Morecambe Offshore Windfarm: Generation Assets

Environmental Statement

Volume 5

Chapter 5 Project Description

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MORECAMBE

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Glossary of Acronyms

AC	Alternating Current
AfL	Agreement for Lease
ALARP	As Low as Reasonably Practicable
BAS	Burial Assessment Study
CAA	Civil Aviation Authority
CBRA	Cable Burial Risk Assessment
COMAH	Control of Major Accident Hazards
CSIP	Cable Specification and Installation Plan
DCO	Development Consent Order
DECC	Department of Energy and Climate Change[1]
DP	Dynamic Positioning
EIA	Environmental Impact Assessment
ES	Environmental Statement
ETG	Expert Topic Group
GBS	Gravity Based Structures
HAT	Highest Astronomical Tide
HRA	Habitats Regulations Assessment
LAT	Lowest Astronomical Tide
MCA	Maritime and Coastguard Agency
MGN	Marine Guidance Note
MHWS	Mean High Water Springs
MMO	Marine Management Organisation
MoD	Ministry of Defence
MSL	Mean Sea Level
MPCP	Marine Pollution Contingency Plan
NPS	National Policy Statement
NRW	Natural Resources Wales
OFTO	Offshore transmission owner
OSP	Offshore substation platform
PDE	Project Design Envelope

[1] The Department of Energy and Climate Change (DECC) was disbanded and merged with the Department for Business, Innovation and Skills to form the Department for Business, Energy and Industrial Strategy (BEIS) in 2016. As of February 2023, BEIS is known as the Department for Energy Security and Net Zero (DESNZ).

PEIR	Preliminary Environmental Information Report
PEMP	Project Environmental Management Plan
PLGR	Pre-lay grapnel run
ROV	Remotely Operated Vehicles
RPM	Rotations per minute
SAC	Special Area of Conservation
SCADA	Supervisory Control and Data Acquisition
SPA	Special Protection Area
TH	Trinity House
TP	Transition Piece
UK	United Kingdom
UXO	Unexploded Ordnance
WTG	Wind turbine generator

Glossary of Unit Terms

km	kilometre
kV	kilovolt
m	metre
mm	millimetre
MW	Megawatts

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Glossary of Terminology

Applicant	Morecambe Offshore Windfarm Ltd
Application	This refers to the Applicant's application for a Development Consent Order (DCO). An application consists of a series of documents and plans which are published on the Planning Inspectorate's (PINS) website.
Agreement for Lease (AfL)	Agreements under which seabed rights are awarded following the completion of The Crown Estate tender process.
European sites	Designated nature conservation sites which include the National Site Network (designated within the UK) and Natura 2000 sites (designated in any European Union country). This includes candidate Special Areas of Conservation (cSAC), Sites of Community Importance, Special Areas of Conservation (SAC) and Special Protection Areas (SPA).
Evidence Plan Process (EPP)	A voluntary consultation process with specialist stakeholders to agree the approach, and information to support, the Environmental Impact Assessment (EIA) and Habitats Regulations Assessment (HRA) for certain topics. The EPP provides a mechanism to agree the information required to be submitted to PINS as part of the DCO Application. This function of the EPP helps Applicants to provide sufficient information in their application, so that the Examining Authority can recommend to the Secretary of State whether or not to accept the application for examination and whether an appropriate assessment is required.
Expert Topic Group (ETG)	A forum for targeted engagement with regulators and interested stakeholders through the EPP.
Generation Assets (the Project)	Generation assets associated with the Morecambe Offshore Windfarm. This is infrastructure in connection with electricity production, namely the fixed foundation wind turbine generators (WTGs), inter-array cables, offshore substation platform(s) (OSP(s)) and possible platform link cables to connect OSP(s).
Inter-array cables	Cables which link the WTGs to each other and the OSP(s).
In-row	The distance separating WTGs in the main rows.
Inter-row	The distance between the main rows.
Landfall	Where the offshore export cables would come ashore.

Morgan and Morecambe Offshore Wind Farms: Transmission Assets	The transmission assets for the Morgan Offshore Wind Project and the Morecambe Offshore Windfarm. This includes the OSP(s[2], interconnector cables, Morgan offshore booster station, offshore export cables, landfall site, onshore export cables, onshore substations, 400kV cables and associated grid connection infrastructure such as circuit breaker infrastructure. Also referred to in this chapter as the Transmission Assets, for ease of reading.
Nacelle	The part of the turbine that houses all of the generating components.
Offshore substation platform(s)	A fixed structure located within the windfarm site, containing electrical equipment to aggregate the power from the WTGs and convert it into a more suitable form for export to shore.
Platform link cable	An electrical cable which links one or more OSP(s).
Safety Zones	An area around a structure or vessel which should be avoided, as set out in Section 95 of the Energy Act 2004 and the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007.
Scour protection	Protective materials to avoid sediment being eroded away from the base of the foundations due to the flow of water.
Study area	This is an area which is defined for each EIA topic which includes the offshore development area as well as potential spatial and temporal considerations of the impacts on relevant receptors. The study area for each EIA topic is intended to cover the area within which an effect can be reasonably expected.
Tidal excursion ellipse	The path followed by a water particle in one complete tidal cycle.
Windfarm site	The area within which the WTGs, inter-array cables, OSP(s) and platform link cables would be present.
Wind turbine generator (WTG)	A fixed structure located within the windfarm site that converts the kinetic energy of wind into electrical energy.
Zone of Influence (ZoI)	The maximum anticipated spatial extent of a given potential impact.

[2] At the time of writing the Environmental Statement (ES), a decision had been taken that the offshore substation platforms (OSP(s)) would remain solely within the Generation Assets application and would not be included within the Development Consent Order (DCO) application for the Transmission Assets. This decision post-dated the Preliminary Environmental Information Report (PEIR) that was prepared for the Transmission Assets. The OSP(s) are still included in the description of the Transmission Assets for the purposes of this ES as the Cumulative Effects Assessment (CEA) carried out in respect of the Generation/Transmission Assets is based on the information available from the Transmission Assets PEIR.

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5 Project Description

5.1 Introduction

5.1 This chapter of the Environmental Statement (ES) provides a full description of the physical components of the Morecambe Offshore Windfarm Generation Assets (the Project). For the purposes of this ES, the "Project" refers to the generation assets of the Morecambe Offshore Windfarm, located within the windfarm site (including wind turbine generators (WTGs), inter-array cables, offshore substation platforms (OSP(s)) and possible platform link cables to connect OSP(s)).

5.2 This chapter describes the construction, operation and maintenance and decommissioning phases of the Project, detailing the proposed activities, likely durations and design parameters. For this ES, it is assumed that the commissioning period is part of the 2.5-year construction phase, and the operation and maintenance duration is 35 years from the date of commercial export, which would then be followed by decommissioning activities. The duration of the lease (with The Crown Estate) of the windfarm site is 60 years and, as such, repowering activities could be expected to extend the operational life of the windfarm, however, separate consent would be required for repowering and, thus, is not considered in this ES.

5.3 The Project description details provided in this chapter inform and underpin the assessments that have been undertaken and presented in this ES. The technical assessment chapters of the ES (chapters 7 to 22) should be referred to for details of how the Project Design Envelope (PDE) outlined in this chapter is used to inform the realistic worst-case scenarios that apply to each assessment topic. Further details of the PDE approach are provided in **Section 5.2**.

5.4 This ES has been informed by the following:

- A Scoping Opinion provided by the Planning Inspectorate (PINS) on 2nd August 2022 in response to an Environmental Impact Assessment (EIA) Scoping Report, submitted by the Applicant on 23rd June 2022
- Ongoing Evidence Plan Process (EPP) through Expert Topic Groups (ETGs) and targeted consultation with other marine users
- Section 42[3] and other consultation responses provided during the Project's Statutory Consultation in response to the Preliminary

[3] Section 42 of the Planning Act 2008 requires a developer to consult local authorities, people with an interest in the land or who may be significantly affected by proposals.

Environmental Information Report (PEIR), published by the Applicant in April 2023

5.5 Comments relevant to this chapter, and how these comments have been addressed, are presented in **Table 5.1**.

Table 5.1 Consultation responses received in relation to the Project Description and how these have been addressed in the ES

Consultee	Date	Comment	Response/where addressed in the ES
Scoping Opinion responses			
PINS	2nd August 2022	Section 6.2 [of the Scoping Report] states that the EIA will be based on parameters for key elements of the Proposed Development rather than finalised detailed design, to retain flexibility. It is stated that a “maximum design scenario” and “options and/ or parameters for which maximum values are defined” will be used to support the impact assessment in the ES. The Inspectorate advises that flexibility in design should only be sought where absolutely necessary, in the interests of a proportionate ES based on the most realistic and refined maximum design envelope possible. For the avoidance of doubt, the ES should assess the worst-case that could potentially be built out in accordance with the Authorised Development of the Development Consent Order (DCO) being applied for; this includes (but is not limited to) parameters relating to the number of turbines, turbine height, foundation types, scour protection, cable protection and the layout of offshore structures.	Information on the Project Design Envelope (PDE) approach is given in **Section 5.2**. PDE parameters are provided in this chapter with the realistic worst-case scenarios identified per impact in technical chapters 7-22.
PINS	2nd August 2022	The Scoping Report sets out an indicative maximum diameter for different foundation types, which appears to include an allowance for scour protection. Paragraph 101 states that the amount of scour protection will be defined and refined during the Preliminary Environmental Information Report (PEIR) process. The ES should confirm the amount of scour protection required for each foundation type under consideration, what the maximum seabed footprints would be and the timeframes for installation.	The PDE parameters of scour protection for different foundation types are detailed in **Section 5.5.3.5**. Information on installation of scour protection, including footprints and timeframes for installation, is given in **Section 5.6.7**.
PINS	2nd August 2022	If drilling is required for the installation of foundations, the ES should identify the likely site for disposal of drilling arisings and include an assessment of effects from these activities.	Disposal of drill arisings would be within the windfarm site boundary and has been assessed as such.

Consultee	Date	Comment	Response/where addressed in the ES
PINS	2nd August 2022	The ES should provide further detail on the proposed seabed preparation activities required and identify the worst-case footprint of seabed disturbance that would arise. Should seabed preparation involve dredging, the ES should identify the quantities of dredged material and likely location for disposal. Any likely significant effects (LSE) from dredging should be assessed.	Pre-installation works, including seabed preparation activities and footprints, are detailed in **Section 5.6.2**. Disposal would be within the windfarm site boundary and has been assessed as such.
PINS	2nd August 2022	It is noted that consent for unexploded ordnance (UXO) removal will be sought in a future Marine Licence application which would be supported by a more detailed assessment. The Inspectorate advises that the ES should still include a high level assessment based on a likely worst-case scenario (any assumptions used in the definition of the worst-case scenario should be explained in the ES). The ES should address any cumulative effects from the construction of the Proposed Development with the likely effects from the UXO clearance. If any preliminary works such as UXO surveys would be permitted under the DCO then the effects of these should also be included in the ES.	Underwater noise modelling of unexploded ordnance (UXO) clearance has been undertaken based on anticipated charge weights, as detailed in **Appendix 11.2**. Information on UXO clearance potentially required for construction is outlined in the relevant chapters (**Chapter 10 Fish and Shellfish** (Document Reference 5.1.10) and **Chapter 11 Marine Mammals** (Document Reference 5.1.11)), however, a separate licence (supported by a detailed assessment) for UXO clearance would be sought after DCO submission or after consent, if required. UXO clearance (if required), is assessed in the cumulative assessments in the relevant chapters noted above.
PINS	2nd August 2022	The Scoping Report states that there will be a target depth of 1m for cable burial, with a range between 0.5m to 3m, to be determined by a Burial Assessment Study (BAS) and Cable Burial Risk Assessment (CBRA). Burial could be achieved through a number of techniques dependent on seabed	Information on the PDE parameters for inter-array cables and platform link cables, including cable protection is given in **Section 5.5.4 .** Anticipated

Consultee	Date	Comment	Response/where addressed in the ES
		conditions, and where burial is not possible protection measures could be used. The BAS and CBRA should be submitted alongside the ES where available. The ES should explain which burial techniques are to be used in which locations and, where a final decision has not been made, include an assessment of the effects using the worst-case scenario. It should detail the maximum volume of material required for cable protection and explain how this has been quantified.	installation methods are detailed in **Section 5.6.6**. Volumes of cable and scour protection are also outlined in an Outline Scour Protection and Cable Protection Plan included with the DCO Application (Document Reference 6.8). Cable installation methods would be detailed in the Cable Burial Assessment (CBA) as part of the Cable Specification and Installation Plan (CSIP), which would be developed post-consent.
PINS	2nd August 2022	Paragraph 125 of the Scoping Report states that onshore works required within a port are excluded from the scope of the ES (on the basis that it relates only to offshore generation assets). Section 7, paragraph 134 confirms that a full and comprehensive assessment of interaction, including cumulative effects, between the Proposed Development and the related proposals for the Transmission Assets would be included. This should include consideration of onshore port works during construction and operation where there is potential for likely significant cumulative effects to occur.	Chapters 7-22 identify any pathways of effects to the onshore environment as a result of the Project. Potential impacts as a result of the Morgan and Morecambe Offshore Wind Farms: Transmission Assets project are included within the cumulative assessments for each chapter (chapters 7-22) and also summarised in a separate **Chapter 23 Summary: Generation and Transmission Assets Assessment** (Document Reference 5.1.23). The selection of the Port(s) used to support the Project is unknown at this time and the approach to the onshore traffic and transport (and related onshore topics) assessment is outlined in **Chapter 22 Traffic and Transport** (Document Reference 5.1.22), **Chapter**

Consultee	Date	Comment	Response/where addressed in the ES
			19 Human Health (Document Reference 5.1.19) and **Chapter 20 Socio-economics, Tourism and Recreation** (Document Reference 5.1.20).
PINS	2nd August 2022	The ES should detail the type, number and frequency of vessel movements required to construct and operate the Proposed Development. If these are unknown, then the ES should explain the assumptions that have been made about vessel movements to inform the assessment.	The anticipated vessels and vessel movements associated with the construction and operation and maintenance phases of the Project are detailed in **Section 5.6.1** and **Section 5.7.1**, respectively.
PINS	2nd August 2022	The Inspectorate notes that a decommissioning plan will be prepared when the Proposed Development reaches the end of its operation. However, the ES should still include an assessment of the effects of decommissioning in as much detail as can be provided at the stage of the DCO application. It should indicate as far as possible the assumptions that have been made about the options likely to be considered for decommissioning and explain how these have been taken into account in the assessment of different aspects of the environment.	Decommissioning activities are discussed in **Section 5.7.4** and assessed in chapters 7-22.
PINS	2nd August 2022	The Proposed Development is located in the Irish Sea with both built and proposed offshore wind farms close by. The Inspectorate considers that it would be useful to include a figure in the introductory section of the ES which places the Proposed Development in the context of the surrounding offshore wind farms.	**Figure 5.2** shows the location of other proposed offshore windfarms and other offshore infrastructure relative to the Project.
PINS	2nd August 2022	The ES should provide a full description of the nature and scope of operation and maintenance activities, including types of activity, frequency, and how works will be carried out. This should include consideration of potential overlapping of activities with those required for the continuing operation of	Operation and maintenance activities are outlined in **Section 5.7** and further detailed in the Outline Offshore Operation and Maintenance Plan

Consultee	Date	Comment	Response/where addressed in the ES
		existing windfarms in the area and construction of those proposed.	(OOMP) (Document Reference 6.6).
PINS	2nd August 2022	The Scoping Report states that major accidents and disasters are not proposed to be considered as a standalone chapter but considered in other relevant aspect chapters of the ES, as listed in paragraph 928. The Inspectorate is content that this aspect does not need to be assessed within a standalone chapter, subject to the following comments: ▪ The ES should include a section which signposts the reader to the specific sections of the ES which deal with the relevant matters. ▪ The Inspectorate notes that the sections of the Scoping Report addressing the aspects listed at paragraph 928 do not specifically state that the assessments will include consideration of major accidents and disasters, as relevant to the identified project risks. The ES should clearly describe the consideration that has been given to this matter and any LSE deriving from vulnerability to risks of major accidents and disasters. ▪ In addition to the aspects listed at paragraph 928, the Applicant should consider whether there is potential for major accidents and disasters relating to the vulnerability of the Proposed Development to climate change. ▪ Any design measures taken to avoid major accidents and disasters should be clearly described within the ES.	A response to potential major accidents and disasters are outlined in **Section 5.9**, with relevant links to other parts of the ES. A climate change resilience assessment has also been undertaken (**Chapter 21 Climate Change** (Document Reference 5.1.21) which considers the Project's adaptive capacity to climate change, defined by the potential or ability to adapt to the effects of climate change such as sea level rise (and to ensure that the design is resilient to the projected effects of climate change). .
Statutory consultation feedback on the PEIR			
Marine Management Organisation (MMO)	30th May 2023	PEIR Chapter 5: Project Description–- Minor Comments–- In Chapter 5 Section 5.6.3, it states that "only one foundation will be installed at any one time in the windfarm site, including only one piling activity occurring at any one time". This implies	It is confirmed that the construction assumptions are that one foundation is installed at a time, with no concurrent piling planned for the Project. This is

Consultee	Date	Comment	Response/where addressed in the ES
		that no concurrent /simultaneous piling activity will occur during the construction phase of the Project. If concurrent/simultaneous piling is expected, then the underwater noise impact assessment would need to be revised to include appropriate modelling. The modelling would need to be based on the maximum hammer energy for a concurrent piling scenario, from a suitable piling location, so that the worst-case scenario in terms of maximum impact range can be more accurately determined and mitigation measures can be recommended, if appropriate.	reflected in the underwater noise modelling (**Appendix 11.2**).
Historic England	30th May 2023	PEIR Chapter 5 – Project Description The Wind Turbine Generators (WTGs) being considered for this project are rated between 12MW and 24MW, i.e. either 40 smaller or 20 larger WTGs with nominal export capacity of 480MW. We note that the array area overlaps with the Morecambe South Gas Fields with associated platforms, pipelines, cables and wells. We also note that there are live telecommunications cables either crossing the array area or immediately adjacent. The description of WTGs which could be used explains that the blade tip height above Highest Astronomical Tide (HAT) could be between 242 and 345m. We also appreciate that the wind turbine layout will not be finalised until closer to construction, given that detailed preconstruction studies inclusive of site investigations, selection of the preferred wind turbine generator (WTG) design and foundation type(s). In reference to the importance of finalising the layout arrangements it is apparent that detailed analysis will be required of seabed and sub-seabed conditions. For example, as mentioned in paragraph 5.24 regarding minimum separation distances as necessary for micrositing requirements.	Noted. Updates have been made to this chapter based on the refinement of the PDE since the PEIR. Layout arrangements would continue to be developed post-consent.

Consultee	Date	Comment	Response/where addressed in the ES
Historic England	30th May 2023	PEIR Chapter 5: This project may require two OSPs each with an anticipated footprint plan of 80m by 55m. We also note the decision not to repurpose existing oil and gas infrastructure to function as OSP(s) as explained in paragraph 5.32.	Noted. OSP footprints have been revised since the PEIR, as described in **Section 5.5.3**.
Historic England	30th May 2023	PEIR Chapter 5: The PEIR states that at this stage foundation design for WTGs could comprise any of the following: ▪ Gravity Base Structure (GBS); ▪ Jacket with piling; ▪ Suction bucket monopile; ▪ Monopile; ▪ Tripod; or ▪ Jacket with suction bucket A maximum base slab diameter is described as 65m (Table 5.4), however, Table 5.15 offers a maximum seabed preparation diameter of 100m with maximum depth of seabed preparation of 1m for monopile, monopod suction bucket, pin piled jacket and jacket suction bucket and 1.5m for GBSs. We must question this estimate and to ask for it to be clarified in the ES, so that a full appreciation can be gained of works necessary for installation. Furthermore, that pile diameters could range from 5-14m with up to 60m penetration depth. However, for suction bucket (monopile) the maximum bucket diameter could be 20-40m, but no depth of seabed penetration is offered. We encourage you to prepare an ES which includes such detail, so that full consideration and assessment can be conducted to determine a possible worst-case scenario, as used within the project design envelope approach described in Chapter 6 (EIA methodology), section 6.6.2. For example, the risk to archaeological materials this by	The range of foundations options (and associated PDE parameters) have been refined since the PEIR, with details of each option updated and provided in this chapter (detailed in **Section 5.5.3**). The seabed preparation area for monopiles has been reduced since the PEIR. This is reflected in this chapter and the realistic worst-case scenario assessments in chapters 7-22 as relevant.

Consultee	Date	Comment	Response/where addressed in the ES
		GBS installation (as described in Chapter 5, sub-section 5.6.3.4).	
Historic England	30th May 2023	PEIR Chapter 5 Section 5.6.2 (Pre-installation works) – describes action to clear debris from the cable route and we stress at this point the importance of archaeological advice to differentiate contemporary debris/litter or geological items (e.g. boulders) from other materials which might be of archaeological interest. It is an important matter that paragraph 5.74 confirms the detailed geophysical survey campaign to be conducted no more than 6 months ahead of commencement of intrusive works, which will also include a UXO survey. We therefore encourage the Applicant to plan these investigation programmes (should consent be obtained), which optimise the timely involvement of professional, experienced and accredited archaeological consultants, so that data acquisition and processing allows for avoidance of known heritage assets and identification and avoidance of presently unknown heritage assets.	Noted. Pre-installation requirements for archaeology are included in **Chapter 15 Marine Archaeology and Cultural Heritage** (Document Reference 5.1.15).
Historic England	30th May 2023	PEIR Chapter 5 Sub-section 5.6.4.1 (WTG installation) – describes the use of jack-up vessels with anticipated seabed footprint. It is therefore a relevant matter that all assessment of risk of encountering elements of the historic environment needs to determine the presence of such material(s) within any area that seabed impacting operations may occur.	Noted. Footprints of jack-up vessels required for WTG/OSP installation are outlined in **Section 5.6.2**, and are assessed in **Chapter 15 Marine Archaeology and Cultural Heritage** and other relevant assessments (e.g. **Chapter 9 Benthic Ecology** (Document Reference 5.1.9)).
Historic England	30th May 2023	PEIR Chapter 5 Section 5.6.6 (‘Inter-array and platform link cables) mentions the completion of geotechnical and geophysical investigations to inform this phase of work. We add that it is essential that a detailed picture of what might exist within or under the contemporary seabed is important. It might be the case that archaeological materials, inclusive of	Noted and assessed in **Chapter 15 Marine Archaeology and Cultural Heritage.**

Consultee	Date	Comment	Response/where addressed in the ES
		palaeo-environmental sequences of archaeological interest, are identified under the depth of proposed cable burial in the array area. Although not directly impacted, it is still the case that access to such materials will subsequently become impossible; this itself represents an 'impact' which requires assessment in the ES with provision made for appropriate mitigation.	
Natural Resources Wales (NRW)	21st May 2023	PEIR Chapter 5: NRW (A) note that Chapter 5, Project Description [of the PEIR], Table 5.2 confirms that the tallest blade tip height within the design envelope for Morecambe is 345 m above highest astronomical tide (HAT) which is 350 m above mean sea level.	Maximum WTG blade tip heights for ES have been reduced from those reflected in the PEIR, as detailed in **Section 5.5.1.1**.
Natural England (ref. E1)	2nd June 2023	Offshore Ornithology: PEIR Chapter 5 Table 5.2 The minimum rotor clearance above sea level is 22m. Natural England highlight that increasing the minimum rotor clearance would reduce collision risk estimates generated by the Project and request that the Applicant explore the feasibility of achieving greater clearance.	The minimum rotor clearance outlined in the PEIR was 22m above highest astronomical tide (HAT), not mean sea level (MSL). Following stakeholder consultation, the minimum rotor clearance has been increased to 25m above HAT (see **Section 5.5**). Collision risk modelling undertaken in **Chapter 12 Offshore Ornithology** (Document Reference 5.1.12) has used the revised (increased) air gap.
Natural England (ref. B1)	2nd June 2023	Benthic ecology: PEIR Chapter 5 Section 5.6.2 NE notes that the full effect of pre- installation works on benthic habitats in the array area, or at distance is not thoroughly assessed. In particular, the impact of UXO clearance is stated to be negligible in the Benthic Ecology chapter, but this is not supported by an assessment of this activity's effects in the Marine Geology, Oceanography	Pre-installation works are described in **Section 5.6.2**. These are assessed in **Chapter 7 Marine Geology, Oceanography and Physical Processes** (Document Reference 5.1.7), **Chapter 8 Marine Sediment and Water Quality** (Document Reference 5.1.8) and **Chapter 9**

Consultee	Date	Comment	Response/where addressed in the ES
		and Physical Processes or Marine Sediment and Water Quality chapter. NE advises that such conclusions should not be drawn until the scope of this work is better understood. Furthermore, it is still important to understand the magnitude of negligible or residual effects as these will need to be scoped in to cumulative and in-combination assessments.	**Benthic Ecology**. Further justification is provided in **Chapter 7 Marine Geology, Oceanography and Physical Processes**, **Chapter 8 Marine Sediment and Water Quality** and **Chapter 9 Benthic Ecology**. It is noted that UXO clearance, if required, would be subject to a separate licence and more detailed assessment.

5.2 Project design envelope

5.6 The Project EIA, reported in this ES, is based on a design envelope approach in accordance with National Policy Statement (NPS) (NPS EN-3 (DESNZ, 2023); paragraph 2.8.74) which recognises that: "*Owing to the complex nature of offshore wind farm development, many of the details of a proposed scheme may be unknown to the applicant at the time of the application to the Secretary of State. Such aspects may include:*

- *The precise location and configuration of turbines and aossicated development;*
- *The foundation type and size;*
- *The installation technique or hammer energy;*
- *The exact turbine blade tip height and rotor swept area;*
- *The cable type and precise cable or offshore transmission route; and*
- *The exact locations of offshore and/or onshore substations"*

5.7 NPS EN-3 (paragraph 2.6.1) recognises that: *"Where details are still to be finalised, applicants should explain in the application which elements of the proposal have yet to be finalised, and the reason why this is the case. Where flexibility is sought in the consent as a result, applicants should, to the best of their knowledge, assess the likely worst case environmental, social and economic effects of the proposed development to ensure that the impacts of the project as it may be constructed have been properly assessed"* (DESNZ, 2023).

5.8 The PDE therefore provides maximum and minimum parameters, where appropriate, to ensure the realistic worst-case scenario can be quantified and is assessed in the EIA while maintaining flexibility.

5.9 This approach has been widely successful in the consenting of offshore wind farms and is consistent with the PINS Advice Note Nine: Rochdale Envelope (PINS, 2018) which states that: "*The Rochdale Envelope assessment approach is an acknowledged way of assessing a Proposed Development comprising EIA development where uncertainty exists and necessary flexibility is sought*". This is further described in **Chapter 6 EIA Methodology** (Document Reference 5.1.6).

5.10 The parameters described in this chapter represent the PDE which have been derived from the range of designs, technologies, and methodologies under consideration. For example, parameters for WTGs have been considered for a range of sizes, with a number of foundation options. Given the range in) WTG sizes, two WTG scenarios are being used to encompass the PDE:

- More (35) smaller WTGs
- Fewer (30) larger WTGs

5.11 Each technical chapter (chapters 7 to 22) of this ES outlines the relevant realistic worst-case scenario, noting that this would vary depending on the receptor and impact being considered. For example, for visual effects, the 30 larger WTGs with the maximum tip height represents the worst-case scenario, as they produce the impacts over a larger distance. Whereas for ornithology, collision risk of the 35 smaller WTGs with the lowest blade tip clearance represents the worst-case scenario, given increased interaction with birds.

5.3 Site description

5.12 The Project windfarm site, containing the generation asset infrastructure, is located in the eastern portion of the Irish Sea (**Figure 5.1**). The nearest point from the windfarm site to shore (coast of northwest England) is approximately 30km.

5.13 The windfarm Agreement for Lease (AfL) area awarded by The Crown Estate, spans 125km^2. Following consultation on the PEIR, the proposed windfarm site development area has been reduced to approximately 87km^2, as further described in **Chapter 4 Site Selection and Assessment of Alternatives** (Document Reference 5.1.4). For clarity, all Project infrastructure would be located within the reduced (87km^2) windfarm site for which the ES assessments are based.

5.14 Water depths within the windfarm site range from 18m to 40m (relative to Lowest Astronomical Tide (LAT)).

5.15 The windfarm site overlaps with the existing South Morecambe gas field and is in proximity to its existing infrastructure of platforms, pipelines, cables and wells. The DP3 platform, which was decommissioned and fully removed in 2023, was previously located within the Project windfarm site. The Calder platform (CA1) is located to the west of the Project windfarm site. The telecommunication cable GTT/Hibernia Atlantic (also known as Hibernia A) traverses the windfarm site in a west-east direction. The Lanis 1 cable, owned by Vodafone, runs along the edge of the windfarm site, defining the southern boundary.

5.16 There are also several operational windfarms and associated cables, marine aggregate areas, offshore shipping separation schemes/lanes and telecommunication and power cables in proximity to the Project. Additional Round 4 offshore windfarms (Mona and Morgan) are also planned to the west of the windfarm site, and DCO consent was granted for the Awel y Môr (AyM) Offshore Wind Farm in September 2023, located 29km to the south of the Project windfarm site. The Mooir Vannin Offshore Wind Farm, proposed for construction in Isle of Man territorial waters, submitted its Scoping Report to the Isle of Man Government in October 2023 (Ørsted, 2023).

5.17 The location of other proposed and operational offshore windfarms, and other offshore infrastructure relative to the Project, is presented in **Figure 5.2**.

5.4 Outline of the Project components

5.18 The key Project components briefly comprise:

- WTGs and their associated foundations (**Section 5.5.1** and **Section 5.5.3**)
- Up to two OSPs and their associated foundations (**Section 5.5.2** and **Section 5.5.3**), and platform link cables (**Section 5.5.4.2**)
- Inter-array cables (**Section 5.5.4.1**)
- Scour protection around foundations and subsea cable protection, where required (**Section 5.5.3.5** and **Section 5.5.4.3**)

5.19 **Section 5.5** outlines the Project components in detail.

5.5 Project components

5.5.1 Wind turbine generators

5.5.1.1 WTG parameters

5.20 The PDE includes a range of WTGs with varying parameters and capacity, to accommodate the ongoing rapid development in WTG technology. Accounting for this range, there could be up to 30 'larger' or 35 'smaller' WTGs installed within the windfarm site to generate the nominal export capacity of 480MW.

5.21 Conventional three-bladed, horizontal axis WTGs would be used, comprising the following main components, as illustrated in **Plate 5.1**:

- Rotor, comprising:
  - Blades
  - Hub – which connects the blades to the horizontal shaft and the drive train contained within the nacelle assembly
- Nacelle assembly – which houses the electrical generator, control electronics and drive system
- Structural support – tubular steel tower atop a foundation structure

5.22 The nacelle assembly and hub assembly is secured at the top of the tower. **Plate 5.1** presents a typical WTG, with the design envelope for WTGs presented in **Table 5.2**.

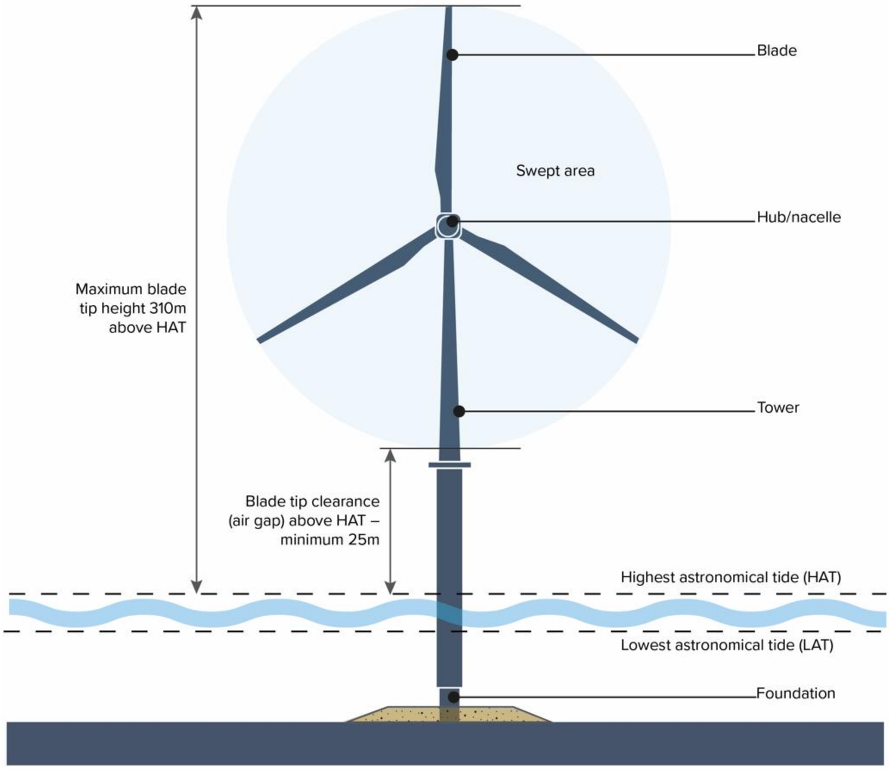

Plate 5.1 Schematic of a WTG

Table 5.2 WTG design envelope

Parameter	Smaller WTGs	Larger WTGs
Maximum number of WTGs	35	30
Maximum rotor diameter (m)	260	280
Maximum blade tip height (m) above highest astronomical tide (HAT)	290	310
Maximum hub height (m above HAT)	160	170
Minimum rotor clearance above sea level (m above HAT)	25[4]	
Indicative rotor speed (rotations per minute (RPM))	8.42	7.09

[4] Equivalent to 34.56m above LAT; 26.07m above MHWS; 29.82m above mean sea level (MSL)

Parameter	Smaller WTGs	Larger WTGs
Maximum rotor swept area for total windfarm site (m^2)	1,858,252	
Minimum separation between WTGs (m) in-row	1,060	1,260
Minimum separation between WTGs (m) inter-row	1,410	1,680

5.5.1.2 WTG layout options

5.23 The layout of the WTGs would be finalised post-consent, in consideration of design rules (as detailed in Marine Guidance Note (MGN) 654) (MCA, 2021a) and in consultation with relevant authorities e.g. MMO, Maritime and Coastguard Agency (MCA) and Trinity House (TH). The required lighting and navigational markings would also be agreed post-consent.

5.24 Exact WTG locations are not included in the DCO Application. This is due to the requirement for flexibility on layout pending further ground investigation, detailed design and commercial negotiations, and is one of the purposes of developing a PDE (as outlined in **Section 5.2**). In developing the final layout, the Applicant would aim to minimise environmental impacts (e.g. through micro-siting if required) and impacts to other users whilst maximising energy yield and cost efficiency.

5.25 The WTG layout can be described in general terms at this stage. It would have some form of regularity in plan (two lines of orientation), i.e., WTGs would be set out in a regular pattern such that they were aligned in two straight, intersecting rows (**Plate 5.2**).

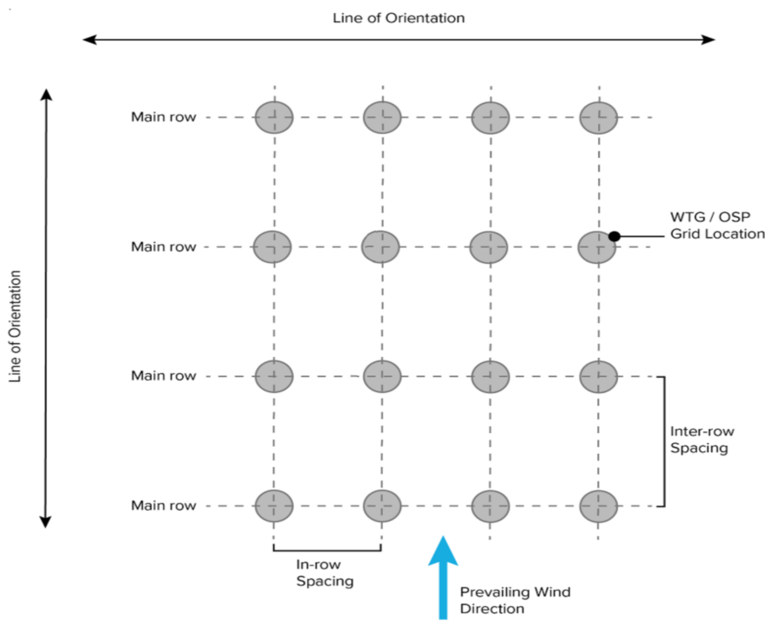

Plate 5.2 Schematic illustrating two lines of orientation and grid spacing terminology

5.26 In-row spacing is the distance separating WTGs in the main rows, which are generally orientated perpendicular to the prevailing wind, or as close to this as is practicable (**Plate 5.2**). Inter-row spacing is the distance between the main rows.

5.27 The minimum WTG separation (defined by the smaller WTGs) is 1,060m for in-row spacing and 1,410m for inter-row spacing. Minimum separation distances are included to allow for any micro-siting requirements due to, for example, seabed conditions or obstacles. Final separation distances may be greater.

5.28 It should also be noted there may be locations within the regular grid of WTGs left unoccupied. This could be due to less favourable ground conditions or exclusion distances from existing infrastructure.

5.29 For each of the relevant chapters (namely, **Chapter 18 Seascape, Landscape and Visual Impact Assessment** (Document Reference 5.1.18), **Chapter 17 Infrastructure and Other Users** (Document Reference 5.1.17), **Chapter 16 Civil and Military Aviation and Radar** (Document Reference 5.1.16) and **Chapter 14 Shipping and Navigation** (Document Reference 5.1.14)) a worst-case layout is defined and presented, to highlight the layout that underpins each assessment.

5.5.2 Offshore substation platforms

5.30 The Project would require up to two OSPs, depending on the electrical system voltage and final layout. The OSPs provide a centralised connection point for the inter-array cable circuits and contain primary electrical equipment, and ancillary components, that are required to transform the voltage of the electricity generated at the WTGs to a higher voltage suitable for transporting power to the onshore electrical transmission network.

5.31 The OSP(s) would be situated within the windfarm site and would comprise the following components:

- Transformers
- Batteries
- Generators
- Switchgear
- Fire systems
- Modular facilities for operational and maintenance activities

5.32 The design of the OSP(s) would include a platform ‘topside’, supported above sea level on a foundation structure.

5.33 The typical deck plan of the OSP(s) topside would be a maximum of 50m by 50m, with the topsides comprising several layers/decks stacked on top of each another, as required. **Plate 5.3** shows a schematic of a typical OSP.

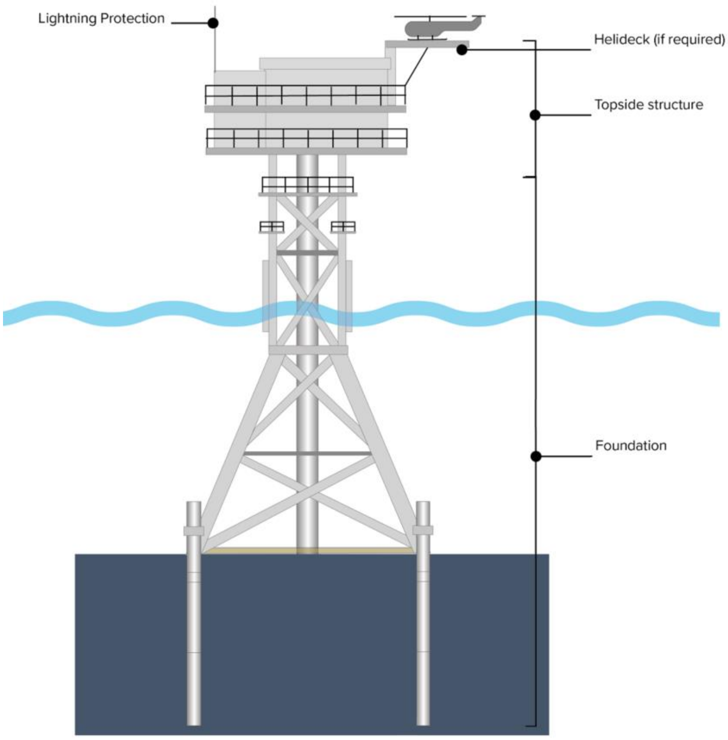

Plate 5.3 Schematic of an OSP. Note: The schematic shows a 'jacket on pin piles' foundation, however, the actual foundation type may differ e.g. monopile.

5.34 The design envelope for the OSP(s) topside(s) is given in **Table 5.3**. The potential OSP (and WTG) foundation structure design envelope parameters are listed in **Section 5.5.3**.

Table 5.3 OSP(s) topside design envelope

Parameter	Value
Maximum number of OSP(s)	2
Maximum topside width (m)	50
Maximum topside length (m)	50
Highest point of topside above HAT (m) (excluding helideck and lightning protection)	50
Highest point of topside above HAT (m) (including helideck and lightning protection)	70

5.5.2.1 Repurposing existing oil and gas facilities

5.35 In the Project Scoping Report, the potential to repurpose oil and gas infrastructure as an OSP for the Project was discussed. Following a study of the existing infrastructure, this option was discounted due to structural integrity risks given the current age of the infrastructure and the design life of the windfarm. It is therefore not considered any further.

5.5.3 Foundations

5.36 This section provides detail on the foundations and substructures that are under consideration and assessed for the WTGs and OSP(s). The decision on the types of foundation and substructure to support the WTGs and OSP(s) would be made post-consent.

5.37 Foundation types would be selected following detailed design, based on suitability of the ground conditions, water depths and WTG/OSP models or design. There may be only one type used, or a combination of foundation types may be used across the windfarm site.

5.38 The following foundation types, as shown in **Plate 5.4**, are currently being considered for use:

- Gravity Base Structure (GBS) (**Section 5.5.3.1**)
- Multi-legged pin-piled jacket (three-legged or four-legged jackets) (**Section 5.5.3.2**)
- Monopile (**Section 5.5.3.3**)
- Multi-legged suction bucket jacket (three-legged jackets) (**Section 5.5.3.4**)

5.39 The design envelopes for individual foundation types are given in **Section 5.5.3.1** to **Section 5.5.3.4**, with the maximum design parameters presented (based on either 35 smaller WTGs or 30 larger WTGs, as applicable). The installation of foundations is discussed in **Section 5.6.3**.

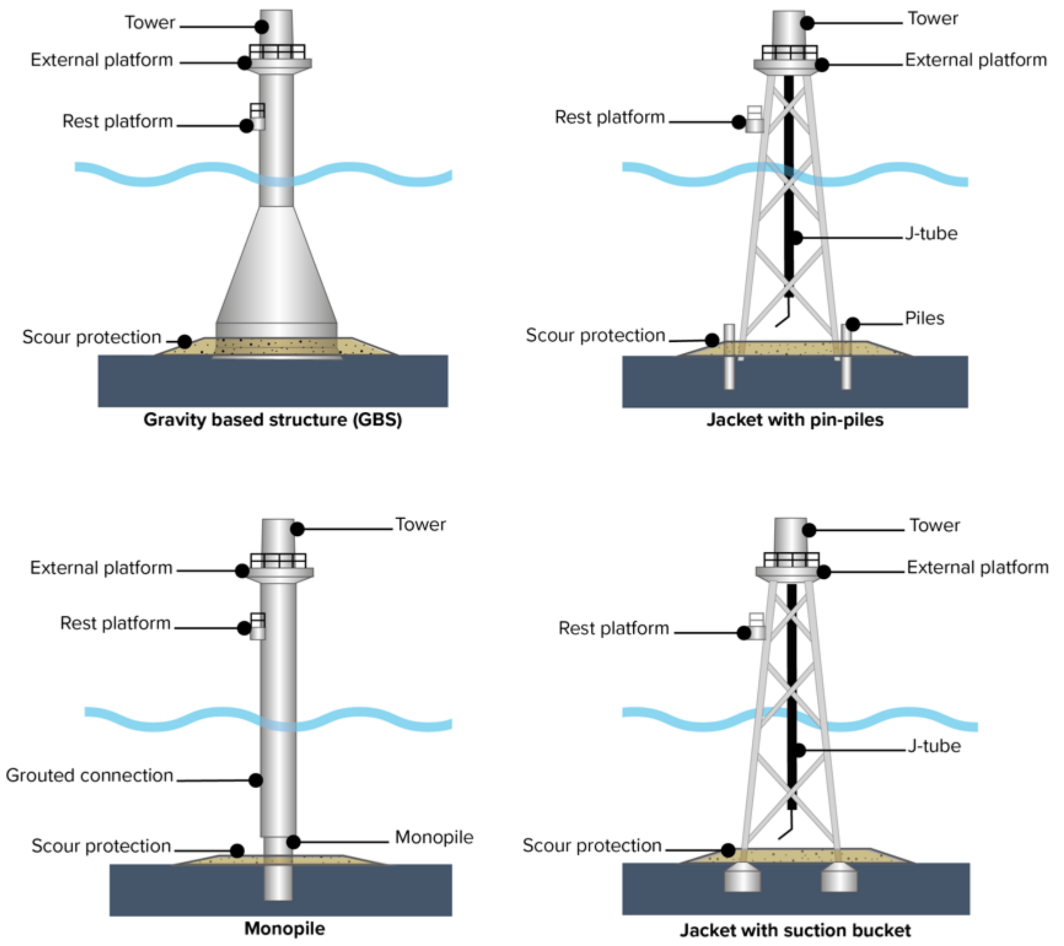

Plate 5.4 WTG/OSP foundation options

5.5.3.1 Gravity-based structures

5.40 There are many possible shapes and sizes being proposed by manufacturers for GBS. GBS usually comprise a base supporting a conical section, which tapers to an upper cylindrical section (shaft) (**Plate 5.4**). Usually the base is hexagonal, octagonal or circular, although shape and size can vary widely.

5.41 GBS adopt a mudmat foundation to achieve permanent vertical and lateral stability under their own weight. A mudmat foundation provides support on the seabed to prevent the foundation from sinking into the seabed. This foundation type is most sensitive to the seabed profile, as no post-installation structure levelling is possible. Where seabed soils are soft, a larger mudmat surface area is required.

5.42 GBS may also include a skirt at their base that penetrates the seabed, adding stability. Under base grouting may also be used, to strengthen the soil beneath the foundation and to fill small voids between the foundation and the seabed.

5.43 GBS are generally fabricated from steel reinforced concrete, ballasted with heavy material, such as rock. Secondary structures, such as handrails, ladders, working platforms etc., may be produced from a range of materials such as steel, concrete, aluminium, other metals and composites.

5.44 The GBS foundation design envelope is outlined in **Table 5.4**. Design envelope parameters for scour protection associated with GBS foundations are detailed in **Section 5.5.3.5**.

Table 5.4 GBS structure WTG/OSP design envelope

Parameter	Value
Maximum base slab diameter (m)	65
Maximum cone bottom diameter (m)	55
Maximum cone top/shaft diameter (m)	15
Maximum cone height (m)	40
Maximum footprint on the seabed per WTG/OSP[5] (m^2)	3,318
Maximum footprint on the seabed for total WTGs/OSPs (m^2)	122,766 (116,130m^2 for 35 WTGs[6] and 6,636m^2 for 2 x OSPs)

5.5.3.2 Multi-legged pin-piled jacket (four-legged[7])

5.45 Jackets with pin-piled foundations are a steel lattice construction (tubular steel and welded joints) secured to the seabed by hollow steel or concrete pin piles (**Plate 5.4**). Each jacket would have up to four legs, supported by pin piles. Pin piles are driven into the seabed using hydraulic piling hammers and/or vibrational methods or a combination of piling and drilling. Secondary structures, such as handrails, ladders, working platforms etc., may be produced from a range of materials, such as steel, aluminium, other metals and composites.

5.46 The design parameters for jacket with pin-piled foundations are shown in **Table 5.5**. Design envelope parameters for scour protection associated with multi-legged pin-piled jacket foundations are detailed in **Section 5.5.3.5**.

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[5] A circular base is assumed as a worst-case.

[6] Noting that both smaller and larger WTGs have the same GBS foundation footprint.

[7] There is a three-legged option, however the foundation design envelope is encompassed by the four-legged option.

Table 5.5 Multi-legged pin-piled jacket WTG/OSP foundation design envelope

Parameter	Value
Maximum legs per jacket foundation	4
Maximum pile diameter (m)	3
Maximum leg spacing at seabed (m)	35
Maximum footprint on the seabed, pile-edge to pile-edge, per WTG/OSP (m^2)	28.5
Maximum footprint on the seabed for total WTGs/OSPs (m^2)	1,055 (998m^2 for 35 x WTGs and 57m^2 for 2 x OSPs)
Maximum pile penetration depth (m)	56

5.5.3.3 Monopile

5.47 Monopile foundations are welded hollow tubular steel structures (**Plate 5.4**) driven into the seabed using hydraulic piling hammers and/or vibrational methods or a combination of piling and drilling. The piles support the weight of the tower and WTG or OSP and rely on the surrounding geology to provide lateral resistance to horizontal forces, such as wind and waves.

5.48 Monopiles are fabricated from steel, with a number of secondary structures on the associated transition pieces (TPs), such as handrails, ladders, working platforms etc. These secondary structures may be produced from a range of materials such as steel, concrete, aluminium, other metals and composites. The TP facilitates the connection between the foundation and the tower and may be either steel or concrete.

5.49 Monopile foundation design envelope parameters are provided in **Table 5.6.** Design envelope parameters for scour protection associated with monopile foundations are detailed in **Section 5.5.3.5**.

Table 5.6 Monopile WTG/OSP foundation design envelope

Parameter	Value
Maximum pile diameter (m)	12
Maximum footprint on the seabed per WTG/OSP (m^2)	114
Maximum footprint on the seabed for total WTGs/OSPs (m^2)	3,648 (3,420m^2 for 30 x WTGs and 228m^2 for 2 x OSPs)
Maximum pile penetration depth (m)	56

5.5.3.4 Multi-legged suction bucket jacket (three-legged jackets)

5.50 A jacket foundation on suction buckets may be used. This would consist of a jacket that would be installed on three suction bucket 'legs' (**Plate 5.4**). These buckets are installed by providing suction to pump out entrained water within the bucket, creating a vacuum and thereby forcing the suction bucket into the seabed, without the use of additional mechanical force. Initially, suction bucket foundations are lowered to the seabed and allowed to self-penetrate under their own weight, followed by pumping water.

5.51 The design envelope for jacket with suction buckets foundation is given in **Table 5.7**. Design envelope parameters for scour protection associated with multi-legged suction bucket jacket foundations are detailed in **Section 5.5.3.5**.

Table 5.7 Multi-legged suction bucket jacket WTG/OSP foundation design envelope

Parameter	Value
Maximum legs per suction bucket (jacket) foundation	3
Maximum bucket diameter (m)	20
Maximum leg spacing at seabed (m)	35
Maximum footprint on the seabed per WTG/OSP (m^2)	945
Maximum footprint on the seabed for WTGs/OSPs (m^2)	34,965 (33,075m^2 for 35 x WTGs and 1,890m^2 for 2 x OSPs)
Maximum bucket penetration depth (m)	25

5.5.3.5 Scour protection

5.52 Foundations may require scour protection to avoid sediment being eroded away from the base of the foundations as a result of the flow of water. Scour protection requirements are built into the design assumptions for each foundation type in consideration.

5.53 Scour protection involves the installation of a layer of material around the base of a foundation to prevent sediment erosion. Materials include, but are not limited to, the use of bagged solutions filled with grout or other materials, protective aprons, mattresses with or without frond devices, and rock, concrete and gravel placement.

5.54 Scour protection material for WTG/OSP foundation structures can be applied before, after or at the same time as the installation of the foundations.

5.55 For scour protection around foundations, typically, rock berms are used and installed from a vessel, via a directional chute. The rock berm consists of an outer armour layer and filter layer, with grading determined by waves and current. Filter layer rock is classed as an intermediate layer of protection against waves and currents. The filter layer is comprised of smaller diameter material, preventing finer materials of the seabed being washed through the voids of the outer armour layer. The armour layer is comprised of larger diameter material than the filter layer and forms the outer layer of protection (against hydrodynamic loading and third-party impact).

5.56 The design envelope for scour protection for each foundation type are given in **Table 5.8.**

5.57 The exact requirements for scour protection would be identified post-consent, prior to the start of construction, based on the final WTG and OSP locations and detailed site surveys.

Table 5.8 Design envelope for scour protection for WTG/OSP foundations

Parameter	Value
GBS	
Maximum height of scour protection per WTG/OSP (m)	2
Maximum footprint on the seabed of scour protection per WTG/OSP (excluding foundation structure) (m^2)	3,770
Maximum footprint on the seabed of scour protection for total WTGs/OSPs (excluding foundation structure) (m^2)	139,490 (131,950m^2 for 35 x WTGs and 7,540m^2 for 2 x OSPs)
Maximum volume of scour protection per WTG/OSP (excluding foundation structure) (m^3)	7,540
Maximum volume of scour protection for total WTGs/OSPs (excluding foundation structure) (m^3)	278,980 (263,900m^3 for 35 x WTGs and 15,080m^3 for 2 x OSPs)
Multi-legged pin-piled jacket (four-legged jackets; encompassing three-legged jackets)	
Maximum height of scour protection per WTG/OSP (m)	2
Maximum footprint on the seabed of scour protection per WTG/OSP (excluding foundation structure) (m^2)	990

Parameter	Value
Maximum footprint on the seabed of scour protection for total WTGs/OSPs (excluding foundation structure) (m^2)	36,630 (34,650m^2 for 35 x WTGs and 1,980m^2 for 2 x OSPs)
Maximum volume of scour protection per WTG/OSP (excluding foundation structure) (m^3)	1,980
Maximum volume of scour protection for total WTGs/OSPs (excluding foundation structure) (m^3)	73,260 (69,300m^3 for 35 x WTGs and 3,960m^3 for 2 x OSPs)
Monopile	
Maximum height of scour protection per WTG/OSP (m)	2
Maximum footprint on the seabed of scour protection per WTG/OSP (excluding foundation structure) (m^2)	3,958
Maximum footprint on the seabed of scour protection for total WTGs/OSPs (excluding foundation structure) (m^2)	126,656 (118,740m^2 for 30 x WTGs, 7,916m^2 for 2 x OSPs
Maximum volume of scour protection per WTG/OSP (excluding foundation structure) (m^3)	7,916
Maximum volume of scour protection for total WTGs/OSPs (excluding foundation structure) (m^3)	253,312 (237,480m^3 for 30 x WTGs and 15,832m^3 for 2 x OSPs)
Multi-legged suction bucket jacket (three-legged jacket)	
Maximum height of scour protection per WTG/OSP (m)	2
Maximum footprint on the seabed of scour protection per WTG/OSP (excluding foundation structure) (m^2)	2,828
Maximum footprint on the seabed of scour protection for total WTGs/OSPs (excluding foundation structure) (m^2)	104,636 (98,980m^2 for 35 x WTGs and 5,656m^2 for 2 x OSPs)
Maximum volume of scour protection per WTG/OSP (excluding foundation structure) (m^3)	5,656

Parameter	Value
Maximum volume of scour protection for total WTGs/OSPs (excluding foundation structure) (m^3)	209,272 (197,960m^3 for 35 x WTGs and 11,312m^3 for 2 x OSPs)

5.5.3.6 Summary

5.58 A summary of the maximum footprint on the seabed of each foundation option outlined in **Sections 5.5.3.1** – **5.5.3.4**, as well as scour protection footprints and volumes is presented in **Table 5.9**.

Table 5.9 WTG/OSP foundation and scour protection summary

Foundation type	Maximum foundation footprint on the seabed for total WTGs/OSPs (m^2)	Maximum scour protection footprint on the seabed for total WTGs/OSPs (excludes foundation structures) (m^2)	Maximum volume of scour protection for total WTGs/OSPs (excludes foundation structures) (m^3)
GBS	122,766 (116,130m^2 for 35 WTGs and 6,636m^2 for 2 x OSPs)	139,490 (131,950m^2 for 35 x WTGs and 7,540m^2 for 2 x OSPs)	278,980 (263,900m^3 for 35 x WTGs and 15,080m^3 for 2 x OSPs)
Multi-legged pin-piled jacket (four-legged)	1,055 (998m^2 for 35 x WTGs and 57m^2 for 2 x OSPs)	36,630 (34,650m^2 for 35 x WTGs and 1,980m^2 for 2 x OSPs)	73,260 (69,300m^3 for 35 x WTGs and 3,960m^3 for 2 x OSPs)
Monopile	3,648 (3,420m^2 for 30 x WTGs and 228m^2 for 2 x OSPs)	126,656 (118,740m^2 for 30 x WTGs, 7,916m^2 for 2 x OSPs	253,312 (237,480m^3 for 30 x WTGs and 15,832m^3 for 2 x OSPs)
Multi-legged suction bucket jacket (three-legged)	34,965 (33,075m^2 for 35 x WTGs and 1,890m^2 for 2 x OSPs)	104,636 (98,980m^2 for 35 x WTGs and 5,656m^2 for 2 x OSPs)	209,272 (197,960m^3 for 35 x WTGs and 11,312m^3 for 2 x OSPs)

5.5.4 Cables

5.5.4.1 Inter-array cables

5.59 Subsea inter-array cables would be installed to connect the individual WTGs and also connect the WTGs to the OSP(s).

5.60 Where possible, inter-array cables would be buried, with depth of burial expected to be between 0.5 and 3m and a target burial depth of 1.5m. Where cable burial is not possible, alternative cable protection measures would be used. This may include rock placement, grout/sandbags, concrete mattresses, and polyethylene ducting (refer to **Section 5.5.4.3**). The appropriate level of protection would be determined based on an assessment of the risks posed to the Project in specific areas. It is assumed that 10% of the inter-array cable length would require additional cable protection due to ground conditions. This assumption is supported by initial assessments as provided in the Outline Scour Protection and Cable Protection Plan (Document Reference 6.8). Cable crossings would also be required, where inter-array cables pass over other cables and/or pipelines. These are outlined in more detail in **Section 5.5.4.3**.

5.61 The inter-array cables are expected to operate at 66kV or 132kV alternating current (AC). It is expected that 132kV AC cables may not be sufficiently ready or available, on an industry-wide level, for installation, but this higher voltage has been retained, pending further electrical studies.

5.62 The outer diameter of the inter-array cables may be up to 220mm. The design envelope for the inter-array cables is given in **Table 5.10**.

Table 5.10 Inter-array cable design envelope

Parameter	Value
Maximum length of inter-array cables (km)	70
Burial depth range (m)	0.5 – 3 (target burial depth of 1.5)
Maximum installation corridor disturbance width (m)	25
Unburied cable parameters	
Maximum height protection (m)	2
Maximum width protection (m)	13
Anticipated % cable unburied due to ground conditions[8]	10

[8] The percentage of cable that remains unburied due to ground conditions is dependent on the results of a cable burial survey. As such, 10% has been used a worst-case assumption.

Parameter	Value
Estimated total length of unburied cable due to ground conditions (km)	7

5.5.4.2 Platform link cables

5.63 Should the Project require two OSPs, then platform link cables would be required to connect each of the OSPs, to enable transfer of generated power from one OSP to the other, and to ensure that electricity transmission can continue in the event of one cable failing. The platform link cables are expected to operate at up to 275kV AC.

5.64 It is assumed that 10% of the platform link cable length would require additional cable protection due to ground conditions. This assumption is supported by initial assessments as provided in the Outline Scour Protection and Cable Protection Plan (Document Reference 6.8).

5.65 Cable crossings would also be required, where platform link cables pass over other cables and/or pipelines. These are outlined in more detail in **Section 5.5.4.3**.

5.66 The design envelope for potential platform link cables is given in **Table 5.11**.

Table 5.11 OSP(s) platform link cable design envelopes

Parameter	Value
General parameters	
Maximum number of cables	2
Maximum length of cable (per cable) (km)	5
Maximum number of cable trenches	2
Maximum total length of all cable trenches (km)	10
Burial depth range (m)	0.5 – 3 (target burial depth of 1.5)
Maximum installation corridor disturbance width (m)	25
Unburied cable parameters	
Maximum height protection (m)	2
Maximum width protection (m)	13

Parameter	Value
Anticipated % cable unburied due to ground conditions[9]	10
Estimated total length of unburied cable due to ground conditions (km)	1

5.5.4.3 Cable protection and cable/pipeline crossings

5.67 As described above, cables would require protection where they cannot be buried due to ground conditions. Additionally, cables would require protection at cable/pipeline crossings and at entry points to the WTGs/OSPs. Cable protection requirements are built into the design assumptions for both inter-array and platform link cables.

5.68 The exact requirements for cable protection would be identified post-consent, prior to the start of construction, based on the final WTG and OSP locations and detailed site surveys.

5.69 Typical options for cable protection include one, or a combination of, the following examples:

- Rock berms or gravel bags
- Concrete mattresses
- Bagged solutions (including geotextile sand containers, rock-filled gabion bags or nets, and grout bags)
- Flow energy dissipation devices (used to describe various solutions that dissipate the flow of energy and entrap sediment, including options such as frond mats, mats of large linked hoops, and structures covered with long spines)

5.70 Concrete mattresses are typically linked concrete blocks 150mm, 300mm or 450mm thick (the thickness used depends on the level of protection required), in a ‘mattress’ of approximately 6m length and 3m width.

5.71 **Plate 5.5** shows a schematic section of a typical rock berm cable protection, for illustrative purposes only. Rock placement configuration for cable protection typically has a berm profile of 3:1, with the total rock berm height from the surrounding seabed of up to 2.0m, with a crest width of 1m and an overall width of 13m.

[9] The percentage of cable that remains unburied due to ground conditions is dependent on the results of a cable burial survey. As such, 10% has been used a worst-case assumption.

5.72 The design envelope for cable protection for inter-array and platform link cables is given in **Table 5.12,** noting key input parameters in relation to unburied cables are also presented in **Table 5.10** and **Table 5.11**. This design envelope reflects the anticipated cable protection required due to ground conditions and at the entry to the WTGs and OSP(s).

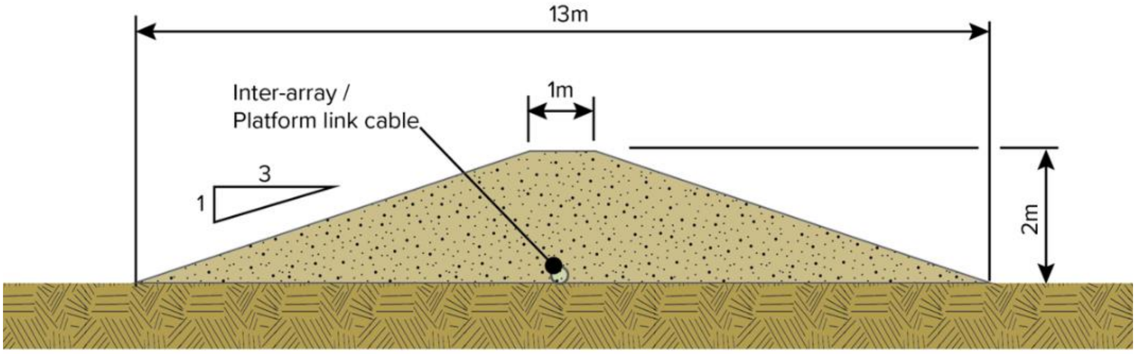

Plate 5.5 Schematic of rock berm cable protection

Table 5.12 Design envelope for cable protection for inter-array and platform link cables (protection due to ground conditions and at entry to WTGs/OSPs)

Parameter	Value
Inter-array cable protection due to ground conditions	
Maximum length of protected cable unburied due to ground conditions (m)	7,000
Maximum width of rock berm protection at the bottom (m)	13
Maximum height of rock berm protection (m)	2
Maximum width at top of rock berm protection (m)	1
Side slope	3:1
Maximum seabed footprint of protection material for inter-array cables (m^2)	91,000
Maximum volume of cable protection (m^3)	98,000
Platform link cable protection due to ground conditions	
Maximum length of protected cable unburied due to ground conditions (m)	1,000
Maximum width of rock berm protection at the bottom (m)	13
Maximum height of rock berm protection (m)	2

Parameter	Value
Maximum width at top of rock berm protection (m)	1
Side slope	3:1
Maximum seabed footprint of protection material for platform link cables (m^2)	13,000
Maximum volume of cable protection (m^3)	14,000
Cable protection at entry of cables to WTGs/OSPs	
Number of entry points to WTGs and OSPs	70
Maximum length of cable protection required at each entry point (m)	50
Maximum length of protected cable (m)	3,500
Maximum width of rock berm protection at the bottom (m)	13
Maximum width at top of rock berm protection (m)	1
Maximum height of berm protection (m)	2
Side slope	3:1
Maximum seabed footprint of protection material for entry to total WTG/OSPs (m^2)	45,500
Maximum volume of cable protection (m^3)	49,000
Total inter-array and platform link cable protection (due to ground conditions and at entry of cables to WTGs/OSPs)	
Maximum length of protected cable (m)	11,500
Maximum seabed footprint of cable protection (m^2)	149,500
Maximum volume of cable protection (m^3)	161,000

5.73 It is anticipated that there could be up to nine cable/pipeline crossings required for inter-array cables, and up to six crossings for platform link cables within the windfarm site. Cable protection would be required at the crossings (and is additional to the cable protection requirements set out in **Table 5.12**).

5.74 **Plate 5.6** shows a schematic of a typical section of a cable/pipeline crossing, for illustrative purposes only. The design envelope for cable/pipeline crossings is given in **Table 5.13**.

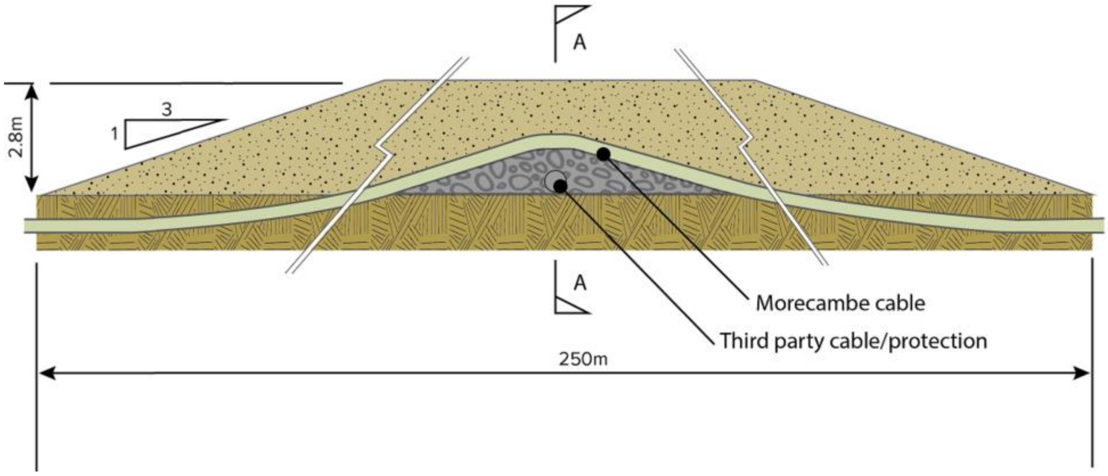

Plate 5.6 Schematic of a cable/pipeline crossing

Table 5.13 Cable/pipeline crossings design envelope

Parameter	Value
Maximum number of cable/pipeline crossings	15 (9 for inter-array cables, 6 for platform link cables)
Maximum cable/pipeline crossing height per crossing (m)	2.8
Maximum side slope	3:1
Maximum cable/pipeline crossing top width (m)	1
Maximum cable/pipeline crossing bottom width per crossing (m)	17.8
Maximum cable/pipeline crossing length per crossing (m)	250
Maximum cable/pipeline crossing seabed footprint per crossing (m^2)	4,450
Maximum cable/pipeline crossing seabed footprint for all crossings (m^2)	66,750
Maximum cable/pipeline crossing volume per crossing (m^3)	6,580
Maximum cable/pipeline crossing volume for all crossings (m^3)	98,700

5.5.5 Navigational markers

5.75 With respect to lighting and marking, the WTGs and OSP(s) topsides would be designed and constructed to satisfy the requirements of the Civil Aviation Authority (CAA), MCA, TH, and the Ministry of Defence (MOD), as required.

5.76 The colour scheme for nacelles, blades and towers is expected to be RAL 7035 (light grey), unless otherwise specified, and foundation steelwork RAL 1023 (traffic yellow) from Highest Astronomical Tide (HAT) up to a minimum of 15m, to be determined by the relevant requirements and guidance at the time.

5.77 Lighting requirements would follow the MCA (2021b) guidance, Offshore Renewable Energy Installations: Requirements, Guidance and Operational Considerations for Search and Rescue and Emergency Response. This would ensure that adequate consideration with regard to lighting of offshore structures is given for Search and Rescue and Emergency Response.

5.78 Further details, including reference to the relevant guidance and regulations, is presented in **Chapter 14 Shipping and Navigation** and **Chapter 16 Civil and Military Aviation and Radar**.

5.6 Construction

5.79 This section summarises the construction and installation of the main components of the Project. A detailed construction programme for the Project has not yet been developed, however, construction and installation are anticipated to last for 2.5 years. An indicative construction sequencing is given below, with indicative timeframes outlined in **Plate 5.7**.

- Detailed pre-construction site investigations (e.g. cone penetration tests, boreholes and high-resolution geophysical surveys)
- Pre-installation works (**Section 5.6.2**)
- Installation of foundations (**Section 5.6.3**)
- Installation of TPs (if applicable)
- Installation of OSP topsides (**Section 5.6.5**)
- Installation of inter-array cables (**Section 5.6.6**)
- Installation of platform link cables (**Section 5.6.6**)
- Installation of WTGs (**Section 5.6.4**)

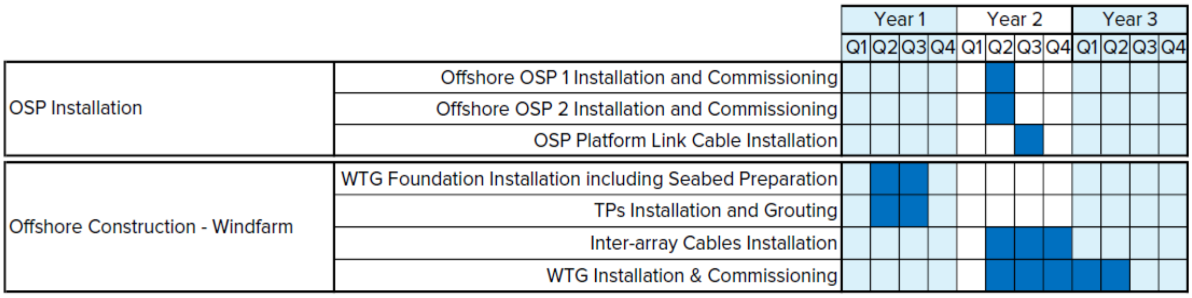

Plate 5.7 Indicative construction schedule

5.80 Offshore operations during the construction phase would typically be performed on a 24-hour basis, depending on suitable construction weather windows. During construction, there would be a minimum 500m radius safety zones around installation vessels, foundation structures, WTGs and OSP(s). A 50m radius safety zone would be established where major construction work has finished, but some works are ongoing (i.e. commissioning).

5.6.1 Vessels and helicopters

5.81 The number and specification of vessels employed during the construction of the Project would be determined by the marine contractor and the construction strategy, following successful consent to construct the Project. It is anticipated that several types of construction vessel could work in parallel during the construction period. During construction, it is estimated there would be up to 2,583 annual return vessel trips to deliver and install the main components to the windfarm site, to undertake cable installation and for support and crew vessels. Overall, a maximum number of 37 vessels are expected on site at any one time.

5.82 The final selection of the port facilities required to construct and operate the Project has not yet been determined, however it is assumed the construction port would be in the United Kingdom (UK) and the operational port would be within 50km of the windfarm site.

5.83 An indicative vessel type (jack-up) required during the construction and operation stages is shown in **Plate 5.8**.

5.84 In addition, it is estimated that a total number of 800 helicopter return trips would be needed over the construction period to facilitate crew changes of construction vessels. It is anticipated that helicopters would travel from Blackpool or Liverpool, however this is indicative at this stage and may be subject to change.

Plate 5.8 Example jack-up vessel used for WTG installation - Vole au vent (Morecambe Offshore Windfarm Ltd, 2023) Credit: Jon Ruszka

5.6.2 Pre-installation works

5.6.2.1 Pre-construction surveys

5.85 Geotechnical and geophysical surveys have been undertaken to support this ES and design development to date. Further surveys are planned to support the evolution of foundation design, installation methodology and pre-installation requirements. Pre-construction surveys would also include further UXO identification surveys.

5.86 These surveys are not part of the ES/DCO Application scope and separate licences would be obtained for such surveys, as required.

5.6.2.2 Unexploded ordnance clearance

5.87 Micro-siting of Project infrastructure would be adopted to avoid UXO where possible. Where avoidance is not possible for any reason, clearance activities may be required to safely remove or detonate any UXO that present a hazard to the construction activities, or the ongoing operation of the windfarm. Such clearance techniques could involve detonation, relocation or retrieval, with the implementation of appropriate safety zones. Low impact clearance techniques would be used where possible, e.g. low order deflagration.

5.88 UXO clearance works would be the subject of separate marine licence application(s) prior to the start of construction, once further details of the requirements are known.

5.6.2.3 Seabed preparation

5.89 As part of the pre-installation works, there may be some seabed preparation, such as removal of surface debris, removal of sub-surface debris, removal of out-of-service telecommunication cables, boulder clearance, sandwave clearance, ground reinforcement and seabed levelling.

5.90 Boulder clearance would be undertaken along the inter-array and platform link cable routes, at WTG and OSP foundation locations, and at jack-up vessel leg locations. The removal of boulders would be undertaken from a vessel, which can be performed using either a pre-lay plough (in areas of high density of boulders) or a subsea grab (in areas of low density of boulders or areas of high slopes) or via remotely operated vehicles (ROVs). Larger boulders are generally cleared by V-shaped ploughs or surface grabs, and smaller items removed by ROVs. Pre-lay ploughs are pulled along the seabed to clear the seabed, whereas subsea grabs pick up and then relocate boulders away from installation areas. The number and size of boulders would be identified during future geophysical surveys, however, survey data to date shows there is a low prevalence of boulders. It is currently assumed that clearance (25m in width) along cable corridors are required for boulder clearance.

5.91 Before cable-laying operations and foundation installation commence, it would be necessary to ensure that the area is free from obstructions, such as discarded trawling gear and abandoned cables identified during the pre-construction survey. A survey vessel would be used to clear all such identified debris, in a pre-lay grapnel run (PLGR). If the grapnel tool cannot remove all obstructions completely, some hydraulic removal works, or ploughing, may take place.

5.92 Levelling and excavation may be required to provide a suitable surface for cable laying and WTG/OSP foundation installation. Methods for such seabed preparation include dredging using a suction hopper dredger, grab dredger or backhoe dredger, specialist bed-leveller or ploughing. Where possible, WTGs/OSP(s), inter-array and platform link cables would avoid areas of sand waves. Where sand waves cannot be avoided, a track through the sand waves would be excavated, likely using a plough, and levelled to allow the cables to be installed below stable seabed level. The volume of sediment removed during seabed preparation/installation activities would be disposed of adjacent to the foundation/cable location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation/cable.

5.93 The design envelope for seabed preparation works (including sandwave clearance) for WTG/OSP foundations are given in **Table 5.14** and for inter-array and platform link cables in **Table 5.15.**

5.94 It is assumed that up to 10% of inter-array and platform link cable length would require excavation/sandwave clearance. For WTG/OSP foundations, it is assumed that seabed preparation would be required at each location and includes sandwave clearance.

Table 5.14 Design envelope for seabed preparation works for WTG and OSP foundations

Parameter	Value
GBS	
Maximum seabed preparation dimensions (diameter) (m)	85
Maximum seabed preparation footprint per WTG/OSP foundation[10] (m^2)	8,675
Maximum seabed preparation footprint for total WTGs & OSPs (m^2)	320,975 (303,625m^2 for 35 x WTGs and 17,350m^2 for 2 x OSPs)
Maximum depth of seabed preparation	1.5
Maximum seabed volume removed per foundation (m^3)	13,013
Maximum seabed volume removed for total WTGs & OSPs (m^3)	481,463 (455,438m^3 for 35 x WTGs and 26,025m^3 for 2 x OSPs)
Multi-legged pin-piled jacket (four-legged jacket)	
Maximum seabed preparation footprint per WTG/OSP foundation[11] (m^2)	3,707
Maximum seabed preparation footprint for total WTGs & OSPs (m^2)	137,159 (129,745m^2 for 35 x WTGs and 7,414m^2 for 2 x OSPs)
Maximum depth of seabed preparation (m)	1
Maximum seabed volume removed per foundation (m^3)	3,707

[10] Assumes GBS diameter of 65m plus 10m either side for seabed preparation area for WTG/OSP + footprint for one jack-up at two positions per foundation (2 x (6 legs x 250m^2 (per leg)))

[11] Assumes 5 x pin pile diameter (x 4 pin piles) for seabed preparation area for WTG/OSP + footprint for one jack-up at two positions per foundation (2 x (6 legs x 250m^2 (per leg)))

Parameter	Value
Maximum seabed volume removed for total WTGs & OSPs (m^3)	137,159 (129,745m^3 for 35 x WTGs and 7,414m^3 for 2 x OSPs)
Monopile	
Maximum seabed preparation footprint per WTG/OSP foundation[12] (m^2)	3,707
Maximum seabed preparation footprint for total WTGs & OSPs (m^2)	137,159 (129,745m^2 for 35 x WTGs and 7,414m^2 for 2 x OSPs)
Maximum depth of seabed preparation (m)	1
Maximum seabed volume removed per foundation (m^3)	3,707
Maximum seabed volume removed for total WTGs & OSPs (m^3)	137,159 (129,745m^3 for 35 x WTGs and 7,414m^3 for 2 x OSPs)
Multi-legged suction bucket jacket	
Maximum seabed preparation footprint per WTG/OSP foundation[13] (m^2)	6,770
Maximum seabed preparation footprint for total WTGs & OSPs (m^2)	250,490 (236,950m^2 for 35 x WTGs and 13,540m^2 for 2 x OSPs)
Maximum depth of seabed preparation (m)	1
Maximum seabed volume removed per foundation (m^3)	6,770
Maximum seabed volume removed for total WTGs & OSPs (m^3)	250,490 (236,950m^3 for 35 x WTGs and 13,540m^3 for 2 x OSPs)

[12] Assumes 2.5 x pile diameter for seabed preparation area for WTG/OSP + footprint for one jack-up at two positions per foundation (2 x (6 legs x 250m^2 (per leg)))

[13] Assumes 2 x bucket diameter (x 3 legs) for seabed preparation area for WTG/OSP + footprint for one jack-up at two positions per foundation (2x (6 legs x 250m^2 (per leg)))

Table 5.15 Design envelope for sand wave clearance/levelling for inter-array and platform link cables

Parameter	Value
Inter-array cables	
Maximum length of cable requiring sandwave clearance / levelling (10% of total length) (m)	7,000
Maximum width of sandwave levelling (m)	10
Average height of sandwaves levelled (m)	1
Maximum area of sandwave clearance / levelling works (m^2)	70,000
Maximum volume of sand removed during sandwave clearance / levelling works (m^3)	70,000
Platform link cables	
Maximum length of cable requiring sand wave levelling (10% of total length) (m)	1,000
Maximum width of sandwave levelling (m)	10
Average height of sandwaves levelled (m)	1
Maximum area of sandwave clearance / levelling works (m^2)	10,000
Maximum volume of sand removed during sandwave clearance / levelling works (m^3)	10,000

5.6.3 Foundation installation

5.95 The type(s) of WTG/OSP foundation to be installed is yet to be determined and would depend on survey data, metocean data and the selected WTG type and OSP topside(s) arrangement. The foundations would be fabricated onshore, shipped from the designated loadout port to be marshalled, assembled with other components, and transported to the offshore site. Specialist installation vessels would be needed for transportation, lifting and installation of the foundations, as described in **Section 5.6.1**.

5.96 Only one foundation would be installed at any one time in the windfarm site, including only one piling activity occurring at any one time (should piling be required). Sequentially (installation one after the other), there may be up to three monopiles or up to four pin piles installed in a 24-hour period.

5.6.3.1 GBS

5.97 GBS would be transported from their construction site to the windfarm site, either by de-ballasting, floating and towing the structures themselves, or via loading onto a transport barge or vessel.

5.98 Once the foundation has arrived at site, if it was towed, then it would be ballasted down onto the seabed, potentially by flooding ballast tanks. If moved by barge, a heavy lift crane would be used to lift the structure and lower it to the seabed. In either case, the seabed would be pre-prepared to remove any obstructions, such as boulders, which could cause damage.

5.99 The overall installation methodology would typically be as follows:

- GBS transported to site, via barge/vessel or floated to site hauled by tugs
- Mobilise heavy lift floating crane (if foundation is non-buoyant solution)
- Lift foundation from transport vessel/barge and lower to prepared area of seabed, or adjust buoyancy of floating foundation and sink to prepared area of seabed
- Install ballast, as necessary
- Install under base grouting, as necessary[14]
- Install scour protection

5.100 Ballast may be in the form of water and/or a heavy material, such as rock. Where water is used, this would be local water added via subsurface valves or ports allowing free flooding. Where rock is used, this would be added via a rock placement vessel, equipped with a fall pipe.

5.6.3.2 Multi-legged pin-piled jacket (four-legged or three-legged jackets)

5.101 Jacket foundations are anchored to the seabed by using single pin piles at each leg. Piles are driven into the seabed using hydraulic piling hammers and/or vibrational methods, or a combination of piling and drilling. If piles are installed before the jacket, a temporary guide frame, or template, is used to ensure they are orientated and positioned correctly. The guide frame is equipped with mudmats, to prevent it from sinking into the seabed as the piles are driven. Each jacket leg (for both WTGs and OSP(s)) would have one pin pile with a maximum diameter of 3m. Given that pin piles are narrower than monopiles, a lower hammer energy is required to install the piles.

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[14] Under base grouting may also be used to uniformly distribute stresses beneath the foundation and to fill small voids between the foundation and the seabed.

5.102 The maximum hammer energy used for pin-pile installation is assumed to be 2,500kJ[15]. Each piling event would commence with a soft-start at a lower hammer energy, followed by a gradual ramp-up to the maximum hammer energy required. Two scenarios are considered for installation which encompass the longest piling duration with a maximum strike rate of 35 blows per minute, and a shorter piling duration with a maximum strike rate of 100 blows per minute.

5.103 Depending on seabed soil properties, pre-drilling at pile locations may be required to allow piles to achieve their target penetrations. The drill arisings (spoil) would be deposited adjacent to the foundation location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation.

5.104 There are a range of commonly used methods for fixing the jacket to the pile:

- Packing the pile sleeve with grout packers and filling up the annulus with grout. When the grout cures, the pile outer surface and the ridged inner surface of the sleeve are effectively bonded
- Hydra Lok uses a “swaged” system, where the pile is deformed by pressure into recesses in the pile sleeve
- Spring Lok uses a spring to push a wedge over a lip in the pile as it is driven to its target penetration

5.105 The installation design envelope for pin-piled jacket foundations is given in **Table 5.16**, noting that percussive piling or drilling methods can be used. When considering drill arisings, it is assumed that drilling would be required at 50% of WTG/OSP locations within the windfarm site and that 50% of depth would need to be drilled at these locations (drive-drill-drive method).

Table 5.16 Installation design envelope for multi-legged pin piled jacket foundations

Parameter	Value
Multi-legged pin-piled jackets	
Maximum hammer driving energy (kJ)	2,500
Maximum active piling time per WTG/OSP (4 pin piles per foundation) (minutes)	1,080
Maximum active piling time for all WTGs/OSPs (100% of locations assuming no drilling) (hours)	666
Maximum drill penetration depth (m)	56

[15] Further information is provided in **Appendix 11.1 Underwater Noise Assessment** (Document Reference 5.2.11.1)

Parameter	Value
Maximum volume drill arisings for an individual WTG or OSP (assuming maximum penetration depth) (m^3)	1,746
Volume of drill arisings for all WTGs & OSPs (m^3) (assumes 50% of WTGs/OSPs are drilled via drive-drill-drive method to 50% of overall maximum penetration depth)	16,151 (15,278m^3 for 35 x WTGs and 873m^3 for 2 x OSPs)

5.6.3.3 Monopile

5.106 Monopiles can be installed with monohull floating, or jack-up, construction vessels. The monopile would be up-ended by crane to a vertical position and lowered to seabed through a pile guide. Once on the seabed, the pile would sink under its own weight (self-penetrate), a piling rig would then be added to the top end of the pile to drive it to the design target depth.

5.107 Installation of the monopile is generally via percussive piling or vibropiling, with or without drilling, with penetration depths below the seabed in the range 30m to 56m.

5.108 The maximum hammer energy used for monopile installation is assumed to be 6,600kJ[16]. Each piling event would commence with a soft-start at a lower hammer energy, followed by a gradual ramp-up to the maximum hammer energy required. Two scenarios are considered for installation which encompass the longest piling duration with a maximum strike rate of 35 blows per minute, and a shorter piling duration with a maximum strike rate of 100 blows per minute.

5.109 Where ground conditions are unsuitable for piling, monopiles may be drilled, or both drilled and driven, into the seabed. The drill arisings (spoil) would be disposed of adjacent to the foundation location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation.

5.110 The installation parameters for monopile foundations are given in **Table 5.17** below, noting that percussive piling or drilling methods can be used. When considering drill arisings, it is assumed that drilling would be required at 50% of WTG/OSP locations within the windfarm site and that 50% of depth would need to be drilled at these locations (drive-drill-drive method).

[16] Further information is provided in **Appendix 11.1.**

Table 5.17 Installation design envelope for monopile foundations

Parameter	Value
Monopile	
Maximum hammer driving energy (kJ)	6,600
Maximum active piling time per pile (minutes)	270
Maximum active piling time for all WTGs/OSPs (hours)	167
Maximum drill penetration depth (m)	56
Maximum volume drill arisings for an individual WTG or OSP (assuming maximum penetration depth) (m^3)	6,983
Maximum volume of drill arisings for all Project WTGs/OSPs (m^3) (assumes 50% WTGs/OSPs are drilled via drive-drill-drive method to 50% of overall maximum penetration depth)	55,865 (52,373m^3 for 30 x WTGs and 3,492m^3 for 2 OSPs)

5.6.3.4 Multi-legged suction bucket jacket

5.111 Jacket on suction bucket foundations would be installed via a suitable construction vessel, by providing suction to pump out entrained water, thereby forcing the jacket leg into the seabed. Initially, buckets would be lowered to the seabed, with top vents open, and allowed to self-penetrate under their own weight.

5.112 When self-penetration is complete, bucket top vents would be sealed and the water volume between the seabed and the bucket inner surface is pumped out, so that the bucket is pushed into the seabed by differential pressure. Typically, the final step includes pumping grout into the remaining space.

5.6.4 WTG installation

5.113 The components of a WTG are the tower, the nacelle assembly (which contains the generator) and the three rotor blades. A barge, or the WTG installation vessel, would transport the components of one or more WTGs from the marshalling port to the windfarm site.

5.114 In the water depths found at the windfarm site, it is expected that the installation vessel would be a jack-up vessel, typically with four or six legs, with each leg equipped with spudcans, which locate the legs onto the seabed. Each spudcan consists of a plate, or mudmat, which forms the base of the leg and minimises penetration into the seabed. Below the mudmat is a cone, which penetrates the seabed over a small area and provides lateral support to the legs.

5.115 A crane located on the installation vessel would be used to lift the WTG components onto the already installed foundation substructure (as described in **Section 5.6.3**). The duration of each WTG installation is anticipated to be typically three to four days.

5.6.5 Offshore substation platform installation

5.116 The OSP foundation(s) would be transported to the windfarm site and installed in line with the approach described in **Section 5.6.3**.

5.117 The OSP topsides would be transported from the onshore fabrication facility to the windfarm site using a transportation barge and installed onto the OSP foundations using a crane vessel.

5.6.6 Inter-array and platform link cable installation

5.118 It is assumed that the cable lay vessel would use dynamic positioning (DP) for the installation of the inter-array and platform link cables.

5.119 Cables would, where possible, be buried for protection purposes, at depths of 0.5m to 3m, with a target depth of 1.5m. This would be outlined in the Cable Burial Risk Assessment (CBRA) as part of the CSIP, which would be developed post-consent.

5.120 Burial can be achieved via a number of techniques, such as ploughing and trenching (including jetting and mechanical cutting). The use of these method(s) would be detailed in the CBA as of the CSIP, which would be developed pre-construction following the completion of pre-construction geotechnical and geophysical investigations.

5.121 Burial by ploughing is undertaken by a forward blade cutting through the seabed. Ploughing tools are pulled directly by a surface vessel. The plough can insert the cable as it passes through the ground or leave an open channel for subsequent cable lay.

5.122 Trenchers are typically self-propelled tracked vehicles which run along the seabed taking power from a DP surface vessel for propulsion. First a trench would be excavated or cut while placing the sediment and fill next to the trench. The cable would then subsequently be laid in the trench and lastly the sediment or fill would be returned to the trench.

5.123 Burial by jetting involves the use of a hydraulically or electrically powered water pump. The equipment uses pressurised water injected from arms, known as swords, that penetrate the seabed and use jets of water to fluidise seabed sediments. The cable, under its own weight, sinks through the fluidised seabed to the depth set by the operator. As the trencher moves forward, the majority of the fluidised sediment settles into the newly formed trench covering the cable. As the sediment is fluidised, a minor amount of sediment spill would be expected.

5.124 Mechanical cutting would be used where other methods are not technically feasible due to the substrate type. Two examples are chain and wheel cutters, that create a slot trench by removing material from the seabed and depositing it either side of the trench. These vehicles can simultaneously cut and embed the cables in one continuous trench.

5.125 The volume of sediment removed during cable installation would be disposed of adjacent to the cable location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each cable.

5.126 Where burial is not possible, cable protection, for example using concrete mattresses and rock placement, may be deployed (see **Section 5.5.4.3** for further discussion on cable protection, including examples and design envelope parameters for cable protection).

Table 5.18 Installation design envelope for inter-array and platform link cable installation

Parameter	Value
Inter-array cables	
Maximum length of cable buried[17] (m)	70,000
Maximum width of trench (m)	3
Maximum width of disturbance (including spoil and pre-lay activities) (m)	25
Maximum footprint of disturbance for inter-array cable installation (m^2)	1,750,000
Maximum volume of sediment displaced during inter-array cable trenching (m^3)	472,500
Platform link cables	
Maximum length of cable buried[18] (m)	10,000
Maximum width of trench (m)	3
Maximum width of disturbance (including spoil and pre-lay activities) (m)	25

[17] 50% of cable length is assumed to be buried at 1.5m, 50% assumed to be buried at 3.0m

[18] 50% of cable length is assumed to be buried at 1.5m, 50% assumed to be buried at 3.0m

Parameter	Value
Maximum footprint of disturbance for platform link cable installation (m^2)	250,000
Maximum volume of sediment displaced during platform link cable trenching (m^3)	67,500
Total inter-array and platform link cables	
Maximum footprint of disturbance for cable installation (m^2)	2,000,000
Maximum volume of sediment displaced during cable trenching (m^3)	540,000

5.6.7 Scour protection installation

5.127 Scour protection material to be installed around each WTG/OSP foundation would typically be installed by a DP rock placement vessel (able to hold station without the use of anchors) equipped with a fall pipe. The scour protection materials would be placed in one or multiple layers.

5.128 Scour protection would be installed as soon as practicable following foundation installation (e.g. within a month). It is estimated that installation of scour protection for each WTG/OSP structure would take approximately a day.

5.129 Scour protection options and the design parameters for scour protection are set out in **Section 5.5.3.5.**

5.6.8 Anchoring

5.130 Where they are used, anchored vessels would have a seabed footprint (as estimated in **Table 5.19**). In the case of monohull floating construction vessels with anchoring, this is likely to be a wire line system with drag/fluke anchors, with up to 12 lines per location.

5.131 The footprint of each anchor would be up to 6m in width (approximately 30m^2), with an anchor line length of up to 1,000m. There would usually be one anchor position per foundation, although re-setting of anchors is sometimes required in the event that they do not hold position (therefore, two anchor positions have been assumed as a worst-case).

Table 5.19 Installation design envelope for anchors for foundation installation

Parameter	Value
No. of vessel anchoring positions assumed per foundation (including resetting)	2
Anchor width (m)	6

Parameter	Value
Anchor footprint per anchor (including resetting) (m^2)	$60m^2$
No. of anchor/mooring lines per vessel anchoring position	12
Maximum anchor footprint on the seabed per WTG/OSPs foundation (m^2)	720
Maximum anchor footprint on the seabed for total WTGs/OSPs (m^2)	26,640 (25,200m^2 for 35 WTGs[19] and 1,440m^2 for 2 x OSPs)

5.132 Marker buoys, beacons and fenders would be used to demarcate the windfarm construction activities, however they would have a small footprint and have not been quantified.

5.7 Operation and maintenance

5.133 During the operational life of the Project, operation and maintenance activities would be required. All offshore infrastructure including WTGs, foundations, cables and OSP(s), would be monitored and maintained during this period to maximise efficiency.

5.134 These operation and maintenance activities can be split into three main categories as follows:

- Scheduled maintenance (such as repair and service work such as regular WTG and/or OSP servicing)
- Unscheduled maintenance (such as fault finding and repairs to WTGs, OSP(s) and cables)
- Emergency/special maintenance (in the event of major equipment breakdown and repairs)

5.135 The Project would be maintained from shore using a number of varying operation and maintenance vessels (e.g. crew transfer vessels, supply vessels) and/or helicopters (in exceptional circumstances). An offshore base, for example a mother ship (a large offshore service vessel), could also be used. Control of the Project would also be managed onshore using a Supervisory Control and Data Acquisition (SCADA) system.

5.136 Given the design life of the offshore components, some refurbishment or replacement would be required during the lifetime of the Project. Details of the

[19] Noting that both smaller and larger WTGs have the same GBS foundation footprint.

anticipated maintenance requirements are included in an Outline Offshore Operation and Maintenance Plan (Document Reference 6.6), which is included in the DCO Application that details the reasonably foreseeable offshore maintenance activities and the broad approach to be taken for each activity.

5.137 The strategy for operation and maintenance would be finalised based on the location of a suitable port/harbour, which is yet to be defined, however, typical activities are described below.

5.7.1 Vessels and helicopters

5.138 A number of vessel visits to each WTG and OSP would be required each year to allow for scheduled and unscheduled maintenance.

5.139 Up to three support vessels are expected on site at any one time during a standard year, with up to ten support vessels expected on site during a 'heavy maintenance' year. A further one jack-up vessel may also be required approximately biennially (once every other year). Overall, a maximum of 384 return vessel trips during a standard year and 832 return vessel trips during a heavy maintenance year (expected to be every fifth year) are expected annually, including operational support vessels and those supporting maintenance activities.

5.140 Helicopters are anticipated to be used only in exceptional circumstances during the operation and maintenance phase. In this event, helicopters would most likely come from Blackpool or Liverpool, however this is indicative at this stage and may be subject to change.

5.141 Vessel anchoring may be required during maintenance activities within the windfarm site. It is assumed that anchor footprints per vessel would be the same as per construction (**Table 5.19**) and be required on average once a year. Disturbance footprints for vessel anchors during the operation and maintenance phase are presented in **Table 5.20**.

Table 5.20 Installation design envelope for anchors for foundation installation

Parameter	Value
No. of vessel anchoring position assumed per foundation (including resetting)	2
Anchor width (m)	6
Anchor footprint per anchor (including resetting) (m^2)	$60m^2$
No. of anchor/mooring lines per vessel anchoring position	12

Parameter	Value
Maximum anchor footprint on the seabed per WTG/OSP foundation (m^2)	720
Maximum anchor footprint on the seabed over the operational period (m^2)	25,200m^2

5.142 Marker buoys/beacons may be used to demarcate the windfarm maintenance activities, however their anchors would have a small footprint and have not been quantified.

5.7.2 WTGs and OSP(s)

5.143 Access to the WTGs and the OSP(s) would be required 365 days a year.

5.144 Operation and maintenance activities are anticipated to include:

- Inspections of cables, foundations, TPs, blades, safety equipment, offshore substation equipment (including geophysical surveys to inspect subsea assets)
- Inspection and survey of cable and scour protection (including geophysical surveys to inspect subsea assets)
- System performance assessments and fault-finding
- Replacement of lubricants, oils and filters
- Grout and corrosion inspection and works (including cathodic protection and anode inspection, grouting core samples and re-grouting)
- Replacement of WTG parts including bearings, gearboxes, generators, nacelles, transformers and blades
- Minor repairs and replacements
- Inspection of marine growth and removal of marine growth and guano
- Structural surveys
- Replenishment of cable and scour protection
- Recovery of dropped objects
- Transport and transfer of staff
- Inspection, maintenance and certification of lifting and lifesaving equipment
- Inspection and maintenance of equipment e.g. metocean equipment, communications systems, coating systems, electrical equipment, navigations aids, design generators, accommodation areas

5.145 Although it is not anticipated that large components would require replacement during the operational phase, it is a possibility. Should this be required, large jack-up vessels may need to operate continuously for significant periods to carry out these major maintenance activities. Replacement of a foundation would require a separate marine licence.

5.146 During operation and maintenance activities the Applicant would seek to agree appropriate safety zones with the MCA around WTGs and work areas to be applied.

5.7.3 Cable remedial burial and repair

5.147 It is possible that inter-array and platform link cables could become exposed from their initial buried condition due to the natural movement of the seabed over the lifetime of the Project and may require remedial burial activities. Design and construction methods would seek to minimise such occurrences through appropriate burial depths, however, if this occurs reburial can be achieved via a number of techniques such as jetting, ploughing, mechanical cutting and dredging undertaken from a vessel using DP.

5.148 Cable exposure may be identified during regular inspection, maintenance or repair regimes, or by cable monitoring systems. An average length of cable reburial of 100m per year is assumed over the operational lifetime. This figure represents an average length per year, however, in reality cable reburial is not anticipated every year and would more likely involve less frequent, unplanned reburial of potentially longer lengths. A 10m disturbance width for remedial burial activities has been assumed, with a 3m maximum depth. Additional or replacement cable protection material may also be required (**Section 5.7.4**).

5.149 It is additionally possible that during the operational lifetime of the cables, they could become damaged and non-operational. This could potentially require fault location, de-burial, retrieval, repair, placement on the seabed and reburial. An average length of cable repair of 200m per year is assumed over the operational lifetime, with a disturbance width of 10m. As noted above, this figure represents an average length per year, however, in reality cable repair/replacement is not anticipated every year and would more likely involve less frequent, unplanned repair/replacement of potentially longer lengths. Repair or replacement would likely be undertaken from a vessel using DP, followed by reburial.

5.150 The parameters for cable repair/replacement and reburial for both inter-array and platform link cables is given in **Table 5.21**.

Table 5.21 Operation and maintenance parameters for average cable repair/replacement and reburial

Parameter	Maximum
Average length of cable repair/replacement assumed per year (m)	200
Average length of cable remedial burial assumed per year (m)	100
Disturbance width (m)	10
Disturbance depth (m)	3
Average footprint of seabed disturbance activities for cable repair/replacement per year (m^2)	2,000
Average footprint of seabed disturbance activities for cable remedial burial per year (m^2)	1,000
Total average footprint of seabed disturbance activities for cable repair/replacement and remedial burial per year (m^2)	3,000
Total average volume of sediment disturbed for cable repair/replacement and remedial burial per year (m^3)	9,000

5.7.4 Replacement scour protection and cable protection material

5.151 It is assumed that up to 10% of the total scour and cable protection material installed during construction would be required to be replaced or replenished during the operation and maintenance phase (**Table 5.22**). It is assumed that all replacement scour and cable protection material would replace/replenish material where it has been dislodged/moved or scoured, hence re-establishing design conditions.

Table 5.22 Design envelope parameters for replacement scour and cable protection material during operation and maintenance phase

Parameter	Value
GBS	
Maximum footprint on the seabed of replacement scour protection for WTGs/OSPs (excluding foundation structure) (m^2)	13,950
Maximum volume of replacement scour protection material for WTGs/OSPs (excluding foundation structure) (m^3)	27,900
Multi-legged pin-pile jacket	
Maximum footprint on the seabed of replacement scour protection for WTGs/OSPs (excluding foundation structure) (m^2)	3,663
Maximum volume of replacement scour protection material for WTGs/OSPs (excluding foundation structure) (m^3)	7,326
Monopile	
Maximum footprint on the seabed of replacement scour protection for WTGs/OSPs (excluding foundation structure) (m^2)	12,666
Maximum volume of replacement scour protection material for WTGs/OSPs (excluding foundation structure) (m^3)	25,331
Multi-legged suction bucket jacket	
Maximum footprint on the seabed of replacement scour protection for WTGs/OSPs (excluding foundation structure) (m^2)	10,464
Maximum volume of replacement scour protection material for WTGs/OSPs (excluding foundation structure) (m^3)	20,927
Inter-array and platform link cables (including protection due to ground conditions, and for crossings and at entry to WTGs/OSPs)	
Maximum footprint on the seabed of replacement cable protection[20] (m^2)	21,625
Maximum volume of replacement cable protection (m^3)	25,970

[20] As noted in **Paragraph 5.151**, it is assumed that all replacement scour and cable protection material would replace/replenish material where it has been dislodged/moved or scoured.

5.8 Decommissioning

5.152 At the end of the operational lifetime of the Project, it is anticipated that decommissioning would involve the removal of all structures above the seabed. Details of the potential decommissioning activities are not known at this time and would be subject to separate consent. However, it is assumed that decommissioning activities would be similar to that of construction.

5.153 A Decommissioning Programme would be prepared during the detailed design and development stage of the Project, prior to construction. The Decommissioning Programme would be refined during the Project's lifetime and finalised as decommissioning approaches. To reflect future best practice and new technologies, the approach and methodologies of the decommissioning activities would be compliant with the relevant legislation, guidance and policy requirements at the time of decommissioning.

5.154 The decommissioning activities are expected to be undertaken in reverse to the sequence of construction activities and involve similar tools, equipment and vessels.

5.155 It is expected that the WTGs would be removed by reversing the methods used to install them. Any piled foundations could be cut, lifted and removed in accordance with the regulations prevalent at the time, to avoid any potential future clash with other seabed users. The remaining foundations below the seabed may be left in a safe and fully buried condition. Any scour protection may also be left in-situ.

5.156 The removal of OSP(s) is expected to be undertaken in two distinct stages; first, the topside would be removed from the foundation and transported to shore for onshore decommissioning, and second, the foundations would be removed in a similar manner to that of the WTG foundations.

5.157 Inter-array and platform link cables may either be left in-situ, the entire cable network removed, or specific sections of the subsea cables could be removed. If it is decided to remove the cables, then similar tools or equipment used for their installation and burial would be utilised, but by reversing the process involved and exposing the cables. Therefore, the area of seabed affected by the removal of cables is expected to be the same as for the installation and burial activities. Once the cables have been retrieved onto vessels, they could be returned to shore for potential recycling of metallic contents (e.g., steel, copper, aluminium) or safe disposal.

5.158 The possibility of leaving structures above the seabed in-situ with appropriate navigation markers, and the associated risks and benefits therein, would also be assessed.

5.9 Response to potential major accidents and disasters

5.159 The Infrastructure Planning (EIA) Regulations 2017 (the EIA Regulations 2017) require significant risks to the receiving communities and environment, for example through major accidents or disasters, to be considered. Similarly, significant effects arising from the vulnerability of the Project to major accidents or disasters should be considered. Relevant risks are covered in the specific topic chapters within this ES.

5.160 A major accident, as defined in the Control of Major Accident Hazards (COMAH) Regulations 2015 (as amended), is "*an occurrence such as a major emission, fire, or explosion resulting from uncontrolled developments in the course of the operation of any establishment to which these Regulations apply, and leading to serious danger to human health or the environment (whether immediate or delayed) inside or outside the establishment, and involving one or more dangerous substances*".

5.161 The Institute of Environmental Management and Assessment (IEMA), 2020 provides the following definitions:

- 'Major accidents' are defined as 'events that threaten immediate or delayed serious environmental effects to human health, welfare and/ or the environment and require the use of resources beyond those of the client or its appointed representatives to manage. Whilst malicious intent is not accidental, the outcome (e.g. train derailment) may be the same and therefore many mitigation measures will apply to both deliberate and accidental events.' (IEMA 2020).
- A 'disaster' is a sudden accident or natural catastrophe that causes great damage or loss of life. These can be natural or can be man-made hazards (e.g. caused by accidental loss of containment) or external hazards (e.g. act of terrorism) which result in consequences for people or the environment.

5.162 Given the location of the windfarm site there would be low vulnerability to environmental hazards, major accidents, human and animal health hazards, societal risks, malicious attacks and crime.

5.163 Offshore wind developments have an intrinsically low risk of causing major accidents. The WTGs, blades, rotors, towers and foundations have an excellent safety record with a very low failure rate and are positioned many kilometres offshore away from populated areas and the public. On the rare occasion that offshore WTG blades have been lost into the sea, or damage has been caused to a WTG by a fire within the nacelle assembly, this has not resulted in injury. The performance of each WTG is constantly monitored through the SCADA system, sending performance data through to a central, partly automated monitoring and control centre. As a result, a problem can be quickly detected and pre-prepared safety management action plans rapidly enacted. An Emergency Response Co-operation Plan for the Project would be developed post-consent.

5.164 Remaining impacts in relation to major accidents and disaster have been assessed within the ES as summarised below and with links to assessments provided:

- Vessel interaction (including collision, allision and snagging) – **Chapter 14 Shipping and Navigation**
- Aviation safety – **Chapter 16 Civil and Military Aviation and Radar**
- Accidental spills of hazardous material – **Chapter 8 Marine Sediment and Water Quality**
- Disturbance of UXO – **Paragraph 5.172** below
- Workplace accidents and impacts to other marine users – **Chapter 17 Infrastructure and Other Users** and Outline PEMP (Document Reference 6.2)

5.165 **Chapter 14 Shipping and Navigation** assesses any risks to navigational safety associated with the Project, including increased vessel movement to and from the Project and the presence of offshore infrastructure during the life cycle of the Project.

5.166 Whilst exposed power cables on the seabed can pose a snagging risk to shipping and fishing vessels, the Project's array cables would be buried, or protected with rock or concrete mattresses to protect the cables and remove or substantially reduce the snagging risk. This is assessed in **Chapter 14 Shipping and Navigation**.

5.167 The buried cables offshore pose very little risk to the public as the system is designed to detect faults and to disconnect the circuits automatically should any failure in insulation along the cable be detected.

5.168 **Chapter 16 Civil and Military Aviation and Radar** assesses risks to aviation safety associated with the Project, including installation of WTGs creating aviation obstacles, and the potential for increased air traffic in the area related to windfarm activities.

5.169 The risk of substation fires is historically low; however, substation fires can impact the supply of electricity and create a localised fire hazard. The highest appropriate levels of fire protection and resilience would be specified for the OSP(s) to minimise fire risks.

5.170 The lubricants, fuel and cleaning equipment required within the Project would be stored in suitable facilities designed to the relevant regulations and policy design guidance. A Project Environmental Management Plan (PEMP) would be produced and followed to cover the construction and operation and maintenance phases of the Project. This would include planning for accidental spills, address all potential contaminant releases and include key emergency contact details. As part of the PEMP, a Marine Pollution Contingency Plan (MPCP) would set the management measures to be implemented to mitigate the risks of accidental spills of hazardous materials. Measures to reduce instances of spills, remedial action and response measures to be used in the event of a spill would also be developed. Further information is available in **Chapter 8 Marine Sediment and Water Quality** and the Outline PEMP.

5.171 The offshore wind industry strives for the highest possible health and safety standards across the supply chain. Risks to other sea users offshore during construction are minimised through the use of vessel safety zones offshore. Further information is detailed in **Chapter 17 Infrastructure and Other Users**.

5.172 Disturbance of UXO could occur in the windfarm site (see **Section 5.6.2.2**). The Project would implement mitigation to minimise risks, including UXO detection surveys and clearance campaigns (if required), prior to foundation or cable installation. A detailed risk mitigation strategy would be developed as part of a UXO Risk Assessment. This includes mitigation strategies to avoid UXOs in the first instance, removing risk receptors or threat sources, if required. The risk of encountering UXO during a routine operation and maintenance year is low, however, this risk would increase during ‘heavy’ maintenance years where jack-up vessels and/or cable repair vessels may be required. UXO would be considered in the area(s) of maintenance operations which interact with the seabed and appropriate As Low as Reasonably Practicable (ALARP) certificates would be in place before such maintenance activities commence.

5.173 The Applicant recognises the importance of the highest performance levels of health and safety to be incorporated into the Project. The Project would enact minimum safety, health and environmental requirements on all suppliers, contractors and subcontractors. The Project would also ensure that employees that are going to work for them have undergone all of the necessary health and safety training.

5.174 With a commitment to the highest health and safety standards in design and working practises enacted, none of the anticipated construction works or operational procedures is expected to pose an appreciable risk of major accidents or disasters. In conclusion, the risk of ‘major accidents and/or disasters’ occurring associated with any aspect of the Project, during the construction, operation and decommissioning phases has been assessed as not significant in EIA terms.

5.10 References

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