Cenos Offshore Windfarm Limited

Cenos EIA

Chapter 5 – Project Description

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ACRONYMS

ACRONYM	DEFINITION
2D	Two-dimensional
3D	Three-dimensional
AC	Alternating Current
BLP	Bridge Linked Platforms
CAA	Civil Aviation Authority
CBRA	Cable Burial Risk Assessment
CEA	Cumulative Effects Assessment
Cefas	Centre for Environment, Fisheries and Aquaculture Science
CIV	Cable Installation Vessel
CNSE	Central North Sea Electrification
CPS	Cable Protection System
CPT	Cone Penetration Test
CSV	Construction Support Vessel
cUXO	Confirmed Unexploded Ordnance
DC	Direct Current
DoB	Depth of Burial
DoL	Depth of Lowering
DP	Dynamic Positioning
EICC	Export/Import Cable Corridor
EIA	Environmental Impact Assessment
EIAR	Environmental Impact Assessment Report
EMF	Electromagnetic Fields
EMP	Environmental Management Plan
EPS	European Protected Species
FTU	Floating Turbine Unit
GMF	Geomagnetic Field
HDD	Horizontal Directional Drilling
HDPE	High-Density Polyethylene
HOD	High Order Detonation
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current

ACRONYM	DEFINITION
IAC	Inter-Array Cable
IALA	International Association of Marine Aids to Navigation and Lighthouse Authorities
IPS	Intermediate Peripheral Structures
JUV	Jack-Up Vessel
kJ	Kilojoule
km	Kilometres
kv	Kilovolt
LAT	Lowest Astronomical Tide
LOD	Low Order Deflagration
m	Metres
MBES	Multibeam Echosounder
MCA	Maritime and Coastguard Agency
MD-LOT	Marine Directorate - Licensing Operations Team
MGN	Marine Guidance Note
MHWS	Mean High Water Springs
MLWS	Mean Low Water Springs
MLA	Marine Licence Application
mm	Millimetre
MPA	Marine Protected Area
MSL	Mean Sea Level
MW	Megawatt
NCMPA	Nature Conservation Marine Protected Area
NLB	Northern Lighthouse Board
NM	Nautical Mile
OSCPs	Offshore Substation Convertor Platforms
OEM	Original Equipment Manufacturer's
PDE	Project Design Envelope
PLGR	Pre-Lay Grapnel Run
PLONOR	Pose Little Or No Risk
pUXO	Potential Unexploded Ordnance
SAC	Special Area of Conservation
SAR	Search and Rescue Operations
SBP	Sub Bottom Profiler

ACRONYM	DEFINITION
SOV	Service Operation Vessel
SPA	Special Protection Area
SPS	Significant Peripheral Structures
SSCV	Semi-Submersible Crane Vessel
SSS	Side Scan Sonar
Te	Tonnes
TLP	Tension Leg Platform
UAV	Unmanned Aerial Vehicle
UK	United Kingdom
UKHO	United Kingdom Hydrographic Office
UXO	Unexploded Ordnance
V/m	Volts per metre
VIV	Vortex Induced Vibrations
ROV	Remotely Operated Vehicle
WTG	Wind Turbine Generator

GLOSSARY

TERM	DEFINITION
2023 Scoping Opinion	Scoping Opinion received in June 2023, superseded by the 2024 Scoping Opinion.
2023 Scoping Report	Environmental Impact Assessment (EIA) Scoping Report submitted in 2023, superseded by the 2024 Scoping Report.
2024 Scoping Opinion	Scoping Opinion received in September 2024, superseding the 2023 Scoping Opinion.
2024 Scoping Report	EIA Scoping Report submitted in April 2024, superseding the 2023 Scoping Report.
Area of Opportunity	The area in which the limits of electricity transmission via High Voltage Alternating Current (HVAC) cables can reach oil and gas assets for decarbonisation. This area is based on assets within a 100 kilometre (km) radius of the Array Area.
Array Area	The area within which the Wind Turbine Generators (WTGs), floating substructures, moorings and anchors, Offshore Substation Converter Platforms (OSCPs) and Inter-Array Cables (IAC) will be present.
Cenos Offshore Windfarm ('the Project')	'The Project' is the term used to describe Cenos Offshore Windfarm. The Project is a floating offshore windfarm located in the North Sea, with a generating capacity of up to 1,350 Megawatts (MW). The Project which defines the Red Line Boundary (RLB) for the Section 36 Consent and Marine Licence Applications (MLA), includes all offshore components seaward of Mean High Water Springs (MHWS) (WTGs, OSCPs, cables, floating substructures moorings and anchors and all other associated infrastructure). The Project is the focus of this Environmental Impact Assessment Report (EIAR).
Cenos Offshore Windfarm Ltd. (The Applicant)	The Applicant for the Section 36 Consent and associated Marine Licences.
Cumulative Assessment	The consideration of potential impacts that could occur cumulatively with other relevant projects, plans, and activities that could result in a cumulative effect on receptors.

TERM	DEFINITION
Developer	Cenos Offshore Windfarm Ltd., a Joint Venture between Flotation Energy and Vårgrønn As (Vårgrønn).
Environmental Impact Assessment (EIA)	The statutory process of evaluating the likely significant environmental effects of a proposed project or development. Assessment of the potential impact of the proposed Project on the physical, biological and human environment during construction, operation and maintenance and decommissioning.
Environmental Impact Assessment Regulations	This term is used to refer to the Environmental Impact Assessment Regulations which are of relevance to the Project. This includes the Electricity Works (Environmental Impact Assessment) (Scotland) Regulations 2017, the Marine Works (Environmental Impact Assessment) (Scotland) Regulations 2017 (as amended); and the Marine Works (Environmental Impact Assessment) Regulations 2007.
Environmental Impact Assessment Report	A report documenting the findings of the EIA for the Project in accordance with relevant EIA Regulations.
Export/Import Cable	High voltage cable used to export/import power between the OSCPs and Landfall.
Export/Import Cable Bundle (EICB)	Comprising two Export/Import Cables and one fibre-optic cable bundled in a single trench.
Export/Import Cable Corridor (EICC)	The area within which the Export/Import Cable Route will be planned and the Export/Import Cable will be laid, from the perimeter of the Array Area to MHWS.
Export/Import Cable Route	The area within the Export/Import Export Corridor (EICC) within which the Export/Import Cable Bundle (EICB) is laid, from the perimeter of the Array Area to MHWS.
Floating Turbine Unit (FTU)	The equipment associated with electricity generation comprising the WTG, the floating substructure which supports the WTG, mooring system and the dynamic section of the IAC.
Flotation Energy	Joint venture partner in Cenos Offshore Windfarm Ltd.

TERM	DEFINITION
Habitats Regulations	The Habitats Directive (Directive 92/43/ECC) and the Wild Birds Directive (Directive 2009/147/EC) were transposed into Scottish Law by the Conservation (Natural Habitats &c) Regulations 1994 ('Habitats Regulations') (up to 12 NM); by the Conservation of Offshore Marine Habitats and Species Regulations 2017 ('Offshore Marine Regulations') (beyond 12 NM); the Conservation of Habitats and Species Regulations 2017 (of relevance to consents under Section 36 of the Electricity Act 1989); the Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001; and the Wildlife and Countryside Act 1981. The Habitats Regulations set out the stages of the Habitats Regulations Appraisal (HRA) process required to assess the potential impacts of a proposed project on European Sites (Special Areas of Conservation, Special Protection Areas, candidate SACs and SPAs and Ramsar Sites).
Habitats Regulations Appraisal	The assessment of the impacts of implementing a plan or policy on a European Site, the purpose being to consider the impacts of a project against conservation objectives of the site and to ascertain whether it would adversely affect the integrity of the site.
High Voltage Alternating Current (HVAC)	Refers to high voltage electricity in Alternating Current (AC) form which is produced by the WTGs and flows through the IAC system to the OSCPs. HVAC may also be used for onward power transmission from the OSCPs to assets or to shore over shorter distances.
High Voltage Direct Current (HVDC)	Refers to high voltage electricity in Direct Current (DC) form which is converted from HVAC to HVDC at the OSCPs and transmitted to shore over longer distances.
Horizontal Directional Drilling (HDD)	An engineering technique for laying cables that avoids open trenches by drilling between two locations beneath the ground's surface.
Innovation and Targeted Oil & Gas (INTOG)	In November 2022, the Crown Estate Scotland (CES) announced the Innovation and Targeted Oil & Gas (INTOG) Leasing Round, to help enable this sector-wide commitment to decarbonisation. INTOG allowed developers to apply for seabed rights to develop offshore windfarms for the purpose of providing low carbon electricity to power oil and gas installations and help to decarbonise the sector. Cenos is an INTOG project and in November 2023 secured an Exclusivity Agreement as part of the INTOG leasing round.

TERM	DEFINITION
Inter-Array Cable (IAC)	The cables which connect the WTGs to the OSCPs. WTGs may be connected with IACs into a hub or in series as a 'string' or a 'loop' such that power from the connected WTGs is gathered to the OSCPs via a single cable.
Joint Venture	The commercial partnership between Flotation Energy and Vårgrønn, the shareholders which hold the Exclusivity Agreement with CES to develop the Cenos site as an INTOG project.
Landfall	The area where the Export/Import Cable from the Array Area will be brought ashore. The interface between the offshore and onshore environments.
Marine Licence	Licence required for certain activities in the marine environment and granted under the Marine and Coastal Access Act 2009 and/or the Marine (Scotland) Act 2010.
Marine Protected Area (MPA)	Marine sites protected at the national level under the Marine (Scotland) Act 2010 out to 12 NM, and the Marine and Coastal Access Act 2009 between 12-200 NM. In Scotland MPAs are areas of sea and seabed defined so as to protect habitats, wildlife, geology, underseas landforms, historic shipwrecks and to demonstrate sustainable management of the sea.
Marine Protected Area (MPA) Assessment	A three-step process for determining whether there is a significant risk that a proposed development could hinder the achievement of the conservation objectives of an MPA.
Mean High Water Springs (MHWS)	The height of Mean High Water Springs is the average throughout the year, of two successive high waters, during a 24-hour period in each month when the range of the tide is at its greatest.
Mean Low Water Springs (MLWS)	The height of Mean Low Water Springs is the average throughout a year of the heights of two successive low waters during periods of 24 hours (approximately once a fortnight).
Mitigation Measures	Measures considered within the topic-specific chapters in order to avoid impacts or reduce them to acceptable levels. • Primary mitigation - measures that are an inherent part of the design of the Project which reduce or avoid the likelihood or magnitude of an adverse environmental effect, including location or design; • Secondary mitigation – additional measures implemented to further reduce environmental effects to 'not significant' levels (where

TERM	DEFINITION
	appropriate) and do not form part of the fundamental design of the Project; and • Tertiary mitigation – measures that are implemented in accordance with industry standard practice or to meet legislative requirements and are independent of the EIA (i.e. they would be implemented regardless of the findings of the EIA). Primary and tertiary mitigation are referred to as embedded mitigation. Secondary mitigation is referred to as additional mitigation.
Mooring System	Comprising the mooring lines and anchors, the mooring system connects the floating substructure to the seabed, provides station-keeping capability for the floating substructure and contributes to the stability of the floating substructure and WTG.
Nature Conservation Marine Protected Area (NCMPA)	MPA designated by Scottish Ministers in the interests of nature conservation under the Marine (Scotland) Act 2010.
Offshore Substation Converter Platforms (OSCPs)	An offshore platform on a fixed jacket substructure, containing electrical equipment to aggregate the power from the WTGs and convert power between HVAC and HVDC for export/import via the Export/Import Cable to/from the shore. The OSCPs will also act as power distribution stations for the Oil & Gas platforms.
Onward Development	Transmission projects which are anticipated to be brought forward for development by 3rd party oil and gas operators to enable electrification of assets via electricity generated by the Project. All Onward Development will subject to separate marine licensing and permitting requirements.
Onward Development Area	The area within which oil and gas assets would have the potential to be electrified by the Project.
Onward Development Connections	Oil and gas assets located in the waters surrounding the Array Area will be electrified via transmission infrastructure which will connect to the Project's OSCPs. These transmission cables are referred to as Onward Development Connections.
Project Area	The area that encompasses both the Array Area and EICC.
Project Design Envelope	A description of the range of possible elements that make up the Project design options under consideration and that are assessed as part of the EIA for the Project.

TERM	DEFINITION
Study Area	Receptor specific area where potential impacts from the Project could occur.
Transboundary Assessment	The consideration of impacts from the Project which have the potential to have a significant effect on another European Economic Area (EEA) state's environment. Where there is a potential for a transboundary effect, as a result of the Project, these are assessed within the relevant EIA chapter.
Transmission Infrastructure	The infrastructure responsible for moving electricity from generating stations to substations, load areas, assets and the electrical grid, comprising the OSCPs, and associated substructure, and the Export/Import Cable.
Vårgrønn As (Vårgrønn)	Joint venture partner in Cenos Offshore Windfarm Ltd.
Wind Turbine Generator (WTG)	The equipment associated with electricity generation from available wind resource, comprising the surface components located above the supporting substructure (e.g., tower, nacelle, hub, blades, and any necessary power transformation equipment, generators, and switchgears).
Worst-Case Scenario	The worst-case scenario based on the Project Design Envelope which varies by receptor and/or impact pathway identified.

5 PROJECT DESCRIPTION

5.1 Introduction

This chapter describes the design details of the Project, comprising all offshore components seaward of Mean High Water Springs (MHWS), including all activities associated with the Project phases from pre-construction and construction, operation and maintenance to decommissioning. Key parameters are described herein, alongside the activities and timescales for each phase of the Project.

5.2 Design envelope approach

The Project has utilised a Project Design Envelope (PDE) approach to inform this Environmental Impact Assessment Report (EIAR). The PDE approach enables a range of values to be presented for each Project aspect, providing the flexibility to allow for further refinement of the Project design.

The first version of the PDE was presented within the 2023 Scoping Report, submitted to Marine Directorate - Licensing Operations Team (MD-LOT) in 2023, and thereafter refined for the 2024 Scoping Report submitted to MD-LOT in April 2024. The PDE has been further refined based on the results of environmental surveys, technical and engineering studies and discussions with stakeholders and the community, as part of the Environmental Impact Assessment (EIA) process. The PDE that informed this EIAR contains a series of design options, including reasoned maximum and minimum parameter values, within which the final design of the Project will sit. In most instances, this chapter refers to the maximum PDE parameter values, as these typically represent the worst-case scenario for the EIA and assessing the maximum impact avoids an overly complex EIA. Where the minimum values constitute the worst-case scenario, these have been described.

The PDE approach has been adopted in accordance with the Scottish Government (2022a) Guidance for applicants on using the design envelope for applications under Section 36 of the Electricity Act 1989. The guidance outlines that, where flexibility in design parameters is required, the reason for this should be clearly explained and assessments should be undertaken on the parameters likely to result in the maximum adverse effect (i.e., the worst-case scenario). In accordance with this guidance, this chapter outlines those parameters where flexibility has been maintained, and the justification for this has been provided either here or in topic-specific chapters.

5.3 Design principles

The Applicant recognises that the climate and biodiversity crises are closely intertwined and, at this early stage of development, has used the EIA process as far as possible to address them. As detailed in EIAR Vol. 2, Chapter 7: EIA Methodology, the EIA process informs the Project design by considering environmental baseline information and key receptor sensitivities. For this project, key receptors identified within the Array Area include protected benthic habitats and associated species, as detailed in EIAR Vol. 3, Chapter 10: Benthic Ecology. In this regard, the Project has considered biodiversity principally though embedded mitigation by minimising seabed footprint of Project infrastructure. For example, by removing the catenary mooring design from the design envelope to reduce maximum seabed disturbance from the mooring line ground chain, as the catenary design has a larger quantity of ground chain on the seabed compared to other mooring designs, and by restricting rock placement within the Array Area to cable/pipeline crossings and the base of the OSCPs only. EIAR Vol. 2, Chapter 4: Site Selection, Section 4.6.1.1 provides more detail on Project design evolution.

Options for incorporating Nature Inclusive Design (NID), as highlighted in the Crown Estate Scotland (2024) Report, indicate that there are limited NID options available for floating wind projects like this one. This is particularly true for the deep offshore circalittoral mud habitat within the Array Area. Consequently, the Applicant has not proposed any NID measures as part of this application. The Project is committed to continuing its employment of environmentally-sensitive design as it moves towards detailed design post-consent. This commitment includes ensuring effects to the seabed are minimised wherever possible, including routing and siting around designated features, as informed by further planned ground investigation works. Additionally, the design selection process will prioritise components which limit both temporary and long-term effects to sensitive habitats and features wherever feasible.

5.4 Project overview

5.4.1 Outline description

The Project is located in the Central North Sea (CNS), approximately 200 kilometres (km) offshore east of Aberdeen at the closest point of the Array Area and comprises both the Array Area and the Export/Import Cable Corridor (EICC). The key components of the Project include:

- Up to 95 Floating Turbine Units (FTUs), each with a Wind Turbine Generator (WTG) and floating substructure, which will be anchored to the seabed to maintain station keeping within an allowable radius for each FTU within the Array Area;
- Up to two Offshore Substation Convertor Platforms (OSCPs) within the Array Area, connected to the WTGs using dynamic subsea Alternating Current (AC) power cables (the Inter-Array Cables (IACs)). OSCPs topsides will be located on bottom-fixed jacket foundations with 50 metre (m) spacing between jackets. OSCPs topsides will be linked via bridge-link;
- Up to 350 km of IACs (including 280 km of buried, static cabling, and 70 km of dynamic cabling); and
- An Export/Import Cable bundle comprising two High Voltage Direct Current (HVDC) cables and a fibre optic cable bundled in a single trench. Each has a maximum length of 230 km from the OSCPs to Landfall at Longhaven.

An overview of the key Project components is provided in Figure 5-1.

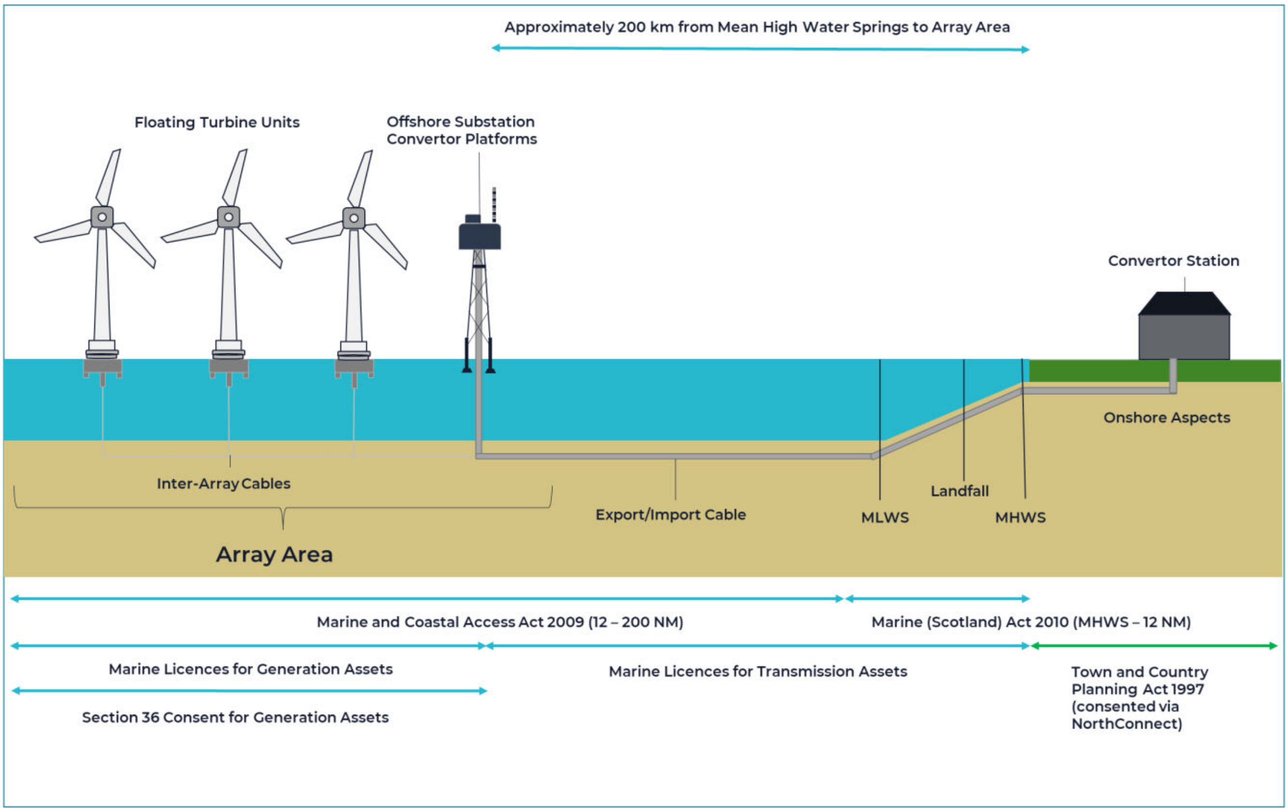

Figure 5-1 Project overview (note onshore aspects are shown for context only)

The Array Area is approximately 333 km^2 and will comprise the Generation Assets (the FTUs and the IACs) and the OSCPs. The EICC is approximately 230 km in length and will run from the OSCPs, located within the Array Area, to the Landfall at Longhaven. Figure 5-2 illustrates the Array Area and EICC within the Project boundary, as well as the Landfall in Aberdeenshire.

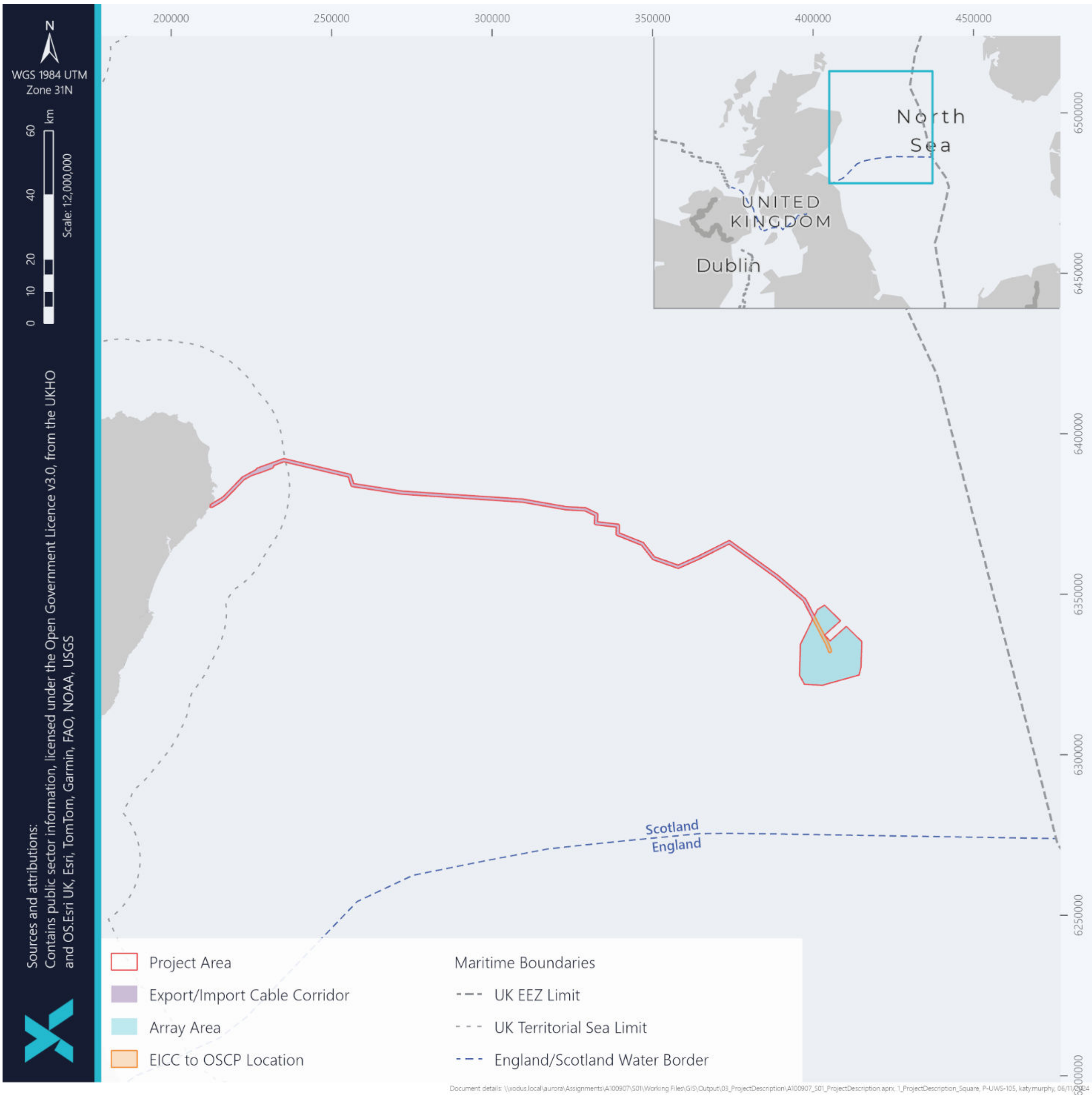

Figure 5-2 Project boundary

It is anticipated that the construction phase of the Project will take up to six years (see Section 5.8). The key Project milestones are likely to be:

- Year 1: Export/Import Cable route preparation and installation of first half of the Export/Import Cable.;
- Year 2: OSCPs to be installed, Export/Import Cable installation of second half of the Export/Import Cable, pulled in at the OSCPs; system powered up, tested, and commissioned, site preparation activities for the Array Area;
- Years 2-4: pre-lay of moorings, IACs, and pre-installation of anchors for each Array Area section in the year prior to tow-out and hook-up; and
- Years 3-6: tow-out and hook-up of FTU's over three years / three Array Area sections due to number to be installed (also considering distance from shore, size of Array Area and weather conditions).

5.5 Pre-construction works

Several activities will be required ahead of construction, including Project-specific and pre-construction surveys, site investigations and site preparation.

5.5.1 Project Specific Surveys and Site Investigation

Project-specific surveys and site investigations will be conducted prior to the construction period. Pre-construction survey campaigns will also be conducted. Firstly, it is assumed up to two geophysical survey campaigns will be conducted. The survey methods / equipment will include:

- Two-dimensional (2D) and three-dimensional (3D) seismic surveys;
- Multibeam Echo Sounder (MBES);
- Side Scan Sonar (SSS);
- Magnetometer;
- Sub-Bottom Profiler (SBP); and
- Remotely Operated Vehicles (ROVs).

Secondly, it is assumed up to two geotechnical survey campaigns will be conducted. The survey methods / equipment will include:

- Deep push seabed Cone Penetration Test (CPT) frames;
- Shallow CPT;
- Vibrocores; and
- Boreholes.

5.5.2 Site Preparation

Project-specific site preparation will be conducted. The activities will include boulder clearance, Pre-Lay Grapnel Runs (PLGR), pre-existing out-of-service cable removal and Unexploded Ordnance (UXO) clearance. Sandwave clearance will not be required.

5.5.2.1 Pre-Lay Grapnel Run

A PLGR operation will be executed shortly prior to the installation of the cables (Export/Import Cable and IACs) to clear the seabed of surface debris. PLGR operations are normally carried out along a proposed cable route centre line to provide 100% coverage of the centre-line route, with the exception of in-service cable and pipeline exclusion zones. Additional passes shall be completed in any area where anomalies and/or debris are expected or located. It is assumed that a corridor of 100 m (i.e. 50 m either side the centre line) is the width of the PLGR operating corridor, however only 10 m of disturbance within the corridor will occur from the PLGR. In addition, the PLGR will recover any out-of-service cables present. It is assumed that detrenching grapnels will be used within a maximum trench depth of 1.8 m where, if a cable is found, both ends of the cable will be recovered up to the border of the corridor and then cut onboard (so the recovered cable will be taken out) and then laid back to the seafloor, outside of the corridor with a clump weight at each end. The clump weights will be concrete discs, typically 0.5 m diameter by 0.2 m thick, or other thin sectioned weights; alternatively, chain may be used. The objective of the weight is to minimise the risk of fastening to fishing gear.

5.5.2.2 Boulder clearance

Boulder fields are present within the Array Area and the EICC and boulder clearance is anticipated to be required as a part of pre-construction site preparation. Boulder clearance is expected to be conducted by a plough or a grab. Charts will be provided to include areas where boulder clearance will likely be conducted (as part of the Cable Burial Risk Assessment (CBRA) from the 12 Nautical Miles (NM) to the OSCPs) (EIAR Vol. 4, Appendix 1: Preliminary CBRA and BAS Report for the Inter Array Cables, and Appendix 2: Preliminary CBRA and BAS Report for the Export Cable Route). If a plough is used, then it will be approximately 13 m wide, which is anticipated to result in a 20 m maximum area of direct disturbance to the seabed. If using a grab, boulders would be placed 10 m either side of the IACs and/or Export/Import Cable within their respective cable corridors. The Project will aim to minimise boulder clearance by micro-routeing cabling, which will be defined during the detailed engineering phase. The assumptions for boulder clearance represents the worst-case scenario for temporary seabed disturbance due to boulder clearance. Boulder clearance techniques such as a boulder grab will reduce the area disturbed by boulder clearance. The design envelope for boulder clearance is provided in Table 5-1.

Table 5-1 Design envelope for boulder clearance

DESIGN PARAMETER	LENGTH OF ROUTE	MAXIMUM BOULDER CLEARANCE AREA
EICC Between MHWS and 12 NM	100% (28 km) of route length will require boulder clearance.	560,000 m^2
EICC From 12 NM to the East of Gannet and Montrose Fields Nature Conservation Marine Protected Area (NCMPA)	13 km of the route length will require boulder clearance with an additional 10% (15.4 km) of the remaining 154 km route length requiring boulder clearance.	568,000 m^2
EICC From the NCMPA to the OSCPs	10% (3.5 km) of the route length (35 km) will require boulder clearance.	70,000 m^2
EICC Total	59.9 km	1,198,000 m^2
IACs Total	100% of the IACs route length (280 km) along the seabed	5,600,000 m^2

Boulder size and distribution within the EICC is shown in Figure 5-3 and Figure 5-4.

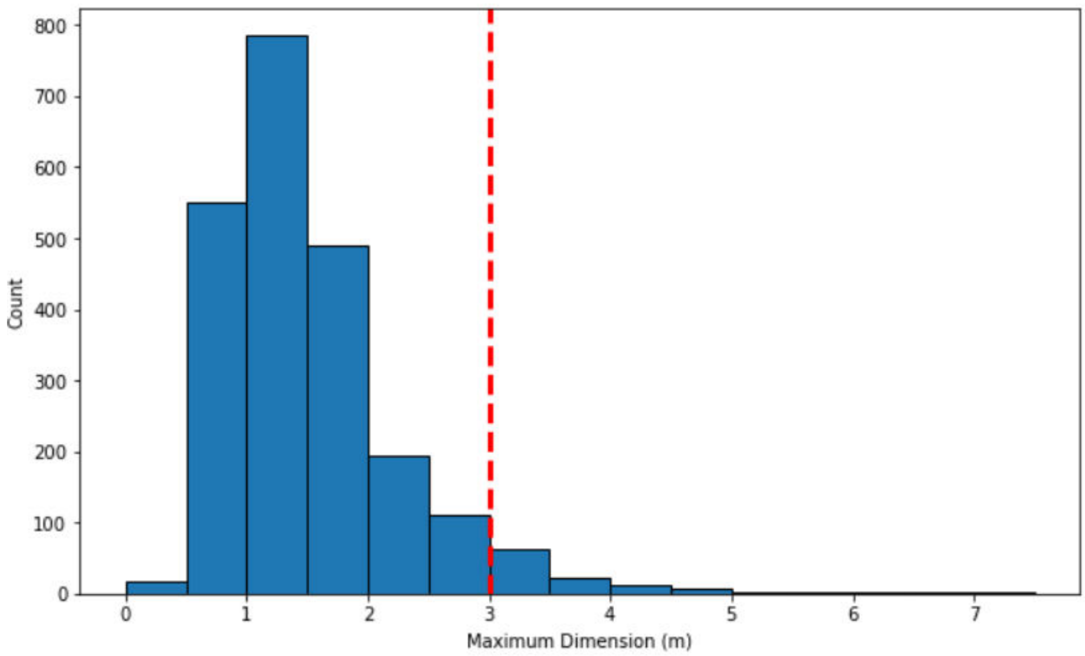

Figure 5-3 Size distribution of boulders within the EICC

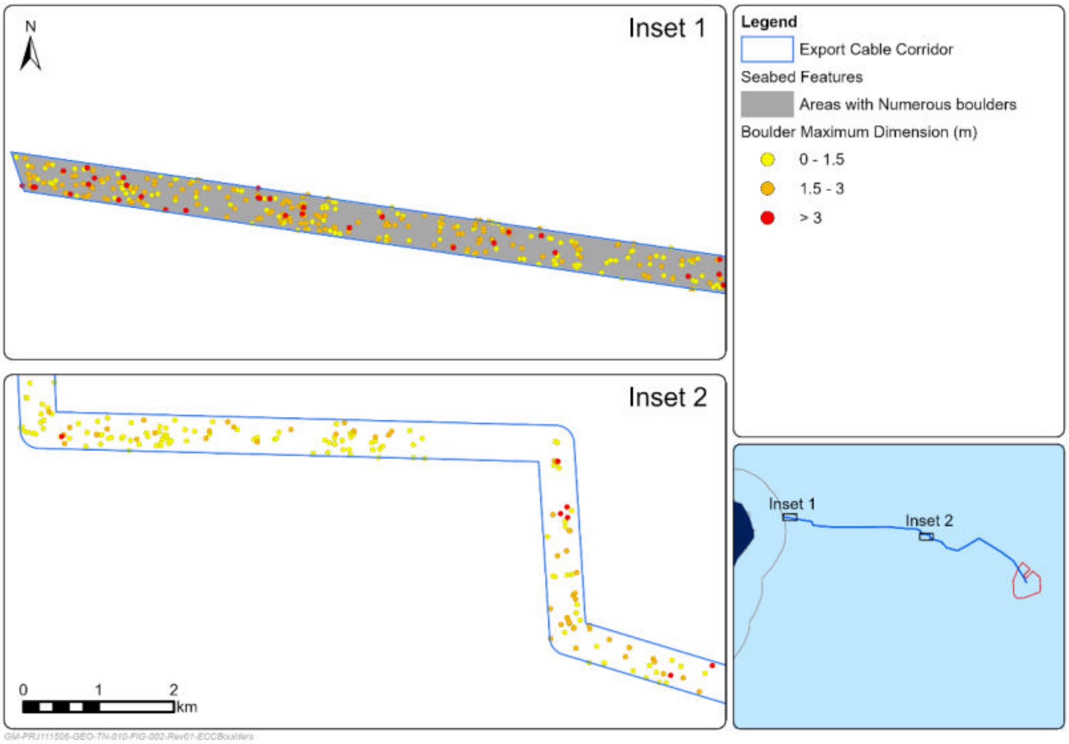

Figure 5-4 Boulder distribution along the EICC

The size distribution indicates that the majority of the boulders within the EICC would be movable with a plough or grab. The limit of 3 m in maximum dimension is highlighted to show the number of boulders that would need to be routed around. Boulders of over 3 m are avoided by the cable route entirely, and boulders smaller than this are avoided unless it becomes too difficult to do so with micro-routeing. In these areas, where routeing cannot avoid the remaining boulders, utilisation of a plough and grab may be necessary. Once final cable routeing is completed, a full listing of boulders to be cleared can be generated.

Boulder size and distribution for the Array Area is shown in Figure 5-5 and Figure 5-6.

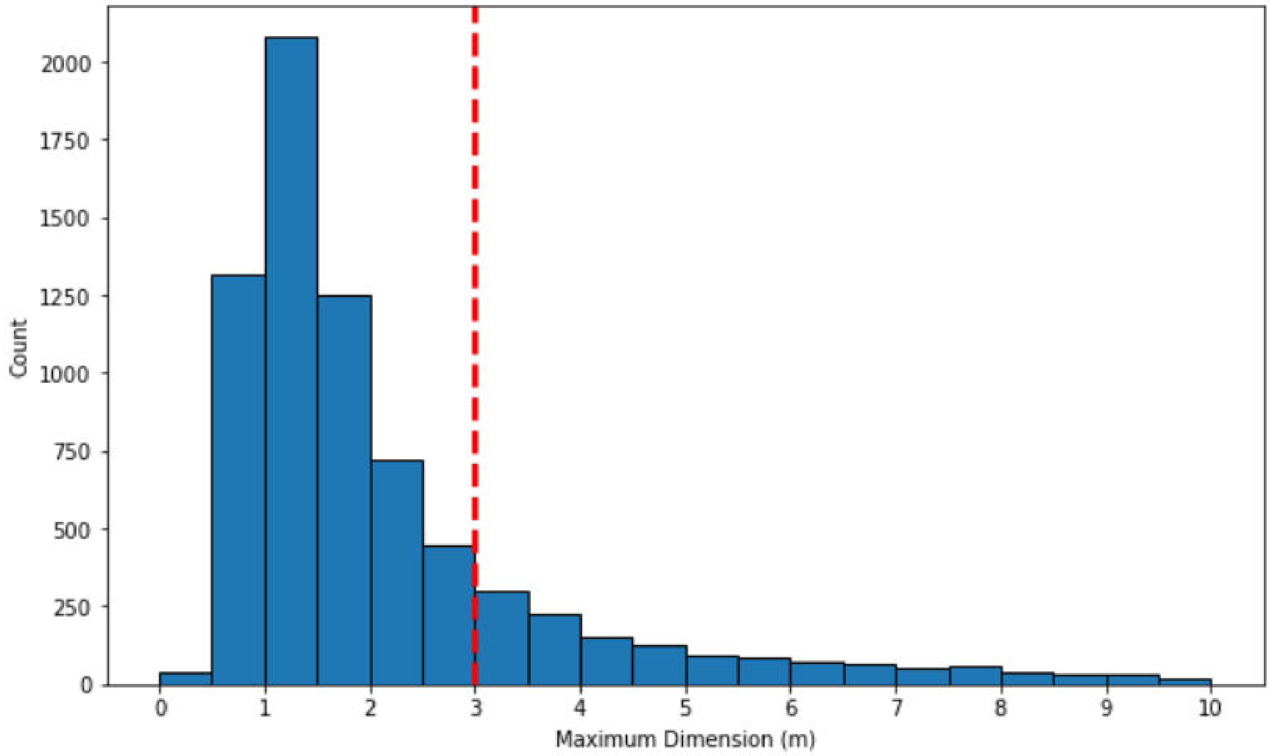

Figure 5-5 Size distribution of boulders within the Array Area

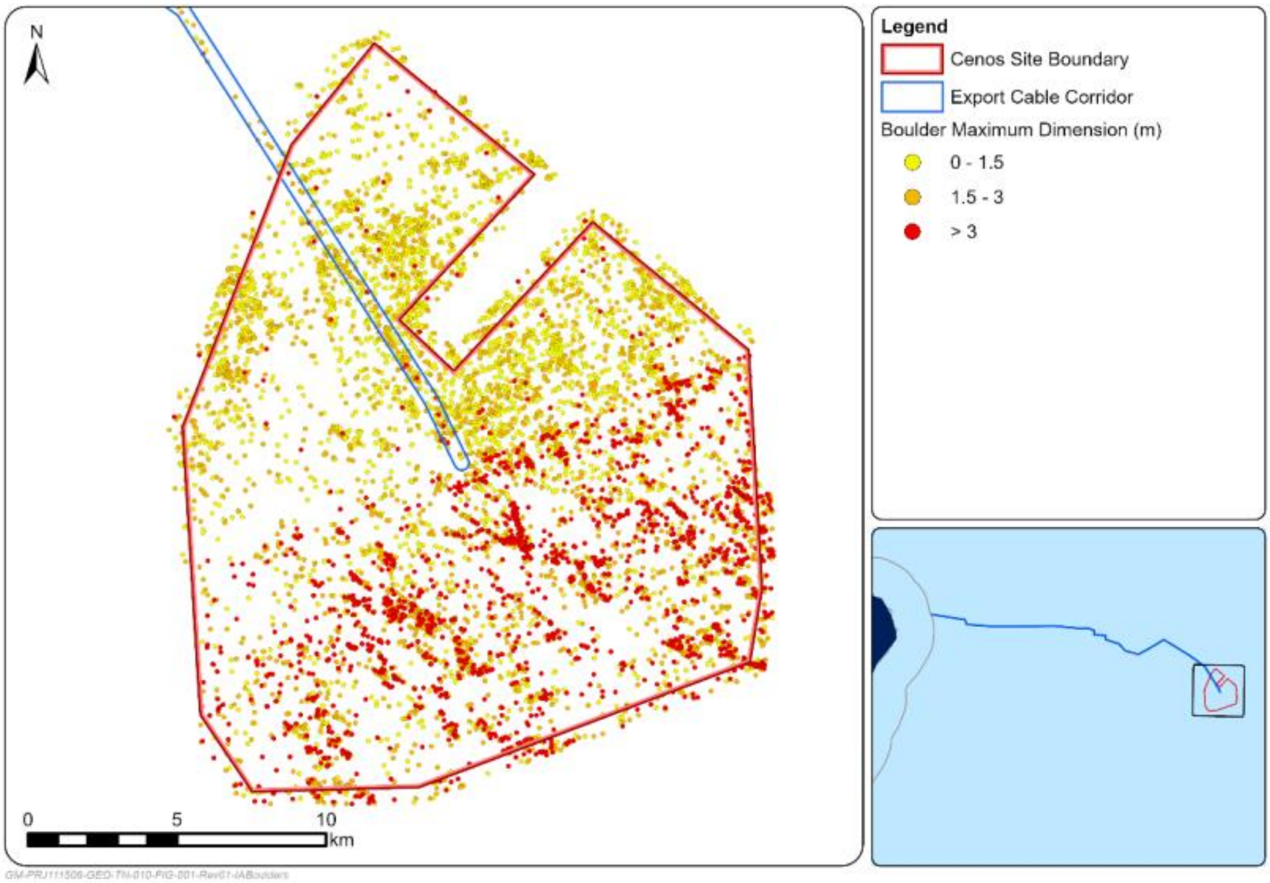

Figure 5-6 Spatial and size distribution of boulders within the Array Area

Of the boulders identified in the Array Area survey data, the majority can be moved by either a plough or grab. There are however a substantial number that will need to be avoided by the cable routes. At the time of writing, the IACs routeing is not yet completed. Once routeing is complete, a listing of boulders that will need clearing can be generated.

5.5.2.3 Sandwave clearance

Sandwave clearance is not required in the Array Area. Within the EICC, sandwave clearance can be avoided through micro-routeing of the Export/Import Cable. Avoidance via micro-routeing is the preferred option followed by deeper burial (underneath the mobile layer) with a plough or mechanical trencher. If micro-routeing or deeper burial is not suitable, then pre-ploughing activities can be considered. No dredging activities are foreseen. Pre-plough may be required on a limited basis. See EIAR Vol. 3, Chapter 8: Marine Geology, Oceanography, and Coastal Processes for the sediment disposal assumptions used.

5.5.2.4 UXO Clearance

The risk associated with UXO has been independently assessed as being 'low' within the Array Area and 'medium' toward the western end of the EICC, approximately 50 – 60 km from Landfall (EIAR Vol. 4, Appendix 4: UXO Survey Specifications, Appendix 5: UXO Threat and Risk Assessment, and Appendix 6: UXO Risk Mitigation Strategy). Given the degree of flexibility afforded by the design of both the Array Area and the width of the EICC, it is anticipated that it will be possible to avoid UXO through micro-siting / micro-routing.

However, where UXO are identified within the Project Area which cannot be avoided or which pose a genuine threat to the safe completion of construction works, clearance will be undertaken as necessary.

Any required clearance, whilst deemed unlikely, would be subject to a separate Marine Licence and associated environmental assessment to be determined by MD-LOT in consultation with relevant stakeholders. A European Protected Species (EPS) Licence would also be sought in conjunction with any such Marine Licence.

The maximum worst-case scenario assumes the clearance of 51 UXO's within the Project Area, with 50 cleared by Low Order Deflagration (LOD) with a donor charge of 0.08 kg and one High Order Detonation (HOD), with a charge weight of 227 kg and 5 kg donor charge, in accordance with predicted charge weights in the UXO risk assessment (EIAR Vol. 4, Appendix 5: UXO Threat and Risk Assessment). It is expected that, where possible, all UXO clearance will be undertaken using low-noise clearance methods, such as deflagration, and all efforts will be made to avoid HOD where possible.

This approach is consistent with the advice from MD-LOT and stakeholders and allows for a meaningful assessment of actual confirmed UXO (cUXO) based on actual locations, seabed conditions and potential threats to taxa. This EIAR assesses the impact of two UXO clearance scenarios: high-order clearance and low-order clearance, outlined in Table 5-2.

Table 5-2 UXO clearance scenarios

DESIGN PARAMETER	DESIGN ENVELOPE
Method of Detonation #1 - High-Order	Detonation
Method of Detonation #2 - Low-Order	Deflagration

5.6 Offshore wind farm infrastructure

5.6.1 Wind Turbine Generators

5.6.1.1 Design

The WTGs convert wind energy to electricity and consist of a tower, a nacelle atop the tower which contains the electrical and mechanical components (e.g. gearboxes, transformers, power electronics and control equipment), and three horizontal axis blades. Electricity generated by the WTGs will be exported via the IACs to the OSCPs and then via the Export/Import Cable to Landfall.

WTG technology is constantly evolving, and a range of WTG options (three options) is therefore being considered to allow for market availability and development. The PDE includes 15, 18, and 21 Megawatt (MW) WTG options in order to consider the worst-case WTG quantities and WTG size (and associated floating substructure and mooring system size) that should be considered for assessment within this EIAR.

The final model of WTG will be selected post-consent, however, Table 5-3 sets out the PDE for the WTGs. Flexibility is required to ensure the supply chain options at the point of WTG procurement can be met. The final WTG parameter values will remain within the PDE provided in Table 5-3.

Table 5-3 WTG design envelope parameters

DESIGN PARAMETER	DESIGN ENVELOPE
WTG type	3-blade Horizontal Axis Wind Turbine
Maximum number of WTGs	95
Minimum to maximum WTG rotor diameter (m)	232 to 280
Maximum WTG hub height above Lowest Astronomical Tide (LAT) (m)	180
Maximum upper blade tip height above LAT (m)	320
Minimum lower blade tip height above Mean Sea Level (MSL) (m)	22
Maximum swept area (m^2) (per WTG, using 95 FTU scenario)	61,575
Maximum swept area (m^2) (entire Array, using 80 FTU scenario)	4,580,442
Minimum turbine spacing (m) (depending on WTG choice)[1]	928 to 1,080

The final WTG layout will be determined post-consent through the design optimisation process, which balances multiple considerations, including model choice, navigational safety considerations, seabed characteristics, metocean conditions, existing infrastructure, foundation type, and engineering and environmental constraints identified through surveys and consultations.

[1] *This separation distance applies to the minimum distance between WTGs in the same row and the minimum distance between rows of WTGs.*

Worst-case scenario layouts have been developed for relevant EIA topics and are presented in the topic-specific chapters, as required.

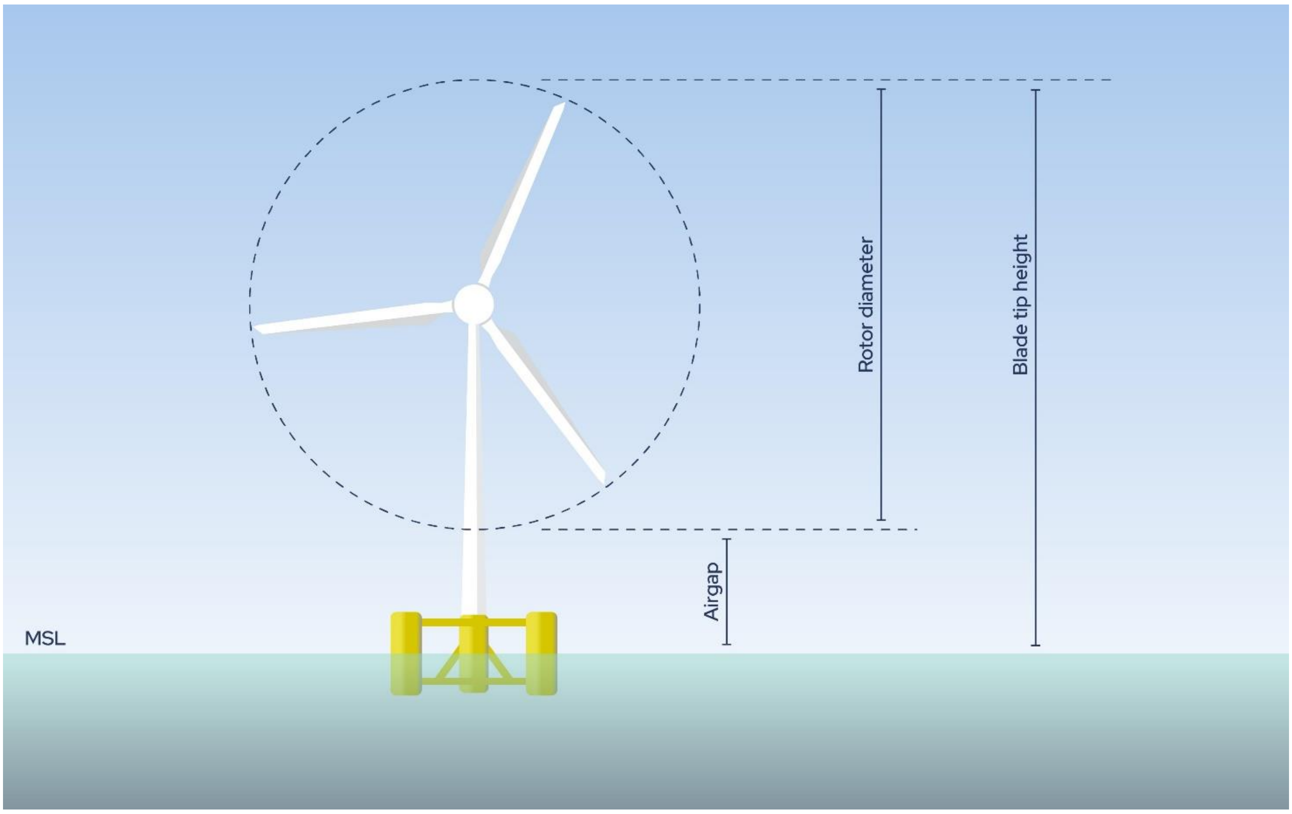

Figure 5-7 Schematic diagram of WTG

5.6.1.2 Navigation and aviation lighting

The operational FTUs will adhere to navigational lighting and marking requirements set out by the Civil Aviation Authority (CAA), Maritime and Coastguard Agency (MCA), Search and Rescue (SAR) operations, and the Northern Lighthouse Board (NLB).

This is anticipated to include Marine Guidance Note (MGN) 654 Annex 5, which states that perimeter WTGs should have a single red aviation hazard light on each nacelle. Perimeter WTGs or Significant Peripheral Structures (SPS) will be marked with lights visible from all directions in the horizontal plane. These lights should be synchronized to display simultaneously an International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA) "special mark" characteristic, flashing yellow, with a range of not less than 5 NM. Selected Intermediate Peripheral Structures (IPS) on the boundary of a wind farm between SPSs may be marked with flashing yellow lights and differ from SPSs lights with a range < 2 NM.[2] Other WTGs will have a steady, red aviation hazard light. Furthermore, marine navigational and aviation markings and lighting will be agreed in consultation with CAA, MCA and NLB post-consent. These will also adhere to the Air Navigational Order 2016 (as amended), IALA guideline G1162 (IALA, 2021) and the

[2] *Source: https://assets.publishing.service.gov.uk/media/6365385d8fa8f57a2afa161f/MGN372_Amendment_1.pdf*

MCA (2024) guidance on Offshore Renewable Energy Installations: Requirements, guidance and operational considerations for SAR and Emergency Response.

The final position of all offshore structures will be communicated to the United Kingdom Hydrographic Office (UKHO) for incorporation into Admiralty Charts and notification procedures.

5.6.1.3 Layout

Figure 5-8 illustrates an indicative turbine layout showing 95 FTUs. The layout will be further refined during subsequent project engineering.

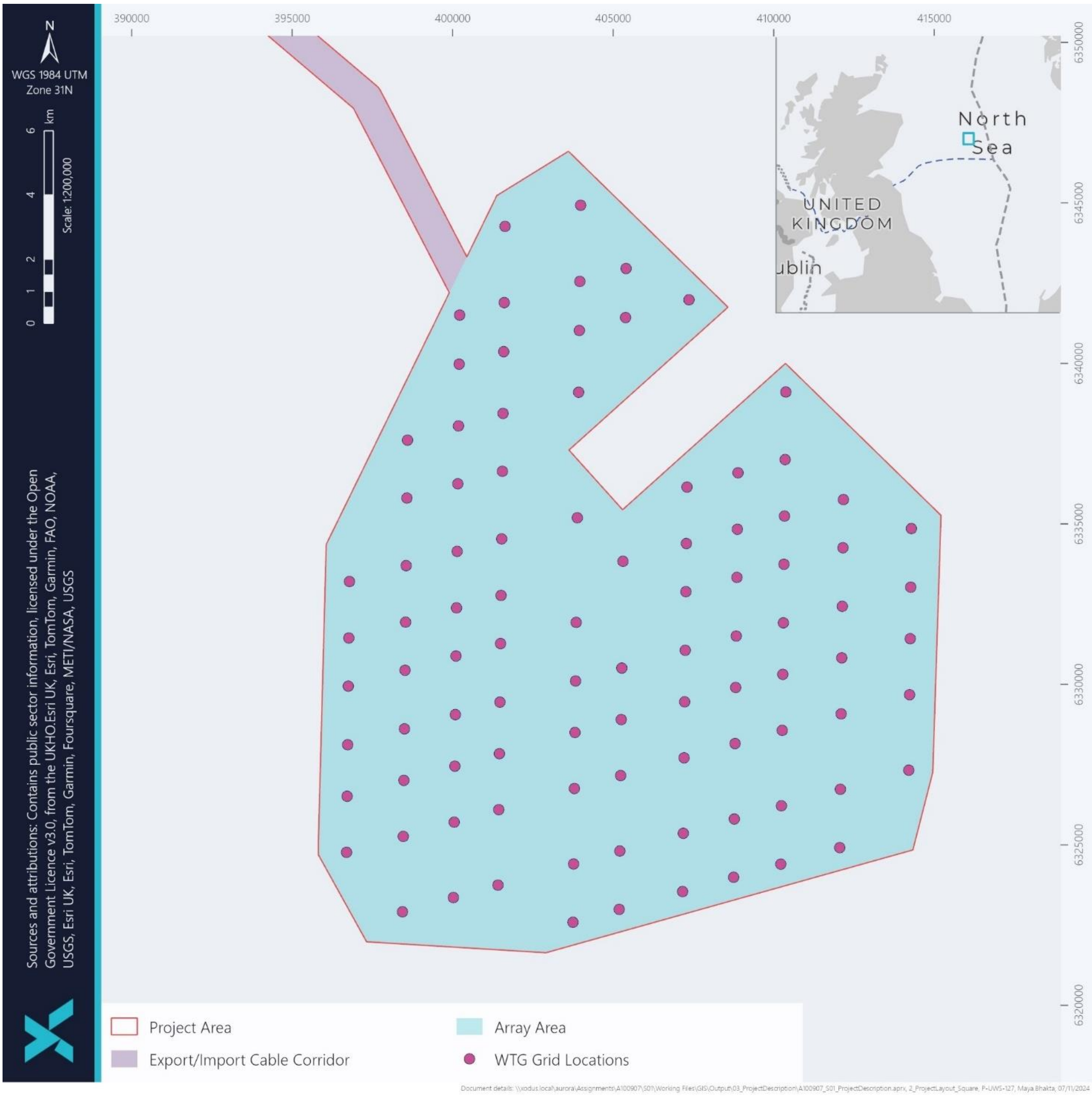

Figure 5-8 Indicative Array Area layout for 95 FTUs

5.6.1.4 Installation

The WTGs will be installed on floating substructures, held in location by a mooring system comprising: mooring lines, anchors and connectors. Section 5.6.2.3 details how the WTGs may be installed relative to the substructures to form the FTUs.

The exact approach for the installation of the WTGs will depend on the final FTU design option and the installation contractor. This will be determined post-consent.

5.6.2 Floating Substructure Foundations

5.6.2.1 Design

The WTGs will be supported by floating substructure foundations which are connected to the mooring systems (and IACs) within the Array Area to form the FTUs. The floating substructures will comprise of steel[3]. Two designs are currently being considered for the floating substructures, semi-submersible and Tension Leg Platform (TLP; as illustrated in Figure 5-9). Figure 5-10 and Figure 5-11 show the side and aerial dimensions of the substructures respectively. Table 5-4 provides the design parameters for both floating substructure options. A flexible design envelope encompassing semi-submersible and TLP designs has been adopted so that the potential technical, commercial and environmental benefits of TLP technology can be further considered. Justification of substructure type selection considered within the design envelope is provided in EIAR Vol. 2, Chapter 4: Site Selection and Consideration of Alternatives.

A semi-submersible substructure supports the WTG via 3-4 buoyant columns positioned around the periphery of the substructure and connected with trusses and provides stability to the WTG. The mooring system maintains the station-keeping of the FTU. There are several mooring system types under consideration for the semi-submersible floating substructure (see Section 5.6.2.2).

A TLP may comprise similar components to the semi-submersible substructure described above, however alternative designs are also considered for the TLP where a central column supporting the WTG is connected to 3-6 buoyant legs. The key difference between a semi-submersible substructure and TLP is that TLP stability is provided through the tension in the mooring system which also maintains station-keeping of the FTU.

[3] *Note: concrete will not be considered*

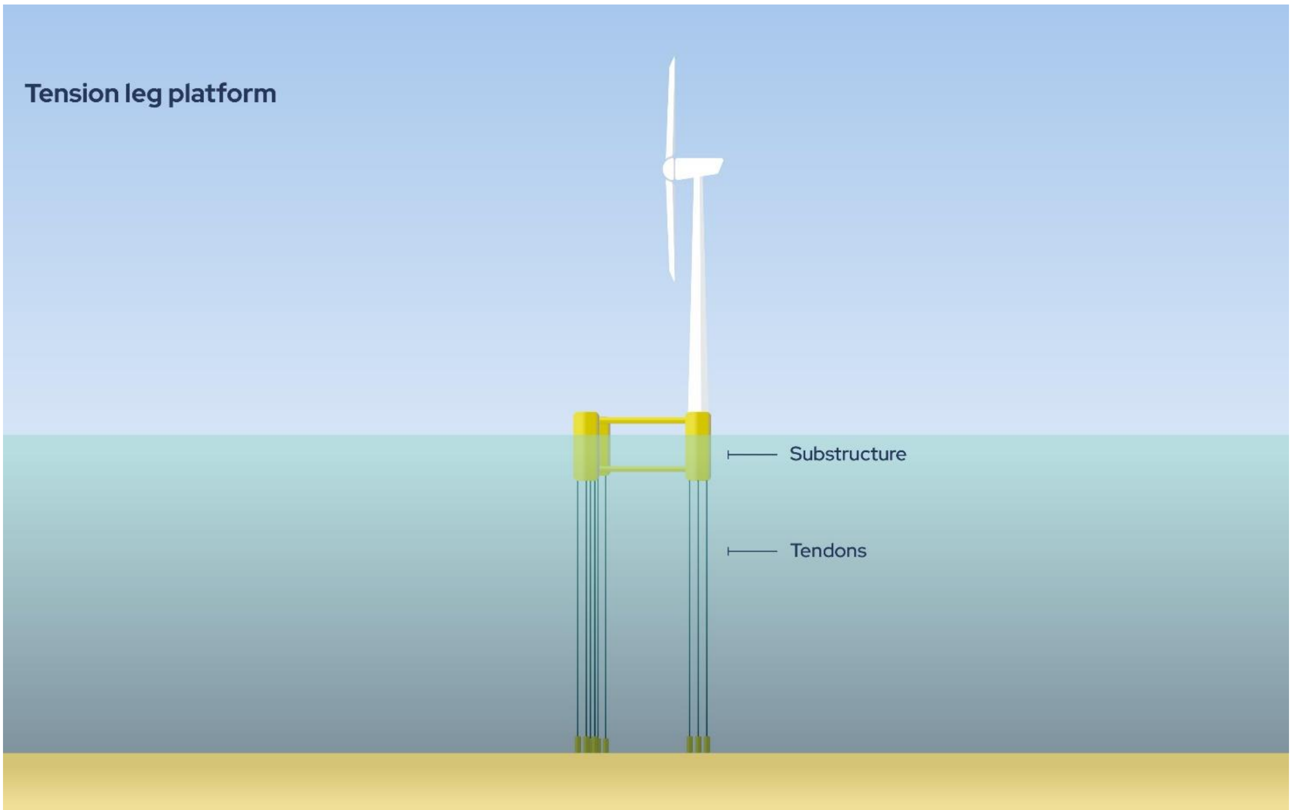

Figure 5-9 Tension Leg Platform

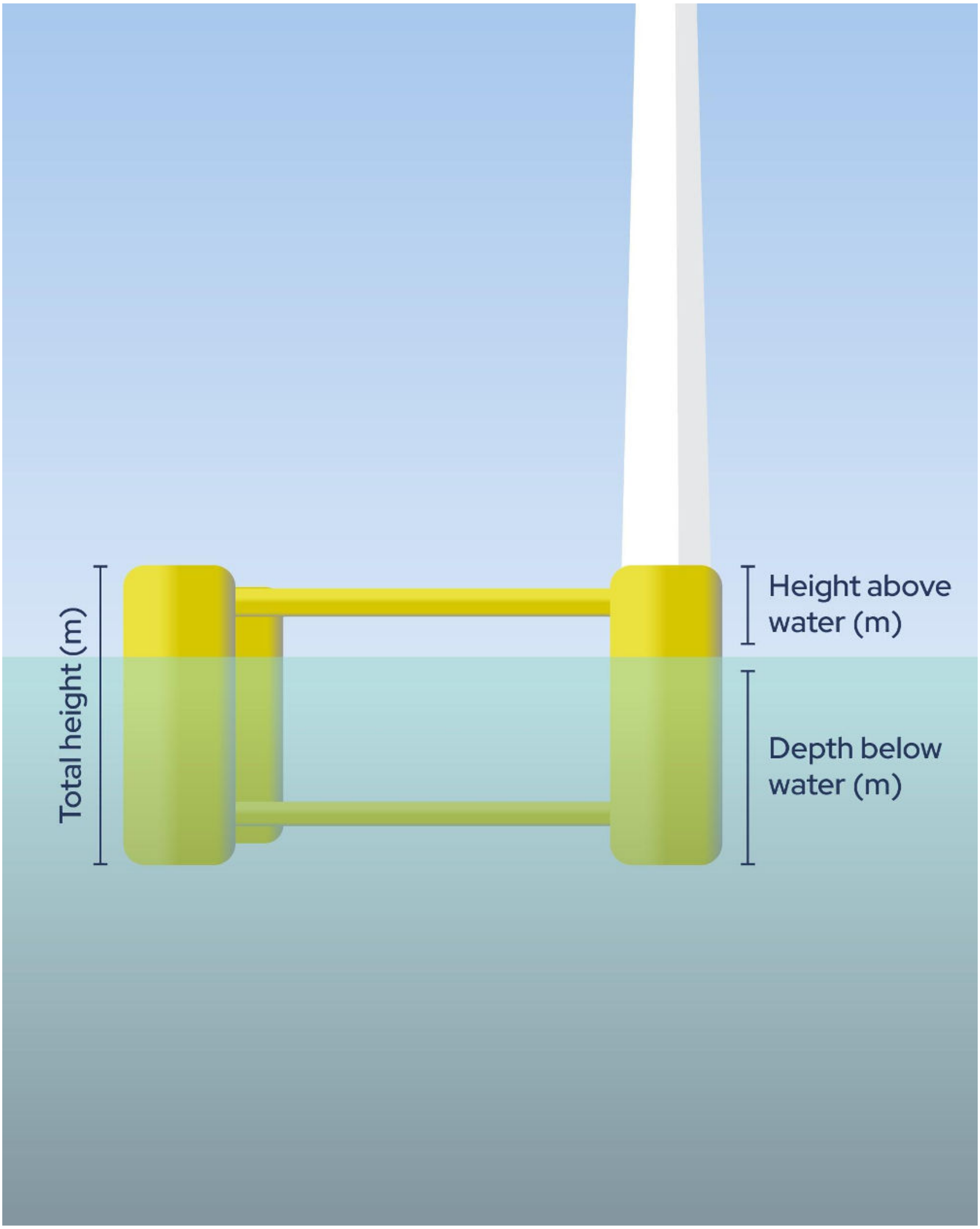

Figure 5-10 Substructure dimensions (side)

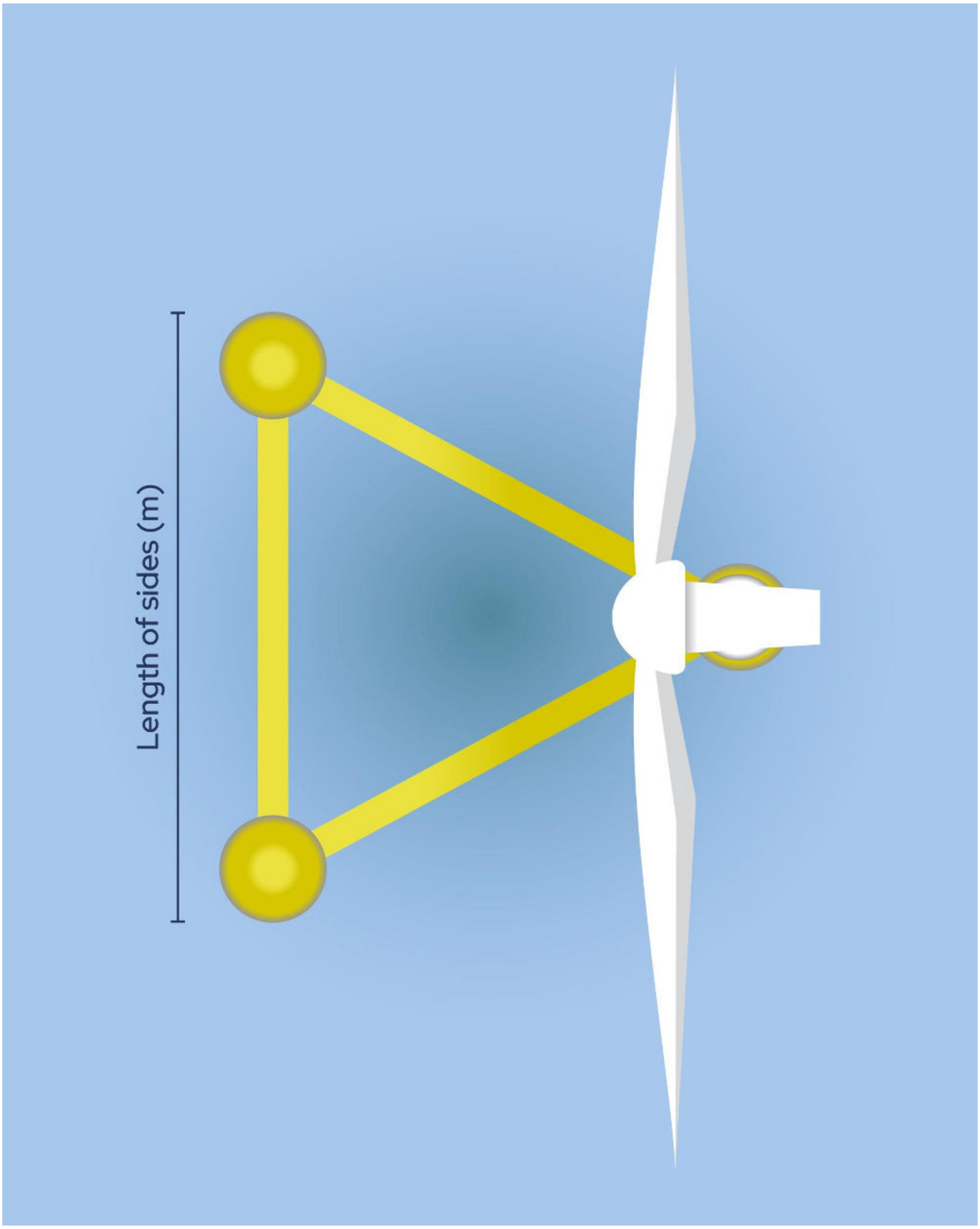

Figure 5-11 Substructure dimensions (aerial)

Table 5-4 FTU floating substructure design envelope parameters

DESIGN PARAMETER	DESIGN ENVELOPE – SEMI-SUBMERSIBLE	DESIGN ENVELOPE – TLP
Substructure type	Buoyancy stabilised	Mooring stabilised
Substructure size (assumes triangular) (m)	112 per side of triangular structure	93 per side of structure
Maximum height of substructure (m)	40	40
Maximum proportion of height above water (m)	22	10
Maximum proportion of depth below water (m)	20	30
Material	Steel	Steel
Overall footprint (at surface) (m^2)	5,600	3,720
Colour above water	RAL1023 Traffic Yellow	RAL1023 Traffic Yellow
Maximum number of mooring lines	Up to 6 mooring lines per FTU	Up to 9 mooring lines per FTU
Navigational lighting	Aids will be in accordance with R0139 The Marking of Man-Made Offshore Structure (IALA, 2021).	

5.6.2.2 Moorings and anchors

Pre-construction surveys and site preparation works will be conducted, as described in Section 5.5. Seabed preparations for WTG floating substructures are normally minimal but bedform clearance and boulder clearance may be required within the floating substructure footprints.

The floating substructures are attached to the seabed via mooring systems, which are comprised of the following:

- Mooring lines, including steel chain, steel tubes, steel rope or polymer rope (see Table 5-5 and Figure 5-12 for the PDE parameters for the mooring lines);
- Anchors (see Table 5-7 and Table 5-8 for the PDE parameters for the anchors, and Figure 5-13);
- Associated connectors between the substructure, the mooring lines and the anchors, and between sections of the mooring lines; and
- Other items connected along the mooring line, such as clump weights, buoyancy elements, and load reduction devices.

It is not anticipated that surface buoys will be required. If the anchors are installed before the mooring system, temporary submerged buoys may be used to identify the anchor position on the seabed for mooring hook up by ROV.

Table 5-5 Mooring line design options

SUBSTRUCTURE DESIGN	MOORING DESIGN	DESCRIPTION
Semi-submersible	Taut moorings	Typically made of synthetic fibre rope and have a smaller mooring radius than catenary lines. The taut mooring line reaches the anchor at an angle to the seabed and therefore there is a vertical force component requiring an anchor with high vertical loading capacity.
	Semi-taut moorings	A hybrid of catenary and taut mooring lines that typically consists of a combination of steel chain, steel wire rope and/or synthetic rope sections, and typically has a mooring footprint smaller than catenary but greater than taut. Anchor loading direction is predominantly horizontal.
Tension Leg Platform	Tension moorings	Used for TLP substructures only. Tendons typically made of steel tube, steel wire or synthetic material run vertically (or near-vertically) from the substructure to the anchors directly below, but other options are being developed. The tension mooring system has a significantly smaller mooring radius compared to taut or semi-taut mooring arrangements. Anchor loading direction is predominantly vertical.

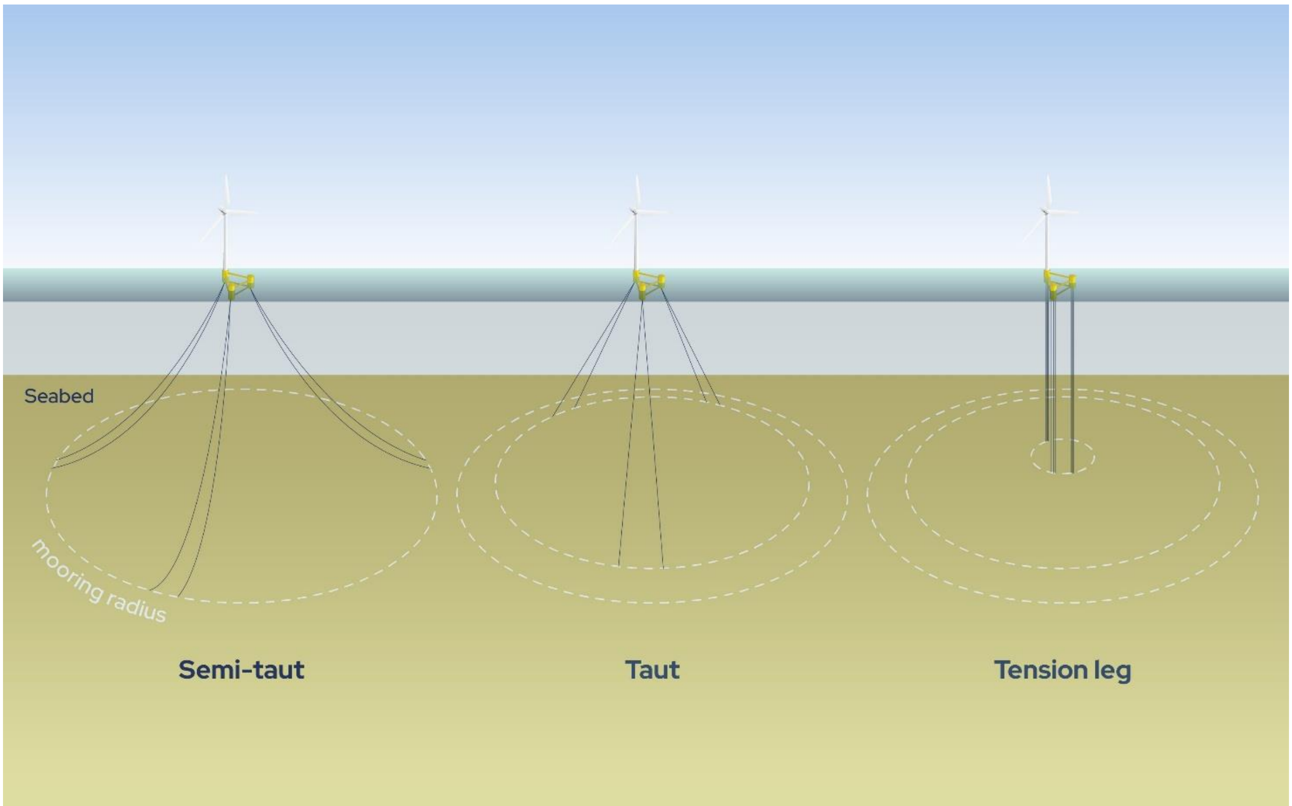

Figure 5-12 Mooring system design options

Table 5-6 Mooring system design parameters

MOORING DESIGN	DESIGN ENVELOPE
Maximum number of moorings per FTU (semi-sub only)	6
Maximum number of tendons per anchor per FTU	9
Maximum mooring line length per line (m) (semi-sub only)	757
Maximum tendon length per line (m) (TLP only)	80
Maximum total mooring line length per FTU (m)	4,541 (semi-submersible; 68 FTU)
Maximum mooring radius around FTU (m)	800
Material of mooring lines	• Steel chain / steel wire / synthetic rope (semi-submersible); and • Synthetic rope / steel wire / steel tube (TLP)
Maximum total area of temporary seabed impact from mooring pre-lay during construction (m^2)	376,200 (semi-submersible; 95 FTU)*
Maximum proportion of each mooring in water column (during operation)** (%)	• 68% (semi-submersible; 68 FTU); and • 100% (TLP)
Maximum proportion of each mooring on seabed (during operation)** (%)	• 34% (semi-submersible; 95 FTU); and • None (TLP)
Maximum seabed area disturbed by chain per FTU (during operation)** (m^2)	• 15,188 (semi-submersible); and • None (TLP)
Total moorings chain seabed swept area* (km^2)	• 1.44 (semi-submersible); and • None (TLP)
Maximum proportion of Array seabed Area disturbed by chain* (%)	• 0.43% (semi-submersible); and • None (TLP)
Minimum underkeel clearance (to seabed) (m)	• 70 (semi-submersible); and • 60 (TLP)
Lateral Movement (m)	• 35 in extreme conditions (semi-submersible); and • 26 in extreme conditions (TLP)

* Assumes (1) 95, 15 MW FTUs (2) 3,960 m length per FTU x 1 m width
** The seabed swept area disturbed by mooring chain considers the range of movement of each mooring chain on the seabed due to movement of the floating substructure during operation

Table 5-7 Description of anchor design options

ANCHOR DESIGN	DESCRIPTION
Driven piles	Tubular piles which are small in diameter relative to their length. They achieve their holding capacity from the frictional force created during embedment. They are designed to withstand horizontal, vertical or multi-directional load, and are therefore suitable to use with a range of mooring line options. They can be used in a wide range of seabed conditions, including where there is hard ground that is less suitable for other anchor types. To install, they are lowered to the seabed and partially sink into the seabed under their own weight. They are then driven to their final embedment depth using an impact or vibro-hammer. Removal of driven piles is difficult, and if piles cannot be fully removed, they will be cut 1-3 m below mudline with internal abrasive water jet cutter to remove the upper section of the pile.
Suction piles	Tubular piles with a top cap and controllable valve which are larger in diameter and shorter in length compared to driven piles. They achieve their holding capacity from the frictional force created during embedment. They are designed to withstand horizontal, vertical or multi-directional load, and are therefore suitable to use with a range of mooring line options. They require seabed conditions that are firm enough to hold suction but not so firm that penetration is impeded. To install, they are lowered to the seabed, open end first, and partially sink into the seabed under their own weight (with the valve open). Final embedment is achieved by suction, the water trapped in the top of the pile is pumped out, lowering the rest of the pile into the seabed. To remove suction anchors during decommissioning, the installation processes is reversed.
Other anchor options	Other novel anchoring methods are also being considered such as suction embedded plate anchors, screw anchors and/or higher numbers of miniature piles. All options are considered to have equivalent or similar parameters and associated impacts and hence are considered within the PDE presented.

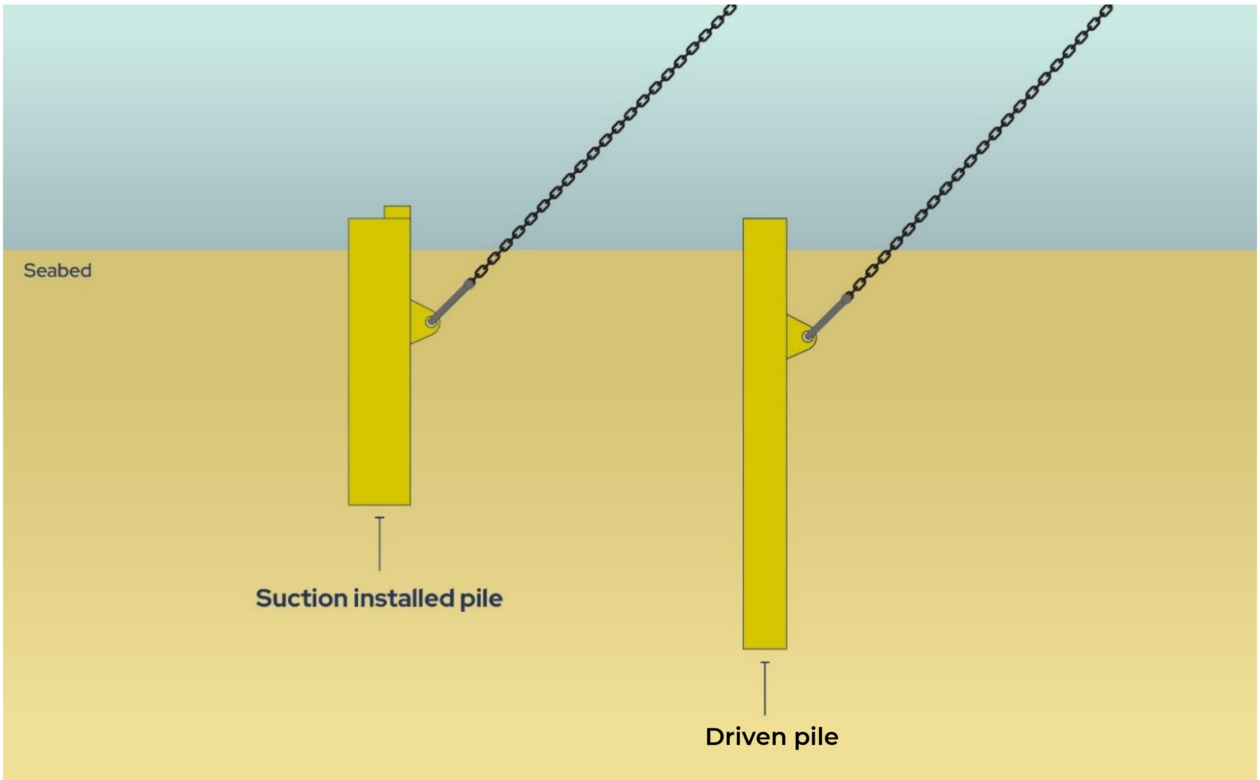

Figure 5-13 Anchor design options

Table 5-8 Anchor design parameters

ANCHOR DESIGN	DESIGN ENVELOPE
Anchor's overview	
No. of anchors per FTU	• Max 6 per FTU (semi-submersible) • 3 piles or 3 clusters of piles. Assume the pile clusters are through a template and their maximum impact should be treated effectively as a single pile (TLP)
Minimum separation distance between different anchors	• 50 m (semi-submersible) • Assume pile clusters are on a 50 m radius with a separation of 120 degrees. - i.e., approx. 90 m between each cluster (TLP only)
Anchor methods	Suction pile or driven pile are considered the base-case Suction Embedded Plate Anchors, and more novel piling methods also considered and assumed to have equivalent or smaller seabed footprint and impacts. This may include suction embedded plate anchors, screw anchors and/or higher numbers of miniature piles. Hybrid Gravity / Suction anchors are also considered. Grouted piles are not considered given decommissioning challenges.

ANCHOR DESIGN	DESIGN ENVELOPE
Suction pile dimensions	
Maximum pile diameter (m)	6.5
Maximum areas at seabed per pile (m^2)	33
Maximum pile penetration depth (m)	36
Driven pile dimensions	
Maximum pile diameter (m)	4.5
Maximum area at seabed per pile (m^2)	16
Maximum pile penetration depth per pile (m)	57
Piling characteristics	
Maximum Hammer Energy (kilojoules (kJ))	• 2,000 (semi-submersible) • 2,500 (TLP)
Soft Start Energy (% of Maximum Hammer Energy)	10%
Soft Start Duration (mins)	20
Strike rate (strikes per minute) - piling	30
Strike rate (strikes per minute) - soft start	30
Maximum duration of piling (per pile) (hours)	• 6 (semi-submersible); • 4 (TLP)
Average duration of piling (per pile) (hours)	• 4 (semi-submersible); and • approx. 100 minutes at 30 blows (bl)/minute (TLP)
Maximum number of piles installed over 24 hours	• 3 (semi-submersible); and • 9 (TLP)
Seabed footprints	
Maximum seabed footprint per FTU (m^2)	• 198 (semi-submersible); and • 297 (TLP)
Maximum seabed footprint for Array Area (m^2)	• 15,840 (semi-submersible); and • 28,215 (TLP)

The floating substructure design will be selected for compatibility with the mooring system, which must be suitable to withstand substructure loads while also reducing the number and extent of mooring lines and anchor points on the seabed. The design and number of anchors and moorings required will be defined by the selected floating substructure, and a review of loading conditions.

Seabed movement within the Array Area is limited due to its distance from shore and deep water depths (i.e. 90-100 m) minimising the influence of marine physical processes on seabed mobility. Within the Array Area, there are no tidal currents or wave action and the sediment remains stable, as indicated by the thin layer of circalittoral mud which has settled across the vast majority of the proposed Project Area. Below this thin layer of mud, ground modelling suggests sediment strata which are supportive of the anchoring systems under consideration by Cenos, including piled, suction-piled and other anchoring methods which are under development (e.g. suction embedded plate anchors, screw anchors and miniature piles). For these reasons, the risk of sediment scour around the anchors for the FTUs is low and scour protection will most likely not be required. If scour protection / mitigation is required, rock protection shall not be considered. Scour protection methods may include scour reduction Vortex Induced Vibration (VIV) strakes and tubular sleeves, with no additional seabed footprint to the existing maximum seabed area detailed for the piles. Scour allowance may also be factored into the design of the piles.

5.6.2.3 Floating Turbine Unit (FTU) installation

Suction piles or driven piles are considered the base-case for the anchors (noting that other novel technologies are under consideration). To install the piled anchors, a piling template will be lowered onto the seabed allowing the piles to be installed through the template. Once piling is complete, the mooring lines are secured to the pile. Piling template configurations can vary depending on the design needs to suit the project, i.e. the size of the foundations being installed, the number of associated piles and the installation method used by the vessels selected for the Project.

Suction piling is conducted via lowering the piles from a construction or anchor handling vessel. The suction pile is lowered into the seabed, penetrating approximately up to 60% into the seabed due to the open bottom of the cylinders. To completely embed the pile, the ROV may be used to pump water from the top suction port of the pile. Conversely, driven piles are foundations that are driven into the seabed using a percussive pile-driving hammer. The hammer type and size, size of the pile, and soil properties influence the number of blows and time required to achieve the target penetration depth. Driven piles can be lowered from a heavy lift vessel or a Semi-Submersible Crane Vessel (SSCV).

The worst-case scenario for temporary seabed disturbance during construction assumes that the mooring system (see Section 5.6.2.2) will be pre-laid and fully placed on the seabed temporarily until the floating substructures are towed to site and ready for hook-up, enabling them to be installed immediately on arrival at the Array Area. The Project is also considering alternative options for mooring installation methods that would minimise the mooring line length that is pre-laid and placed on the seabed and would reduce the area of temporary seabed disturbance. The exact installation method will be influenced by the substructure type chosen (e.g., semi-submersible or TLP) and the mooring system used (e.g. semi-taut, taut or tension-leg). Both anchor options described above may be suitable for use with taut, semi-taut or tendon mooring systems.

There are two options being considered for FTU installation:

- The WTGs are installed onto the floating substructure at the construction port, and the fully assembled unit is towed out to the Array Area and installed onto the pre-laid moorings; or
- The floating substructure is towed out to the Array Area and installed onto the pre-laid moorings, and the WTG is subsequently installed onto the substructure by a heavy lift vessel, or alternative offshore crane solution.

A list of potential construction ports is provided below, however the list of ports provided is not exhaustive. All ports are under consideration on the East coast of Scotland and North-East of England. Use of ports in Norway, the Netherlands, or the rest of the North Sea region cannot be ruled out at this stage. The likely ports for majority of construction activity, including FTU integration and WTG assembly include:

- Cromarty Firth;
- Invergordon;
- Nigg;
- Ardersier; and
- Burntisland

Other construction and marshalling activities may occur from:

- Aberdeen;
- Peterhead;
- Forth ports & estuary;
- Newcastle & other North of England ports
- Dundee;
- Montrose; and
- Leith.

Potential ports for personnel transfer, operations and maintenance include):

- Aberdeen;
- Peterhead; and
- Montrose.

5.6.3 Inter-Array Cables

The IACs will connect the OSCPs to the FTUs. The IACs will transfer electricity generated by the WTGs to the OSCPs and facilitate communications to allow operation of the WTGs to be monitored and controlled.

5.6.3.1 Design

The IACs will consist of HVAC power cables with a maximum capacity of 66 kilovolt (kV) or 132 kV. Fibre optic communication cables will be integrated into the cables.

For floating wind, sections of both dynamic and static cabling will be required. Dynamic cabling (Figure 5-14) is required in floating wind developments as cable systems must be able to accommodate the movement of the floating substructure without imparting any direct loads on the cables (i.e. acting as a form of mooring). As such, the dynamic cable section design often adopts a ‘lazy wave’ configuration using buoyancy modules attached to a portion / midpoint of the cable. The ‘lazy wave’ allows the cable configuration to expand and contract in shape, in response to the movements of the floating substructure. Other configurations may be adopted for the same purpose i.e. catenary / tethered-wave / mid-water arch. The design of the dynamic cable includes additional armouring layers compared to the static cable design to provide protection against dynamic loading regimes. The cable design may comprise of a fully dynamic design or a partially dynamic and partially static cable design.

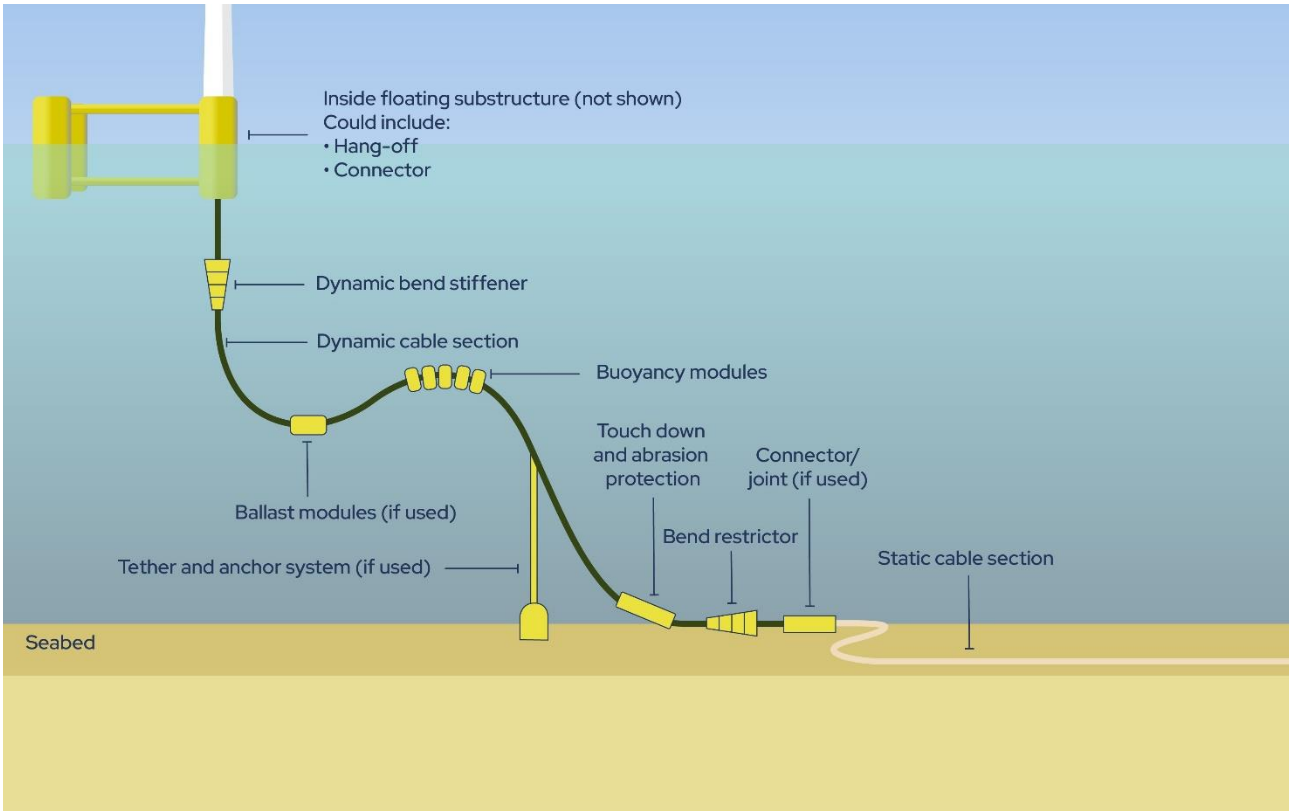

Figure 5-14 Dynamic cable system description

The static sections of the IACs will be from touchdown of the cable on the seabed to the OSCPs. A tether and anchor system may be used to provide stability to the IACs where it transitions from the dynamic to the static (seabed) section. A description of the anchors is provided in Table 5-9. From the point where no movement in the cable is expected on the seabed (the static cable section), each IACs will be laid on the seabed, either in a trench or buried. Where burial to the required depth is not achievable, cable protection measures will be used and placed over the top of the cable. Abrasion or touchdown protection using protection sleeves / pipes or protection mattresses may be used to protect the cable where it lies exposed on the seabed or where it enters / exits the seabed. No rock placement is assumed for cable touchdown points, instead it may be necessary to place concrete mattresses around the touchdown points. A description of these is provided in Table 5-9. While the exact layout will be optimised as part of the final design and determined post-consent, the IACs will likely be arranged in a loop (Figure 5-15) or string (Figure 5-16) connecting a series of FTUs with the cables extending radially from the OSCPs, which will be located at a central point in the Array Area. Other layout configurations under consideration include the 'star' (Figure 5-17) configuration where the dynamic cables from several FTUs are connected into a subsea hub and the power is exported from each subsea hub to the OSCPs via a single static cable. The star configuration requires additional seabed footprint for the subsea hubs but reduces the number of dynamic cable sections by 50%, reduces the total quantity of cable length, and reduces the proportion of IACs on the seabed. The design envelope detailed in Table 5-9 considers the worst-case impact for IACs connected between FTUs in series in a loop and for IACs connected to FTUs via a subsea hub.

Table 5-9 Inter-Array Cables design envelope

DESIGN PARAMETER	DESIGN ENVELOPE
IAC voltage (kV)	66 or 132 (HVAC)
Maximum total length of IACs (km)	350
Maximum cable outer diameter (millimetre (mm))	350
Number of FTUs per IAC string (for loop configuration)	3-6
Maximum length of IACs in water column (km)	70
Maximum length of cable on seabed (km)	280
Maximum number of anchors (if required)	190 Gravity anchors for cable tethers (loop configuration) 95 Gravity anchors for cable tethers (star configuration)
Maximum footprint area per anchor (m^2)	12
Total maximum footprint area of anchors across Array Area (m^2) (if required)	2,280 (loop configuration) 1,140 (star configuration)
Maximum number of concrete mattresses per touchdown location	5
Maximum footprint area of concrete mattress cable protection per touchdown location (m^2)	90
Maximum total footprint area of concrete mattress cable protection across Array Area touchdown locations (m^2)	17,100 (loop configuration) 8,550 (star configuration)
Minimum number of FTU connections per Subsea Hub (for star configuration)	5
Maximum number of subsea hubs across Array Area	19
Maximum footprint area per subsea hub (m^2) (if required)	90
Maximum footprint area of subsea hubs across Array Area (m^2) (if required)	1,710

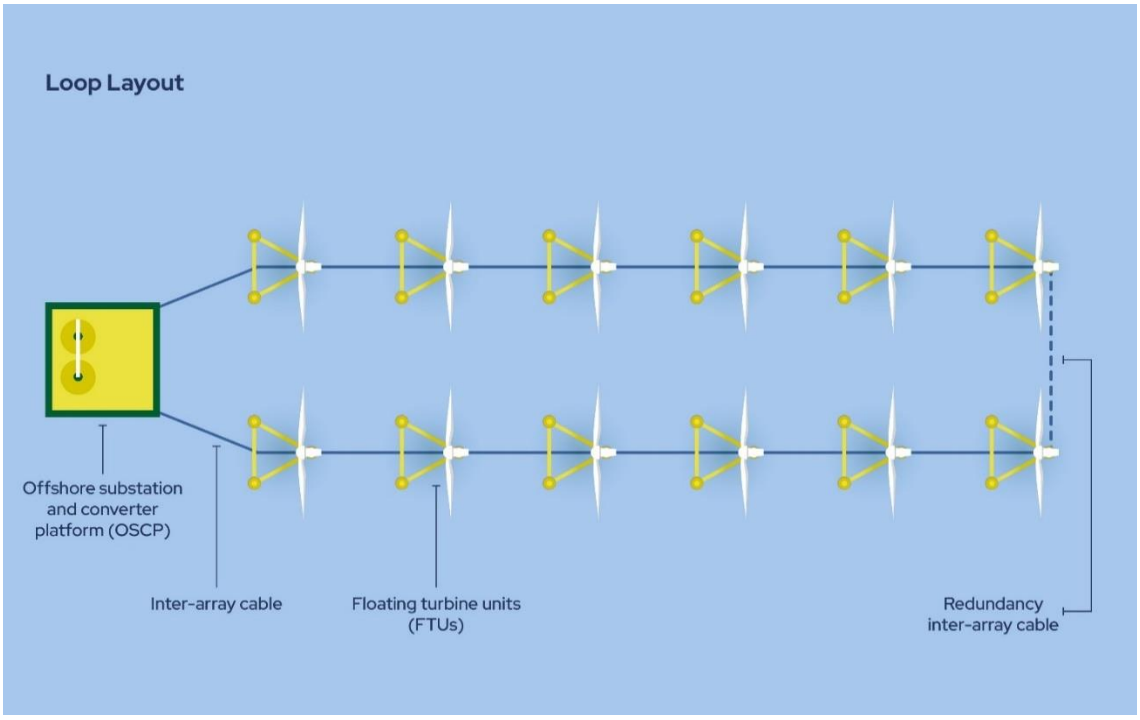

Figure 5-15 Loop layout option

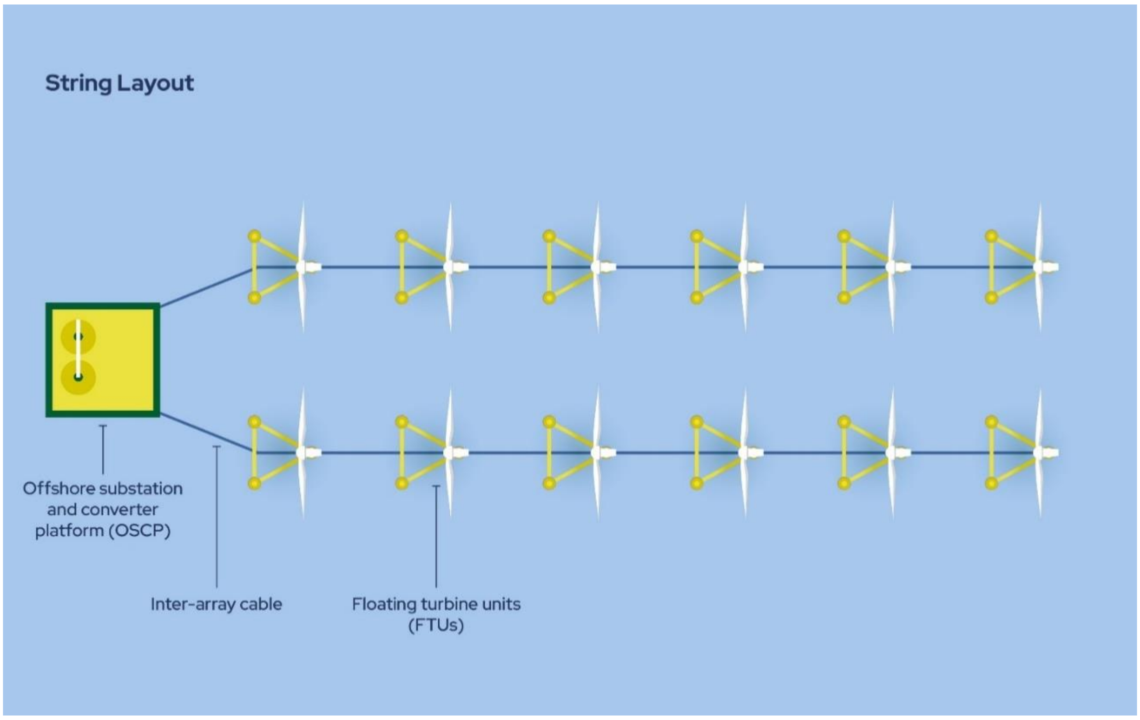

Figure 5-16 String layout option

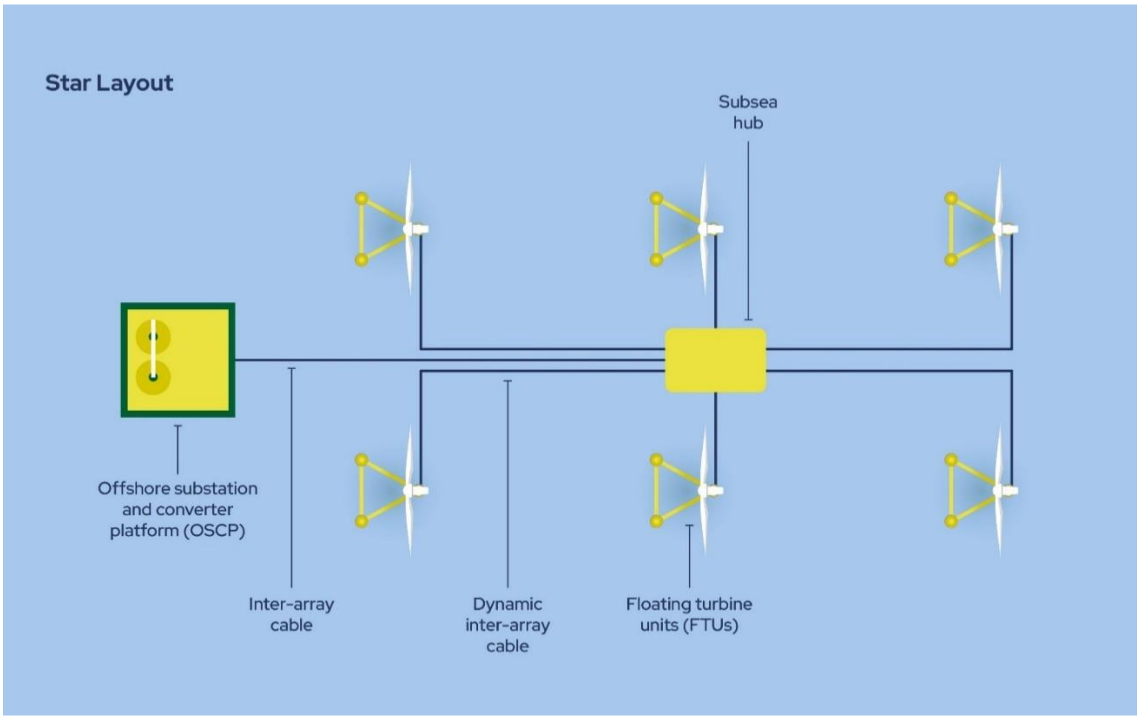

Figure 5-17 Star layout option

5.6.3.2 Installation

The IACs will be laid by a suitable installation vessel, which will transport the cables to the Array Area in carousels or reels. The installation vessels will be Dynamic Positioning (DP) vessels. The IACs may be laid either before or after installation of the FTUs: the pre-laid sections will lie tethered on the seabed (protected by mattresses), except for instances where lengths associated with buoyancy modules are buoyed in the water column.

Any seabed obstructions, including UXO, which cannot be avoided will be removed prior to IACs installation where necessary, as described in Section 5.5. The primary approach will be to micro-route around any seabed obstructions or sensitive environmental receptors. A PLGR will be conducted to remove any surface debris (Section 5.5.2.1).

The two options being considered for the installation and burial of the IACs are outlined below (descriptions are displayed in Table 5-10):

- Pre-lay trenching – a plough (or similar tool) is used to create a trench for the cable, which is then either left to naturally backfill, or the plough is used to push material back into the trench (post-lay burial); or
- Post-lay trenching – jetting: water is injected at high pressure in the area surrounding the cable using a trenching tool (e.g. jetting tool). The cable sinks to the required target burial depth and sediment reconstitutes above the cable achieving simultaneous burial or, mechanical: by lifting the laid cable whilst excavating a trench below, and then replacing the cable at the base of the trench and allowing the soil to naturally backfill behind the trencher.

Table 5-10 Description of installation tools.

TOOL	DESCRIPTION
Cable plough	Cable ploughs use a forward facing blade to cut and lift a wedge of seabed and create a slit trench into which the cable is then depressed. Cable ploughs are commonly used as part of a simultaneous lay and burial campaign, but can also be used to post lay bury cables. The ploughs may be mounted on a self-propelled tracked vehicle or pulled directly from a surface vessel.
Jet trencher	Jet trenchers (either self-propelled or mounted as skids onto ROVs) inject water at high pressure into the sediment surrounding the cable. The seabed is temporarily fluidised, and the cable is lowered to the required depth. Displaced material is suspended in the water and then resettles over the cable. Jetting may also be used for post-lay burial on a pre-laid cable.
Mechanical trenching	Mechanical trenchers bury the cable by lifting the laid cable whilst excavating a trench below, and then replacing the cable at the base of the trench and allowing the soil to naturally backfill behind the trencher.

The PDE for the IACs installation and protection in presented in Table 5-11. The maximum trench depth will be 1.8 m and the IACs will be buried to a maximum target Depth of Lowering (DoL) of 1.5 m, noting a 0.4 m minimum Depth of Burial (DoB). Figure 5-18 presents a visual definition of the target DoL and the depth of trench proposed for the IACs installation. The detail will be determined by a CBRA during the detailed design stage of the Project. This is considered the primary approach to protecting the cable itself. Burial is the preferred protection method, however at asset crossings and where a minimum DoB cannot be achieved, external cable protection may be required. Cable protection parameters are presented in Table 5-12. No rock placement, as a cable protection method, will be required within the Array Area except at cable/pipeline crossings (Section 5.6.3.3) and the OSCPs (see Section 5.7.1).

Table 5-11 Design envelope for the Inter-Array Cables installation

DESIGN PARAMETER	DESIGN ENVELOPE
Installation methodology for static section	Jet trenching, ploughing (simultaneous lay & burial) & mechanical trenching (Table 5-10)
Maximum trench burial depth (m)	1.8
Minimum DoB (m)	0.4
Maximum DoL (m)	1.5
Maximum trench width (m)	2
Maximum width of seabed disturbance from installation tool (m)	20
Total area of seabed disturbance for Array Area from installation tool (km^2)	5.6
Maximum temporary footprint of concrete mattresses	Total of 1,080 m^2 per cable installation (up to 60 x 18 m^2 mattresses) Up to 50 cables will require temporary mattresses during installation, therefore maximum footprint is 54,000 m^2.

5.6.3.3 Crossings

Up to eight crossings within the Array Area have been identified. These include up to two crossings of the Export/Import Cable and up to six IACs crossing across existing Culzean 22" Gas Export pipeline and planned Central North Sea Electrification (CNSE) cables. The potential crossing methodologies are as follows: concrete mattresses, rock placement, rock bags, grout/cement bags or a polyurethane Cable Protection System (CPS). Cable/pipeline crossing details are displayed below in Table 5-12.

Table 5-12 Cable/pipeline crossing design parameters

DESIGN PARAMETER	DESIGN ENVELOPE
Crossing material	Concrete mattresses, rock placement, rock bags, grout/cement bags, polyurethane CPS.
Maximum Length of crossing (per crossing) (m)	500 m comprising 100 m of large volume rock berm, and 400 m of small volume rock berm.
Maximum Width of crossing (m)	15.2 (large berm) 7.6 (small berm)
Maximum footprint area per crossing (m^2)	4,560
Total footprint area of crossings (m^2)	36,480
Maximum height of crossings (m)	2.25
Maximum volume of protection material per crossing (m^3)	3,056 (of rock)
Maximum Total volume of crossing protection material across Array Area (m^3)	24,448

5.7 Offshore transmission infrastructure

5.7.1 Offshore Substation and Convertor Platform(s)

5.7.1.1 Design and Foundations

The export/import of power between the Array Area and the shore and the distribution of power to the oil and gas assets will be facilitated by the OSCPs. The OSCPs will aggregate and convert the power between HVAC (generated by the WTGs and used by the oil and gas assets) and HVDC (transmitted to/from shore) and will aggregate and distribute HVAC power to the oil and gas assets.

The offshore transmission infrastructure will consist of either:

- One OSCP fully integrated to provide HVDC power transmission and HVAC power distribution; or
- Two OSCPs to provide HVDC power transmission and HVAC power distribution, where the two OSCPs jackets will be positioned adjacently at the same location, with 50 m minimum spacing between jackets. The two OSCPs will be bridge-linked following full construction.

The worst-case scenario for the offshore transmission infrastructure detailed in Table 5-13, and Table 5-14 considers two bridge-linked OSCPs structures.

Table 5-13 Design parameters for OSCPs

DESIGN PARAMETER	OSCPs DESIGN ENVELOPE
Maximum number of OSCPs topsides	2 (bridge-linked)
HVDC / HVAC	HVDC and HVAC
Maximum height of topside structure (m) (above LAT) (m)	22
Maximum height of lightning protection (above LAT) (m)	80
Maximum height of helideck (above LAT) (m)	60
Maximum height of crane (above LAT) (m)	60
Maximum height of top of main structure (above LAT) (m)	60
Maximum height of top of antenna structure (above LAT) (m)	80
Maximum topside length (m)	75
Maximum topside width (m)	40
Maximum topside weight (t)	14,000
Lighting parameters on OSCPs (position, number of OSCPs with lighting etc).	Lighting to be in accordance with MCA guidelines and requirements of NLB.
Cable protection at base of OSCPs	Up to 22 cables each requiring 100 m of rock protection of 7 m width
Foundations	
Maximum number of OSCPs jackets	2
Maximum number of legs per jacket	• 6 at surface; • 4 at mudline
Maximum number of piles per leg (corner legs only)	• 3 piles per corner; and • 12 piles total per jacket
Maximum diameter of jacket leg (m)	4
Jacket leg spacing (at seabed and surface) (m)	40-45 between corners.
Pile diameter (m)	3.05
Pile penetration depth (m)	57
Maximum area of mud-mats (if applicable) (m^2)	• 1,209 per jacket; and • 2,418 total
Maximum width of jackets (m)	50

DESIGN PARAMETER	OSCPs DESIGN ENVELOPE
Depth (m)	• Total jacket height = 122; • Depth below sea level = 100; and • Height above sea level = 22
Total seabed footprint for Array Area (equivalent to mud-mat footprint, which encompasses the pile footprint) (m^2)	• 1,209 per jacket • 2,418 total
Minimum separation between platforms (m)	~50
Minimum separation to turbines (m)	1,200

5.7.1.2 Installation

The OSCPs jackets will be loaded onto a vessel or barge at the construction base and taken to the Array Area. The jackets will be launched or lifted from the vessel and placed into location by a crane. If required, mud-mats will be used to stabilise the jacket on the seabed prior to being piled into place. Once the jacket is successfully piled into place, the topside will be delivered by the main installation vessel a SSCV and lifted by cranes into the jacket. The topsides will be manufactured onshore and will be installed as a single structure. Once secured into place, commissioning will commence, supported by a Jack-Up Vessel (JUV) or equivalent, and cable connections will be secured to bring the systems online. The OSCPs piling design parameters are displayed in Table 5-14.

Table 5-14 OSCPs Piling Design Parameters

DESIGN PARAMETER	OSCPs DESIGN ENVELOPE
No. of piles	12 per structure 24 total
Maximum Hammer Energy (kJ)	4,400
Average Maximum Hammer Energy (kJ)	2,000-3,500
Soft Start Energy (% of Maximum Hammer Energy)	10
Soft Start Duration	20 mins
Maximum duration of piling (per pile) (hours)	4 hours
Average duration of piling (per pile) (hours)	approx. 100 minutes at 30bl/minute
Number of piles installed over 24 hours	Max 12, min 1, average of 4
No of concurrent piling events	None - piling for each structure will be sequential. In 2 jacket case they will be installed a year apart
Maximum duration of piling per day over construction period (hours)	24 hrs
Total number of days when piling may occur over construction period	7 per structure 14 total
Grout volume for pile sleeves (m^3)	300 per jacket 600 total

Seabed movement within the Array Area is limited due to its distance from shore and deep water depths (i.e. 90-100 m) minimising the influence of marine physical processes on seabed mobility. Within the Array Area, there are no tidal currents or wave action and the sediment remains stable, as indicated by the thin layer of circalittoral mud which has settled across the vast majority of the Project Area. Below this thin layer of mud, ground modelling suggests sediment strata which are supportive of the OSCPs jacket piling solution. For these reasons, the risk of sediment scour around the foundations of the OSCPs is low and scour protection will most likely not be required. If scour protection / mitigation is required, rock protection shall not be considered. Scour protection methods may include scour reduction VIV strakes and tubular sleeves, with no additional seabed footprint to the existing maximum seabed area detailed for the OSCPs foundations. Scour allowance may also be factored into the design of the OSCPs foundations.

5.7.2 Oil and Gas – Onward Development Connections

A central aim of the Project is to provide the opportunity for oil and gas assets located in the waters surrounding the Array Area to electrify via transmission infrastructure connecting to Cenos' electricity hub (i.e. OSCPs). These future projects form part of the anticipated future Onward Development which will be originated by Cenos, referred to as Onward Development Connections.

The Onward Development Connections for oil and gas electrification will be finalised and brought forward by 3rd party oil and gas operators, subject to separate marine licensing and permitting requirements (including separate EIA, as appropriate). At this very early stage in the process, the information available about these connections is limited and cannot be confirmed by the Project. In accordance with standard practice and relevant industry guidance, the level of information available means there is insufficient detail to enable full inclusion within a cumulative effects assessment. However, recognising industry feedback and a keen interest in this topic from stakeholders, the Applicant has voluntarily provided a qualitative assessment of the combined impact of the Project and Onward Development Connections, to the extent it can with the limited details on possible Onward Development. Please refer to EIAR Vol. 3, Chapter 22: Statement of Combined Effects for further details.

5.7.3 Export/Import Cable

The Export/Import Cable will carry power from the OSCPs within the Array Area to Landfall at Longhaven. The Export/Import Cable will be bi-directional, also importing power from the UK grid to the OSCPs for onward power supply to the oil and gas assets in time of insufficient power generation from the WTGs.

The Export/Import Cable will be sited within a one km wide EICC, with a maximum length of 230 km between Landfall and touchdown at the OSCPs.

The Export/Import Cable will comprise of two HVDC cables and one fibre optic cable bundled in a single trench. As with the IACs (see Section 5.6.3), burial is the preferred protection method, however at asset crossings and where DoB cannot be achieved, external cable protection may be required. Preliminary CBRA results indicate that up to 5% of the Export/Import Cable Route between 12 NM and the East of Gannet and Montrose Fields NCMPA boundary will require cable protection, and up to 64% of the Export/Import Cable Route between MHWS and 12 NM will require cable protection. There is no cable protection required on the Export/Import Cable Route between the East of Gannet and Montrose Fields NCMPA boundary and the OSCPs, excluding at cable/pipeline crossings. The preliminary CBRA conducted indicates that the target cable DoB for the majority of the EICC will be significantly lower than the maximum depth presented in Table 5-17. The target cable DoB will be refined by a detailed CBRA completed during detailed design, post-consent.

The Export/Import Cable will be installed using the same methods outlined for the IACs (see Section 5.6.3): pre-lay trenching, post-lay trenching, or post-lay burial and cable protection. Table 5-15 details the non-burial cable protection methods under consideration.

Table 5-15 Summary of non-burial cable protection methods

CABLE PROTECTION METHOD	DESCRIPTION
Rock placement	Made up of graded stones placed on or around the structure that requires protection to form trapezoid rock berms. The length of the berm depends on the length of cable requiring protection. Rock is typically deployed by a fall pipe vessel.
Concrete mattresses	Concrete blocks linked together. This protection measure is frequently used to protect subsea cables and can also be used to construct crossings over existing subsea cables and pipelines. Typically, concrete mattresses are deployed using a crane and positioned using either divers or a ROV.
Gabion bags (e.g. Sand, rock and grout bags)	Sand and rock bags are pre-filled prior to being placed above the cables. Rock bags consist of various sized rocks contained within a rope or wire net. Sand and rock bags are lowered towards the seabed. Once they are in the correct position they are released on to the seabed. Rock bags are circular in design with dimensions typically 0.7 m in height by 3 m in diameter.
Polyurethane CPS, articulated pipes, cast iron shells	Protective sleeves / pipes / shells typically made of polyurethane or cast-iron can be used to provide protection against impact, abrasion and overbending. Use of articulated half pipes will be assessed based on localised ground conditions.

Due to lack of sufficient data for the selection of the protection method per section along the cable route, rock placement is considered as the worst-case scenario. Inshore (within 12 NM) where burial is not possible, pre-ploughing with rock placement in the trench to the seabed level is assumed.

Table 5-17 presents the installation design parameters and Table 5-18 presents the design envelope for cable protection. Figure 5-18 presents a visual definition of the target depth of lowering and the depth of trench proposed for the Export/Import Cable.

Table 5-16 Export/Import Cable design envelope

DESIGN PARAMETERS	DESIGN ENVELOPE
Maximum number of cables	A single cable bundle comprising of two HVDC cables and one fibre optic cable
Maximum total length of Export/Import Cable (km)	Up to 230
Export/Import Cable voltage (kV)	320 or 525
HVAC / HVDC	HVDC.
Maximum external cable diameter (mm)	300 per individual cable.
Maximum total width of EICC (km)	1

Table 5-17 Export/Import Cable installation design envelope

DESIGN PARAMETERS	DESIGN ENVELOPE
Burial technique	Between MHWS and 12 NM, the majority (~64%) of installation will be undertaken using pre-lay trenching via a plough, the remainder will be via jetting; and Beyond 12 NM ploughing, trenching or jetting; installation could be undertaken using two different approaches – either as a simultaneous lay and burial operation or as a lay and post burial operation. Several campaigns are foreseen to install this cable bundle.
Minimum depth of burial (m)	0.4
Target depth of lowering (m)	1
Maximum depth of lowering (m)	1.5
Maximum Depth of trench (m)	1.8
Maximum trench width (m)	• 3 between MHWS and 12 NM (for pre-lay trenching via a plough • 2 between MHWS and 12 NM (for jetting). • 2 beyond 12 NM
Maximum width of seabed disturbance from installation tool (m)	20
Total area of seabed disturbance for Export/Import Cable Route (km^2)	4.6
Minimum proportion of Export/Import Cable buried (%)	95% between MPA and 12 NM (excluding cable/pipeline crossings) 100% within MPA
Total length of Export/Import Cable buried (km)	28 km between MHWS and 12 NM 158.65 km between East of Gannet and Montrose Fields NCMPA and 12 NM 35 km within East of Gannet and Montrose Fields NCMPA 221.65 km total
Burial method	Ploughing, jetting and rock placement

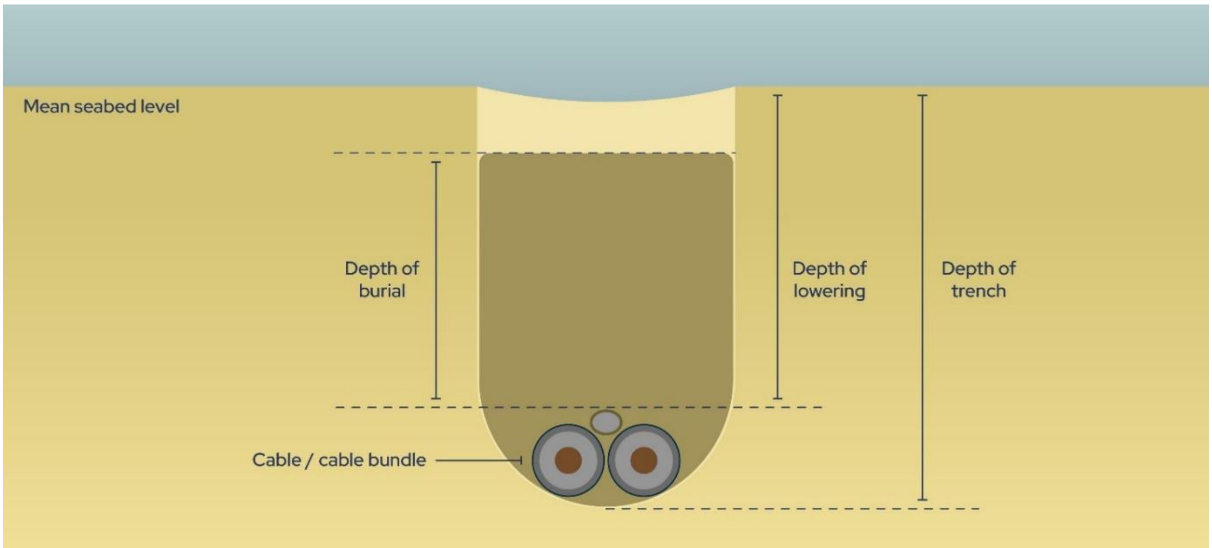

Figure 5-18 Export/Import Cable target depth of lowering and depth of trench parameters

Table 5-18 Export/Import Cable protection design envelope

DESIGN PARAMETERS	DESIGN ENVELOPE
Cable protection material (type), especially where cables will not be buried	Rock bags, rock placement, concrete mattresses, cement bags, sandbags, articulated pipe, polyurethane CPS, filter units, gabion bags, cast iron shells, bend restrictors, VIV suppression.
Length of cables requiring cable protection (km)	• Up to 18 within 12 NM • Up to 8.35 between 12 NM and NCMPA* • 0 within NCMPA
Length of unprotected sections (m)	0 (full length requiring burial or protection)
Maximum cable protection height (m)	1
Maximum cable protection width (m)	11
Total cable protection footprint for Export/Import Cable Route (m^2)	• 75,000 within 12 NM • 91,850 between 12 NM and NCMPA* • 700 within NCMPA at base of OSCPs
Total cable protection volume for Export/Import Cable Route (m^3)	• 38,339 within 12 NM • 91,349 between 12 NM and NCMPA* • 400 within NCMPA at base of OSCPs
Total cable protection weight (Tonnes (Te))	• 107,349 within 12 NM • 155,293 between 12 NM and NCMPA* • 1,120 within NCMPA* at base of OSCPs
Profile of protection structures	1:3 rock berm

* East of Gannet and Montrose Fields

5.7.3.1 Cable/pipeline crossing

Up to 20 crossings have been identified along the Export/Import Cable Route. At all crossings, a pre-rock placement will be executed, followed by the cable with High-Density Polyethylene (HDPE) articulated tubular protection system, followed by post-rock placement. The potential crossing methodologies are as follows:

- Rock berm assumed (base-case); and
- Mattresses, sandbags, rock bags, and HDPE tubular systems or precast concrete crossing structures (considered as alternatives or mitigations, in particular to reduce rock volumes within the MPA).

Cable/pipeline crossing parameters are listed in Table 5-19 below, an example schematic is provided in Figure 5-19.

Table 5-19 Export/Import Cable/pipeline crossing design parameters

DESIGN PARAMETERS	DESIGN ENVELOPE
MHWS to 12 NM	
Maximum number of crossings	7
Maximum height of crossing (m)	3.5
Maximum length of crossing (per crossing) (m)	520
Maximum width of crossing (m)	Maximum width is 24 m, reducing to 17 m over the first 50 m rock berm each side of the pipeline.
Total area of Crossings (m^2)	• 9,063 per crossing • 63,441 total for 7 crossings
12 NM to East of Gannet and Montrose Fields NCMPA	
Number of crossings	11
Maximum height of crossing (m)	3.5
Length of crossing (per crossing) (m)	520
Width of crossing (m)	Maximum width is 24 m, reducing to 17 m over the first 50 m rock berm each side of the pipeline.
Total area of crossings (m^2)	• 9,063 per crossing • 99,693 total for 11 crossings
Within East of Gannet and Montrose Fields NCMPA	
Number of crossings	2
Maximum height of crossing (m)	3.5
Length of crossing (per crossing) (m)	520
Width of crossing (m)	Maximum width is 24 m, reducing to 17 m over the first 50 m rock berm each side of the pipeline.
Total area of Crossings (m^2)	• 9,063 per crossing • 18,126 total for 2 crossings
Total volumes of protection	
Volume of protection material per crossing (m^3)	12,618
MHWS to 12 NM (m^3)	88,326 (7 crossings)
12 NM to MPA (m^3)	138,798 (11 crossings)
MPA to OSCPs (m^3)	25,236 (2 crossings)
Total for EICC (m^3)	252,377

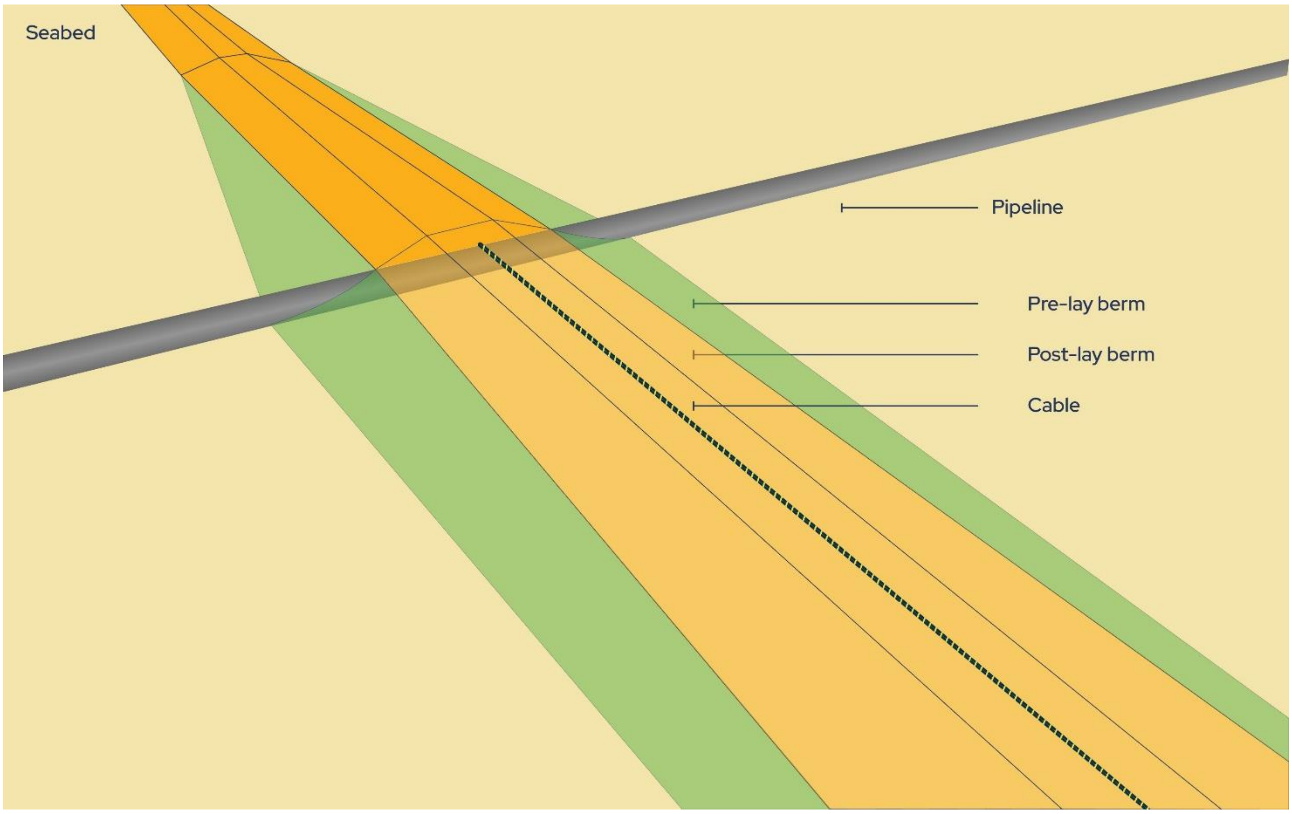

Figure 5-19 Cable/pipeline crossings schematic example

5.7.3.2 NorthConnect Limited

The inshore section of the EICC (from 12 NM to MHWS) overlaps with the NorthConnect cable corridor. The Project and the NorthConnect interconnector will only require one set of infrastructure and therefore one Marine Licence within this inshore area. This inshore section of the EICC already has consent for cable infrastructure as part of the NorthConnect EIA and associated MLAs. Nonetheless, this EIAR assesses the EICC from the OSCPs within the Array Area to MHWS. The EIA for NorthConnect will be considered where appropriate in this assessment for the EICC between MHWS and 12 NM.

5.7.4 Landfall

The Landfall is located at Longhaven and is where the Export/Import Cable will be brought ashore. The Landfall is an interface between the offshore and onshore aspects of the Project. As such the construction work will typically involve both offshore and onshore elements.

The onshore aspects of the Project e.g., those landward of Mean Low Water Springs (MLWS), including the onshore Horizontal Directional Drilling (HDD) entry point and cable pull through, have been consented through the NorthConnect HVDC Cable Planning Consent[4]. These onshore aspects will therefore not be assessed as part of the

[4] *Source: https://aberdeenshire.moderngov.co.uk/Data/Aberdeenshire%20Council/20190117/Agenda/04A%20APP-2018-1831%20North%20Connect%20Report.pdf*

Project. Outline design and installation details for the offshore elements of the landfall (e.g. those seaward of MHWS) are provided below and has been assessed as part of the Project EIA.

The cable installation method at landfall will be via HDD, as described fully in Section 5.7.4.1 below. The HDD exit point will be located in water depths of approximately 26.5 m, which is approximately 190 m offshore (from MHWS) from the Landfall location. Three separate boreholes / pop-outs will be required; one for each of the two HVDC cables and one for the fibre optic cable or as a contingency duct. Within 100 m of the HDD exit point, the cables will be bundled together and jet trenched into the seabed. Furthermore, the individual cables will be trenched in from 10 m from the HDD exit to the cable bundle start location, leaving approximately 10 m untrenched cable or lower protected cable which requires protection by rock or mattress placement.

5.7.4.1 Installation

HDD is a trenchless landfall installation technique. The following general HDD procedure is anticipated:

- Mobilise onshore equipment for the HDD works and construction of the onshore HDD compound (not within the scope of the Project, but provided here for completeness);
- Drilling of pilot holes from the onshore HDD entry point, beneath the intertidal area, to a point prior to the HDD exit point at the seabed surface using a drill bit and drill head. Inert drilling fluids are used to create a thick material to suspend soil and rock cuttings, which are carried out of the hole;
- The drilling fluids are treated and recycled onshore prior to the hole being extended to the seabed to minimise losses to the marine environment at the pop-out;
- The cable ducts are installed from the HDD entry point and once in place, a cap is placed onto the duct to ‘close’ it off from the sea. Temporary protection is placed over the seaward end, awaiting cable installation (this will be in the form of rock protection or mattresses);
- The cable pull-in operation will commence where the cables are pulled ashore through the ducts from an installation vessel; and
- Bentonite, a non-toxic and inert natural clay mineral, is pumped into the duct from the landward end, to fix the cable in place within the duct.

Some material removed from the bore path may be lost to the marine environment, as will small volumes of drilling fluid. This is a normal event as part of the HDD process and is unavoidable, however will be minimised insofar as practicable through the implementation of industry best practice for example, clearing runs or reducing the volume of drilling fluids in the borehole prior to breakout to the marine environment. This will be adequately controlled via the Environmental Management Plan (EMP) for the Marine Scheme. All drilling fluids are biodegradable and would be certified to relevant environmental standards (e.g. Centre for Environment, Fisheries and Aquaculture Science (Cefas) registered).

Bentonite consists of a clay-like material which is generated (typically) through the alteration of volcanic ash product. The substance is considered to Pose Little or No Risk (PLONOR) to the environment according to OSPAR (OSPAR Commission, 2021). Bentonite comprises 95% water and 5% bentonite clay which is a non-toxic, natural substance. Bentonite drilling fluid is non-toxic and can be commonly used in farming practices. Every endeavour will be made to avoid a breakout (loss of drilling fluid to the surface). A typical procedure for managing a breakout under water would include:

- Stop drilling immediately;

- Pump lost circulation material (mica), which will swell and plug any fissures;
- Check and monitor mud volumes and pressures as the works recommence; and
- Repeat process as necessary until the breakout has been sealed.

The HDD works and cable pull in will be timed as per the NorthConnect EIAR[5] to specifically avoid disturbance of breeding birds. The Buchan Ness to Collieston and the Ythan Estuary, Sands of Forvie and Meikle Loch Special Protection Areas (SPAs) are the nearest protected bird sites to the HDD works location, situated immediately south of Peterhead. The nearest Special Area of Conservation (SAC) is the Moray Firth SAC ~93 km from the site. Specific HDD design parameters are displayed in Table 5-20.

Table 5-20 HDD design parameters.

DESIGN PARAMETERS	DESIGN ENVELOPE
Trenchless burial depth Intertidal (m)	Not applicable: interactions with the intertidal zone will be avoided as cable installation is via HDD which emerges approx. 26.5 m below MHWS.
Trenchless length Intertidal (m)	• Not applicable. Cable will be installed by HDD through and under cliffs to emerge approx. 26.5 m below MHWS. • Total HDD drilled length is 409 m. Trenchless intertidal length the same as distance from MHWS to exit point – 190 m.
Location of exit point (offshore) (water depth in m)	approx. 26.5 depth below MHWS.
Distance from MHWS of exit points (offshore) (m)	190
Protection of exit point	• HDD ends will be protected with rock placement or mattresses. • Rock placement: 10 m length x 20 m width x 1.5 m height (slope 1:3) • Mattress placement: 4x mattresses of 3 m x 6 m x 30-50 cm thickness.
Volume of HDD drilling material losses	• 3,000 m^3 of fluid, including 18 m^3 of total solids (most likely bentonite). • 1,000 m^3 of fluid including 6 m^3 of solids for one HDD borehole drilling at any one time.

5.8 Construction programme and sequencing

The indicative construction programme is presented in Table 5-21. Construction works would typically be undertaken 24 hours a day, seven days a week offshore, dependent upon weather conditions, which will likely limit the majority of major construction works to seasonal campaigns. Durations for major works are subject to change, arising, for example, from weather or site conditions. Specific installation details may vary depending on the technologies adopted and technological and supply chain improvements.

[5] *NorthConnect EIAR Chapter 2: Project Description, available at: https://marine.gov.scot/data/northconnect-hvdc-cable-environmental-impact-assessment-report-volume-2*

Table 5-21 Offshore Construction Activity Summary

STAGE	CONSTRUCTION ACTIVITIES
Year 1 (2030)	Transmission • EICC PLGR, boulder & UXO clearance (as necessary). • Export/Import Cable preparation – existing pipeline / cable/pipeline crossing sites, HDD. • Export/Import Cable laying and trenching of first half of the Export/Import Cable.
Year 2 (2031)	Transmission • Installation of OSCPs jacket(s) and topsides; heavy lift campaign. • Export/Import Cable laying and trenching of second half of the Export/Import Cable. • OSCPs commissioning (Export/Import Cable pull-ins, powering up from shore; testing). • First power to oil and gas assets. Generation • Array Area enabling works boulder and UXO clearance (as necessary). • Installation of anchors / piles for FTU's & moorings pre-lay (mooring system installation without hook-up to infrastructure) for first section of Array Area in following year. • IACs pre-lay: PLGR, cable laying / trenching, temporary mattress protection of cable tail-ends prior to installation of first section of Array Area in following year.
Year 3 (2032)	Generation • Turbine installation - tow-out & hook-up to pre-laid moorings and IAC's of FTUs for first section of Array Area. • IACs pre-lay: PLGR, cable laying / trenching, temporary mattress protection of cable tail-ends prior to installation of second section of Array Area in following year. • Installation of anchors/piles for FTUs & moorings pre-lay (mooring system installation without hook-up to infrastructure) for 2nd section of Array Area in following year.
Year 4 (2033)	Generation • Turbine installation - tow-out & hook-up to pre-laid moorings and IACs of FTUs for second section of Array Area. • Pre-lay of IACs – PLGR, cable laying / trenching, temporary mattress protection of cable tail-ends prior to installation of third section of Array Area in following year. • Installation of anchors/piles for FTUs & moorings pre-lay (mooring system installation without hook-up to infrastructure) for third section of Array Area in following year.
Year 5 (2034)	Generation • Turbine installation - tow-out & hook-up to pre-laid moorings and IACs of FTUs for third section of Array Area.
Year 6 (2035 - if required)	Generation • Turbine installation - tow-out & hook-up to pre-laid moorings and IACs of remaining FTUs due to weather delays, etc.

Several vessel types will be utilised during the construction phase of the Project. These vessels will include but are not limited to Construction Support Vessels (CSVs), SSCVs as the main installation vessels, Service Operations Vessels (SOVs), Cable Installation Vessels (CIVs) etc. There will be up to 22 vessels and one helicopter operating simultaneously during the construction phase. Specific information regarding vessels and movements are detailed in Table 5-22.

Table 5-22 Vessels in operation during construction

VESSEL TYPE	NO OF VESSELS SIMULTANEOUS	MAXIMUM NO. OF TRANSITS IN CONSTRUCTION PERIOD
Pre-installation boulder removal/clearing vessels	1	6
Pre-construction survey vessel	3	3
SSCV	1	2 for construction, 2 for decommissioning
Tug/Anchor Handlers	6	285 return vessel trips
IACs CIVs	3	114
Export/Import Cable CIVs	1	3
CSV	2	288
Rock Placement	2	20
JUV	1	1
Geotech survey vessel	2	8
Guard Vessels	2	168
Service Operations Vessel (SOVs)	2	588
UXO clearance vessel	1	1
Helicopters	1	208 assuming 2 weekly crew changes for 26 weeks per year

5.9 Operations and maintenance

The operation and maintenance phase will commence once the Project is commissioned. Once operational, the Project will supply power to the oil and gas assets within the Onward Development Area, and to the national grid. The operational life of the Project is 35 years.

The Project will be managed, monitored and operated remotely from an onshore facility with access to the OSCPs and individual FTUs, to manage which WTGs are operational, and to monitor efficiencies.

During the operation and maintenance period, there will be minimum day-to-day intervention. Both planned and unscheduled monitoring and maintenance of the generation and transmission infrastructure will be required. This includes refurbishment or replacement of infrastructure. All offshore infrastructure, including FTUs, moorings, the Export/Import Cable, the IACs and OSCPs will be included in monitoring and maintenance programmes.

Maintenance can be separated into three categories:

- Planned maintenance: Servicing of components in line with the maintenance schedule, which will take account of the lifespan of the various components such that they are replaced prior to failure. It will include inspection and testing, fluid (oils and hydraulics) top-ups and part refurbishment/replacement;
- Unplanned maintenance: This applies to defects occurring that require correction outside the planned maintenance periods, either remotely or through the attendance of technicians and/or trouble-shooters. The scope of such maintenance would range from small defects on non-critical systems to failure or breakdown of main components potentially requiring them to be repaired or replaced; and
- Periodic overhauls: including statutory inspections and certification of equipment in accordance with manufacturer warranty.

Maintenance and inspection activities will be carried out in-person from maintenance vessels, SOVs, CSVs, cable lay vessels, survey vessels and helicopters (from Aberdeen) which will return to port for crew change and resupply periodically. Maintenance and inspection may take place throughout the year, however more activity will likely take place during the spring and summer months when the weather is more workable (e.g. 24/7 operations focused on the summer period). The Project will try to minimise maintenance activities during winter months; however, these may still be required for unplanned maintenance and cannot be ruled out. Additional maintenance vessels may be mobilised in times of more intensive maintenance.

In general, all maintenance shall be undertaken in-situ without tow-back of FTUs to shore. During instances of periodic overhauls or significant malfunctions which cannot be rectified offshore, the FTU will be detached from the IACs and mooring system. Subsequently, it will be towed back to shore for necessary maintenance procedures to be conducted within a port facility. If tow-back to shore is included in the maintenance philosophy, the system shall be designed to enable this and for tow-back to a UK port where feasible to do so. Detached mooring lines will be laid on the seabed and cables will be laid on the seabed or stored in the water column with appropriate markers for retrieval. This strategy ensures that upon the FTUs return, the moorings and cables can be efficiently retrieved and reconnected to the substructure.

Operation and maintenance activities and vessel movements specific to the Project are summarised below in Table 5-23 and Table 5-24.

Table 5-23 Operation and maintenance activities for the Project

ACTIVITY		DESCRIPTION OF OPERATION AND MAINTENANCE ACTIVITIES	FREQUENCY/DURATION
WTG	WTG inspection, maintenance & repair	*Personnel undertaking planned and reactive maintenance activities.* Personnel stationed on SOV and transit to/from turbines via Walk to Work direct from SOV or via daughter craft and boat-landing if weather permissible (use of Get up safe or similar system not discounted). Unmanned Aerial Vehicles (UAVs) (i.e. drones) may be used for cargo transfer from SOV to nacelle or laydown at tower base as well as for inspection of blades or other components. Increased use of UAVs for inspection is envisaged to reduce personnel exposure. Certain repair activities may be undertaken by robots or UAVs in the future.	24/7 operations Daily frequency - focused on summer period 5 days per WTG. Annual maintenance as required by OEM.
	Major component exchange / major structural issue (tow-back to shore)	*Change-out of major components, e.g. gearbox or transformer.* As a base case this shall be done offshore using uptower or similar cranes, but potential disconnect of FTU and tow-back to shore twice during lifetime of asset should not be discounted. This may also be applicable for major structural issues which cannot be repaired offshore.	Assume tow to shore up to twice per FTU in operational life (i.e. up to 190 operations).
	Major Component exchange (*in-situ*)	*Change-out of major components, e.g. gearbox or transformer.* As a base case this shall be done offshore using uptower or similar cranes, but potential disconnect of FTU and tow-back to shore up to three times per FTU during lifetime of asset should not be discounted.	Assume up to three times per FTU in operational life. Operation anticipated to be during good weather periods e.g. April to October, but operations at any point in the year cannot be ruled out.
Substructures, incl. moorings	Floater inspection, maintenance and repair	*Inspection surface / sub-surface, including. moorings, anchors, cables.* Surface inspection by Rope Access Technicians where necessary. *Subsurface inspection by ROV.* Ballast tanks to be inspected at regular intervals by trained operatives and or unmanned vehicles (drones / robotic crawlers).	24/7 operations Assume basic inspections on annual basis of moorings, hull, cables, and 5 yearly inspections with increased detail. Expect to coincide with planned maintenance of turbine.

ACTIVITY		DESCRIPTION OF OPERATION AND MAINTENANCE ACTIVITIES	FREQUENCY/DURATION
	Mooring line (re)tensioning	Re-tensioning of a mooring line.	Assume up to 12 operations of this nature per year throughout lifetime of windfarm. (i.e., twice per mooring line) (i.e. 1140 operations over operational life)
	Mooring line replacement	Replacement of a complete mooring line (from pile to Substructure attachment point.	Assume up to 10% of moorings replaced throughout operational lifetime (10% of 95*6 = 57 operations total)
IACs	Array Area seabed cable inspection	Visual inspection by ROV of cable routes coupled with side-scan sonar or similar techniques.	Up to an annual inspection of cable route, with a minimum inspection every five years. Assume up to 30 days inspection infield annually
	Cable repair	Identification of cable failure location, deburial, splicing/jointing, reburial.	Assume up to one week for two vessels per operation. Assume up to 10% of cables need repair through life of windfarm, i.e. up to 10% of 5.6 km^2 = 0.56 km^2 of temporary seabed disturbance from cable lay and burial.
	Dynamic cable replacement	Replacement of dynamic IACs between Substructure and seabed	Assume up to one week for two vessels per operation. Assume up to 10% of cables need replacement through life of windfarm, i.e. up to 10% of 190 = 19 cables
Export/Import Cable	Export/Import Cable inspection	Visual inspection by ROV of cable routes coupled with side-scan sonar or similar techniques	Up to an annual inspection of cable route, with a minimum inspection every five years. Assume 10-day inspection of route
	Cable repair	Identification of cable failure location, deburial, splicing/jointing, reburial	Up to 4 Export/Import Cable repairs during operational lifetime. Maximum seabed disturbance 52,560 m^2 over operational life. Assume 10 days per repair.
Helicopter operations	Crew-change to SOV	Crew change to SOV	Assume 2 per week, i.e. 104 annually as roundtrips
	Maintenance trips to OSCPs	Maintenance trip to OSCPs	Assume weekly, i.e. 52 round trips

Table 5-24 Vessels and helicopters in operation during operation and maintenance

VESSEL TYPE	NO. OF VESSELS	NO. OF OPERATION AND MAINTENANCE VESSEL TRANSITS PER YEAR IN OPERATIONAL PERIOD
SOV	2	56
CSV	7	288
Anchor Handler	7	17
Construction Vessel	1	18
CIV	2	2
Survey Vessel	2	2
Helicopter	1	156
	Total = 22*	Total = 539
*Not all vessels will be operating simultaneously. A maximum of 10 vessels may be in simultaneous operation.		

5.9.1 Electromagnetic Fields (EMF)

The transmission of electricity through subsea cables results in the formation of Electromagnetic Fields (EMF). EMF comprise electrical fields (E-fields), measured in volts per metre (V/m), and magnetic fields (B-fields), measured in micro-Tesla (μT). B-fields penetrate most materials and so are emitted into the marine environment which, can result in an induced electric field (iE-field). Comparatively, direct E-fields are blocked by conductive metallic sheathing within the cables and are not emitted from the cables. The Earth has its own natural Geomagnetic Field (GMF). In the vicinity of the Project, background measurements of the magnetic field are approximately 50.5 μT, and the naturally occurring electric field in the North Sea is approximately 25 microvolts per metre (μV/m) (Tasker *et al.*, 2010).

An EMF study has been conducted to ascertain the likely EMF strengths emitted from both the Export/Import Cable and the IACs (both static and dynamic). The studies are provided in EIAR Vol. 4, Appendix 14A: EMF Assessment Report Vol. 1 and EIAR Vol. 4, Appendix 14B: EMF Assessment Report Vol. 2, and the results are summarised below.

5.9.1.1 Cable configurations for EMF modelling

The study has applied the following cable designs for the modelling:

- IACs (both static and dynamic);
  - Trefoil cables of either 66 kV HVAC cables or 132 kV HVAC cables.
- Export/Import Cable:
  - Symmetric monopole arrangement comprising either two 320 kV HVDC cables or two 525 kV HVDC cables.

5.9.1.2 Assumptions

For the EMF study, the following inputs and assumptions were made:

- IACs: A trefoil configuration of either 1) static 66 kV with a current of 760 ampere (A) or 2) static 132 kV with a current of 850A or 3) dynamic 66 kV with a current of 1120 A or 4) dynamic 132 kV with a current of 1,255 A has been calculated based on a maximum of six, 15 MW WTGs per string.
- Export/Import Cable: A symmetric monopole arrangement of 1) 320 kV with a current of 2325 A or 2) 525 kV with a current of 1310 A;
- Any currents induced within the metallic sheath of each power core are not included;
- The cables are assumed to have infinite length, and there is no consideration of external influences such as other cables, crossing locations, nearby metallic structures, magnetic anomalies or pipelines;
- Calculations do not include any EMF attenuation caused by armour wire layers or metallic sheath
- DoL are assumed to be a minimum of 0.4 m and maximum 1.5 m, both between mean seabed level and top of cable;
- Attenuation: EMF emission from a cable rapidly reduces with distance away from the cable. Reduction of the EMF emissions is based on the distance from the cable, as described by the Biot-Savart Law. No allowance for harmonic and transient currents has been made. A steady state continuous current is assumed.
- Current flow was assumed to be at maximum power output from all WTGs; and
- Coordinates of latitude and longitude were applied within the National Oceanic and Atmospheric Administration (NOAA) online calculator (NOAA, N.D.) and used to calculate earth's magnetic field at KP locations (Nb. applicable to assessment of the HVDC Export/Import Cable modelling only).

5.9.1.3 Results

Static Inter-Array Cables

Results from EMF calculations for the assumed 66 kV and 132 kV static HVAC IACs are presented in Table 5-25 and Table 5-26 for burial depths of 0.4 m and 1.5 m.

Table 5-25 Maximum EMF intensities for 66 kV static IACs

HEIGHT ABOVE SEABED (m)	MAXIMUM EMF (μT)	
	DoL 0.4 m	DoL 1.5 m
0.0	66.23	6.05
1.0	6.90	2.26
5.0	0.50	0.35
10.0	0.14	0.11

Table 5-26 Maximum EMF intensities for 132 kV static IACs

HEIGHT ABOVE SEABED (m)	MAXIMUM EMF (μT)	
	DoL 0.4 m	DoL 1.5 m
0.0	70.37	6.66
1.0	7.57	2.50
5.0	0.56	0.39
10.0	0.15	0.12

From the EMF intensity plots shown in Figure 5-20 and Figure 5-21, it can be seen that the EMF intensity reduces rapidly when the horizontal position is beyond a metre or so for both 66 kV and 132 kV cable specifications.

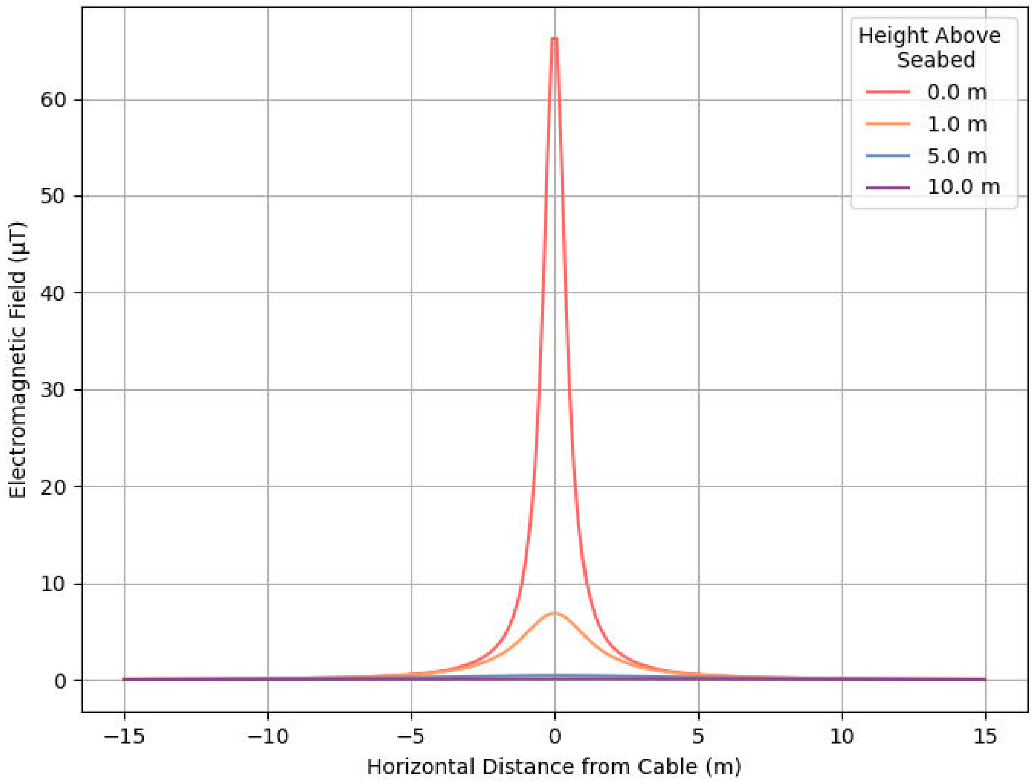

Figure 5-20 EMF intensity as a function of height above the seabed and horizontal distance for the 66 kV static IACs at a burial depth of 0.4 m

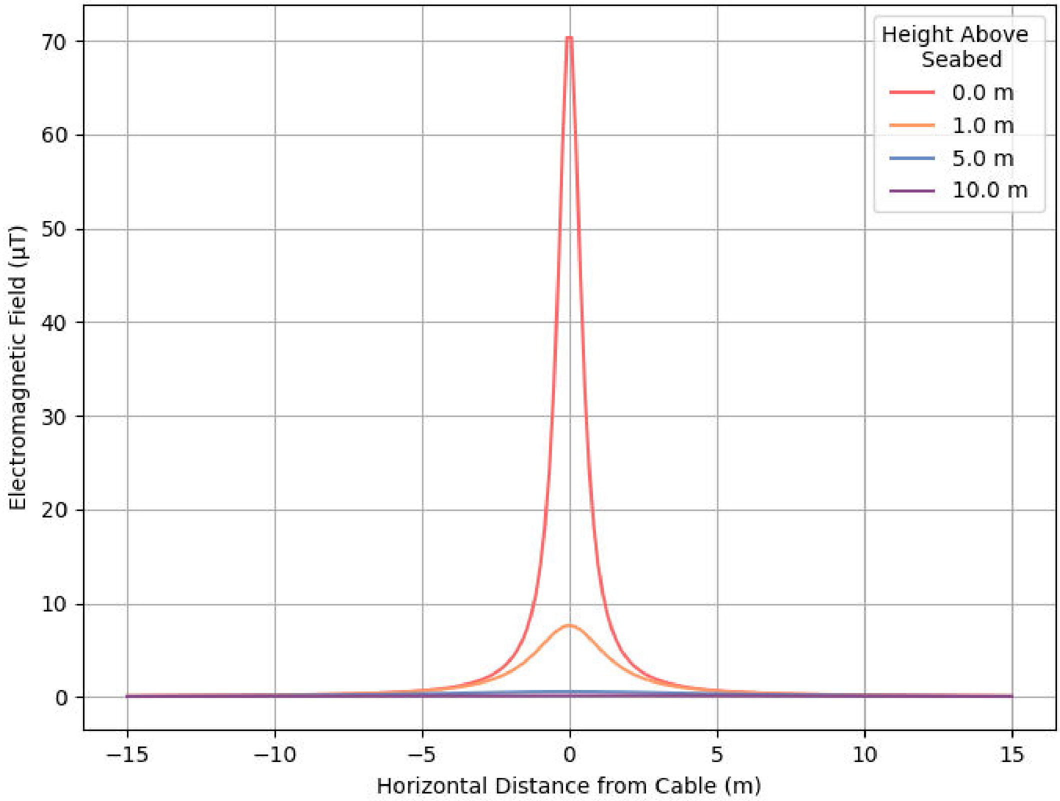

Figure 5-21 EMF intensity as a function of height above the seabed and horizontal distance for the 132 kV static IACs at a burial depth of 0.4 m

There is no consideration of GMF as HVAC cables are not influenced by GMF, so the field strength remains the same.

Dynamic Inter-Array Cables

Table 5-27 shows the cable surface EMF intensity for a 66kV dynamic cable is calculated as 1861.96 µT, however, the intensity rapidly diminishes through the water column and would shift according to extents of movement permitted by sub-structure mooring lines, wind and tidal motions. Typically, the cable would be tethered to the seabed, limiting movement. The tether would likely not influence attenuation of the EMF generated by the current flow.

Table 5-27 Maximum EMF intensities for 66 kV dynamic IACs

DISTANCE AWAY FROM CABLE SURFACE (m)	MAXIMUM EMF (μT)
Cable surface	1,861.96
1.0	18.90
5.0	0.85
10.0	0.22

Table 5-28 shows the cable surface EMF intensity for a 132 kV dynamic cable is calculated as 1780.3 μT, however, the intensity rapidly diminishes through the water column and would shift according to extents of movement permitted by sub-structure mooring lines, wind and tidal motions.

Table 5-28 Maximum EMF intensities for 132 kV dynamic cable build

DISTANCE AWAY FROM CABLE SURFACE (M)	MAXIMUM EMF (μT)
Cable surface	1780.30
1.0	20.69
5.0	0.95
10.0	0.24

Inter-Array Cable conclusions

The worst-case EMF calculations for both buried and dynamic sections of IACs have been presented for the Project. Static IACs sections will be buried in the seabed to a proposed minimum DoL of 0.4 m, providing some mitigation of EMF intensity through burial depth. Dynamic cable sections will be suspended within the seawater column, down to the seabed where they would transition to a static cable section. The calculated EMF at the cable surface is exposed throughout the seawater column along the cable surface, with mitigation provided by the extent of EMF attenuation caused by the armour wire layers (typically two for a dynamic cable), metallic sheath and power core helical periods. Dynamic cables move within the water column, effectively shifting the EMF.

Export/Import Cable

Results from EMF calculations for the assumed 320 kV HVDC Export/Import Cable are presented in Table 5-29. The calculation methodology to obtain these field intensities involved calculating the distance to the point of interest, based on the geometry of the laid Export/Import Cable and adding the resultant vectors (within each plane; X, Y and Z) together to obtain a resultant, combined cable-GMF strength.

The respective graphs for 0.4 DoL are provided in Figure 5-22 and Figure 5-23, which shows EMF reducing with horizontal distance from the cable. Further detail, including results for the 1.5 m DoL scenario are provided in EIAR Vol. 4, Appendix 14A: EMF Assessment Report Vol.1.

Table 5-29 Average EMF intensity for the 320 kV and 525 kV bundled configuration including GMF across Export/Import Cable Route locations KP0-KP227

HEIGHT ABOVE MEAN SEABED LEVEL (m)		0		0.5		1		5	
DoL (m)		0.4	1.5	0.4	1.5	0.4	1.5	0.4	1.5
Average EMF intensity (µT)	320 kV	451.0	79.3	130.5	66.8	83.6	60.9	52.8	52.2
	525 kV	363.7	73.4	113.9	63.4	76.8	58.8	52.4	51.8

Figure 5-23 illustrates that the EMF from the 320 kV cable reduces to the background GMF level of approximately 50 µT between 5.0 m and 10.0 m either side of the cable.

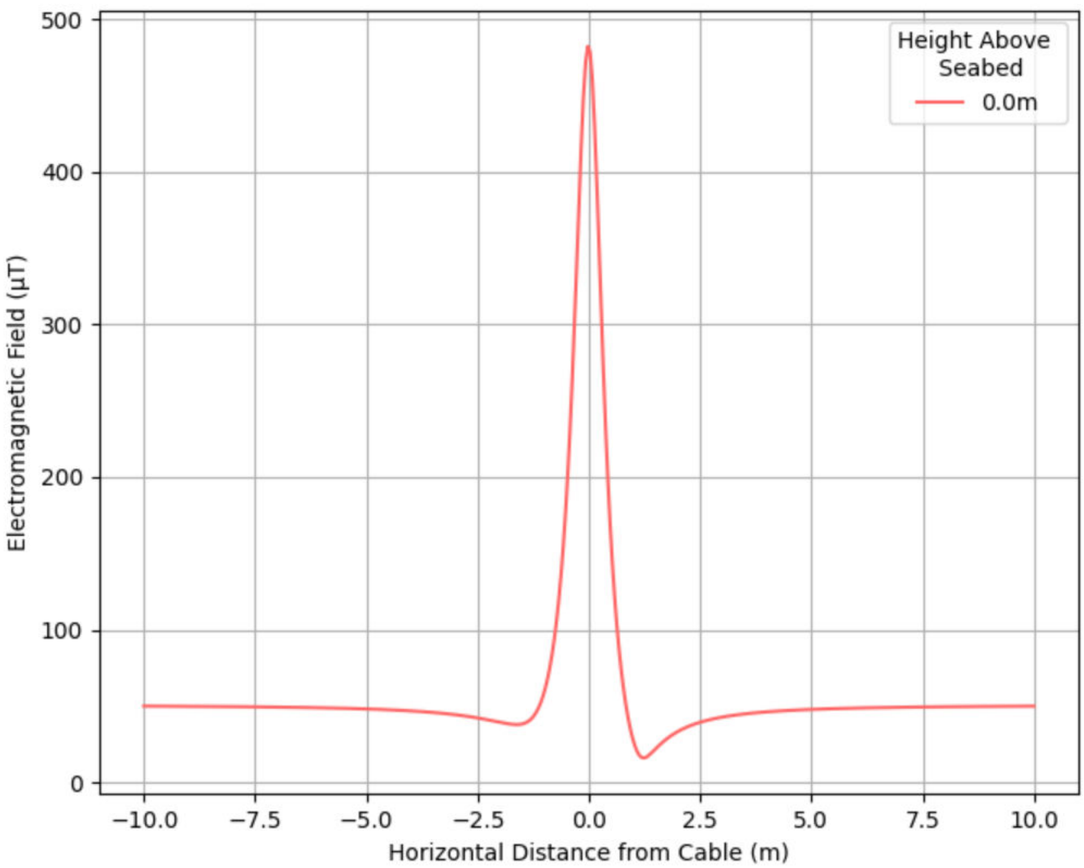

Figure 5-22 320 kV cable maximum EMF intensity along the seabed for a DoL of 0.4 m

Figure 5-23 presents the results of the assessment for the 525 kV cable.

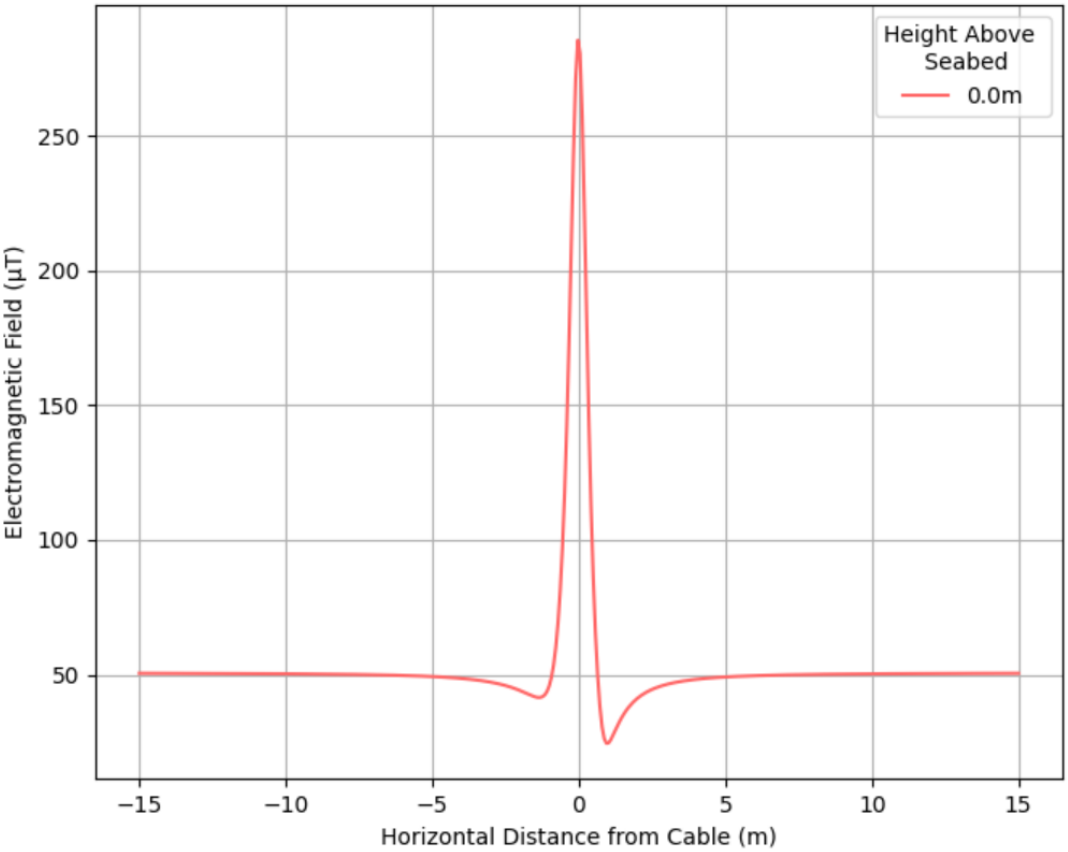

Figure 5-23 525 kV cable maximum EMF intensity along the seabed for a DoL of 0.4 m

For both 320 kV and 525 kV cable designs, calculations show that lowest EMF intensities on the seabed were calculated for an increased DoL of 1.5 m. The GMF intensity remains relatively constant along the Export/Import Cable Route. A bundled configuration of pole cables provides lower EMF intensities along the seabed and above the cables due to interactions of the fields. The calculated EMF intensities tend towards Earth's background GMF levels beyond approximately 5.0 m either side of the Export/Import Cable.

Compass Deviation

A Compass Deviation Assessment was undertaken for the Project EICC (EIAR Vol. 4, Appendix 14C: EMF Assessment Report Vol.3) and is summarised here. The offshore Export/Import Cable system is assumed to be buried along the EICC at a minimum of 0.4 m DoL (Mean Seabed Level to the top of the Cable), providing a worst-case scenario.

The magnetic fields from the cables will combine with the Earth's GMF and can cause a magnetic compass to indicate north in a different direction to the magnetic north pole, referred to as compass deviation. Current advice from the MCA states that they would be willing to accept a deviation for no more than three degrees for 95% of the length of the Export/Import Cable and for the remaining 5%, no more than five degrees of deviation.

The assessment is based on two HVDC cable configurations; a 320 kV subsea cable, and a 525 kV subsea cable. The compass deviation angle is influenced by disturbance to Earth's EMF horizontal components, which are the EMF components in the Y-axis and X-axis. Therefore, at each KP location the circuit angle was estimated relative to magnetic north, and the Earth's GMF intensities and directions determined from coordinates of longitude and latitude. Figure 5-24 and Figure 5-25 are provided below to illustrate the relationship between the KP locations, water depths, circuit angle and compass deviation.

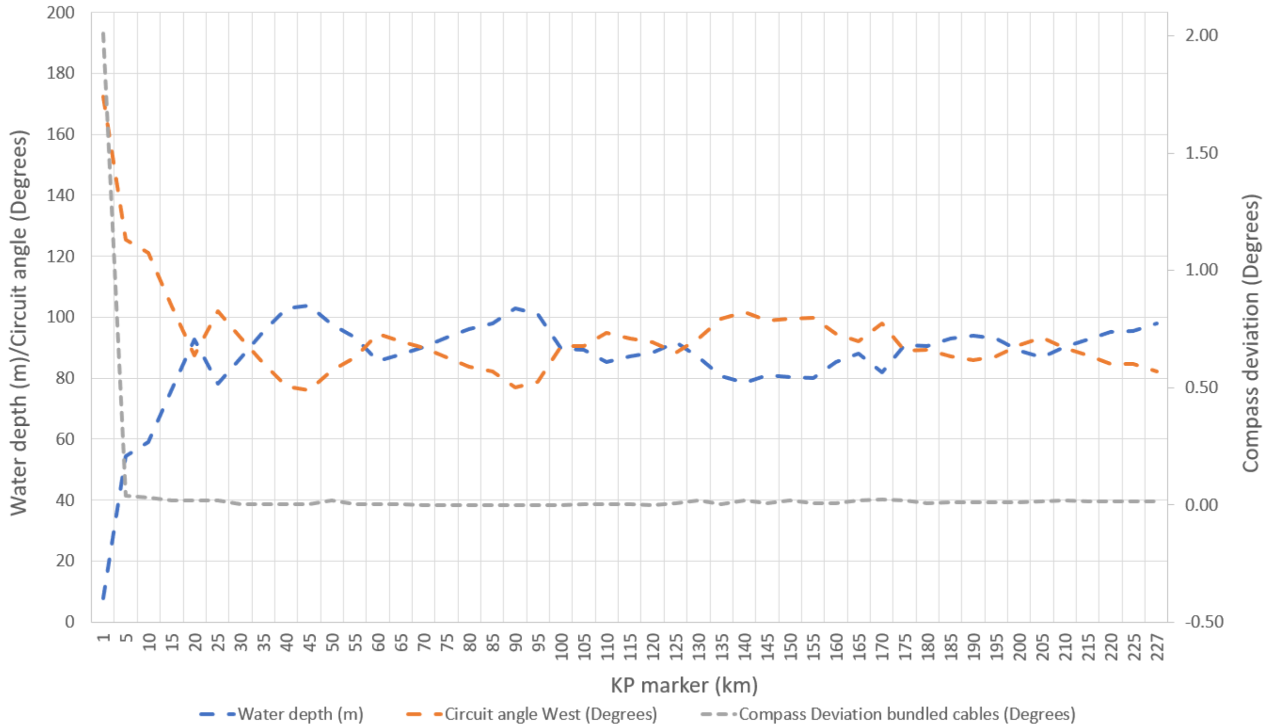

Figure 5-24 Compass deviation as a function of water depth and circuit angle for 320 kV bundled pole cables

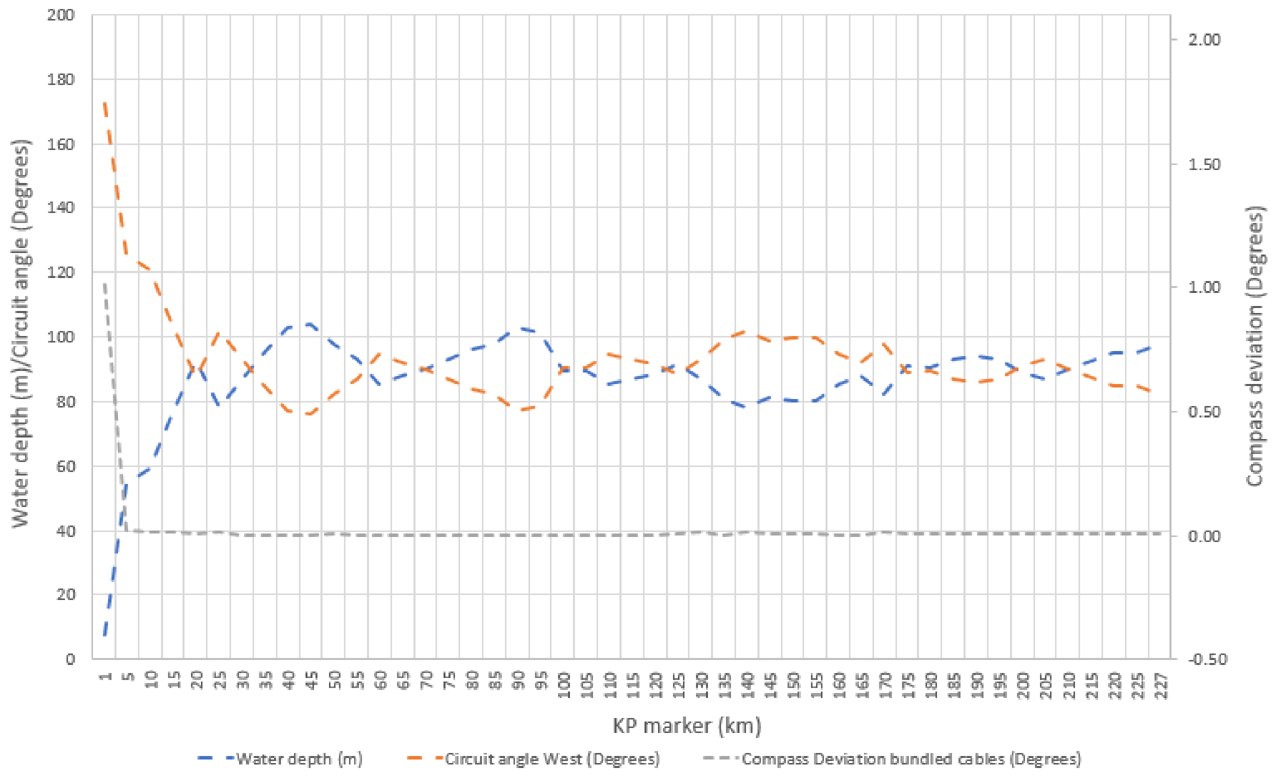

Figure 5-25 Compass deviation as a function of water depth and circuit angle for 525 kV bundled pole cables

As shown in the figures above, compass deviations along the entire EICC for the assumed 320 kV cable are all significantly below 3 degrees. Compass deviations for the whole length of the EICC for the assumed 525 kV cable are also all significantly below 3 degrees. These results are as expected, due to the water depths involved. At such depths, intensities of EMFs at the sea surface resulting from the cable are almost insignificant, and hence compass deviations are minimal. To summarise, all compass deviations were calculated as below 3 degrees for the entire subsea route.

5.10 Decommissioning

The Energy Act 2004, as amended by the Scotland Act 2016 contains statutory requirements in relation to the decommissioning of Offshore Renewable Energy Installations and require the Project to provide a Decommissioning Programme, supported by details of the type and timing of appropriate financial security proposed. The Decommissioning Programme will follow the guidance found in the Scottish Government's Decommissioning of Offshore Renewable Energy Installations in Scottish Waters (Scottish Government, 2022b). Decommissioning activities will comply with all relevant legislation at that time and best practice at the time of decommissioning will be followed.

Throughout the Project lifespan, the Decommissioning Programme will be reviewed and updated every five years. It is anticipated that the final revision process will commence two years prior to the initiation of decommissioning activities. Best practice will be followed when developing a Decommissioning Programme.

For the purposes of the EIAR, the following decommissioning principles have been assumed:

- FTU substructure components will be removed and towed to port;
- Mooring lines will be removed and where possible, piles will be removed or cut to a suitable distance below the mudline such that the upper portion is removed;
- Cables no longer required will be removed where safe to do so. Where they cross live third-party assets, they may be cut and left in-situ to prevent damage to third-party operations; and
- The OSCPs will be decommissioned, and the jacket and topside(s) will be towed to shore. The piles will be cut to a suitable distance below the mudline.

It is expected that decommissioning will require similar vessels to those used in construction and take a similar period of time.

5.10.1 Repowering

If any of the infrastructure, moorings, cabling or OSCPs are suitable for repowering, they will be retained for reuse in the updated system. All materials brought to shore will be decommissioned and waste managed in accordance with the waste hierarchy (Waste (Scotland) Regulations 2012). For example, they may be reused or recycled rather than disposed of to land. All the steel elements will be recyclable[6].

5.11 Safety zones

Statutory and advisory safety zones may be utilised during the various phases of the Project. The safety zone requirements across the construction, operation and maintenance and decommissioning phases are summarised in Table 5-30.

[6] *Repowering subject to a separate consenting process.*

Table 5-30 Safety zone requirements across all phases of the Project

PHASE	SAFETY ZONE REQUIREMENT
Construction	During the construction period, it is expected that a statutory 500 m safety zone around the outer edge of the proposed FTU and OSCPs locations will be applied for under Section 95 of the Energy Act 2004 and in accordance with Schedule 16 of the Energy Act 2004 and the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007. The statutory 500 m safety zone will be in operation where construction work is underway and while Restricted in Ability to Manoeuvre vessels are present. The statutory safety zones will be implemented on a 'rolling' basis, meaning that the 500 m statutory safety zones will be phased throughout the Array Area. Therefore, when construction is completed at one location, the 500 m statutory safety zone will be lifted, and a subsequent 500 m statutory safety zone will be placed around the next construction location. The safety zones will be reduced to 50 m around any FTU or OSCPs where construction work is not underway, and around any completed structure prior to commissioning. This is intended to reduce the extent of the area from which vessels will be excluded during construction and decommissioning. Statutory safety zones cannot be established around vessels themselves. However, it is standard safe working practice to establish advisory minimum safe passing distances around areas of vessel activity that present a navigational safety risk to marine users. These advisory safety zones are generally 500 m and move with the vessel during its operation. Cenos intend to submit an application for statutory safety zones during construction.
Operation and maintenance	During times of major maintenance works, a temporary 500 m statutory safety zone may be applied for under the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007. The Applicant intends to submit an application for statutory safety zones during major operation and maintenance activities.
Decommissioning	During decommissioning, safety zones may also be required, and this will be determined at a later stage when decommissioning plans are known. It is expected that safety zones will be applied for in a similar manner to the construction phase.

5.12 Consideration of hazards, accidents and risks

Major accidents and disasters associated with the Project may result from two main sources:

- Internal: the potential for the Project to cause a major accident and/or disaster; or
- External: the potential for the Project to interact with an external hazard to increase the risk of a major accident and/or disaster.

EIAR Vol. 2, Chapter 21: Major Accidents and Disasters assesses the potential vulnerability of the Project to Major Accidents and Disasters, both in terms of the potential for the Project to interact with an external Major Accidents and Disaster and the potential for the Project to cause a Major Accidents and Disasters. This includes consideration of natural disasters (e.g. geophysical, hydrological, climatological and meteorological, and biological), and technological or manmade disasters (societal, major industrial incidents, transport accidents, pollution incidents, utility failures, engineering accidents, malicious attacks, ground hazards, and workplace accidents).

All risk events are assessed as being tolerable with the implementation of embedded mitigation measures, and therefore, managed to an acceptable level. Risks from the Project will continue to be reviewed, assessed and managed, in accordance with relevant regulations, throughout the Project life-cycle.

5.13 Embedded mitigation

Embedded mitigation measures are measures that reduce the potential for impacts to the environment. As described in EIAR Vol. 2, Chapter 7: EIA Methodology, primary mitigation refers to measures built into the design of the Project. The primary measures for the Project are summarised in EIAR Vol. 2, Chapter 23: Summary of Mitigation and Monitoring. Other forms of mitigation, including secondary and tertiary mitigation do not form part of the fundamental design of the Project and are highlighted within each topic-specific chapter.

Relevant mitigation measures (including primary, secondary and tertiary) and management plans for each EIA topic are detailed in the topic-specific EIA chapters (chapters 8 – 22).

5.14 Variances in the Project Design Envelope from Scoping to EIA

Table 5-31 Variations in the PDE from parameters presented within 2024 Scoping Report

DESIGN PARAMETERS	PARAMETER WITHIN 2024 SCOPING REPORT	PDE PARAMETER	EXPLANATION FOR DIFFERENCE
Maximum swept area (m^2) (per turbine)	45,996 (15 MW, diameter 236 m)	61,575 (21 MW, diameter 280 m)	Increase is to account for maximum possible WTG size within the PDE (21 MW).
Total moorings chain seabed swept area (km^2)	N/A	1.44 km^2 assuming mooring chains of 95 FTUs in the Array Area (0.0025 km^2 of seabed disturbance by movement of each mooring chain, 6 mooring chains per FTU).	This is the maximum seabed footprint from the movement of mooring lines on the seabed during operational life of the Project. The calculation of this parameter was considered after the submission of the 2024 Scoping Report.
EICC length (km)	250	230	Length refined based on preliminary EICC routeing work.
Mooring design being considered	Catenary, taut, semi-taut and tension leg	Taut, semi-taut and tension leg	Catenary design removed from design envelope to reduce maximum seabed disturbance from mooring line ground chain, as the catenary design has larger quantity of ground chain on the seabed compared to other mooring designs.
Total seabed footprint for Array Area (m^2) (FTU foundations)	N/A	15,840 for TLP	This is the maximum seabed footprint resulting from the most onerous pile sizing scenario. The calculation of this parameter was considered after the submission of the 2024 Scoping Report.
Maximum length of IACs (km)	330	350	280 km of buried, static cabling, and 70 km of dynamic, floating cabling with no contact with the seabed.

5.15 References

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