The required cable for these electrification cases could be challenging to handle during installation and would require a dynamic qualification program for 1250-1550m water depths, as there is currently no suitable dynamic HVDC cable that has been qualified for that depth.

Further, since DC requires two runs of cable, the costs associated with manufacturing and installing those lengths are increased. Total cross sectional copper area for two lengths of DC cable would be on the range of 1600-2400mm², where the equivalent distance for LFAC cable, when considering all three cores, would have an average cross sectional area of approximately 1500-1800mm², which is a reduction in overall copper.

Although not studied in detail, it is assumed that a higher transmission voltage level would be a better suited solution with respect to the distance and power losses, however a higher transmission voltage (Typically +/- 150 kV DC) would result in a considerably larger HVDC-module offshore and increase the technology-gap for dynamic HVDC subsea cable and swivel qualifications.

8.3.2.1 HVDC Cost and Size Considerations

Based on past projects in Europe, and for informational purposes, the +/-80kV HVDC system that would be required is estimated to have the following weight, size, and cost implications (+/- 40%):

Onboard FPSO Converter Module:
- Weight: 2800 tons
- Size: 25x30x20 (WxLxH)
- Cost: *<Costs redacted from public report>*

Onshore distribution facility:
- Cost: *<Costs redacted from public report>*

Costs are based on Aker’s experience in Norway. The use of Nalcor/NL Hydro design standards and equipment contractors may reduce costs relative to estimates based out of Norway.

Based on our two regions of focus, HVDC is not a suitable solution from a technology readiness, cost, and complexity perspective. The required space, cost, and maintenance for the HVDC equipment will require valuable space on already typically crowded FPSO designs, and the required dynamic cables and swivel will require comprehensive qualification programs before being ready for field installation and service.

8.3.3 LFAC Transmission Assessment

Power transfer at a low frequency provides a significant reduction in cable charging current and system impedance when compared to HVAC transmission. This allows for improved system voltage stability without requiring a series capacitor, and removes the requirement for subsea reactor stations. In this, the recommended scenario, power will be transferred subsea at a nominal voltage of between 132kV and 145kV and at a frequency of 20Hz. A subsea transformer would then reduce this voltage to between 50 and 66kV for connection through a rated swivel that is currently qualified and available from Focal or SBM. While not absolutely required, a land based midpoint reactor station in the Labrador South case would help to mitigate power losses and it is recommended for consideration.

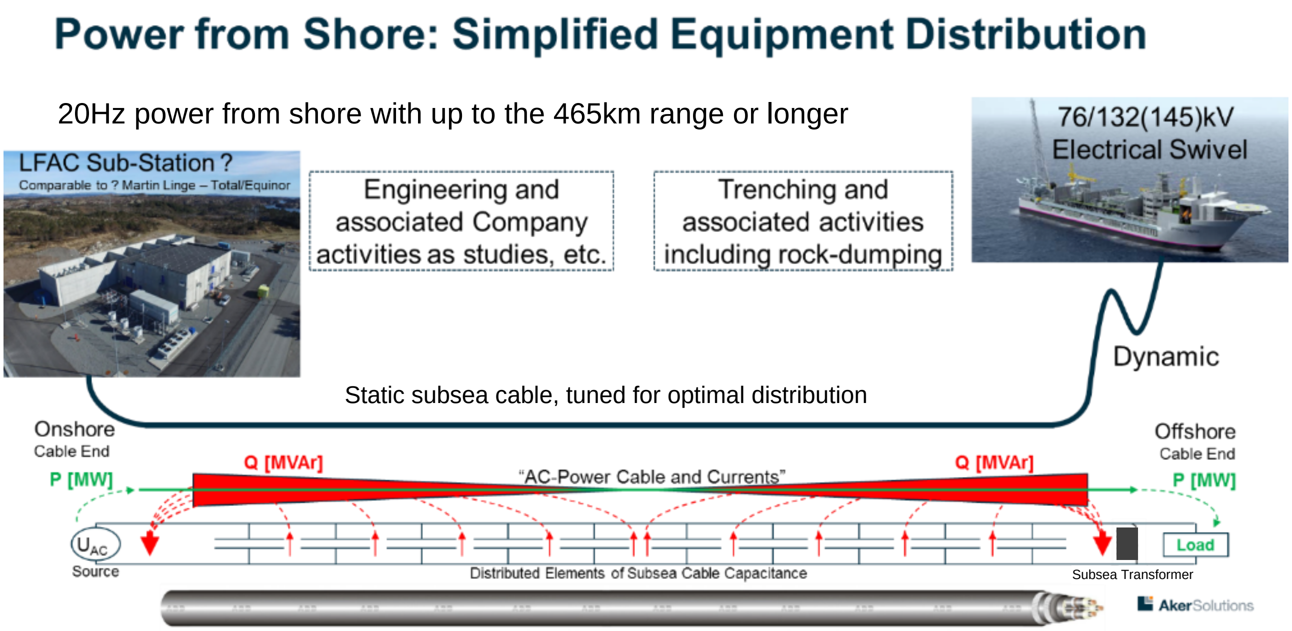


Figure 8-6: Example Low frequency AC power transmission to FPSO.

The following sections outline the design parameters and simulation results based on each region of interest.

8.3.3.1 Labrador South

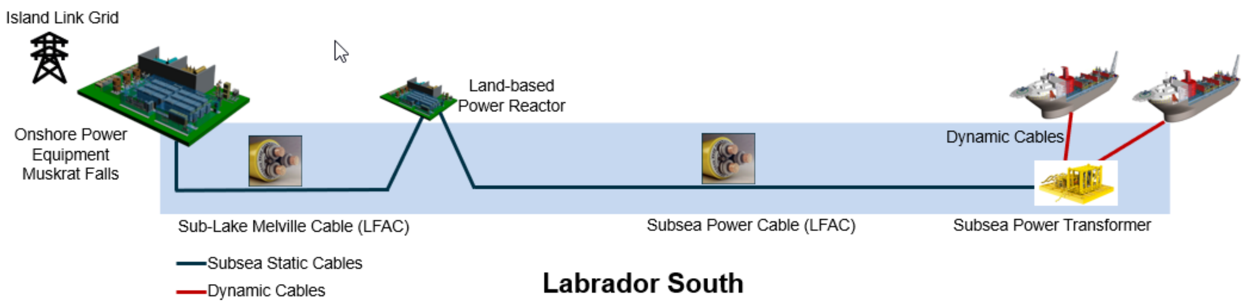


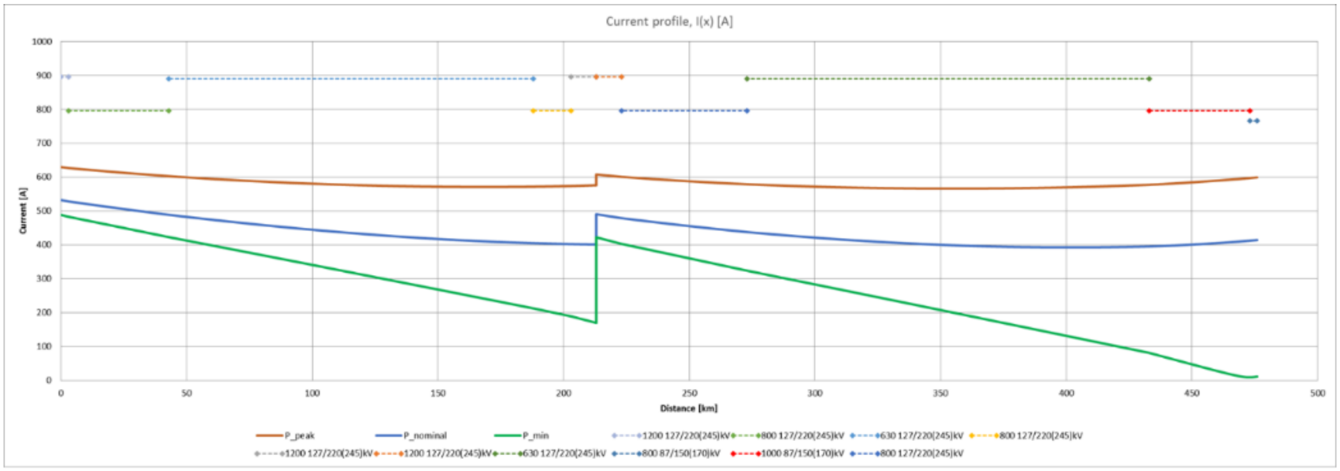
Figure 8-7: Sample Layout 2x45MW FPSO Labrador South

DESIGN DATA			
Transmission nominal frequency	f	20	Hz
Offshore platform (load)	Load voltage (line-to-line)	132.0	kV
	Pr_peak	130	MW
	Power factor_max	0.950	
	Pr_normal	90.0	MW
	Power factor_nominal	0.950	
	Pr_min	2.0	MW
	Power factor_min	0.8	

Figure 8-8: Labrador South design data

CABLE DATA												
Cable Section		Description	Length [km]	Cables	Cores	CSA [mm2]	Insulation Level	Current Rating [A]	Derating factor	Actual Rating [A]	Rdc (20°C) [Ω/km]	Average temp [°C]
	1	Onshore cable-trench	3	3	1	1200	127/220(245)kV	1280	0.70	896	0.0151	60
	2	«Churchill River»	40	1	3	800	127/220(245)kV	995	0.80	796	0.0221	60
	3	"Lake Melville"	145	1	3	630	127/220(245)kV	890	1.00	890	0.0283	60
	4	"Near-shore"	15	1	3	800	127/220(245)kV	995	0.80	796	0.0221	60
	5	Onshore cable-trench	10	3	1	1200	127/220(245)kV	1280	0.70	896	0.0151	60
	-	Shunt Reactor	-	-	-	-	-	-	-	-	-	-
	6	Onshore cable-trench	10	3	1	1200	127/220(245)kV	1280	0.70	896	0.0151	60
	7	"Near-shore"	50	1	3	800	127/220(245)kV	995	0.80	796	0.0221	60
	8	subsea	160	1	3	630	127/220(245)kV	890	1.00	890	0.0283	60
	9	"Deep water"	40	1	3	800	87/150(170)kV	995	0.80	796	0.0221	60
	10	Dynamic	3	3	1	1000	87/150(170)kV	1095	0.70	766.5	0.0176	60
Total			476									

Figure 8-9: 2x45MW-65MW FPSO Labrador South cable design



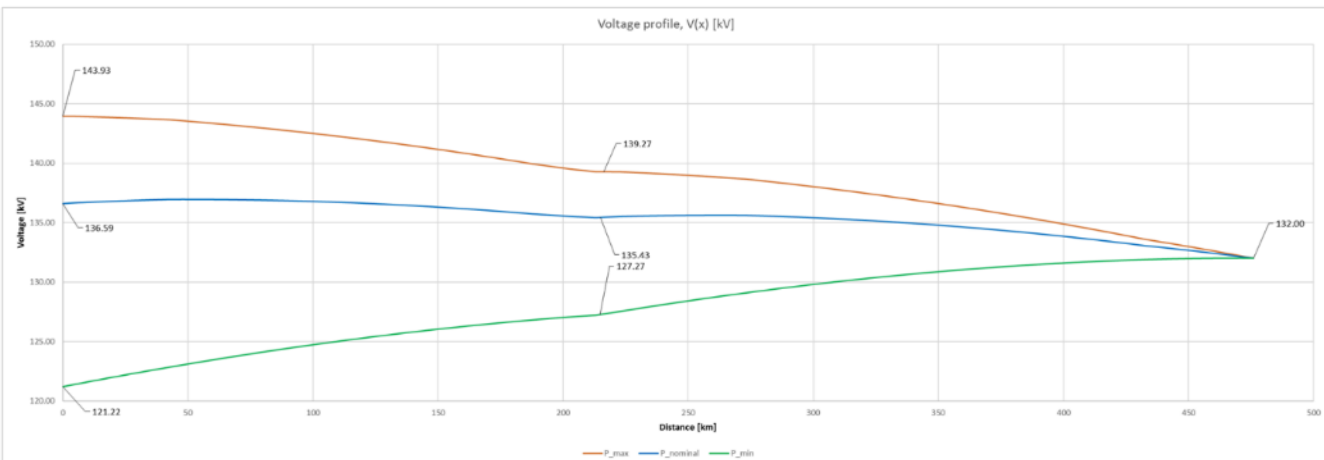


Figure 8-10: 2x45MW-65MW FPSO Labrador South current and voltage profiles

RESULTS																					
Location	Pr_peak							Pr_normal							Pr_min						
	U [kV]	I_in[A]	P [MW]	Q	S	cos phi	P_loss [MW]	U [kV]	I_in[A]	P	Q	S	cos phi	P_loss [MW]	U [kV]	I_in[A]	P	Q	S	cos phi	P_loss [MW]
Onshore	143.93	628.8	144.28	-61.33	156.77	0.920	0.000	136.59	532.0	97.90	-79.12	125.87	0.778	0.000	121.22	488.0	5.54	-102.31	102.46	0.054	0.000
Cable segment 1	143.93	628.8	144.28	-61.33	156.77	0.920	0.062	136.59	532.0	97.90	-79.12	125.87	0.778	0.044	121.22	488.0	5.54	-102.31	102.46	0.054	0.037
Cable segment 2	143.94	626.3	144.21	-59.86	156.14	0.924	1.155	136.63	528.1	97.85	-77.76	124.99	0.783	0.791	121.34	482.4	5.50	-101.24	101.39	0.054	0.628
Cable segment 3	143.65	602.1	143.06	-44.46	149.81	0.955	4.783	136.94	488.6	97.06	-63.32	115.89	0.838	2.751	122.87	422.3	4.88	-89.73	89.87	0.054	1.489
Cable segment 4	139.92	571.2	138.28	6.80	138.44	0.999	0.376	135.72	405.2	94.31	-13.30	95.24	0.990	0.187	126.82	212.1	3.39	-46.47	46.60	0.073	0.046
Cable segment 5	139.49	573.0	137.90	12.32	138.45	0.996	0.173	135.51	402.4	94.12	-7.77	94.44	0.997	0.085	127.07	188.7	3.34	-41.40	41.54	0.080	0.017
Reactor	139.27	276.89	0.00	0.00	0.00	0.000	0.000	135.41	269.20	0.00	0.00	0.00	0.000	0.000	127.21	252.91	0.00	0.00	0.00	0.000	0.000
Cable segment 6	139.27	607.1	137.73	-49.81	146.46	0.940	0.191	135.41	490.6	94.04	-66.29	115.05	0.817	0.123	127.21	421.9	3.32	-92.91	92.96	0.036	0.089
Cable segment 7	139.26	600.2	137.54	-45.20	144.77	0.950	1.327	135.50	479.0	93.91	-61.78	112.41	0.835	0.803	127.54	402.5	3.24	-88.86	88.92	0.036	0.507
Cable segment 8	138.66	578.3	136.21	-27.18	138.89	0.981	5.092	135.60	438.0	93.11	-43.72	102.87	0.905	2.582	129.09	323.4	2.73	-72.26	72.32	0.038	0.721
Cable segment 9	133.57	576.7	131.12	24.64	133.41	0.983	1.052	133.04	395.5	90.53	10.49	91.13	0.993	0.497	131.89	80.9	2.01	-18.38	18.49	0.109	0.007
Cable segment 10	132.10	596.5	130.07	41.36	136.48	0.953	0.000	132.07	412.3	90.03	28.14	94.33	0.954	0.000	132.00	8.7	2.00	-0.01	2.00	1.000	0.000
Offshore end	132.00	598.5	130.07	41.36	136.48	0.953	0.000	132.00	414.4	90.03	28.14	94.33	0.954	0.000	0.00	10.9	2.00	-0.01	2.00	1.000	0.000
Total							14.210							7.864							3.542
Total efficiency [%]							90.15							91.97							36.09

Figure 8-11: 2x45MW-65MW FPSO Labrador South simulation results

For the Labrador South transmission case there is potential to install a midpoint reactor on land where the transmission cable exits the lake and before it enters the sea. The midpoint reactor is a compensating device that consumes charging currents, or reactive power, that are generated by the cable. A reactor causes cable charging currents to be distributed more evenly on the line and transmission losses can be reduced. The cost of a land based reactor will be offset by the reduction in power losses along the transmission line. The figure below shows some possible locations for a land based reactor station. There are a number of factors to be considered when selecting a site, including proximity to roads, communities, and access for site preparation equipment. Such a reactor station could also be designed to branch and supply power to communities that are in the vicinity.

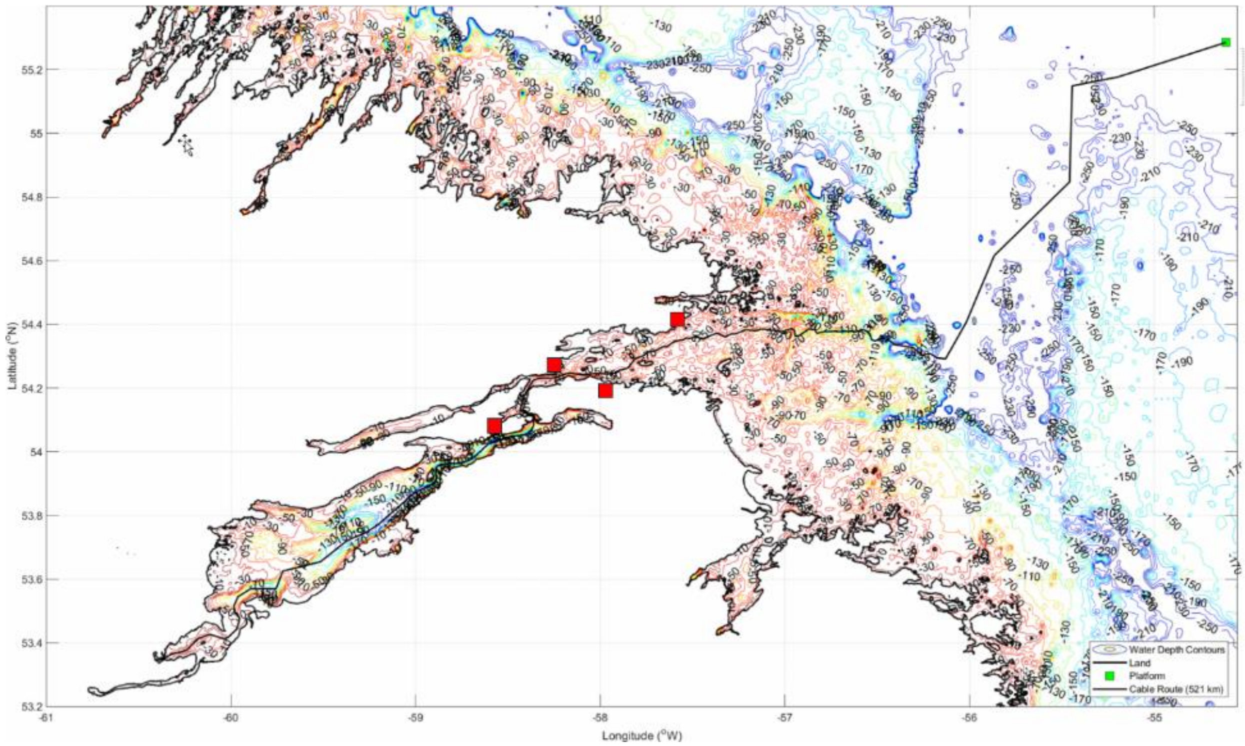


Figure 8-12: Possible locations for land based reactor station

8.3.3.2 4x50MW FPSO Solders Pond to West Orphan Basin

The diagram below illustrates a sample power distribution scheme for powering four FPSO vessels from shore. The subsea cable would terminate on the primary side of the first subsea transformer and the secondary side of that transformer would act as a distribution point for two FPSOs. A second subsea cable would connect the primary side of the first transformer with the primary side of the second transformer. The secondary side of the second transformer acts as a distribution point to the remaining two FPSOs. Each transformer would accommodate up to 120MVA for distribution.

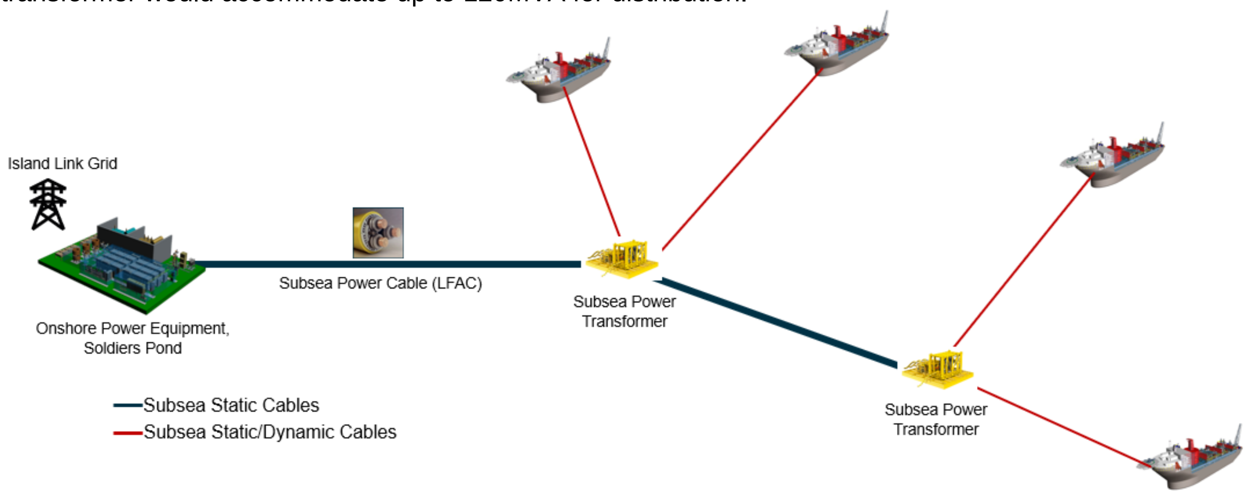


Figure 8-13: Sample Layout 4x50MW FPSO Soldiers Pond to West Orphan Basin

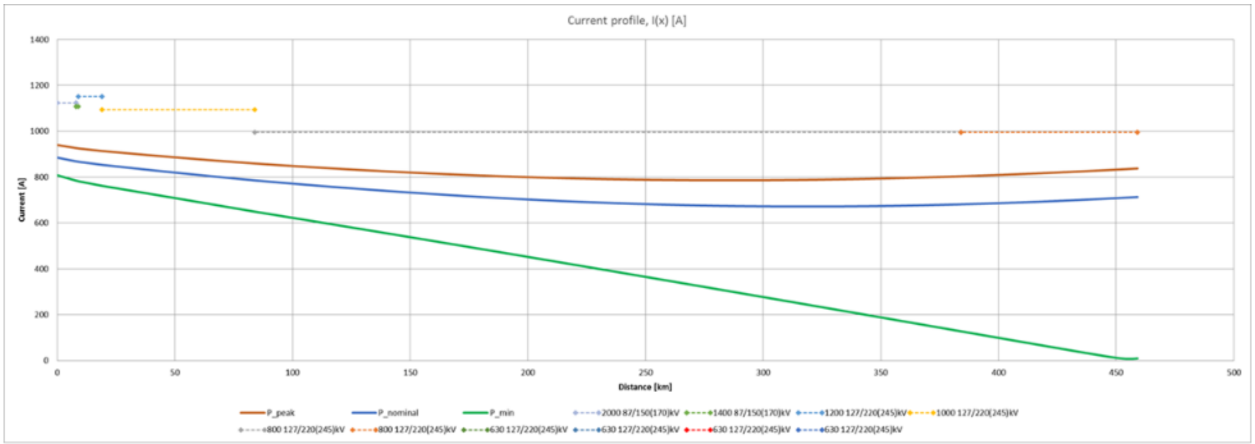
DESIGN DATA			
Transmission nominal frequency	f	20	Hz
Offshore platform (load)	Load voltage (line-to-line)	145.0	kV
	Pr_peak	200	MW
	Power factor_max	0.950	
	Pr_normal	170.0	MW
	Power factor_nominal	0.950	
	Pr_min	2.0	MW
	Power factor_min	0.8	

Figure 8-14: 4x50MW FPSO Soldiers Pond to West Orphan Basin design data

CABLE DATA

Cable Section	Description	Length [km]	Cables	Cores	CSA [mm2]	Insulation Level	Current Rating [A]	Derating factor	Actual Rating [A]	Rdc (20°C) [Ω/km]	Average temp [°C]
1	Onshore	8	3	1	2000	87/150(170)kV	1605	0.70	1124	0.009	60
2	Bore-Hole	1	1	3	1400	87/150(170)kV	1385	0.80	1108	0.0132	60
3	"Inshore"	10	1	3	1200	127/220(245)kV	1280	0.90	1152	0.0151	60
4	"Near-shore"	65	1	3	1000	127/220(245)kV	1095	1.00	1095	0.0176	60
5	"subsea"	300	1	3	800	127/220(245)kV	995	1.00	995	0.0221	60
-	Shunt Reactor	-	-	-	-	-	-	-	-	-	-
6	"Deep water"	75	1	3	800	127/220(245)kV	995	1.00	995	0.0221	60
7		0			630	127/220(245)kV	890	1.00	890	0.0283	60
8		0			630	127/220(245)kV	890	1.00	890	0.0283	60
9		0			630	127/220(245)kV	890	1.00	890	0.0283	60
10		0			630	127/220(245)kV	890	1.00	890	0.0283	60
Total		459									

Figure 8-15: 4x50MW FPSO Soldiers Pond to West Orphan Basin cable design



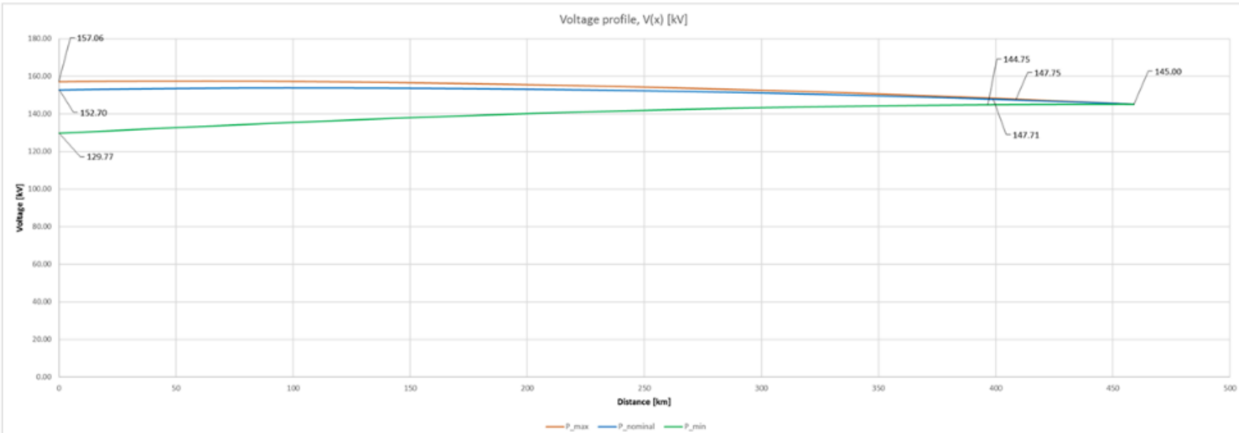


Figure 8-16: 4x50MW FPSO Soldiers Pond to West Orphan Basin simulation results

RESULTS

Location	Pr_peak						
	U [kV]	I_in[A]	P [MW]	Q	S	cos phi	P_loss [MW]
Onshore	157.06	941.0	222.61	-126.38	255.98	0.870	0.000
Cable segment 1	157.06	941.0	222.61	-126.38	255.98	0.870	0.218
Cable segment 2	157.19	927.3	222.39	-119.53	252.48	0.881	0.039
Cable segment 3	157.20	925.8	222.35	-118.77	252.08	0.882	0.443
Cable segment 4	157.30	914.7	221.91	-113.43	249.22	0.890	3.118
Cable segment 5	157.40	860.1	218.79	-84.32	234.48	0.933	14.926
Reactor	148.98	0.00	0.00	0.00	0.00	0.000	0.000
Cable segment 6	148.98	804.2	203.86	38.69	207.50	0.982	3.864
Cable segment 7	145.00	838.3	200.00	65.74	210.53	0.950	0.000
Cable segment 8	145.00	838.3	200.00	65.74	210.53	0.950	0.000
Cable segment 9	145.00	838.3	200.00	65.74	210.53	0.950	0.000
Cable segment 10	145.00	838.3	200.00	65.74	210.53	0.950	0.000
Offshore end	145.00	838.3	200.00	65.74	210.53	0.950	0.000
Total							22.608
Total efficiency [%]							89.84

Location	Pr_normal						
	U [kV]	I_in[A]	P	Q	S	cos phi	P_loss [MW]
Onshore	152.70	884.0	187.42	-139.79	233.81	0.802	0.000
Cable segment 1	152.70	884.0	187.42	-139.79	233.81	0.802	0.192
Cable segment 2	152.89	867.8	187.23	-133.26	229.81	0.815	0.034
Cable segment 3	152.90	866.0	187.19	-132.53	229.36	0.816	0.387
Cable segment 4	153.08	852.7	186.80	-127.38	226.10	0.826	2.655
Cable segment 5	153.78	784.9	184.15	-98.98	209.07	0.881	11.373
Reactor	148.31	0.00	0.00	0.00	0.00	0.000	0.000
Cable segment 6	148.31	680.7	172.78	26.85	174.85	0.988	2.776
Cable segment 7	145.00	712.5	170.00	55.88	178.95	0.950	0.000
Cable segment 8	145.00	712.5	170.00	55.88	178.95	0.950	0.000
Cable segment 9	145.00	712.5	170.00	55.88	178.95	0.950	0.000
Cable segment 10	145.00	712.5	170.00	55.88	178.95	0.950	0.000
Offshore end	145.00	712.5	170.00	55.88	178.95	0.950	0.000
Total							17.417
Total efficiency [%]							90.71

Location	Pr_min						
	U [kV]	I_in[A]	P	Q	S	cos phi	P_loss [MW]
Onshore	129.77	807.1	8.55	-181.21	181.41	0.047	0.000
Cable segment 1	129.77	807.1	8.55	-181.21	181.41	0.047	0.158
Cable segment 2	130.20	783.8	8.39	-176.55	176.75	0.047	0.028
Cable segment 3	130.26	781.1	8.36	-176.03	176.23	0.047	0.311
Cable segment 4	130.87	761.2	8.05	-172.36	172.55	0.047	1.977
Cable segment 5	134.59	648.6	6.08	-151.08	151.21	0.040	4.046
Reactor	144.63	0.00	0.00	0.00	0.00	0.000	0.000
Cable segment 6	144.63	128.3	2.03	-32.07	32.14	0.063	0.030
Cable segment 7	145.00	10.0	2.00	1.50	2.50	0.800	0.000
Cable segment 8	145.00	10.0	2.00	1.50	2.50	0.800	0.000
Cable segment 9	145.00	10.0	2.00	1.50	2.50	0.800	0.000
Cable segment 10	145.00	10.0	2.00	1.50	2.50	0.800	0.000
Offshore end	0.00	10.0	2.00	1.50	2.50	0.800	0.000
Total							6.551
Total efficiency [%]							23.39

Figure 8-17: 4x50MW FPSO Soldiers Pond to West Orphan Basin simulation results

8.3.4 Subsea Cable Design

The subsea cable represents the largest part of the project cost when considering power from shore transmission. For this reason, the cable has been divided into sections that are sized according to their purpose and can be spliced together in accordance with the cable capacity of cable laying vessels. By sizing the cable according to a current profile over the distance of transmission, the cost of the cable can be optimized. On shore, the cable is heavily de-rated due to the high current experienced close to the point of interconnection to the grid. As the cable transitions to subsea, its size is reduced but remains large enough to handle the current and the rigors of being installed in a typical shore crossing for transition to subsea if required. The cable size continues to reduce as it heads offshore, being trenched or buried as necessary for protection and stability, and then reduces to its minimum size for the bulk of the distance until it increases in size as it reaches the primary connection side of the subsea transformer. This cable tuning significantly reduces the amount of copper required for the transmission cable and minimizes losses.

8.3.5 Sample Distribution and Equipment Schematic

The following figures illustrate a potential design for power from shore that includes connections to the Island Link transmission system at Soldiers Pond, and would be similar to the Labrador South case. The schematic was completed for a load of 2x45MW FPSOs. It should also be noted that the simulated loads and voltages shown in the diagram are just a single possible design of many possible design configurations. Design voltages can be adjust within certain limits to allow for use of equipment that may be more qualified and proven in the real world. This flexibility helps reduce any technology gaps that may exist for transmission solutions in the two regions of focus.

<Diagram redacted from public study>

This design above was simulated and found to be stable for both Labrador South and West Orphan Basin scenarios for 2x45MW load and is provided as an illustrative example for possible transmission equipment and FPSO distribution and process equipment to take advantage of the LFAC power.

The presented design case is based on a connection to the grid at a strong AC connection point with voltages of 230kV at 60Hz for Soldiers pond, and is also suitable for connection to 315kV at 60Hz in Muskrat Falls. From there, transformers reduce the voltage to 11kV so that reasonably sized, cost effective converters can convert the 60Hz frequency to 20Hz. A second transformer steps the voltage up to between 132kV and 145kV for transmission offshore. Once transferred close to the FPSOs, a subsea transformer steps the voltage down to between 50kV and 66kV so that power can be transferred via a qualified swivel on the vessel. It should be noted that the transformer also acts as a distribution point so that multiple FPSOs can be powered independently.

8.3.6 FPSO Electrical Distribution and Equipment Considerations

Although not specifically in scope, we have reviewed a typical FPSO distribution system to confirm feasibility of the concept.

The distribution layout is designed to take advantage of equipment that can utilize 20Hz power. This eliminates the need for a complex set of converters on the FPSO to convert all of the incoming power to 60Hz. The power distribution graphic in section 8.3.5 outlines several different alternatives for large compressor drives that have high power consumption and also illustrates a distribution scheme for an 11kV(or 13.8kV) bus at 60Hz, and a 6.6kV bus at 20Hz. Each have options for equipment to utilize 60Hz and 20Hz power respectively. This allows for a lot of design and physical layout flexibility and minimizes equipment size, weight, and cost.

Based on the recommendation to utilize LFAC for transmission of power from shore to the FPSO, as presented in the power distribution graphic, the incoming power supply at the point of entry to the FPSO will be between 50kV and 66kV at 20Hz. There are multiple configurations possible for distributing power to the various power consumers from this point of entry.

The arrangement presented in the power distribution graphic consists of utilizing the incoming LFAC shore power supply to power a significant amount of the FPSO load without the need to first convert it to 60Hz AC, as would be required in the HVDC case. VFDs for larger motor loads such as gas compressors and water injection pumps can utilize the low frequency supply to drive the connected load. The largest of these motor loads can be configured to have a dedicated connection to the LFAC switchgear via an input transformer which is required to step the voltage level of the low frequency supply down to a level that can be utilized by the VFD. Other smaller, but still significant, VFD driven motor loads can be grouped on switchgear bus that are supplied from the LFAC shore power supply via power transformers operating at 20 Hz. As with the larger VFDs, the transformers are required to step the voltage level of the low frequency supply down to a level that can be utilized by the VFD. The example presented in the power distribution graphic shows a typical two bus configuration (Bus A and Bus B) with a number of low frequency input VFDs grouped together on each bus. In this case the transformers are sized based on all of the loads connected to the common bus. The balance of shore power capacity to the FPSO will be converted from LFAC to 60Hz AC using frequency converters equipped with input transformers to achieve the required voltage level. There are two converters presented in this example with each one rated for 25 MVA; however, the rating and number of converters may vary (e.g. a larger number of smaller rated units) depending on the specific design of the FPSO power system. This AC supply will be distributed to the various power consumers throughout the FPSO, including static loads and smaller low voltage motor loads, using standard AC power distribution equipment that is typical for any FPSO regardless of whether is receives power from shore or via onboard AC power generators.

There are a number of possible variations to the configuration shown in the power distribution graphic that will impact the amount of power that must be converted from LFAC to AC. The arrangement selected for a given FPSO may be influence by process design requirements, CAPEX budget, space constraints, Operator preference, etc., and will be determined during the engineering phase for the given facility. These variations in system configuration will not have any impact on the shore power supply up to and including the point of entry to the FPSO.

One potential variation to the configuration presented in the power distribution graphic will be to only power the largest of the VFD driven motor loads directly from the LFAC switchgear (i.e. gas compressors in the example presented), with all remaining loads being supplied from the AC power distribution. This arrangement will require a larger amount of power to be converted from LFAC to AC using frequency converters, which will increase the number of frequency converters required and / or increase the rating of the converters. Another possible variation consists of having frequency converters that convert the full capacity of the shore power supply to the FPSO from LFAC to AC prior to distributing to the various power consumers and does not utilize LFAC input VFDs to drive large process loads. Under this arrangement, all power consumers, including the largest VFD driven motor loads, will receive their power from the AC supply via power distribution equipment that is rated for the nominal frequency of the AC power system. This will either require a larger number of frequency converters operating in parallel or frequency converters that have a higher power rating than what is presented in the example in the power distribution graphic since no power consumers will derive any power directly from the incoming LFAC supply. It is recommended that more, smaller, converters operating in parallel be considered due to limitations on equipment layout and mechanical handling.

It is assumed that all large motor driven process loads will be driven from VFDs, regardless of whether these VFDs are powered from a LFAC or AC supply, since this will allow for better control over varying process conditions. This is now typical for most new build FPSOs. Since the rating of these VFDs will be determined by the connected motor / motor load, their physical size and cost should be reasonably comparable regardless of whether they utilize a LFAC supply or an AC supply. Similarly, the switchgear requirements to supply these VFDs will occupy a similar amount of space regardless of the input frequency, however, the input transformers will be physically larger at lower power frequency for the same power rating. Therefore, the advantage of the first option presented is that it requires less power to be converted from 20Hz LFAC to 60Hz AC, prior to being distributed to the various power consumers (e.g. static and low voltage motor loads), since some of the largest power consumers on a typical FPSO will be powered directly from the LFAC switchgear. This will result in smaller frequency converters required to convert from LFAC to AC, which makes it the recommended arrangement to implement.

Further, several smaller dual fuel source engines are connected to provide backup power that can feed back through each level of the distribution design to power essential equipment required by SOLAS and even support production if required. Several of these smaller engines could take the place of larger gas turbine generators and allow for finer control over the amount of power that is generated when in a disconnected state. This gives the operator more control over the environmental impact when compared to having to start multiple large turbine generators when the capacity of just over one generator may be required. Further, the several smaller dual fuel engines will typically have lower emissions than a gas turbine generator when sized to handle the same load.

8.3.7 LFAC Transmission Losses

The analysis shows that losses in the transmission system, from point of connection at the grid, to connection at the FPSO are approximately 10-11% for LFAC scenarios. This is in line with other AC subsea power projects when looking at power loss per KM of transmission. This is also in line with HVDC losses of 13% for the same length of transmission.

8.3.8 LFAC Reliability

Anecdotally, and excluding any availability constraints imposed by the electrical grid, LFAC can be designed to offer 99.9% uptime and no requirement for complete shutdown during maintenance, by utilizing a redundant design methodology. As an example, use of parallel static frequency converters and associated transformers allows for taking down part of the system for maintenance while still allowing power to be transmitted offshore. This is in contrast to an HVDC system that typically does not have redundancy and requires shut down for maintenance for one to two days per year.

8.4 Equipment Assessment

The equipment presented in the following sections covers a wide range of power, voltage, and frequency ranges. This is provided for a sake of completeness in order to understand the state of technology in the industry. Also, in a number of cases equipment in the range of 52kV is often more qualified or in use than equipment in the 66kV and higher range. For this reason the power transmission voltage between the transformer secondary and the electric swivel could better be set to 52kV as there are more products that are qualified and proven by use in the field.

8.4.1 Dynamic Cables

A requirement for both geostationary and ship-shaped FPSO is dynamic cables that can withstand the pressure, stress, and strain caused by ocean currents and floating vessel movement. The dynamic cable travels from subsea equipment installed on the ocean floor up to a floating vessel. A well designed dynamic cable provides stable power transmission and will mitigate the effects of wear and tear it will experience.

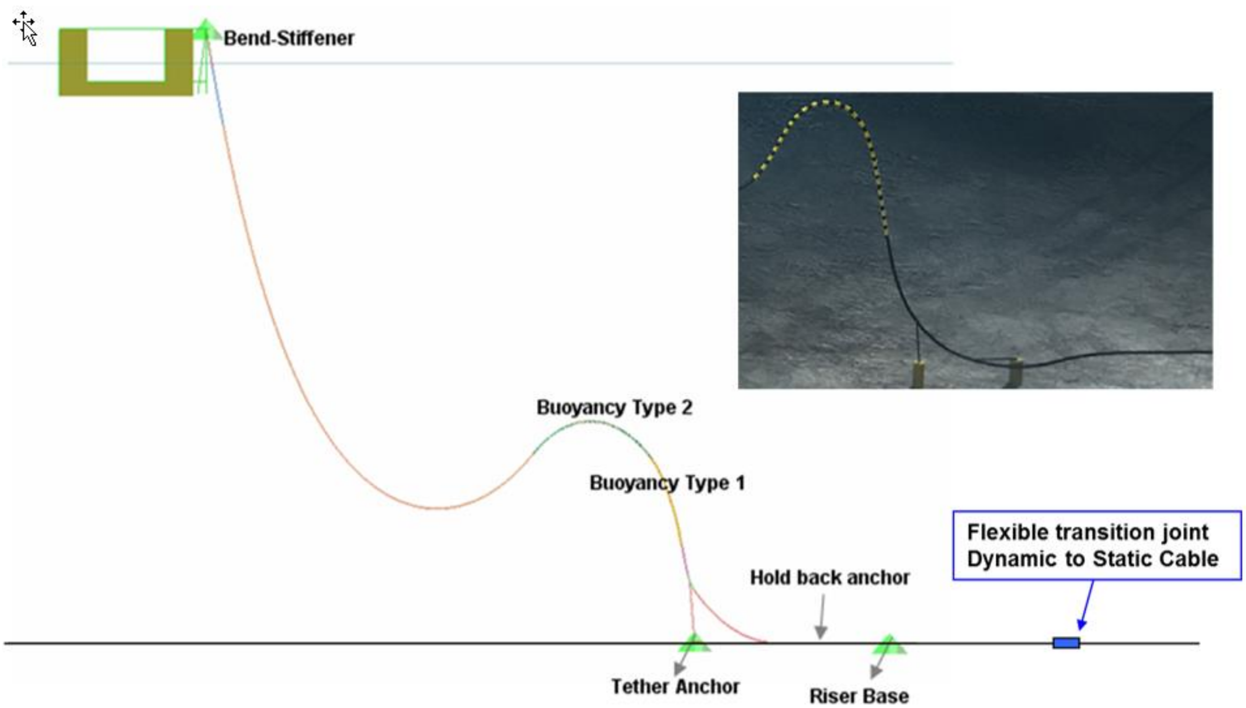


Figure 8-18: Typical dynamic subsea cable or umbilical riser configuration

There are qualified dynamic power cables available in the market, however dynamic properties must be evaluated against the movements of the floater and water depth. Dynamic AC cables up to 123kV are qualified and in operation for Gjøa and Goliat and are showing no issues.

Several suppliers are in the process of qualifying dynamic AC cables. The recommended solution is to put a subsea transformer station on the seabed and use wet design cables from the seabed up to the FPSO. There are several vendors with qualified wet design cables and the dynamic properties for the cables are very good. In the case of Goliat, a 123kV, 1.5km dynamic cable is installed and in use, and several vendors such as NKT, ABB, and Aker solutions have dynamic cables that are in service up to depths of 2500m. It should be noted that there are currently no qualified dynamic HVDC cables at this time, and any dynamic HVDC cables would have to go through a qualification program to ensure they are acceptable for use in these conditions. This adds extra cost and time and complexity to projects, and there is still a risk that the cables will not qualify.

8.4.2 Subsea Transformer Station

The long cable transmission required for AC voltage for our regions of interest indicates that it needs to be in the range of 132kV-145kV, nominally. Because of this, a subsea transformer is required to reduce the voltage that will be transmitted through the swivel located on a ship-shaped FPSO and act as a connection point for multiple dynamic cables that will reach from the seabed to each FPSO.

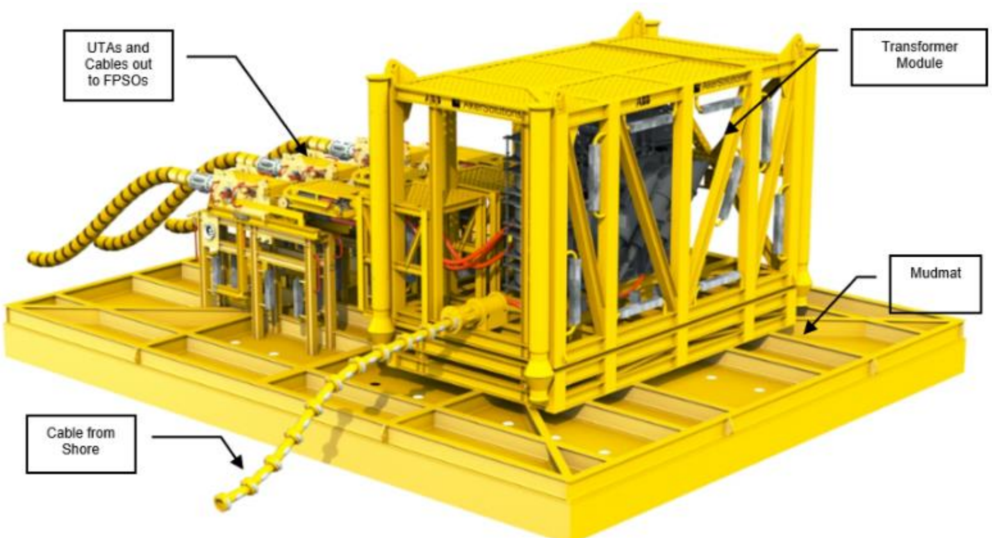


Figure 8-19: Typical Subsea Transformer Station Layout

This section describes the Subsea Transformer Station for two FPSOs, and covers the solution needed for both the West Orphan Basin (basis for sizing in this section) the Labrador South (slightly lower reactive power flow than Project 1, due to midpoint reactor), and the 4x50MW FPSO case for the West Orphan Basin.

This subsea transformer station has an incoming 132kV-145kV cable from shore, and one output feeder of 45kV (this voltage may be too low, but would be needed for wet mate connection) or 66kV (voltage can be increased if the same dry termination as on the primary side is used) to a dynamic power cable to each FPSO. A wet mate connection can be made subsea, and a dry mate connection must be made above sea and then the equipment and cable must be lowered down together. Dry mate connections increase complexity. Further, if the weight of these transformer stations are an issue, the design can utilize more, smaller transformer units to achieve the same purpose.

It should be noted that there are no HVDC subsea transformers, and any HVDC equipment on the offshore side would have to be located on the FPSO, or a separate floating platform. Also, subsea transformers can be designed for operational life of 30 or 50 years if required.

8.4.2.1 Subsea Transformer Unit and Module

The proposed subsea step-down transformer module is based on subsea transformer units from ABB. The core is located inside an oil-filled tank with two barriers to sea, and designed with pressure compensators for the actual sea depth. The transformer unit is integrated and marinized into Aker Solutions subsea module structure design with HV connections, mating mechanisms, control pods and other key functions.

These subsea transformers have been widely used in the Oil & Gas industry for subsea production, boosting and compression projects, and are qualified with a TRL of 7. ABB has around 40 subsea transformer references, with the first unit installed in 1998, and operational experience has demonstrated flawless operation over the last 22 years.

Aker Solutions have been working together with ABB on subsea transformer solutions in projects such as Equinor Tyrihans (3x 4.5 MVA), Shell Ormen Lange Compression Pilot (20 MVA, 16 MVA and 500 kVA) and the Equinor Åsgard Subsea Compression System (3x 100 kVA, 3x 1.5 MVA and 3x 19 MVA), and a total of 17 of these ABB references are based on Aker Solutions subsea module designs. In a recent detailed FEED on subsea compression, a 105 MVA 132/33 kV subsea transformer has been designed, including qualification program for HV connections (to be completed by end of 2020), which has a rating in the same range as needed in this study.

This Subsea Transformer technology is currently designed up to 210 MVA and qualified down to 3000 m water depth.

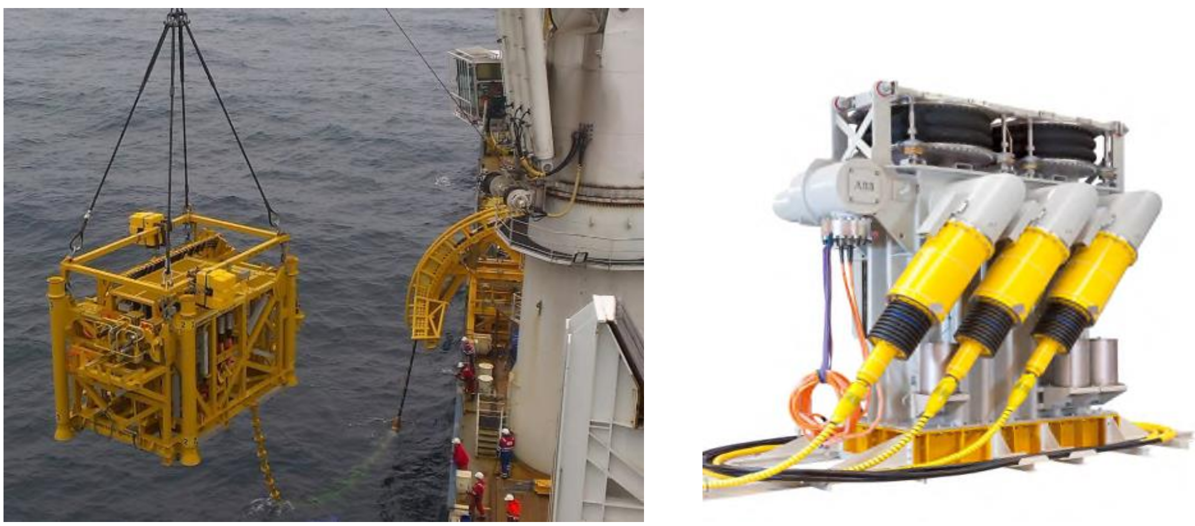


Figure 8-20: 19 MVA Aker Solutions Åsgard subsea compressor transformer module (left) and ABB subsea transformer unit (left) The Mecon 145kV Dry Mate connection is shown with yellow paint.

Low frequency AC transformers are widely used in European railway systems, where 16.7Hz is common in some countries, including Norway. Subsea design principles and material selection is the same as for 50/60Hz transformers.

Operating the subsea transformer at 20 Hz mainly means that the core will have to increase by a factor of 2.5 compared to a 50 Hz design, which together with increased diameter for the windings implies higher weight. At present a 3-phase 50/60 Hz subsea transformer design is considered to be feasible up to 300 MVA (above this level, it might be more practicable (due to weight) with 3x single phase transformers or two 3-phase transformers in parallel).

For this project, with a 3-winding subsea 20 Hz transformer having power flow of 110 MVA for 2 off 45 MW FPSOs (similar total MVA rating as the above mentioned recent detailed FEED study transformer), a 2.5x larger core would correspond to a 50 Hz subsea transformer core of 275 MVA. In other words, a single transformer is proposed for this project, and splitting it in two is not necessary unless the two FPSOs are very long apart.

8.4.2.2 Primary Side Subsea Connection System – Dry Termination

Today the leading commercially available high voltage Mecon dry-mate connector from Baker Hughes (BH) is capable of handling operating line-to-line voltages of up to 132 kV, with an insulation rating of 76/132(145) kV and current rating of 700 A at 200 Hz. This means it will be able to carry more than 1000 A at 20 Hz, which corresponds to minimum 228 MVA (@ 132 kV). The Mecon 145 Dry Mate (DM) connector is currently qualified for water depths down to 1100 m (TRL 7), but an updated design is currently undergoing qualification for water depth of 1500 m.

Operation at 20Hz instead of 50/60Hz gives less skin effect / heating and means lower temperature in the connector. This also applies to the secondary side connectors. The skin effect causes equipment to heat up.

Figure 8-21: Baker Hughes MECON DM 145/700 (Courtesy of Baker Hughes)

It is assumed that the existing connector is capable of higher voltage ratings, as it is recognized that products developed for the oil and gas industry include contingency and margin exceeding the requirements given by international standards. Validation could be confirmed through a connector study including necessary electrical analysis as well as initial tests, subject to availability of test object.

Since this represents a dry connection between the main cable from shore and subsea transformer, the installation sequence would normally require the subsea transformer to be the vessel's first installation end. Installations of laying towards shore need to be evaluated as part of any future study.

8.4.2.3 Secondary Side Subsea Connection System – Wet Mate Connectors

Depending on selected operational voltage level there are several wet mate connection solutions that can be used:

- SIEMENS Spectron 45	26/45(52) kV	1250 A	TRL 4
- TE Deutsch	18/30(36) kV	400 A	TRL 7
- Benestad	18/30(36) kV	2000 A	TRL 3 (under development)

Some of these solutions may be possible to stretch to 72 kV (66kV operational voltage) by design updates and re-qualification.

8.4.2.3.1 Benestad 36kV Wet Mate Connector

Figure 8-22: Benestad Power Wet Mate Connector 36 kV / 1300A

Benestad are currently qualifying a wet mate connector for 18/30(36) kV and 1300 A (extendable by a 2000 A design). The ongoing qualification program has the aim of reaching TRL 4 during Q4 2021 (as of today TRL level 3 is achieved). It is expected that this product portfolio will be commercially available within 2 years.

8.4.2.3.2 SIEMENS Spectron 45 Wet Mate Connector

For voltages up to 45 kV, the newly qualified Siemens SpecTRON 45 single phase wet-mate connection system with rating of 26/45(52) kV and 1250 A can be used. Technology readiness for this connection system is currently TRL 4. It has been qualified to interface towards subsea transformers and submarine cables.

Figure 8-23: Siemens SpecTRON 45 with cable gland (top), male connector (lower left) and female connector (courtesy of Siemens Energy)

Since U_m (maximum value of the highest system voltage) for this connection system is 52 kV, it is possible to select operational voltage of up to around 48 kV.

8.4.2.3.3 TE Deutsch 36kV Wet Mate Connector

The Tyco Electronics (TE) Deutsch P18-SW900 wet-mate connection system is currently qualified at TRL 5 with voltage / current rating of 18/30(36) kV and 900 A (TRL 5 in the Ormen Lange Pilot Project, 2015). Rated water depth is 2000 m and 25 years design life. The P18 can also be supplied with a 400 A version that is TRL 7. This will require two times more connections and dynamic power cables to FPSO in parallel.

Figure 8-24: TE Deutsch P18-SW400 (Courtesy of TE)

8.4.2.4 Recommended Transformer Station - 2 off 45MW FPSOs

The table below summarizes the recommended solution for the case with two 45MW FPSOs, based on today's technology status:

Component	Supplier / Type	Rating	Project rating needed (2x 45MW)	TRL	Comment
Subsea transformer	ABB	120 MVA 132/66 kV or 132/45kV	110 MVA 132/66kV or 132/45kV	7	Aker Solutions Module design
Primary side connection system	Baker Hughes Mecon 145/700	72/123(145) kV 1000 A @ 20Hz	132 kV 479 A	4	TRL 7 for 1100m design, being updated for 1500m by Q4 2020
Secondary side connection system	Siemens Spectron 45	26/45(52) kV 1250 A	132 kV 497 A @ 66kV 728 A @ 45kV	4	Aker Solutions Mating Mechanism

Table 8-6: Recommended equipment selection based on highest TRL – 2x 45MW FPSOs

120 MVA 20 Hz Subsea Transformer Module data:

- Module weight: approx. 400-450 metric tonnes
- Module size (LxWxH): approx. 12 x 6 x 7 m

This size/weight is within the envelope of what was the largest modules in the Åsgard Subsea Compression project, and there are various vessels capable of installing this module size.

The transformer module will sit on a mud mat, and the dynamic power cables to FPSOs will have UTAs (umbilical termination assemblies) for tie-in and mating to the transformer.

The figure below shows a typical seabed rendering of this Transformer Station.

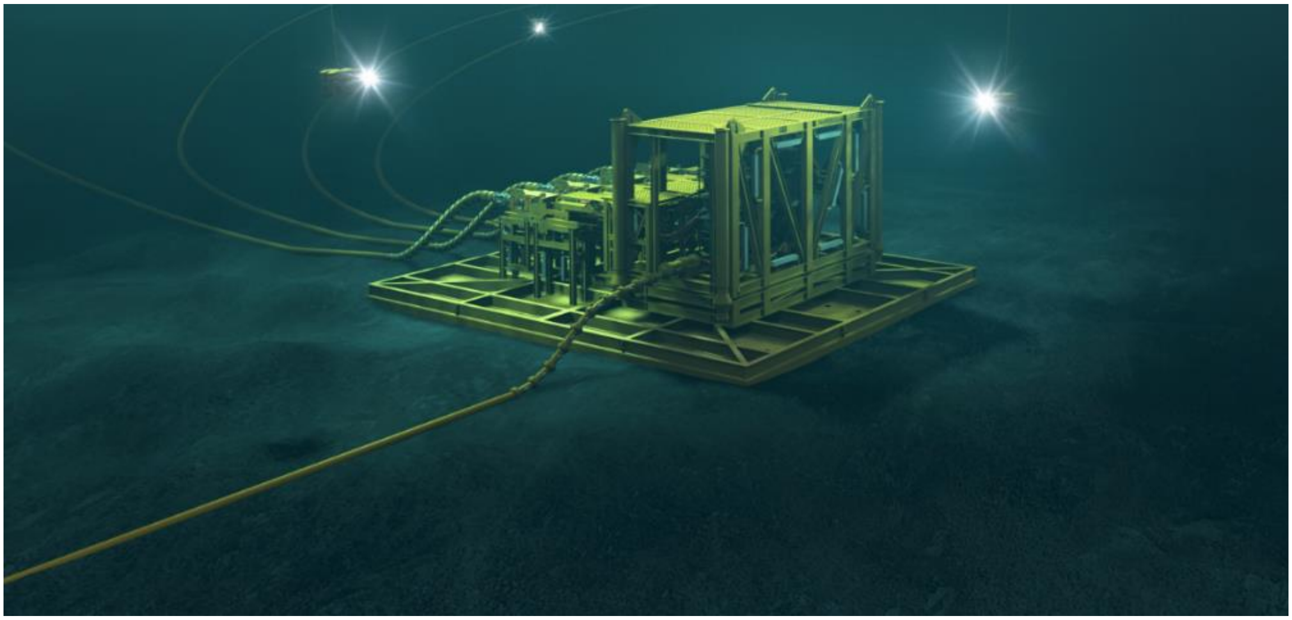


Figure 8-25: Subsea Transformer Station with incoming cable from shore (front) and outgoing cables to FPSOs (back). Here shown with 4 output cables, two to each FPSO

Conclusion

The main conclusion is that this Subsea Transformer Station for 2x 45 MW FPSOs is feasible for 1500 m water depth, and can be based on components with TRL between 4 and 7 (API 17N).

Having this station on the seabed saves weight and space on the FPSO, and allows for using available swivel technology.

8.4.2.5 Recommended Transformer Station - 2 off 65MW FPSOs

A sensitivity case with 20 MW higher power demand at each FPSO, leading to a total power need of 2x 65 MW, has also been studied.

In this case the equipment selection table will look like the following, based on today's technology status:

Component	Supplier / Type	Rating	Project rating needed (2x 65MW)	TRL	Comment
Subsea transformer	ABB	160 MVA 132/66 kV or 132/45kV	146 MVA 132/66kV or 132/45kV	7	Aker Solutions Module design
Primary side connection system	Baker Hughes Mecon 145/700	72/123(145) kV 1000 A @ 20Hz	132 kV 640 A	4	TRL 7 for 1100m design, being updated for 1500m by Q4 2020
Secondary side connection system	Siemens Spectron 45	26/45(52) kV 1250 A	132 kV 640 A @ 66kV 939 A @ 45kV	4	Aker Solutions Mating Mechanism

Table 8-26: Recommended equipment selection based on highest TRL – 2x 65MW FPSOs

160 MVA 20 Hz Subsea Transformer Module data:

- Module weight: approx. 450-500 metric tonnes
- Module size (LxWxH): approx. 14 x 6 x 7 m

Conclusion

The main conclusion is that this Subsea Transformer Station for 2x 65 MW FPSOs is also feasible for 1500 m water depth, and can be based on components with TRL between 4 and 7 (API 17N) and anticipated to be at TRL6-7 within the next 2 years.

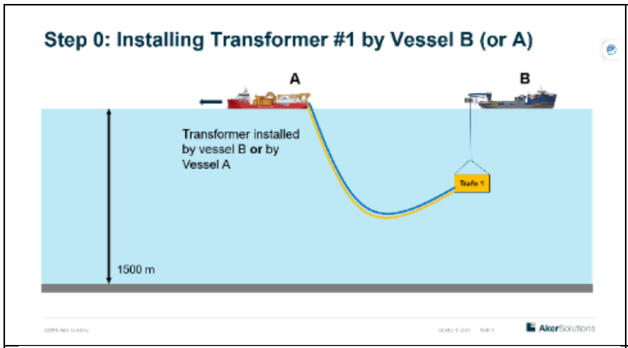
The additional power demand in this sensitivity scenario increases the weight to a level close to the limit for the most relevant installation vessel class, and is something that should be evaluated further in a more detailed phase.

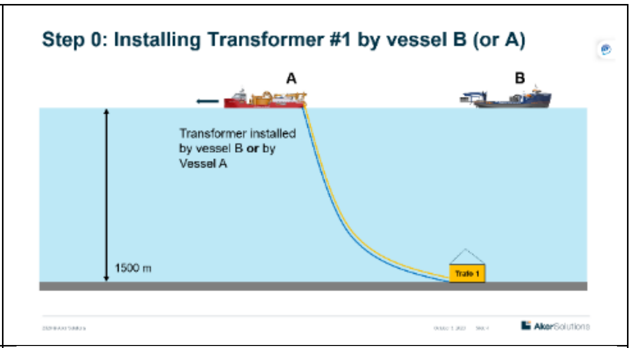
This power level pushes the transformer to its installation weight limit and splitting it in two modules is a fallback option. Having two subsea transformers is also a relevant option if the subsea FPSOs are far apart.

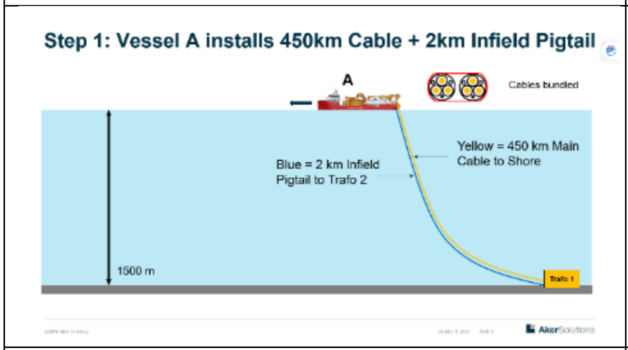
This will however increase installation complexity with the pre-terminated output cable pigtail which needs to be lowered together with the main cable from shore, after landing the first FPSO transformer. Then the pigtail to the next transformer needs to be picked up to surface and spliced with the pre-installed 145 kV cable going to the far end FPSO.

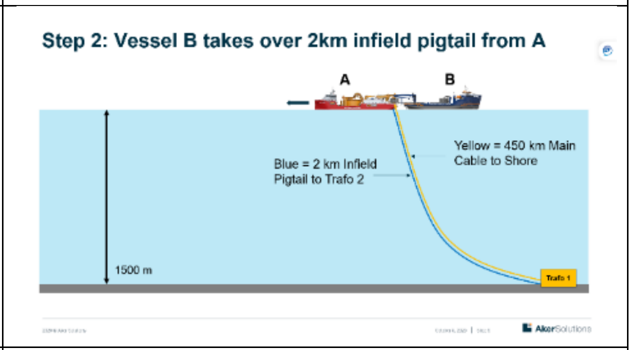
8.4.2.6 Installation Considerations

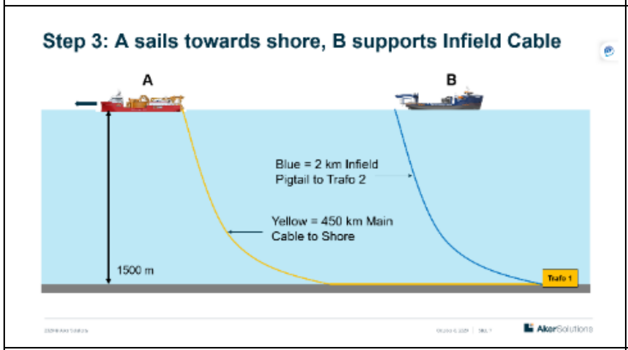
An outline installation sequence / procedure is shown below. First the subsea transformers are installed (Step 0), and then the submarine cable from shore as well as infield power cable pigtails are spliced and installed.

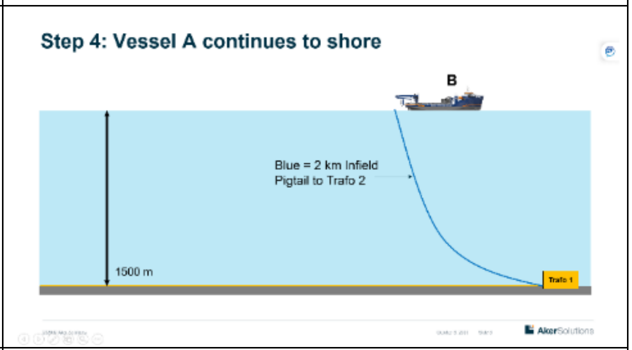

Step 0: Installing Transformer #1 by Vessel B (or A)
A
B
Transformer installed by vessel B or by Vessel A
Trafo 1
1500 m
AkerSolutions

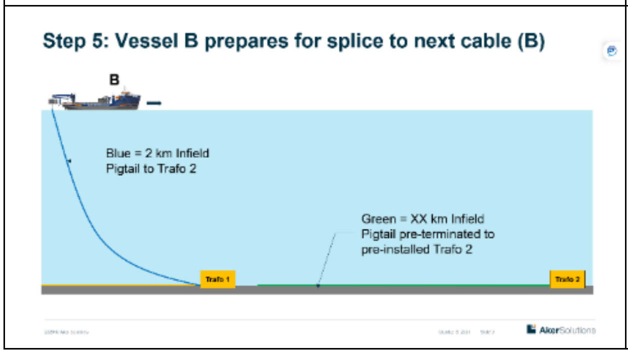

Step 0: Installing Transformer #1 by vessel B (or A)
A
B
Transformer installed by vessel B or by Vessel A
Trafo 1
1500 m
AkerSolutions

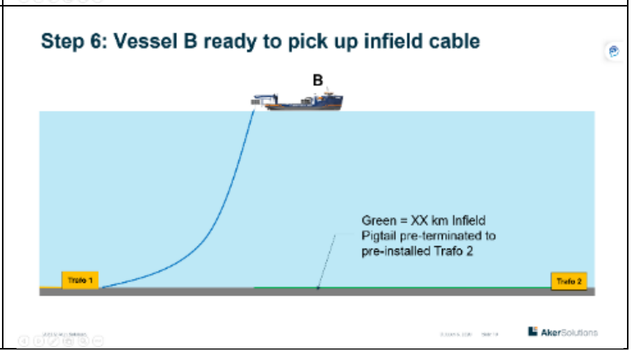

Step 1: Vessel A installs 450km Cable + 2km Infield Pigtail
A
Cables bundled
Yellow = 450 km Main Cable to Shore
Blue = 2 km Infield Pigtail to Trafo 2
1500 m
Trafo 1
AkerSolutions


Step 2: Vessel B takes over 2km infield pigtail from A
A
B
Yellow = 450 km Main Cable to Shore
Blue = 2 km Infield Pigtail to Trafo 2
1500 m
Trafo 1
AkerSolutions


Step 3: A sails towards shore, B supports Infield Cable
A
B
Blue = 2 km Infield Pigtail to Trafo 2
Yellow = 450 km Main Cable to Shore
1500 m
Trafo 1
AkerSolutions


Step 4: Vessel A continues to shore
B
Blue = 2 km Infield Pigtail to Trafo 2
1500 m
Trafo 1
AkerSolutions


Step 5: Vessel B prepares for splice to next cable (B)
B
Blue = 2 km Infield Pigtail to Trafo 2
Green = XX km Infield Pigtail pre-terminated to pre-installed Trafo 2
Trafo 1
Trafo 2
AkerSolutions


Step 6: Vessel B ready to pick up infield cable
B
Green = XX km Infield Pigtail pre-terminated to pre-installed Trafo 2
Trafo 1
Trafo 2
AkerSolutions

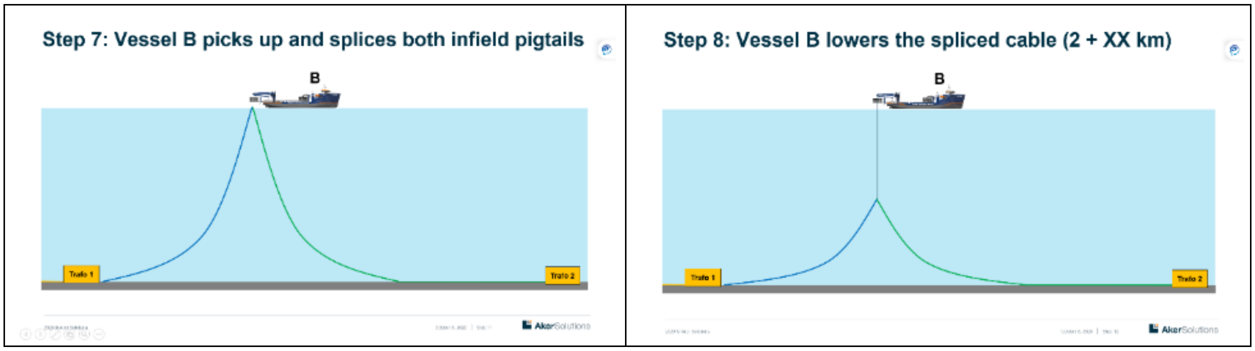


Figure 8-27: Outline installation sequence / procedures for two subsea transformers and splicing of infield power cable

8.4.2.7 Recommended Transformer Station - 4 off 50MW FPSOs

As described in section 8.3.3.2, an additional sensitivity case with 4x 50 MW for 4 FPSOs in the same area, connected to the single cable from shore, has also been considered. Figure 8-13 shows the system topology, and a key feature in this architecture is that the first subsea transformer primary side bus-work has input of the total 200 MW power, but utilizes a split the primary 145 kV side, allowing 100 MW to be routed to the far end second subsea transformer.

Both 120 MVA transformers will have an identical design, except that Subsea Transformer 2 will not have the split at the input side. This ensures standardisation and possibilities for using an identical spare transformer.

Each of these two transformer stations will be similar to the ones described previously, for 2x 45 MW and 2x 65 MW, only with slightly different dimensions and weight.

8.4.3 Swivels

For a ship shaped FPSO, it is necessary to have an electrical swivel for connecting the subsea power from shore cable. It should be noted that there are no HVDC swivels that are currently qualified for the scenarios of focus. HVDC swivels from Focal and SBM are currently identified as TRL 3. Also, swivels at lower voltage ratings are more qualified and tested than those with higher voltages. For this reason it is recommended that a subsea transformer be installed to reduce the voltage requirements of the swivel. The information below is based on a general request for turret information from manufacturer SBM. It indicates which swivels are at TRL 7 which indicates the equipment is integrated into intended operating system and has operated with acceptable performance and reliability within a pre-defined criteria. This definition is based on the Technology Readiness Levels in Oil and Gas Industry found in API 17N.

For a LFAC scenario, the recommended swivel would be the 25Hz 26/45(52)kV swivel from SBM that is at TRL 7 and has been use on the Asgard-A FPSO and is suitable for 20Hz application. This would require reducing the voltage on the secondary side of the subsea transformer to 52kV, but that is well within the parameters of the design. If a higher voltage would be necessary, then there are swivels at TRL4 that can accommodate higher voltages.

The following pictures show examples of electrical swivels delivered by Focal to a few different offshore installations where a position-anchored production ship with geostationary swivel towers has been selected as part of a field development solution and strategy.

Figure 8-28: OSX-3 MVES, Exp, IP66, 18 × 11kV @ 650A plus 6 × 6.6kV @ 600A, approximately 5m tall - Focal

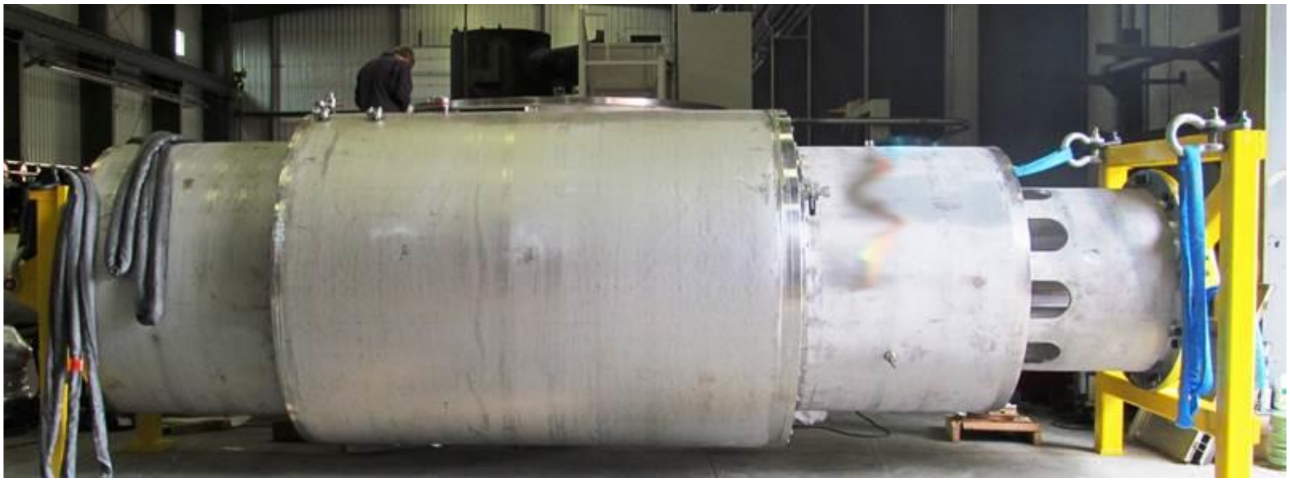


Figure -: BZ-25 MVES – Ex o, IP66, 9 × 35kV @ 400A sliprings, approximately 8.5m tall – Focal

Figure 8-29: N_2 insulated 36/60(72.5)kV Swivel concept, 3 × 72.5kV @ 1440A, approximately 3m tall – Focal

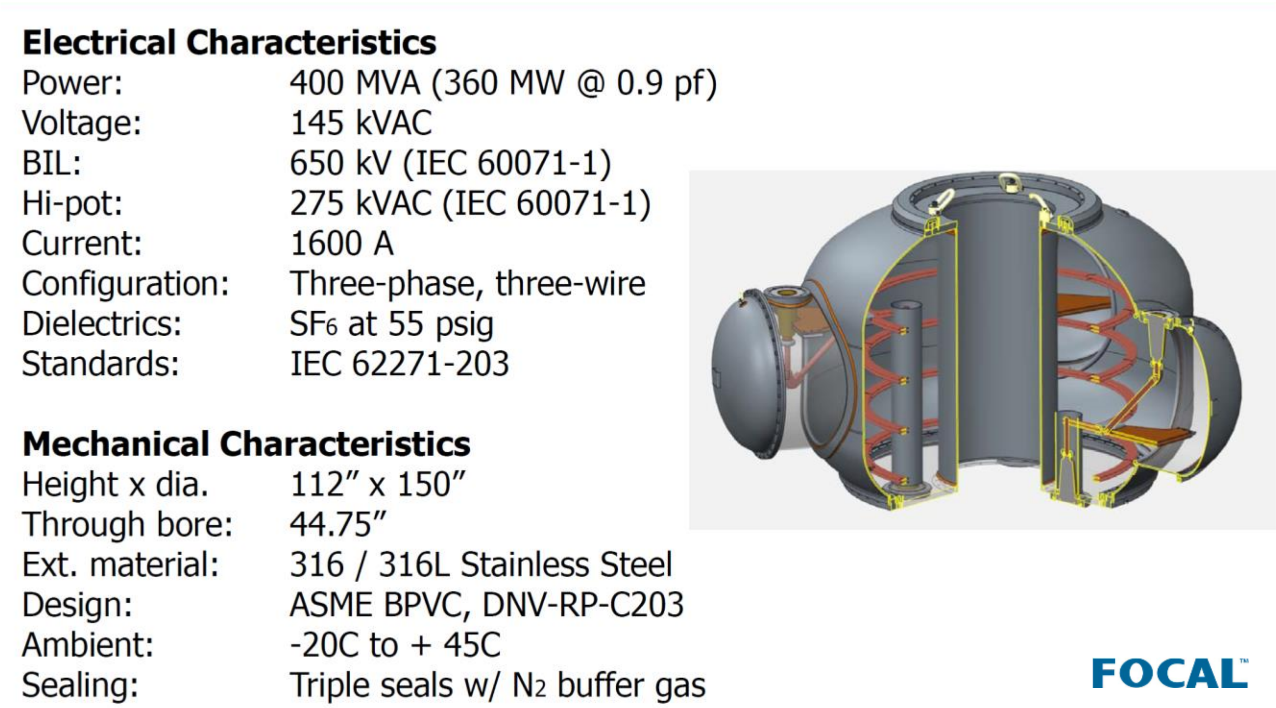


Figure 8-30: SF_6 insulated 76/132(145)kV swivel concept, 3 × 145kV @ 1600A, approx. 3m tall

The following table summarizes the technology status for both AC and DC power transmissions options to position-anchored production ships with geostationary swivel towers, design adaptation that allows them to comply with weather and wind changes.

AC – Options	Advantages	Cons
30 kV Power import from 18/30(36) kV sliprings	• Qualified technology. • Fully feasible with dry insulated transformers • 33kV distribution suitable to supply larger consumers directly • Most likely cost effective competitive up to 50 km and about 20 MW	• Relatively high transfer losses for typical effects and distances • Higher OPEX • Cable cross-sections are likely to occupy more turret slots • Good voltage stability may require some local power generation or STATCOM functions.
Up to 132 kV power transmission through subsea transformer(s) and 30 kV or 45kV swivel. (technology will probably shortly	• The technology is qualified • 76/132(145kV) insulation level provides relatively low transmission loss for typical power demand vs. distance • Opportunities for subsea 18/30(36) kV power distribution: Synergies. • Better voltage stability on the "33kV" level	• Higher CAPEX • Selected technology may later be abandoned in favour of other technologies. • No available turret slots for non-electrical use. • Reliability of Subsea equipment.

be available for 60kV swivels) 	• "18/30(36)kV" distribution suitable for direct supply of larger consumers • Fully feasible with 33 kV "dry" topside transformers. • 45+kV solutions available for cases with high power demands from the offshore Wind development	
Up to 132 kV power import via turret transformer and a 30 kV or 45kV swivel. (technology will probably shortly be available for 60kV swivels)	• 76/132(145kV) insulation level provides relatively low transmission loss for normal power demand versus distance. • Technology is qualified • It is possible to have turret slots available for non-electrical use. • Better voltage stability on the "33kV" level • 45kV+ solutions available for case with high power demands	• Space availability at Turret • Layout of the Turret will be challenging • Possible Ex-requirement on the Turret. • Material handling in the turret areas can be demanding. • Oil-filled transformers on turret versus possible Ex requirements.
60 to132 kV power import directly via swivel slip rings 	• Available technology • "Acceptable" lead time • 76/132(145kV) insulation level provides relatively low transmission loss for normal power demand versus distance. • OK for 25Hz, 50Hz and 60Hz transmission • Two swivel suppliers have indicated technology availability with some prerequisites: • Focal™ : 365MVA @ 132kV • SBM™ : 365MVA @ 132kV • Possible 60 or 132 kV distribution Topside equivalent to Gjøa, Goliat, Martin Linge, and more. • Turret slots available for non-electrical use	• Some technology qualification to be completed (low risk) • Oil-filled transformers Topside(but are considered acceptable) • Mechanical tolerances versus turret movements and possible risk of minor SF6 gas leaks. • Risks associated with a 132kV oil-filled electric swivel far down in the turret are evaluated to be acceptable. • Prototypes to be built.

DC – Options	**Advantages**	**Cons**
Electric power import via +/- 45 kV DC slip rings	• Available technology. • Enables energy transfer over long distances • No dependency between feeding and receiving end frequency • Good AC voltage stability with local STATCOM functions • Manageable re-start procedure and requirements for operation of support systems before restart	• Relatively significant transmission losses for typical power demands and distances • Higher CAPEX and OPEX • Risk of HVDC earth leakage • Equipment will require significant area and weight offshore • Dynamic DC cables for the applicable water depths are not qualified • Sea cable cross-sections can occupy several turret sloths

Electric power import via +/- 80 kV DC slip rings	• Assumed some available technology. • Voltage and insulation level provide relatively low transmission loss for normal power demand versus distance • Good AC voltage stability with local STATCOM functions • Experience transfer from projects with 76/132(145V) swivels • 2 swivel suppliers have indicated the need for technology development with several prerequisites	• High CAPEX • Equipment will require significant area and weight offshore • Selected technology may later be abandoned in favour of other technologies • Dynamic DC cables for the applicable water depths are not qualified • Risk of HVDC earth leakage • Reliability of subsea equipment • Will requires relatively many and power demanding support systems in operation to be able to re-start after shutdown of the HVDC Link
Electric power import via 0/- 150 kV DC slip rings	• Assumed that some technology are available.	• Very few tests carried out in connection with turrets • Risk of HVDC earth leakage
Electric power import via +/- 150 kV DC slip rings	• Assumed that very little technology are available.	• Very few tests carried out in connection with turrets • Setup more suitable for power levels higher that what is typical for the oil and gas installations.

Table 8-7: Overview of current solutions for transferring power to/from permanently anchored production vessels

It will take some time before technology will allow an FPSO to receive HVDC power transmission from shore, however in time, the necessary dynamic cables and swivels for HVDC transfer through a swivel will be developed, tested, and qualified for use.

8.4.4 Power Transmission Cables

Cables for each option studied consist of a terrestrial cable, a subsea static cable that lays on the seabed and a dynamic riser cable that reaches from the seabed to the FPSO. In the case of a ship-shaped FPSO the dynamic cable would connect to a turret, and for a geostationary FPSO it would just be a fixed connection inside the vessel.

HVAC and HVDC cables have different design properties. HVDC cables can be designed based on current capacity and loss requirement, however HVAC cable design is more involved and must be designed based on an iterative process that changes voltage, cable cross sectional area, and insulation based on distance and power loss requirements. Further, tuning an HVAC cable helps optimize the cable size and reduces overall cost of the cable required. While this study has provided some details on the cable design, a more in-depth study would be required to fully design and specify a required cable.

Both HVDC and HVAC cables can be designed and supplied for these applications by vendors such as Prysmian, Nexans, NKT, and Aker solutions. Aker Solutions also has dynamic cables that are qualified for installation at depth of 3000m and currently installed at a depth of 2500m at the Cascade Chinook site in the Gulf of Mexico.

The terrestrial cables required for this project would be typical cables suitable for burial or aerial transmission depending on the site. At the Labrador site it should be noted that the terrestrial portion of cable could be run as aerial transmission, or also run subsea under Lake Melville. This would require further study, as there may be difficulties for cable laying vessels to operate in the Lake.

For some of the static cable designs used for power from shore there are limits for hydrostatic pressure and tension during installation that has to be focused on for the specific water depths. It may limit the number of potential vendors or require further qualification from some of the vendors.

8.4.5 Switchgear

Suitable switchgear will be required at the supply end (shore based) for protection and isolation of the transmission system and subsea equipment offshore. This switchgear must be rated based on the LFAC transmission voltage and the power rating of the shore power supply. One option for this equipment is the Siemens 8DN8 series, which has available ratings up to 170kV, 4000 Amps.

A preliminary review by Aker Solutions has also determined that ABB offers an ELK series of switchgear that also has available ratings up to 170kV, 4000 Amps. A query has also been sent to GE in order to find alternative equipment, but we have not received a response at the time of completing this study.

Switchgear required at the point of entry to the FPSO and all downstream switchgear for power distribution throughout the FPSO is standard product offering by multiple equipment manufacturers, including Siemens, ABB and GE. This includes the switchgear rated up to 66kV for the incoming LFAC shore power connection and subsequent distribution and for AC distribution.

8.4.6 Converters

Frequency converters are required to convert 60Hz AC grid power to 20Hz LFAC power for transmission offshore and then also required to convert 20Hz LFAC to 60Hz AC for distribution to the various AC power consumers on the FPSO. The number, configuration, rating and size of the converters required will be dependent on the specific power system design and AC power needs for a given FPSO. There are multiple possible configurations for these converters as discussed in Section 8.2.2.6, with the selected option determining the power rating requirements of the converters.

There are qualified frequency converters available in the market. For example, the Siemens SINAMICS line of products contains the SH150 model of frequency converter that has a power rating up to 24MVA at 11kV and offers the option for an AFE that will provide better voltage control and produce a better quality (cleaner) AC output. Other manufacturers, including GE and ABB, have similar converter technology available in various ratings that will be suitable for this application. All product lines currently available will require an input transformer at the FPSO to step the LFAC AC shore power supply down to an input voltage that can be utilized by the converter. Each converter will typically require a dedicated input transformer, but it is possible to supply two converters from a single multi-winding transformer (e.g. supply two converters from a single 3-winding transformer).

8.4.7 Drives

One potential benefit of using LFAC is that large VFD driven motors may be connected directly to the shore power supply bus which reduces the power rating and size of the frequency converters required to condition the balance of shore power from LFAC to AC to power remaining AC loads. The rating of the VFD will be dependent on the specific power demand for the driven motor load which will be reflected in the power system design for a given FPSO.

There are qualified VFDs available in the market. For example, the Siemens SINAMICS, the GE MV7000, and the ABB ACS line of VFD are all available in various configurations, including DFE or AFE, and power ratings that will be suitable for this application. Each VFD will typically require a dedicated input transformer, but GE does offer a transformer-less option that can potentially be used provided that the power system voltage matches the available input ratings for this type of VFD.

8.5 Cost and Schedule Considerations

The LFAC transmission solution is the recommended solution from a technical and readiness point of view. The estimated order of magnitude cost of an LFAC distribution system, excluding engineering, project management, spares, and insurance for the scenarios is given in the table below. Prices are in CAD and are based on historical pricing estimates out of Europe, +/-40%. It should be noted that with the use of local contractors and suppliers, some of these costs may be reduced. Also equipment costs will decrease in the years leading up to the project, based on wider availability.

The cost of cables and installation is based on high level quotes received from Prysmian and include estimations for the following:

- Project management and engineering
- Supply of cable
- Transportation of cables from manufacturing site to installation location
- Route Clearance works (Boulder clearance, PLGR and Pre-lay Inspection Survey)
- All accessories and tooling necessary for installation
- Cable lay
- Cable burial and protection, including seabed preparation as necessary
- Cable jointing (as needed), including transition joint to onshore cable
- Cable crossing design and construction (as needed)
- Cable termination and pull-in
- Provision of pull-in equipment
- All requisite project documentation

The vendor has also indicated that qualification and final type testing for cables will likely be required, along with R&D study work related to these specific cases. This cost has not been included. These quotes can be further refined as more detailed project specification work is provided.

High level costs for each of the three scenarios are outlined in the tables below:
<*Costs redacted from public report*>

Component	Vendor	Example Part	Estimated Cost (Million CAD)	Estimated Schedule
Dynamic Cables Static Subsea Cables Cable Installation Subsea Transformer Installation	Prysmian, Nexans, NKT. Aker can supply dynamic cables	N/A		2-4 years from project start to end of testing and commissioning.
Subsea Transformer Station, including connectors	Aker Solutions can provide station comprised of transformer from ABB connectors from Siemens and BH	ABB Transformer, Mecon 145 and Siemens 45 connectors		2.5 years, including engineering. Parts should be ordered at project start, provided FEED was done in advance
Land based reactor station	Multiple vendors (Local EPCI, ABB, Siemens, GE)	N/A		1-2 years
Land based substation	Multiple vendors (Local EPCI, ABB, Siemens, GE)	N/A		Includes substation electrical equipment. Up to 2.5 years.
Electrical Swivel (x2)	Focal or SBM	20Hz and up to 66kV		1.5 – 2 years
	Total:			

Table 8-8: Cost overview 2xFPSO Labrador South

Component	Vendor	Example Part	Estimated Cost (Million CAD)	Estimated Schedule
Dynamic Cables Static Subsea Cables Cable Installation Subsea Transformer Installation	Prysmian, Nexans, NKT. Aker can supply dynamic cables	N/A		2-4 years from project start to end of testing and commissioning.
Subsea Transformer Station, including connectors	Aker Solutions can provide station comprised of transformer from ABB connectors from Siemens and BH	ABB Transformer, Mecon 145 and Siemens 45 connectors		2.5 years, including engineering. Parts should be ordered at project start, provided FEED was done in advance
Land based substation	Multiple vendors (Local EPCI, ABB, Siemens, GE)	N/A		Includes substation electrical equipment. Up to 2.5 years.
Electrical Swivel (x2)	Focal or SBM	20Hz and up to 66kV		1.5 – 2 years
	Total:			

Table 8-9: Cost overview 2xFPSO West Orphan Basin
***This number is estimated based on the quotes received for the 2xFPSO Labrador and 4xFPSO Soldiers Pond cases**

Component	Vendor	Example Part	Estimated Cost (Million CAD)	Estimated Schedule
Dynamic Cables Subsea Cables Cable Installation Subsea Transformer Installation	Prysmian, Nexans, NKT. Aker can supply dynamic cables	N/A		2-4 years from project start to end of testing and commissioning.
Subsea Transformer Station (x2), including connectors.	Aker Solutions can provide station comprised of transformer from ABB connectors from Siemens and BH	ABB Transformer, Mecon 145 and Siemens 45 connectors		2.5 years, including engineering. Parts should be ordered at project start, provided FEED was done in advance
Land based substation	Multiple vendors (Local EPCI, ABB, Siemens, GE)	N/A		Includes substation electrical equipment. Up to 2.5 years.
Electrical Swivel (x4)	Focal or SBM: 20Hz up to 66kV	20Hz and up to 66kV		1.5 – 2 years
	Total:			

Table 8-10: Cost overview 4xFPSO West Orphan Basin

9 Scope 4 – Turret Based Vs Geostationary FPSOs

9.1 Management Summary

Review, compare and contrast the technical readiness for power transmission though a turret based FPSO vs that of a geostationary FPSO. Highlight how transformers can enable high voltage transfer from shore while delivering lower voltage through the turret. Identify how this would be different for a geostationary/cylindrical FPSO.

Due to the specified distances for our regions of interest, high voltage power transmission will be a requirement. High Voltage power connections – particularly those for turret based facilities will be a challenge as the technology required has various levels of readiness. Geostationary (Circular or Spar type) FPSO's do not require turrets, and thus have reduced complexity and cost associated with them in this area as power can be directly connected in through the hull.

In the case of HVDC power transfer, there are currently no qualified swivel products that allow for connection to a ship-shaped FPSO. Qualification of suitable swivels adds cost, complexity and risk to a project. Further to this, there are no existing HVDC subsea converters/transformer solutions which means ship shaped FPSOs must qualify at least one new technology to utilize HVDC power from shore. Should these technology challenges be overcome it is still necessary to install a large transformer on the topsides to convert to AC for distribution to users across the platform.

In this scenario geostationary FPSOs therefore offer an advantage in that swivel technology is not required, thus reducing complexity and risk. However due to the lack of qualified dynamic riser cables this in itself is not sufficient to support an HVDC based geostationary FPSO development.

For a low frequency AC development a subsea transformer is required to allow voltages to be stepped down to a suitable level allowing for the use of a fully qualified medium voltage electrical swivel with a ship shaped FPSO. This equipment is not essential to a geostationary FPSO as the cable can be connected directly to the facility, however valuable topsides space and weight capacity is then consumed by the need for a large HVAC converter/transformer on the topsides, and a subsea transformer allows electrical distribution of power between facilities. Therefore, for a two FPSO development case there are limited benefits of utilising a geostationary FPSO.

In both cases for the vessel to be disconnected in the event of iceberg approach high voltage connectors are required. Disconnection of a ship shaped FPSO has been proven in the Newfoundland Labrador Offshore with both Terra Nova and SeaRose - to the best of our knowledge a rapid disconnection functionality for geostationary / cylindrical FPSOs has never been delivered.

9.2 Assessment

Because a geostationary FPSO is a floating, fixed position vessel, there is no requirement for a turret, or an electrical swivel to connect to a power from shore cable. The cable can be entered and directly connected inside the vessel because there will be no twisting or weathervane forces experienced by the FPSO or the subsea the cable. In the case of a ship-shaped FPSO, a turret is required in order to allow the vessel to weathervane and adjust position around a moored turret connection. Because of this, an electrical swivel mechanism is required. The swivel slip rings allow for continuous power transfer as the ship rotates around the fixed turret mechanism. The table below outlines a high level evaluation of readiness and considerations for ship-shaped vs geostationary FPSOs with respect to power from shore. No assessment is carried out regarding environmental performance, topsides load/storage capacity, or requirement for disconnection.

Option	Technical Readiness	Safety / Environment	Complexity	Cost & Schedule
Ship Shaped	All major components for power from shore are available and qualified	Possibility for leak of oil filled swivels	Requires swivel for electrical connection which requires subsea transformer	Turret and electrical swivel components add cost and time
Geostationary	All major components for power from shore are available and qualified	Current designs unable to support disconnect for ice or weather events	Power cable can be directly entered into hull for connection, however subsea transformer required for distribution	No additional cost and schedule implications
	Best Option or No major issues identified	Some issues or technology gaps being currently filled	Worst Issue or gaps unlikely to be filled in time for development	

Table 9-1: Labrador Sea and West Orphan Basin – Ship Shaped Vs Cylindrical FPSO

9.2.1 Swivel Readiness

As detailed in Scope 3, there are a number of possible candidates for AC electrical swivels that will allow for power transfer through a turret. These swivels range from medium to high voltage and vary in technical readiness from TRL2-TRL7, essentially in the design phase all the way up to service level. The choice of AC electrical swivel is based on a number of design considerations, however the most available choice for our LFAC scenario is a 52kV swivel at TRL7 from SBM. This swivel is readily available and has been in use on Asgard A for a number of years and proves to be of low risk. As outlined in Scope 3, this swivel will be sufficient for our reference design provided the voltage on the secondary of the subsea transformer is lowered. Second to that, a 66kV swivel from SBM is at TRL4 and is ready for first production use if a higher voltage level is required, but this adds risk and complexity related to further qualification and testing.

Also detailed in Scope 3 is the fact that there are no qualified swivels available for HVDC power transfer at present. Identified swivels are at TRL3 and require further development and testing by both SBM and Focal. It is possible that a suitable HVDC swivel will come to market in the next 5 years, and operator interest could accelerate that timeline. Risk is to be accounted for if HVDC power from shore is considered for ship-shaped FPSO connection.

Figure 9-1: Position-anchored production ship with geostationary swivel tower – ref. SBM / Equinor

9.2.2 Subsea Transformer

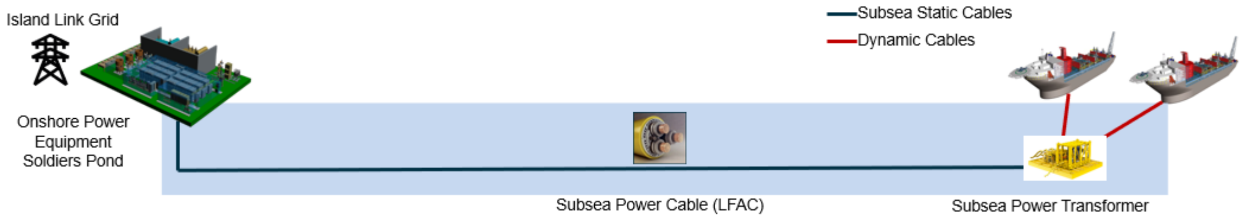


Figure 9-2: Representation of an LFAC power from shore transmission system

The use of subsea transformers has been considered when transmitting AC and LFAC power from shore to both types of FPSO vessels. A subsea transformer is the technology that enables high voltage power transferred from shore to be stepped down to a level where a medium voltage swivel can be utilized. This reduces the cost and the complexity of the swivel mechanism, and as per Scope 3, enables the use of an SBM qualified and in service swivel that operates in the 52kV-66kV range. Subsea transformers like those available from ABB are in service on numerous projects and have no reported problems. The transformer technology required for this study is thus readily available and has limited risk for these scenarios.

Further, in our design cases, the subsea transformer acts as a distribution point that allows for power connections to multiple FPSO vessels. Without it there is no practical way to distribute power to multiple vessels from the seafloor.

In the case of HVDC power transmission, there are currently no available subsea converters to allow for use of a subsea transformer. This means that HVDC would be directly connected through a swivel or a fixed connection to an FPSO and would require a large onboard converter and transformer to stepdown the voltage before conversion to suitable AC power. Further, with no subsea equipment to act as a distribution point, there would be no practical way to connect multiple FPSOs to HVDC power

Details on suitable subsea transformers have been outlined in Scope 3.

9.2.3 Electrical Connectors

A suitable electrical connector is required so that the dynamic riser cable can be connected and disconnected from an FPSO in the event that it needs to avoid an iceberg, storms, or needs to sail for shore based maintenance. The Siemens Spectron 45 is a suitable connector for connection in both types of FPSO, however to the best of our knowledge this has never been delivered in practice for a geostationary FPSO due to the fixed nature of the vessel. Additional work is required to develop the disconnection process to minimize impact on other facilities in the field and to ensure the system is highly reliable and easily automated.

9.2.4 Dynamic Riser Cable

For the AC power transfer case, a suitable AC dynamic riser cable has been qualified for use up to 3000m, and is currently in use in Cascade Chinook at a depth of 2500m. This cable is provided by Aker, however there are other vendors who can provide design services for dynamic cables rated for the 1250-1550m depth of this study. The AC dynamic cable poses minimal risk to these projects, and would be suitable for both geostationary and ship-shaped FPSO.

For the HVDC power transfer case, there are currently no dynamic HVDC cables that are qualified for the required depth of 1250-1500m for our areas of study. Dynamic HVDC cables for this depth would require further design and qualification which would add complexity and risk to the project.

10 Scope 5 – 4x50WM FPSOs Soldiers Pond to West Orphan Basin

10.1 Summary Analysis

Per client request, make recommendations on a 4x50MW FPSO case for the Soldiers Pond to West Orphan Basin route.

This scope builds upon the initial 2x45-65MW analyses that have been completed to identify a feasible power from shore concept. Extending the power from shore transmission system to accommodate 4xFPSO facilities with a peak load of 50MW each could be laid out like the following:

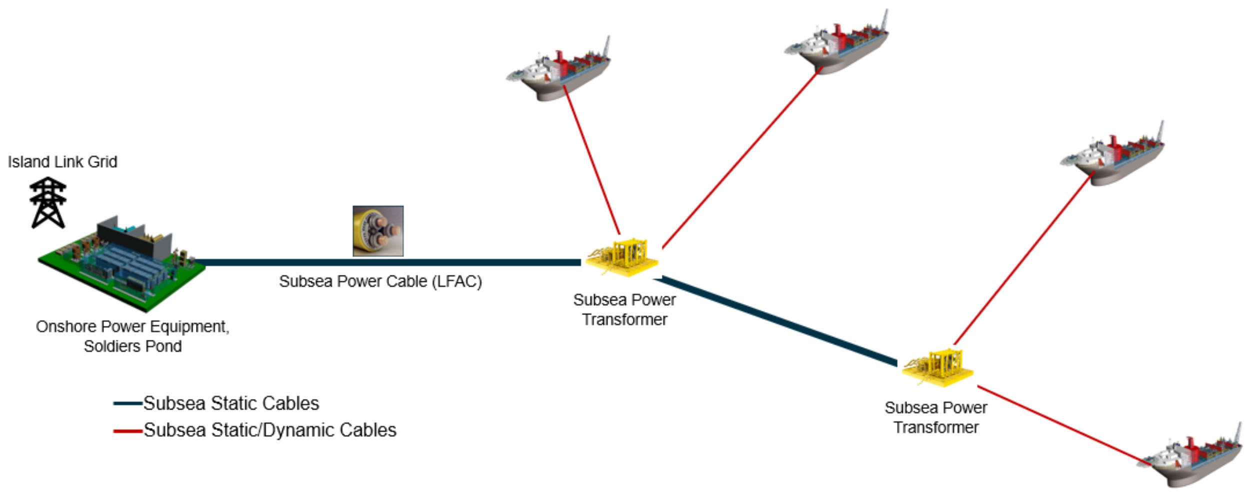


Figure 10-1: Sample Layout 4x50MW FPSO Soldiers Pond to West Orphan Basin

The recommended solution remains an LFAC transmission system to achieve power from shore, and the required equipment, while sized differently, remains largely the same.

Notable differences in design for 4x50MW FPSO case:

- Increased number of parallel AFE frequency converters and transformers will be required in the onshore substation.
- Cables will be sized for the load as outlined in section 8.
- Subsea transformers will be larger and able to accommodate 120MW each. Two will be required to accommodate and distribute power.
- The Mecon and Siemens connectors are both rated for the required current and voltage for this case.
- The dynamic cable and swivel selections remain the same for the 50MW FPSOs.

Technical details, and power system analysis are available in section 8, and the load analysis for this system is available in appendix D.

The estimated order of magnitude cost of an LFAC distribution system, excluding engineering, project management, spares, and insurance for the scenarios is given in the table below. Prices are in CAD and are based on historical pricing estimates out of Europe, +/-40%. It should be noted that with the use of local contractors and suppliers, some of these costs may be reduced. Also equipment costs will go down in the years leading up to the project, based on wider availability.

The cost of cables and installation is based on high level quotes received from Prysmian and include estimations for the following:

- Project management and engineering
- Supply of cable
- Transportation of cables from manufacturing site to installation location
- Route Clearance works (Boulder clearance, PLGR and Pre-lay Inspection Survey)
- All accessories and tooling necessary for installation
- Cable lay
- Cable burial and protection, including seabed preparation as necessary
- Cable jointing (as needed), including transition joint to onshore cable
- Cable crossing design and construction (as needed)
- Cable termination and pull-in
- Provision of pull-in equipment
- All requisite project documentation

The vendor has also indicated that qualification and final type testing for cables will likely be required, along with R&D study work related to these specific cases. This cost has not been included. These quotes can be further refined as more detailed project specification work is provided.

<Costs redacted from public report>

Component	Vendor	Example Part	Estimated Cost (Million CAD)	Estimated Schedule
Dynamic Cables	Prysmian, Nexans, NKT. Aker can supply dynamic cables	N/A		2-4 years from project start to end of testing and commissioning.
Subsea Cables				
Cable Installation				
Subsea Transformer Installation				
Subsea Transformer Station (x2), including connectors.	Aker Solutions can provide station comprised of transformer from ABB connectors from Siemens and BH	ABB Transformer, Mecon 145 and Siemens 45 connectors		2.5 years, including engineering. Parts should be ordered at project start, provided FEED was done in advance
Land based substation	Multiple vendors (Local EPCI, ABB, Siemens, GE)	N/A		Includes substation electrical equipment. Up to 2.5 years.
Electrical Swivel (x4)	Focal or SBM: 20Hz up to 66kV	20Hz and up to 66kV		1.5 – 2 years
	Total:			

Table 10-1: Cost overview 4xFPSO West Orphan Basin

11 Next Steps

Throughout this study we have identified points of interest for further study focus. These areas were outside the scope of this study but certainly merit further investigation.

- Conduct more detailed availability assessment to determine availability of power from shore based upon details of connection point configuration and results of refined cable routing assessments.

- Refine cable routing work including;
    - Seafloor troughing and cable burial detail study based upon additional survey data
    - Investigation of Pack Ice risks associated with Labrador routing
    - Cable interaction study based on chosen routes
    - Investigate potential shore crossing locations and methodologies

- Review grid connection details at Muskrat Falls / Soldiers Pond, and investigate potential point of interconnection to grid for Trinity Bay route.

- Review installation approach and timeline for power from shore associated with different assumptions regarding offshore development timeline – for example how does configuration and installation approach change if twin FPSOs are installed within 1-2 years vs 5-10 years apart.

- Review FPSO disconnection / reconnection approach and establish functional requirements for turret or riser / topsides connection equipment.

12 References

Muskrat Falls and Soldiers pond Single Line Diagrams -
http://www.pub.nl.ca/applications/islandinterconnectedsystem/files/rfi/PUB-NLH-246.pdf

13 Appendices

Appendix A: C-CORE Ice Risk Analysis

Appendix B: 2x45-65MW FPSO LFAC Load Analysis *<Redacted from public report>*

Appendix C: LFAC Power Distribution Schematic *<Redacted from public report>*

Appendix D: 4x50MW FPSO LFAC Load Analysis *<Redacted from public report>*

Appendix A: C-CORE Ice Risk Analysis

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FPSO Electrification: Iceberg Risk to Cables

C-CORE Report Number
R-20-037-1591

Prepared for: AkerSolutions

Revision 2.0
September, 2020

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The correct citation for this document is:
C-CORE. 2020. “FPSO Electrification: Iceberg Risk to Cables.” Proposal R-20-037-1591, Revision 2.0.

Project Team
Tony King (Project Manager)

REVISION HISTORY

VERSION	NAME	DATE OF CHANGES	COMMENTS
1.0	Tony King	Sept. 16, 2020	Draft Submitted to Client
2.0	Tony King	Sept. 23, 2020	Reviewed Report Submitted

DISTRIBUTION LIST

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1 Introduction

Power cables running from Newfoundland and Labrador (NL) to the West Orphan Basin and Labrador South will be subject to risk from free-floating and scouring icebergs. While the risk from free-floating icebergs will be minimized for a relatively small diameter cable laid on the seabed, scour risk will be the same as for larger diameter pipelines. Iceberg risk is assessed for cables running to the West Orphan Basin and Labrador South from specified landfall locations (Figure 1) using a geometric iceberg grounding model (King et al., 2003), calibrated against repetitive seabed mapping data (Sonnichsen et al., 2009; Sonnichsen and King, 2011), and iceberg scour data from the Jeanne d'Arc basin (Sonnichsen and King, 2011) and the Makkovik Bank (King and Sonnichsen, 2014). Iceberg risk is estimated for cables laid on the seabed, as well as trenched for a range of cover depths.

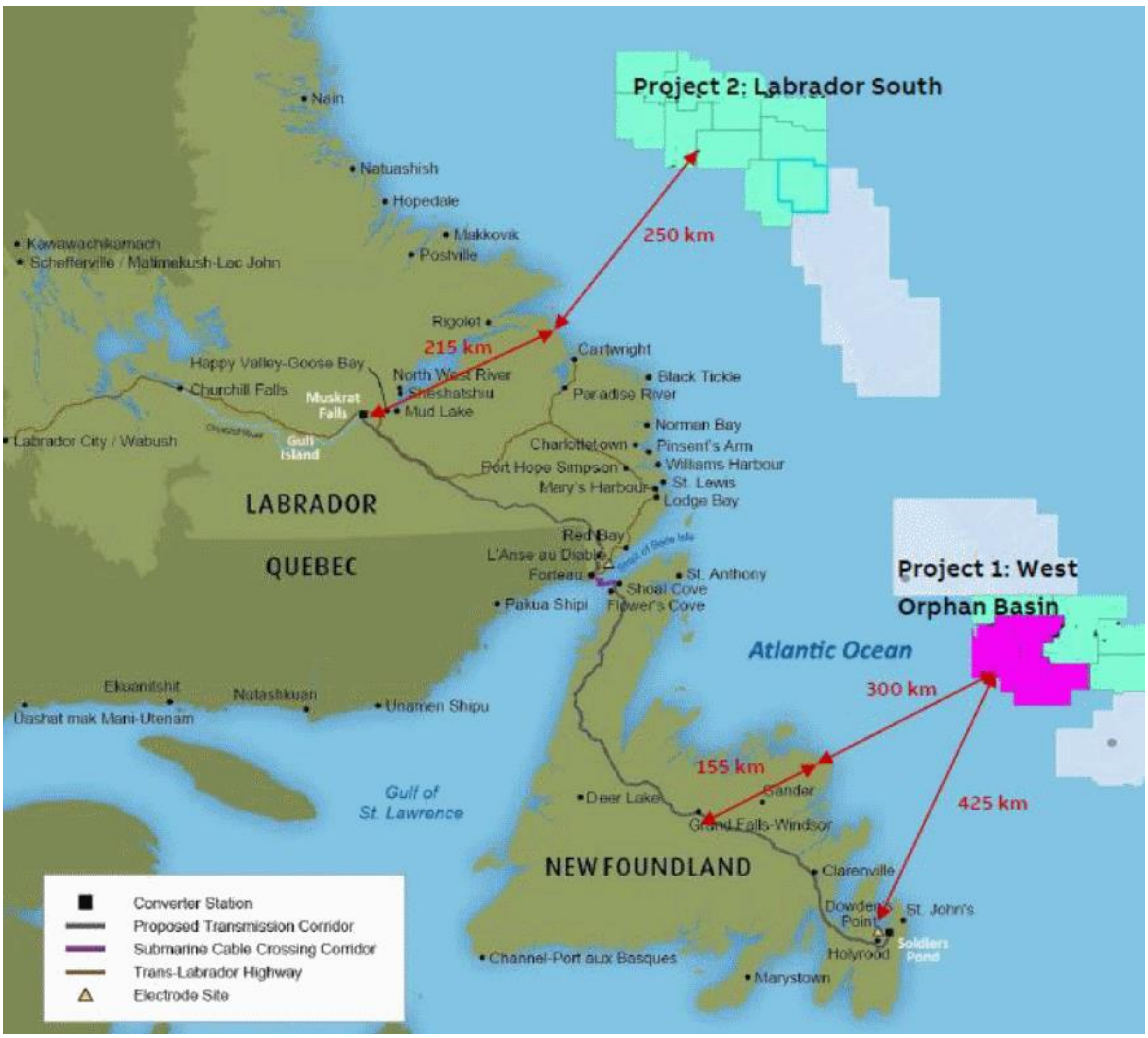

Figure 1. Potential power from shore development areas (NEIA, 2020)

2 Methodology

Cables laid on the seabed are subject to risk from free-floating or scouring/gouging ice keels (Figure 2). Here, the terms scouring and gouging are used interchangeably. Scours features can take the form of longer linear furrows or circular/oval pits (Figure 3). Once the cable is trenched into the seabed the risk from free-floating icebergs is eliminated and the iceberg risk is then a function of the furrow and pit depth distributions and the depth the cable is trenched into the seabed. The following sections outline the approach and data used for the analysis.

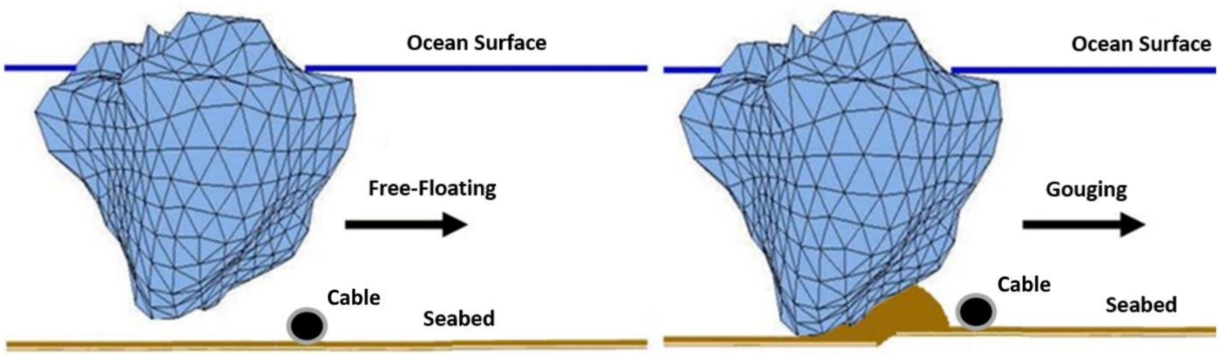

Figure 2. Iceberg interaction with a cable on the seabed

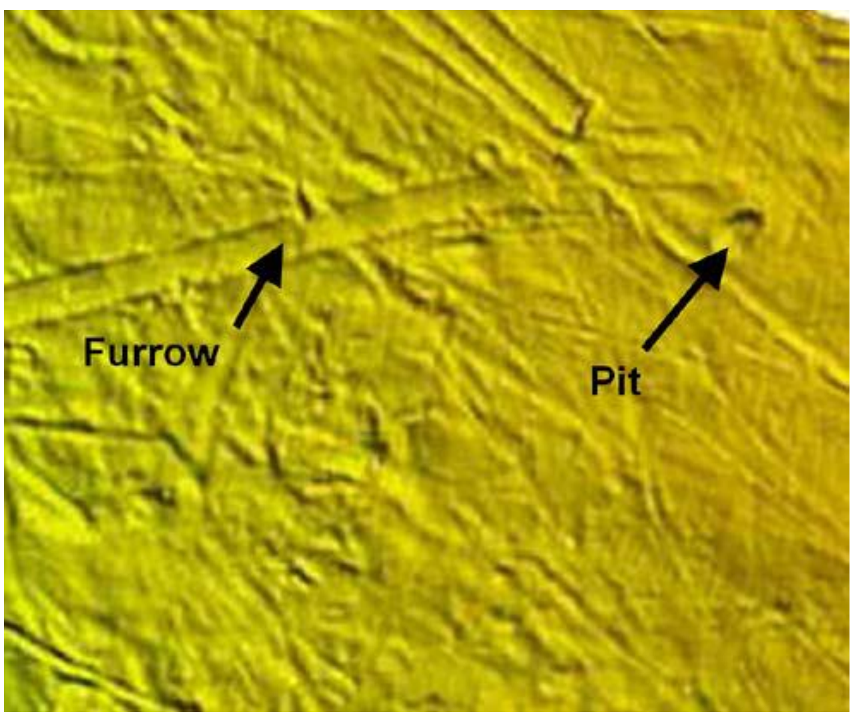

Figure 3. Furrows and pits formed by iceberg interaction with the seabed (Ralph, King & Zakeri, 2011)

2.1 Scouring Iceberg Interactions

2.1.1 Analysis Approach

Iceberg grounding rates may be estimated using a geometric grounding model (King, 2002; King et al., 2003), as follows:

$$\rho_g = \frac{1}{\pi} r_d n_o S \bar{U} t \tag{1}$$

Where ρ_g is the iceberg grounding rate per unit area of seabed, r_d is the proportion of iceberg keels in the metre of the water column immediately above the seabed, n_o is the annual average areal density of icebergs, S is the seabed slope, $\bar{U}$ is the mean iceberg drift speed and t is time (the number of seconds in a year, if an annual iceberg grounding rate is desired). All iceberg groundings are assumed to result in scour features which are broken down into furrows and pits. The proportion of furrows and pits are based on seabed survey data. In the Jeanne d'Arc Basin there are approximately twice as many furrows as pits (Sonnichsen and King, 2011). This proportion does vary with location, and limited data indicates that scour features near shore are mostly pits.

The rate (n_f) at which scouring (furrowing) icebergs cross over a cable laid on (or trenched into) the seabed may be calculated using:

$$n_f = \frac{2}{\pi} \rho_f L_c \overline{L_f} \tag{2}$$

where ρ_f is the furrow formation rate, L_c is the cable length (or cable subsection length), and $\overline{L_f}$ is the mean furrow length. This equation assumes a uniform distribution of furrow direction (equally likely from any direction). A similar approach is used in Equation (3) for pit formation rates (n_p) over the cables, except furrow formation rates is replaced with pit formation rate (ρ_p) and the mean furrow length is replaced with mean pit diameter ($\overline{D_p}$).

$$n_p = \rho_p L_c \overline{D_p} \tag{3}$$

With pit and crossing frequency over the cable (or cable segment) defined, the annual contact rate (n) due to furrow (n_f) and pit (n_p) interaction events as a function of burial depth (D) can be calculated as follows in equation (4):

$$n = n_f \, \mathrm{P_{exc}}(Mean_f, S.D._f, D) + n_p \, \mathrm{P_{exc}}(Mean_p, S.D._p, D) \tag{4}$$

Where P_{exc} is the probability of exceeding D for a given mean and standard deviation of furrow or pit depth, given that the event occurs.

2.1.2 Proportion of Iceberg Keels Capable of Contacting Seabed

The proportion of iceberg keels in the metre of the water column above the seabed, r_d, is determined using an iceberg length/draft relationship derived from iceberg survey data. Figure 4 shows 283 data points collected from 1981 to 2018, along with a line representing the best fit relationship. When this relationship is combined with a waterline length distribution (exponential with a mean of 59 m; Jordaan et al., 1995) and a random term to properly characterize the scatter in the iceberg length/draft dataset, an iceberg draft distribution is obtained (Figure 5) which can be used in the iceberg grounding model. Iceberg risk is considered to be zero for water depths greater than 250 m. The draft distribution excludes berg bits or growlers (waterline lengths less than 15 m).

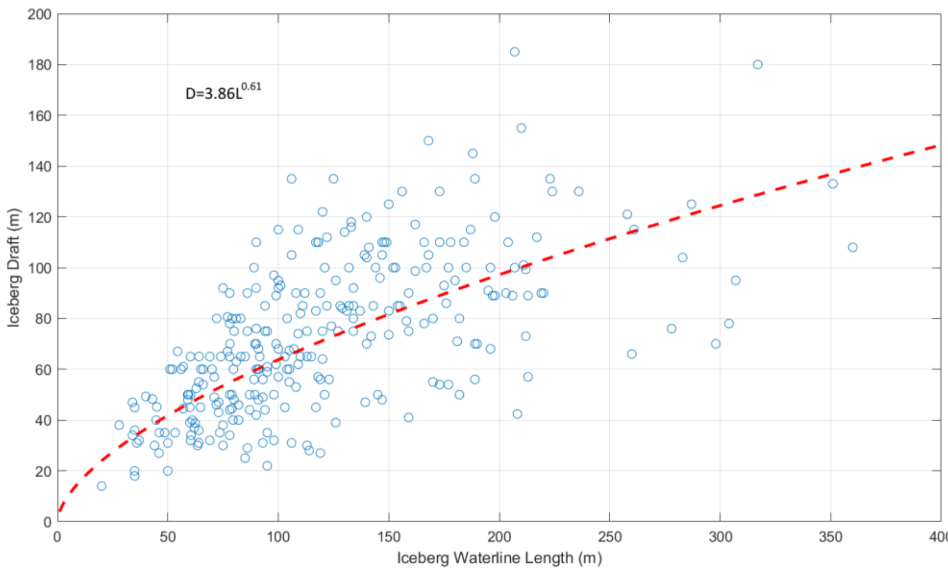

Figure 4. Iceberg length/draft dataset

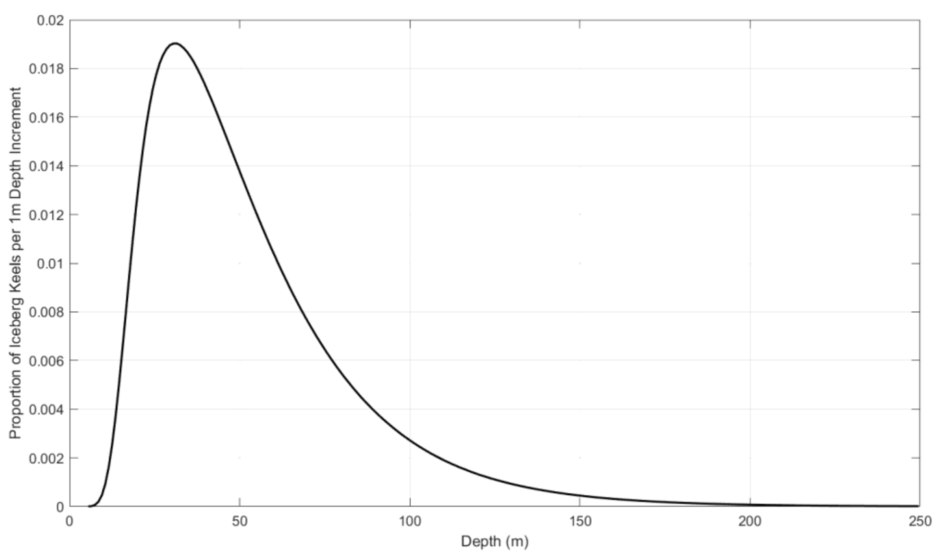

Figure 5. Iceberg draft distribution (excluding bergy bits and growlers)

2.1.3 Iceberg Frequency

Iceberg frequency, n_o, is the average annual iceberg areal density. This value is typically based on iceberg charts, aerial reconnaissance surveys and satellite data. It represents an average iceberg density (number per unit area) which would be determined over an extended period (e.g. years to decades) by numerous repeat surveys. In 2017 C-CORE produced the Metocean Climate Study Offshore Newfoundland and Labrador for Nalcor Energy (C-CORE, 2017), which included an analysis of iceberg areal density (Figure 6). Results shown in Figure 6, based on an analysis of aerial reconnaissance and satellite data, are specified to be "open water" values as it is not possible to reliably identify icebergs in pack ice. Average annual density values for locations of interest are given in Table 1.

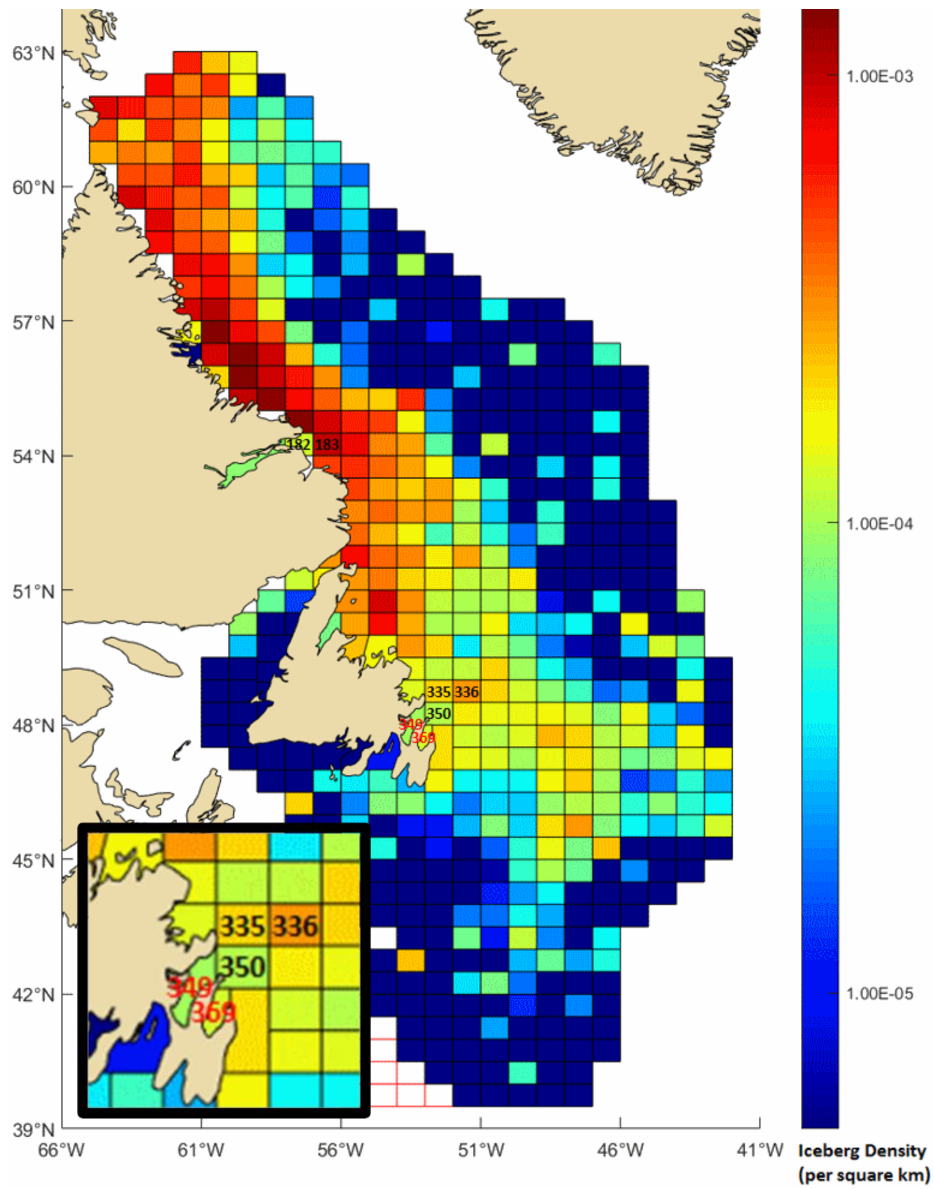

Figure 6. Mean annual open-water iceberg densities (km^{-2}), with cells of interest indicated

Table 1. Average annual iceberg density values from the Nalcor Metocean Study (C-CORE, 2017)

Location	Cell # (C-CORE, 2017)	Average Annual Iceberg Density (km^{-2})
Conception Bay Landfall	369	8.4×10^{-5}
Trinity Bay Landfall	349	7.0×10^{-5}
Mouth of Conception/Trinity Bay	350	1.1×10^{-4}
Off Cape Bonavista	335	2.0×10^{-4}
North of Grand Banks	336	2.8×10^{-4}
Labrador Landfall	182	4.7×10^{-4}
Inner Shelf Channel	183	1.8×10^{-3}

2.1.4 Seabed Slope

Seabed slope, S, is calculated using bathymetric data and is simply the change in water depth over distance. Calculations of seabed slope can depend on the distance scales utilized (e.g. looking at a smaller scale such as tens of meters versus hundreds of meters or kilometers), with smaller scales often indicating "rougher" seabeds (greater slope values). Previous calibrations of the grounding model have used slopes generated at 100 m intervals, therefore for applications to the cable iceberg risk the seabed slope will be calculated at the same interval along the cable routes, which generally run directly upslope/downslope.

GEBCO bathymetric data (GEBCO, 2020) is used for the Labrador South cable route and appears to provide reasonably accurate data source for the region. GEBCO was also used for both options considered for the West Orphan Basin cable route. However, when examining GECCO bathymetry in Trinity Bay a sill was observed across the Trinity Bay (water depth approximately 200 m), which seemed to contradict bathymetry from the Canadian Hydrographic Service (CHS). For this reason, additional iceberg risk analyses were conducted using data digitized from CHS chart for the Trinity and Conception Bay landfall routes.

2.1.5 Mean Iceberg Drift Speed

Mean iceberg drift speed, $\overline{U}$, is based on trajectory data. Typical values for iceberg drift (excluding periods when grounded) are 0.31 m/s for the Grand Banks or 0.24 m/s for the Makkovik Bank (King, 2002). Very limited iceberg drift data is available outside these area, therefore for the Nalcor study (C-CORE, 2017) a correlation between mean iceberg drift speeds and mean current speeds was used to estimate iceberg drift speeds over the study area. Table 2 summarizes mean drift speeds for the various areas of interest. Areas without modeled current speeds are listed as "no data" and mean values from adjacent cells were used. It should be noted that mean drift speeds will be much lower near shore, where icebergs can remain grounded for extended periods of time. While no data are available for analysis, it is known that icebergs near shore may be grounded for extended periods, and mean drift speeds may be reduced on the order of 90% (or more) as a result.

Table 2. Mean iceberg drift speeds from the Nalcor Metocean Study (C-CORE, 2017)

Location	Cell # (C-CORE, 2017)	Mean Iceberg Drift Speed (m/s)
Conception Bay	369	0.25
Trinity Bay	349	No data
Mouth of Conception/Trinity Bay	350	0.30
Off Cape Bonavista	335	0.33
North of Grand Banks	336	0.32
Labrador Landfall	182	No data
Inner Shelf Channel	183	0.31

2.1.6 Scour Dimensions

The relevant scour dimensions are the mean furrow length, the mean pit diameter, the furrow depth distribution and the pit depth distribution. Since the cable routes start at shore and extend out into deep water (> 1000 m) relationships were required that capture variations in scour parameters. While available multibeam data from the Grand Banks cover a water depth range from 72.2 m to 161.3 m (Sonnichsen and King, 2011), data from the Makkovik Bank (King and Sonnichsen, 2014) covers a much greater range of water depths (3.7 m to 553 m) and is considered more applicable for the analyses here, although collection of seabed survey data is recommended for both cable routes.

The mean furrow length, $\overline{L_f}$, typically used for risk calculations for pipelines on the Grand Banks is 650 m (King, 2019) based on an analysis of regional survey data. The mean furrow length for the Makkovik Bank is 309 m (King and Sonnichsen, 2014). Figure 7 shows the mean furrow length and Figure 8 shows mean pit diameter, $\overline{D_p}$, as functions of water depth based on an analysis of Makkovik Bank data.

Furrows and pits depths on the Grand Banks and the Makkovik Bank are fairly well represented by lognormal distributions. Means and standard deviations of furrow and pit distributions as a function of water depth are shown in Figure 9 and Figure 10, respectively.

2.1.7 Scour Infill Correction

Scours (furrows and pits) observed on the seabed are considered to be infilled to some degree, however there is insufficient data to determine the depth distribution of newly formed features. The degree of infill for the total scour population is a function of factors such as time since scour formation, sediment type, bottom currents, water depth and the wave regime. Data for assessing infill is limited as the age of most scours is unknown. Sonnichsen et al. (2005) reported results from multibeam surveys of iceberg grounding sites identified during the 2000 iceberg season. A summary of furrow parameters is shown in Table 3 and survey locations are shown in **Error! Reference source not found.**. The average of the mean furrow depths is 0.48 m. However, there is one feature for which no depth was reported because it was too shallow (00-09). With this feature included, the average of the furrow depth decreases to 0.40 m. The mean measured furrow depth in the 2004 Repetitive Mapping Survey (covering 70 to 150 m water depth) is 0.23 m (Sonnichsen and King, 2011). Using this limited data set, a scour infill correction factor of two is estimated, meaning that scour depths generated parameters previously outlined are doubled to account for sediment infill.

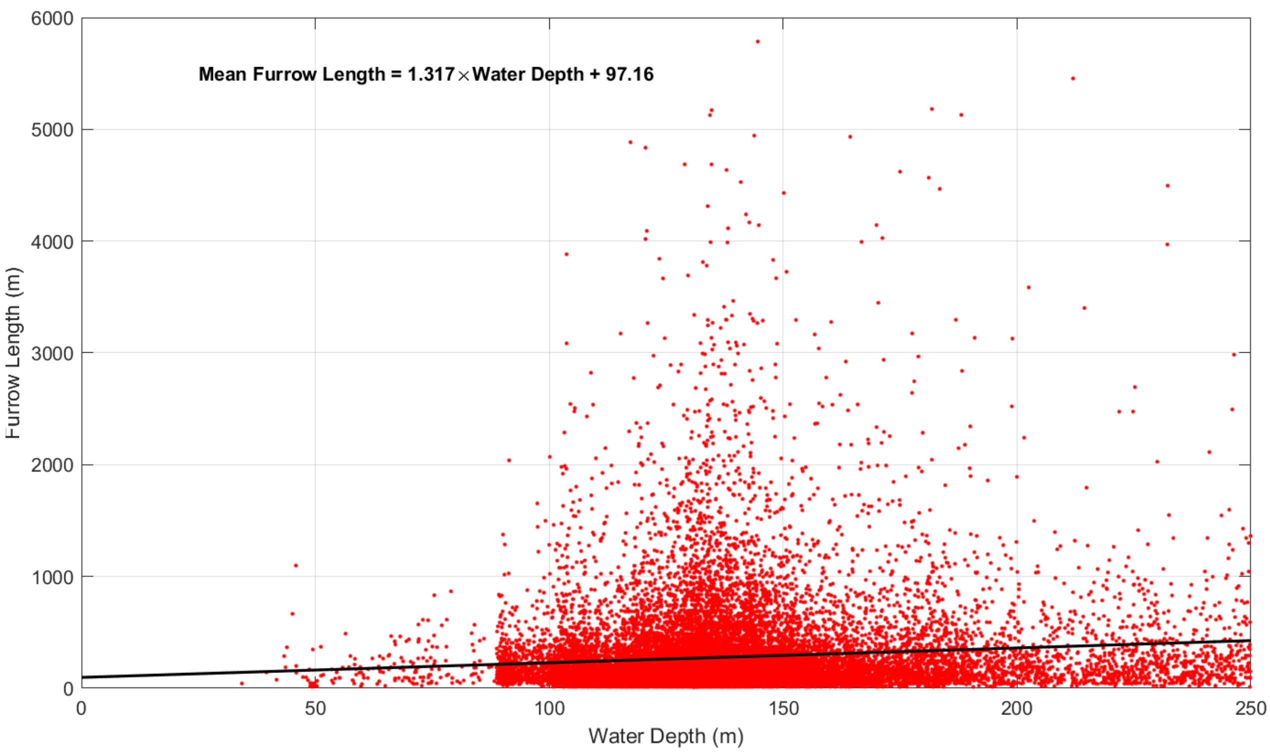

Figure 7. Mean furrow length as a function of water depth, Makkovik Bank region

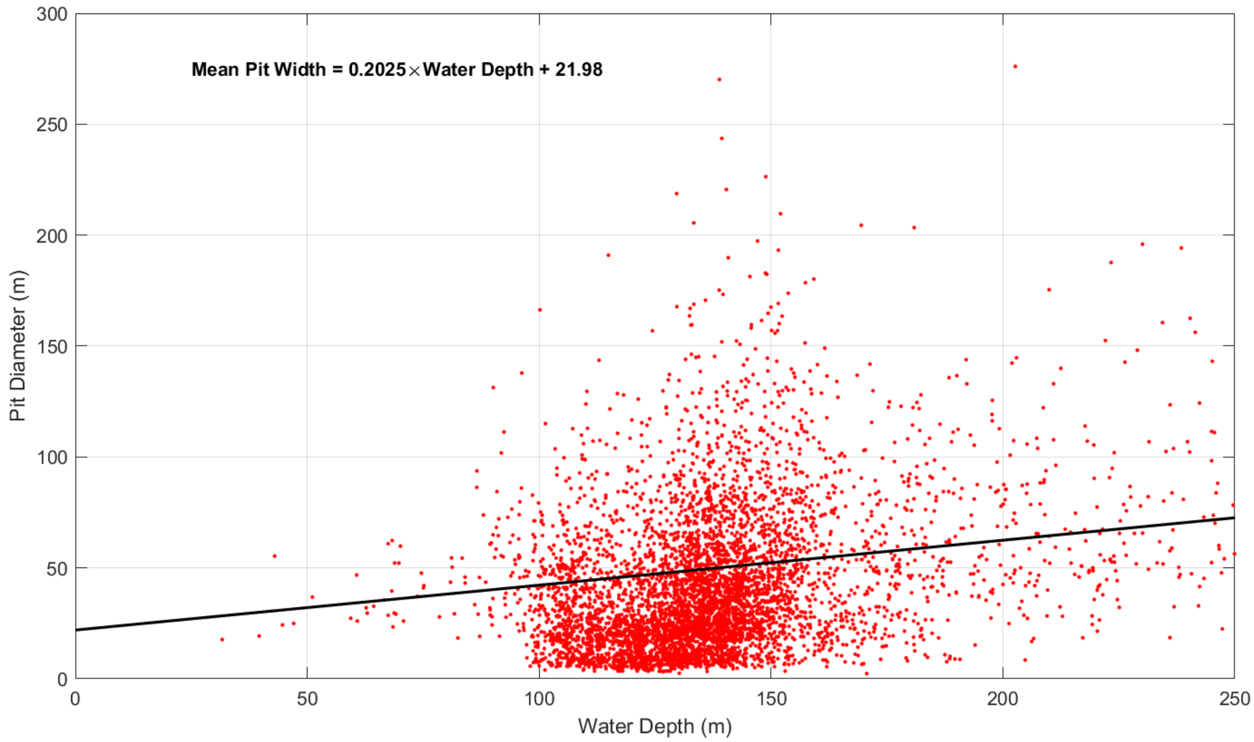

Figure 8. Mean pit diameter as a function of water depth, Makkovik Bank region

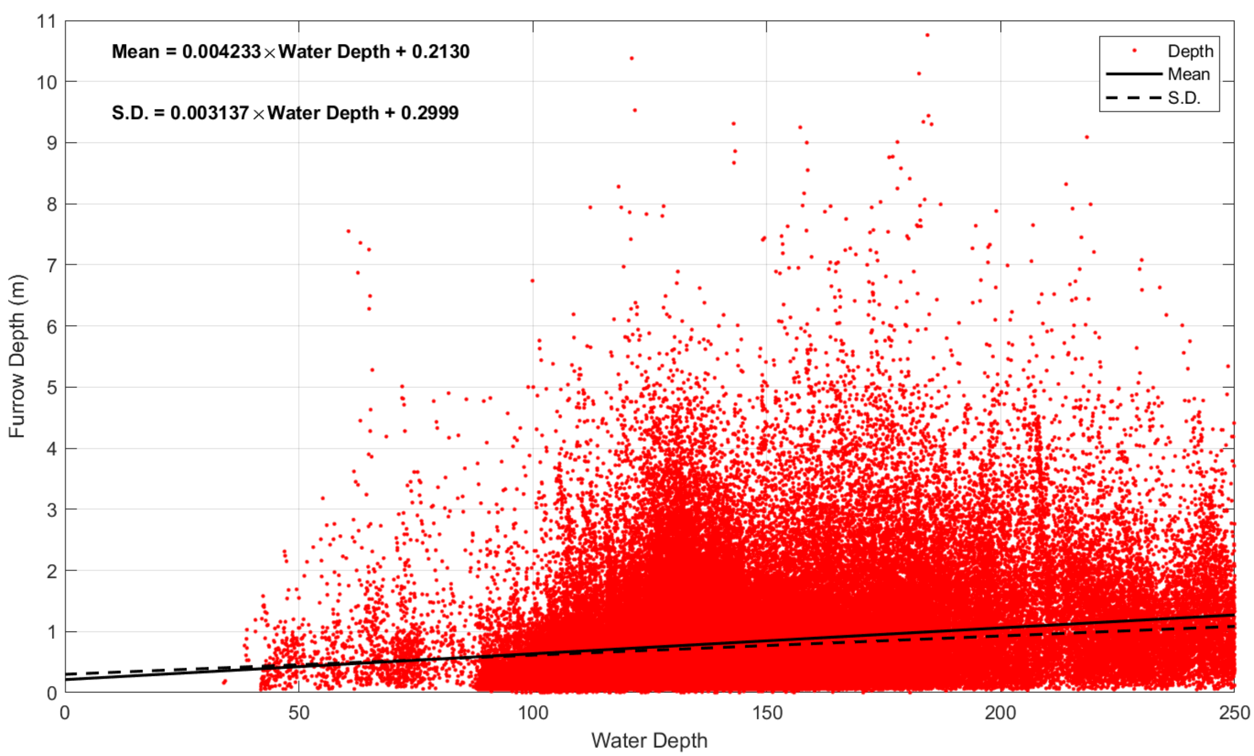

Figure 9. Furrow depth as a function of water depth, Makkovik Bank region

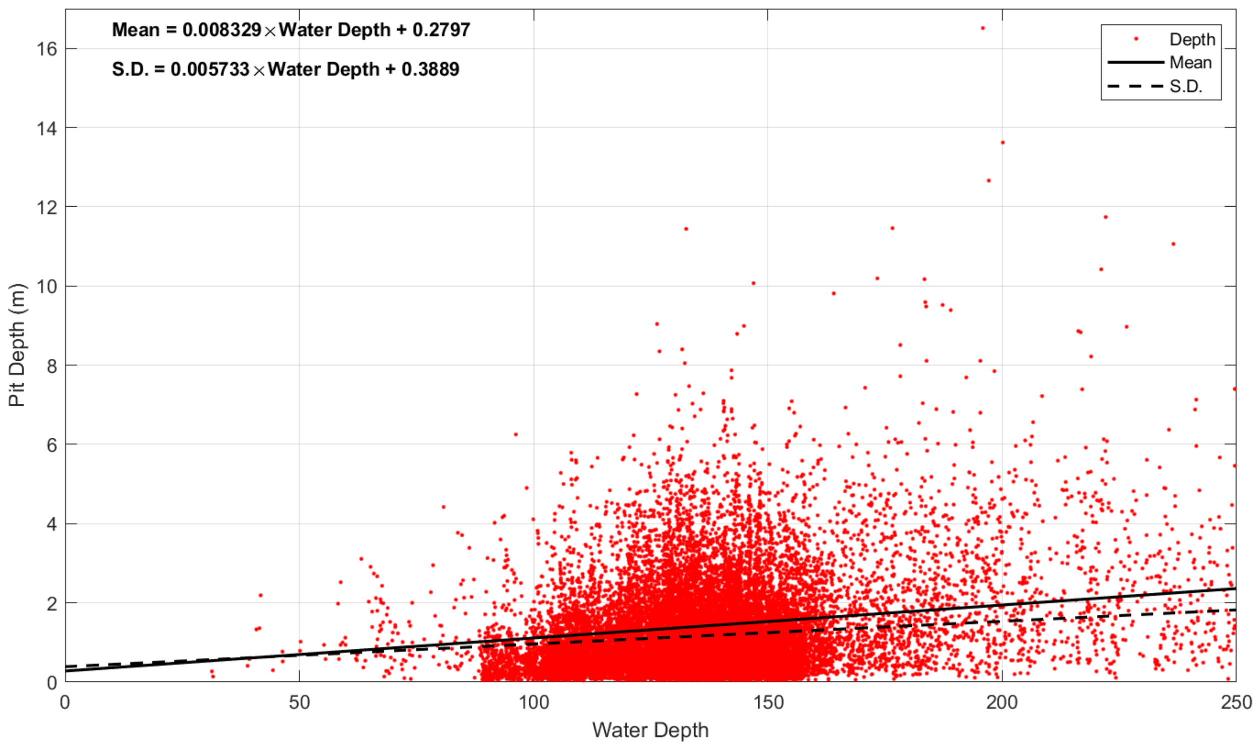

Figure 10. Pit depth as a function of water depth, Makkovik Bank region

Table 3. Summary of furrow measurements from multibeam bathymetry (Sonnichsen et al., 2005)

Furrow	Bathymetry (m)	Furrow length (m)	Statistics	Berm height (m)	Trough depth (m)	Berm width (m)*	Furrow width (m)**
00-18	102	400	Mean	0.1	-0.3	18.8	10.6
			STDEV	0.1	0.1	4.2	2.5
00-65	127	1500	Mean	0.3	-0.4	25.7	13.6
			STDEV	0.2	0.3	7.2	7.4
00-68	75	4500	Mean	0.3	-0.5	47.9	29.2
			STDEV	0.2	0.2	7.4	6.6
88-01	124	1000	Mean	0.2	-0.7	25.8	20.6
			STDEV	0.2	0.5	10.2	23.9
83-95	86	2000	Mean	0.2	-0.5	34.5	18.8
			STDEV	0.1	0.3	8.2	7.1
Overall mean	102.8			0.2	-0.5	30.5	17.8
Overall STDEV	22.6			0.2	0.3	12.3	9.4

STDEV= standard deviation *Berm width is crest to crest
**Furrow width is the width at the seafloor

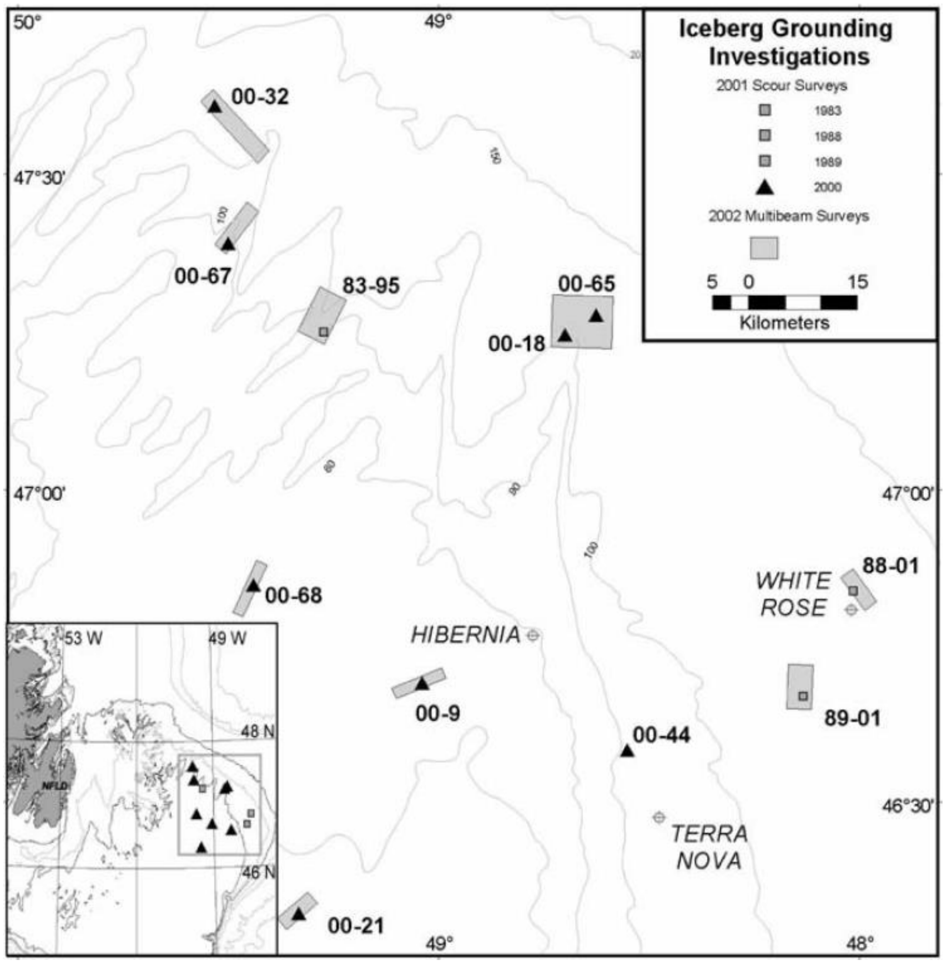

Figure 11. Survey locations for investigation of iceberg groundings (Sonnichsen et al., 2005)

2.2 Free-Floating Iceberg Interactions

2.2.1 Analysis Approach

The free-floating iceberg contact frequency, n_{ff}, with a cable laid on the seabed is calculated as follows (King, 2019):

$$n_{ff} = \frac{2}{\pi} n_o r'_d L_c \bar{U} t \tag{5}$$

Where all terms have been previously defined, except r'_d, which is the proportion of icebergs with drafts capable of contacting the cable.

2.2.2 Proportion of Iceberg Keels Capable of Contacting Cable

The proportion of free-floating iceberg keel capable of contacting the cable, r'_d, differs from r_d in Equation (1) in that the value of r'_d depends on the diameter of the cable and r_d is specific to the meter water column immediately above the seabed. The cable that would be used for FPDO electrification would have a diameter on the order of 0.1 m. Therefore, r'_d is a proportion of r_d. Analysis of output from the Monte Carlo iceberg contact model used for assessing iceberg risk in the Jeanne d'Arc Basin (King, 2019) shows that iceberg keels are concentrated near the seabed (Figure 12). An allowance of 0.1 m for iceberg heave has been included. Therefore, r'_d is approximately 43% of r_d.

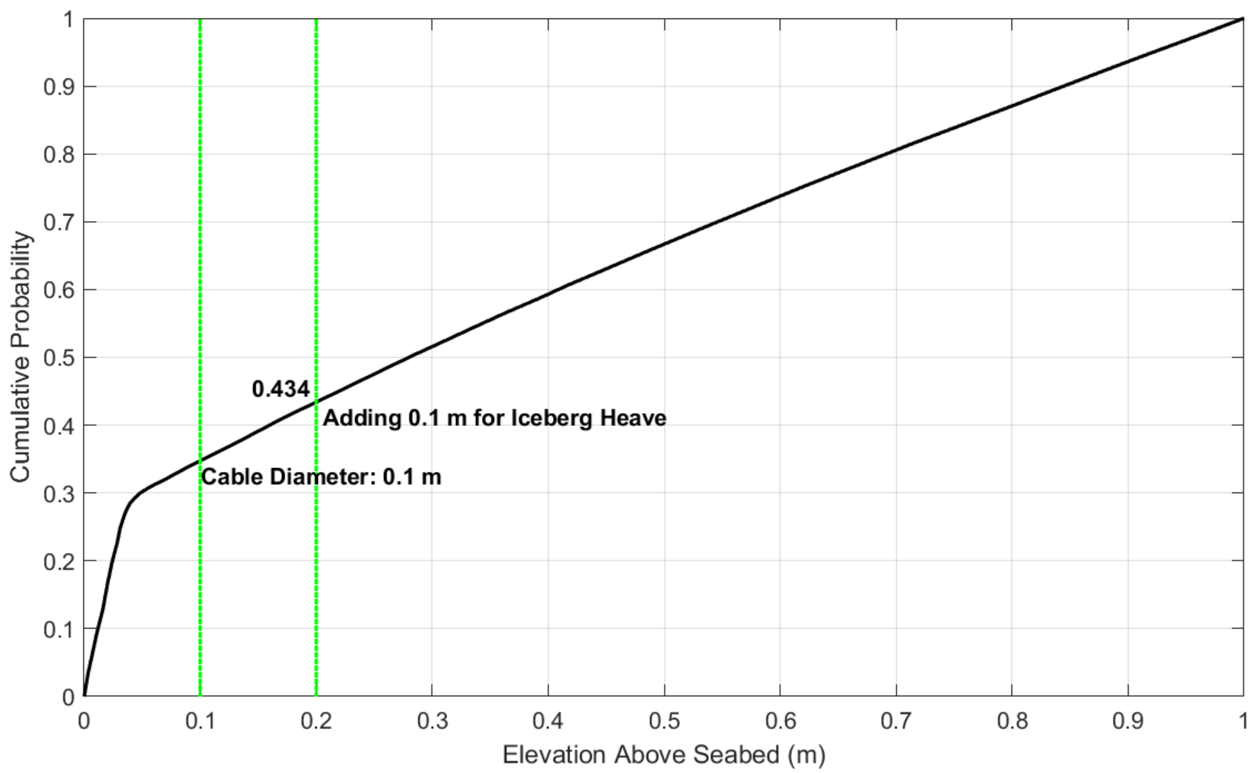

Figure 12. Proportion of free-floating iceberg keels within 1 m of seabed capable of contacting cable

3 Cable Route Analysis Results

3.1 Labrador South

The cable route for Labrador South runs from 55.2854°N, -54.6128°W to an arbitrary landfall at 54.0000°N, -57.2900°W (Figure 13). The cable route length is 264.3 km. A sheltered channel running roughly east/west is utilized in order to minimize iceberg risk to the cable when crossing the inner shelf close to shore (Figure 14). Once the cable reaches deeper water in the Cartwright Saddle, the cable is routed to keep it in water depths greater than 250 m, minimizing exposure to iceberg risk. The water depth profile along the cable route is shown in Figure 15. Water depths less than 250 m only occur in the first 75 km while crossing the inner shelf and only this portion of the route needs to be considered in the iceberg risk analysis.

Figure 16 shows the results of the iceberg risk analysis. The top subplot shows the portions of the route exposed to iceberg keel contacts. The total length of the route exposed to iceberg risk is 24.1 km. It is likely that the channel provides a higher level of protection from iceberg keels than these results suggest, but it would require the use of a drift-based iceberg contact model to capture this effect. The GEBCO bathymetry used in the analysis shows that a water depth of approximately 20 m is reached 1 km from shore, therefore directional drilling would allow any risk from bergy bits, growler or pack ice (not assessed here) to be avoided. The contact rate for the cable on the seabed includes free-floating, furrowing and pitting icebergs.

Figure 17 shows the cumulative iceberg contact risk along the cable route. The majority of the risk is incurred in the first 25 km. Figure 18 shows mean return periods for iceberg contact with the cable as a function of cover depth. In this case, zero cover depth means the top of the cable is flush with the seabed.

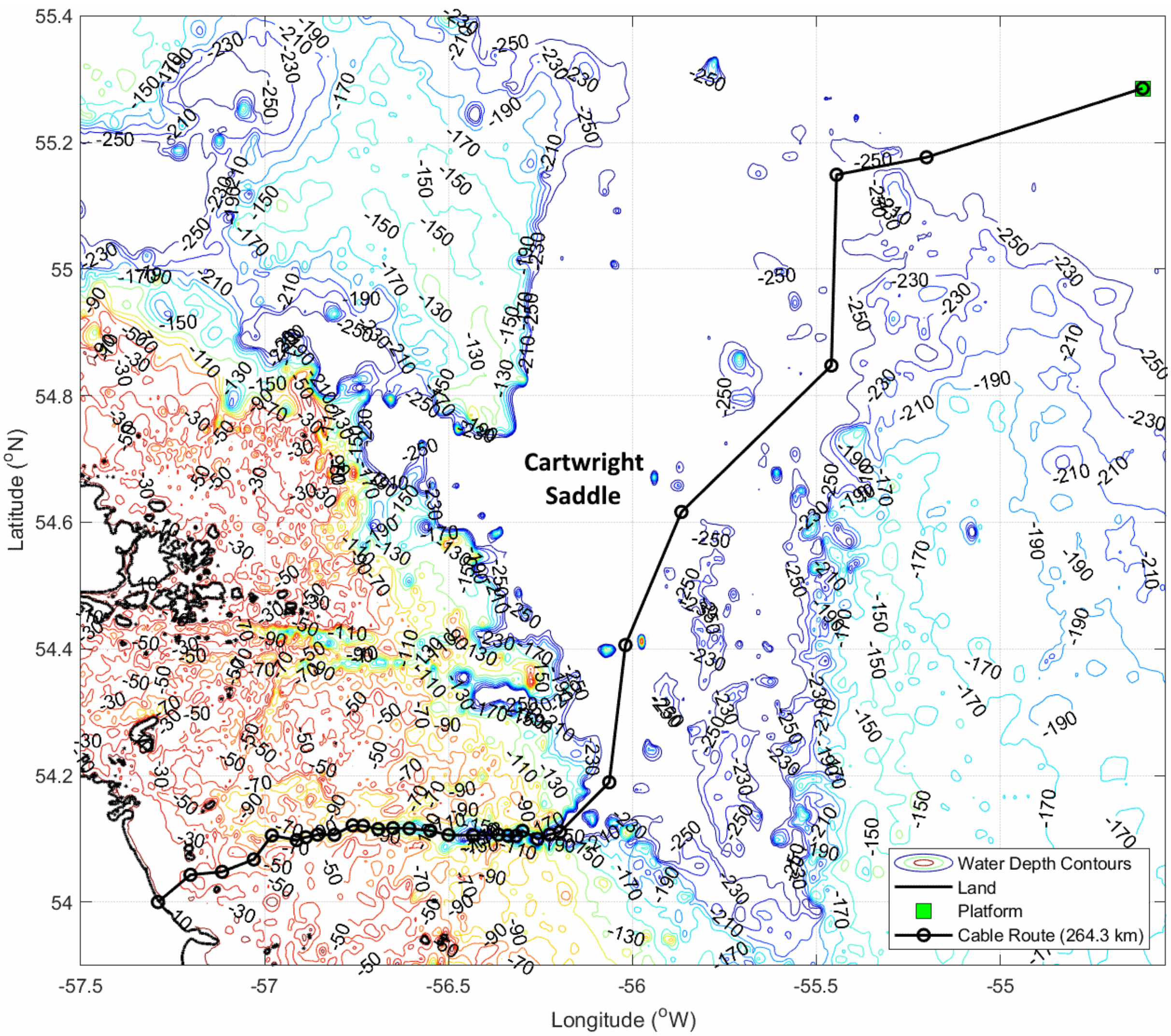

Figure 13. Cable route for Labrador South

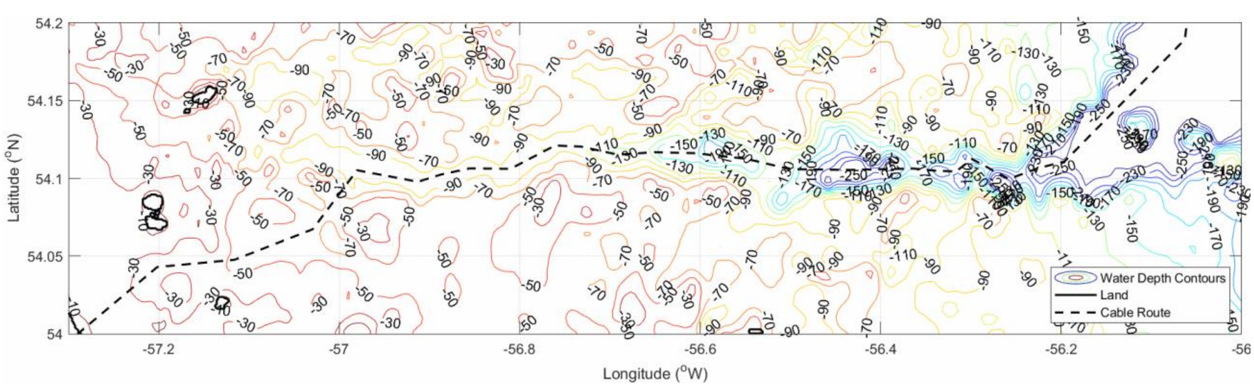

Figure 14. Cable route across inner shelf

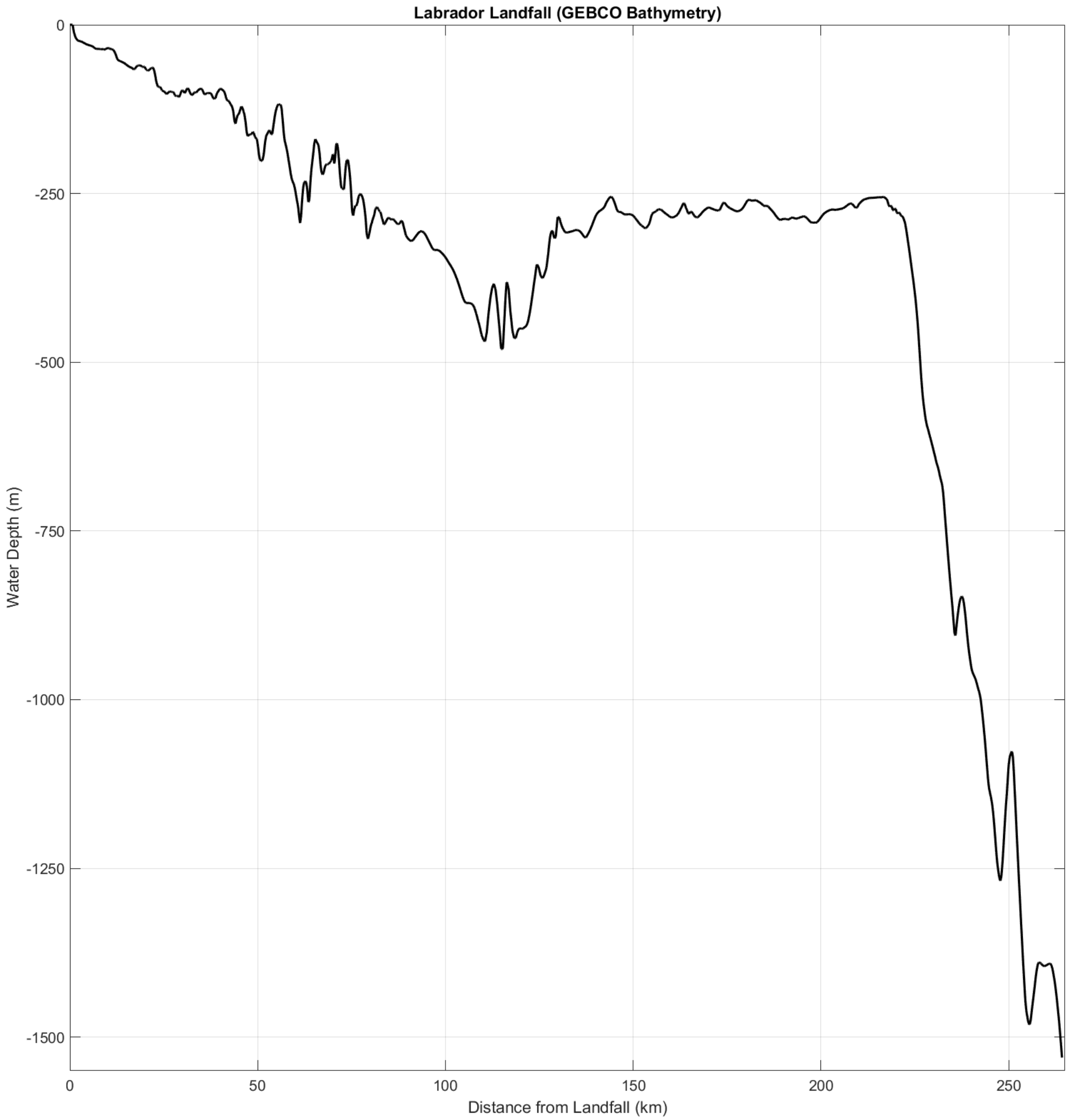

Figure 15. Water depth profile along Labrador South cable route

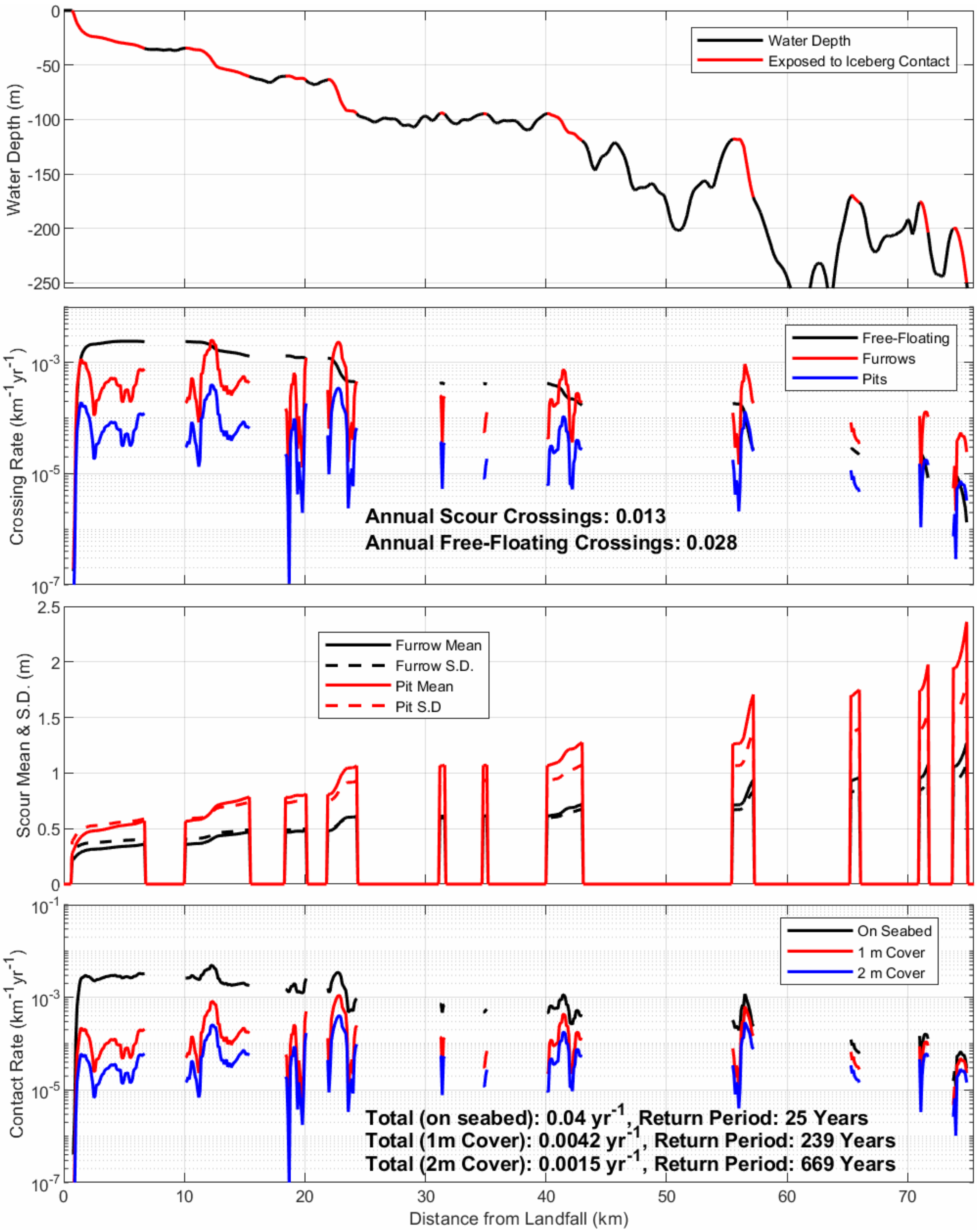

Figure 16. Labrador South cable risk analysis: portions of route exposed to icebergs, iceberg crossing rates over the cable, furrow and pit depth parameters, and contact rates

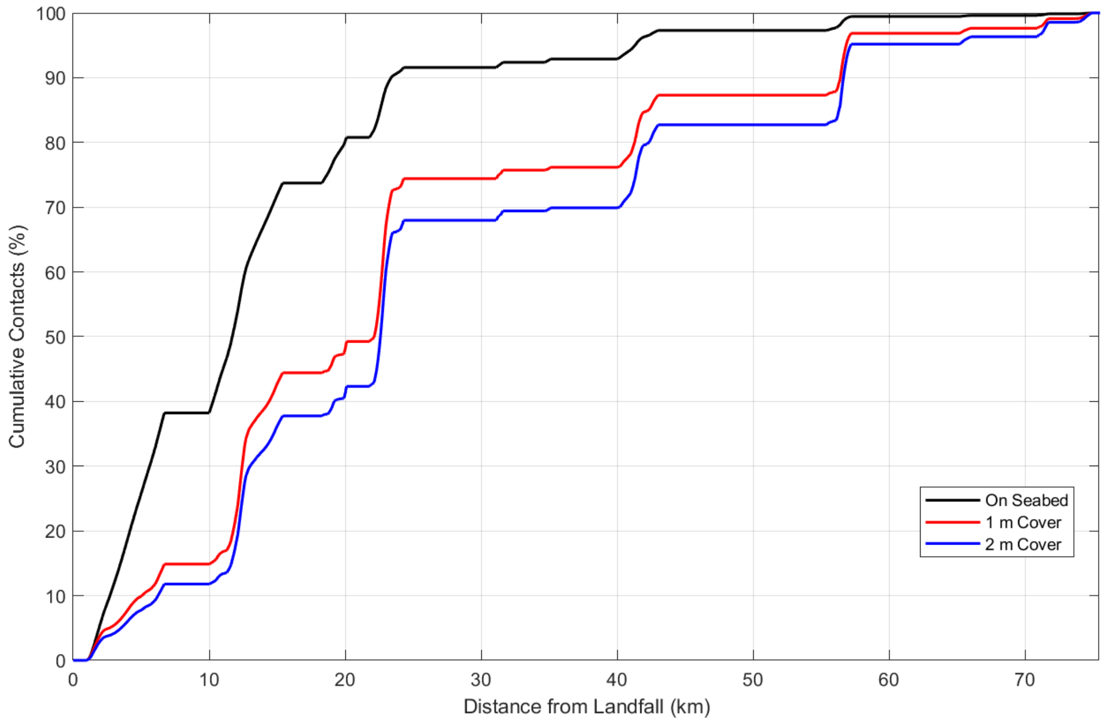

Figure 17. Cumulative contact rate along route for cable on seabed and trenched with 1 and 2 m cover

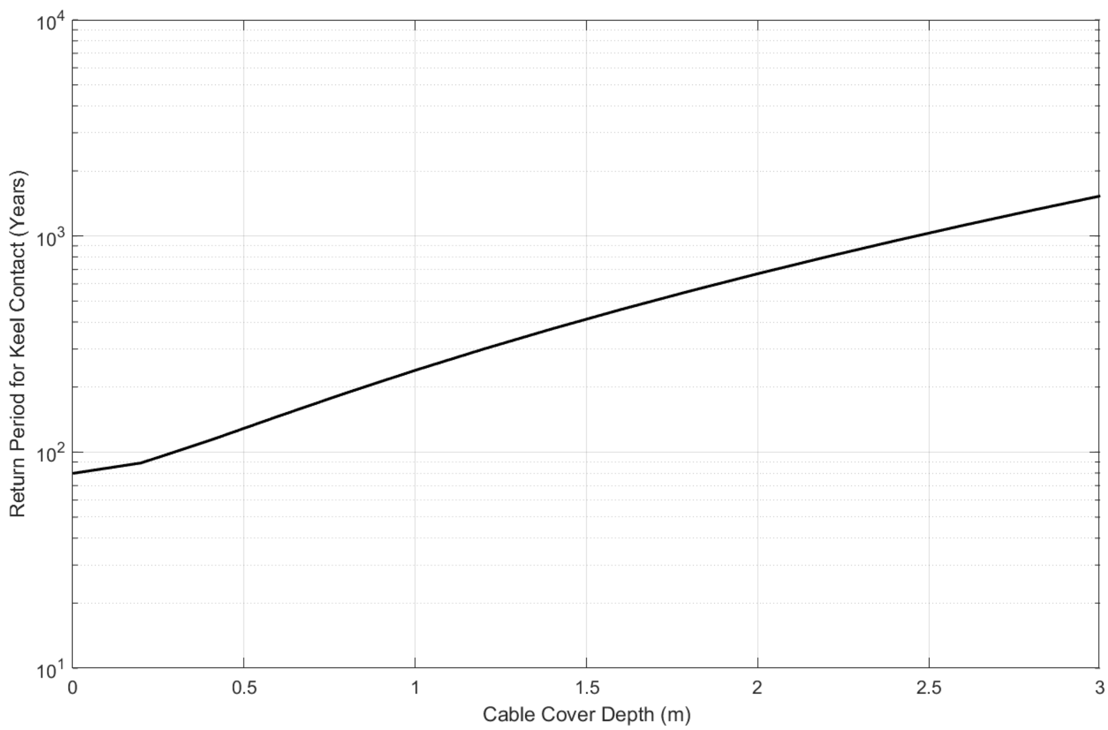

Figure 18. Mean return periods for cable contact as a function of cover depth

3.2 West Orphan Basin

The end coordinates for the West Orphan Basin cable are 50.4724°N, -49.8318°W. Iceberg risk for landfalls in Conception Bay and Trinity Bay is assessed in the following sections.

3.2.1 Conception Bay Landfall

The Conception Bay landfall is near the Holyrood generating facility at 47.4485°N, -53.1030°W. The route heads out to the deepest part of Conception Bay where it is sheltered from iceberg interaction and then straight out to the facility, for a route length of 414 km (Figure 19). Figure 20 shows the water depth profile along the route. The GEBCO bathymetric data indicates that a water depth in excess of 35 m is reached within 1 km of shore.

Figure 21 shows the result of the iceberg risk analysis. A relatively long portion of the cable route (110.3 km) is exposed to iceberg contact. The analysis shows that return periods for iceberg contact in excess of 100 years can be obtained by simply placing the cable on the seabed. While icebergs often drift into Conception Bay and ground off Belle Isle and various locations, available data indicates this particular location within Conception Bay is not an area where icebergs tend to occur. This could be confirmed via local knowledge.

Figure 22 shows the cumulative iceberg contact risk along the cable route. Approximately 50% of the iceberg contact risk is incurred in the first 5 km. Figure 23 shows the cable contact rate as a function of cover depth.

An analysis of iceberg risk using data digitized from Canadian Hydrographic Service bathymetry charts showed similar results, with contact rates approximately 40% lower. These results are summarized in Table 4 in Section 4.1.

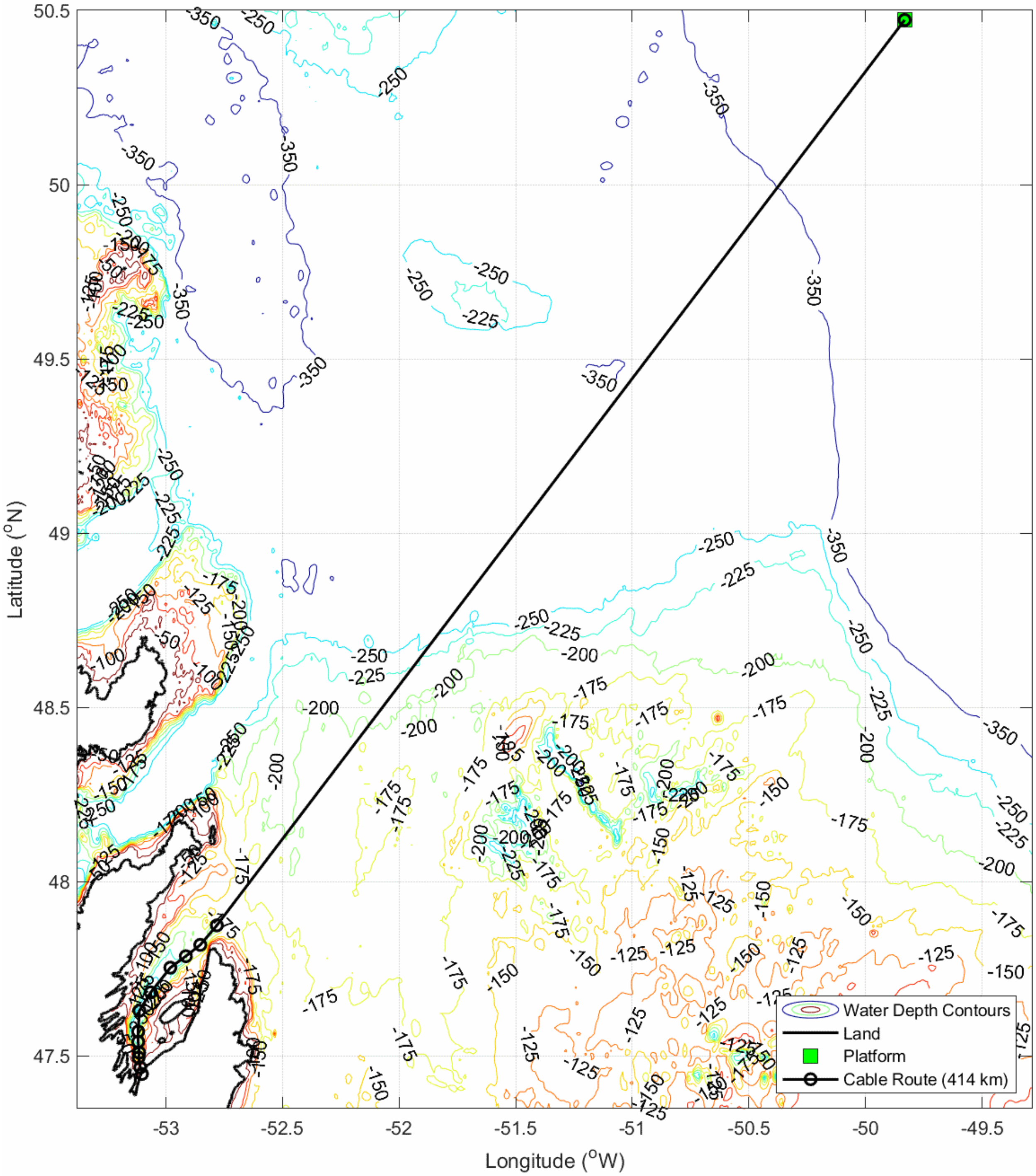

Figure 19. Cable route for West Orphan Basin, Conception Bay landfall

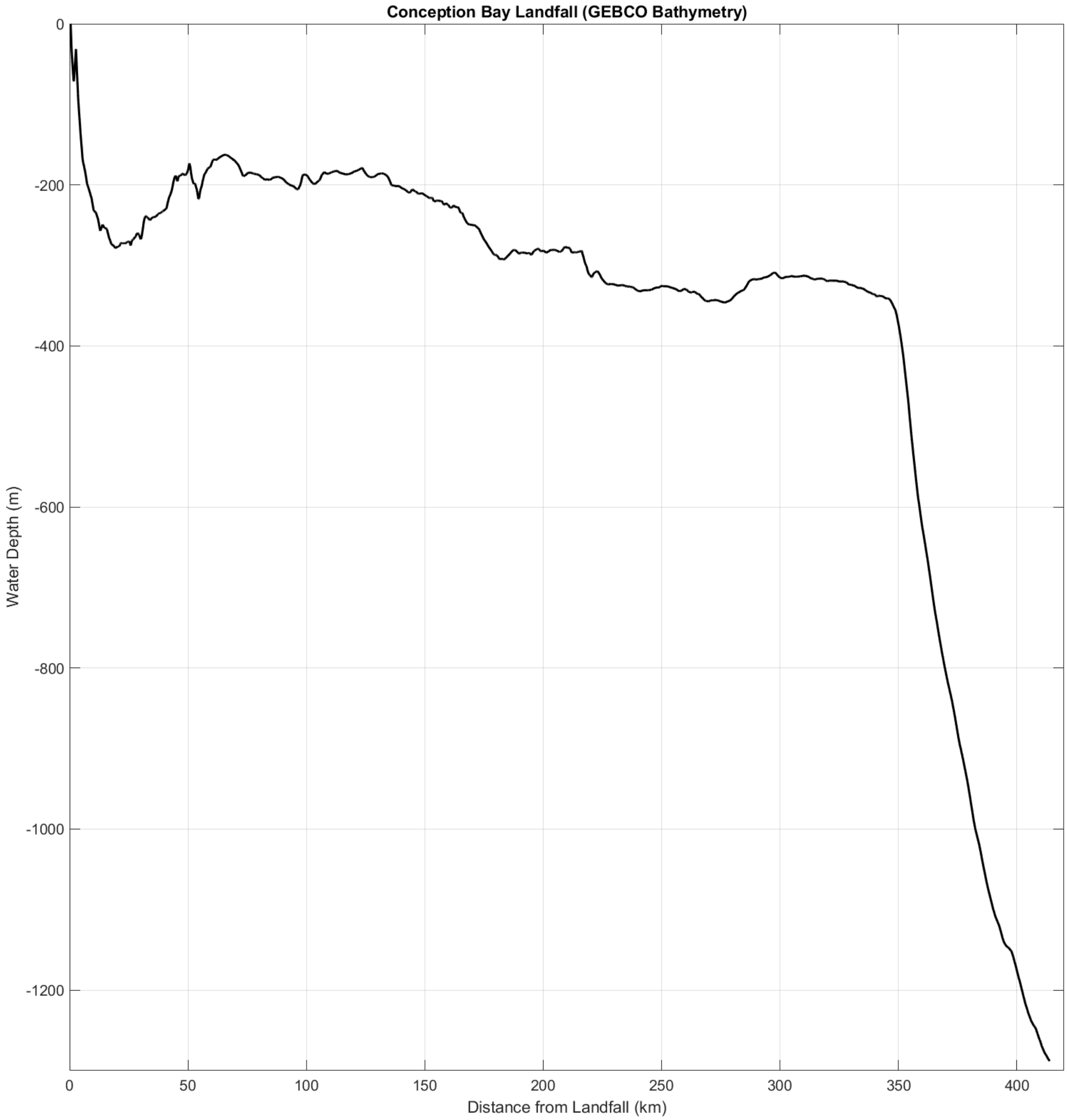

Figure 20. Water depth profile along West Orphan Basin cable route, Conception Bay landfall

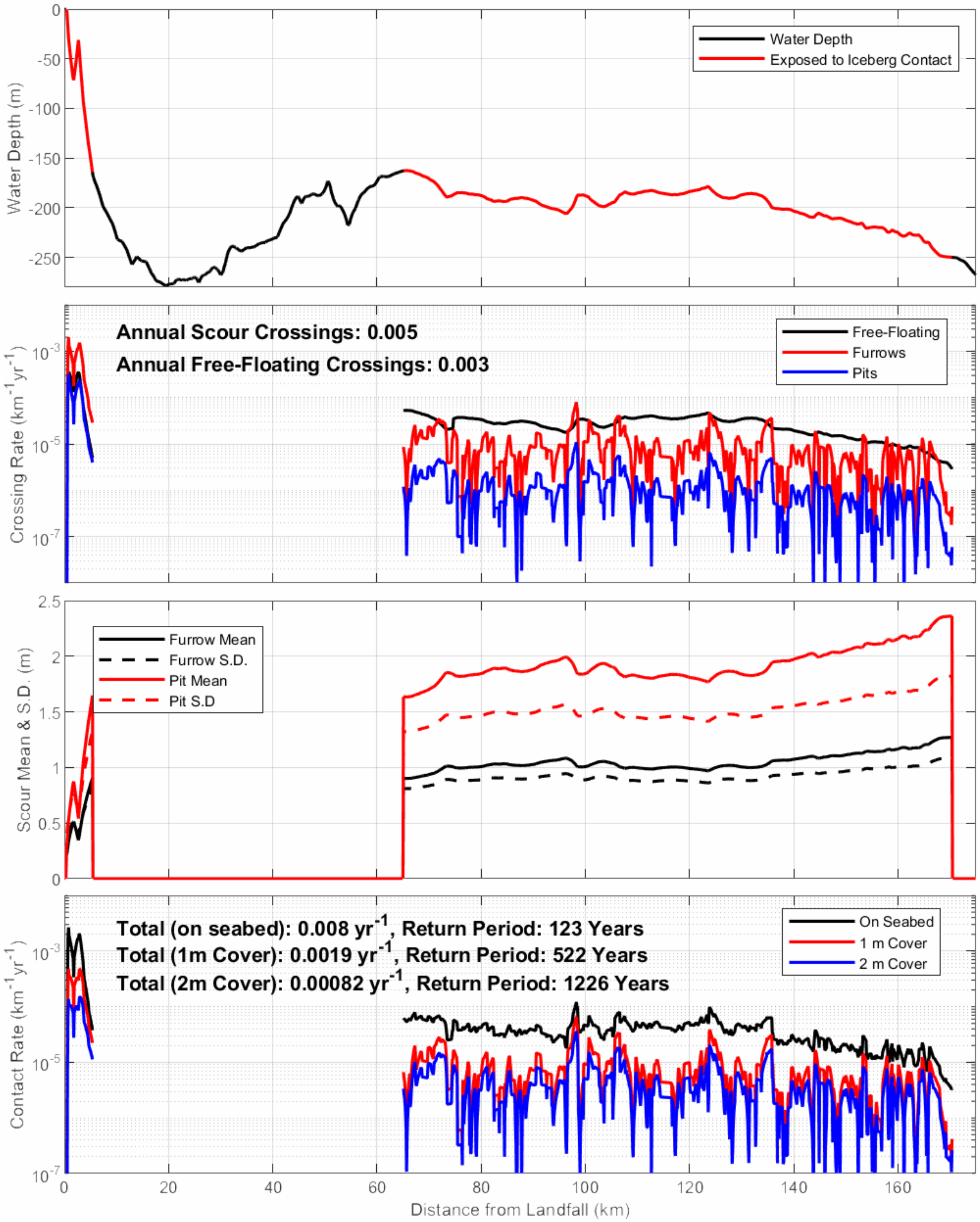

Figure 21. West Orphan Basin cable risk analysis (Conception Bay landfall): portions of route exposed to icebergs, iceberg crossing rates over the cable, furrow and pit depth parameters, and contact rates

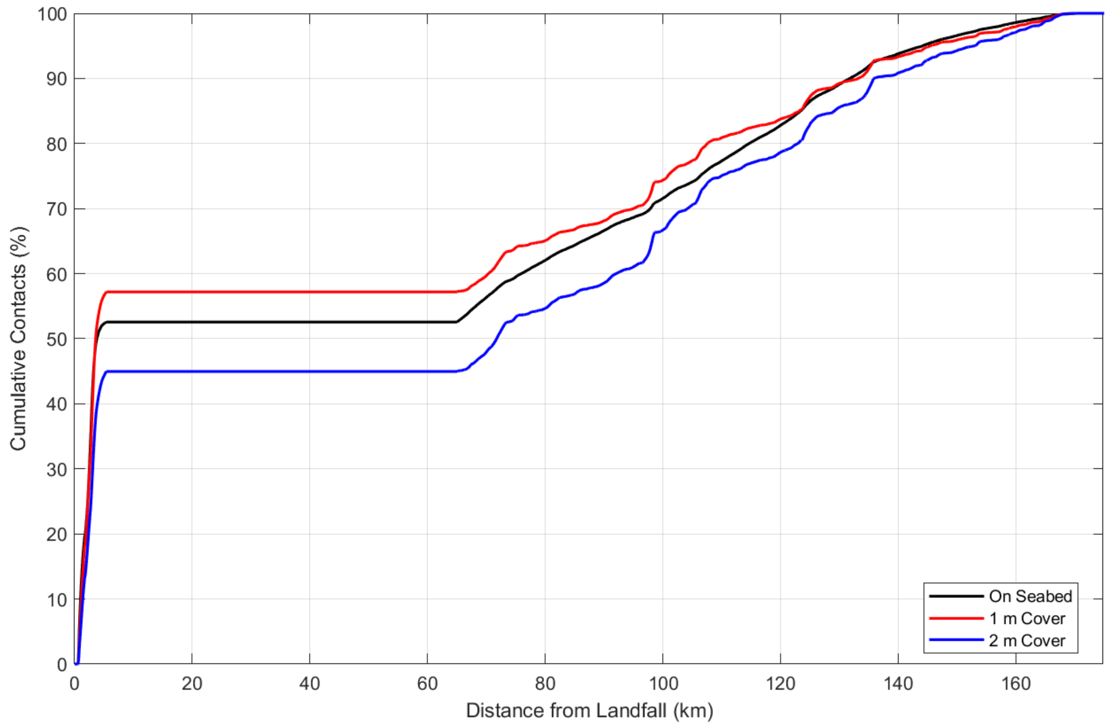

Figure 22. Cumulative iceberg contact risk for cable on seabed and trenched with 1 and 2 m cover

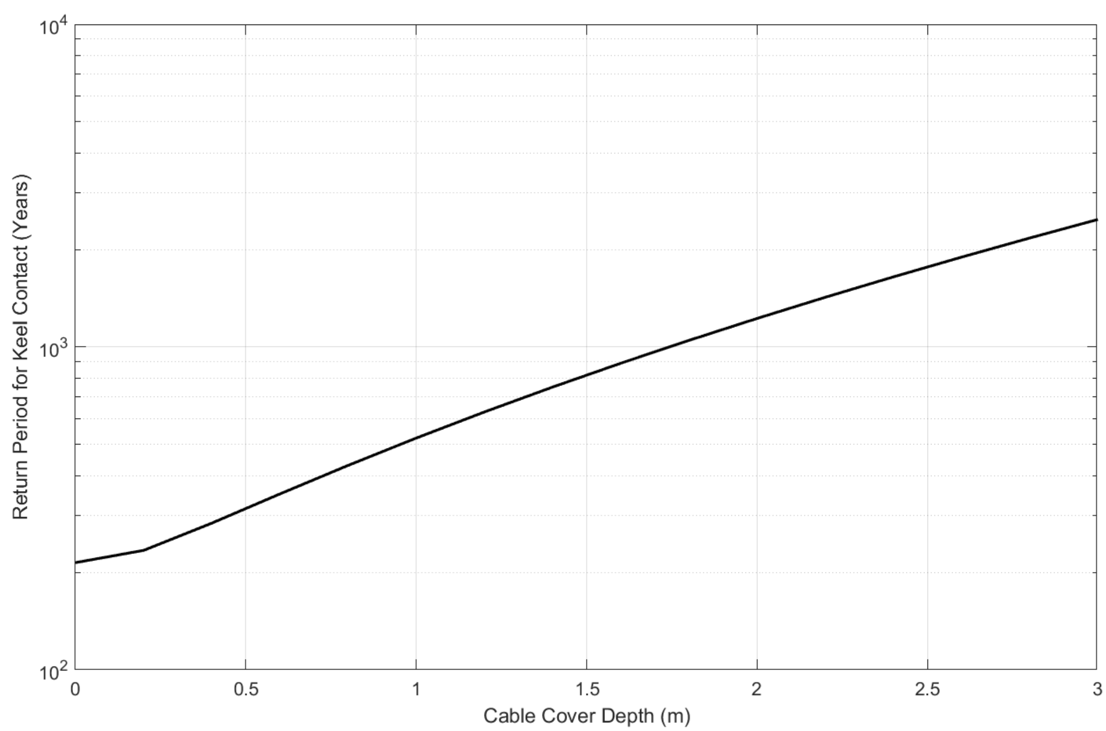

Figure 23. Mean return periods for cable contact as a function of cover depth

3.2.2 Trinity Bay Landfall

The Trinity Bay landfall is near Bull Arm at 47.7191°N, -53.8346 °W. This route takes advantage of the deep water in Trinity Bay to minimize iceberg contact risk. This route is 426 km long, 12 km more than the Conception Bay landfall route. As with the Conception Bay landfall, once out of Trinity Bay the cable route runs directly to the facility location (Figure 24). The water depth profile along the route is shown in Figure 25. Based on the GEBCO bathymetry database, at 60 km from the landfall (off Random Island) the cable route crosses a sill where the water depth decreases to about 197 m. This feature is not shown in Canadian Hydrographic Service charts and may be a flaw in the GEBCO dataset.

Figure 26 shows the results of the iceberg risk analysis for this landfall route. Only a very short portion (12.4 km) is exposed to iceberg contact. As a result of the short section of cable exposed to iceberg contacts, the risk is significantly lower than for the Conception Bay landfall, with a mean return period of almost 500 years for iceberg contact with a cable laid on the seabed.

The cumulative iceberg contact risk is shown in Figure 27. Over 50% of the iceberg contact risk is incurred in the first kilometer. Figure 28 shows mean return periods for iceberg contact as a function of cover depth.

An analysis using bathymetric data digitized from CHS gave iceberg contact rates approximately 30% higher than those obtained using GEBCO bathymetry. These results are summarized in Table 4 in Section 4.1.

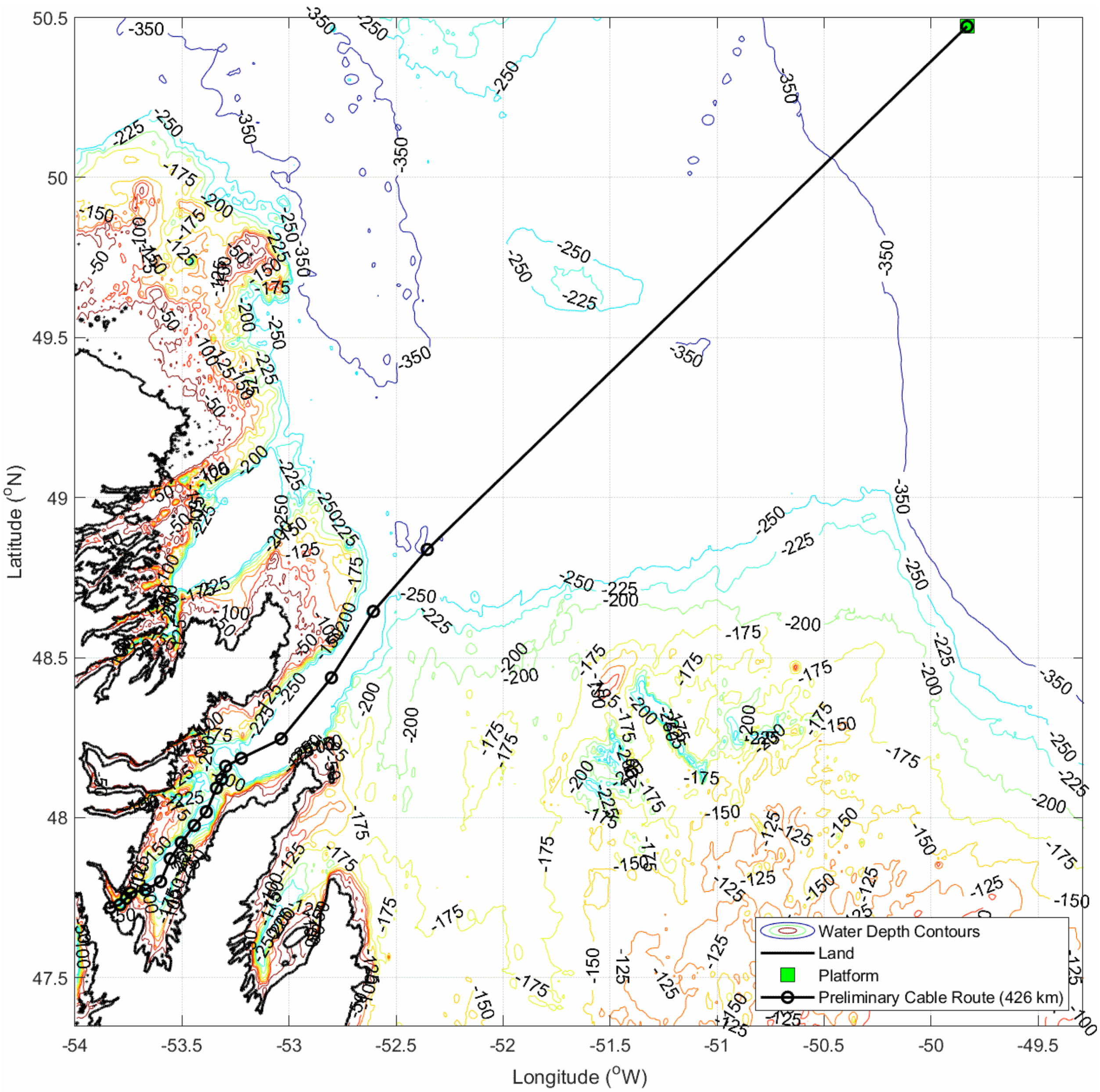

Figure 24. Cable route for West Orphan Basin, Trinity Bay landfall, GEBCO bathymetry

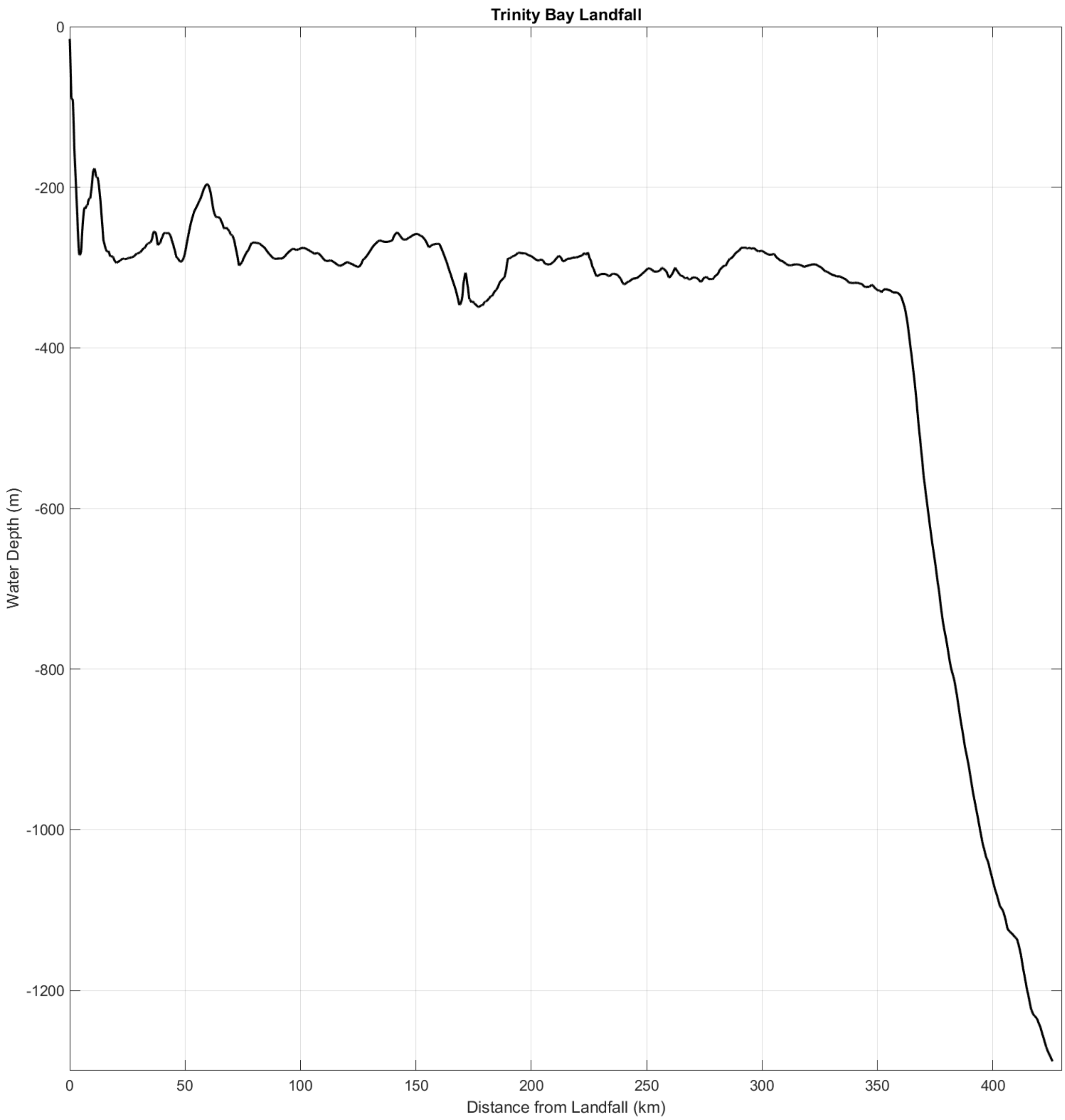

Figure 25. Water depth profile along West Orphan Basin cable route, Trinity Bay landfall

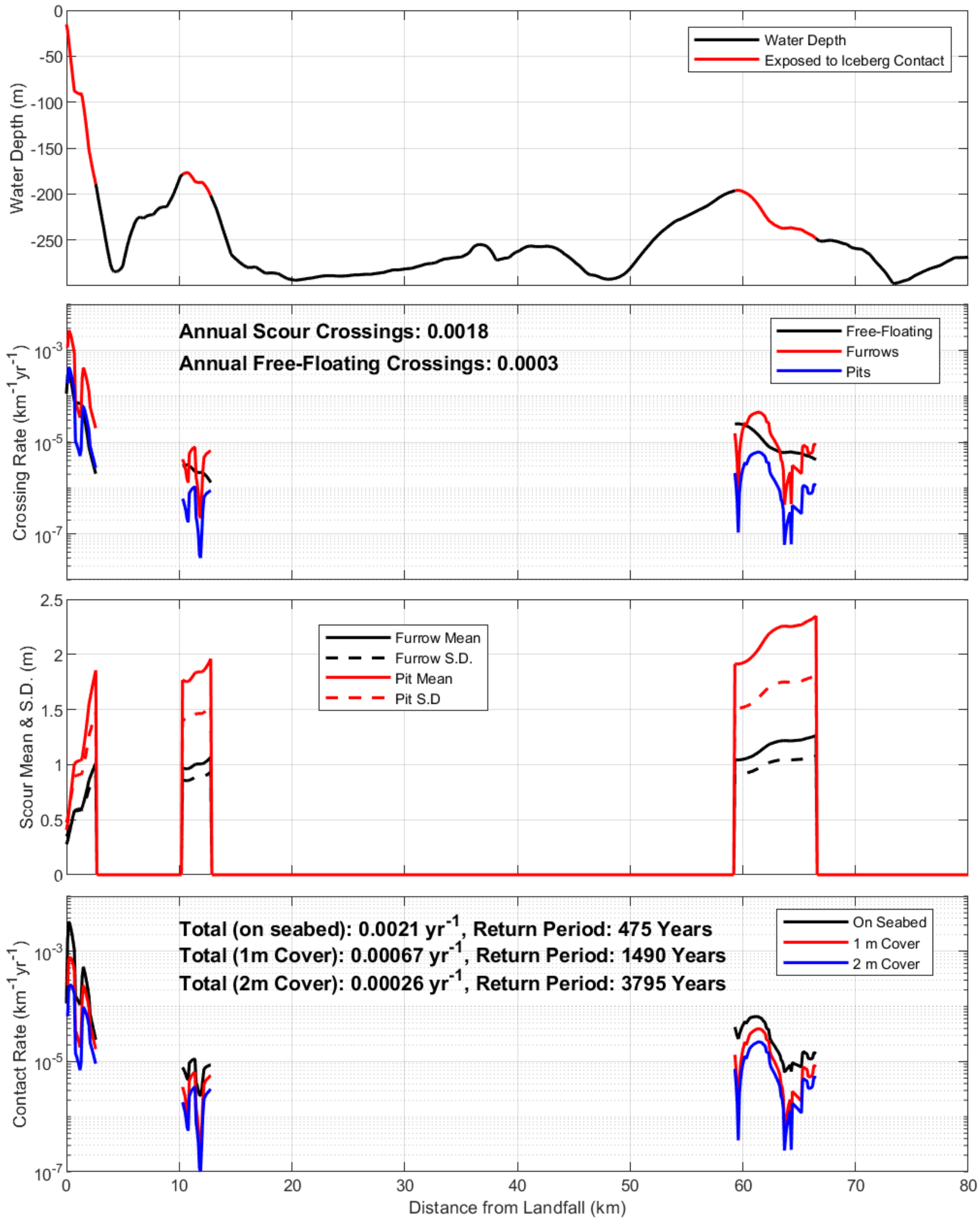

Figure 26. West Orphan Basin cable risk analysis (Trinity Bay landfall): portions of route exposed to icebergs, iceberg crossing rates over the cable, furrow and pit depth parameters, and contact rates

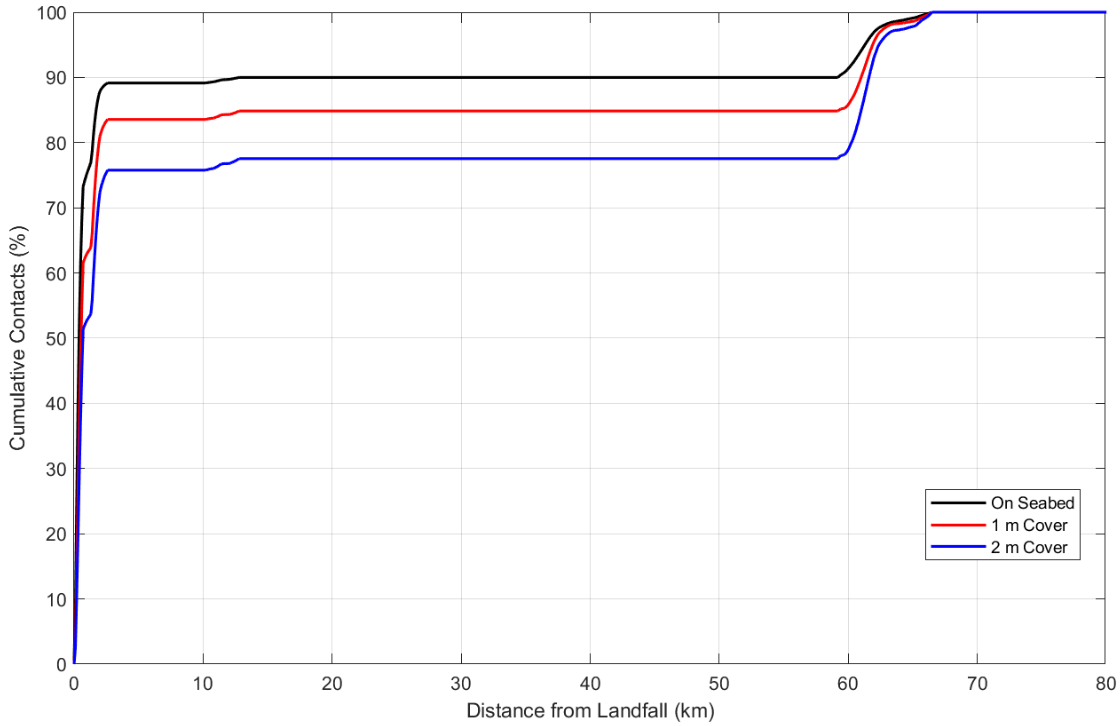

Figure 27. Cumulative iceberg contact risk for cable on seabed and trenched with 1 and 2 m cover

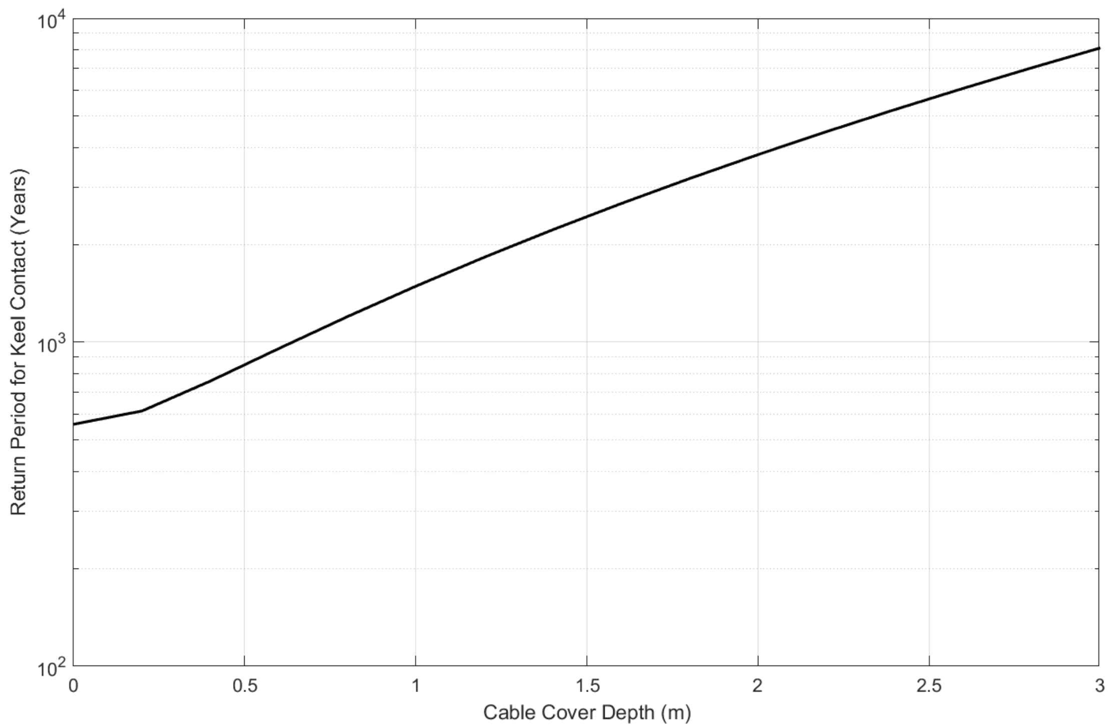

Figure 28. Mean return periods for cable contact as a function of cover depth

4 Conclusions and Recommendations

4.1 Conclusions

A summary of results of the iceberg risk analyses are given in Table 4. Iceberg risk for trenched cables is based on direct keel contact. Typically, a pipeline burial analysis would include a clearance between the scouring keel and the pipe crown. A similar allowance may be required for cables, but this would require a more in-depth analysis. Trenching for the cable cover depths indicated would only be required for portions of the routes indicated as being at risk of iceberg contact, not the full route.

Table 4. Summary of annual iceberg contact rates (mean return periods in years shown in brackets)

Route	Bathymetry Source	Route		
		On Seabed	1 m Cover	2 m Cover
Labrador South	GEBCO	0.040 (25)	0.0042 (240)	0.0015 (670)
West Orphan Basin (Conception Bay landfall)	GEBCO	0.0081 (125)	0.0019 (520)	0.00082 (1200)
West Orphan Basin (Conception Bay landfall)	CHS	0.0060 (165)	0.0011 (920)	0.00049 (2100)
West Orphan Basin (Trinity Bay landfall)	GEBCO	0.0021 (475)	0.00067 (1500)	0.00026 (3800)
West Orphan Basin (Trinity Bay landfall)	CHS	0.0031 (325)	0.00084 (1200)	0.00030 (3400)

4.2 Recommendations

Collection of additional seabed survey data along the various cable routes is recommended. In some cases existing data, such as seabed survey data collected in Trinity Bay for the Hebron GBS tow-out could be utilized. Shallow water surveys in early spring near the Labrador cable landfall would show whether pack ice might be a consideration. Also with respect to the Labrador landfall, the sheltered channel in the inner shelf should be targeted for a multibeam survey.

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Appendix B: 2x45-65MW FPSO LFAC Load Analysis

Load analysis based on 2x45MW load with 2x65MW peak.
<*Redacted from public report*>

Appendix C: Representative LFAC Power Distribution Schematic

Power distribution schematic is preliminary and based on a 2x45MW load.
<Redacted from public report>

Appendix D: 4x50MW FPSO LFAC Load Analysis

Load analysis based on 4x50MW load with 2x65MW peak.
<*Redacted from public report*>