FLOATING OFFSHORE WIND CENTRE OF EXCELLENCE

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FLOATING OFFSHORE WIND CENTRE OF EXCELLENCE

MOORING LINE AND DYNAMIC CABLE MONITORING AND REPLACEMENT METHODOLOGIES

Public Summary Report

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PREFACE

Offshore Renewable Energy Catapult (ORE Catapult) has established the Floating Offshore Wind Centre of Excellence (FOW CoE). The FOW CoE is a collaborative programme with industry, academic and stakeholder partners.

The vision of the FOW CoE is to establish an internationally recognised centre of excellence in floating offshore wind which will work towards reducing the Levelised Cost of Energy (LCOE) from floating wind to a commercially manageable rate, cut back development time for FOW farms and develop opportunities for the local supply chain, driving innovation in manufacturing, installation and Operations and Maintenance (O&M) methodologies in floating wind.

More details on the FOW CoE can be found on: https://fowcoe.co.uk/

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1 EXECUTIVE SUMMARY

This study establishes a practical framework for the monitoring, repair, and maintenance of mooring systems and dynamic cables in floating offshore wind farms. The study assumes a representative 900 MW North Sea site as a case study, examining failure behaviour, repair methodologies, and operational constraints. At this scale, arrays comprise hundreds of mooring lines and dynamic cable systems, resulting in significant operational, logistical, and cost implications.

Mooring failure is a major concern for floating wind arrays, due to the cost of repair, and the potential for more serious cascading consequences. Decades of oil and gas mooring experience shows that mooring failure is inevitable at the Gigawatt array scale; mooring systems must be designed for repair.

Mooring failures may range from isolated events with specific causes, to systemic degradation requiring large-scale replacement campaigns. Single mooring line repairs can typically be completed within approximately 4–6 vessel days at a cost of around £1 million per event. Winter weather downtime can double or triple this cost. Larger replacement campaigns scale rapidly, with replacement of 36 lines (10% of the array) requiring 1–2 months of vessel time and a cost of £7 million. Replacing half of the mooring lines in an array (180 lines), which is a credible scenario for systematic mooring integrity issues, can extend beyond 200 days with costs in excess of £30 million.

It is also imperative that mooring design and integrity response planning prevents single line failures from cascading to corner failure or free drift. Most recorded integrity issues have proven to be systematic, which increases the risk of failure for multiple lines. The consequence of corner failure or free drift can exceed £100 million. If not properly assessed and mitigated, such events give intolerable risk at the Gigawatt array scale. A risk-based approach is recommended to eliminate, mitigate, and detect mooring integrity risks.

Efforts to reduce these risks are hindered by lack of sharing of mooring integrity and performance lessons learned on floating wind demonstrator projects. This is a missed opportunity for the sector as it allows critical exposures to be replicated on multiple systems.

End-to-end inter-array cable replacement can typically be completed within approximately 15 days under favourable conditions, costing £5 million in vessel hire. More complex repair joint operations require longer durations and are significantly more sensitive to weather downtime.

Weather downtime is shown to be a key driver for repair cost, with winter operations on average taking twice as long and incurring double the cost compared to equivalent summer activities. This effect increases disproportionately with the scale of intervention, such that cable repair and large scale mooring replacement campaigns become highly dependent on favourable seasonal windows. A two week cable repair operation in summer conditions increases to 1 to 3 months in winter conditions.

Array cable risk is driven by the interaction between weather conditions, lead time, and lost revenue impact. The extent of lost revenue depends on cable topology and fault location. In high curtailment scenarios where the array has limited redundancy for power transfer, immediate repair during winter may be more cost-effective, despite increased vessel costs. However, for weather-sensitive operations, delaying intervention to favourable seasonal windows can reduce overall cost. Vessel availability may be limited for immediate repair during periods of peak construction demand, or when responding to multiple failures caused by the same storm. Operators can expect to pay a premium vessel day rate for short term repair operations in such periods.

Overall, there is no one approach that is optimised for all cases. A robust maintenance strategy should explore a range of scenarios and be adaptable. Decision-making should include consideration of integrity risk, spares and vessels availability, production downtime, and weather downtime.

CONTENTS

NOMENCLATURE

ALARP	As Low As Reasonably Practical
ALS	Accidental limit state
AUV	Autonomous Underwater Vehicle
CFE	Controlled Flow Excavator
CoE	Centre of Excellence
DGPS	Differential global positioning system
DVL	Doppler velocity log
FMECA	Failure Mode, Effects, and Criticality Analysis
FOW	Floating Offshore Wind
FOWT	Floating Offshore Wind Turbine
FPSO	Floating Production, Storage and Offloading vessel
HLS	Horizontal lay system
IAC	Inter Array Cable
IMU	Inertial measurement unit
ORE	Offshore Renewable Energy
O&G	Oil and Gas
O&M	Operations and Maintenance
ROV	Remotely Operated Vehicle
SOV	Service operation vessel
ULS	Ultimate limit state
VLS	Vertical lay system

WP	Work Package
W2W	Walk to work

2 INTRODUCTION

2.1 Study aims and overview

With substantial commitments to developing Floating Offshore Wind technology for ScotWind and other initiatives, there will be a large number of mooring lines and dynamic cables in service – approximately 1000 dynamic cable connections and 2000 mooring lines for 6GW of floating wind by 2035. Experience from floating production assets and bottom fixed wind arrays indicates that mooring lines and cables are prone to degradation and failure. Efficient and well understood integrity management, repair and replacement strategies are required to ensure manageable OPEX costs for Gigawatt scale floating wind arrays. Such strategies are best understood early in the project lifecycle to guide design and procurement decisions.

This project is an important opportunity to establish a practical baseline for the monitoring, repair and replacement operations for mooring systems and dynamic cables. The study highlights the scale of the mooring and cable repair challenge. The impact to bottom-line costs are demonstrated and demystified with in-depth storyboards. Importantly, the opportunity to reduce cost and risk impacts will be explored with a range of technology and methodology sensitivity scenarios.

2.2 References to other work

Relevant studies are referenced though this study including:

- ORE Catapult – Gigawatt scale floating wind mooring and cable installation study [1]
- ORE Catapult – Tow to port off-station management study [2]
- ORE Catapult – Dynamic cable connection and topology comparison [5]
- ORE Catapult – Failure implications of different mooring spreads and lines [6]
- ORE Catapult – Dynamic cable technology qualification framework and case studies [7]

3 CASE STUDY DEFINTION

3.1 Wind farm location

The base case for this report focuses on a floating wind development site 100km off the North-East coast of Scotland in 100m water depth. The location is geographically representative of many ScotWind sites. Distances between sites and suitable ports range from 50 Nautical Miles to 100 Nautical Miles, giving a 5 to 10 hour transit at 10 knots. An upper bound 10-hour transit is considered in the study.

The study wind farm layout is shown in Figure 1. It consists of five clusters comprising of 60 FOWTs, each rated at 15MW, placed 2500m apart.

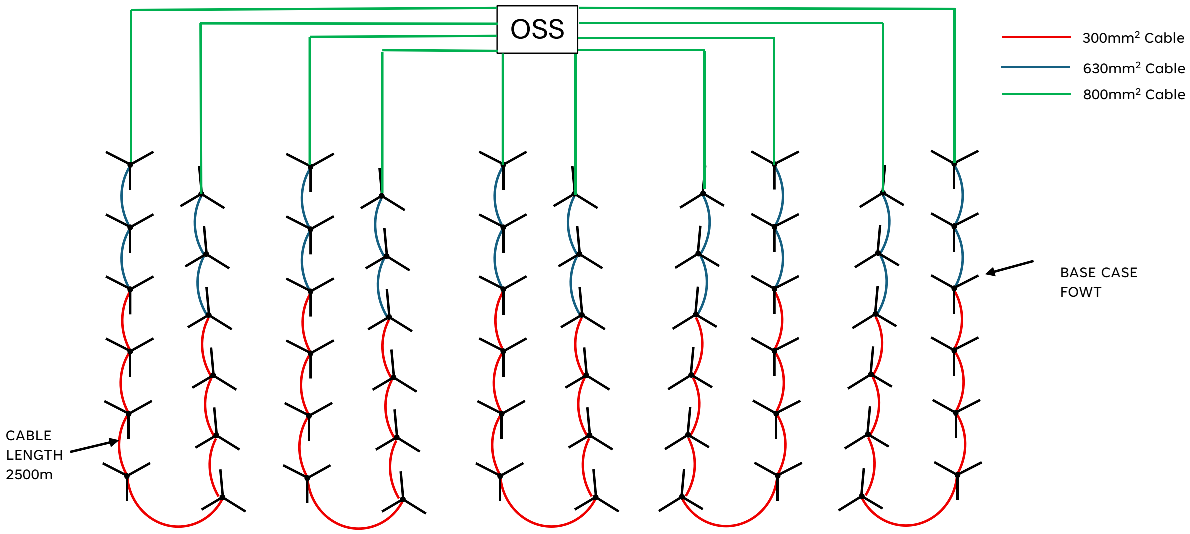


Figure 1 – Base case five cluster field comprising of 60 FOWTs (900MW)

The base case study site and array parameters have been chosen to be consistent with the ORE Catapult gigawatt scale installation project [1] and tow to port study [2].

3.2 Floating offshore wind turbine definition

The base case foundation for this study is the University of Maine VolturnUS steel semi-submersible 15 MW offshore turbine [4]. The scale and main dimensions of the FOWT are shown in Figure 2.

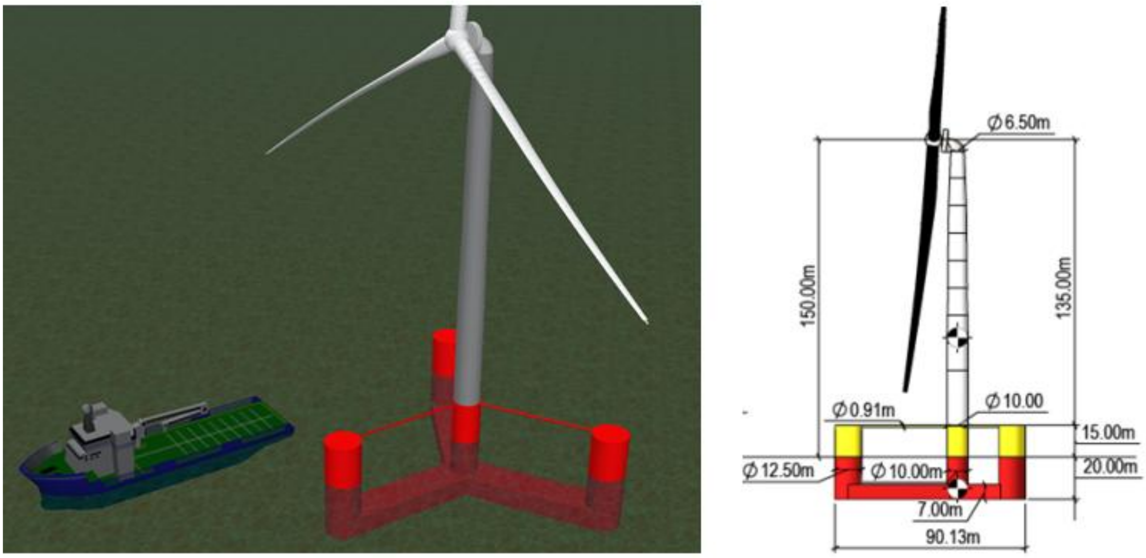


Figure 2 – 15MW FOWT alongside a 90m long installation vessel (left) and main dimension (right)

3.3 Mooring system base case

The base case mooring design for this study is shown below. It consists of a 6-line semi-taut polyester system with a 150m section of 132mm bottom chain and 700m of 218mm polyester rope. In-line buoys are included to maintain positive polyester rope clearance from the seabed for leeward lines. A direct rope pull-through quick-connection system allows each mooring rope to be pulled into the FOWT with a work wire. Note that 'base case' denotes the system design that is the primary focus for this study, however further designs are considered as sensitivities.

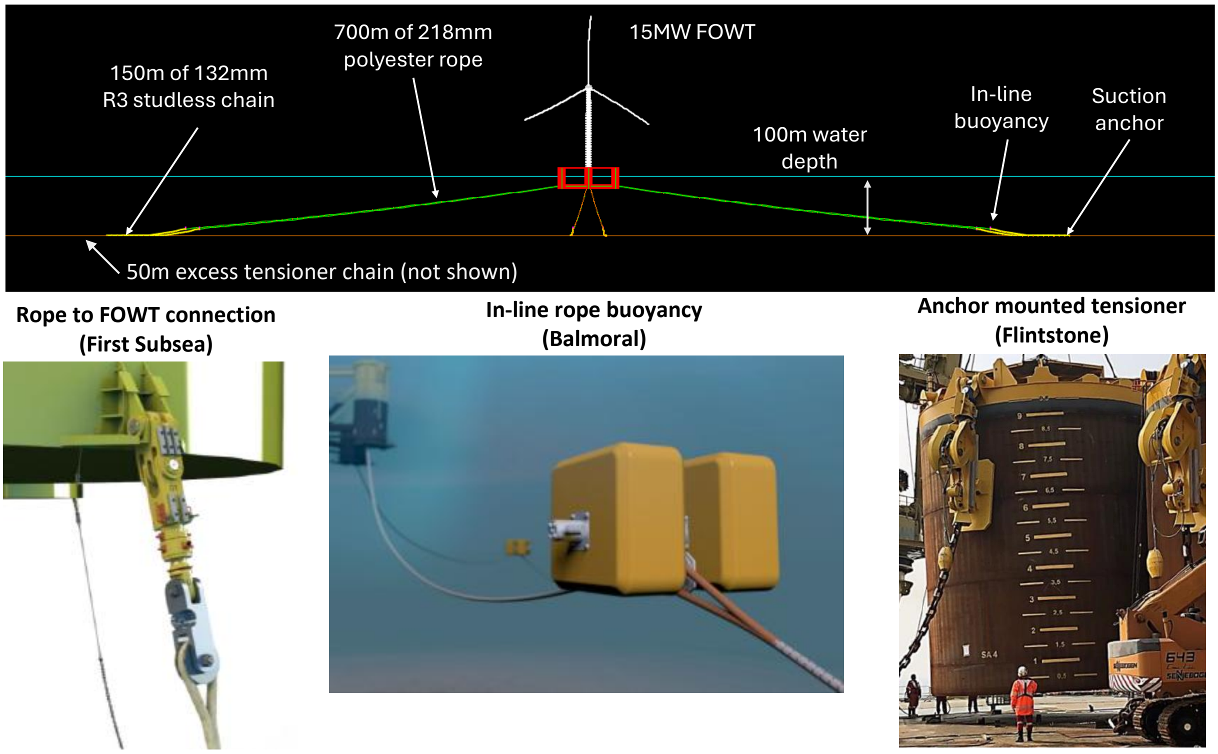


Figure 3 – Base case 6-line mooring system

3.4 Cable system base case definition

The dynamic cables utilise a lazy wave configuration and comprise of buoyancy modules, tether camps, hold back anchor and bend stiffeners as shown in Figure 4.

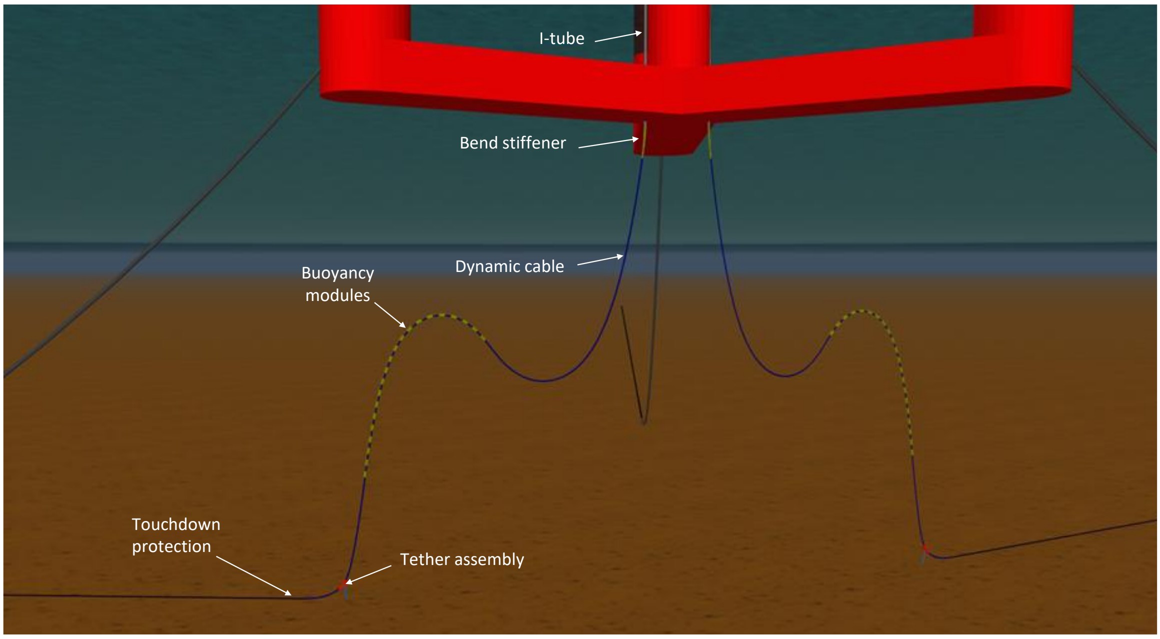


Figure 4 – Dynamic tethered cable lazy wave configuration

The cable ends are terminated within a pull-in head, with dry mate connectors fitted in the cable factory. The cables are pulled in via a winch and suitable sheave on the installation vessel. An example of a pre-terminated cable reel and a schematic of the pull-in system is shown in Figure 5.

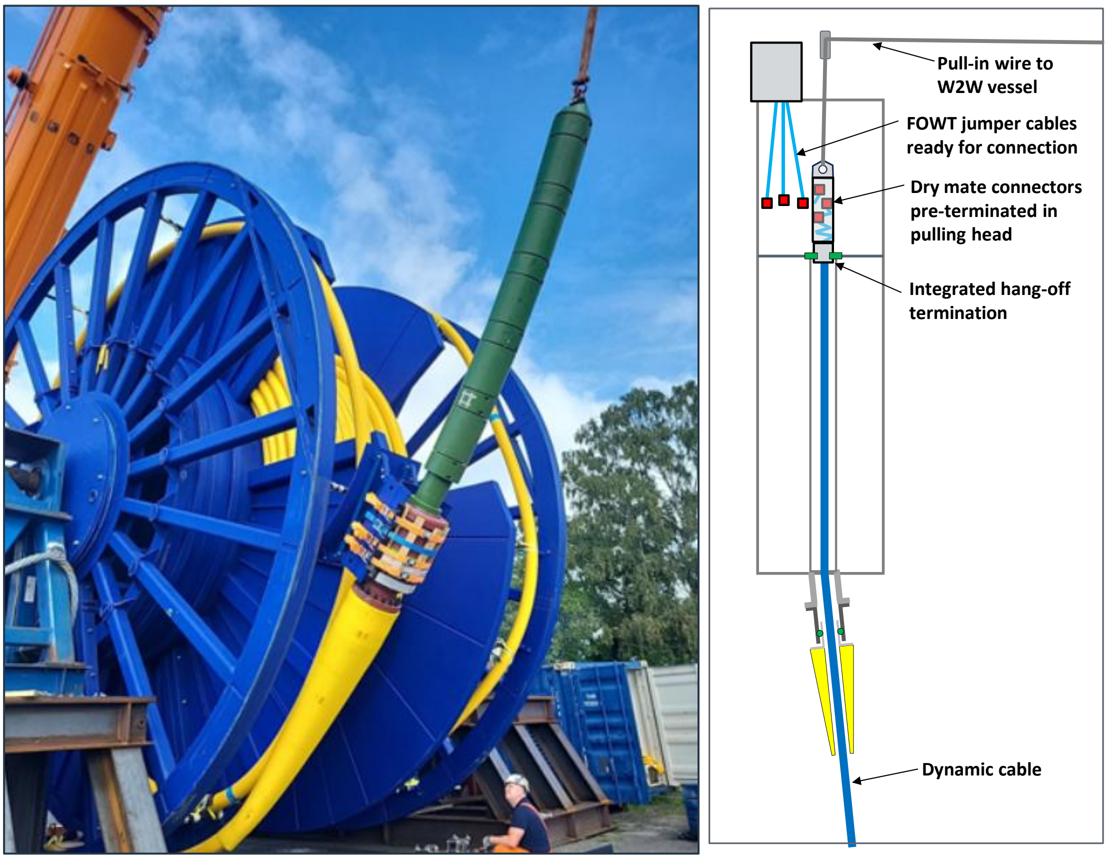


Figure 5 – Pre-terminated and reel mounted 66kV 150mm^2 cables for the Provence Grand Large project (left) and a dry mate pull-in system schematic (right)

3.5 Vessel & equipment definition

The offshore installation vessels are defined to be consistent with previous installation and tow to port studies [1] [2]. The cost, duration, and weather limit requirements for the offshore repair operation are highly dependent on the vessels selected for the job.

Vessel day rates have been forecast referencing installation in 2028. Note that vessel day rates can vary by an order of magnitude depending on capability, and spot market variability, and long-term constraints on vessel supply. Historically, lower day rates occur during periods of vessel inactivity, whilst a high day rate occurs during a peak summer demand period.

Considered vessels include W2W-equipped SOV, support AHTS, a main AHTS, minor cable handler, and a major cable handler.

3.6 Cable repair vessel and mobilisation

For cable handling operations, multi-purpose construction vessels have been selected. These vessels are widely available on the market and provide versatility in terms of the required lifting, cable handling, and ROV survey capability. For cable pull-in and wet storage operations, a W2W vessel could be used with minor modifications. For more complex cable handling operations, a cable lay vessel with a tensioner system will be required. It should be noted that the installation of dynamic cables requires a different lay spread arrangement and vessel type from static cables, which is likely to attract a higher vessel day rate.

This project used DOF's Skadi Acergy with a reel drive and Horizontal Lay System (HLS). Alternative methods could use a Vertical Lay System (VLS) and underdeck carouself for cable storage. A spare 2.5km length inter-array cable reel of each size (300mm2, 630mm2, and 800mm2) is assumed to be available in storage for repair operations. Two pre-terminated dynamic sections with connectors, pull-in head, bend stiffeners, buoyancy, and other ancillaries are included with the spare cable sections. Two cable repair joints should also be available as spares for the largest OSS cable string size to enable a repair of that section.

3.7 Mooring repair vessel and mobilisation

For single line mooring repair operations, a minimum requirement is an AHTS vessel equipped with a work ROV, deck and winch capacity for large diameter mooring rope and chain handling, and sufficient bollard pull or crane capacity to re-tension mooring lines.

It is assumed that the following spare mooring components are available ready for repair operations:

- 6 x spare bottom chain sections (200m length each)
- 6 x spare polyester sections terminated with FOWT quick-connect at one end and thimble at the other end (700m length each)
- 6 x spare mooring buoys and a full set of spare connectors for one FOWT mooring

The above spares are well within the chain locker and deck capacity of a capable anchor handler if a complete FOWT mooring change-out was required. For 132mm chain, large anchor handlers can fit 12 x 200m sections on board. Up to 12 rope lengths could be stored on board, assuming some rope reels could be stored on deck and transpooled to the winches in operation. It is assumed that anchors could be sourced or fabricated for a major anchor replacement operation, and would not be required to be held as a spare. An outline of the quay space requirements for storage of the full set of spare equipment alongside the Skandi Skansen at Montrose South Quay is outlined below.

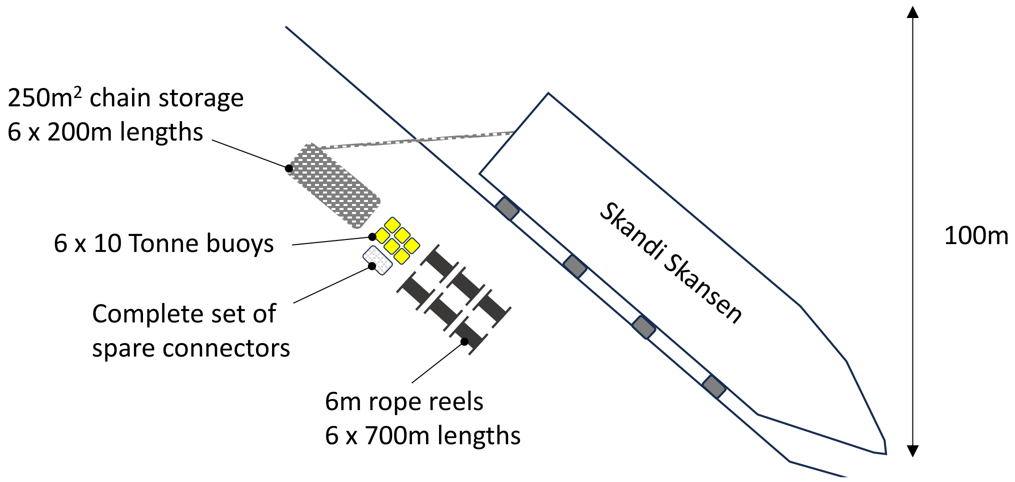


Figure 6 – Skandi Skansen complete FOWT mooring loadout alongside Montrose South Quay

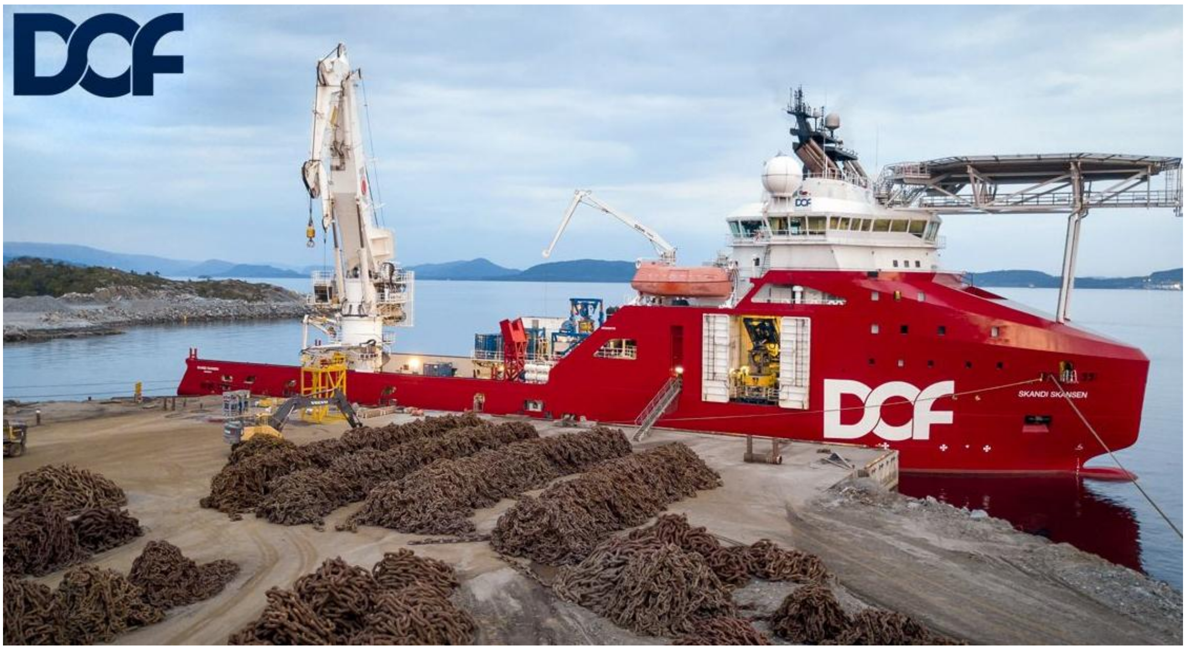


Figure 7 – High-capacity AHTS: Skandi Skansen

4 MOORING FAILURE MODES & MONITORING

4.1 Floating wind mooring failure publications

Previous studies on mooring integrity risks for floating wind are highlighted in the table below. It is notable that the publications to date have focussed on future floating wind arrays, with limited data on the performance of the current fleet of floating wind demonstrators. Where historical integrity issues are referenced, statistics and lessons learned from O&G mooring system failures are used.

Table 1: Publications on floating wind mooring integrity

Publisher	Document	Scope
HSE & MCA	Regulatory expectations on moorings for floating wind and marine devices (2017)	Outlines legal requirements and regulatory expectations for mooring integrity risk.
WFO	Insurability of floating offshore wind (2021)	Includes section on mooring risk and insurability
WFO	Mooring systems for floating offshore wind: integrity management concepts, risks, and mitigation (2022)	Guidance on mooring integrity risk and integrity management.
The Carbon Trust	Moorings system redundancy, reliability and integrity (2023)	Mooring failure rate and mooring integrity risk study.
JNRC	Risk Engineering Guidelines for the Insurance of Floating Offshore Wind Farms (2024)	Includes section on mooring risk and insurability
HM Coastguard	Floating Offshore Wind Workshop report (2024)	Reviews emergency response planning for drifting floating turbines
ORE Catapult	Failure implications of different mooring spreads and lines (2024)	Quantitative risk assessment of floating wind mooring failure with different redundancy levels.
The Carbon Trust	Commercial Scale Mooring Integrity Management (2025)	Building on the 2023 study to focus on mooring integrity risk management.

4.2 Oil & Gas failure statistics

There is very little public domain data on FOWT mooring failures and integrity issues. Insights into documented failure events from O&G studies have been used to build credible failure scenarios and reliability estimates.

4.2.1 Probability of failure

The 2022 DeepStar JIP publication [8] is used as the governing mooring line failure data set for the risk study, as it contains the most recent and comprehensive incident and population data. The data covers 77 permanently moored floating production assets operating worldwide. Two thirds of the assets were spread or turret moored ship shaped units. The remaining assets semi-submersibles, spars and CALM buoys. The failure rate statistics are consistent with previous studies such as Ma *et al.* [9], Fontaine *et al.* [10], and North Sea specific data sets.

The following probabilities are assumed:

- Single line failure: 0.22% per mooring line year (sample size of 42 incidents)
- Multiple line failure: 0.48% per unit year (sample size of 8 incidents)
- Pre-emptive replacement (excluding installation remediation): 2.1% per unit year or 0.21% per mooring line year (34 incidents)
- One-off repair (excluding installation remediation): 0.9% per unit year or 0.08% per mooring line year (14 incidents)

Single line failures are caused by defects that influence one line more than others (e.g. installation damage or manufacturing defects). For the purposes of this study a multiple line failure event is taken as a corner failure. Corner failure could occur due to a common cause of degradation (e.g. excessive wear, bending fatigue, corrosion, or over-trawling damage). Overload (e.g. due to design error or extreme metocean) would also be likely to lead to a corner failure soon after an initiating single line failure.

4.2.2 Modes of failure

DNV-RP-E308 [12] gives a useful visual overview of causes of mooring failure by catenary location and by component, as shown in Figure 8 and Figure 9. O&G asset mooring systems tend to be composed mostly of chain and steel wire. In the North Sea synthetic rope and semi-taut mooring systems are less common.

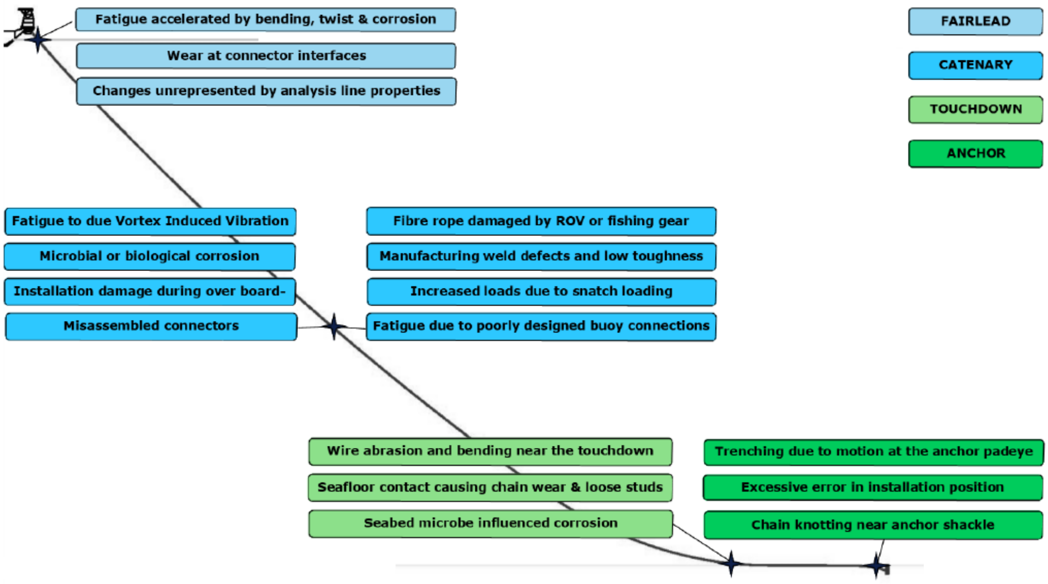


Figure 8 – Breakdown of failure modes by catenary location [12]

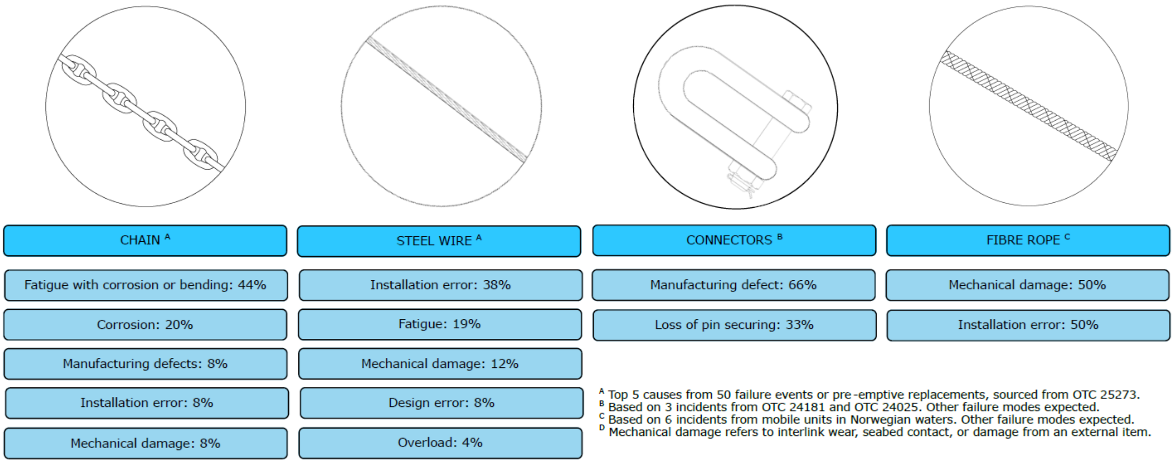


Figure 9 – Most common failure modes by component type [10,12]

Figure 10 presents a summary of primary degradation mechanisms identified for mooring line failure events and their respective outcomes from the Deepstar project database [8]. The review showed that many of the line failures are attributed to fatigue, manufacturing defects and installation issues, modes which are harder to detect through visual inspection. Additional modes such as corrosion, wear and external damage also contribute to the failure data, but preventative measures such as repair or pre-emptive replacement are able to occur as these issues are more easily detectable by visual inspection and physical measurement.

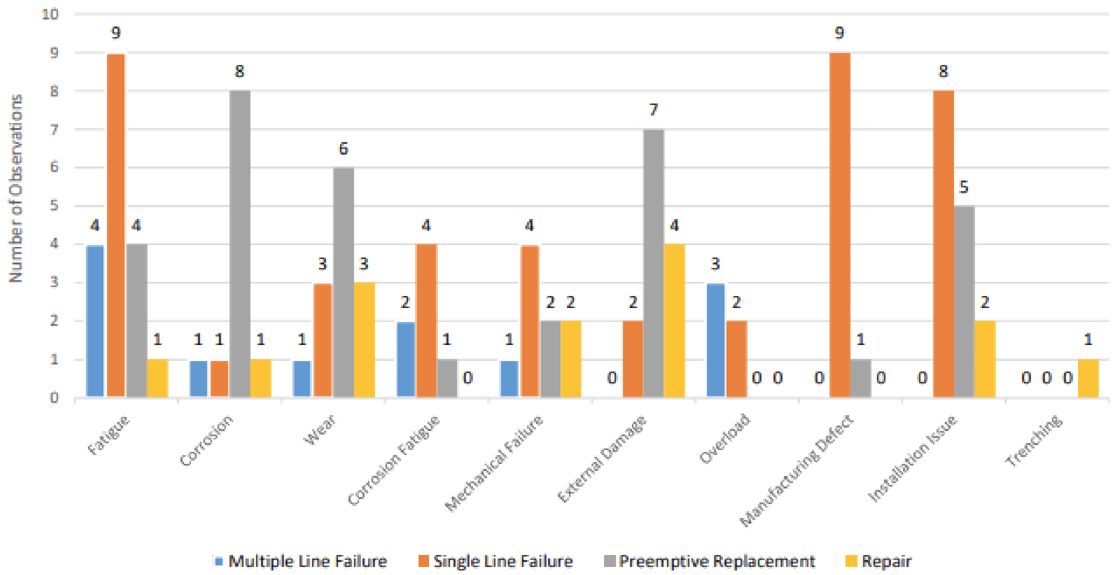


Figure 10 – Primary degradation mechanisms for mooring line failure [8]

4.2.3 Failure by component

Figure 11 shows the primary degradation mechanism by component. For chain the most common failure modes were fatigue, corrosion, corrosion fatigue and wear. Corrosion issues are likely to be biassed towards assets in tropical waters, which experience higher rates of corrosion.

Synthetic rope failure occurred either due to installation issues or external damage. It should be noted that synthetic rope is highly susceptible to external damage, with a common cause stated as “by ROV tether/umbilical or other work lines rubbing against the wire rope or synthetic fibre rope during routine inspections, subsea field expansion, addition of risers, etc.”. Resilience of the rope jacket to external damage is discussed later in the report.

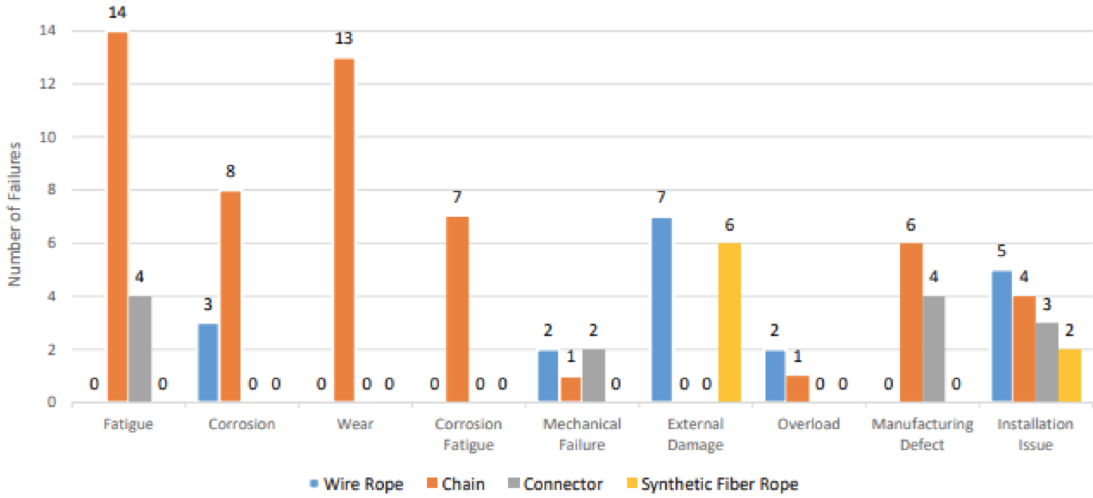


Figure 11 – Distribution of primary degradation mode by component [8]

4.2.4 North Sea FPSO experience

Over half the North Sea production assets have required major mooring line replacement operations, focussing on top chain replacement. Replacements were typically performed in late life, around 20 years after installation. Many of the repair operations above were associated with systemic design issues. A common issue was premature and unexpected chain wear close to the termination of the mooring at the FPSO turret.

A summary of known failures and major replacement operations for a decade of North Sea FPS operations is visualised below. Failure and replacement data was derived from in-house knowledge, industry papers, and online press releases. It is likely that some incidents are missing where some failure events or repair campaigns were not fully attributed to a specific FPSO.

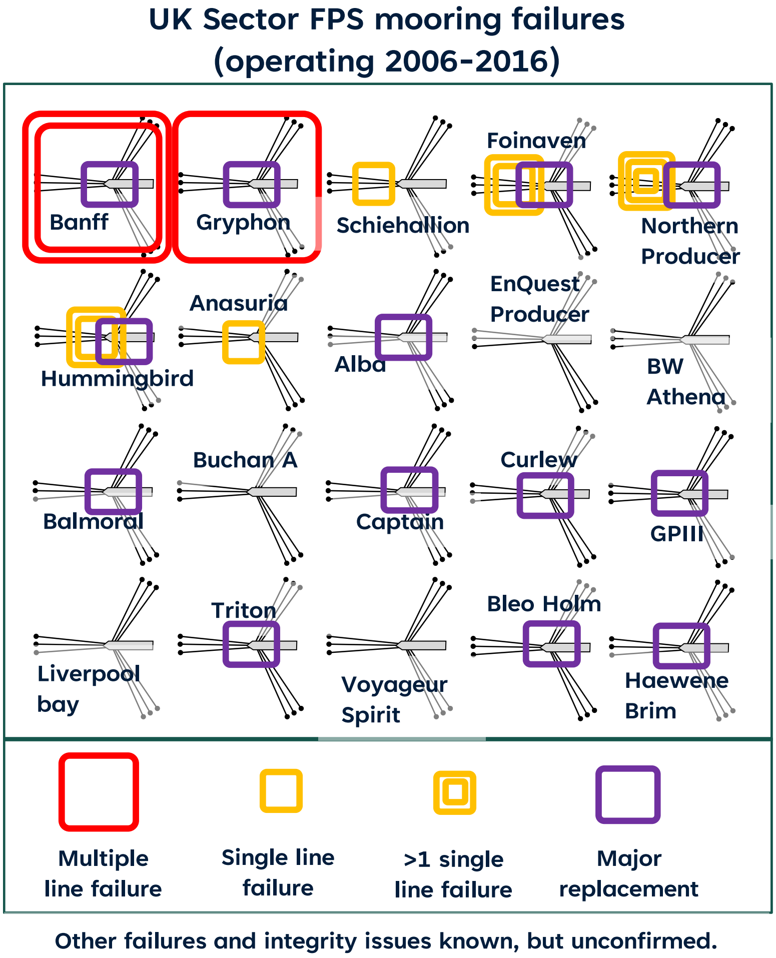


Figure 12 – UK FPSO population in 2016 with known failure events

The data demonstrates how repair operations can be driven by common failure modes affecting all lines. This is important for floating wind, where cloned assets may require replacement campaigns involving hundreds of similarly degraded mooring lines.

4.3 Applicability of O&G mooring failure rates to floating wind

Some failure modes contained in the DeepStar floating production asset data are less applicable to North Sea floating offshore wind. For example:

- Corrosion failures, since these failures occurred predominantly in tropical waters where chain corrosion and pitting rates were higher than assumed in the original design. Whilst some North Sea assets have experienced fatigue enhanced by microbial corrosion (e.g. Varg and Foinaven), wear due to excessive motions is a more common cause of degradation compared to corrosion.
- Failures involving wire rope are less relevant for floating wind systems, although some of the failure modes for wire rope such as installation damage are somewhat applicable to designs employing synthetic rope.
- The number of mooring lines involved in a floating wind farm is an order of magnitude more than used for an oil and gas floating asset, and these lines are cloned. Many integrity issues

within an array are likely to be binary – influencing all lines or none – compared to a wider variation of integrity issues amongst a population of dissimilar FPSOs.

- The North Sea does not see hurricane or cyclone events, which were a common cause of multiple line failures in the China Sea and the Gulf of Mexico. Whilst mooring failures tend to occur during a North Sea storm, the root cause is normally related to other issues such as design defects and degradation.
- Mooring line spreads are different with the current FOWT designs employing long lengths of synthetic rope, compared to many FPSOs employing a predominately steel chain or wire system. This could reduce the occurrence wear, corrosion, fatigue and manufacturing defects, at the expense of increasing the chances of external damage failures. External damage – for example due to anchor drag or trawl wire run-over – could have a greater chance of damaging all lines in a corner.
- In the event of corner failure or free drift, the shorter ground chain sections present much lower seabed friction resistance, which could lead to higher vessel drift speeds into and even outwith the array. For example, the Gryphon FPSO drifted 180m in an extreme storm (Figure 13, left), whereas a free drift of several kilometres is possible for a semi-taut polyester system.

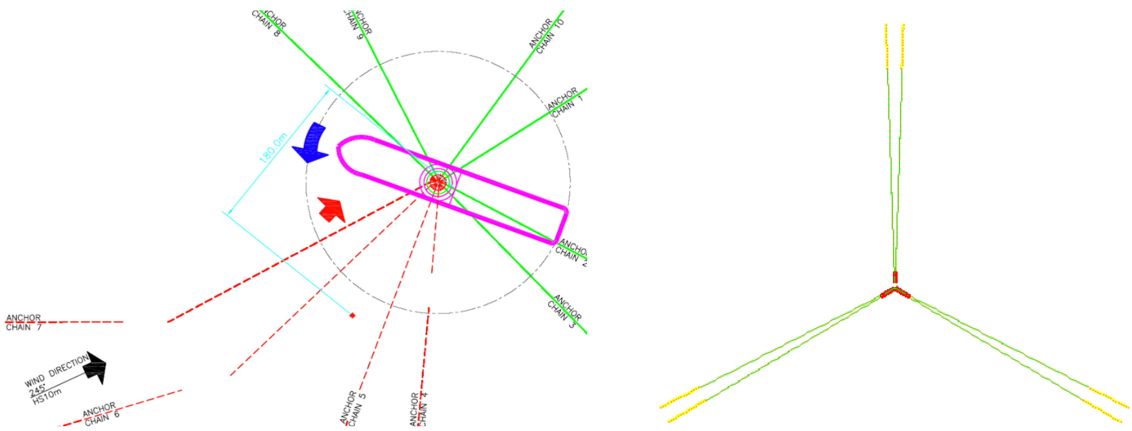


Figure 13 – Comparison of mooring line spreads between a FPSO (all-chain Gryphon incident) and a FOWT with long lengths of grouped polyester lines

Mooring line failure modes for FOWT mooring systems are likely to share many of the same integrity issues and failure modes as those of oil and gas assets, albeit in different proportions. Issues such as fatigue, wear, external damage and manufacturing defects will likely remain common for a FOWT mooring system.

Some modes may have a higher chance of occurring such as external damage due to the prevalence of synthetic rope, and fatigue failures driven by the turbine loading regime (see Section 4.5). It should be noted that most FPS mooring systems were subject to active inspection, integrity management, and design code assessment. The OPEX budget for a FPSO is substantially higher per asset than for a single FOWT, with substantial investment from O&G operators on reducing mooring integrity issues at least since 2012.

Despite this attention and the high consequences associated with FPS mooring failure, the failure rates remained high and statistically constant from 2006 to 2020 [8]. As shown below, over a decade of renewed focus, published guidance, JIPs, and high-profile failure incidents did not statistically move the dial on failure rates.

Therefore, it is reasonable to assume that permanent floating production unit mooring line failure statistics are applicable to FOWT mooring systems, and failure rates cannot easily be reduced without a step change in approach to mooring integrity.

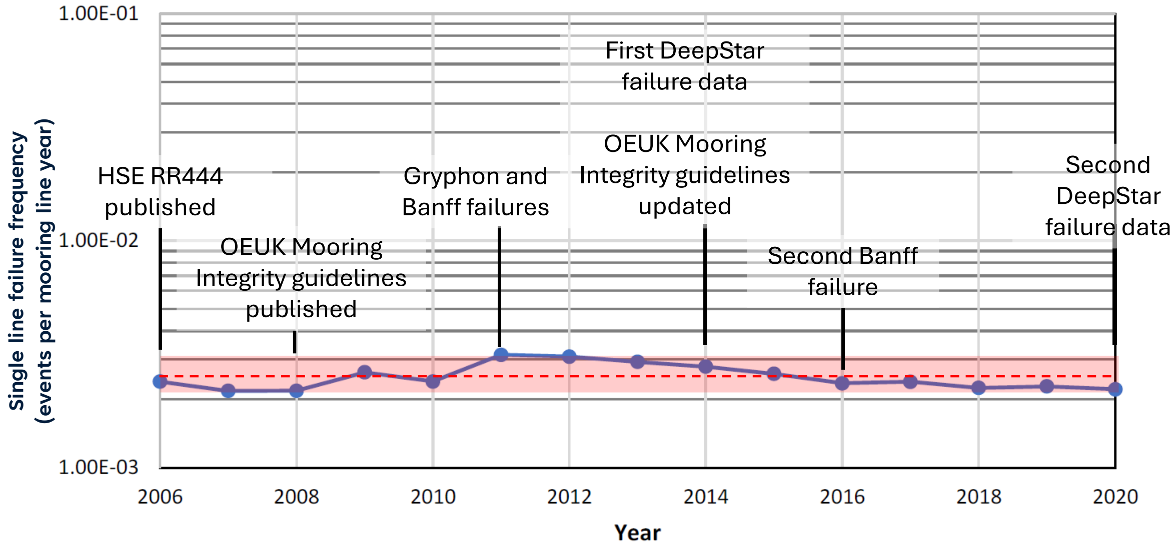


Figure 14 – O&G floating production failure rates over 14 years (red area shows range of annual failure rate with the dotted red line representing the mean), adapted from [8]

4.4 Floating wind demonstrator lessons learned

Anecdotally there have been mooring integrity issues, mooring line failures, and cable integrity issues found on floating wind demonstrator projects. To date, there has been limited public sharing on these mooring or cable integrity lessons learned. This is a missed opportunity for the sector as it allows critical exposures to be replicated on multiple systems.

A summary of floating wind demonstrator projects in European waters is provided below for reference.

Table 2: European waters floating wind demonstrator and pre-commercial projects

Project	Turbines	Installed
Hywind Demo	1 x 2 MW	2009
WindFloat 1	1 x 2 MW	2011
Hywind Scotland	5 x 6 MW	2017
Floatgen	1 x 2 MW	2017
WindFloat Atlantic	3 x 8 MW	2020
Kincardine	5 x 9.5 MW	2021
TetraSpar	1 x 4 MW	2021
DemoSATH	1 x 2 MW	2022
EGFL	3 x 10MW	2025
EOLMED	3 x 10 MW	2025

Some insight into mooring integrity issues can be found in the following learnings which were shared by floating wind developers and O&G operators:

- The Hywind Scotland and Tampen mooring systems are performing as designed, making use of robust plain chain catenary moorings. It is noted that these simple catenary moorings are unlikely to be economic for large scale floating wind arrays.
- Some floating wind developers are planning for failures over a 30-year design life, including mid-life overhaul of half of mooring lines in the O&M budget.
- The cost reduction curve for floating wind requires robust and low intervention mooring ropes. Forensic test data on retrieved demonstrator ropes could be a valuable asset to improve confidence in mooring rope performance and build lessons learned into future designs. More could be done to plan for rope investigations for floating wind demonstrator moorings nearing end-of-life.
- Mooring monitoring is important for reactive maintenance, but getting in-place mooring response data is unreliable. Inclinometers, load cells, and other systems have all been observed to fail within the first year of operation. Rope behaviour and ageing are a major challenge for reliable monitoring, so overcoming the reliability challenge of getting direct tension data from mooring lines is important.
- One floating wind demonstrator project uses stiff HMPE ropes, clump weights, and dynamic buoy connections, which were observed to cause integrity issues in service. In earlier decades, O&G shallow water systems were designed with these features, which have subsequently been engineered out.
- The use of clump weights, buoys, short rope lengths, and multiple other accessories all drive integrity issues, and should be avoided wherever possible.

The point below highlights where learning from O&G to floating wind could be improved. In this case the same clump weight design known to cause integrity issues are used decades on for floating wind mooring systems.

Figure 15 – High wear inside FPSO mooring clump weights and recovered clump weights from 2006 HSE RR444 report

Figure 16 – WindFloat Atlantic clump weight testing from OTC 31744. It is noted the system was installed in 2019.

The discrepancy between open sharing of failure lessons learned from FPSO moorings and the lack of sharing or learning from floating wind demonstrator projects is a problem for the industry. This is a gap that must be addressed if floating wind is to scale without major reliability issues. It is understood that part of the problem is that failure data is seen as intellectual property required to gain a competitive advantage. Confidentiality agreements between equipment suppliers, sub-contractors, and floating wind developers presents another barrier. There must be shift for stakeholders to recognise that mooring integrity risks are an existential threat across all players in the industry. The potential consequences of multiple line failure and free drifting turbines are irrefutable.

Anonymised data sharing is one solution to the problem, with the ELECTRODE and SPARTA programmes being good examples. However, these have been slow to show results for cable failures, with limited evidence of widespread sharing. The other drawback of these anonymised programmes is that the specific details of integrity issues and mitigation actions cannot be shared, which dilutes the value of the data.

The O&G industry has been through the same journey and overcome this issue. There was a series of early life and high profile mooring failures, which FPS operators to form JIPs which gathered failure data. A few shared openly, but others were initially cagey. As more and more cases came to light then the scale of the problem became apparent, and integrity issues were no longer seen as a liability, but rather an opportunity to learn and improve. The challenge to the FOW sector is not to have to wait for the failures, but to recognise the seriousness of the issue and share proactively.

Regulators and site leasing bodies could mandate requirements for failure reporting and lessons learned sharing. A good example is what the Norwegian Petroleum Directorate has disseminated on O&G mooring failure case studies. The Marine Accident Investigation Branch gives a template for what is possible in terms of robust failure investigation and dissemination. In UK waters the MCA, HSE, Crown Estate and Great British Energy could play a role in encouraging failure reporting.

It is recommended that mechanisms for improved lessons learned sharing are explored by the ORE Catapult and floating wind centre of excellence partners.

4.5 Mooring system FMECA

A mooring line Failure Mode, Effects, and Criticality Analysis (FMECA) was conducted to assess the likely failure modes, and the consequence of failure for different components within the base case FOWT mooring system. It is assumed that the mooring system has been robustly designed, specified, manufactured, and installed based on current integrity knowledge. A mooring system not designed for integrity will have additional failure modes e.g. clump weights falling off, connector pins working loose, and additional systematic or early life failures.

The risk matrices used to conduct the criticality analysis has been adapted from the OEUK Mooring Integrity Guidance [18]. Failure rate and consequence estimates have been grounded using the O&G statistical data discussed in Section 0, and adapted based on projections for floating wind system characteristics.

Table 3: Risk matrix likelihood and criticality summary

Typical cost per incident	Likelihood				
	V. unlikely	Unlikely	Fairly likely	Near certain	**Frequency**
	0.01% / year	0.1% / year	1% / year	10% / year	**Per floating unit [D]**
	No cases	1-3 cases	10% assets	Most assets	**O&G experience [E]**
£100k					
£1m			FPSO SLF [A]		
£10m			FPSO planned repair [C]		
£100m		FPSO MLF [B]			

[A] FPSO Single line failure rate: 2.4% per floating unit per year. Typical single line repair cost £500k to £2m.

[B] Multiple line failure with known £100m to £400m consequences (Gryphon, Banff): 0.48% per year.

[C] North Sea FPSO top chain replacement campaigns on half of floating units, circa 2% per unit year. Multiple top chain replacements and multi-vessel month long campaigns gives £5m to £20m.

[D] Implies that failure frequency for a 100-floating unit wind array is two orders of magnitude higher than a single FPSO.

[E] Case study experience from the worldwide population of 140 O&G floating units over 30-years, from Mooring Integrity User Group, DeepStar [8] and various FPS integrity studies.

Table 4: Risk matrix criticality summary

Criticality	Requirements
Acceptable	No further risk reduction necessary, but could be considered if low cost
Ensure ALARP	Additional risk reduction should be considered as low as reasonably practical (ALARP).
Ensure ALARP	As above, but higher onus on risk reduction. Seek alternatives where possible.
Intolerable	The risk prior to application of additional risk reduction measures is considered intolerably high

The failure mode assessment matrix is shown below.

ID	Module	Failure mode	Applicable components								Failure frequency					Monitoring value				Initial criticality		
			Whole system	Anchor pile	Chain tensioner	Ground chain	In-line buoyancy	Buoy connections	Polyester rope	FOWT connection	1-line repair	wholesale repair	Single line failure	Corner failure	Free drift	FOWT monitoring	Catenary sensing	Load sensing	Inspection	£	P	Risk
1	Design error	Anchor pull out		x							L	L	L	-	L	-	-	-	H	2	3	2
2		Metocean input error	x								-	L	L	L	L	M	-	-	-	4	2	3
3		FOWT input error	x								-	-	M	M	M	M	-	H	-	4	3	4
4		Turbine input error	x								-	-	M	M	M	M	-	L	-	4	3	4
5A		Mooring stiffness error							x		L	L	M	L	L	L	-	M	-	3	3	3
5B		Marine growth input error							x		M	M	L	-	-	-	L	-	H	1	3	1
6A		ULS analysis error	x								-	-	L	L	L	M	-	H	-	4	1	2
6B		ALS analysis error	x								-	-	-	M	H	H	-	M	-	4	2	3
6C		FLS analysis error (chain)				x					-	L	M	L	L	M	-	M	-	2	3	2
6D		FLS analysis error (rope)							x		-	L	L	L	L	M	-	M	-	2	3	2
7A	Build	Material QA/QC (rope)							x		M	L	M	-	-	-	-	-	-	2	1	1
7B		Material QA/QC (steel)				x		x		x	L	L	H	-	-	-	-	-	-	2	3	2
8		Rope creep in service							x		L	H	L	-	-	M	M	H	M	2	3	2
9	Install	Storage UV damage							x		L	L	L	-	-	-	-	-	-	2	1	1
10		Rope overbending							x		M	L	L	-	-	-	-	-	L	2	1	1
11		Connector misassembly						x		x	M	L	L	-	-	-	-	-	H	2	2	1
12		Position/length tolerance		x		x			x		L	L	L	-	-	-	M	-	M	2	1	1
13		Contact during installation					x		x		H	L	M	-	-	-	-	-	H	2	3	2
14	Overload	Poor load sharing							x		M	L	L	-	-	M	-	H	M	2	3	2
15		Snatch load							x		-	-	L	L	L	L	-	M	-	2	1	1
16		Means of securing						x		x	M	L	H	-	-	-	-	-	M	2	2	1
17	Wear	Quick connect interface								x	M	M	M	L	-	-	-	-	M	3	3	3
18		Chain to buoy interface						x			L	M	H	M	-	-	-	-	M	3	4	4
19		Chain to tensioner			x						L	L	M	-	-	-	-	-	M	3	2	2
20		Rope internal fibre wear							x		L	M	H	M	L	-	-	-	-	3	2	2
21		Chain interlink wear				x					L	H	M	M	-	-	-	-	H	3	4	4
22		Chain seabed wear				x					L	L	L	L	-	-	M	-	L	2	2	1
23	Contact	Rope cut externally							x		-	-	H	H	M	-	-	L	H	4	3	4
24		Rope contact with seabed							x		H	L	M	-	-	-	M	M	H	2	3	2
25		Adjacent ropes clash							x		-	L	M	L	L	L	-	-	H	3	1	1
26	Fatigue	Chain tension-fatigue				x					L	L	M	-	-	M	-	M	-	2	3	2
27A		Bending fatigue at top								x	L	L	M	-	-	-	-	-	L	3	2	2
27B		Bending fatigue at buoy						x			-	L	M	-	-	-	-	-	L	2	3	2
27C		Bending fatigue at anchor			x						-	L	M	-	-	-	-	-	L	2	2	1
28		Torsion-fatigue					x			x	L	-	M	-	-	M	-	L	-	2	3	2
29		VIV-fatigue						x		x	-	-	L	L	-	M	-	M	-	2	2	1
30	Corrosion	Overall corrosion			x					x	L	L	L	-	-	-	-	-	M	2	2	1
31		Galvanic or pitting			x			x		x	M	L	L	-	-	-	-	-	H	2	2	1
32		Microbial				x		x		x	M	L	L	-	-	-	-	-	M	3	2	2
33		Hydrogen embrittlement								x	L	L	L	-	-	-	-	-	L	3	1	1
34	Motion	Seabed scouring		x							L	-	L	-	-	-	-	-	H	2	2	1
35		Trenching		x							L	-	L	-	-	-	-	-	H	3	2	2

Figure 17 – FMECA failure mode assessment matrix prior to mitigation

The emphasis is on critical failure modes that could lead to major replacement campaigns of hundreds of lines, multiple line failure, or free drift. The most critical failure modes (risk > £1m/year) were found to be:

- **Design FOWT and turbine input error**: design uncertainties associated with a complex control system. Could lead to free drift in extreme cases.
- **Rope cutting due to external damage**: over-trawling or anchor run-over could feasibly fail an entire corner in one incident.
- **Chain and connector wear**: systemic bottom chain and top quick connector wear on multiple adjacent lines could lead to corner failure if undetected. If detected, a major replacement campaign may be required, as required for many North Sea FPSO top chains.

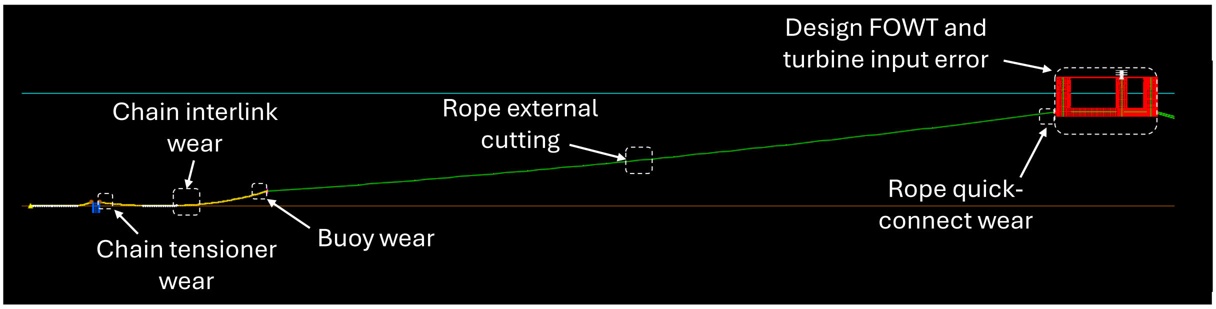


Figure 18 – Locations of the high risk unmitigated failure modes identified for the base case mooring

It is notable that fatigue is not scored as one of the highest risk failure modes. Fatigue is a common cause of single line failure for North Sea FPSO moorings, and has the potential to become more prevalent for floating wind due to turbine drag forces driving fatigue loading. However, even systemic fatigue problems tend to give failures that are spaced out over months or years.

Similarly, installation damage and one-off manufacturing defects are scored as relatively low risk. Whilst corrosion is a common cause of failure in tropical waters, wear is a more common cause of degradation for North Sea assets than corrosion.

4.6 Mooring system monitoring

A review of mooring line monitoring systems has been performed, considering the capability of the system to detect the failures and degradation reviewed in the FMECA study. Based on this review a recommended combination of monitoring systems has been developed to provide coverage across as many failure modes as possible whilst considering CAPEX, OPEX and the lifetime of the system. This system comprises of:

- **High accuracy DGPS combined with redundant motion monitoring** provide reliable and accurate platform position monitoring across the array. This can be applied to 100% of assets at acceptable cost, and is the primary means of monitoring mooring performance.
- **Wave and current monitoring** to capture live weather conditions. Accurate weather monitoring is critical for a reliable digital twin and mooring failure detection system. Two to four wave radar and current measurement systems are recommended to be spread over the array – both to provide redundancy for reliable interruption free data quality, and also to capture seastate variation and shielding effects of the 10 km of the array length. Wind speed and turbine control

data must also be fed into the monitoring system from the array Supervisory Control and Data Acquisition (SCADA) platform.

- **Mooring line monitoring**, either through catenary motion sensing for catenary systems or in-line load cells for taut systems. This provides higher fidelity monitoring data to supplement and validate the mooring response predictions inferred from motion data alone. In-water mooring monitoring systems have historically had a low reliability and high OPEX cost; therefore these systems are seen as a short term (1-2 years) ancillary system, which could be applied to 10% of FOWT moorings to provide early life validation and calibration for the digital twin.

- **Periodic in-water inspection** via ROV to detect degradation and damage outwith the capability of monitoring systems – for example external rope damage, marine growth levels, and excessive corrosion and wear. An initial inspection coverage of 10% of turbines within the array per year is recommended, focussing on high-risk areas through a risk-based inspection strategy. There are opportunities for significant cost savings or enhanced coverage through autonomous vessel innovation.

- **Periodic in-water measurement**. During in-water visual surveys, the opportunity can be taken to measure catenary coordinates to infer in-line tension. At the component level, photogrammetry, laser scanning, or specialist ROV chain measurement tools can be used to perform quantitative measurement of chain and connector wear rates.

- **Combined system digital twin**. A digital twin of each FOWT mooring system can be built from a combination of platform motion and weather monitoring data. The monitoring data is processed to provide performance monitoring, early detection of anomalous behaviour, fatigue damage prediction, and to inform risk-based maintenance planning. The success of a digital twin relies on high quality input monitoring data. Lessons learned from the Hywind Scotland turbine monitoring showed that spurious GPS signals, lack of redundancy in motion data, and faulty in-line tension load cell data limited the ability to monitor mooring performance [34]. For a digital twin to be sufficiently reliable and robust for mooring line failure and fatigue damage detection, the mooring response must be well validated. This would ideally take place in a year 1 or year 2 validation campaign, where the underlying physical models of the mooring, floating foundation, and turbine are calibrated and validated using the full suite of monitoring data, including in-line mooring tension data. To avoid spurious digital twin predictions, the input data must be autonomously cleaned and validated using redundant sensors in a similar manner to a safety critical DP system. The next generation of digital twin development for moorings is underway with demonstrator and pre-commercial FOWTs - for example on Kincardine [32] and the Tetraspar demonstrator [33]).

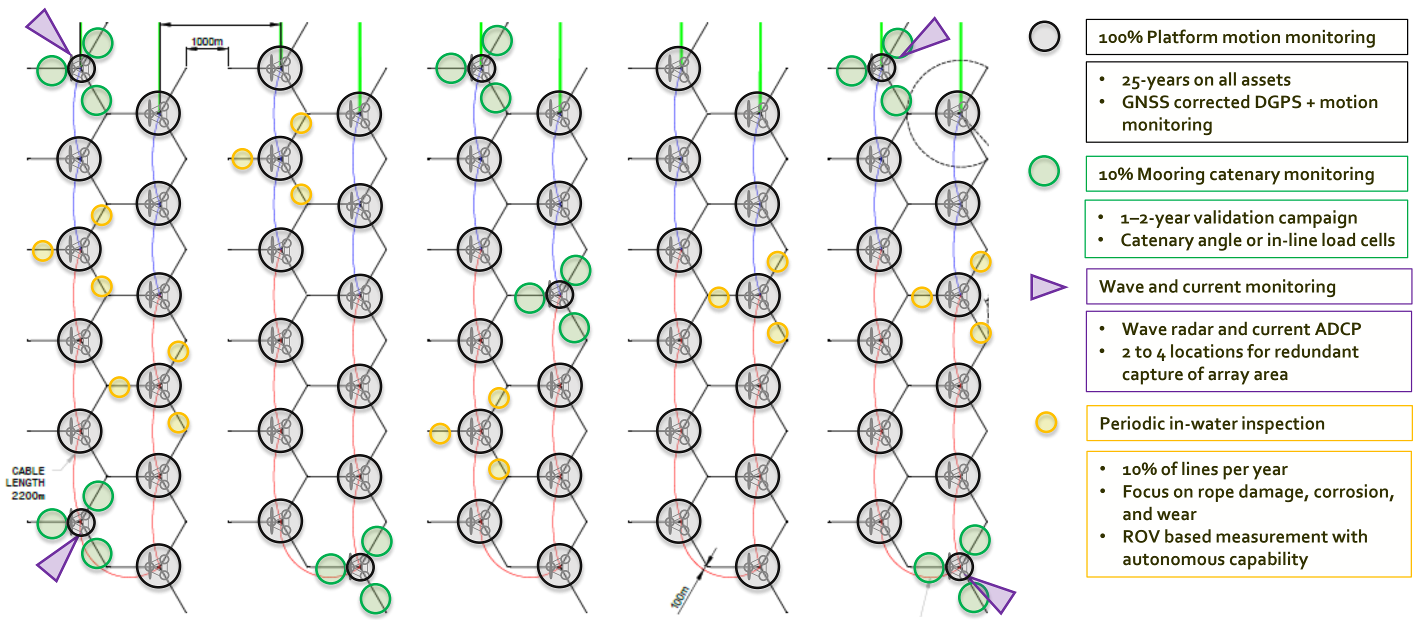


Figure 19 – A combined mooring line monitoring and inspection system (foundations not to scale)

Table 5: Case study combined mooring line monitoring and inspection system

ID	System Type	Example equipment details	Detection capability (Low/Mid/High)										Array coverage % of assets	Typical reliable lifetime
			Fatigue	Wear	External Damage	Above design loading	Manufacturing Defect	Corrosion	Pre-tension / creep	Single line failure	Corner Failure	Free Drift		
ALL	**Combined system**	Integrated monitoring and inspection digtal twin.	H	H	M	H	-	M	H	H	H	H	100%	25+ years
1	Weather monitoring	Wave radar, current ADCP, wind, and turbine SCADA data at array corners.	-	-	-	-	-	-	-	-	-	-	10%	10-20 years
2C	DGPS (with IMU and seabed reference)	Seabed reference and inertial Motion Unit e.g. Sonardyne SPRINT-Nav.	L	-	-	L	-	-	-	M	H	H	100%	25+ years
10	Load Cell (in-line)	Long term mooring load link, such as the Inter-M Pulse H-link.	M	-	-	M	-	-	H	H	H	-	5%	1-2 years
11	Close visual inspection	ROV camera system	-	L	M	-	-	L	-	H	-	-	10% per year	-
13	Chain wear measurement	ROV measurement or 3D imaging to quantify wear and degradation rates.	-	H	M	-	-	M	-	-	-	-	10% per year	-
14	Catenary measurement	ROV measured inclination and catenary coordinates	-	-	-	-	-	-	M	-	-	-	10% per year	-

5 REPAIR OPERATION WEATHER LIMITS

The offshore operation weather limits are governed by significant wave height. Representative significant wave height limits are defined below based on DOF experience of typical operations.

Table 6: Indicative weather limit definition guidance

Operation type	Description	Typical Hs limit (m)
ROV deployment and recovery	Assuming deployed and recovered at a safe distance away from the FOWT. Vessel heading is unrestricted and can be set for favorable weather limits.	3.5 to **4.0** (Note 1)
W2W operations	Based on floating wind demonstrator access experience for the present generation of W2W vessels and gangways. Detailed limits in Ref. [37].	1.5 to **2.0** (Note 2)
ROV operations near the FOWT	Work ROV operations (e.g. messenger line handling) near the FOWT requires fine control and is influenced by wave action near the surface. Limit depends on ROV capability, proximity to surface, and specific operation.	1.5 to **2.5** (Note 1)
FOWT pull-in operations	Mooring or cable pull-in handling near the floater implies close vessel proximity and heading restrictions. The potential for dynamic motions to over-pull the pennant wire and hull connections drives down the limit.	1.5 to **2.5** (Note 1)
Normal cable lay	Where there is a cable catenary, normal cable handling weather limits increase.	2.5 to **3.5** (Note 1)
Normal mooring deck handling	Anchor handling deck operations normally limited by crew safety considerations when handling and overboarding large diameter moorings.	3.0
Mooring winch operations at anchor end	Limits are defined assuming no heave compensation, to minimize cost and vessel selection impacts. Option to increase limits at the anchor end by laying down the chain in a catenary, at the expense of a more complex operation. Some vessels, such as the Skandi Skansen, could use a heave compensated crane with a secondary pennant to increase Hs limits.	1.5 to **2.5** (Note 1)
Note 1: Near-FOWT operation limits are on the upper end, and depend on vessel capability and connection equipment specifications. Weather limits are based on using high specification state of the art installation vessels. Base case limit shown in bold with sensitivities to lower limits explored in the weather downtime assessment. Note 2: W2W transfer limits depend heavily on wave period, heading, W2W system, vessel and floating foundation characteristics. Lower bound W2W limits have been defined based on floating wind demonstrator experience, noting there are opportunities to increase W2W transfer limits towards a 3.0m Hs.		

Using Hs is a crude measure of operability. Actual weather limits will depend on the specific lay spread, vessel capabilities, equipment limits, available vessel setup headings relative to waves, and wave peak period. This should be driven by detailed analysis of the project specific mooring equipment, procedures, and lay spread.

Note that whilst major contingency time is not explicitly included in the schedule timings, the estimated hours per operation step are based on real-world offshore experience from floating wind and O&G floating platform installation.

Wind speed limits are usually restricted to 30 knots for general anchor handling operations, and 20 knots for crane operations. Normally wave limits would govern (typically 3m to 4m Hs in 20 knots). Currents in excess of 1 knot may influence cable and ROV operability, depending on vessel heading and site specific conditions.

6 MOORING REPAIR METHODS

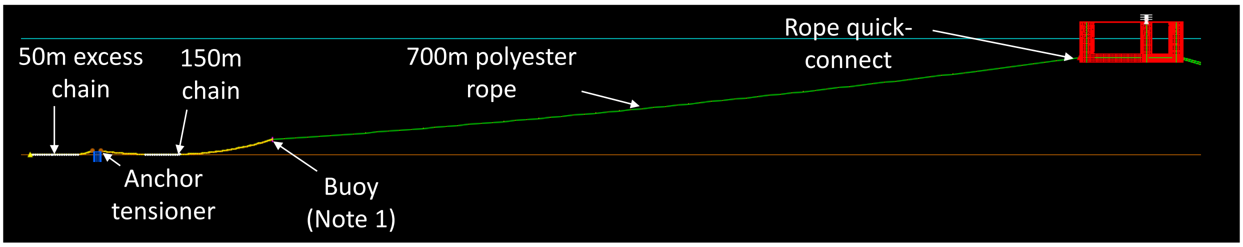
The table below shows the different mooring system configurations that will be considered in this study, comprising of varying mooring line numbers, designs, materials and top and bottom connection sections. Each variation presents different repair challenges and opportunities.

Table 7: Mooring system design sensitivities

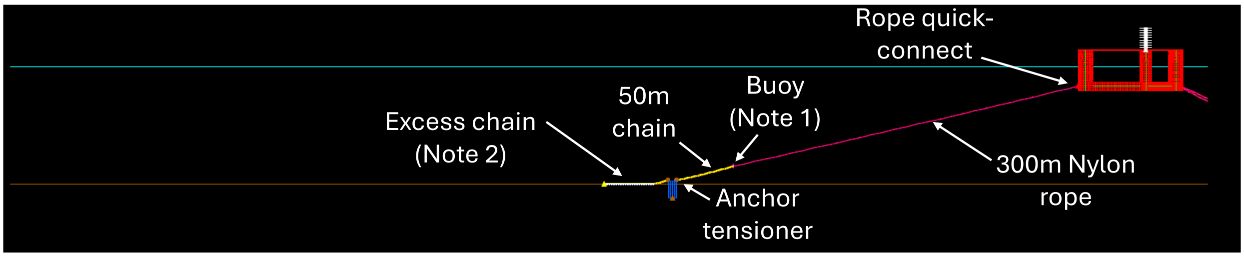
No.	Sensitivity	Mooring system Description	Repair scenario
1	Base Case	6-line semi-taut polyester mooring system with tensioner at anchor pile top and direct rope to FOWT quick-connection. 150m of 132mm bottom chain in catenary with 50m of reserve chain slack behind the anchor for tensioning, 700m of 218mm polyester rope	Replace damaged rope. Commentary on repair of other components.
2	Short bottom chain section & nylon system	6-line taut nylon mooring system with tensioner at anchor pile top and direct rope to FOWT quick-connection. 50m of 132mm bottom chain, 300m of 232mm nylon rope. Bottom chain connection system to be explored in WP3.	Replace damaged rope. Commentary on repair of other components, and re-tensioning Nylon.
3	Tensioner at FOWT	6-line semi-taut polyester mooring system with tensioner at FOWT. Anchor connection at lower padeye with inverse chain catenary. 150m of 132mm bottom chain, 680m of 226m polyester rope, 20m of 132mm top chain	Replace top chain. Commentary on repair of other components.
4	Direct rope to anchor connection	6-line taut nylon mooring system with direct rope to anchor connection, and a chain tensioner at the FOWT. 50m of top chain with 300m of 232mm nylon.	Replace damaged rope.
5	3-line system	3-line semi taut polyester mooring system with tensioner at anchor pile top 150m of 172mm bottom chain, 700m of 242mm polyester rope	Replace damaged rope.

Systems 1-3 are compared in the figure below. The repair method is driven by the connection system at the anchor and FOWT.

System No 1: Base case



System No 2: Short bottom chain section & nylon system



System No 3: Tensioner at FOWT

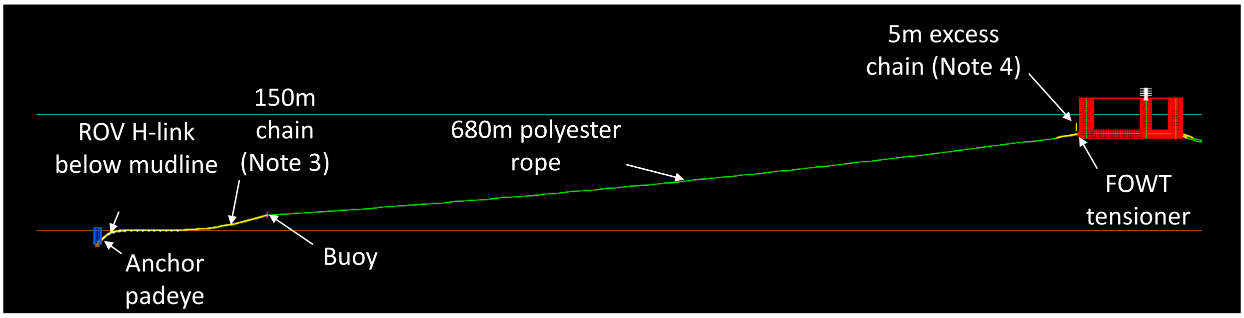


Figure 20 – Mooring design variations covered to the highest level of detail

Note 1: In-line buoy could be replaced with in-built buoyancy along the line, for example with a buoyant foam extruded along the rope length in the case of Bexco's Manta line.

Note 2: Options to enable rope replacement discussed later in the report:

Note 3: The chain section could be replaced by a direct anchor pull-through connector. The impact on mooring risk and repair handling will be discussed later in the report.

Note 4: Some tensioning devices have a chute for hanging off excess links. Another option is a winch and pennant wire to pull-in and hang-off excess chain. Excess chain may be connected for repair via ROV attachable LLC links.

6.1 Other mooring repair scenario sensitivities

Additional mooring repair scenario sensitivities included in the study are outlined below.

Table 8: Other mooring repair scenario sensitivities

No.	Sensitivity	Repair operation description
1	Major replacement campaign	A systemic integrity issue (such as fatigue or wear) requires 50% of mooring lines within the array to be replaced.
2	Mooring corner failure and repair	2 of 6 lines failed causing large offsets, cable failure, and loss of position. Re-instatement similar to original mooring and cable installation procedure.
3	Free drifting turbine and arrest	Assuming all lines broken at FOWT, rope, or anchor in a 1-year storm. Assess drift speed, distance, time to arrest, and emergency towline connection options.
4	Anchor repair	Loss of anchor capacity or inability to replace mooring. Anchor replacement methods explored.

6.2 Base case mooring repair method

The base case mooring line repair scenario is a complete change-out of one damaged mooring rope. The operation is performed by a single AHV equipped with a work class ROV – for example the Skandi Skansen. Other than general rigging equipment, no additional specialist equipment is required for the base case operation. It is assumed that the replacement mooring rope is spooled onto one of the vessel winches with an additional vessel winch available for the recovery of the damaged mooring rope. Spare connectors and a spare mooring buoyancy module are loaded and secured on the AHV deck as a contingency.

The table below provides a summary of the durations for the repair of one mooring rope. The total vessel hire duration from mobilisation to demobilisation is approximately 4 days, excluding weather downtime.

Table 9: Base case mooring rope replacement duration summary

Storyboard No.	Step description	Operation duration	Figure references
-	Mobilize vessel and project personnel	10 hours	-
-	Loadout mooring components and ROV tooling	24 hours	Figure 6
-	Transit to field	12 hours	-
-	DP trials and setup on location	2 hours	-
-	As-found ROV survey	2 hours	-
1	Release of anchor chain stopper	2 hours	-
2	Slacken off ground chain	2.5 hours	Figure 21
3 to 7	Disconnection of quick connector at FOWT	2 hours	Figure 22 to Figure 23
8 to 9	Recovery of mooring rope and connectors	2.5 hours	Figure 24 to Figure 26
10	Replacement of mooring rope and connectors	2.5 hours	Figure 27
11 to 13	Connection of mooring line at FOWT	2 hours	Figure 28
14	Re-tension from anchor mounted tensioner	2.5 hours	Figure 29
-	As-left ROV survey	2 hours	-
-	Transit to port	12 hours	-
-	Demobilisation of equipment and personnel	12 hours	-
	Total duration (excluding weather downtime)	92 hours	

6.3 Base case mooring repair storyboards

Once the AHV has arrived on location, the anchor mounted tensioner is opened to allow the ground chain to be slackened off. This is required to avoid excessive tensions for the pull-through connector release, and to ensure there is sufficient ground chain outboard of the anchor to allow rope retrieval to deck. An additional work wire is connected to the ground chain to assist with pulling the chain slack.

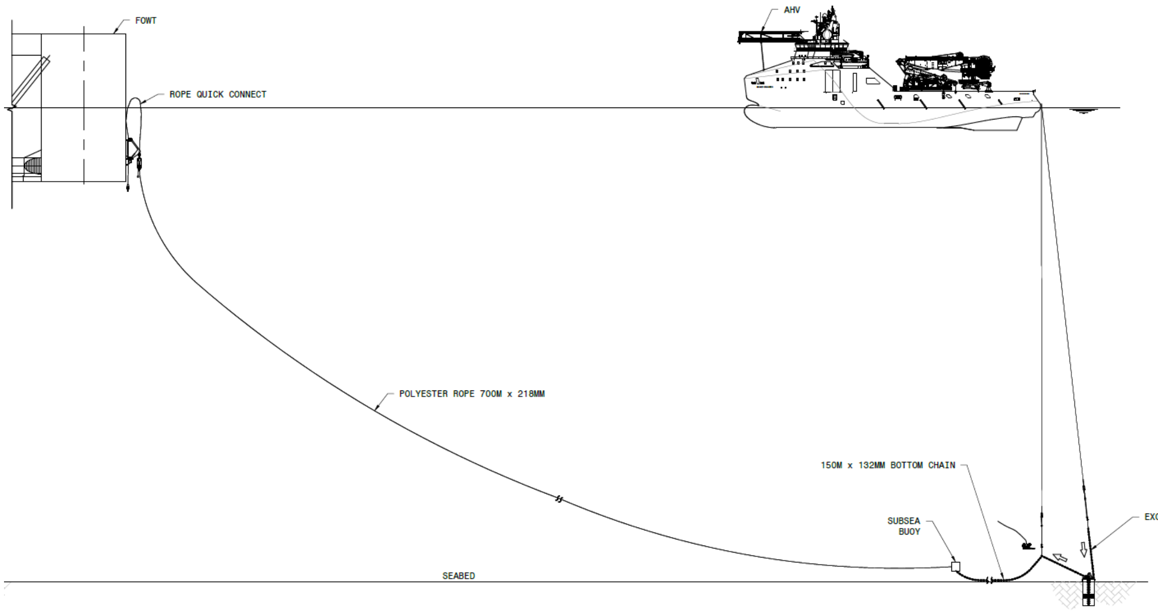


Figure 21 – Release anchor chain stopper and slacken off ground chain

The vessel repositions to the FOWT end for the ROV to grab the pull-through connector pennant wire.

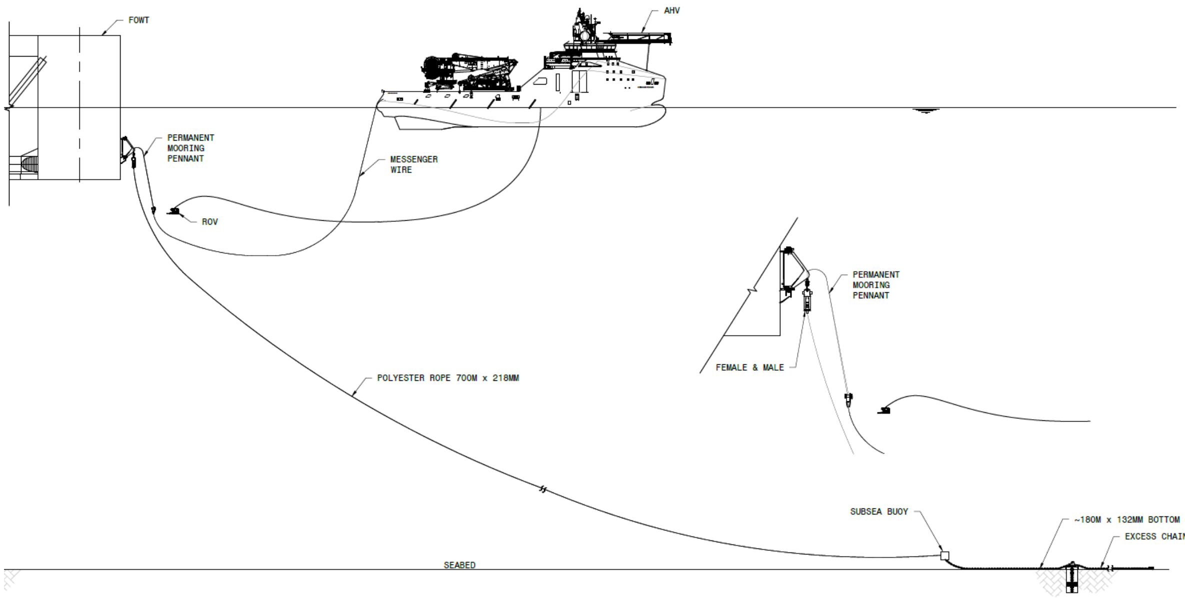


Figure 22 – Connect the AHV messenger wire to the pull through connector

The AHV takes up the tension on the pennant wire whilst the ROV releases the pull-through connector locking mechanism. This allows the male part of the connector to be released and lowered out of the female connector.

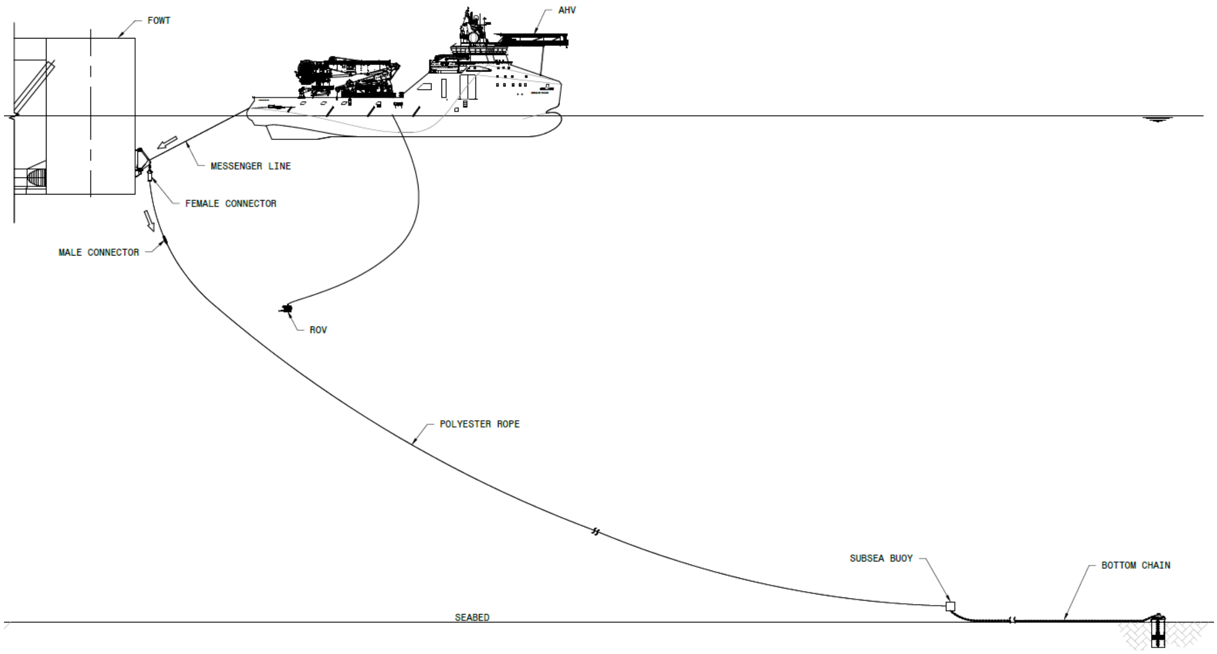


Figure 23 – Lower the male connector out of the female connector

The ROV connects the transfer rigging to the male connector, so that it can be brought onto the AHV deck.

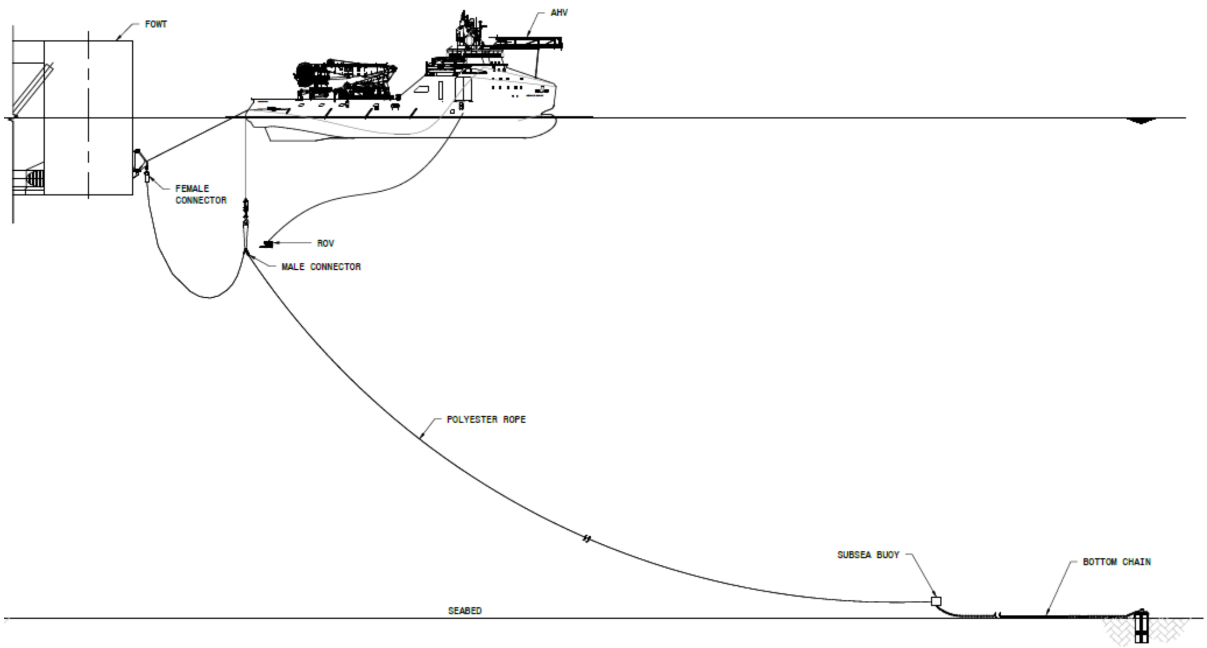


Figure 24 – ROV connects transfer rigging to commence retrieval of the male connector to deck

The male part of the connector is recovered to deck and the messenger line is released.

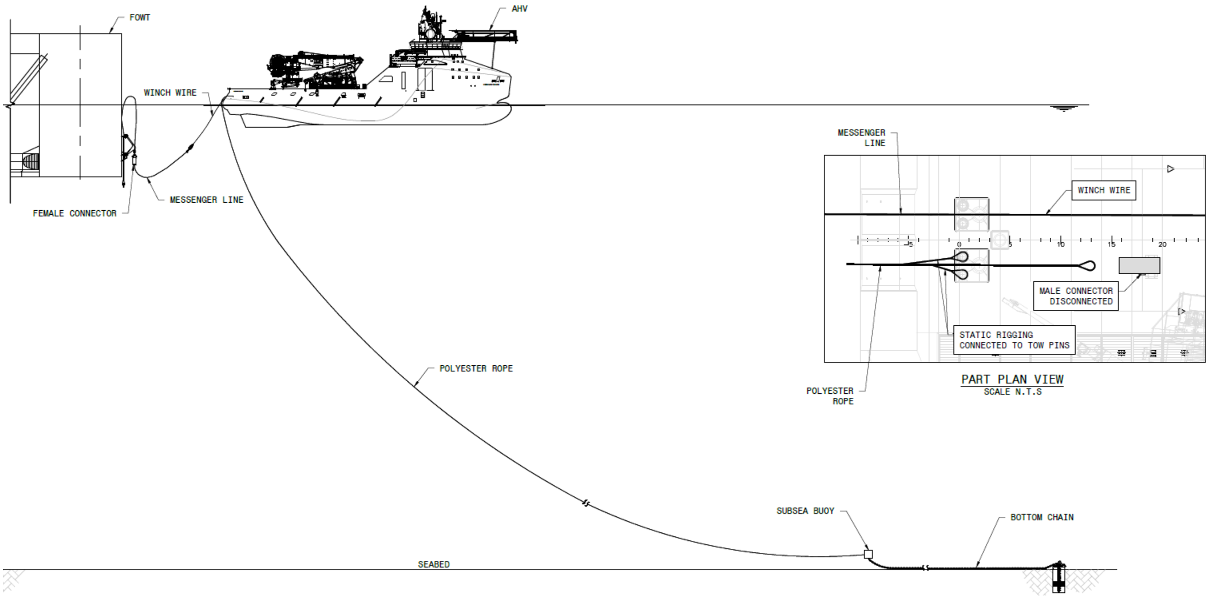


Figure 25 – Male connector brought onto deck for disconnection

The polyester rope is connected to the AHV storage winch and recovered towards the anchor until the buoyancy module has been brought onto deck and the ground chain end is secured in the AHV sharks jaws. The damaged mooring rope is disconnected from the buoy and the new rope section connected.

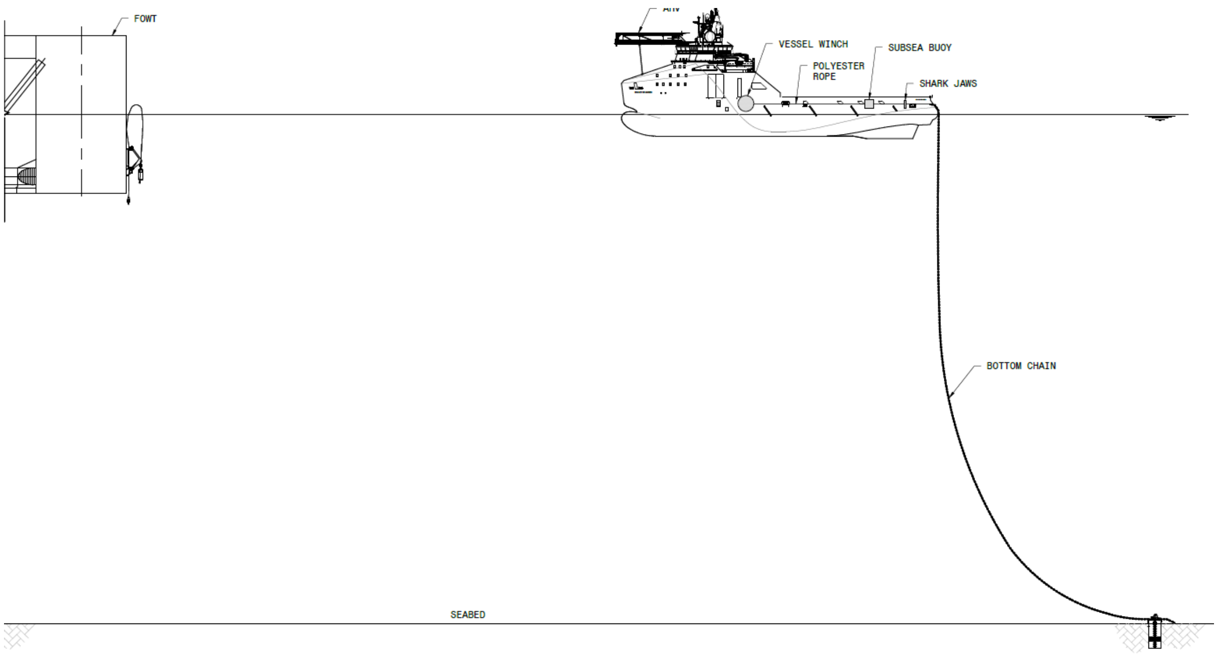


Figure 26 – Polyester rope recovery to the subsea buoyancy module

The process is reversed to deploy the new rope towards the FOWT and retrieve the FOWT messenger line. The transfer rigging is used to lower the male part of the connector to the catenary, ready for pull-in.

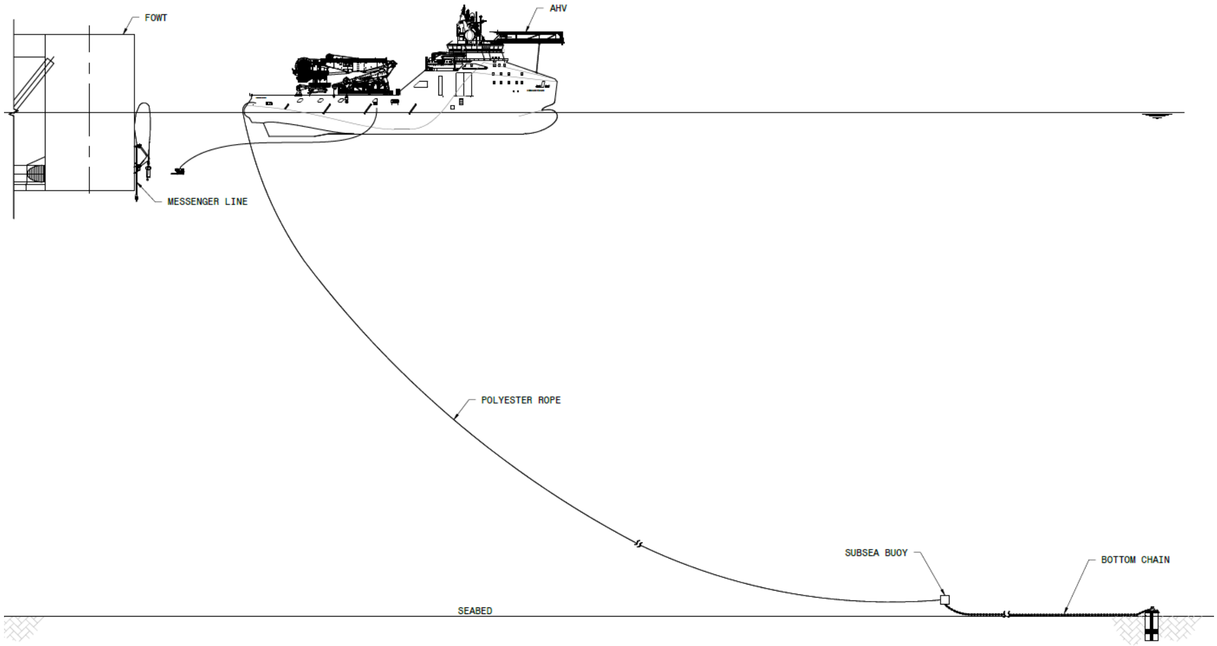


Figure 27 – New polyester rope deployment towards the FOWT

The male connector is pulled into the female part, and the ROV is used to lock off the connector, release and secure the pennant wire.

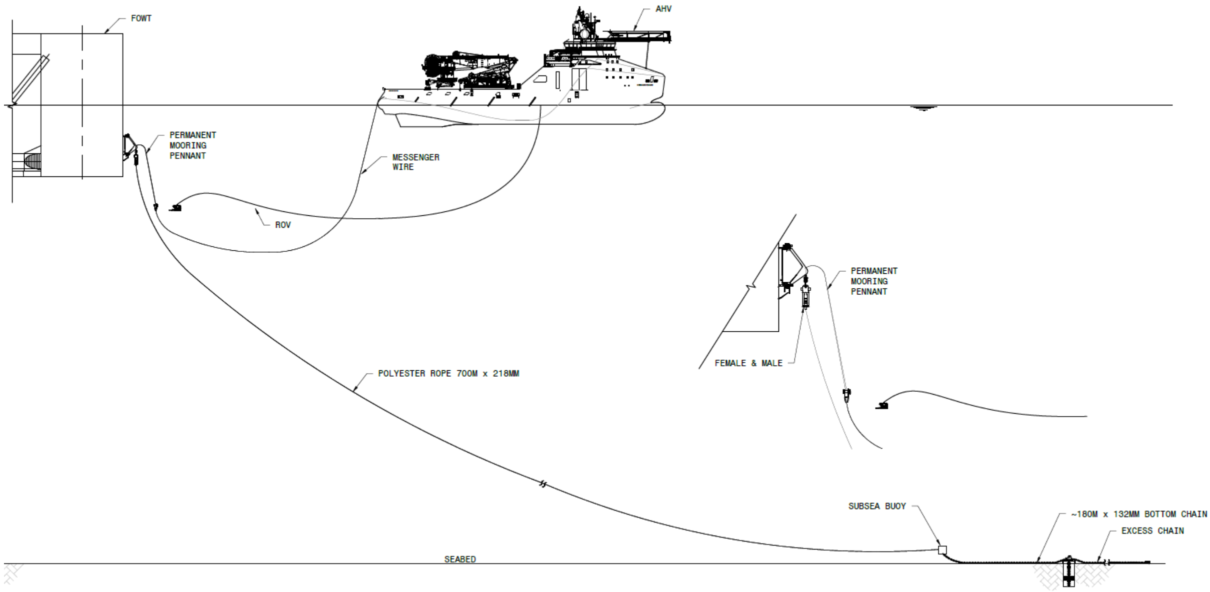


Figure 28 – Connector pull-through and pennant wire release

Finally, the AHV relocates to the anchor and re-tensions the mooring line. At this stage an as-left survey is performed and the AHV transits back to port for demobilisation.

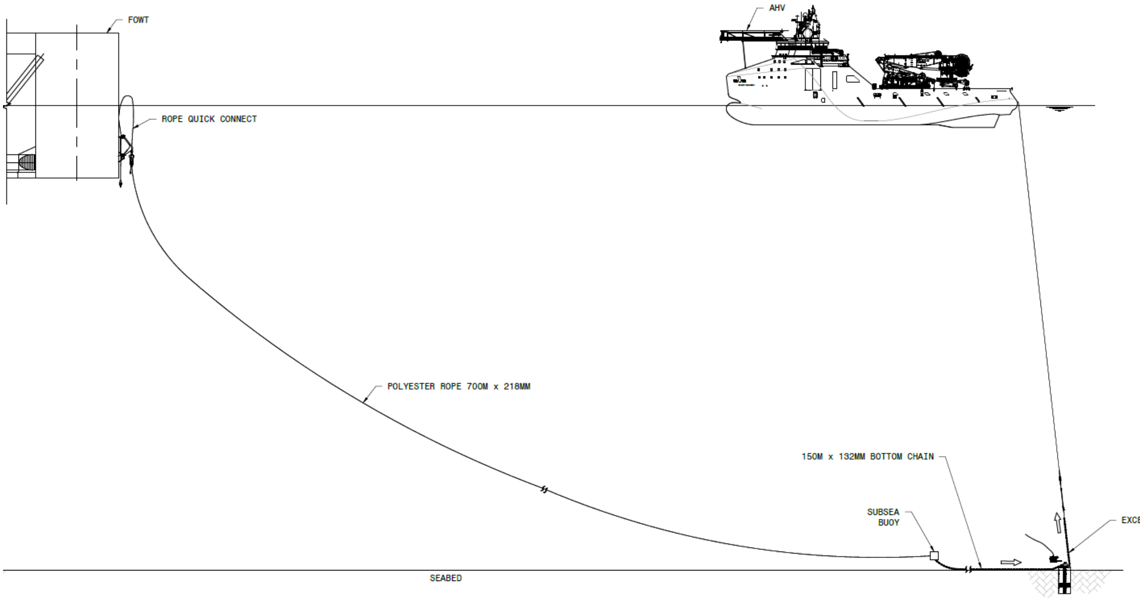


Figure 29 – Mooring line re-tensioning

6.4 Alternative mooring repair scenario: breakage of mooring rope

The base case repair scenario covers replacement of an intact mooring line. If the rope has been severed, there will be a section of the rope hanging from the FOWT and another hanging from the subsea buoy.

The repair operation in this scenario would follow a similar procedure to the base case: the rope is first disconnected by releasing the pull-through connector at the top end, and the AHV proceeds to the second rope end for disconnection and retrieval to deck. The line replacement then proceeds as per the base case.

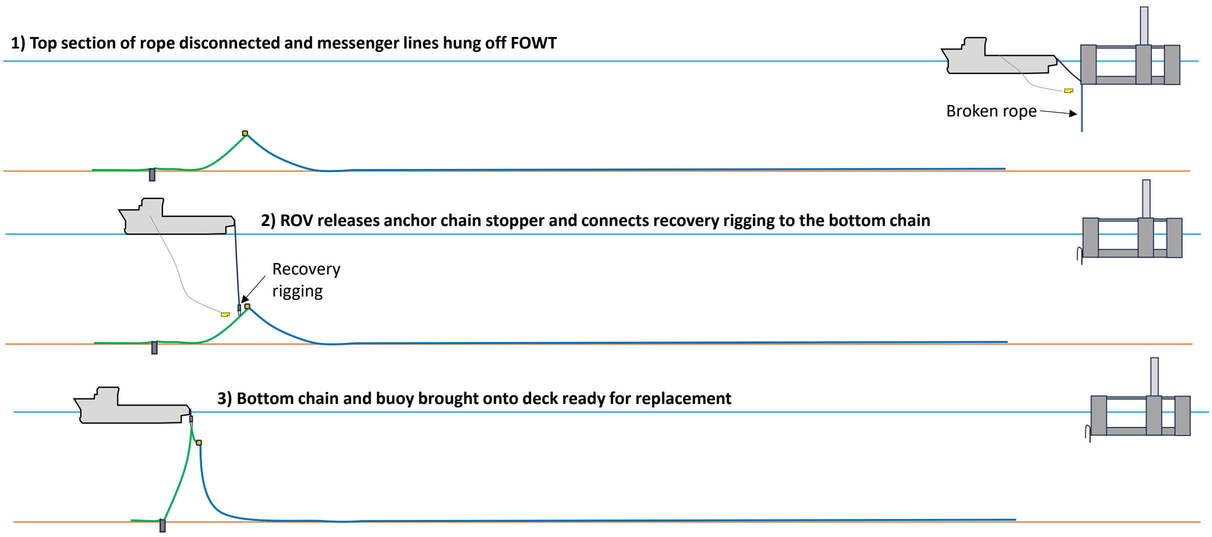


Figure 30 – Broken rope replacement scenario

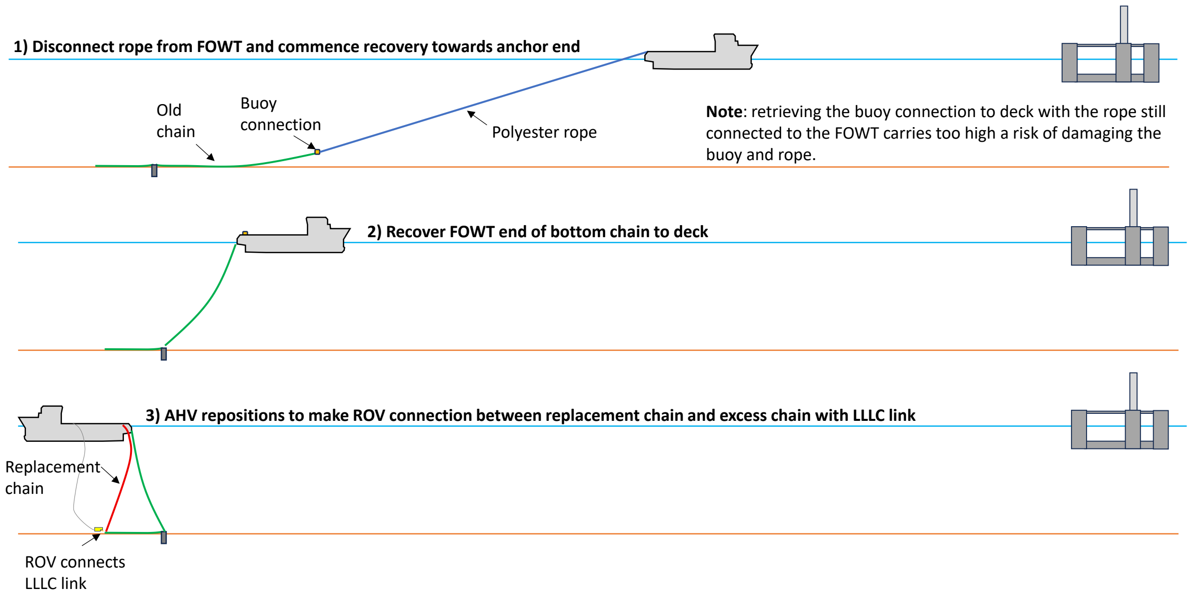
For recovery of the bottom chain end to deck, the bottom chain could be held in the sharks jaws, with the chain hanging off the deck in two bights. A work wire would be connected to the inboard chain end and pulled-in until the rope was brought on deck. The rope could be secured with soft slings to disconnect the rope connection from the chain, and connected to the vessel winch wire for recovery. Once the rope has been fully recovered to the broken end, the replacement rope section can be connected ready for installation.

An additional 8 hours should be allowed for additional time for subsea ROV connection and the broken rope retrieval.

6.5 Alternative mooring repair scenario: replacement of bottom chain

Should the bottom chain section need to be replaced or repaired near the anchor connection, an extension chain section or pennant suitable for passing through the tensioner will be required. Any replacement chain sections must be loaded into the vessel chain lockers.

It is assumed that the extension chain or pennant will be connected with an ROV operable connector that can pass through the tensioner such as a Vicinay LLLC link. Connection of this link may be assisted by use of a subsea frame, vessel AHC crane, or a passive heave system.



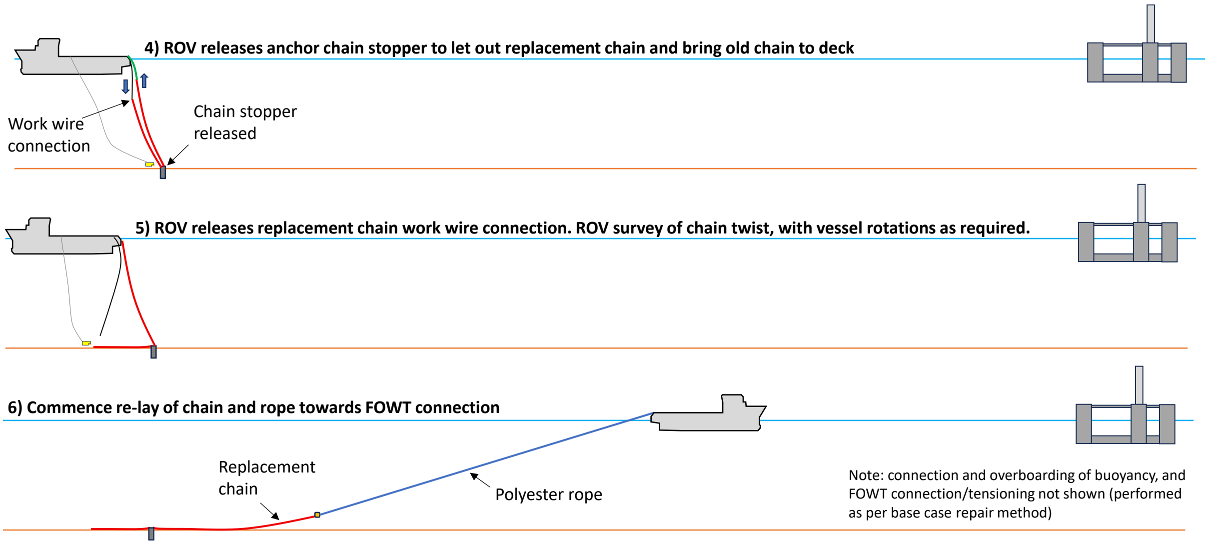


Figure 31 – Bottom chain replacement scenario

The operation is not straightforward. ROV pre-connection and crane lift may be required to safely bring the buoy onboard, depending on size, geometry, and the buoy mooring connection arrangement. Ideally, the buoyancy should be designed for in-line recovery over the stern roller (see Figure 3).

Handling the chain through the tensioner in Step 4 may require additional chain laydown steps, depending on the tensioner design limits and chain friction. For a major chain replacement campaign, it may be more efficient to use two AHV to enable a more efficient process through Step 3 and 4, and to keep weather windows more manageable. For a single AHV, an **additional 16 hours should be allowed for the additional bottom chain replacement steps 3 to 5 above**, in addition to the base case rope repair duration.

6.6 Alternative mooring repair scenario: major replacement campaign

The base case scenario considers a one-off repair of a single line. A systemic integrity issue – such as excessive fatigue, wear, or corrosion – can require a major replacement campaign of all lines on a floating turbine, or in the extreme all lines within the array.

For replacement of more than one line, the offshore operation methods will remain the same per line. Based on oil and gas experience of major replacement and installation operations, a time learning factor of 5% for every doubling of the operation scale is applied to capture the efficiency improvements for repeated operations. For major replacements, mobilisation, loadout and transit durations will be more efficient, to the point where chain locker and deck space capacity is reached.

Total vessel time of each repair operation is in the table below. This includes mobilisation, loadout, transit, offshore operations, and demobilization.

Table 10: Mooring line repair operation overview

Repair operation description	Loadouts	Offshore time learning factor	Total vessel hire duration excluding weather (days)

1 x rope replacement	1	100%	3.8
1 x bottom chain replacement	1	100%	4.5
6 x rope replacement (1 FOWT)	1	85%	7.3
6 x bottom chain replacement (1 FOWT)	1	85%	11
36 x bottom chain replacement (10%)	3	75%	46
180 x bottom chain replacement (50%)	15	70%	207

6.7 Mooring repair sensitivity: short bottom chain & nylon system

The mooring line repair scenario for a system with a shorter bottom chain and nylon rope is covered in this chapter.

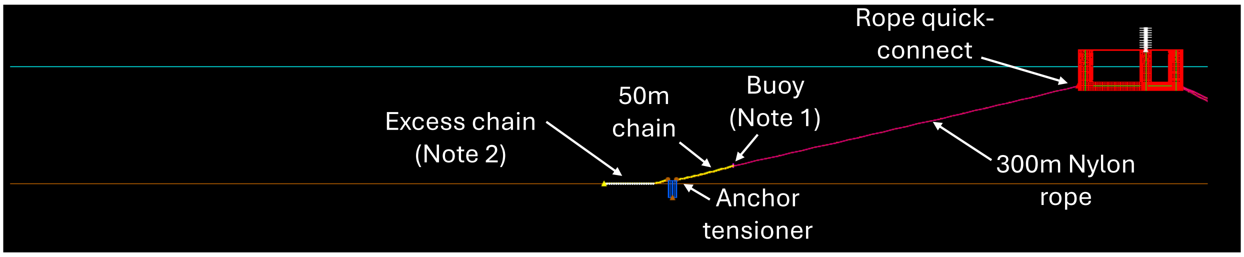


Figure 32 – Mooring repair sensitivity: short bottom chain & nylon system

A major challenge with this system design is that there is insufficient ground chain length to be brought to the surface. There are several options for addressing this challenge to replace a damaged mooring rope:

- **Option A**: Connect a temporary section of installation chain (100m length) to the reserve chain behind the anchor using a slimline ROV connectable link. Use this extra length to pass through the tensioner and bring the rope connection to the surface. Disconnect the installation chain once the system is re-tensioned. Subsea connection of the temporary chain may require a connection frame. The installation chain and connection system should be pre-engineered and procured as spares.

- **Option B**: This method assumes that instead of having or connecting excess chain on the slack side of the anchor tensioner, the mooring line is cut and re-connected on the catenary side of the tensioner. The chain is cut subsea (e.g. with a rotating blade) just inboard of the buoy connection. A connection is made to a replacement rope section on the outboard end of the anchor chain using a Long Term Mooring (LTM) rated ROV shackle. The benefit of this approach would be that less additional chain would be required, as the system does not need to be recovered to the surface, and it would be completed through a single vessel approach. Substantial engineering and testing of a suitable ROV operable LTM shackle and connection frame system would be required for this option; such a solution is not readily available 'off the shelf'.

- **Option C**: A permanent 150m reserve chain length is installed behind the anchor tensioner. A lower diameter could be used for the reserve chain provided it fits through the tensioner and is sufficient for Nylon pre-stretching to 40% MBL. No subsea installation chain or H-link connection is needed. This enables the most efficient repair method and equipment, but requires a substantial CAPEX investment to provide the reserve chain on each line.

The Nylon mooring rope requires pre-stretching to avoid excessive creep and elongation in-service, achieved via direct pull through the anchor tensioner. It is assumed that up to 60m of excess chain may be required to be removed following pre-stretching i.e. permanent elongation of up to 20% of the rope length is possible (see Section 6.13).

6.8 Mooring repair sensitivity: tensioner at FOWT

The mooring line repair scenario for a system with the tensioner at the FOWT rather than the anchor is covered in this chapter.

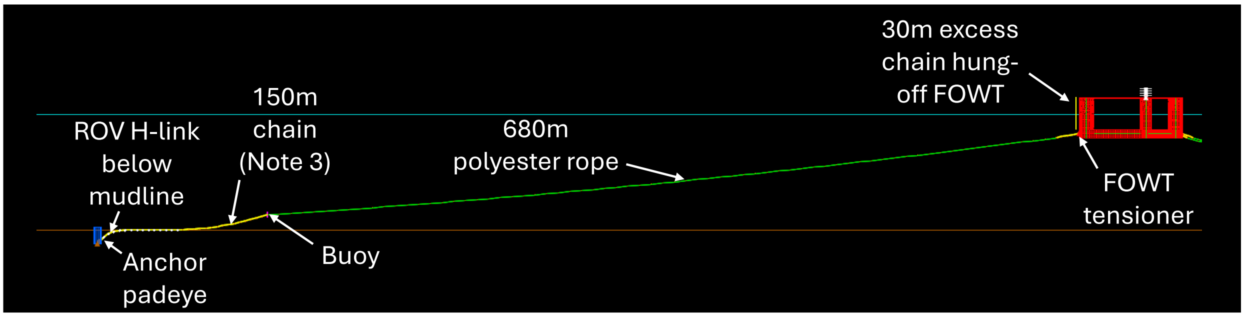


Figure 33 – Mooring repair sensitivity: tensioner at FOWT

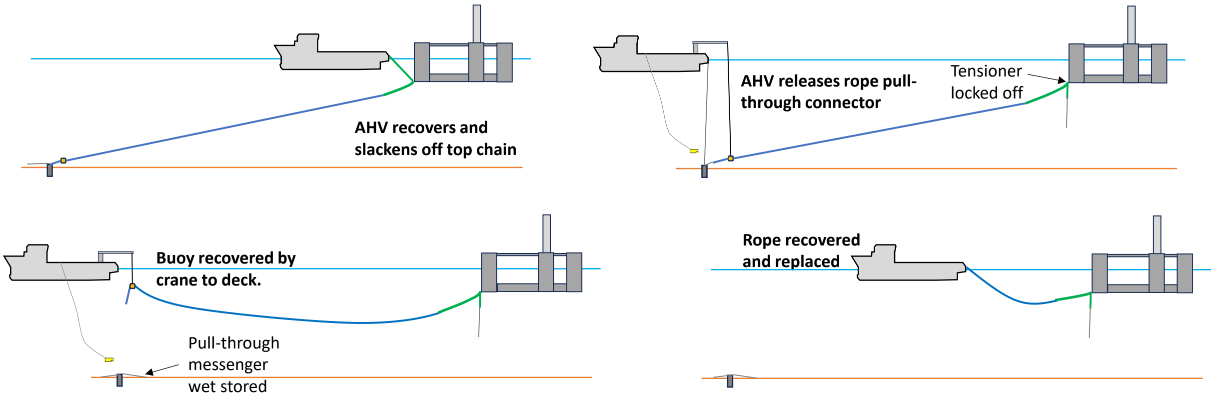
As with the base case the mooring line repair, the operation will be performed by a single AHV equipped with an ROV. The AHV should be equipped with a subsea crane. It may be feasible to complete without the subsea crane, however the reach of the crane will assist in mooring connection operations in close proximity to the FOWT. Operations include ROV surveys, release of mooring line at FOWT, top chain recovery, and replacement of components and tensioning.

The total vessel hire duration from mobilisation to demobilisation is approximately 3.5 days, excluding weather downtime, similar to the base case, but with shorter weather window for the replacement operation.

6.9 Alternative mooring repair scenario: direct rope to anchor quick-connect

A more novel mooring design entirely eliminates the ground chain to anchor connection, which is replaced with a direct rope to anchor connection via a pull-through type connector. This system has the advantage of avoiding the scenario of ground chain replacement, and reduces the risk to 3rd party assets associated with a free drifting turbine.

The top chain replacement procedure would be similar to the method shown in Section 6.8. Replacement of the rope section or pull-through connector could be achieved by first slackening off the top chain, then relocating to the anchor end to recover the pull-through connector to the surface. The AHV should be equipped with a subsea crane to aid pull-in line handling and buoy retrieval to deck.



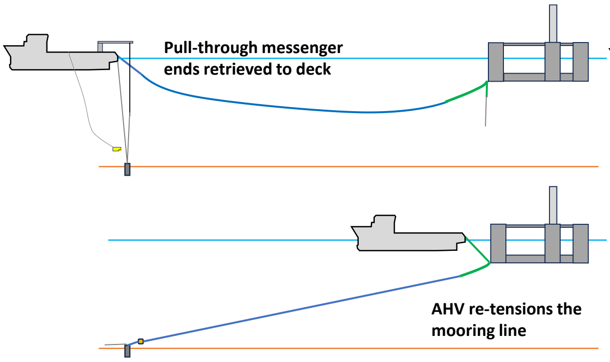


Figure 34 – Mooring rope replacement operation with direct rope to anchor connection

An alternative to the pull-through connection is a vertical stab connection, which has been widely used for deep water floating production unit anchor connections, with examples shown below. These offer a more straightforward anchor connection process without the need for pull-through messenger line handling to the surface. For a stab-type connection, the end weight must overcome the buoyancy force i.e. the connector will drag along the seabed in the case of mooring failure. This is potentially less attractive than a system with positive net buoyancy, which is designed to return to the surface in the case of failure.

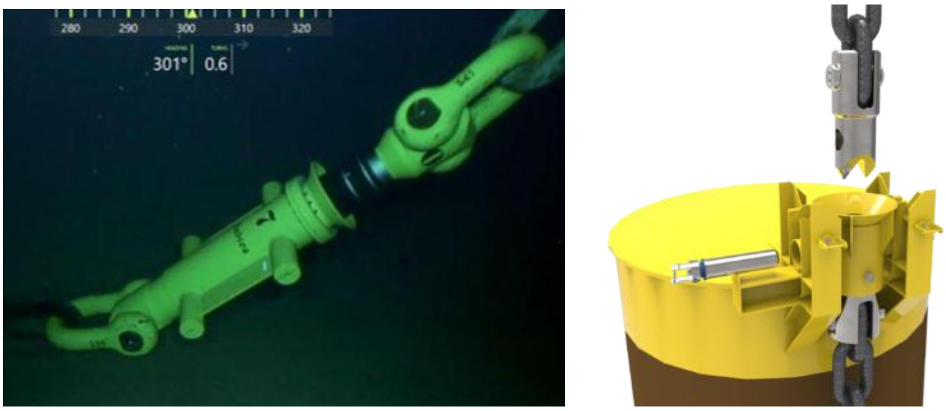


Figure 35 – Example Ballgrab connector (First Subsea) and Subsea Mooring Connector (Flintstone)

6.10 Alternative mooring repair scenarios: Corner failure or 3-line system failure

Corner failure may be due to excessive common degradation, or an overloading mechanism. The turbine drifts 300m to 900m (depending on mooring rope length) over a period of approximately 15-minutes to the new downwind equilibrium position. For a 3-line system, this large drift event would occur immediately following a single line failure, with similar consequences.

The repair operation would require the repair of two mooring lines as a minimum, with a high likelihood of the requirement to replace all mooring ropes due to seabed dragging over several hundred meters. The cable would break free or be released to the seabed, and cable replacement is likely to be required. Power on the cable string would be lost until both the mooring and cable system can be re-instated.

For mooring line re-connection, three high capacity anchor handlers are required to maintain heading and position. An estimated 3-days of continuous offshore operations time is required to reconnect and re-tension two to three mooring lines, excluding transit and mobilisation [1][JD22.1]. The combined 9 days of offshore vessel hire time compares to unfavourably to the single AHV 16-hour operation for the base case mooring repair operation.

6.11 Alternative mooring repair scenarios: Free drifting FOWT

For free drift to cascade from a corner failure, the remaining lines must break free. To avoid free drift, the system must be designed to hold for the duration of an extreme storm, over a typical peak period of 3 to 6 hours. Following anchor or fairlead connection failure, the FOWT would be free to drift.

It is likely that vessels would only be able to make headway in 2-3m Hs conditions. As a drift-off incident is likely to occur towards the peak of the worst storm of the year, it would typically take 12 to 30 hours for the weather to abate to less than a 4m Hs. With a 1-2 knot drift speed, this would give a drift distance of 20 to 40 km.

One high capacity anchor handler is required as a minimum to hold position, with additional support vessels preferred to provide redundancy and control heading.

The FOWT would not be manned following failure in a storm, therefore getting hold of a towline will be difficult in severe weather conditions. There are currently no proven methods of remote towline connection for a floating wind turbine. If crew transfer is required to handover messenger lines and rig the tow bridle, operable weather limits reduce to the 2m Hs for safe personnel transfer.

Trailing mooring lines would pose a significant vessel navigation hazard. It is likely to be necessary to release or cut trailing mooring lines, which would further increase the time to initiate a safe tow and force the requirement for a personnel transfer.

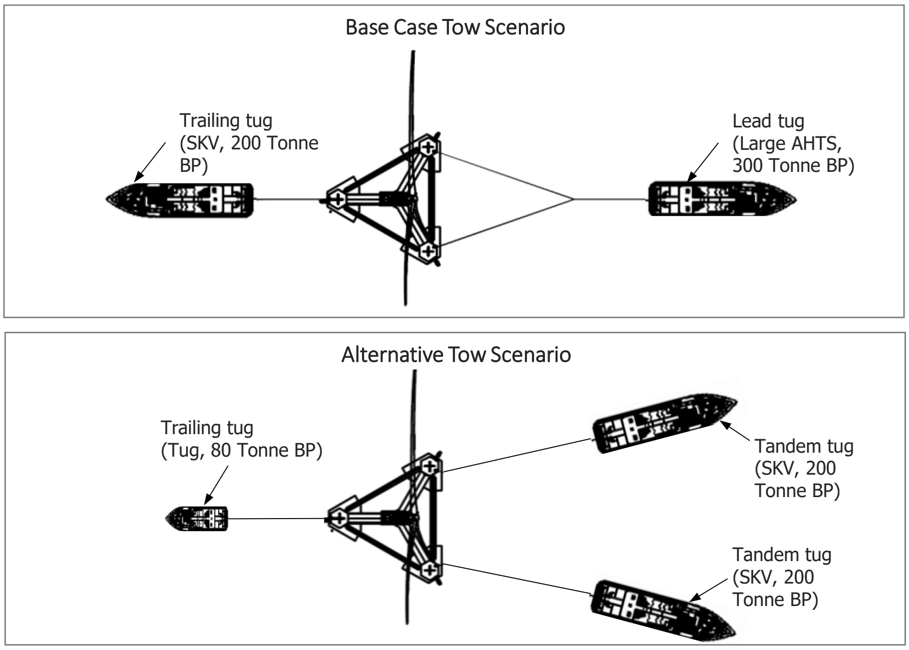


Figure 36 Single versus dual tow vessel scenarios [1]

6.12 Alternative mooring repair scenarios: Anchor replacement

6.12.1 Suction anchor replacement

From the oil and gas sector, suction anchors are typically well proven and robust, with the requirement for replacement relatively rare.

Reverse suction can be applied to a suction anchor to pull the anchor out of the seabed. Success of this operation is not guaranteed, and depends on the level of seabed consolidation. A lower risk option would be to leave the anchor in place and install a replacement anchor approximately 20m to the side and behind of the existing anchor. This would avoid clashing with the existing anchor, whilst having only a minor deviation on as-designed mooring range and heading. Driven piles could not be practically removed in-service, and would be left in place.

Estimated durations for anchor replacement are as follows. It is assumed that for one-off anchor replacement, an AHV would be deployed to complete the whole job and minimise mobilisation costs. The replacement is expected to take four days.

If a suction anchor is shared, replacement would be substantially more complex. All mooring lines would need to be disconnected at the anchor and flaked off. The anchor would then need to be removed, or the new anchor strategically positioned to avoid a clash. The offshore replacement time is estimated to increase by two days.

6.12.2 Drag anchor replacement

Removal and retrieval of drag anchors to deck is common practice for mobile mooring systems. This is normally achieved by pulling vertically on the ground chain, and as required gradually reversing the load to break the anchor out of the seabed.

Recovery force is generally 20-40% of anchor installation load by pulling away from FOWT to trip out the anchor (depending on soils, anchor design, installation method). This implies a 100 Tonne to 200

Tonne vertical force for a 500 Tonne installation load. This is high but achievable with the bollard pull of anchor handlers required to perform the large diameter chain handling operations.

Drag anchor test tensioning is highly challenging, with tensions of 500 Tonnes to be applied at the anchor. Previous work has envisioned two high capacity AHTS are required to achieve this tensioning load [1]. Test tensioning for installation would be performed during pre-lay, before arrival of the FOWT on station.

Replacement support technologies include utilising a tri-place connection with two anchor handlers working in tandem, shown below. This operation is expected to take 9 hours per anchor for removal [68] with another 5 hours for installation.

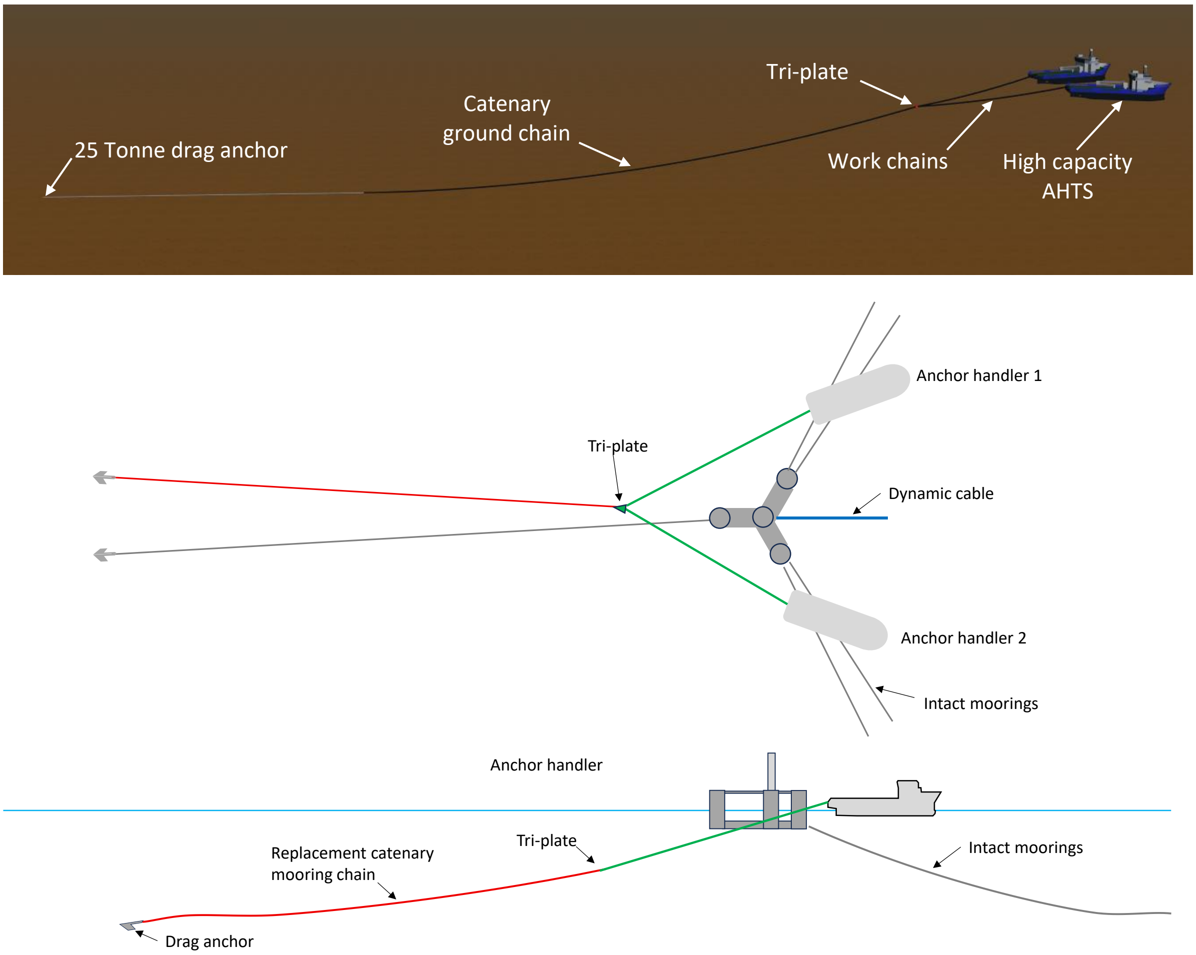


Figure 37 – Drag anchor test tensioning with parallel AHTS: each vessel applies 290 Tonne bollard pull

An more controlled tensioning operation could be performed using a Stevtensioner to maintain clearances between the floating platform and the anchor handler. Depending on the orientation of the intact moorings and cables, it may be necessary to thread the reaction mooring lines under other moorings or the FOWT. An example of the equipment required – including two reaction anchors – is shown in the figure below.

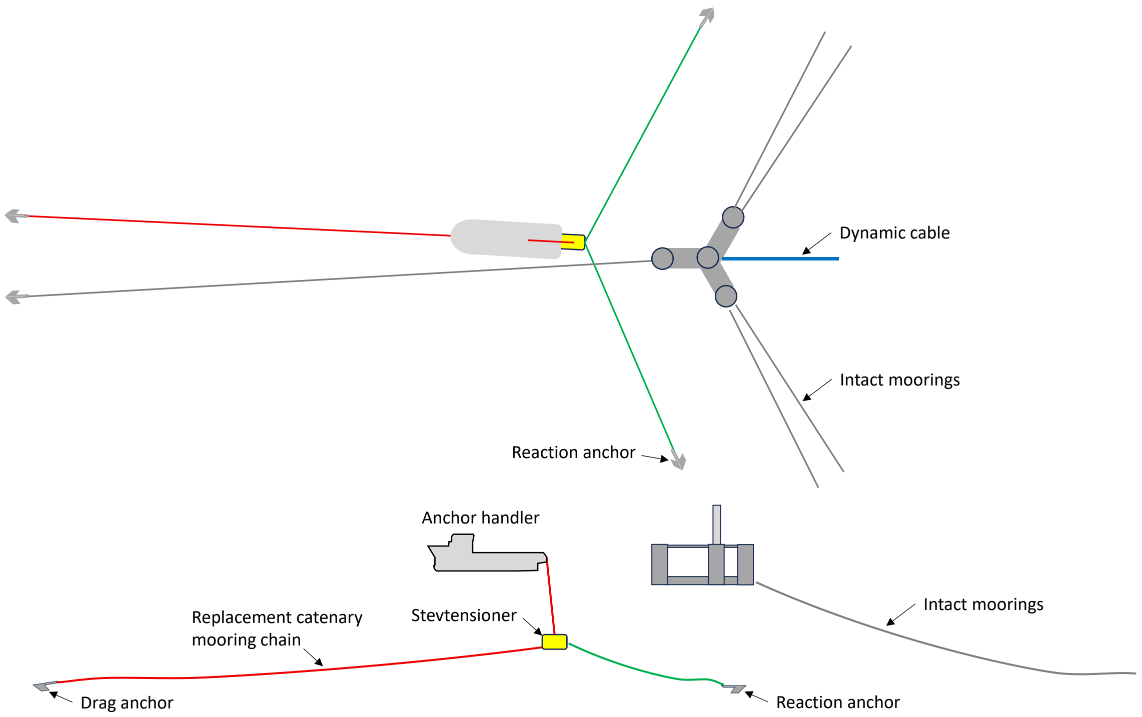


Figure 38 – Drag anchor test tensioning with a Stevtensioner: one vessel applies a 200 Tonne load

6.13 Alternative mooring repair scenarios: Mooring line re-tensioning

Synthetic ropes can permanently stretch over time after the initial installation. There is limited data published by rope suppliers on long term elongation and creep performance.

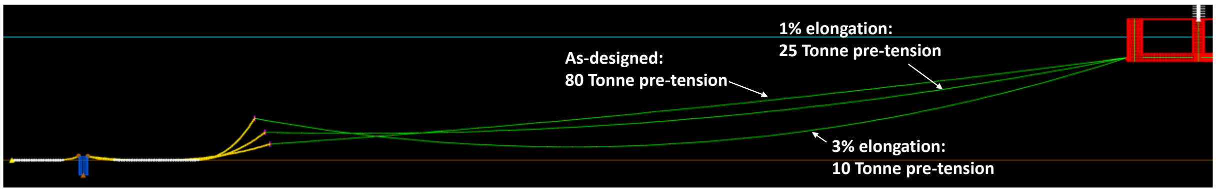


Figure 39 – Taut polyester catenary variation with 1% and 3% rope elongation

For taut or semi-taut synthetic systems, there is a high likelihood of requiring re-tensioning of lines in service. Re-tensioning of complete an array of 360 mooring lines is estimated to require 48 AHV days: 3 days for mobilisation, transit, and demobilisation, and 45 days for the re-tensioning operation, assuming 3 hours to tension each mooring line.

6.14 Alternative mooring repair scenario: Anode system retrofit

If fatigue or excessive corrosion is found to be a problem in-service, this may necessitate a wholesale chain replacement programme. At the array scale this could be very expensive, with a multi-year AHV hire required.

There are limited options to mitigate fatigue or corrosion in-service. One potential option is to retrofit a series of anodes on the chain. The Cathodic Protection (CP) inhibits corrosion, reducing overall corrosion rates, and reduces pitting and microbial corrosion risk. Fatigue also progresses more slowly in a CP environment. If evidence of excessive corrosion or fatigue could be identified early, then a targeted retrofit CP programme could reduce a floating wind array mooring risk profile, and offer the prize of avoiding a major replacement campaign.

7 CABLE SYSTEM REPAIR METHODS

The repair scenarios considered within this study are summarised below. The default repair scenario for most inter-array cable repair operations is to perform an end-to-end cable removal and replacement. An alternative is to use repair joints in a replacement section of cable, but due to complexity, risk, and repair time introduced, is only considered where there is insufficient spare cable to complete a full end-to-end replacement – for example on the longest final cable string to the OSS.

Table 11: Cable system repair scenarios

No.	Sensitivity	Repair operation description
1	IAC replacement	End-to-end replacement of dynamic cable section. This is the default cable repair method, and is largely a repeat of the installation method. It is assumed that a spare 2.5km end-to-end cable section of each cable size is available to make the repair. The cable spare sections should be complete with ancillaries and dry mate connection
2	End of string replacement at FOWT end	Replacement of end of string cable section towards the substation. It is assumed that the most likely failure location is the final FOWT dynamic section, and a full length of spare cable (5km to 20km) is not available to replace the section end-for-end. The 300m dynamic section would be cropped back to a functional cable end. A spare 1km length is assumed to be available, complete with ancillaries and dry mate connection. The connection of the cropped cable end and replacement dynamic cable section is completed on deck as a field joint. Finally, the dynamic end is pulled in to the FOWT and terminated.
3	IAC repair joint	Use a repair joint and a spare cable section to replace only one end of an IAC.
4	End of string replacement mid-line	Use two repair joints and a spare cable section to replace a IAC static section.
5	Subsea hub	Subsea hub replacement and star configuration cable replacement
6	Quick connect system	Failure of quick-connection system plug
7	Ancillary replacement	Buoyancy module or bend stiffener replacement
8	Termination maintenance	Electrical joint repair within turbine
9	External Maintenance	Cable sheath repair or marine grown removal
10	Cable release	Cable emergency release (shear) system triggered too early or too late

The figure below illustrates the repair configuration for the three main cable repair scenarios, assuming repair between two WTGs or one WTG and the substation.

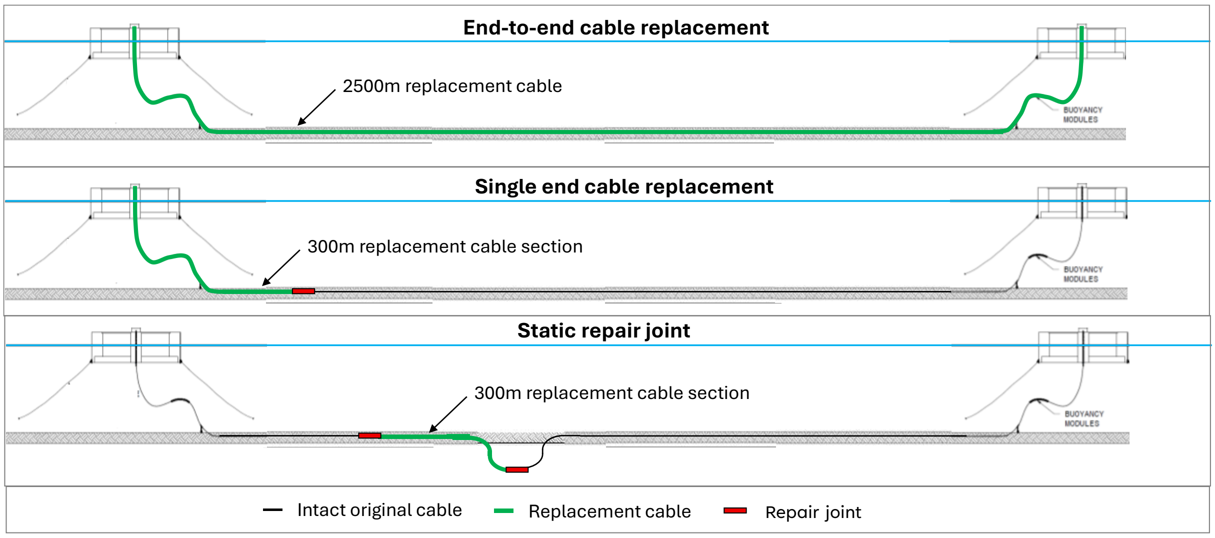


Figure 40 – Comparison of inter-array cable repair options (not to scale)

7.1 Base case end-to-end cable replacement method

The default end-to-end inter-array cable removal and replacement scenario is outlined in this chapter. In this scenario, a failure has occurred on a length of cable between two FOWTs. The short length (2.5km) between FOWTs allows a spare cable to be used for an end-for-end replacement. This enables a more efficient and lower risk repair operation than a repair. The cable configuration is shown below.

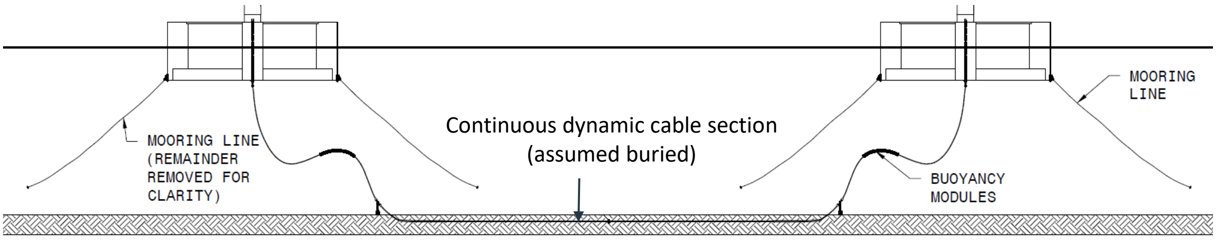


Figure 41 – End to end 2.5km length dynamic cable section for complete replacement

The operation can be performed by a single W2W capable vessel equipped with a work class ROV and a HLS or VLS dynamic cable lay spread. The Skandi Acergy multi-purpose construction vessel has been selected for the case study. It is assumed that a spare inter-array cable reel with a pre-terminated dry mate connection is loaded out, including all associated ancillaries.

The table below provides a summary of the durations for the repair of one end-to-end cable replacement. **The total cable lay vessel hire duration from mobilisation to demobilisation is approximately 15 days, excluding weather downtime**. Depending on availability of a suitable vessel and equipment, mobilisation and loadout time could more than double i.e. an array cable downtime of 30 to 60 days can be expected.

The durations are minimum reasonably optimistic estimates, with the potential to increase by 50% depending on the specific equipment, vessel, and crew experience.

Table 12: Base case cable replacement duration summary

Step description	Operation duration
W2W access for cables team to complete isolation, disconnect dry mate connections, and setup pull-in rigging (Note 1)	12 hours
Mobilize vessel and project personnel	10 hours
Loadout cable lay spread	108 hours
Transit to field (Note 3)	20 hours
DP trials and survey setup on location	4 hours
Cable end-to-end ROV survey & cleaning	24 hours
Cable CFE de-burial (if buried)	24 hours
Cable first end recovery (Note 2)	13 hours
Cable second end recovery (Note 2)	18 hours
First end cable installation	12 hours
Cable lay towards second end (Note 2)	6 hours
Second end cable installation (Note 2)	12 hours
Cable burial (if buried)	24 hours
As-left ROV survey	12 hours
Transit to port	20 hours
Demobilisation of equipment and personnel	52 hours
W2W access for cables team to complete hang-off, electrical termination and tests (Note 1)	24 hours
Total duration (excluding electrical termination and weather downtime)	361 hours

The base case cable repair assumes use of a cable repair vessel equipped with an ROV and a W2W vessel.

During the cable repair vessel mobilisation, a separate W2W vessel transfers test and termination personnel on to the two FOWTs to complete electrical isolation, disconnect the dry mate cable terminations, and prepare the pull-in rigging for cable lowering. It is assumed that this can be performed off the critical path.

7.2 Sensitivity cable replacement case: repair joint in FOWT to OSS cable

If the repair location is more than 1km from the FOWT, two repair joints are required to enable the damaged cable section to be brought to the surface and spliced with a spare cable section. This operation requires an extra repair joint, and approximately 100 hours of extra time to install and terminate the second report joint.

The table below provides a summary of the durations for the repair of a cable repair joint installation and dynamic section replacement. **The total cable lay vessel hire duration from mobilisation to demobilisation is approximately 18 days, excluding weather downtime.** Depending on availability of a suitable vessel and equipment, mobilisation and loadout time could more than double.

Table 13: Sensitivity case cable repair duration summary

Step description	Operation duration
W2W access for cables team to complete isolation, disconnect dry mate connections, and setup pull-in rigging	12 hours
Mobilise vessel and project personnel	12 hours
Loadout cable lay spread	108 hours
Transit to field	20 hours
DP trials and survey setup on location	4 hours
Cable ROV survey & cleaning	24 hours
Cable CFE de-burial	16 hours
Cable first end recovery	12 hours
Cable recovery to jointing location	12 hours
Cable jointing	96 hours
Inline joint overboarding	6 hours
Cable lay towards FOWT	2 hours
Second end cable installation at FOWT	17 hours
Cable burial (if buried)	24 hours
As-left ROV survey	12 hours
Transit to port	20 hours
Demobilisation of equipment and personnel	52 hours
W2W access for cables team to complete hang-off, electrical termination and tests	24 hours
Total duration (excluding electrical termination and weather downtime)	437

The critical in-line repair joint overboarding step is shown below. A cable tensioner controls cable payout and tensions, whilst the main crane controls the joint orientation. The vessel lays away towards the FOWT with the replacement section of dynamic cable.

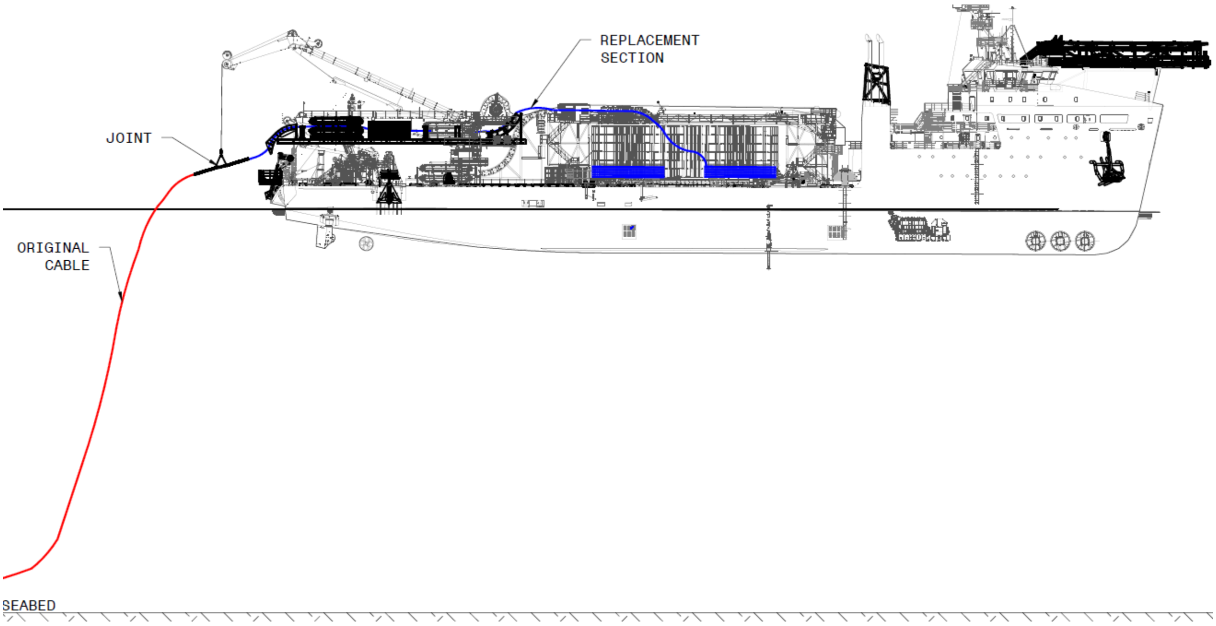


Figure 42 – In-line repair joint deployment storyboard extract

7.3 Sensitivity cable replacement case: repair joint in towards OSS end of cable

If the repair location is more than 1km from the FOWT, two repair joints are required to enable the damaged cable section to be brought to the surface and spliced with a spare cable section. This operation requires an extra repair joint, and approximately 100 hours of extra time to install and terminate the second report joint.

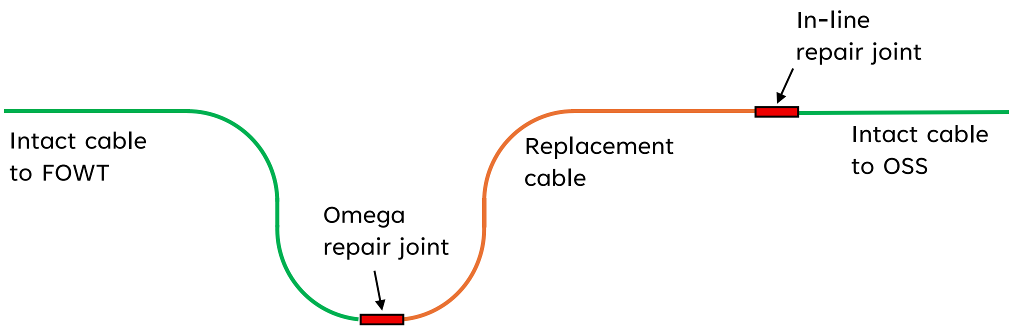


Figure 43 – Repair joint configuration in plan view for a static cable repair

The rigging and deck spread requirements for an Omega joint are more complex. Two overboarding chutes are required, and ideally a quadrant with suitable lift rigging to support overboarding. Wave limits associated with overboarding an Omega joint are typically lower e.g. close to 1m Hs.

7.4 Comparison of end-for-end replacement with repair joint method

For the inter-array cable sections, repair joints can be used as an alternative to end-for-end replacement. The operational steps and vessel requirements would be the same for a WTG to WTG cable repair as the WTG to OSS cable repair covered in Section 7.2 and 7.3. The alternative repair scenarios are summarised in the table below.

Table 14: Inter-array cable repair operation comparison (durations excluding weather delays)

Repair operation	Spares required	Vessel spread	Main offshore operation	Vessel hire duration
End-to-end replacement	• 2.5km spare dynamic cable • 2 x dynamic cable ancillary sets	CLV with HLS or VLS	3.5 days	15 days
Single end replacement	• 300m spare dynamic cable • 1 x dynamic cable ancillary set • 1 x repair joint	CLV with HLS or VLS, with in-line joint overboarding spread	6 days	18 days
Static repair joints	• 300m spare static or dynamic cable • 2 x repair joints	CSV or CLV with Omega joint overboarding spread	10 days	22 days

7.5 Alternative cable repair scenario: Cable release system malfunction

Cable emergency release systems disconnect the cable in the event of a mooring failure. The cable could in theory be preserved for re-connection following emergency release. However; some level of overbending and external damage is likely, which would require a crop and repair of the cable end section, or complete cable replacement.

A cable emergency release is a necessity for a three-line mooring system, and an option for a more redundant 6-line system. The emergency release can be operated by an active hydraulic release, or via a passive over-tension shear pin system.

There are two possible malfunctions of an emergency release system:

- The release triggers too early under normal operation or installation loads, and accidentally drops to the seabed;
- The emergency release fails to trigger in a mooring failure scenario.

A general issue has been flagged that the breakaway system operates on too fine a margin between the lower and upper bound limit, which makes failure more likely.

The scenario where the cable release does not work is illustrated below. The inter-array cable will be picked up by the drifting turbine and form a catenary between the two daisy chained turbines. The cable, which can have minimum breaking loads in excess of 300 Tonnes, could double the mean mooring force on the upwind turbine. This can increase the peak load on mooring system by 50%, which could be sufficient to erode design safety factors and lead to overload. The consequence is a second drifting turbine, with the same sequence now occurring for a third or a fourth upwind turbine. Quickly the loads become unmanageable for the mooring systems, and a conga line of free drifting turbines exits the array.

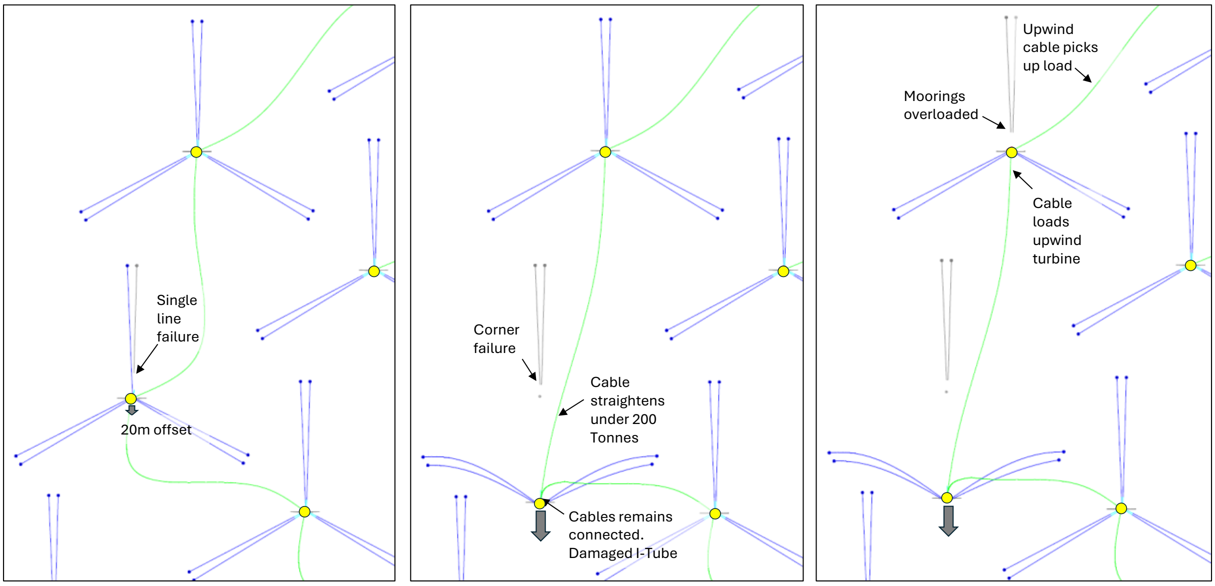


Figure 44 – Cable system release failure consequence illustration

It is imperative that the above scenario is avoided. Even for a redundant 6-line mooring system, there are many factors which could plausibly lead to mooring corner failure: fatigue, wear, corrosion, systemic design defects, common manufacturing defects, load underprediction, cut ropes, or even sabotage. Therefore it is recommended that all large-scale floating wind arrays have robustly engineered and tested cable emergency release systems.

7.6 Alternative cable repair scenarios

Further alternative repair scenarios are discussed in the full report, covering:

- Electrical termination repair
- Bend stiffener and buoyancy module placement
- Marine growth removal
- Subsea hub repair
- Quick connector repair

8 MAINTENANCE REQUIREMENTS

This section covers a high-level understanding of maintenance requirements for floating offshore wind farms. The objective is to evaluate how different maintenance requirements influence:

- Operational feasibility
- Repair duration and weather downtime
- Vessel utilisation and cost
- Production losses associated with outage or curtailment

The emphasis of this section is on an assessment of realistic maintenance requirements based on the scenarios and assumptions defined in Section 6 and weather downtime analysis detailed in the full report.

The analysis focuses on the practical implications of different repair approaches for both mooring and cable systems, considering variations in repair scope, environmental conditions, and system behaviour. How these factors influence intervention duration, weather sensitivity, and associated operational impacts is discussed. Particular emphasis is on identifying the conditions under which immediate repair or delayed intervention may be preferred.

Maintenance decisions are inherently dynamic and dependent on a range of factors, including failure type, severity, environmental conditions, and system criticality. It should be noted that no fixed maintenance strategy is defined at this stage. Instead, the analysis is intended to explore key drivers and trade-offs, identify critical sensitivity and to provide a framework for maintenance budget setting and decision-making under varying conditions.

The following general assumptions have been made:

- Environmental conditions are based on representative (50th percentile) site conditions, with limited sensitivity scenarios presented for more extreme weather downtime (90th percentile).
- Distance to shore, transit duration, and logistics assumptions are consistent with the defined project base case.
- Repair methodologies, durations, and resource requirements are derived from the installation and O&M assessments presented in Sections 6 and 7.

8.1 Mooring System maintenance

A range of representative mooring failure scenarios has been considered to reflect both localised and large-scale intervention requirements.

8.1.1 Mooring monitoring and inspection strategy

The risk-based mooring monitoring and inspection strategy described in Section 4.6 is recommended.

One of the challenges of making the case for expenditure on mooring integrity management is that important findings are rarely good news. Once discovered through inspection or monitoring, remediation of integrity issues can be very expensive at the array scale. There are limited tools available to the operator to reduce risk, beyond wholesale mooring replacement or power production shutdown.

However; ignorance of integrity issues can be an order of magnitude more expensive. Knowing about integrity issues early can significantly reduce costs of a full scale repair operation. Examples of where inspection and monitoring can add value are summarised below.

Table 15: Examples of mooring integrity management added value

Integrity issue detected	Example detection method	Response requirement	Value added through early detection	Criticality
Single line failure	Line tension & excursion monitoring	Mooring repair	Reduce likelihood of corner failure and free drift	Very high
External damage to chain due to wear or corrosion	In-water ROV inspection & measurement	Replacement or retrofit anodes	Reduced likelihood of failure. Summer vs winter replacement. Opportunity to retrofit anodes.	High
External damage to rope	In-water ROV inspection	Replacement or sheath repair	Reduced likelihood of failure. Summer vs winter replacement. Opportunity for sheath repair.	High
Loss of pre-tension due to rope creep	Line tension monitoring	Re-tensioning	Reduced likelihood of cable failure and rope seabed contact.	Medium
Design flaws	Digital twin monitoring	Limited options	Lessons learned shared within the operator, and ideally with the industry.	Low

8.1.2 Mooring failure rates

The best source of mooring failure, repair, and replacement frequency data available at present is from several decades of FPSO operations. Many of the repair operations were associated with systemic design issues, which required replacement of components on all lines.

The expected frequency of major repair operations for floating wind arrays requires some interpretation. Some scenarios assume cloned assets impacting hundreds of similarly degraded mooring lines, while other scenarios have only a limited number of lines in need of repair due to local damage.

The combined overall line repair rates per FOWT per year from the different repair scenarios has been estimated to align with observed FPSO failure frequencies:

- Single line failure: 0.22% per mooring line year (merged with one-off repair)
- One-off repair: 0.08% per mooring line year (merged with single line failure)

- Pre-emptive replacement: 0.21% per mooring line year (spread across 3 different scenarios)

Note that the risk associated with multiple line or corner failure is in a different category to the above scenarios, and is not driven by repair vessel costs. Corner failure and free drift risk is discussed in Section 6.10 and 6.11.

8.1.3 Mooring replacement weather downtime analysis

Weather downtime and overall cost modelling has been performed assuming operations are carried out using the primary anchor handling vessel.

Even for relatively routine interventions, weather downtime can become a dominant cost driver, outweighing the direct vessel day-rate contribution. As such, timing of intervention is a key lever in reducing overall maintenance cost.

The following seasonal windows are identified as favourable for each mooring replacement scenario, assuming mobilisation commences on the first day of the campaign and the operation is executed as a single continuous activity:

- Single-line replacement: performed year-round
- 6-line replacement: Spring to Autumn preferred
- 36-line replacement: Summer only (Mar-Sep), feasible in a single season
- 180-line replacement: Summer only (Mar-Sep), may require a multi-year campaign

8.2 Multiple line mooring failure costs

In addition the pre-emptive repair and single line failure repair operations described above, mooring repair costs can also be driven by multiple line failure risk. The most serious multiple line failure scenario is for the FOWT to freely drift in a storm (see Section 6.11). The figure below illustrates a possible FOWT drift path in a storm.

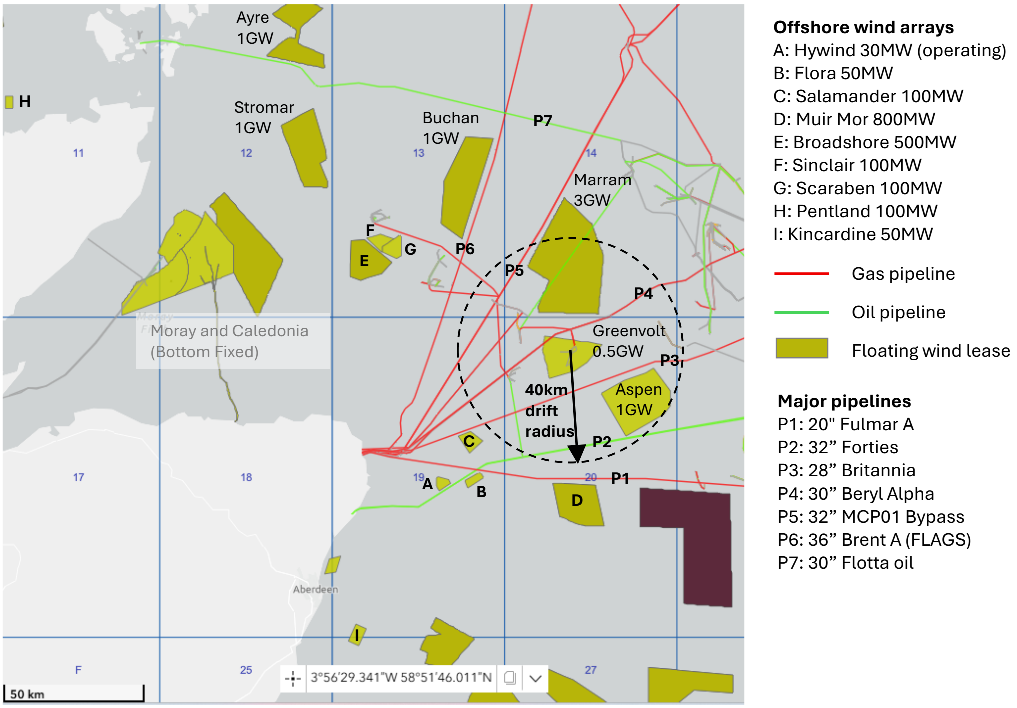


Figure 45 – Oil and gas pipelines in proximity to ScotWind sites (Source: NSTA lease agreements map)

The ground chain on the remaining lines will be dragged along the seabed. Heavy ground chain can act as a cutting tool for subsea pipelines, moorings, and cables. An example of gas and oil pipelines damaged relatively small diameter MODU mooring chains drifting in the Gulf of Mexico are shown below.

Figure 46 Kinked and cracked pipelines following Hurricane MODU run-over [25]

The following assumptions are made to give a high-level estimate of risk profile:

- FOWT corner failure frequency is equivalent to O&G FPSO multiple line failure rates.
- The FOWT mooring has not been designed for large corner failure excursions. As such, the FOWT has a 50% chance of free drift (all lines broken) following a corner failure.
- The drift event occurs in an extreme storm, meaning the FOWT drifts at 0.5 knots for 24 hours before the weather abates, and the turbine can be safely connected to a towline.
- In this time, the turbine drifts at least 20km with large diameter chains and connectors dragging on the seabed.

- The trailing chains dragging along the seabed have a 50% likelihood of rupturing a major oil or gas pipeline, with an estimated cost of repair and lost production of £250 million.

The overall cost and risk profile is outlined below, with the cost of single line failures included for reference.

Table 16: Multiple mooring line repair costs – conservative scenario

Event	Frequency per FOWT	Frequency per array	Primary consequence	Consequence event cost	Average risk cost per array per year
Singe line failure	1.8%/year	≈1/year	Repair 1 mooring	£1 million	£1.1 million
Corner failure	0.50%/year	30%/year	Replace 2 cables	£20 million	£6.6 million
Free drift	0.25%/year	15%/year	Replace 6 moorings and extended tow	£10 million	£1.5 million
Major pipeline rupture	0.12%/year	7%/year	Lost gas revenue Oil release Pipeline repair	£250 million	£19 million

The £250 million pipeline rupture cost is estimated based on the throughput of the major gas pipelines being in the order of 10 to 20 million m^3 per day. The lost revenue from flared gas could be £100 to £300 million over a 30 day repair period. For a major oil pipeline rupture, the cost of environmental and reputational damage would be expected to exceed £100 million.

The 50% likelihood of pipeline rupture following a run-over event is justified on the basis that the mooring chains will be heavy (one tonne of mass per 3 links), with similar diameter to a 36” pipeline, and the geometry of the chain links acting as a cutting tool. Export oil and gas pipelines are typically unburied and uncoated along most of their length.

It can be seen that corner failure and pipeline risk dominate the overall mooring failure risk profile, with cumulative mooring failure risk of £28 million/year. This is approximately half of a typical array OPEX budget, which could increase LCOE by approximately 5%. The negative reputation impact for the floating wind operator and the industry as a whole could be even more damaging.

Actual risks will be highly location and mooring design specific. Sensitivity to an improved scenario where risk has been mitigated is presented below:

- The mooring system (ropes, anchors, FOWT connection) have been designed for resilience against corner failure. As such, the FOWT has a 10% chance of free drift (all lines broken) following a corner failure.

- The mooring system has been designed to avoid pipeline damage, for example by eliminating bottom chain and adding ‘fail safe’ buoyancy to prevent dragging chain. The likelihood of rupturing a major oil or gas pipeline following free drift reduces to 10%.

Table 17: Multiple mooring line repair costs – optimistic scenario

Event	Frequency per FOWT	Frequency per array	Primary consequence	Consequence event cost	Average risk cost per array per year
Singe line failure	1.8%/year	≈1/year	Repair 1 mooring	£1 million	£1.1 million
Corner failure	0.50%/year	30%/year	Replace 2 cables	£20 million	£6.6 million
Free drift	0.05%/year	3%/year	Replace 6 moorings and extended tow	£10 million	£0.3 million
Major pipeline rupture	0.005%/year	0.3%/year	Lost gas revenue Oil release Pipeline repair	£250 million	£0.75 million

It is notable that even in the optimistic scenario, the cumulative risk costs remain high at £9 million, which could increase LCOE by 1-2%. As discussed, the floating wind industry has a long way to go to target reliability levels above that of FPSOs.

The following risks are credible and potentially important, but are outwith the scope of the current study:

- Risk of run-over and damage to other synthetic mooring lines within the array. This could govern the overall risk profile if ropes are not suitably robust against chain run-over.
- Cable emergency release fails to trigger, causing upwind FOWT moorings to be overloaded. Given the high probability of corner failure at the array scale, careful consideration should be given to cable emergency release system reliability.
- Incursion into other floating wind arrays or O&G fields. Closely spaced ScotWind arrays with mooring ropes sensitive to run-over increase the overall risk profile.
- Export or array cable run-over.
- FOWT grounding or collision with another asset.

8.3 Cable System repair and replacement

8.3.1 Cable monitoring and inspection strategy

A risk-based cable monitoring and inspection strategy is recommended. In a similar manner to mooring monitoring, it is expected that this will comprise FOWT motion monitoring, which is complemented by a limited sample of periodic in-water survey data.

As with mooring lines, dynamic cable designs and operating conditions are cloned across the array. Many design, installation, manufacturing, and through-life integrity issues within an array are likely to influence all cables or none.

However, unlike mooring lines, a failed cable does not add load to adjacent cables, and there is no risk of a cascading failure event. Cable failure will be immediately obvious by loss of power transfer capacity. Examples of where inspection and monitoring can add value are summarised below.

Table 18: Examples of cable integrity management added value

Integrity issue detected	Example detection method	Response requirement	Value added through early detection	Criticality
Excessive marine growth	In-water inspection or cable depth sensing	In-water cleaning	Reduced likelihood of excessive drag loading or seabed contact	Medium
Electrical/thermal degradation	Thermal, optical or electrical sensing	Turbine de-rating Cable replacement	Extended life if de-rated Time to plan summer repair.	Medium
Cable overbending or overloading	Platform excursion or cable shape sensing	Cable replacement	Early detection can provide evidence to support failure investigation of subsequent thermal or electrical failure. Lessons learned shared within the operator, and ideally with the industry.	Low
External damage	In-water ROV inspection	Cable replacement		Low
Design flaws	Digital twin monitoring	Limited options		Low

8.3.2 Cable failure rates

Array cable failure rates are based on published industry data on a mix of cable types. The most robust cable failure data sets currently have a small population of array cables and no dynamic cable data. For example, the 4C Offshore data set of 373 cable failures [39], which was used to derive the 0.002 failures/km/year rate is made up of:

- 17% inter-array cable failures (62 events)
- 78% export cable or interconnector failures
- 5% onshore cable failures

This data is of limited applicability to offshore wind dynamic cables, with most of the failure data set being governed by long lengths of export cables. Even for bottom-fixed turbine inter-array cables, the failure modes for notionally static cables will be different versus dynamic cables. The latest industry published failure rates specifically for floating wind give an order of magnitude variation from 0.020 to 0.002 failures/km/year [40]. A lower bound failure rate has been used, assuming a well-designed and well-qualified dynamic cable system has been deployed:

- Indicative failure rate of 0.002 failures/km/year
- Equivalent to approximately 0.6% failure rate per year per WTG (≈3km of cable per WTG)
- Equivalent to approximately 0.4 failures per year per array (≈200km of cable per array)
- Corresponding to an average repair interval of approximately one failure every 2 years

These assumptions are applied across WTG-to-WTG array cables, and WTG-to-OSS cables. The costs presented in this chapter should be viewed with the potential for a 10 times higher failure cost at the array scale, given the variability in estimated failure rates, and uncertainty over long-term reliability of future 66kV dynamic cable systems at the Gigawatt scale.

8.3.3 Cable Replacement scenarios

The following representative repair scenarios are selected:

- Case A: End-to-end inter array cable replacement (WTG–WTG), where cable length <5km
- Case B: Localised cable repair using jointing (WTG–OSS), where cable length >5km

Vessel assumptions:

- Operations undertaken using a major cable repair vessel (e.g. cable lay or intervention vessel)
- Representative mid-range day rate of a capable CLV of approximately £200k/day

8.3.4 Cable repair weather window analysis

The effect of seasonal weather conditions on cable replacement operations has been assessed for both repair scenarios.

For the end-to-end replacement scenario (Case A), the operation is technically feasible throughout the year, with a maximum vessel hire duration of approximately 30 days. However, the analysis shows that where replacement is carried out during the summer period (May to August), operations can be executed with low weather downtime, resulting in approximately half the total duration and cost compared to operations undertaken during the October to February period.

For the repair joint scenario (Case B), although the nominal repair duration is only marginally longer than that of the end-to-end replacement, the operation is significantly more sensitive to environmental conditions. As a result, the repair joint scenario experiences substantially higher weather downtime, particularly during the period from September to March, leading to prolonged overall operation durations, and a higher risk of extended weather downtime. The weather downtime versus operations time by start month is shown below.

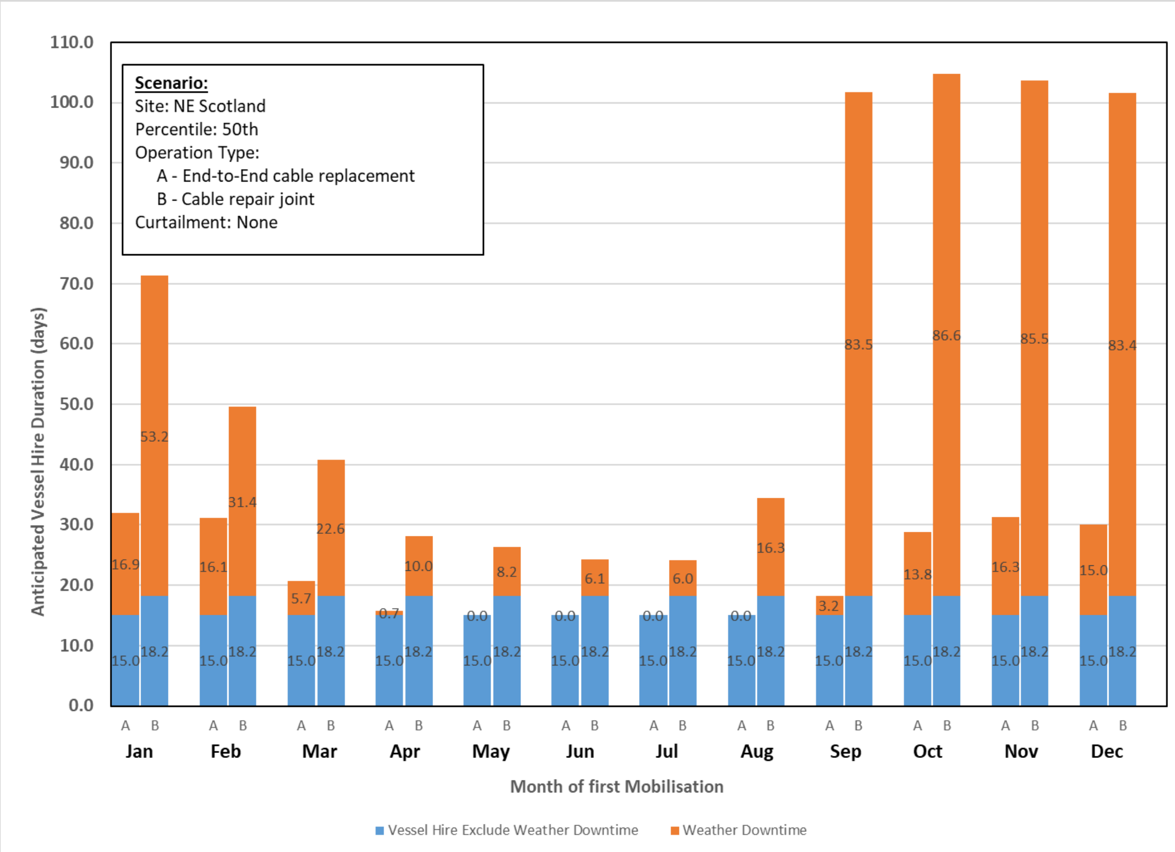


Figure 47 – Cable replacement vessel hire duration

8.3.5 Overall costs excluding curtailment

The overall costs associated with vessel hire and production losses are shown below. The production losses only include lost revenue during a two WTGs (between cable) shutdown during the repair operation to enable safe cable connection and personnel access.

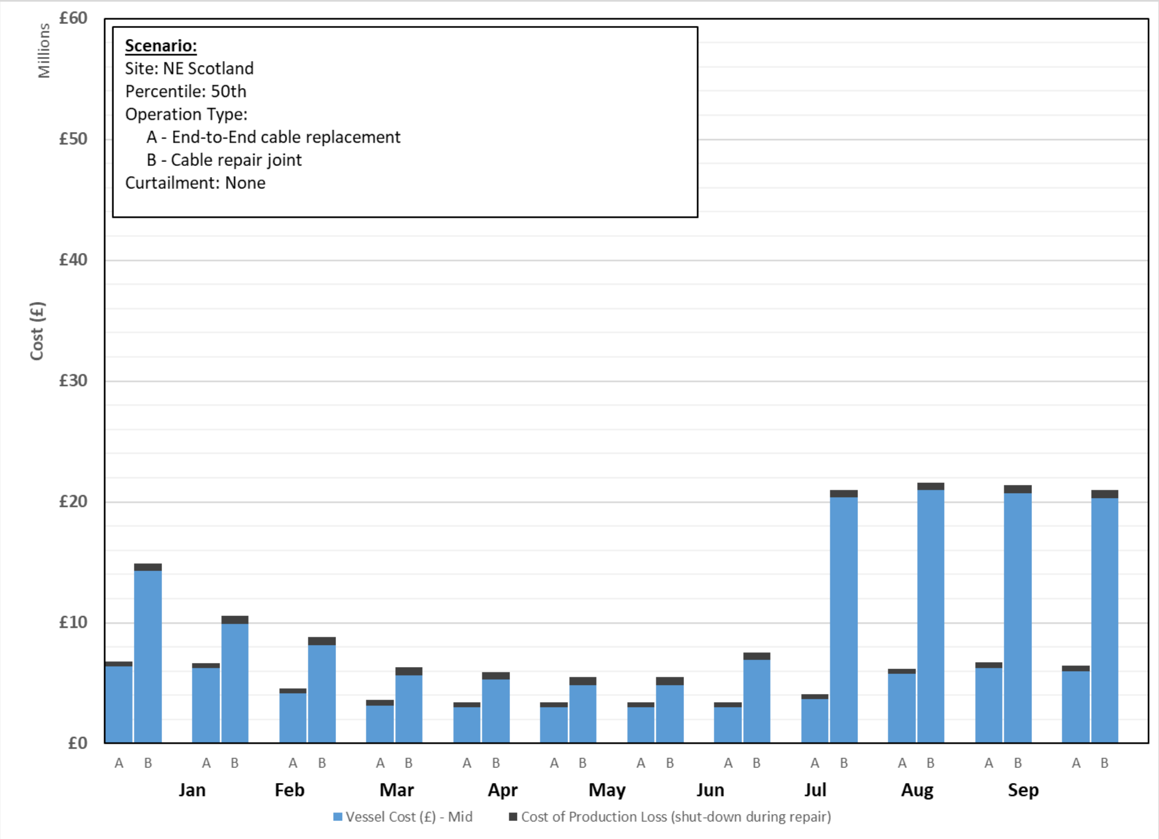


Figure 48 – Cable replacement cost

8.3.6 Production loss and revenue impact

The total cost implication of a cable failure is more complex than that of the mooring replacement scenario, as it depends on multiple interacting factors. These include:

- The failure location (WTG-to-WTG or WTG-to-OSS), which drives the repair approach.
- The time of year, which drives weather downtime.
- The availability of vessels and spare components, which drives the lead time.
- The level of system redundancy and position of the failure, which drives the production losses.

Depending on the level of redundancy in the array configuration and location of cable failure, the required curtailment can vary between 0MW and 70MW.

8.4 Maintenance requirements summary

The optimal repair strategy is highly dependent on the interaction between repair methodology, weather conditions, curtailment level, and lead time. The decision to perform a winter repair operation should be made on a case-by-case basis, considering the trade-off between lost production and weather downtime. Considerations should include:

- Criticality-based assessment to determine if repair can be deferred to favourable seasonal windows
- Evaluation of total cost of immediate repair against risk of delay to a favourable season

- Sensitivity of operation to environmental conditions
- Asset integrity and risk of escalation if operation is delayed
- Availability of spare components and mobilisation of vessels

Overall, there is no one approach that is optimised for all cases. A robust maintenance strategy should explore a range of scenarios and be adaptable. The same failure event occurring at different times of the year may require different responses. Decision-making should include consideration of integrity risk, spares and vessels availability, production downtime, and weather downtime.

9 CONCLUSIONS

This study establishes a practical framework for the monitoring, repair, and maintenance of mooring systems and dynamic cables in floating offshore wind farms.

Mooring failures may range from isolated events to systemic degradation requiring large-scale replacement campaigns. Mooring systems should be designed for inevitable repair and maintenance requirements.

It is also imperative that mooring design and integrity response planning prevents single line failures from cascading to corner failure or free drift. The consequence of corner failure or free drift can exceed £100 million. If not properly assessed and mitigated, such events become intolerably likely at the Gigawatt array scale. A risk-based approach is recommended to eliminate, mitigate, and detect mooring integrity risks. Efforts to reduce these risks is hindered by lack of sharing of mooring integrity and performance lessons learned on floating wind demonstrator projects. The sector needs to improve in this area if floating wind is to scale successfully.

Array cable failure presents a different nature of risk, which is driven by vessel weather downtime and revenue loss. The extent of both consequences depends on cable topology and fault location. End-to-end inter-array cable replacement is the preferred repair method where practical, as repair joint operations require longer durations and are significantly more sensitive to weather.

The analysis shows that total repair cost is driven by the interaction between weather conditions, lead time, and production impact. In high curtailment scenarios, immediate repair during winter may be more cost-effective despite increased vessel cost, whereas for weather-sensitive operations, delaying intervention to favourable seasonal windows can reduce overall cost.

Overall, there are many permutations and there is no one approach that is optimised for all cases. A robust maintenance strategy should explore a range of scenarios and be adaptable.

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