Environmental Impact Assessment Report
Volume 1, Chapter 4: Project Description

MarramWind Offshore Wind Farm

December 2025

MarramWind

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Contents

4. Project Description

4.1 Introduction

4.1.1 Overview

4.1.1.1 This Chapter of the Environmental Impact Assessment (EIA) Report provides a description of MarramWind Offshore Windfarm (hereafter, referred to 'the Project') and summarises the key components including the offshore wind farm and associated onshore / offshore infrastructure. It also describes the key activities that will be undertaken during construction, operation and maintenance (O&M), and decommissioning, along with indicative timescales. The details within this Chapter provide the basis for the assessment of effects undertaken for each technical aspect chapter of the EIA Report (**Chapters 6** to **31**).

4.1.2 Design envelope

4.1.2.1 The description of the Project for the EIA is indicative and a 'design envelope' approach, also known as the 'Rochdale Envelope', has been adopted. The provision of a design envelope is intended to identify key design assumptions to enable the environmental assessment to be carried out whilst retaining enough flexibility to accommodate further refinement during detailed design. The design envelope approach is widely used and accepted for major infrastructure projects in the United Kingdom (UK), including for recent applications for offshore wind farms. The approach is recognised by Marine Scotland and the Energy Consents Unit in their guidance on how the design envelope assessment approach may be applied in the context of applications received for generating stations under Section 36 (s.36) of the Electricity Act 1989 (Scottish Government, 2022). This states:

> "*…in some instances, the nature of the proposed development and evolving technology mean that some aspects of the final project are yet to be settled in precise detail at the time that the application is submitted (such as the precise location of certain types of infrastructure, the foundation type, the size of certain structures or the turbine model). Where that is the case and some details are still the be finalised, the design envelope approach can be employed for such applications to enable a degree of flexibility and address these uncertainties. Through the design envelope approach, the application can set out parameters for the proposal including the maximum extents of the proposal and can assess on that basis what the likely worst case effects of the proposal may be. The detailed design of the project can then vary within this 'envelope' to ensure that the project as-constructed has been properly assessed.*"

4.1.2.2 There is also UK guidance for the design envelope approach, including within the UK National Policy Statement for Renewable Energy Infrastructure (EN-3) (Department for Energy Security & Net Zero, 2023) and in the Planning Inspectorate's Advice Note Nine: Rochdale Envelope (Planning Inspectorate, 2018). Both of these guides closely align with the Marine Scotland and the Energy Consents Unit guidance.

4.1.2.3 Assessing the Project using a design envelope approach means that the assessment will consider a maximum design scenario, which allows flexibility to make design decisions in the future that cannot be finalised at the time of submission of the application for development consent. Such design decisions may include the precise models and dimensions of wind turbine generators (WTGs) that will be available at the time of placing orders for the Project, a final offshore WTG layout design to optimise wind energy capture, and detailed engineering factors for both the offshore and onshore infrastructure.

4.1.2.4 This enables a meaningful and comprehensive assessment of the Project on a reasonable worst-case scenario basis, whilst maintaining flexibility for refinements to the design as it continues to evolve. The reasonable worst-case scenario defined for any given parameter may vary by technical aspect, depending on how the parameter can be expected to interact with the receptor being considered. The use of this approach has been adopted for this EIA Report and also enables the EIA to be based on a description of the location, design and size of the Project that is suitable to allow an assessment of its likely significant environmental effects.

4.1.3 The Project's design process

4.1.3.1 During the Project's design process, changes to the design have been made as more environmental and engineering information became available and in response to stakeholder feedback. **Chapter 3: Site Selection and Consideration of Alternatives** of this EIA Report describes the reasonable alternatives that have been considered by the Applicant to date, and the reasons why the proposed design envelope has been chosen instead of the alternative locations and technologies. As described in **Chapter 5: Approach to the EIA**, where the design is still evolving, a precautionary approach is applied to ensure a maximum design scenario that represents the worst-case scenario for each aspect is assessed in this EIA Report. Each individual aspect chapter, **Chapter 6** to **Chapter 31**, provides commentary on the appropriate reasonable worst-case scenario, within the maximum design scenario, adopted for the individual assessments.

4.1.3.2 The evolution of design of the Project has taken account of consultation feedback received throughout the design process. This includes responses to Marine Directorate – Licensing Operations Team's (MD–LOT) and Aberdeenshire Council's Scoping Opinions and Statutory Consultation undertaken by the Applicant.

4.1.3.3 A summary of all issues raised as part of the Statutory Consultation feedback and the Project responses to them are provided in the **Pre-Application Consultation Report**.

4.1.4 Environmental measures

4.1.4.1 As part of the Project design process and in response to consultation, embedded environmental measures have been adopted to reduce the potential for environmental impacts and effects. They have fed iteratively into the EIA. As there is a commitment to implementing these embedded environmental measures and to various standard sectoral practices and procedures, they are inherently considered part of the design of the Project and are set out in this EIA Report. The embedded environmental measures have been developed in accordance with the mitigation hierarchy, a fundamental principle in design evolution that indicates the order in which the impacts of a development should be considered and addressed. The EIA Regulations define the mitigation hierarchy as follows:

- avoid;
- prevent;
- reduce; and
- offset

4.1.4.2 The measures are presented in full in **Volume 3, Appendix 5.2: Commitments Register**.

4.1.4.3 **Chapter 5: Approach to the EIA** of this EIA Report explains the approach to embedded environmental measures that has been applied in the EIA Report. The environmental assessments presented in **Chapters 6** to **31** provide details of how specific embedded environmental measures are proposed to avoid or reduce environmental effects.

4.1.4.4 The Project acknowledges the importance of contributing positively to biodiversity and supports the principle of including nature inclusive design and nature enhancement where feasible. Opportunities, both onshore and offshore, for biodiversity enhancement have been considered, and initial measures are outlined in the **Nature Positive Plan**. These measures will be further refined in consultation with stakeholders as the Project progresses.

4.1.5 Key components of the Project

4.1.5.1 The key components of the Project are described broadly in relation to the jurisdictions of the consenting regimes that cover them. As described in **Chapter 2: Legislative and Policy Context,** the offshore consenting regime covers works seaward of Mean High Water Springs (MHWS), while the onshore consenting regime covers works landward of Mean Low Water Springs (MLWS).

4.1.5.2 The Project's offshore infrastructure, located seaward of MHWS, includes the following:

- WTGs, including floating units (platforms and station keeping system);
- array cables;
- subsea distribution centres;
- subsea substations;
- offshore substations;
- reactive compensation platform(s) (RCPs) (if required); and
- offshore export cables to connect the offshore infrastructure to the landfall(s).

4.1.5.3 The Project's onshore infrastructure, located landward of MLWS includes:

- landfall(s) – the infrastructure associated with landfall(s) located above MLWS;
- underground onshore export cables running from the landfall(s) to the onshore substations;
- onshore substations co-located at one site;
- underground grid connection cables connecting the onshore substations to the grid connection point at Scottish and Southern Electricity Networks (SSEN) Netherton Hub; and
- tie-in to the grid connection point (SSEN substation at the SSEN Netherton Hub, which is a separate project and does not form part of the consenting applications that this EIA relates to).

4.1.5.4 Further details on the key components of the Project are provided in **Section 4.4**.

4.1.6 Consultation and engagement

4.1.6.1 Section 5.5 in **Chapter 5: Approach to the EIA** sets out the Project's approach to consultation and engagement.

4.1.6.2 **Volume 3, Appendix 5.1: Stakeholder Issues Responses** sets out the comments raised by stakeholders from pre-engagement, Scoping workshops, Scoping Opinions, post-Scoping workshops relevant to the Project Description and how these have been addressed in the EIA Report.

4.1.7 Structure of the Chapter

4.1.7.1 The remainder of this Chapter is structured as follows:

- **Section 4.2:** Phasing and the requirement for design flexibility;
- **Section 4.3:** Location and site information;
- **Section 4.4:** Key components of the Project infrastructure;
- **Section 4.5**: Offshore elements of the Project;
- **Section 4.6:** Offshore installation methodology;
- **Section 4.7:** Landfall;
- **Section 4.8:** Onshore elements of the Project;
- **Section 4.9:** Project construction programme and construction timings;
- **Section 4.10:** General construction practices;
- **Section 4.11:** O&M stage;
- **Section 4.12:** Decommissioning stage;
- **Section 4.13:** References; and
- **Section 4.14:** Glossary of terms and abbreviations.

4.2 Phasing and the requirement for design flexibility

4.2.1.1 Given the scale of the Project, a phased approach to the installation and energisation of the WTGs is proposed. The Applicant intends to apply the design envelope approach to the EIA, which will provide the reasonable worst-case parameters or scenario that will encompass the flexibility required for relevant Project infrastructure. The need for a phased approach and an explanation of the necessary design envelope flexibility are described in **Section 4.2.2**.

4.2.2 Need for a phased approach

4.2.2.1 Prior to securing the seabed rights through the ScotWind leasing round, a 3 gigawatts (GW) grid connection offer was accepted and secured on the National Electricity System Operator (NESO) Transmission Entry Capacity Register. This offer was on the basis of a 3GW connection to New Deer substation. An updated grid connection offer was expected in early 2022 following the conclusion of the ScotWind leasing round.

4.2.2.2 The results of the NESO Holistic Network Design (HND) in July 2022 (NESO, 2022) confirmed a 1.5GW connection to a new substation in the vicinity of Peterhead, with the remaining 1.5GW being subject to the HND Follow Up Exercise.

4.2.2.3 In March 2024, (NESO, 2024) published the Beyond 2030 report, which confirmed the full 3GW connection for the Project will connect into SSEN Netherton Hub at Longside, near Peterhead.

4.2.2.4 Due to the extensive onshore and offshore enabling works required to provide the 3GW capacity for the Project to connect into SSEN Netherton Hub, NESO / SSEN have proposed a staged connection with access to grid capacity to be made available in stages. The grid capacity availability is dependent on the enabling works delivery timelines and therefore earliest in service dates that could be possible for the Project.

4.2.2.5 In addition, the Connections Reform process is looking to simplify and rationalise the current grid queue system. This process will result in a revised contract being issued to the Project by end Q3 2026. The Project will review this once received prior to entering into a formal signed contract with confirmed connection dates.

4.2.2.6 Whilst the grid connection offer provides the basis of a three-phased approach for the installation and energisation of the Project, there are other factors that may influence the final design / phasing requirements, for example:

- Route to market - it is necessary to retain flexibility both in terms of size and timing due to the inherently competitive nature of current Contracts for Difference (CfD) process and a Government mandated maximum budget, which is unlikely to be able to support a single 3GW application. It is also anticipated that the CfD process may change in the coming years.
- Supply chain for floating units and WTGs original equipment manufacturers - the capabilities and availability related to the commercial scale build out of floating units remains under development. The value and risk profile of the supply chain to be able to commit to a single 3GW contract on new technology is also considered to be a constraint to phasing size.
- Transmission technology - further technological advances may influence the electrical transmission option to be adopted for each phase.

4.2.2.7 Each phase of the Project will be operational for up to 35 years from completion of installation and commissioning of offshore WTGs. Further information on the indicative operational programme is provided in **Section 4.11**.

4.2.2.8 The construction of the Project would consequently align with the energisation of the Project over three phases and be based on the construction scenarios identified in **Table 4.1**. Further information on the indicative construction programme is provided in **Section 4.9**.

Table 4.1 Construction scenarios

Component	Scenario
Array	The three phases of the array, including WTGs and necessary substations, will be installed within the Northeast 7 (NE7) Option Agreement Area (OAA). The spatial extent of the individual three phases within the OAA are not determined. The EIA Report will consider the full 3GW build-out over time. However, operational access and O&M vessel movement will be anticipated across the full OAA. The three phases will be electrified sequentially, with individual WTGs or strings of WTGs coming online as they are commissioned.
Offshore export cables	The offshore export cables will be installed in three phases to align with the energisation of the WTGs. The EIA is based on the maximum footprint defined in aggregate for all three phases. Offshore export cables will be buried except where localised site conditions prevent burial. This will be subject to a cable burial risk assessment.
Offshore platforms	To support energy transmission across the three phases of the array energisation, there will be up to four offshore substations located within the OAA, and up to two RCPs located appropriately along the export cable corridor. The locations and capacities of the offshore substations and RCPs will be located within the Red Line Boundary and will relate to the output capacity of the individual phases, which are not yet determined. The EIA

Component	Scenario
	will consider the worst-case scenario to be based on the maximum number of platforms.
Landfall(s)	More than one landfall may be required to accommodate the cabling necessary for the Project's full 3GW. The Project's intent is to utilise one landfall location but retains the worst case due to the competitive landscape, in the event the Project cannot secure sufficient space at a single location. The worst-case scenario for the purposes of the EIA Report is the requirement for up to three distinct landfall(s). The landfall(s) infrastructure includes transition joint bays and connecting ducts in the nearshore area. The landfall(s) infrastructure will be constructed in three phases, to align with the phased energisation of the WTGs and the associated three-phased installation of the offshore export cables. Trenchless methods will be used at landfall for each installation of the ducts through the nearshore up to the transition joint bays.
Onshore export cables	The onshore export cables will be installed in three phases to align with the energisation of the WTGs. During Phase 1, the onshore export cables will either be directly installed in trenches or in ducts laid along with the ducts required for the later installation of onshore export cables in Phases 2 and 3. Installation of Phase 2 and 3 ducts during Phase 1 will mitigate the need to re-excavate along the full onshore export cable corridor during these subsequent phases. Onshore export cables and the associated joint bays required for Phase 2 and 3 will be installed to align with the phased installation of offshore export cables and energisation of the WTGs. However, in the event that more than one landfall is required, the connecting onshore export cables, from the common onshore export cable corridor to the additional landfall(s), may be laid in trenches or installed in ducts to align with the phased installation of the landfall(s).
Onshore substations	The Project requires three onshore substations co-located on one site. There will be one onshore substation for each of the three Project phases. Each onshore substation will be constructed to align with the phased energisation of the WTGs and the associated installation of the onshore export cables.

4.2.3 Design flexibility

4.2.3.1 The Applicant is proposing to retain the following design flexibility associated with the phased build out of the Project.

WTGs

4.2.3.2 The generating capacity of the offshore wind array depends upon a range of WTG specifications, which are not yet agreed. For the basis of assessment, each WTG will have an individual generation capacity of up to 25 megawatts (MW).

4.2.3.3 Depending on the final WTGs selected, the Project is expected to have in the region of 126 to 225 WTGs. This is the current basis of assessment for this EIA Report. As WTG technology is continually evolving, it is difficult to definitively predict the generating capacity of WTGs that will be commercially available at the point of construction.

4.2.3.4 As the phased installation and energisation of the WTGs will take place over a period of up to 12 years, the WTG parameters may therefore vary between each phase.

Floating units

4.2.3.5 The WTGs will each be mounted on a floating unit, which will consist of a floating platform or 'floating unit' that will be secured to the seabed by a dedicated 'station keeping system' consisting primarily of mooring lines and seabed anchors.

4.2.3.6 Several design options are being considered for the floating unit at this stage of the Project. The final design concept will be identified following further market engagement, site survey and design development.

4.2.3.7 The EIA will consider a design envelope associated with a potential range of floating unit types. Similar to the WTGs, the floating unit concept may vary between phases and also within the same phase more than one concept may be deployed.

Transmission technology

4.2.3.8 The Project requires both High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) electrical transmission technology, with both technologies and their associated infrastructure considered within the EIA with the appropriate design envelope.

4.2.3.9 The infrastructure required for both types of transmission is broadly similar, as illustrated in **Plate 4.1**. The key differences are as follows and are included within the Project design envelope considered in the EIA:

- HVDC transmission technology requires additional converter technology offshore (located on the relevant offshore HVDC substation platform within the OAA).
- HVDC is being considered for parts of the wind farm furthest from shore and where the electrical losses associated with HVAC transmission become prohibitive.
- HVAC transmission may require up to two RCP's at a location along the offshore cable corridor route. This is dependent on the total length of transmission from the offshore substation to SSEN Netherton Hub, with the RCP(s) expected to be approximately midway along the transmission route.
- HVAC will be used for the area of the wind farm closest to shore, where the HVAC technology is economic and efficient.

- The offshore and onshore export cables will be different in number, design, installation and spacing between HVDC and HVAC.
- The onshore substations will be different in design and size for HVDC and HVAC.

4.2.3.10 The transmission of electricity from the Project's onshore substations to the point of connection at SSEN's Netherton Hub will be via an HVAC connection.

Landfall(s) location

4.2.3.11 It has been necessary to present more than one landfall option in the EIA Report due to landfall space requirements for a 3GW project and the number of both offshore wind farms and transmission projects seeking to make landfall in the vicinity of Peterhead.

4.2.3.12 The inclusion of multiple landfall options is intended to provide the Project with flexibility with regard to securing sufficient space, in appropriate locations, to construct the landfall(s) and associated onshore and offshore export cables necessary to facilitate a 3GW Project, whilst ensuring any environmental impact is kept to a minimum in isolation and cumulatively.

4.2.3.13 The locations of the landfall(s) options are shown in **Volume 2, Figure 4.1: Onshore Red Line Boundary and indicative onshore infrastructure layout**.

4.2.3.14 The landfall(s) options that are assessed in the EIA Report are:

- Option 1: Lunderton – all export cables would make landfall at Lunderton, based on the following scenarios:
  - Option 1a: all export cables make landfall at Lunderton North; or
  - Option 1b: all export cables would make landfall at a combination of Lunderton North and Lunderton South;
- Option 2: Scotstown and Lunderton – export cables would make landfall at a combination of Lunderton (North and / or South) and Scotstown.

4.2.3.15 A final decision on the landfall/s to be taken forward will be subject to land agreements and detailed design post-consent.

Onshore substations

4.2.3.16 The onshore substations will house the electrical components required to ensure that the Project's export power is compliant (NESO, 2023) at the time of connection to SSEN Netherton Hub.

4.2.3.17 The onshore substation for each phase of the Project will either be an HVAC substation, or an HVDC converter station, see Transmission Technology section above. The onshore substation for each phase of the Project will be co-located on one site. As both transmission technologies may be required, both options are assessed in the EIA report.

4.2.3.18 The inclusion of both HVAC and HVDC technology requires both gas insulated switchgear (GIS) and air insulated switchgear to be considered. The onshore substations electrical infrastructure may require to be fully housed in buildings or be partially placed outdoors. Consequently, both options are assessed in the EIA Report.

Approach to EIA

4.2.3.19 Given the design flexibility described above, each technical aspect within the EIA Report considers the scenario that would give rise to the greatest potential effect as relevant to the aspect-specific receptors. This reasonable worst-case scenario is presented in each aspect chapter, with clear justification for why it has been selected as the worst case for that aspect's assessment.

4.3 Location and site information

4.3.1 Red Line Boundary

4.3.1.1 The Red Line Boundary (illustrated in **Volume 2, Figure 1.1: Red Line Boundary**) used to inform this EIA Report is defined as the area within which the Project and associated infrastructure will be located, including temporary construction activities onshore for the lifecycle of the Project.

4.3.1.2 The Offshore Red Line Boundary does not include areas that may be used for the temporary floating storage of Project components (commonly referred to as 'wet storage') as these have not yet been identified. The consent and assessment of wet storage areas is outside the remit of the Project EIA and will be considered as part of any necessary separate consents (for example harbour development works).

4.3.2 Offshore Red Line Boundary and site information

4.3.2.1 The Offshore Red Line Boundary (illustrated in **Volume 2, Figure 4.2: Offshore Red Line Boundary**) includes:

- the NE7 OAA where the wind farm array will be located; and
- the offshore export cable corridor up to MHWS.

4.3.2.2 **Table 4.2** provides the key characteristics of the area enclosed by the Offshore Red Line Boundary.

Table 4.2 Offshore Red Line Boundary characteristics

Parameters	Values
OAA surface area	684 square kilometres (km^2)
Water depth range in OAA	87.8 metres(m) to 133.7m[1]
Closest distance to shore of OAA	75km
Farthest distance to shore of OAA	110km
Export cable corridor surface area	575km^2
Total offshore development surface area (including OAA and offshore export cable corridor)	1,259km^2

[1] Further details on of the geophysical surveys; bathymetry and seabed composition at the OAA are presented in **Chapter 6: Marine Geology, Oceanography and Physical Processes** and **Chapter 7: Marine Water and Sediment Quality**.

4.3.3 Onshore Red Line Boundary and site information

4.3.3.1 The Onshore Red Line Boundary and indicative onshore infrastructure footprint is illustrated in **Volume 2, Figure 4.1** and includes the following:

- landfall(s) – the infrastructure associated with the landfall(s) located above MLWS;
- underground onshore export cables running from the landfall(s) to the onshore substations;
- onshore substations co-located at one site;
- underground grid connection cables (connecting the onshore substations to the grid connection point at SSEN Netherton Hub);
- tie-in to grid connection point (SSEN substation at SSEN Netherton Hub, which is a separate project and does not form part of the consenting applications which this EIA relates to); and
- associated temporary construction areas, including for example construction compounds, access tracks and haul roads.

4.3.3.2 The onshore elements of the Project are located in Aberdeenshire, Scotland. The Onshore Red Line Boundary has an elevation ranging from approximately 0.8m above ordnance datum (AOD) at its lowest point in the eastern area of the Project, rising to approximately 59.3m AOD in the southern area of the Project.

4.3.3.3 The onshore infrastructure is predominantly situated on agricultural land, with residential areas at St Fergus to the west and Inverugie to the south-east. The larger town of Peterhead also lies to the east / south-east of the Project, and scattered dwellings are present in the surrounding area. Longside Airfield is located directly to the west of the onshore export cable corridor before crossing the A950 and is located to the north of the onshore substations.

4.3.3.4 The Project has good accessibility from the A950 road to the west of Peterhead and from the A90, which intersects the Project in the north.

4.3.3.5 There are numerous watercourses present within the Onshore Red Line Boundary, these range in size from field drainage ditches to the River Ugie and its wider catchment. The majority of these watercourses drain into the River Ugie, which is formed from the confluence of the North and South Ugie Waters and flows in a predominantly eastern trajectory before discharging into the North Sea, directly north of Peterhead, Aberdeenshire.

4.3.3.6 **Table 4.3** provides the key characteristics of the area enclosed by the Onshore Red Line Boundary.

Table 4.3 Onshore Red Line Boundary characteristics

Parameters	Values
Onshore export cable corridor length	Approximately 13.35km.
Typical onshore export cable corridor width	From the landfall(s) to the onshore substations, the temporary corridor is typically up to 89m wide, with a permanent (servitude) width of typically up to 61m. From the onshore substations to SSEN Netherton Hub, the corridor is typically up to 99m wide, with a permanent (servitude) width of typically up to 71m.

4.4 Key components of the Project infrastructure

4.4.1.1 For the purpose of this EIA Report, the key components of the Project are separated into offshore, landfall(s) and onshore elements, with an overview of each provided below in **Sections 4.5** to **Section 4.8**. These subsequent sections provide detail and parameters where possible at this stage of design development and are described in accordance with the indicative design envelope principle.

4.4.1.2 The key components of the Project are shown in **Plate 4.1**, noting the components that are common to both HVDC and HVAC technology. A description of the function of each component is provided in **Table 4.4**.

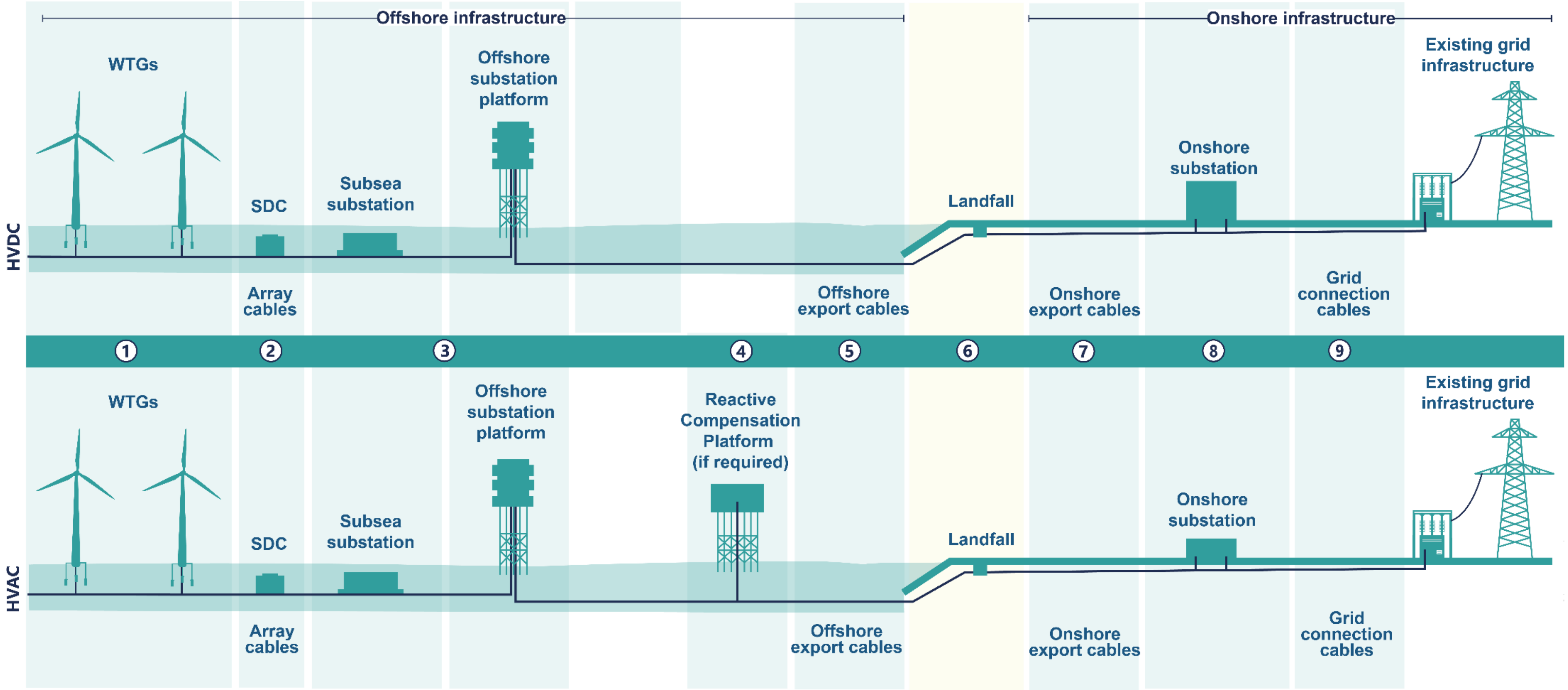
Table 4.4 Key components and functionality

Plate 4.1 ID	Component	Purpose / function
Offshore infrastructure		
1	**Floating WTGs**	WTGs convert wind energy to electricity. Each floating WTG will comprise a tower (assembled in sections), a rotor with three blades attached to a nacelle. The nacelle typically houses a gearbox, generator, converter, transformer, and control equipment.
	WTG floating unit	Each WTG is supported by a floating unit that is positively buoyant and moored in position on the seabed. A number of floating unit concepts are currently under consideration.
	WTG station keeping system	Each WTG on its floating unit will be secured in place using a station keeping or mooring system, involving anchors and mooring lines. Typically, multiple mooring lines will spread out radially from the floating structure, each ending in an anchor point on the seabed.
2	**Array cables**	Array cables will be used to connect the WTGs to the offshore substation. This will be via other WTGs if in a string or loop arrangement, or to a subsea distribution centre, and then onto the offshore substation if in a star configuration. The cables will have a requirement to withstand both dynamic conditions at

Plate 4.1 ID	Component	Purpose / function
		the floating units as well as static lay and burial in or on the seabed.
	Subsea distribution centres (SDC)	The SDCs allow cables from multiple WTGs to connect, with a single array cable then going from the subsea distribution centre to the offshore substation. Subsea distribution centres comprise a foundation support structure and protection structure.
3	**Offshore substation(s)**	Offshore substations are installed to collect the energy generated by the WTGs and house transmission equipment. The latter is required to convert the wind farm electricity to higher voltages necessary for long distance transmission through subsea cables to the onshore grid. Offshore substations can be above the sea surface on a platform and / or subsea. Up to four platforms may be required for the Project.
	Subsea substations	Subsea substations comprise a foundation support structure and protection structure, which is secured subsea to support associated collection and transmission equipment. Given the access restrictions from being subsea, they will be designed for ease of access for O&M activities.
4	**RCP**	For HVAC transmission, there is an upper limit of offshore export cable route length, beyond which the electrical losses incurred during transmission become prohibitive. This limit can be increased using reactive power compensation equipment connected through a separate substation(s) along the offshore export cable route, typically close to the mid-point between the offshore substation and onshore substations.
5	**Offshore export cables**	Subsea export cables connect the offshore substation(s) to the landfall(s)where a transition joint bay links the offshore subsea cables to the onshore underground cables. This cable system is necessary to export power from the offshore wind farm through the onshore substations to the existing grid network.
Landfall(s)		
6	**Landfall(s)**	The landfall is the point at which the offshore export cables cross from the marine environment through the intertidal zone to the terrestrial environment and connect to the onshore export cables via transition joint bays. A trenchless solution is to be implemented to install ducts. Whilst other trenchless methods are available, horizontal directional drilling (HDD) (or similar trenchless technique) is assessed in the EIA Report. In relation to trenchless crossings, HDD has been presented in the EIA. Whilst other trenchless methods are available, HDD is presented herein as it is likely to have the largest construction footprint.
	Transition joint bay	This is a component of the landfall where the offshore export cables connect with the onshore export cables. Transition joint bays are permanent, below ground infrastructure, where the offshore and onshore export cables are jointed together.

Plate 4.1 ID	Component	Purpose / function
Onshore infrastructure		
7	**Onshore export cables**	These are underground cables that connect from the landfall transition joint bays to the onshore substations. As with the offshore export cables, the type and number of cables will depend on the transmission technology used. Cables are typically installed in ducts in a standard buried trench arrangement where possible. A trenchless method may be necessary to cross sensitive features such as watercourses, roads and pipelines. Whilst other trenchless methods are available, HDD (or similar trenchless technique) is assessed in the EIA Report.
8	**Onshore substations**	Three onshore substations are required to transform / convert the onshore export cable voltage to the 400 kilovolts (kVs) required to connect to SSEN Netherton Hub.
9	**Grid connection cables**	These are the underground cables that connect from the proposed onshore substations to the grid connection point at SSEN Netherton Hub. These cables will be 400kV alternating current (AC); compatible with grid requirements at the grid connection point. Cables are typically installed in ducts in a standard buried trench arrangement where possible. A trenchless method may be necessary to cross sensitive features such as watercourses, roads and pipelines. Whilst other trenchless methods are available, HDD (or similar trenchless technique) is assessed in the EIA Report.
	Grid connection	The nominated 400kV SSEN substation at SSEN Netherton Hub into which the Project will connect, noting that SSEN Netherton Hub is a separate project and does not form part of the consenting applications that this EIA relates to.

Plate 4.1 Key components of the Project



4.5 Offshore elements of the Project

4.5.1 Overview

4.5.1.1 The offshore elements of the Project refer to works seaward of MHWS at the coast and will include the following key components:

- WTGs, including floating units (platforms and station keeping system);
- array cables;
- subsea distribution centres;
- subsea substations;
- offshore substations;
- RCPs (if required); and
- offshore export cables to connect the offshore infrastructure to the landfall(s).

4.5.1.2 These are described in this Section, with the relevant installation methodologies described in **Section 4.6**.

4.5.1.3 The Offshore Red Line Boundary is illustrated in **Volume 2, Figure 4.2**. The design envelope for the key offshore components are provided in the following sections.

4.5.2 WTG

4.5.2.1 The Project will have a total grid connection capacity of up to 3GW. The generating capacity of the offshore wind array depends upon a range of WTG specifications, which are not yet agreed.

4.5.2.2 Depending on the final WTG size selected, the Project is expected to have in the region of 126 to 225 WTGs (assuming a typical overplanting of around 5%). As WTG technology is continually evolving, it is difficult to definitively predict the generating capacity of WTGs that will be commercially available at the point of construction. As is common for all offshore wind farms, the final choice of WTG will be subject to a procurement exercise carried out post-consent.

4.5.2.3 This EIA considers two WTG power outputs based on the minimum and maximum characteristics of turbine models that are expected to be available at the time of procurement. These are described throughout this EIA Report as a '14MW WTG' and '25MW WTG', and the EIA considers two design scenarios based on up to 225 turbines for the 14MW WTG and up to 126 turbines for the 25MW WTG.

4.5.2.4 Irrespective of size, the WTGs will comprise three turbine blades linked to a horizontal rotor axis and attached to a nacelle, which houses a gearbox, generator, and transformer (see **Plate 4.2**). This will be placed at the top of a tower, which is expected to be assembled in sections. The nacelle will be able to rotate on the vertical axis in order to face the oncoming wind direction. The WTGs will include appropriate lighting and markers for aviation and navigation.

4.5.2.5 The WTGs will be arranged in a suitable configuration for the site (for example strings, stars or loops). The exact design selection is subject to ongoing technology review and design evolution. The final number, size, capacity and layout of WTGs will be determined post-consent based upon further assessment of the optimum wind resource, prevailing site conditions, the capacity of each individual WTG and findings of environmental and engineering surveys.

4.5.2.6 Where a layout is required to assess specific impact pathways for EIA technical aspects, indicative worst-case layouts have been developed based on two WTG scenarios (see **Volume 2, Figure 4.3: Indicative layout for 225 WTGs with a 14MW capacity** and **Figure 4.4: Indicative layout for 126 WTGs with a 25MW capacity**, respectively). The assumptions upon which these indicative worst-case layouts have been based are described in the respective EIA Report chapters.

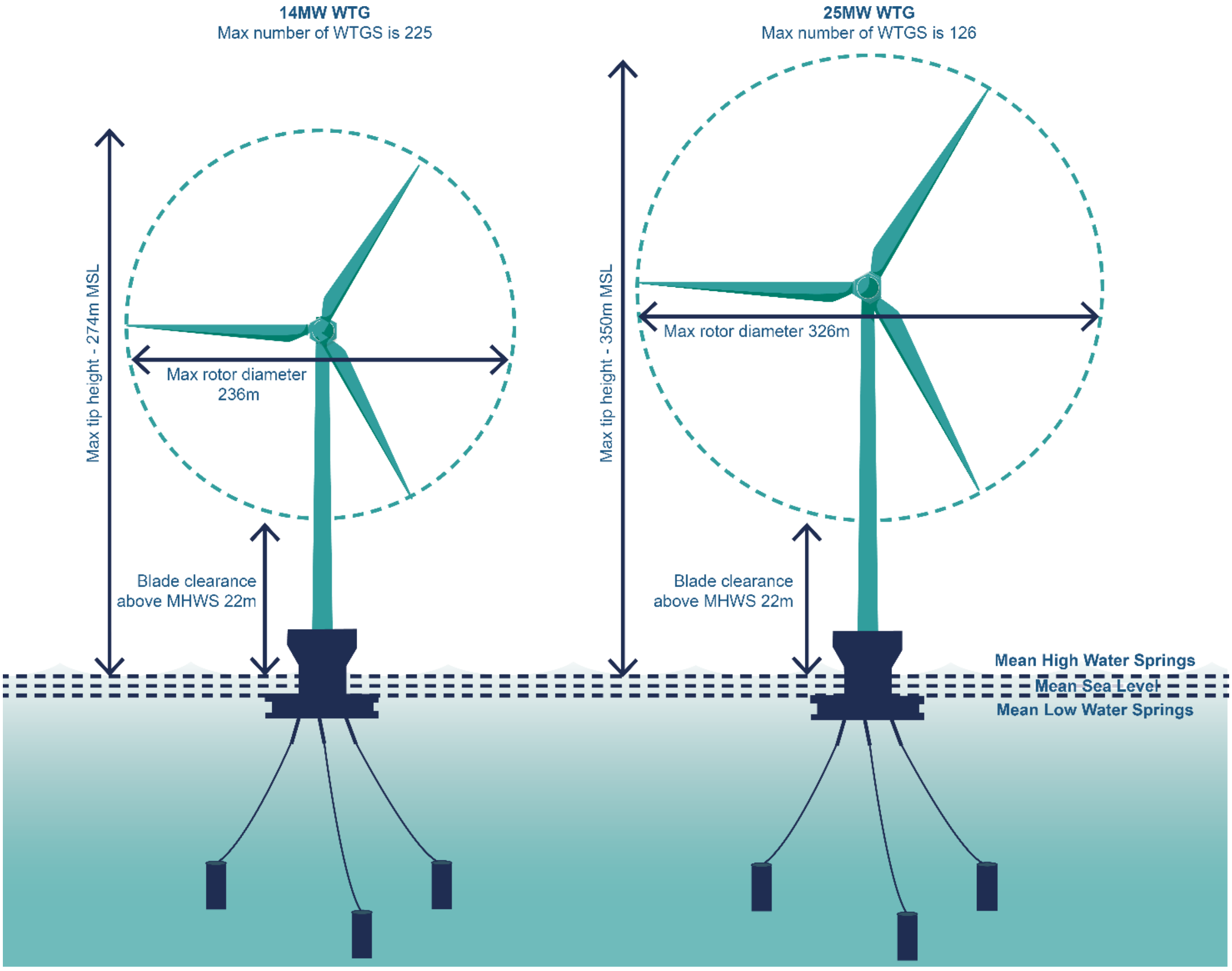
4.5.2.7 The maximum design scenario for the WTGs is provided in **Table 4.5** and illustrated in **Plate 4.2**.

4.5.2.8 Installation methods are outlined below in **Section4.6**.

Table 4.5 Wind turbine generator parameters

Parameters	Indicative design envelope	
Maximum turbine power output	14MW	25MW
Maximum number of WTGs	225	126
WTG hub height (to centreline of hub) (mean sea level) (MSL)	142m	182m
Operational wind speed (rotor cut-in / cut-out range)	3 / 28m/s	3 / 28m/s
Maximum rotor diameter	236m	326m
Rotor blade width	5.1m	10m
Rotor blade length	115m	155m
Number of blades per WTG	Three	Three
Rotation speed (minimum / maximum)	0 / 8 revolutions per minute (rpm).	0 / 7.62rpm
Blade pitch	3.5º	3.5º
Maximum rotor blade tip height (MSL)	274m	350m
Minimum rotor blade tip height (above MLWS)	260m	340m
Turbine colour	Assumed white.	Assumed white.
Blade clearance above MHWS	22m	22m
Navigational lighting	As required by Civil Aviation Authority (CAA), Maritime and Coastguard Agency (MCA).	As required by CAA and MCA.

Plate 4.2 Illustration of wind turbine generator maximum dimensions



See **Plate 4.3** and **Plate 4.5** for further mooring concepts.

4.5.3 Floating units

4.5.3.1 The WTGs will each be mounted on a floating unit, which will consist of a floating platform or 'floating unit' that will be secured to the seabed by a dedicated 'station keeping system'. The station keeping system consists primarily of mooring lines and seabed anchors. Several design options are being considered for the floating unit. The final design concept will be identified following further market engagement, site survey and design development. This EIA Report considers a design envelope associated with a potential range of floating unit types. Three designs are currently being considered for the floating units: semi-submersible, barge and tension leg platform (as illustrated in **Plate 4.3** and **Plate 4.4**). However, any other hybrid design to take into account emerging or future technologies will also be considered.

4.5.3.2 A semi-submersible floating unit supports the WTG via typically three or four corner columns with a supporting structure to connect the columns together, and the WTG situated on one of the columns or centrally within the structure.

4.5.3.3 A barge floating unit is typically a solid structure, sometimes containing a moonpool structure.

4.5.3.4 A tension leg platform seen from the water appears similar to a monopile structure, having a small dimension at the waterline. Below the surface, there is additional structure providing greater buoyancy than required, the structure is stabilised and position maintained by taut tendons. Typically tension leg platform will require the tension from the tendons to remain stable.

4.5.3.5 **Table 4.6** provides the maximum design scenarios for the three types of floating unit described. Justification for the floating unit type selection considered within the design envelope is provided in **Chapter 3: Site Selection and Consideration of Alternatives**.

Plate 4.3 Illustration of floating unit types considered

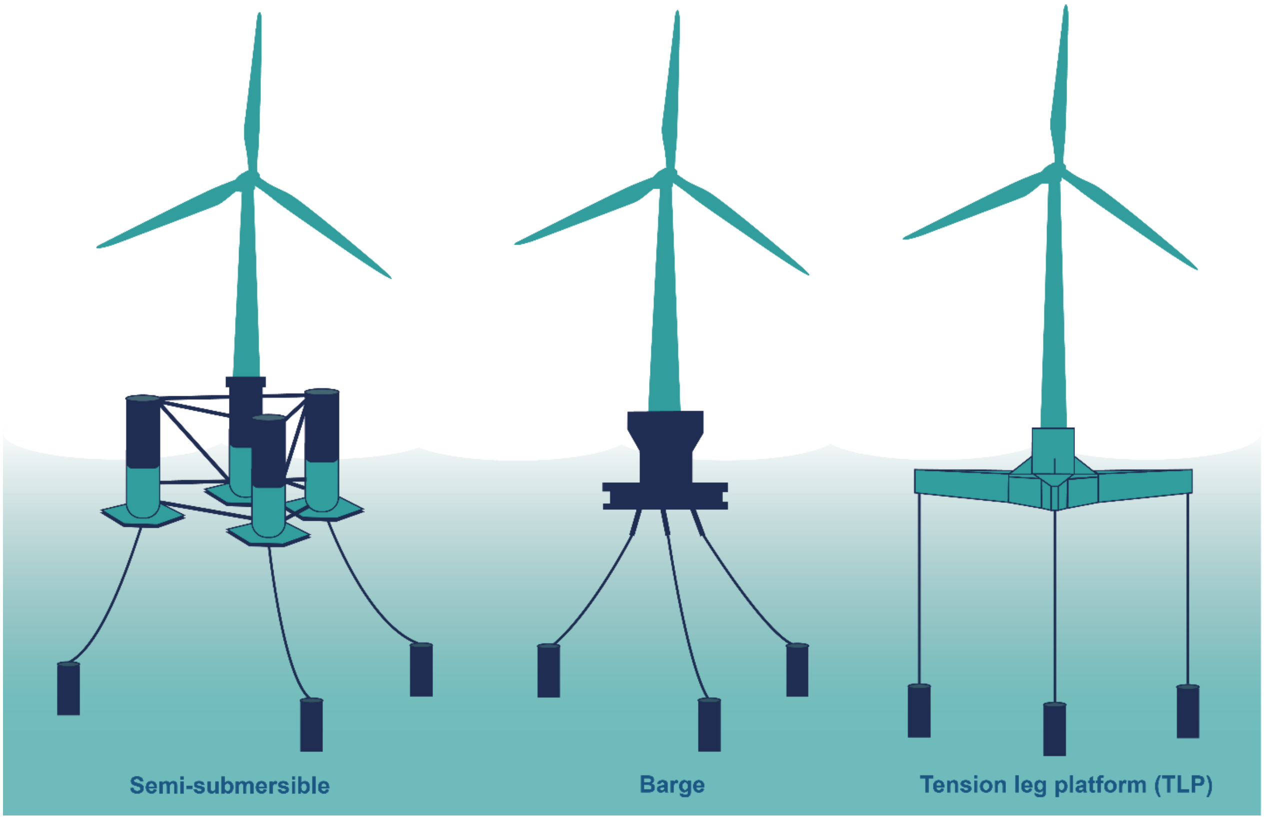


Plate 4.4 Floating platform key spatial parameters

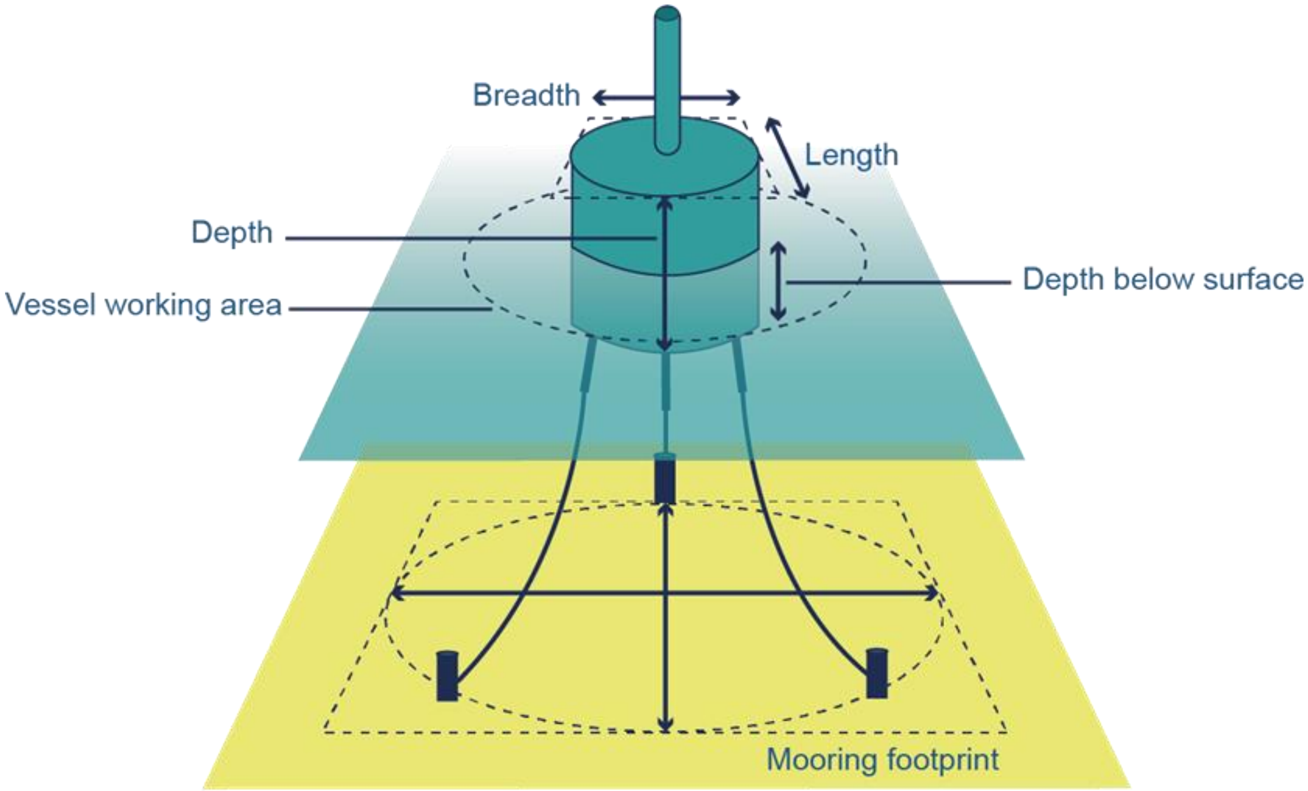


Table 4.6 Floating unit parameters

Parameters	Indicative design envelope
Floating unit concepts considered	Semi-submersible, barge, tension leg platform, or any other hybrid design to take into account emerging or future technologies.
Floating unit surface dimensions	100m x 120m maximum size of floating unit (relates to semi-submersible as worst case).
Floating unit shape	Rectangular, circular, triangular or hexagonal.
Floating unit minimum spacing from other structures	800m from centre of WTG to centre of nearest adjacent WTG. Minimum of 500m from WTG blade tip to offshore substation topsides.
Elevation above waterline	Minimum 15m to maximum 25m above MSL.
Floating unit cable location	Typically the base or one side of the floating unit.
Mooring line connection points	Connection point is likely to be below the surface at the base of the floating unit. Alternatively, it might be connected above the waterline.

Parameters	Indicative design envelope
Navigational safety lighting	All offshore infrastructure will have navigational safety lighting, the details of which will be agreed with key stakeholders (i.e. MCA and Northern Lighthouse Board) and as per International Association of Marine Aids to Navigation and Lighthouse Authorities Recommendation G1162 (IALA, 2021) via Volume 4: Lighting and Marking Plan.
Number of mooring lines per floating unit	Maximum of eight (see Table 4.7 for further details on mooring lines).
Platform colour	As required by MCA.

Moorings

4.5.3.6 A key component of all floating unit designs is the mooring of the floating unit to anchor points on the seabed. The purpose of moorings is to maintain the position of the floating unit and WTG against the forces of wind and waves over the lifetime of the Project. Mooring lines may be made up of chain, synthetic fibre or steel wire elements or any combination of these.

4.5.3.7 The overall seabed footprint of the WTG floating unit, whichever design concept is selected, will depend on the mooring concept selected (see **Plate 4.5**), which could be:

- catenary mooring (in which each mooring line hangs in a slack curve dictated by its own weight);
- semi-taut mooring (in which slack and taut elements are used in combination in the mooring system);
- taut-line mooring (in which each mooring line is tensioned until it is taut); and
- vertical tension mooring (in which each mooring line, or 'tendon', is installed near vertically and kept under constant high tension, with stability providing by the restoring force from the tendons resisting vertical displacement of the floating structure).

4.5.3.8 **Table 4.7** provides the maximum design scenarios for the three types of mooring concept considered.

Plate 4.5 Mooring concepts

Table 4.7 Moorings parameters

Parameters	Indicative design envelope	
Mooring concepts considered	Catenary mooring, taut-line mooring, semi-taut mooring, vertical tendon mooring.	
Number of mooring line connection points	Semi-submersible floating unit.	Minimum three, maximum eight using catenary mooring or semi-taut moorings.
	Barge floating unit.	Minimum three, maximum eight using catenary mooring or semi-taut moorings.
	Tension leg platform floating unit.	Minimum three, maximum eight tendons.
Mooring footprint (max)	800m radius per individually moored floating unit (all mooring lines and mooring footprint will be within the OAA boundary).	
Total mooring footprint (max)	2,010,619m^2 / 2.01km^2	

Anchors

4.5.3.9 Anchoring is an integral part of the overall mooring system and there is a wide spectrum of anchoring solutions that could installed for the floating unit concepts identified above. These include drag embedment anchors, driven piles and suction anchors. Justification of the anchor type selection considered within the design envelope is provided in **Chapter 3: Site Selection and Consideration of Alternatives**.

4.5.3.10 Drag embedment anchors are large steel structures that use frictional and pull force on the mooring lines such that part of the anchor penetrates and grips the seabed.

4.5.3.11 Driven pile anchors are typically hollow steel columns or piles, that are driven into the seabed by hammer as a means of maintaining station.

4.5.3.12 Suction anchors comprise a steel cylinder with the lower end open to face the seabed and the upper end sealed above. Suction anchors use suction to create a pressure differential the interior of the anchor and the water column to maintain station. The installation methodology for all anchor types is described in **Section 4.6.3**.

4.5.3.13 **Table 4.8** provides the scenarios for the three types of anchors considered.

Table 4.8 Anchor parameters

Parameters	Indicative design envelope (per anchor)
Drag embedment anchors	
Maximum length	12m
Width	12.5m
Height	7m
Height proud of seabed once fully installed	0m
Maximum seabed displacement	3,750m^2
Driven pile anchors	
Maximum pile length	30m
Pile diameter	3m
Maximum hammer energy	3,500 kilojoules (kJ)
Number of piles per day	Minimum of one and maximum of two.
Length of pile proud of seabed once fully installed	0.5m
Maximum seabed displacement	7.07m^2
Suction anchors	
Maximum pile length	20m
Pile diameter	6.5m
Length of pile proud of seabed once fully installed	0.5m
Maximum seabed displacement	33.18m^2

4.5.4 Array cables

4.5.4.1 Each array cable will be a single 3-core AC cable, constructed using a ‘dynamic’ cable design with additional mechanical protection. The cable can be described in two sections: a dynamic section required to move with the floating unit; and a static section, which will most likely be buried for protection.

4.5.4.2 The array cables will be up to 132kV dependant on size of WTG. The total maximum array cable length for the full 3GW expected to be up to 680km.

4.5.4.3 The dynamic array cables will typically be in an lazy 's' configuration (see **Plate 4.6**), likely with the addition of a tethered clump weight to maintain the dynamic section of the array cable in position and clear of the mooring lines.

4.5.4.4 In the case of a string design, there will be a dynamic section on both ends of the cable (for instance between two floating units) with a static section in the middle. The floating unit that is at the start of the string will have a static second end, which will be connected into a J-tube / I-tube on the offshore substation.

4.5.4.5 If a star design is used then the second end will be static and connected into a subsea connection station, after which a separate static cable connecting the subsea connection station to the offshore substation will be required.

4.5.4.6 These different configurations (for example strings, stars or loops) have variable operational and maintenance requirements and so the selection of the most appropriate design is the subject of ongoing technology review and design evolution.

4.5.4.7 The maximum design scenario for the array cables is provided in **Table 4.9**.

Plate 4.6 Illustration of 'lazy wave' dynamic cable

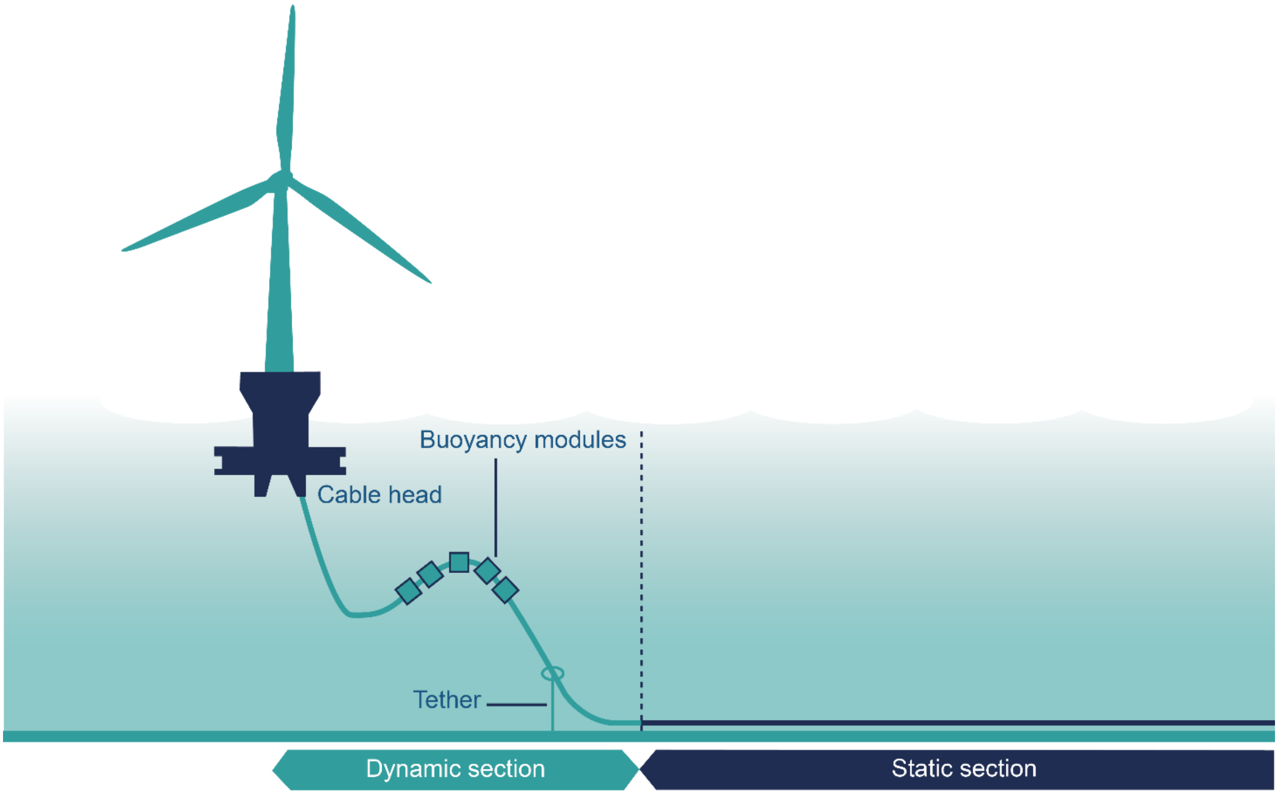


Table 4.9 Array cable parameters

Parameters	Indicative design envelope	
	14MW WTG	**25MW WTG**
Proposed operating voltage	Between 66kV and 132kV.	Between 66kV and 132kV.
Number of cables	225	126
Secondary protection considered	Rock placement. Localised: concrete mattresses and bags.	Rock placement. Localised: concrete mattresses and bags.
Cable protection type, volume and location(s)	1,122,000m^3 of rock; or 22,666 mattresses; or a combination of both.	874,500m^3 of rock; or 17,667 mattresses; or a combination of both.
Total array cable length	680km	530km
Permanent array cable corridor swathe width (m) and area	3m width except for areas of rock placement where 15m is conservatively assumed. Area of 2.04km^2.	3m width except for areas of rock placement where 15m is conservatively assumed. Area of 1.59km^2.

Parameters	Indicative design envelope	
	14MW WTG	25MW WTG
Maximum extent of burial	680km (assuming 100% burial of total length of cable is possible).	530km (assuming 100% burial of total length of cable is possible).
Trench / disturbance width	30m per trench.	30m per trench.
Length of unburied cable	136km (assuming a worst case of 20% of cable length cannot be buried).	106km (assuming a worst case of 20% of cable length cannot be buried).

4.5.4.8 It is anticipated that there could be up to six crossings for array cables within the Project's OAA. Further information on cable crossings is provided in **Section 4.6**.

Subsea distribution centres and subsea substations

4.5.4.9 Concepts currently being considered for the Project are SDCs and subsea substations, both of which are installed on the seafloor. SDCs connects cables from multiple WTGs, allowing a star configuration of the WTGs and array cables. This benefits operational phase efficiency by maintaining transmission for WTGs in the star in the event of a failure in an array cable or WTG. Only the faulty cable or WTG would become off-line, with the remainder of the WTGs connected to the SDC continuing to generate.

4.5.4.10 Subsea substations are an alternative to tradition offshore HVAC fixed platform / topsides substation. They perform the same functionality in that they collect and transmit the electricity generated from the WTGs (see **Section 4.5.5**) but will house different (typically less) equipment that on a topside platform. The electricity transmitted is in HVAC form.

4.5.4.11 The maximum design scenario for the subsea distribution centres and subsea substations is provided in **Table 4.10**.

Table 4.10 Subsea distribution centres and subsea substations parameters

Parameters	Indicative design envelope
Maximum number of subsea distribution centres	45 (between five to eight array cables can be connected into one subsea distribution centres).
Maximum dimensions of subsea distribution centre (length x width x height)	18m x 8m x 5m
Maximum dimensions of subsea distribution centre including cable protection (length x width)	38m x 28m
SDC construction footprint (length x width)	58m x 48m
Foundation type for subsea distribution centre	Suction caisson / skirt and gravity base foundations.
Maximum number of subsea substations	Four

Parameters	Indicative design envelope
Maximum dimensions of subsea substation centres (length x width x height)	22m x 20m x 16m
Maximum dimensions of subsea substation including cable protection (length x width)	42m x 40m
Foundation type for subsea substation	Suction caisson / skirt and gravity base foundations.

4.5.5 Offshore substation

4.5.5.1 The WTGs will connect (via the array cables and subsea distribution centres, if deployed) to substation platforms located within the OAA. It is anticipated that there will be up to four offshore substations associated with the Project. The offshore substations will transform generated electricity from the WTGs to a higher voltage for transmission to shore via offshore export cables. The location and extent of the offshore substations will be confirmed through detailed design process but will be located within the Red Line Boundary. The worst case locations have been considered for the purpose of the assessment. The offshore substations may be interconnected by link cables to deliver the combined output to a common export location, and for redundancy.

4.5.5.2 The offshore substations will house the main electrical equipment, auxiliary, controls and operational systems necessary. The offshore substations may also include a helideck. The offshore substations will include appropriate lighting and markers for aviation and navigational safety.

4.5.5.3 It is anticipated that the offshore substation platform foundations that will support the topside equipment will be either jacket secured by driven piles or suction caisson fixed foundations. The fixed design concept types being considered are shown in **Plate 4.7**.

4.5.5.4 The requirement for scour protection cannot be ruled out at this stage until the jacket designs are developed further and the scour risks have been quantified. Scour protection could include rock placement.

4.5.5.5 The scour protection area and volume has been calculated based on independent areas for each platform leg or suction caisson.

4.5.5.6 The maximum design scenario for the offshore substations is provided in **Table 4.11**, including the foundation footprint sizes with the inclusion of scour protection, the form and scale of which would be decided either following geophysical and technical surveys and design phase of the Project and / or from post installation surveys.

Plate 4.7 Illustration of fixed foundation types

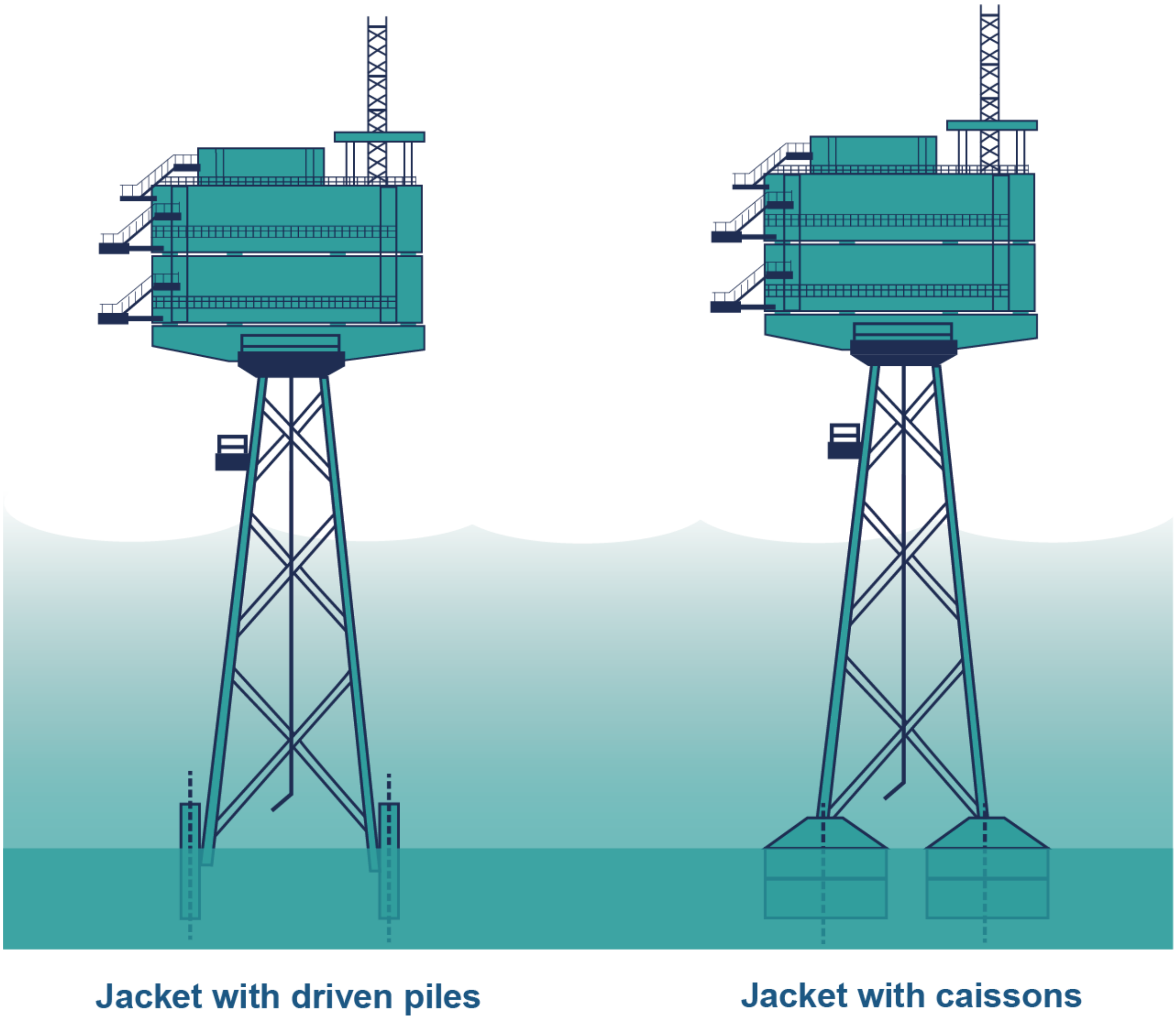


Table 4.11 Offshore substation parameters

Parameters	Indicative design envelope
Number of offshore substations	Four
Water depth at proposed locations	Between 87.8m to 133.7m.
Offshore substation foundation type	Jacket foundations secured by driven piles or suction caisson.
Offshore substation shape	Rectangular or square topsides.
Minimum spacing to other structures	500m to other offshore substations.

Parameters	Indicative design envelope
	500m from WTG blade tip to offshore substation topsides infrastructure.
Offshore substation topsides above-surface dimensions (maximum)	80m above lowest astronomical tide (LAT) (not including mast and lightning conductor and cranes). 100m above LAT (including mast and lighting conductor and cranes). 106m length. 70m width.
Offshore substation foundation above-surface dimensions	20m above LAT. 80m length. 60m width.
Offshore substation foundation below-surface dimensions (maximum) (width x length)	80m x 60m
Minimum height above water	20m (height from LAT to main deck of topsides).
Driven piles length	95m
Number of driven piles in total	12 for each offshore substation.
Driven pile maximum diameter	3m
Driven pile maximum hammer energy	3,500kJ
Number of driven piles per day	Minimum of one and maximum of two.
Length of pile proud of seabed once fully installed	0.5m
Offshore substations construction footprint	130m x 110m
Maximum seabed footprint (including scour protection)	110m x 90m
Scour protection types	Rock placement. Localised: concrete mattresses and bags.
Scour protection quantity per foundation	500m^3 per offshore substation.

4.5.6 Offshore export cables

4.5.6.1 The wind farm would be connected to the landfall(s) by a maximum of five offshore export cable circuits. Each will be laid in a separate trench in the seabed. They will connect to onshore export cables via a transition joint bay, that will connect via further cables onward to the onshore substations. The offshore export cables will consist of one copper or aluminium conductor with electrical insulation material, screens, communication fibre and protective armour layers at expected voltages of 275kV for HVAC and either ±320kV or ±525kV for HVDC (depending on what type of HVDC technology is deployed). Each export cable would have a fibre optic cable (FOC) either integrated within the cable or secured to the outside.

4.5.6.2 The offshore export cables will be typically buried 1m to 2m below the seabed for most of their length to the landfall(s) (see **Section 4.7** for further information), depending on the outcome of the cable burial risk assessment. The exact routing of the export cables within the offshore export cable corridor will be determined during the detailed design process of the Project, with consideration of seabed conditions and environmental sensitivities following pre-construction surveys.

4.5.6.3 The maximum design scenario for the offshore export cables is provided in **Table 4.12**.

Table 4.12 Offshore export cable parameters

Parameters	Indicative design envelope
Expected offshore export cable maximum voltage	275kV for HVAC. ±320kV or ±525kV for HVDC (depending on what type of HVDC technology is deployed).
Grid transmission route length offshore	130km to 140km depending on the offshore substation and landfall(s) location(s)
Number of offshore cable trenches (maximum)	Five
Cable trench width	Up to 30m per trench.
Percentage of offshore export cable corridor considered suitable for burial	Target burial of 100% of offshore export cables.
Number of infrastructure crossings (max)	16 known crossings and an additional six (to take account of other developers export cables) within the offshore export cable corridor and six assumed crossings within the OAA.
Trench / disturbance width	30m per trench. 150m total.
Burial depth	The offshore export cables will be typically buried 1m to 2m below the seabed.
Separation distance between cable trenches	Closest distance will be three times the water depth along the offshore export cable route.

Parameters	Indicative design envelope
Permanent cable corridor swathe width and area	3m width except for areas of rock placement (20% of cable route) where 15m is conservatively assumed. Total area for five cable trenches is 21km^2.
Cable protection type	Rock placement. Localised: concrete mattresses, bags or steel split pipe.
Cable protection locations	Worst case assumes 20% of length requires rock placement.
Cable protection berm dimension (height x width)	2m x 7m
Cable protection volume	1,155,000m^3
Dredging volume	35,000m^3

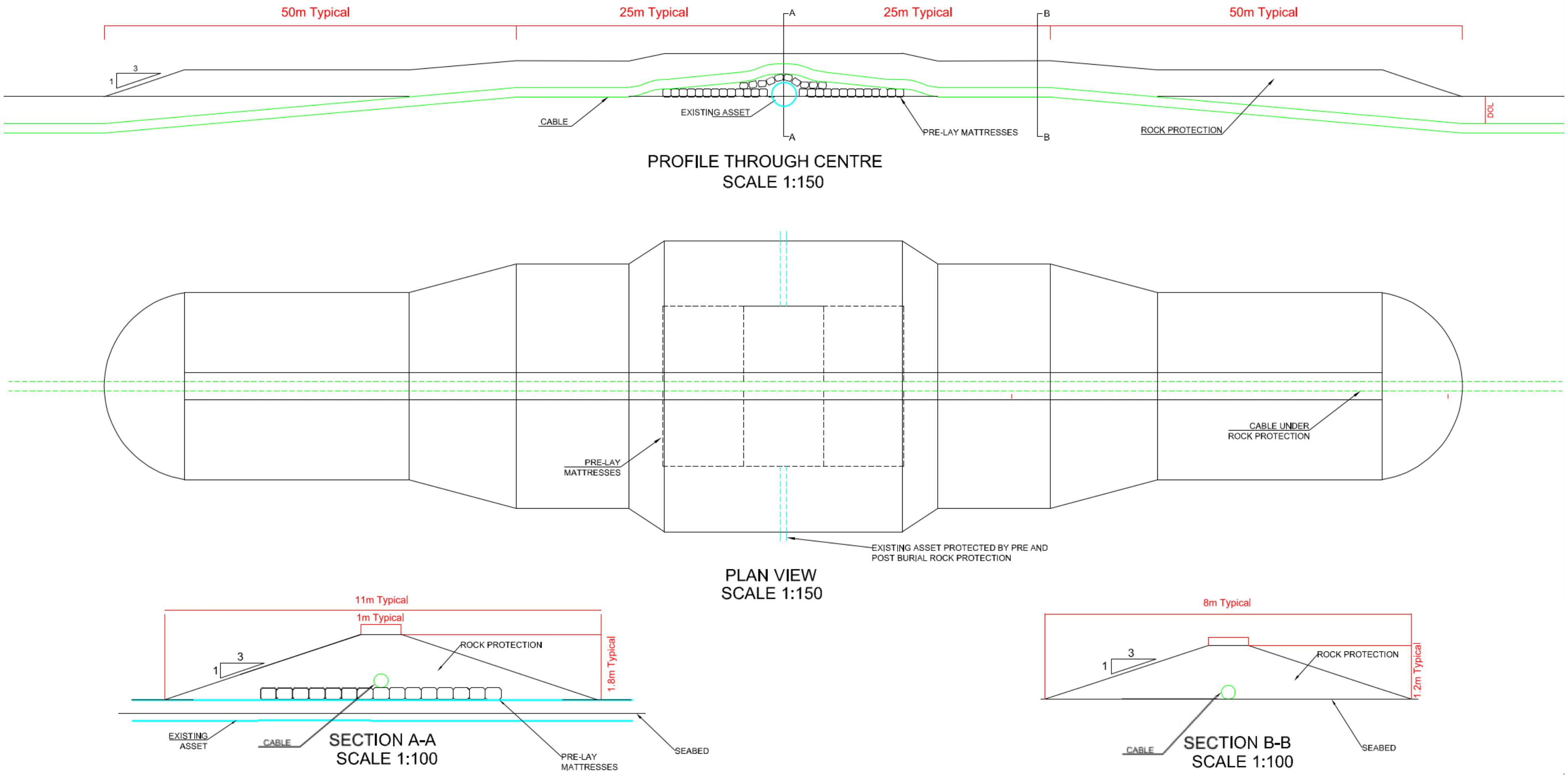
4.5.6.4 There are currently 16 known cable crossings required along the offshore export cable corridor outwith of the OAA. The Applicant has included an additional six number of crossings as a contingency, to include for potential cable discoveries post-consent, which will be informed by pre-construction magnetometer surveys and / or due to the competitive nature of the nearshore area it is possible that additional crossings maybe necessary if other developments are constructed ahead of the Project. In addition, an assumption of six crossings are included within the OAA itself to enable the offshore export cables to exist the OAA in close vicinity to each other. There a total number of 28 crossings are included.

4.5.6.5 The maximum design scenario for the cable crossings is provided in **Table 4.13**. A typical crossing is presented in **Plate 4.8**.

Table 4.13 Cable crossings parameters

Parameters	Indicative design envelope
Number of cable crossings	28 (per cable trench).
Permanent crossing dimensions (including rock placement) (length x width)	150m x 11m.
Permanent crossings area (including rock placement)	1,650m^2
Crossing construction footprint (length x width)	170m x 30m.
Crossing protection volume	850km^3 per crossing.

Plate 4.8 Protection for cable crossings



Electromagnetic fields and heat generated

4.5.6.6 The offshore export cables transmit electricity at a higher voltage than is used in the array cables.

4.5.6.7 Electromagnetic fields (EMF) emitted by HVAC offshore subsea cable are minimised by the arrangement of cable cores; three cores are laid together in trefoil and as the phase currents are balanced, the magnetic fields of the three cores tend to zero. The magnitude of the magnetic fields in the proximity of the cable is null and its presence in the sea bottom inert. Burial of the cable will also act to minimise emission of EMF.

4.5.7 RCP (HVAC only)

4.5.7.1 Long distance, large capacity HVAC transmission systems may require RCPs to reduce the reactive power generated by the capacitance of the offshore export cable to improve power quality, voltage stability and transmission efficiency.

4.5.7.2 A maximum of two RCPs (if required) will be located within the offshore export cable corridor, typically between 40% to 60% of the total length from an offshore substation within the OAA to the onshore substations. Offshore export cables from the OAA would connect into the RCP before exiting the RCP and continuing to the landfall(s). While the location is not yet determined, the Applicant has included possible areas for installation of the structures within the Red Line Boundary and relevant consenting applications.

4.5.7.3 The final location of the offshore RCP(s) within the identified search area will be defined in the detailed design stage, post consent. The siting will take into account final electrical design, water depth, ground conditions, marine traffic, proximity to shore, other existing / planned infrastructure and other engineering and economic factors.

4.5.7.4 The RCPs will likely be paired in proximity to each other and may be connected by a bridge.

4.5.7.5 The design of an RCP would be similar to the offshore substations. This is likely to be a multi-tier topside module containing the RCP equipment, which is installed on a foundation structure. It is anticipated that the RCP foundations will be either jacket or suction caisson fixed foundations. The fixed design concept types being considered are shown in **Plate 4.7**.

4.5.7.6 The maximum design scenario for the RCP is provided in **Table 4.14**.

Table 4.14 RCP parameters

Parameters	Indicative design envelope
Number of RCPs (maximum)	Two
Water depth range at proposed locations	73.74m to 110.53m
RCP foundation type	Jacket foundations secured by driven piles or suction caisson.
Offshore RCP shape	Rectangular or square topsides.
Spacing separation distance between RCPs	50 to 150m

Parameters	Indicative design envelope
RCP topsides above-surface dimensions	80m above LAT (not including mast and lightning conductor and cranes). 100m above LAT (including mast and lighting conductor and cranes). 50m length. 50m width.
RCP foundation above-surface dimensions (length x width)	35m x 35m
Minimum height above water	20m LAT.
Driven piles length	95m
Number of driven piles in total	Four for each RCP.
Driven pile maximum diameter	3m
Driven pile maximum hammer energy	3,500kJ
Number of driven piles per day	Minimum of one and maximum of two.
Length of pile proud of seabed once fully installed	0.5m
RCP construction footprint	85m x 85m
Maximum seabed footprint (including scour protection)	65m x 65m
Scour protection types and quantity per foundation	Rock placement. Localised: concrete mattresses and bags.
Scour protection quantity per foundation	500m^3 per RCP.
Closest distance to shore (MHWS) of RCP search area	31.85km

4.6 Offshore installation methodology

4.6.1 Overview

4.6.1.1 Construction of the offshore components of the Project will be completed in a number of stages. The stages are described sequentially below, although given the scale of the Project it is likely that some stages are undertaken in parallel in practice. The stages are described as follows:

- pre-construction surveys and seabed preparation activities (**Section 4.6.2**);

- anchor and mooring line installation (**Section 4.6.3**);
- floating unit and wind turbine preparatory works (**Section 4.6.4**);
- mooring installation (**Section 4.6.5**);
- floating wind turbine towing to site (**Section 4.6.6**);
- array cable and SDC installation (**Section 4.6.7**);
- offshore platform foundation installation and piling (**Section 4.6.8**);
- offshore platform topside installation (**Section 4.6.9**);
- offshore export cable installation (**Section 4.6.10** to **Section 4.6.12**); and
- WTG commissioning (**Section 4.6.13**).

4.6.1.2 Equipment and offshore installation activities will be designed to avoid the need for divers wherever possible. However, in some instances this may not be possible and diver operations may be undertaken subject to the appropriate procedures and risk assessment.

4.6.2 Pre-construction surveys and seabed preparation

4.6.2.1 Geophysical and geotechnical surveys of the OAA and offshore export cable corridor will be conducted to determine the seabed preparation activities necessary in advance of construction. These surveys will be undertaken by a dedicated marine survey vessel, generally with remotely operated vehicle (ROV) and will identify bedforms, obstacles and debris on the seabed within the Offshore Red Line Boundary.

4.6.2.2 Seabed preparation activities can be necessary to clear and stabilise the seabed in advance of construction activities. Works can include the removal of boulders, sand wave levelling, and the removal of debris such as lost fishing gear. The clearance or removal of material or objects from the seabed would be undertaken using suitable equipment.

4.6.2.3 Depending on the density of boulders, these will typically be relocated to a nearby position on the seabed and a safe distance from the planned construction activities.

4.6.2.4 Sediment displaced during the seabed preparation phase would be undertaken by suitable dredging techniques, which will be selected based on soil types, water depths and environmental factors. Dredging would be performed by multiple passes of the area until the required depth of dredging has been achieved.

4.6.2.5 Any licensing requirements for the removal of materials from the seabed will be identified following these pre-construction surveys and applied for by MarramWind Limited (hereafter, referred to as ‘the Applicant’) under the Marine (Scotland) Act 2010 for activities within 12 nautical miles (nm) of the coast, and under the Marine and Coastal Access Act 2009 for activities beyond 12nm.

4.6.3 Anchor and mooring line installation

4.6.3.1 Anchors and mooring lines will be transported to the OAA by vessels prior to the installation of the floating units. Given likely weather window and storage constraints, anchors may be installed year-round and up to several years in advance of the mooring lines and floating units. Mooring lines would be installed in advance (within the same installation year) and wet stored on the seabed awaiting the installation of floating units.

Installation of drag embedment anchors

4.6.3.2 The anchor and mooring lines will be deployed from a vessel to a pre-determined location and orientation. Once in location load will be applied to the anchor drawing it forward and embedding the anchor into the seabed. The load and displacement will be closely monitored throughout and upon completion of the requisite load tests the final position shall be determined and either the mooring line length compensated or in some cases the anchor may be recovered and relayed in an alternate location and process repeated before the floating unit may be connected. Mooring lines will then be connected to the anchor later prior to installation of the floating unit.

Installation of suction anchors

4.6.3.3 Suction anchors will be deployed from a vessel by crane to a predetermined location and orientation on the seabed. Water will then be pumped out of the suction anchor creating a reduced pressure within the anchor, this will result in the anchor being drawn into the seabed. Mooring lines will then be connected to the anchor later prior to installation of the floating unit.

Installation of driven pile anchors

4.6.3.4 Driven pile anchors will be deployed from a vessel by crane to a predetermined location and orientation on the seabed. The crane will lower the pile to the seabed and will be kept in position using a pile gripper. To enable pile placement, a pile installation frame may be temporarily placed on the seabed and removed once the piles are installed. A hydraulic hammer will be positioned onto the pile, driving it to the target depth.

4.6.3.5 Piling will commence with a low hammer energy that slowly ramps up to the maximum necessary. It is anticipated that the maximum hammer energy will only be necessary at certain (not yet defined) piling locations.

4.6.3.6 Detailed geotechnical data of the OAA will be reviewed to inform a driveability assessment. The findings will allow the final hammer energies to be optimised, maintaining piling progress while minimising required hammer energy.

4.6.3.7 Up to two piling events occurring simultaneously at WTG locations (or at WTG and offshore substation locations) are considered within the design envelope. However, no concurrent piling of offshore substation foundations is proposed (see **Volume 4: Outline Piling Strategy** for further information).

4.6.3.8 Mooring lines will then be connected to the anchor later prior to installation of the floating unit.

4.6.4 Floating unit and wind turbine preparatory works

4.6.4.1 Floating unit fabrication will occur at a suitable facility subject to market availability at the time of fabrication. Floating unit assembly (if required), will occur at a suitable port, depending on port availability at the time of assembly. The specific locations of the fabrication facility and assembly port are not yet confirmed.

4.6.4.2 Once the floating unit is assembled and launched, it will be positioned along a quayside or facility for WTG integration. Where possible, tower sections and other components may be preassembled and pre-commissioned prior to integration.

4.6.4.3 Following WTG integration, the floating unit may be relocated to a secondary site to finalise commissioning activities and prepare for tow-out.

4.6.4.4 The completed floating unit will then be towed to the OAA and connected to the pre-installed anchor and mooring system.

4.6.4.5 Ports with adequate capacity to support the marshalling, integration and assembly work will be required but are not yet confirmed.

4.6.4.6 It may be required to temporarily relocate or hold the floating units at a wet storage location to complete these activities or await a suitable installation weather window, but wet storage is not expected for prolonged periods.

4.6.4.7 The location of possible areas for wet storage has not yet been identified but is expected to be within or vicinity of the selected integration port. The consent and assessment covering the temporary storage of floating units is outside the remit of the project EIA and will be considered as part of any separate consents for wet storage (for example harbour development works).

4.6.5 Mooring installation

Installation of mooring lines

4.6.5.1 Anchors and mooring lines will be transported to the OAA by vessels prior to the installation of the floating units. Given likely weather window and storage constraints, anchors may be installed year-round and up to several years in advance of the mooring lines and floating units. Mooring lines would be installed in advance (within the same installation year) and wet stored on the seabed awaiting the installation of floating units.

Installation of drag embedment anchors

4.6.5.2 The anchor and mooring lines will be deployed from a vessel to a pre-determined location and orientation. Once in location load will be applied to the anchor drawing it forward and embedding the anchor into the seabed. The load and displacement will be closely monitored throughout and upon completion of the requisite load tests the final position shall be determined and either the mooring line length compensated or in some cases the anchor may be recovered and relayed in and alternate location and process repeated before the floating unit may be connected.

Installation of suction anchors

4.6.5.3 Suction pile anchors will be deployed from a vessel by crane to a predetermined location and orientation on the seabed. Water will then be pumped out of the suction anchor creating a reduced pressure within the anchor, this will result in the anchor being drawn into the seabed. Mooring lines will then be connected to the anchor later prior to installation of the floating unit.

Installation of driven pile anchors

4.6.5.4 Driven pile anchor installation typically involves construction support vessels (CSVs) equipped with large cranes. The crane will lower the pile to the seabed and will be kept in position using a pile gripper. To enable pile placement, a pile installation frame may be temporarily placed on the seabed and removed once the piles are installed. A hydraulic hammer will be positioned onto the pile, driving it to the target depth.

4.6.5.5 Piling will commence with a low hammer energy that slowly ramps up to the maximum necessary. It is anticipated that the maximum hammer energy will only be necessary at certain (not yet defined) piling locations.

4.6.5.6 Detailed geotechnical data of the OAA will be reviewed to inform a driveability assessment. The findings will allow the final hammer energies to be optimized, maintaining piling progress while minimizing required hammer energy.

4.6.5.7 Up to two piling events occurring simultaneously at WTG locations (or at WTG and offshore substation locations) are considered within the design envelope. However, no concurrent piling of offshore substation foundations is proposed.

4.6.6 Floating wind turbine towing to site

4.6.6.1 Floating units will be prepared for towage to site at the integration port fitted with the requisite navigation aids and towed during an acceptable weather period by a predetermined arrangement of vessels.

Hook up mooring lines and floating unit connection

4.6.6.2 Once the floating unit arrives in the OAA, the vessels may change from a towing arrangement to an installation arrangement. The floating unit will be positioned at the intended installation location within the OAA by the installation vessels utilising dynamic positioning. The floating unit will be held in position whilst further installation vessels will lift the pre-laid mooring system from the seabed and connect it to the floating unit. Once a storm safe arrangement of moorings has been achieved, the vessels holding the floating unit may be released and any final mooring lines connected.

4.6.6.3 Upon completion of the mooring line connections, further mooring line and floating unit commissioning activities may be progressed. These may include any tensioning and adjustments to mooring lines and ballasting of the floating unit to ensure the station and condition of the floating unit is correct in readiness for further installation or WTG commissioning activities.

4.6.7 Array cables and subsea distribution centres installation

4.6.7.1 The array cables will typically be installed on powered reels or carousels from a cable lay vessel. The cable is led along a trackway and overboard through a cable chute of the vessel.

4.6.7.2 The array cables will typically be pulled into the floating unit via a I-tube or J-Tube (or alternative cable entry system) for connection to the WTG. In all cases, the section of the array cable from the floating unit to the seabed will be dynamic and subject to water column movements. Dynamic sections are typically laid in a lazy 's' pliant wave configuration, potentially with the addition of a tether to maintain the dynamic section of the array cable in position.

4.6.7.3 Dependant on the layout, the cable may then be routed to an adjacent floating unit or statically connected via a SDC. Where SDCs are utilised, it is anticipated that that these will be installed via a CSV using the vessel's crane.

4.6.7.4 The cables will be laid by the cable laying vessel in sections and joined together. The cables are then typically buried 1m to 2m beneath the seabed. Cable burial techniques are described in **Section 4.6.10**.

4.6.7.5 Site preparation activities, unexploded ordnance (UXO) and boulder clearance activities may be required along cable routes and at SDC locations. Pre-lay grapnel run is also expected to be performed to clear any objects or debris along cable routes prior to installation.

4.6.8 Offshore platform installation and piling

4.6.8.1 The following is relevant to all offshore platforms (i.e. offshore substations and RCPs). The first step is the installation of the foundation. This will be transported to the OAA by a specialist installation vessel or as a towed structure. It will then be up righted via an engineered procedure (heavy lift or de-ballasted) and lowered to the seabed at the prepared location. The foundation is then secured to the seabed by driven piles or suction caissons.

4.6.8.2 The next step is the installation of the topside's pre-equipped module, which would typically be completed in a single operation. The module would be transported from the fabrication site (yet to be determined) by specialist heavy lift vessel or a towed offshore transportation barge. The module would then be installed on the preinstalled foundation in an engineered operation, either as a single heavy lift or a float over operation.

Jacket foundations secured by driven piles

4.6.8.3 For piled jacket foundations, the piles could be installed by either post-piled (piled post installation of the jacket) or pre-piled (before the jacket structure is placed on the seabed). It is anticipated that piles would generally be driven, but alternative installation techniques and mitigations (e.g. drilling or vibration) may be required depending on ground conditions and operational constraints.

4.6.8.4 For post-piled jackets, the sequence would typically be:

- jacket piles transported to site by construction vessel or offshore transportation barge;
- lifting of driven piles from barge and placement into sleeves on jacket;
- driven piles allowed to naturally penetrate seabed;
- driven piles driven to depth using pilling hammer;
- levelling of jacket via jacking off piles; and
- grouting and / or mechanical locking of jacket to pile connections.

4.6.8.5 The overall installation methodology for a pre-piled arrangement would typically be:

- driven piles and d pile installation frame transported to site by construction vessel or offshore transportation barge;
- driven pile installation frame placed on seabed;
- driven piles placed on seabed within frame and driven to target depth;
- driven pile installation frame recovered;
- installed driven pile locations surveyed and jacket dimensions adjusted;
- jacket installed;
- levelling of jacket, grouting and / or mechanical locking of jacket-to-pile connections; and
- scour protection installation (if required).

Spoil removal and disposal for jacket foundations

4.6.8.6 For jacket foundations, the amount of spoil requiring disposal is likely to be limited.

4.6.8.7 Some dredging may be required for levelling the seabed prior to the installation of a pile template (if used). It should be possible to spread this material close to the installation works, within the Red Line Boundary.

4.6.8.8 Based on preliminary geotechnical information, it is thought likely that pile driving would be possible across the OAA. This would be confirmed via pre-construction surveys. Driven pile is unlikely to generate spoil material.

Jacket foundations secured by suction caisson

4.6.8.9 Jackets secured by suction caisson foundations would be transported to site (as outlined in **paragraph 4.6.8.1** and **4.6.8.2** and installed using an appropriate installation vessel that lowers the structure to the seabed.

4.6.8.10 Once positioned on the seabed at desired location, the initial penetration occurs under foundation self-weight. Pumps are then attached to caisson and water evacuated. Reducing pressure within the caissons and drawing the structure into the seabed. Water jetting may additionally be used at the tip of the skirt to facilitate penetration. Once at the predetermined penetration equipment is removed.

4.6.8.11 In areas where the seabed is level, the suction caisson foundation may not require significant seabed preparation. However, measures may be required in areas where sand waves are present to provide a level and stable seabed for the installation and to allow scour protection to be later placed around the foundation. It is possible that excavation to the trough of the sand wave would be necessary before installing the suction caisson foundation structure. If this foundation type is adopted, detailed work would be required pre-construction to determine the preparation required for each foundation.

4.6.8.12 Scour protection would be provided around the installed suction caisson (if required). The quantities and extent of scour protection are outline in and

4.6.8.13 Detailed pre-construction work would be required to design the scour protection for each foundation. However, it is anticipated that the scour protection area would be twice the diameter of the foundation for suction caisson foundations.

Spoil removal and disposal for jacket and suction caisson foundations

4.6.8.14 For jacket foundations, the amount of spoil requiring disposal is likely to be limited.

4.6.8.15 Some dredging may be required for levelling the seabed prior to the installation of a pile frame (if used). It should be possible to spread this material close to the installation works, within the Red Line Boundary.

4.6.8.16 Based on preliminary geotechnical information, it is thought likely that pile driving would be possible across the OAA. This would be confirmed via pre-construction surveys. Driven pile is unlikely to generate spoil material.

4.6.8.17 Any sediment displaced during seabed preparation for jackets with suction caissons would be deposited within the OAA. Should this not be possible, any marine licensing requirements for spoil removal or disposal will be identified and applied for by the Applicant under the Marine and Coastal Access Act 2009 for activities beyond 12nm.

4.6.9 Installation of topsides of the offshore platforms

4.6.9.1 Installation of the offshore topsides would be undertaken by heavy lift or float over operation. Depending on the selected methodology for installation, the topside unit and associated foundation will be specifically designed for that operation. The operation for the installation will be highly engineered and subject to specific weather and operational limits.

4.6.9.2 **Heavy lift**: the topside unit will be transported to the OAA on a suitable offshore barge, or if a small topside, like an RCP could be on the deck of the heavy lift vessel itself. A large capacity heavy lift crane vessel will then connect to the topside unit, lifting it from the offshore barge or vessel deck before moving the topside unit into position over the pre-installed foundation and setting it down on the foundation.

4.6.9.3 **Float over**: The topside unit will be transported to the OAA on suitable offshore barges or specialist heavy lift vessels. The barges or vessels will then undergo ballasting operations to ensure sufficient clearance with the installed foundation before positioning over the pre-installed foundation and undergoing further ballasting operation to transfer the topside unit on top of the foundation.

4.6.10 Export cable installation

Pre-lay works

4.6.10.1 In areas with large ripples and sand waves, the seabed may first require (subject to detailed studies) sand wave levelling by dredging before the cable could be installed. Sand wave levelling would be in discrete areas and not along the full length of the corridor.

4.6.10.2 The offshore export cable would be routed as far as possible in soft sediments to allow it to be buried into the seabed. If boulders or debris are encountered on the seabed, these would be removed before the cable is laid.

4.6.10.3 The maximum cable installation swathe will encompass the pre-lay grapnel run. A conservative maximum width of seabed disturbance along the pre-lay grapnel run has been assumed to account for potential future increases in cable laying plough and pre-lay grapnel run requirements.

4.6.10.4 If the offshore cable corridor intersects an out of service cable, the latter may be recovered, but more likely it will be cut and the cut ends laid on the seabed with clump weights to stabilise the free end. The out of service cable removal method is subject to detailed surveys, engineering, accessibility and agreement with the cable owners that the cable or sections of it can be removed or crossed.

4.6.10.5 The removal of material would be subject to separate consent as outlined in **paragraph 4.6.2.5**.

Offshore export cable laying

4.6.10.6 The cable installation method and burial details for the offshore export cable will be determined upon completion of pre-construction surveys. The method selected will consider risks during cable laying and lifetime maintenance. This may vary or be a combination of techniques over the offshore export cable corridor route. The Project anticipates burying the cable along its length as this protects the cables from damage. Where burial is not possible, typically rock placement, would be installed. Other examples or more localised protection could be in the form of concrete mattresses / bags or steel split pipe, used in isolation or under rock placement, but only where not introducing hazards for vessels, such as fishing vessels. Other protection would be installed directly onto the cable, such as steel split pipe, typically only used at exit of cable bores where rock placement may not be possible or in sensitive environmental areas where seabed intervention is not acceptable.

4.6.10.7 There are two main installation techniques for the offshore export cables:

- Cables are laid and buried in a simultaneous operation with burial equipment being towed by the cable laying vessel.
- Cables and burial are done in separate operation. For example, cable laid and later buried / protection, or trench created then cable laid and closed at a later date.

4.6.10.8 Cable burial is undertaken using a combination of the following installation strategies, depending on soil conditions along the cable route and will be informed by the cable burial risk assessment:

- **Ploughing**: a plough is towed by a vessel along the cable route, creating a trench into which the cable is placed and buried with backfill material. This technique is commonly used in simultaneous cable lay and burial operations, where the cable is laid and buried in one step.
- **Jet trenching**: Jet trenches use water jets to fluidise the seabed along the cable route, allowing the cable to settle below the seabed.
- **Mechanical trenching**: this method involves using a chain or wheel to cut a trench, enabling the cable to be buried and covered with backfill material.
- **Pre-cut trenching**: this method uses a barge mounted excavator. The trench is pre-cut with spoil heaps placed to side of trench for later back filling after cable is laid. This is a possible solution in nearshore areas.

4.6.10.9 The Project will select the cable burial method that provides the best results considering the length, impact and challenges of the respective cable lay operations, this may vary or be a combination of techniques over the cable route both for the offshore export cable corridor and within the OAA.

Cable burial methods: ploughing

4.6.10.10 Ploughing is typically done simultaneously with cable lay - termed simultaneous lay and burial. This technique involves the cable lay vessel towing the plough at a set distance behind the touch down point of the cable. This could be in the region of 200m, depending on water depth.

4.6.10.11 Ploughs are towed along on flat skids that keep the plough on the surface of the seabed. At the start of trenching, the cable is mechanically lifted into the plough and guided into the burial system by handling arms. During ploughing, the cable is pushed into the bottom of the trench by a depressor arm on the back of the plough share. This ensures the cable is buried at the target trench depth.

4.6.10.12 At crossing locations, the plough transitions out of the trench, the cable is released, and the plough is recovered and re-launched once the crossing is passed.

4.6.10.13 The plough may be a hybrid type plough, which includes water jet nozzles on the share to fluidize the seabed and reduce the tow force required

Cable burial methods: jet trenching

4.6.10.14 Jet trenching is a post lay burial technique, where a jet trencher is landed over the cable by the support vessel and engages two powerful jet swords into the soil either side of the cable. The jetting device uses pressurised water to fluidise sediment in a trench which allows the cable to embed within the trench. Once jetting stops or moves on sediment is no longer fluidised and so the cable is buried.

Cable burial methods: mechanical trenching

4.6.10.15 Mechanical trenching is a post-lay trenching technique, operating in a similar manner to jet trenching. The trenching tool is deployed from a support vessel and landed over the cable. The trencher then lifts the cable inside the body of the trencher and into the cable guide system.

4.6.10.16 Rather than using water jets to penetrate the soil, the mechanical trencher uses either a cutting wheel or cutting chain to break up the seabed and lower the cable into the bottom of the trench. Tracks fitted to the trencher allow it to move along the cable.

4.6.10.17 Mechanical trenchers are designed to work in stiffer soil conditions such as stiff clay and weak rock, compared to jet trenchers which are predominantly for sands or soft clays.

4.6.10.18 Typical progress rates for mechanical trenchers are in the region of 100m/hr, and may operate from 10m water depth, or in some cases shallower. Some mechanical trenchers are designed with both jetting swords and cutting tools to maintain flexibility in operations.

Cable burial methods: pre-cut trenching

4.6.10.19 Pre-cut trenching typically involves backhoe excavator mounted on a barge and using a sophisticated survey system to accurately excavate a pre-cut trench in the seabed, or removal of small seabed features to facilitate cable lay. This technique would be used where other methods for burying the cable are not economically and / or technically feasible. One such area is in the nearshore area at the cable bores' exit location.

4.6.10.20 First a trench is excavated or cut, then the cable is laid into the trench, then the excavated sediment is used to backfill the trench.

Cable laying and burial speeds

4.6.10.21 The speed of cable laying would differ between the lay and burial method being used, and will depend on the ground conditions, seabed profile and water depth.

4.6.10.22 Offshore export cable lay vessels can lay at a rate of up to 1km/hr (typically 600m/hr to 800m/hr), depending on the number of cables being laid, the type of burial planned and the seabed conditions.

4.6.10.23 Arrays cable lay vessels can typically lay at a rate of up to 400m/hr to 500m/hr, depending on the layout configuration (for instance, faster if laying straight compared to curves).

Separation distance between offshore export cables and trenches

4.6.10.24 The minimum separation of the offshore export cables is determined primarily to reduce the risk involved of damaging a pre-laid cable during installation of an adjacent cable. In addition, the separation distance allows a working area for the recovery of a cable requiring maintenance or repair, and its re-installation without disturbing or damaging the adjacent cables.

4.6.10.25 The space required to install a repaired cable would depend on the water depth at the fault location. Obstacles including wrecks and other sub-sea cables or pipelines are also secondary factors that would influence this spacing.

4.6.10.26 The offshore cable corridor width needs to allow for:

- sufficient space to allow crossing of existing cables and pipelines as close as possible to a 90-degree angle;
- sufficient space that the offshore export cable route does not inhibit the O&M activities of existing cables and pipelines;
- sufficient width for installation vessels to manoeuvre and anchor (if required);
- sufficient width between offshore export cables to allow for any maintenance activities, including space to effect cable recovery and repairs;
- to incorporate seabed lease requirements from the Crown Estate Scotland; and
- to incorporate best practice guidelines (as far possible) from latest DNV-KEMA guidelines.

4.6.10.27 The offshore cable corridor width will be widened along the location(s) of the RCP(s) (if required).

4.6.10.28 When offshore export cables are installed, there needs to be sufficient space between them to:

- mitigate cable systems constraints such as mutual heating and electrical interaction between adjacent cables;
- minimise the risk of plough (or another burial tool) over-run;
- allow for installation vessels to manoeuvre during installation where there are bends in the offshore cable corridor; and
- allow the repair bight to be laid out where repairs are needed.

4.6.10.29 Based on the above requirements, an offshore export cable corridor has been determined that takes into account a minimum distance of three times the varying water depth along the route between the export cables, to have sufficient space, to necessitate a repair, and a further 1km boundary either side of the corridor to take account of any issues found during offshore installation. For instance, pre-lay survey findings that require a re-route. The offshore export cable corridor will be located within the Offshore Red Line Boundary, which has a minimum width of 3.5km and widens to over 8km in some areas to account for constraints to cable routing on the seabed. The width of the Offshore Red Line Boundary takes into account the necessary minimum cable separation distances. The actual cable corridor width is expected to be refined throughout the design process, following detailed cable burial risk assessment and pre-lay surveys, prior to the construction of the Project.

4.6.11 Cable protection

4.6.11.1 In the few areas where cable burial cannot be achieved, other alternative methods of cable protection will be used. This may be where unsuitable seabed conditions exist or where another cable or pipeline is already in place. External cable protection options include rock armour or concrete mattresses, the exact type, location and dimensions of which are yet to be determined.

4.6.11.2 Rock armour involves the placement of rocks on top of the cable to provide protection that is effective on crossings or areas where unsuitable seabed conditions are encountered. This can be used where long sections of cable require protection.

4.6.11.3 Concrete mattresses are prefabricated flexible concrete coverings that are laid on top of the cable, as an alternative to rock placement. The placement of concrete mattresses is slow and as such is only be used for short sections of cable protection. Bags or steel split pipe can be used for smaller scale applications. Concrete mattresses, bags or steel split pipe will only be installed where safe to do and they do not cause a snagging risk for other sea users, for example fishing vessels along the offshore export cable corridor, where the route will be designed to be over trawable.

4.6.11.4 The worst case estimates for the offshore export cable protection required due to unsuitable ground conditions and cable crossings in the offshore cable corridor are presented in **Table 4.15**. These have been estimated based on up to 20% of the offshore export cables being unable to be buried because of ground conditions and therefore requiring cable protection. This will be refined subject to Cable Burial Risk Assessment which will confirm the type of protection required along the route (for instance buried or otherwise).

4.6.11.5 In reality it is likely that, due to the sandy and gravely nature of the sediment along the offshore cable corridor, the majority of the offshore export cables will be able to be buried and will not require external cable protection.

Table 4.15 Cable protection requirements for the offshore export cable corridor

Cable type and location	Total area (m^2)	Total volume (m^3)
Cable protection for offshore export cable	Assume 20% of length requires rock placement.	1,155,000m^3

4.6.12 Cable crossings

4.6.12.1 Where cable or pipeline crossings occur (whether by an array cable or the offshore export cables), they will be subject to respective crossing agreements between the infrastructure owner and the Applicant.

4.6.12.2 Where the offshore export cable intersects existing infrastructure, external protection is required to protect the pipeline or cable being crossed and to protect the new cable being laid because it cannot be buried at this location.

4.6.12.3 It is anticipated that a combination of some of the following rock placement; or localised concrete mattresses, bags or steel split pipe would be used for protection at cable crossings. However, in all cases the design will be over trawable and discussed with seabed users, for example fisheries. In shallow waters, the height of cable crossings may be required to be reduced to avoid reduced water depth for navigation. reduced water depth for navigation.

4.6.12.4 The design required would depend on the size, type and vertical position of the asset to be crossed, the number of cables crossed and the separation of the cables that can be achieved at the point of the crossing.

4.6.12.5 Each crossing will be specifically reviewed and designed for the site conditions and constraints. However, a typical crossing is presented in **Plate 4.8**.

4.6.12.6 There is currently 16 known cable crossings required along the offshore export cable route. The Applicant has included an additional six number of crossings as a contingency. This is calculated from the Applicant's current understanding of the likely cables to be present but with contingency built in to include potential cable discoveries post-consent, which will be informed by pre-construction magnetometer surveys.

4.6.12.7 Where the offshore export cable crosses an out of service cable, the Applicant may wish to cut the disused cable at each end and bury the offshore export cable through the path created. Clump weights would likely be placed at each end of the cut cable to prevent its re-emergence. This procedure would be subject to detailed magnetometer surveys and agreement with the cable owner.

4.6.13 WTG commissioning

4.6.13.1 Upon installation and hook up of the floating unit to the mooring system, completion of the dynamic array cable pull-in and connection to the floating unit, the final commissioning of the WTG will commence. This involves a process of electrical and mechanical testing to ensure that all components are operational. WTG commissioning allows the energisation of the WTGs and the generation and transmission of electricity to commence.

4.6.14 Access and logistics for construction

4.6.14.1 The number and specification of vessels employed during the construction of the Project would be determined by the appointed marine contractor and in line with the construction strategy. It is anticipated that several types of construction vessel could work in parallel during the construction period.

4.6.14.2 Indicative vessel types required during the construction and operation stages are shown in **Table 4.16**. The vessel estimates are based on the construction of three phases delivering a total of 3GW installed capacity, in accordance with the outline construction programme. Overlaps between phases have been included where appropriate.

Table 4.16 Indicative vessel requirements at construction stage

Activity	Vessel type	Indicative number	Round transits[2]
Offshore substations foundation installation	Heavy lift vessel.	1	12
	Support vessel.	5	90
	Barge (if required).	1	12
Floating units towage	Anchor handling tug supply (AHTS) vessel.	3	675
Floating units installation / mooring hook up	AHTS vessel.	5	1125
Cable installation for the offshore export cable corridor	Survey vessel (pre- and post-lay).	1	20
	Cable lay vessel.	1	70
	AHTS vessel (for trenching / bounder removal / pre-lay grapnel run / UXO removal).	2	40
	Offshore construction / larger AHTS vessel (for sand wave clearance).	2	40

[2] A transit is defined as a single uninterrupted journey either from port to worksite or from worksite to port. Each leg of the journey constitutes one transit. Therefore, for a single operation where a vessel departs from port, performs work offshore, and returns to port, this would be classed as two transits. This definition applies to vessel movements only; helicopter movements are referred to separately as 'trips'.

Activity	Vessel type	Indicative number	Round transits[2]
	Rock placement vessel.	2	80 to Norway
Cable installation for the array cables	Survey vessel (pre- and post-lay).	2	60
	Cable lay vessel.	2	50
	AHTS vessel (for trenching).	2	80
	Rock placement vessel.	2	30 to Norway
Anchor installation	Offshore construction vessel / larger AHTS.	2	675
Mooring line installation	Offshore construction vessel.	2	144
	AHTS vessel.	2	675
Support vessels	Guard vessel.	2	208
	Service operation vessel (SOV).	2	208
	Support vessel.	3	312

4.6.14.3 It is anticipated that approximately ten vessels would be on site at any one time during the construction of the Project. The numbers of vessels will be confirmed with further input from construction contractors post-consent.

4.6.14.4 It is estimated that approximately 3,838 individual vessels transits (each representing a one-way journey between port and worksite) would be required during the construction of the Project. It is estimated that the installation of each floating unit will require up to three vessel transits of the installation vessel.

4.6.14.5 Upon arrival at the offshore worksite, installation vessel(s) may require repositioning within the field to complete the installation procedure. Following completion of the procedure, the vessel(s) may undertake a return transit to port.

4.6.14.6 The routing of vessel trips will depend upon the final selection of the port facilities required to construct and operate the Project, which has not yet been determined.

4.6.14.7 There may also be a requirement for helicopters to travel to and from the OAA to assist with construction activities. Helicopters will largely be used to transfer personnel in between port visits and to any accommodation vessels but may also be used for construction materials or to support specific construction activities. It is estimated that two helicopter trips per week for duration of the main offshore construction, approximately 1,040 helicopter round trips may be required during the offshore construction period. The helicopter port or airfield location has not yet been determined but is expected to be Aberdeen bases on facilities at time of writing.

4.6.15 Construction ports

4.6.15.1 The Project will endeavour to use Scottish and UK ports during the construction stage, with an indicative shortlist of ports considered for the Project identified in **Table 4.17**. This is based on the main construction activities that are envisaged to be required under the current Project requirements and port capabilities.

4.6.15.2 The shortlist of ports is not definitive and does not preclude the potential consideration of other suitable locations at the time of final port selection. Final port selection will be dependent upon, and only take place following:

- the grant of development consent for the Project;
- confirmation of route to market including final investment decision, and
- on the findings of further technical and commercial studies.

4.6.15.3 Additional activities may occur at other ports and locations further afield; the global nature of supply chains means it is not possible to identify or assess these at this relatively early stage.

Table 4.17 Potential construction ports

Construction activity	Potential ports
Construction / fabrication	
Station keeping system **for example, anchors / suction piles / drive piles / mooring system**	Inverness and Cromarty Firth Green Freeport, for example Nigg, Invergordon, Ardersier, Inverness. Forth Green free port area plus Methil and Dundee, for example Burntisland, Leith, Rosyth, Grangemouth plus Methil & Dundee. North East Scotland, for example Aberdeen, Peterhead, Montrose. England: Teesside freeport area and Port of Tyne.
Array cables	Rosyth Newcastle / Teesside. Gravesend Nigg
Floating units **Concrete semi-submersible**	Ardersier Kishorn Invergordon
Floating units **Steel semi / tension leg platform. Assembly of steel components.**	Rosyth Nigg Methil Invergordon
Subsea substations / power collectors	Invergordon Nigg Methil Burntisland Rosyth Teesside
Integration of floaters / floating units / WTG's	
	Inverness and Cromarty Firth Green Freeport, for example Nigg, Invergordon or Ardersier.

Construction activity	Potential ports
	Forth Green Freeport, for example Burntisland & Leith.
Marshalling	
WTG / floating unit components to be marshalled near to integration port	Invergordon Nigg Ardersier Inverness Dundee Methil Montrose Rosyth Leith Aberdeen
Station keeping system	Peterhead Aberdeen Grangemouth Leith Montrose Dundee

4.7 Landfall(s)

4.7.1 Overview

4.7.1.1 The landfall is the point at which the offshore export cables cross from the marine environment through the intertidal zone to the terrestrial environment and connect to the onshore export cables.

4.7.1.2 The landfall(s) infrastructure will be constructed in three phases, to align with the phased installation of the offshore export cables and energisation of the WTGs. Further information on the indicative construction programme for landfalls is provided in **Section 4.9**.

4.7.1.3 The key works for landfall(s) construction above and below MHWS are listed below.

4.7.1.4 Landfall(s) works landward of MLWS include:

- construction of access to the landfall(s) and landfall(s) temporary construction compound;
- establishment of a landfall(s) temporary construction compound;
- drilling of bores for cable ducts (24-hour working);
- installation of ducts into the bores;
- construction of transition joint bays;
- pull-in of offshore export cables into ducts from the cable lay vessel;
- jointing of offshore cables to onshore export cables in transition joint bays;
- backfilling of transition joint bays; and
- demobilisation of site and reinstatement works.

4.7.1.5 Landfall works seaward of MHWS include:

- marine support during drilling of bores;
- marine support during installation of ducts;
- marine support during pulling in of offshore cables into ducts;
- installation of cable protection systems (if required); and
- burial / protection of duct ends and offshore cables in duct vicinity.

4.7.1.6 To reduce the environmental impact of the landfall, a trenchless solution is to be implemented to install ducts. Whilst other trenchless methods are available, HDD (or similar trenchless technique) is presented herein as it is likely to have the largest construction footprint. Determination of the most suitable trenchless landfall crossing method will be undertaken during the detailed design stage of the Project, following geotechnical investigation of the onshore and nearshore areas.

4.7.1.7 The proposed indicative design envelope for key characteristics of the Project landfall(s) are summarised in **Table 4.18**.

Table 4.18 Landfall(s) parameters

Parameters	Indicative design envelope
Landfall(s) location	Up to three.
Number of HDD (or similar trenchless technique) cable ducts	Up to eight (including one spare duct / bore).
Number of transition joint bays	Up to seven.
Transition joint bay: width, length and depth	3.5m x 12m x 2.5m
Link box: width, length and depth	1m x 3m x 1.5m
Fibre optic cable junction box: width, length and depth	1m x 3m x 1.5m
Landfall(s) temporary construction compound: length and width	Up to 345m x 70m (combined area for all three phases).

4.7.2 Landfall works above MHWS

Access to the landfall(s) and associated landfall(s) temporary construction compound

4.7.2.1 Temporary construction access to the landfall(s) will be from the A90 as indicated in **Volume 2, Figure 4.1**. A temporary construction access road, approximately 6m in width, will be constructed from the road network to the landfall(s) temporary construction compound at each landfall. This temporary access road will allow movement of personnel and equipment to / from the road network to the landfall(s) temporary construction compound. The temporary access road will typically comprise crushed aggregates and a geotextile membrane. The landfall(s) temporary construction compound and associated temporary construction access road will be established at the start of construction.

Construction working area

4.7.2.2 The location of landfall(s) temporary construction compound(s) is indicated in **Volume 2, Figure 4.1**. The figure shows search areas within which the temporary construction compound(s) would be located. A landfall temporary construction compound is a fenced off area within which the HDD (or similar trenchless technique) operations are undertaken, transition joint bays are constructed, and offshore export cables are pulled through ducts and connected to the onshore export cables (at the transition joint bays). The landfall(s) temporary construction compound will accommodate all drilling activities and equipment, provide a laydown area for construction equipment and materials, parking for vehicles, and offices and welfare facilities for site workers, see **Section 4.7.3** on the HDD (or similar trenchless technique) operations.

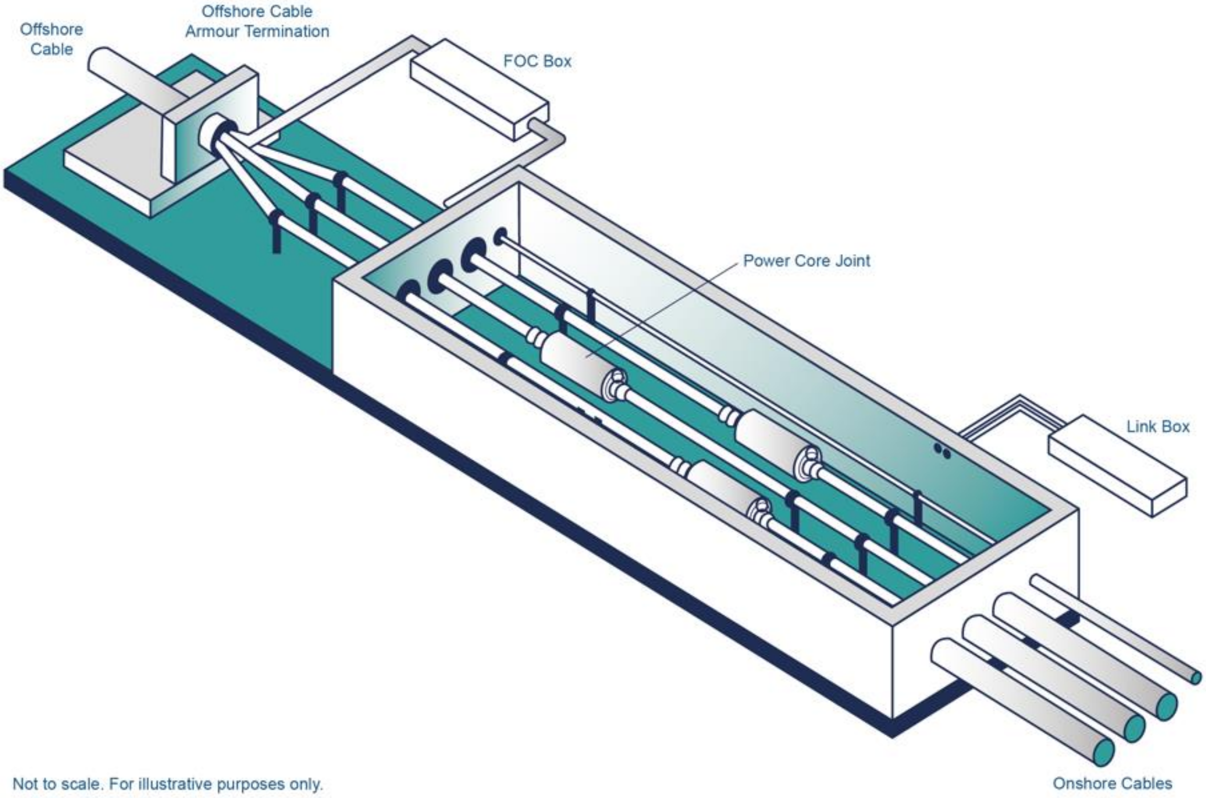
4.7.2.3 Part of the landfall(s) temporary construction compound(s) will comprise crushed aggregates and a geotextile membrane, as required, to support construction activities.

4.7.2.4 Prior to any construction, survey works and site clearance will be undertaken, to include geotechnical, topographical, UXO and environmental surveys. The landfall(s) temporary construction compound(s) and construction access road(s) will be cleared (topsoil removal etc.) in line with environmental requirements and embedded mitigation measures described in **Volume 4: Outline Construction Environmental Management Plan**.

Transition joint bay construction

4.7.2.5 **Plate 4.9** presents an illustration of a typical transition joint bay arrangement.

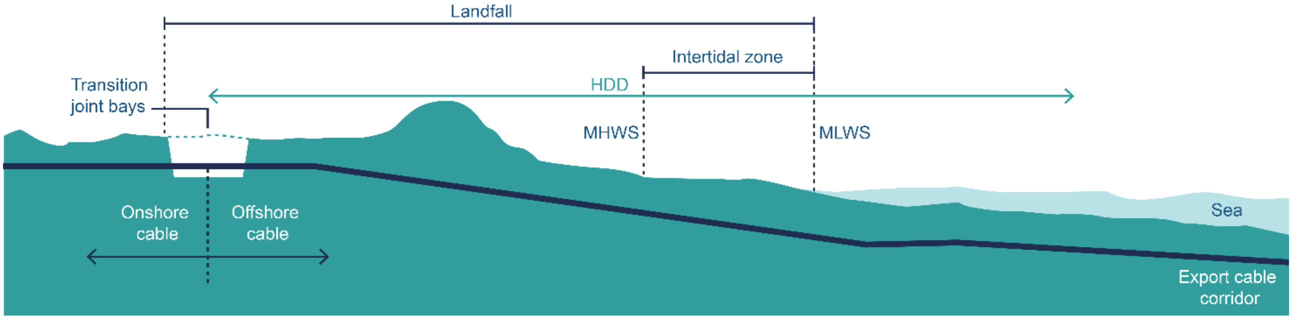
Plate 4.9 Illustration of a typical transition joint bay arrangement



4.7.2.6 The transition joint bays are located at the landward end of the landfall; above MHWS. Transition joint bays are permanent, below ground infrastructure, where the offshore and onshore export cables are jointed together. Each transition joint bay is a large, concrete-lined, excavated pit in which the component cable cores are split out for jointing. The transition joint bays are buried underground but each will have an associated surface-mounted link box and fibre optic cables junction box. These link boxes enable electrical checks and testing to be carried out on the cable system during O&M. A schematic diagram to illustrate the location of the transition joint bays relative to the intertidal zone and how buried export cables pass through the transition joint bays is shown in **Plate 4.10**.

4.7.2.7 Final location of the HDD (or similar trenchless technique) entry points and transition joint bays will be decided following ground investigation and detailed design of the onshore and offshore export cable corridors.

Plate 4.10 Landfall(s) profile



4.7.2.8 The installation of the transition joint bays would involve:

- Removal of the topsoil.
- Mechanical excavation of the transition joint bay pit chamber (excavation would be slightly larger than the transition joint bay dimensions). Excavated material will either be used as backfill or removed from the site and suitably disposed of.
- Dewatering of excavations may be required. This will require establishment of a pump for dewatering the excavations which may be required to run overnight.
- Construction of the concrete transition joint bay chamber floor and walls would involve either the installation of shuttered walls, reinforcement and poured concrete (which would be transported to the site) with the shuttering would be removed once the concrete is suitably cured); or the installation of precast concrete walls.
- Following cable installation and testing the transition joint bays will be covered (and may also be permanently backfilled), and the working area reinstated.

4.7.2.9 The transition joint bays will be constructed to align with the phased installation of offshore export cables and energisation of the WTGs. Further information on the indicative construction programme for the construction of the transition joint bays is provided in **Section 4.9**.

4.7.3 Landfall works from the transition joint bay to below MHWS

Trenchless installation

4.7.3.1 Following establishment of the landfall(s) temporary construction compound(s), the ground will be prepared (potentially including a small excavation at each HDD (or similar trenchless technique) entry point) to facilitate drilling operations and the set-up of drilling equipment. Drilling works will then commence, exiting at a targeted location on the seabed.

4.7.3.2 HDD (or similar trenchless technique) involves a three-stage process for each export cable wherein:

- The first stage involves drilling a small diameter pilot bore along the designated route between the entry (onshore) and exit (offshore) points for each offshore export cable.
- The second stage enlarges the bore by passing a larger cutting tool known as a reamer through the bore a number of times to progressively enlarge the bore to the required diameter.
- The third stage places a duct in the enlarged bore. The ducts (with a messenger wire inside) will be pulled or pushed into place between the landfall(s) temporary construction

compound and the seaward exit point. Once complete, the seaward duct end will be capped with the messenger wire inside.

4.7.3.3 The HDD (or similar trenchless technique) offshore exit points (one per bore) will be spaced some distance apart, typically 20m to 50m depending on local environmental and technical constraints. Some excavation may be required at or around the exit points, which will typically be achieved using a shallow draft vessel. A shallow draft vessel or jack up barge may be located at the exit point while each HDD (or similar trenchless technique) is completed, and each duct installed. A shallow water post-lay burial tool may be required to bury the cables in the area between the exit pit and deeper waters where normal offshore cable burial tools can be deployed.

4.7.3.4 Drilling fluid is used as part of the HDD (or similar trenchless technique) process. It is typically an environmentally benign mixture of water and bentonite or polymer continuously pumped to the cutting head or drill bit to facilitate the removal of cuttings, stabilise the borehole, cool the cutting head, and lubricate the passage of the duct.

4.7.3.5 The entry and exit points and the consequential length and depth of the HDD (or similar trenchless technique) depend on factors such as water depth, seabed topography, shallow geology / soil conditions and environmental constraints.

4.7.3.6 It has been assumed that 24-hour lighting would be required at the landfall(s) temporary construction compound during HDD (or similar trenchless technique) operations.

4.7.3.7 Following ducts installation, the offshore export cables will be pulled shoreward through the ducts by winching equipment stationed in the landfall(s) temporary construction compound. A cable lay vessel or barge will be stationed at the seaward duct end during the cable pulling activities. The messenger wire end from the seaward duct will be recovered onto the vessel. The messenger wire is reeled in to pull the winch wire through the duct and out to the vessel. The pulling head of the cable is then attached to the winch wire and pulled through the duct to the transition joint bay. Once the cable reaches the transition joint bay the end will be secured and the cable lay vessel will commence the offshore cable lay.

4.7.3.8 Following completion of the offshore and onshore export cable installation, the cables will undergo final testing and commissioning. The landfall(s) temporary construction compound and temporary construction access road will be removed and the landfall(s) will be reinstated in full and handed back to the landowner, this work will include the removal of all equipment and facilities, temporary fencing, haul road and reinstatement of topsoil.

4.7.3.9 Both Aberdeenshire Council and MD–LOT will need to consider the cable infrastructure in the intertidal zone as their respective jurisdictions overlap (see **Chapter 1: Introduction** for further details).

Construction equipment

4.7.3.10 For HDD (or similar trenchless technique) operations, plant would typically include:

- drill rig, control cabin, power packs;
- drilling fluid mixing, recycling and pumping equipment;
- drill pipe, pipe racks and downhole tools;
- fluid storage tanks;
- tractors / excavators/dumpers / telehandlers;
- generators and pumps;
- tower lights; and

- temporary offices and welfare facilities.

4.7.3.11 For the transition joint bays, plant would typically include:

- tractors / excavators / dumpers;
- bulldozers;
- generators and pumps;
- concrete mixers and equipment; and
- lifting equipment.

4.7.3.12 During pull-in operations, plant would typically include:

- winch and winch anchor;
- pulling wire and messenger wires;
- piling equipment (if required for anchoring winches);
- cable lay vessel (carrying offshore cable);
- dredging vessel / subsea excavation equipment (if required); and
- support vessels, including small boats / rigid inflatable boats with divers;
- shallow water burial spread.

4.7.4 Construction traffic

4.7.4.1 Construction of the onshore infrastructure will generate traffic on the local road network. This will include Heavy Goods Vehicles (HGVs) and Light Goods Vehicles (LGVs). Indicative construction traffic movements and potential resulting effects based on a worst-case construction scenario are assessed in **Chapter 26: Traffic and Transport**.

4.7.4.2 An Outline Construction Traffic Management Plan (CTMP) has also been prepared and submitted as part of the planning application (see **Volume 4: Construction Traffic Management Plan**). A full CTMP will be developed prior to construction. The CTMP will include details of delivery timings for plant and equipment, vehicle access routes and temporary road closures diversions and / or other local traffic management that will be necessary, restrictions to timing of vehicle movements, construction signage and car parking arrangements as well as any other key requirements.

4.7.5 Workforce

4.7.5.1 The total number of construction employees required onshore at the landfall(s) construction site will vary but it is expected to range from ten to 40 per day.

4.8 Onshore elements of the Project

4.8.1 Overview

4.8.1.1 The onshore elements of the Project relate to the onshore electricity grid connection infrastructure, landward of MLWS. The key components are:

- landfall(s) – the infrastructure associated with landfall(s) located above MLWS is explained in **Section 4.7.2** above;

- underground onshore export cables running from the landfall(s) to the onshore substations;
- onshore substations co-located on one site;
- underground grid connection cables (connecting the onshore substations to the grid connection point at SSEN Netherton Hub); and
- tie-in to the grid connection point (SSEN substation at the Netherton Hub, which is a separate project and does not form part of the consenting applications which this EIA relates to).

4.8.1.2 The location of the onshore infrastructure is presented in **Volume 2, Figure 4.1** and the key components of the onshore infrastructure of the Project are described in **Section 4.8.2**.

4.8.2 Onshore export cable corridor

4.8.2.1 The onshore export cable corridor will include the underground export cables to be installed between the landfall(s) and the three proposed onshore substations co-located at the onshore substation site, and from the onshore substations to the point of connection at SSEN Netherton Hub (see **Volume 2, Figure 4.1**). The onshore export cables will be installed in three phases to align with the energisation of the WTGs.

4.8.2.2 The onshore export cables for Phase 1 will be either laid directly in trenches or cable ducts will be installed and the onshore export cables for Phase 1 installed into the ducts. In Phase 1 cable ducts will also be installed to enable the later phase cables (Phases 2 and 3) to be installed without having to re-excavate along the entire route. The joint bays, required to connect each section of onshore export cable to the next, will be constructed in three phases, to align with the phased installation of associated onshore export cables. The temporary construction corridor is generally routed as straight as possible to reduce overall length and to facilitate the pulling of cables into ducts.

4.8.2.3 In the event that more than one landfall is required, the connecting onshore export cables, from the common onshore export cable corridor to the additional landfall(s), may be laid in trenches or installed in ducts to align with the phased installation of the landfalls.

4.8.2.4 See **Section 4.9** for further information on the phased installation of the onshore export cables.

4.8.2.5 Design refinement of the onshore infrastructure since the Scoping stage is described in **Chapter 3: Site Selection and Consideration of Alternatives**.

4.8.2.6 The proposed indicative design envelope for key parameters of the onshore export cable corridor are summarised in **Table 4.19**.

Table 4.19 Indicative onshore export cable corridor parameters

Parameters	Onshore export cable corridor from the landfall(s) to the onshore substations	Onshore export cable corridor from the onshore substations to SSEN Netherton Hub
Voltage	275kV – 400kV (HVAC) ±320kV – ±525kV (HVDC)	400kV
Number of cable circuits	Up to five.	Up to seven.
Number of onshore export cables	Up to 19 onshore export cables - based on four HVAC circuits (each with three power cores and one FOC) and one HVDC circuit (two power cores and one FOC).	Up to 28 onshore export cables - based on up to three power cables in each circuit (plus one FOC for each circuit).
Maximum number of trenches	Up to six.	Up to seven.
Typical trench width: at base	Up to 1m.	
Typical trench width: at surface	Up to 4m dependant on soil strength. Maximum angle of trench dependant on soil strength.	
Typical trench depth	Up to 1.5m, dependent on ground conditions.	
Typical depth to top of buried infrastructure (ducts)	0.9m to 1.2m.	
Number of ducts (including fibre optics)	Up to 19.	Up to 28.
Corridor width: permanent (servitude)	Up to 61m.	Up to 71m.
Corridor width: temporary construction corridor width	Up to 89m.	Up to 99m.
Onshore export cable corridor length	11.0km	2.35km.
No. of expected trenchless crossings (as per Volume 3, Appendix 4.1: Crossings Register)	Two	Two

4.8.2.7 **Plate 4.11** illustrates a typical onshore export cable configuration and temporary construction corridor cross-section for the onshore export cable corridor from the landfall(s) to the onshore substations.

4.8.2.8 **Plate 4.12** illustrates a typical onshore export cable configuration and temporary construction corridor cross-section for the onshore export cable corridor from the onshore substations to SSEN Netherton Hub.

Plate 4.11 Typical construction corridor cross-section for the onshore export cable corridor from the landfall(s) to the onshore substations

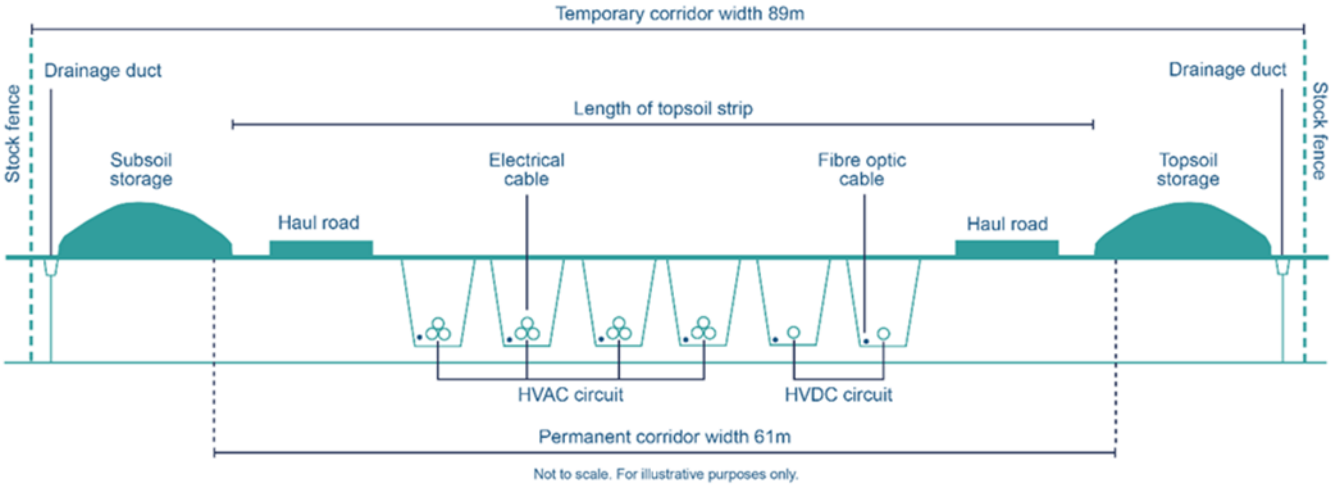
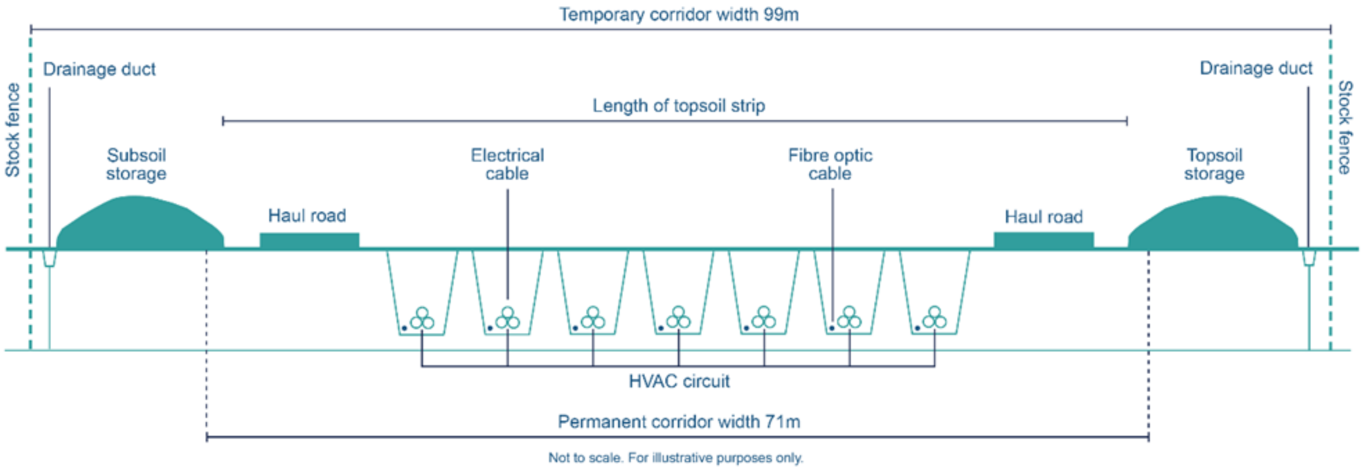


Plate 4.12 Typical construction corridor cross-section for the onshore export cable corridor from the onshore substations to SSEN Netherton Hub

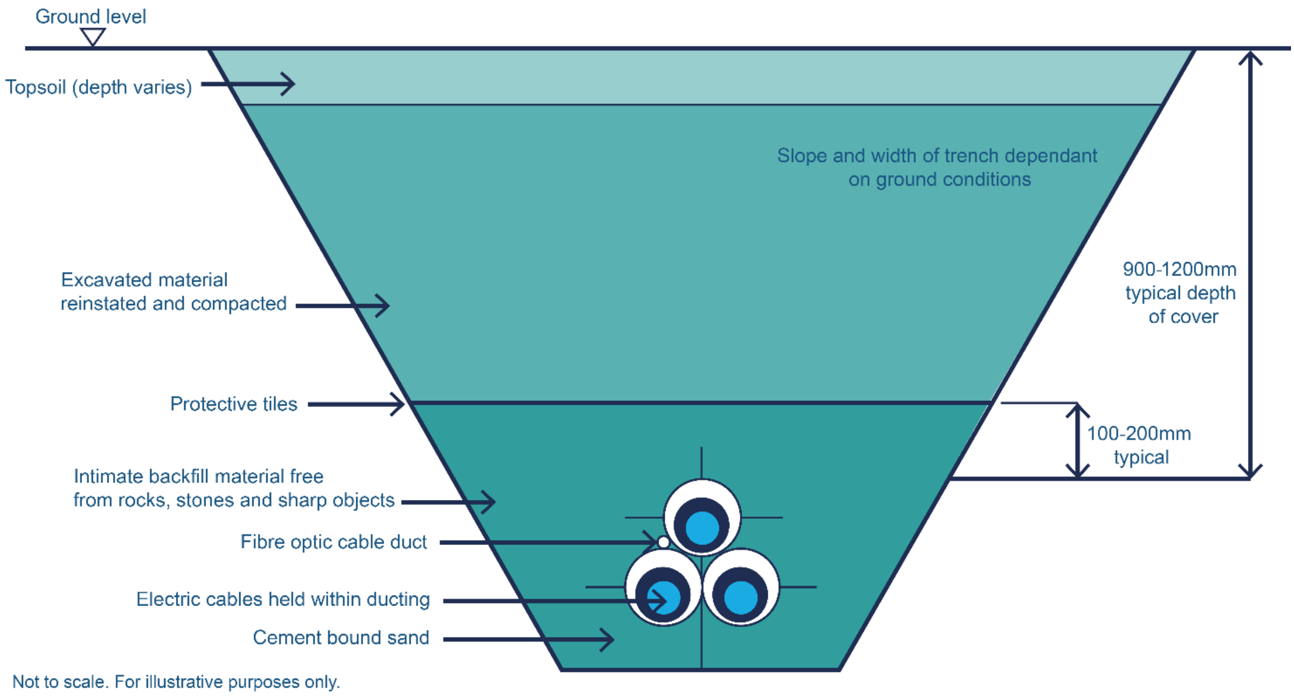


4.8.2.9 The temporary construction corridor consists of the trenches, space for storage of excavated material, and haul roads. The temporary construction corridor may require widening beyond the standard width to allow enough space for access / equipment at crossing points with roads, rivers or utilities, and to avoid other obstacles to installation. The proposed Red Line Boundary has been defined to allow for this enlargement at potential locations and to account for uncertainty in ground conditions at this stage. The standard temporary construction corridor is also narrowed in certain locations for limited lengths as a result of constraints such as watercourses or woodland.

4.8.2.10 Sufficient space to provide adjacent temporary infrastructure such as temporary construction compounds and construction drainage has also been included in the onshore part of the Red Line Boundary.

4.8.2.11 The temporary construction haul roads will enable the transportation of plant used for topsoil stripping, subsoil excavation and for delivery of cables, cable duct and sand or cement bound sand bedding material. Soil will be stored in bunds within the temporary construction corridor. It is anticipated that a mechanical excavator will be used for these activities. **Plate 4.13** presents a typical trench profile for a single trench.

Plate 4.13 Typical trench profile for a single trench



4.8.2.12 Where required, a layer of stabilised backfill (likely sandy material or cement bound sand (CBS)) will be deposited for the purposes of protection under the cable. The onshore export cables will either be laid directly in the trench or cable ducts will be installed, to enable a phased, subsequent installation of cables into the ducts a later date.

4.8.2.13 Trenches will be backfilled with the originally excavated material to the layer of the protective tiles / tape. Protective cover tiles / tape will be placed on top of the material to prevent the cable from being damaged. The cable protection tiles used will comply with the Energy Networks Association (2018) Technical Specification 12-23 (ENA, 2018). These will typically be made of plastic and will have clear warning of the underlaid cable written on top of the tile. Any surplus material from excavation will be spread across the temporary construction corridor. The topsoil material will be reinstated, and the land returned to its original use.

4.8.2.14 Each power cable is likely to consist of an oversheath, a metallic sheath, a metallic screen, insulation and conducting cores. Power cable cores are likely to be made of copper or aluminium and the insulation is likely to be cross-linked polyethylene. An FOC will be installed alongside the electrical cables for communication and monitoring purposes as illustrated in **Plate 4.13**.

4.8.2.15 Post construction, a permanent cable corridor servitude is required, save where construction processes or other reasons require a wider permanent servitude (for instance where HDD (or similar trenchless technique) is utilised, or unexpected engineering difficulties occur). The permanent cable corridor servitude ensures the long-term protection of the onshore export cables and associated FOCs, allowing sufficient spacing between cable trenches to prevent cable overheating, plus room for any O&M works.

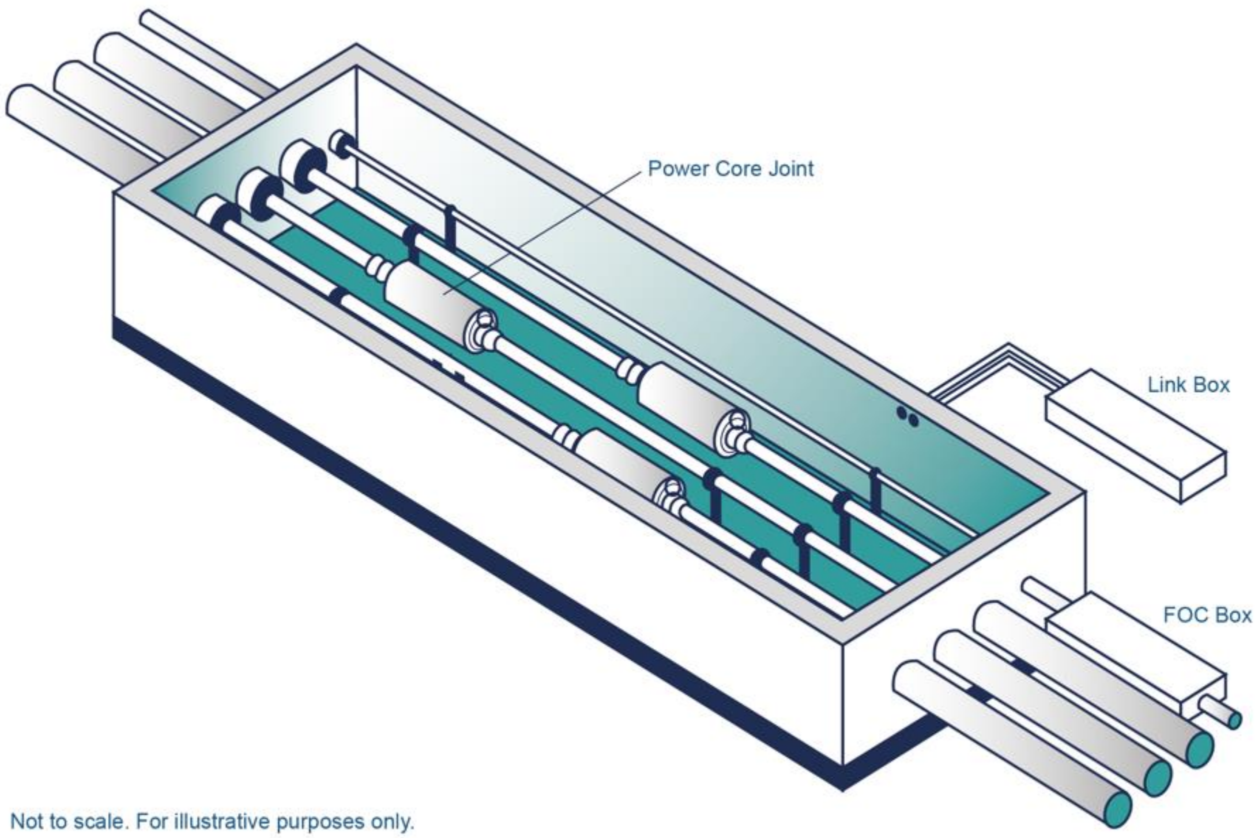
Joint bays and cable jointing

4.8.2.16 The joint bays are subsurface structures with an associated link box and FOC junction box that will be accessible at surface level. These link boxes enable electrical checks and testing to be carried out on the cable system during O&M.

4.8.2.17 In all cases, the joint bays will be sited within the footprint of the onshore export cable corridor.

4.8.2.18 The locations of the joint bays for each Phase will be determined during the detailed design stage. Onshore cabling is typically provided on drums of 1,000m in length, although can be provided in differing lengths ranging from 500m up to 2,000m. Typically, joint bays are located every 600m to 1000m, however the location depends on factors such as crossings, bends, access and / or the need to avoid surficial or sub-surface features. **Plate 4.14** presents an illustration of a typical joint bay arrangement.

Plate 4.14 Illustration of a typical joint bay arrangement



4.8.2.19 **Table 4.20** provides maximum indicative design assessment assumptions for joint bays.

Table 4.20 Joint bay, link box and FOC junction box design parameters

Parameters	Onshore export cable corridor from the landfall(s) to the onshore substations	Onshore export cable corridor from the onshore substations to SSEN Netherton Hub
Approximate number of joint bay locations	Eight to 24.	Two to six.
Number of joint bays per location	At each joint bay location, along the onshore export cable corridor from the landfall(s) to the onshore substations, there are up to six joint bays.	At each joint bay location, along the onshore export cable corridor from the onshore substations to SSEN Netherton Hub, there are up to seven joint bays.
Joint bay: width, length and depth	3m x 9m x 2m	
Link box: width, length and depth	1m x 3m x 1.5m	
FOC junction box: width, length and depth	1m x 3m x 1.5m	
Joint bay construction duration per location (does not include cable pulling duration)	Six to ten weeks.	

Cable clamping

4.8.2.20 If the onshore export cable corridor encounters steep slopes, or if there is a risk of lateral movement of the ducts during cable pull-in, cable / duct clamping may be required. The cable itself is heavy and high mechanical loads can be generated in the cable at the top part of slopes by virtue of the cable wanting to travel down the slope under its own weight. In particular, these high mechanical loads can be subsequently transferred to the nearest adjacent joint and cause it to fail.

4.8.2.21 To mitigate the risk of movement, cable clamping may be applied at certain locations, typically close to joint bay locations on the side where the downward slope occurs. This would involve the installation of concrete block (approximately $2m^3$ in volume) into an excavated pit below the planned burial depth of the cable. Bolted to the concrete block would be a number of metal cleats, through which each of the cables would pass. These cleats clamp the cables to the concrete block, arresting any movement.

4.8.2.22 Once installed, the ground above these clamping arrangements will be reinstated as per the same specification as the rest of the onshore export cable corridor.

Crossings

4.8.2.23 There is road, watercourse, footpath, third party services, and other crossings along the onshore export cable corridor. Each crossing will be individually reviewed / surveyed again during detailed design to confirm the crossing method to be employed. Crossing techniques are broadly classified as 'open cut', in which the onshore export cable trenches continue across the feature, or 'trenchless', under which different cable installation methods are employed, but all have the aim of avoiding trenching through the feature.

4.8.2.24 Further information is provided below for each method installation. A crossings schedule is provided in the **Volume 3, Appendix 4.1**.

Open cut trenched crossing

4.8.2.25 Open cut trenching will predominantly be used for minor crossings, unless ground conditions, stakeholder or owner requirements, or environmental sensitivities dictate otherwise. This involves the preparation of the crossing (damming / fluming / pumping in the case of water courses) to allow the trenches to be excavated across the feature and ducts installed. The crossing area will be reinstated to the original form following the installation of cables / ducts.

4.8.2.26 Similarly, open cut trench footpath crossings will be temporarily diverted, where possible, in a safe and controlled manner, with minimal disruption. Whilst there may still be a need for short-term closures, these will be communicated in advance and kept to a minimum (as described in Appendix 2 of **Volume 4: Outline Construction Traffic Management Plan**. **Volume 2, Figure 4.1** shows the location of all expected open cut trenched crossings on the onshore export cable corridor. Traffic control measures and diversions will be implemented for open cut trench road crossings.

Trenchless crossings

4.8.2.27 Some crossing locations will require the option of using trenchless crossing techniques where open cut trenching is not suitable due to the width and / or type of feature being crossed.

4.8.2.28 Trenchless crossings are expected to be used for main watercourses, such as the River Ugie and its tributaries, key third-party services such as gas mains and the crossing of the A90 and A950 roads.

4.8.2.29 In relation to trenchless crossings, HDD (or similar trenchless technique) has been assessed in the EIA. Whilst other trenchless methods are available, HDD (or similar trenchless technique) is presented herein as it is likely to have the largest construction footprint. Determination of the most suitable trenchless crossing method will be undertaken during the detailed design stage of the Project and following geotechnical investigation of each crossing area.

4.8.2.30 HDD (or similar trenchless technique) involves drilling a bore underground from an entry point on one side of the crossed feature to an exit point on the other side. Prior to completion of the bore, ducts are connected in a string longer than the bore and then pulled through the bore to provide a continuous passage for the cable. Each onshore export cable will have a separate duct. With trenchless methods the depth at which the cable ducts are installed depends on the topology and geology at the crossing site and the nature of the feature being crossed.

4.8.2.31 **Volume 2, Figure 4.1** shows the location of all expected trenchless crossings on the onshore export cable corridor, including the flexibility to undertake the drill from either side of the crossed feature. The figure shows search areas within which the trenchless crossing compounds would be located. There would be two temporary compounds associated with each trenchless crossing, one on the side from which the drilling is undertaken and a second, smaller compound on the exit side, each within the search area identified. The exact location of the trenchless crossing compounds will be determined during the detailed design stage and informed by the EIA process. The use of HDD (or similar trenchless technique) is less intrusive than open cut crossings from a crossing interaction, traffic management and environmental perspective; however, the equipment used generates greater noise and, as it may require 24-hour working, proximity to noise receptors must be considered. Key assessment assumptions of the trenchless crossing compounds are presented in **Table 4.21**.

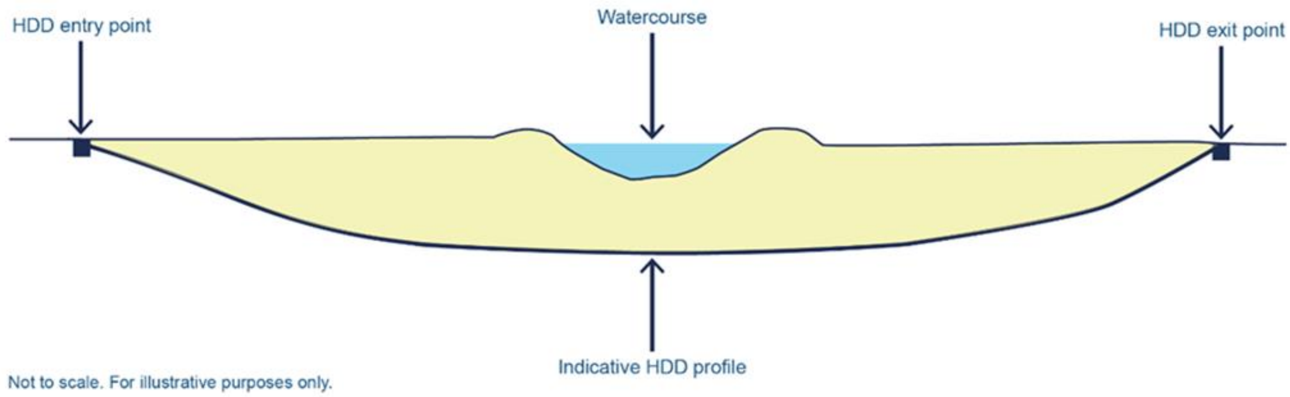
4.8.2.32 The Red Line Boundary has been widened in areas to accommodate the need for trenchless crossings at the locations defined in **Volume 3, Appendix 4.1**. The typical onshore export cable corridor width would be widened to up to 300m where there is a requirement for a trenchless crossing to be implemented.

Table 4.21 Trenchless crossing compound parameters

Parameters	Onshore export cable corridor from the landfall(s) to the onshore substations	Onshore export cable corridor from the onshore substations to SSEN Netherton Hub
Number of trenchless crossing compounds	Nine crossings = 18 compounds (two per crossing; one on either side of crossed feature).	Two crossings = four compounds (two per crossing; one on either side of crossed feature).
Temporary trenchless crossing compound dimensions (length and width)	Up to 300m x 50m.	
Trenchless crossing construction duration per location (does not include cable pulling duration)	Six to 12 months.	

4.8.2.33 **Plate 4.15** shows an example of a typical trenchless crossing method.

Plate 4.15 Typical trenchless crossing



Temporary construction access and haul roads

4.8.2.34 Temporary construction access points from the road network are required along the onshore export cable corridor to allow the transportation of materials, equipment, and personnel to and from the construction areas. These temporary construction access points will allow access to the temporary construction corridor, via temporary construction access roads, and subsequently the temporary construction haul road running along the onshore export cable corridor, except for locations where there are trenchless or road crossings. **Volume 2, Figure 4.1** presents the indicative locations of all the proposed temporary construction access points along the onshore export cable corridor. Key assessment assumptions for the temporary construction access and haul roads are presented in **Table 4.22**.

4.8.2.35 The use of temporary culverts, flume pipes or bridges may be required where obstacles are encountered along the haul road.

4.8.2.36 The temporary access roads and construction haul road will comprise crushed aggregates and a geotextile membrane. They will be used to enable onshore export cable trenching and duct construction activities and the subsequent installation of onshore export cables and associated joint bays in Phase 1, with the ground, access tracks and haul road reinstated on completion.

4.8.2.37 To enable the installation of onshore export cables and associated joint bays in Phases 2 and 3, temporary access tracks will be required from suitable access points to the location of each joint bay. Once the onshore export cables and associated joint bays for Phases 2 and 3 are installed, the ground and the access will be re-instated.

4.8.2.38 Temporary construction access points are proposed along the onshore export cable corridor based on suitability for the Project requirements, likely environmental and social impacts, highway safety and connection to key road infrastructure. Existing access points and tracks will be utilised where possible.

4.8.2.39 The temporary construction access points identified have been assessed for the effect on the road network, along with associated traffic management arrangements identified in **Chapter 26: Traffic and Transport**. Further details on temporary construction access are documented in **Volume 4: Outline Construction Traffic Management Plan**.

Table 4.22 Maximum access road and construction haul road parameters

Parameters	Indicative design envelope
Temporary access roads and construction haul road width	Approximately 6m.
Aggregate depth	Approximately 0.3m.

Primary construction compounds

4.8.2.40 Along the onshore export cable corridor up to three sites have been identified as locations for primary construction compounds. These compounds are expected to include:

- material storage for use on the onshore export cable corridor including cable drums and cable ducting;
- storage for topsoil stripped during compound establishment;

- perimeter fencing (typically wooden hoarding up to 2.4m high);
- site security hut and access gate;
- storage and maintenance area for plant and machinery;
- CBS batching plant;
- waste facilities including space for separation of recyclable materials;
- fuel and chemical storage including bunding;
- office space including portacabins;
- parking spaces for construction vehicles, site workers and visitors; and
- welfare facilities for site workers.

4.8.2.41 Primary construction compounds would be required for the duration of the installation of the Phase 1 cables and associated joint bays and construction of continuous ducts for the later installation of the onshore export cables and joint bays required for Phases 2 and 3. Indicative locations are shown in **Volume 2, Figure 4.1**.

4.8.2.42 Following completion of constructions works, the primary construction compound facilities will be removed, and each compound site will be returned to its original state. Primary construction compound details are provided in **Table 4.23**.

Table 4.23 Primary construction compound parameters

Parameters	Indicative design envelope
Number of primary construction compounds	Up to three.
Primary construction compounds (length and width)	Up to 125m x 125m.
Aggregate depth	Approximately 0.3m.

Secondary construction compounds

4.8.2.43 Secondary construction compounds are required along the temporary construction corridor to support the installation of the onshore export cable and associated trenchless crossings and joint bays. The secondary construction compounds are used to provide laydown areas for construction equipment and materials, and / or to provide parking and welfare facilities for site workers. The secondary construction compounds will comprise crushed aggregates and a geotextile membrane.

4.8.2.44 All secondary construction compounds are located within the proposed planning application boundary and indicative locations are shown in **Volume 2, Figure 4.1**.

4.8.2.45 Following completion of constructions works, the secondary construction compound facilities will be removed, and each compound site will be returned to its original state. Secondary construction compound details are provided in **Table 4.24**.

Table 4.24 Secondary construction compound parameters

Parameters	Indicative design envelope
Number of secondary construction compounds	Up to six.
Temporary secondary compound dimensions (length and width)	Up to 100m x 100m.
Aggregate depth	Approximately 0.3m.

Pre-construction

4.8.2.46 Pre-construction activities are 'onshore site preparation works' to secure and prepare all sites and access for the construction activities. These operations consist of:

- site clearance;
- demolition, where necessary;
- pre-planting of landscaping works;
- archaeological investigations, which may include intrusive investigations including archaeological trial trenching, as described in **Volume 4: Outline Onshore Written Scheme of Investigation**;
- environmental surveys in accordance with **Volume 4: Outline Construction Environmental Management Plan**;
- investigations for the purpose of assessing ground conditions;
- pre-construction surveys (utility surveys, UXO surveys, watercourse bed and water level surveys etc.)
- remedial work in respect of any UXO, contamination or other adverse ground conditions;
- diversion and laying of services;
- erection of any temporary fencing or other means of enclosure to mark out the onshore export cable corridor area;
- creation of site accesses; and
- the temporary display of site notices or advertisements.

4.8.2.47 Vegetation will be cleared, where appropriate, from the working width of the onshore export cable corridor at the appropriate time of year.

Construction

4.8.2.48 Construction along the onshore export cable corridor will be performed with the commitment to a safe work site and to minimise potential impacts as much as practicable. Generally, where possible construction will take place during daylight hours with a requirement only for local task lighting. The high-level construction sequence for Phase 1 is as follows:

- stripping of topsoil;
- excavate all trenches;

- lay Phase 1 onshore export cables in trenches or, where appropriate connect ducts and place the ducts in the trenches;
- connect ducts and place the ducts in the trenches for later installation of onshore export cables in Phases 2 and 3;
- safety measures such as warning tape and protective tiles are buried above the cable ducts to flag the presence of the cable to anyone digging in the area;
- trenches will be backfilled with an initial layer of fine protective material, overlaid by warning tiles and excavated subsoil; and
- reinstatement of the topsoil.

4.8.2.49 In parallel to the above sequence, the joint bays, FOC junction boxes (FOC joint bays) and link boxes required for Phase 1 will be constructed. This involves:

- excavation; and
- associated civil works.

4.8.2.50 Following completion of the construction joint bays, FOC joint bay, and link boxes, associated with Phase 1, the joint bays, FOC joint bay, and link boxes will be backfilled and the associated construction area reinstated, leaving access to the surface mounted link boxes for future O&M.

4.8.2.51 Joint bays, FOC joint bay and link boxes for Phases 2 and 3 will be constructed prior to installation of the relevant phase onshore export cables. The process and stages followed will be broadly identical to Phase 1 joint bay construction, with the exception that it will be necessary to cut out a section of continuous (pre-installed) ducting at each joint bay location. See **Section 4.9** for further information on the phased installation of the onshore export cables.

4.8.2.52 Where onshore export cables are installed in pre-laid ducts, each cable is pulled from one joint bay to the next. Onshore export cables will be installed sequentially in three phases, with a gap between the installation of export cables to align with the energisation of the WTGs.

4.8.2.53 Testing will be performed to confirm the integrity of each section of installed cable. This sequence repeats for all cables along the entire length of the onshore export cable corridor. Once the onshore and offshore cable installation is complete final testing / commissioning will be undertaken.

4.8.2.54 Access to all construction sites will be managed throughout the construction stage with suitable supervision provided at access points to the onshore export cable corridor, and temporary construction compounds. Access to all construction sites will be managed by the construction contractor. Where open cut trenching methodology is used for road crossings, traffic management will be in operation.

Construction lighting regime for the onshore export cable and onshore substations

4.8.2.55 External lighting of the construction site for both the onshore export cables and the new onshore substations will be directional. The work will usually be scheduled during daylight hours. If night or 24-hour working is required, such as may be required during trenchless crossing operations, then portable directional task lighting will be deployed. Further detail regarding construction lighting is provided in **Volume 4: Outline Construction Environmental Management Plan**. External lighting of the construction site will be designed and positioned to:

- provide the necessary levels for safe working;
- minimise light spillage and / or light pollution; and
- avoid disturbance to adjoining residents / occupiers of buildings and to wildlife.

4.8.2.56 Site or welfare cabins, equipment and lighting will be sited to minimise visual intrusion as far as is consistent with the safe and efficient operation of the work site. Implementation will comply with the requirements set out in the following standards and guides as far as it is reasonably practicable and applicable to construction works:

- British Standards (BS) Institution, (2014). *BS EN 12464-2:2014 Light and lighting. Lighting of work places. Outdoor work places;*
- Institute of Lighting Professionals, (2021). *Guidance Note 1 for the Reduction of Obtrusive Light;*
- Chartered Institute of Building Services Engineers (CIBSE), (2018). *Society of Light and Lighting Guide 1: The Industrial Environment; and*
- CIBSE, (2016). *Society of Light and Lighting Guide 6: The Exterior Environment*.

4.8.2.57 Further details regarding lighting during the construction stage will be developed with the construction contractor.

Construction equipment

4.8.2.58 Typical construction equipment utilised in the installation of the onshore export cable corridor would include:

- tracked / backhoe excavators;
- bulldozers;
- wheeled loaders;
- articulated dump trucks ;
- forward tipping dumpers;
- mobile cranes;
- drilling rigs and associated equipment spreads;
- water pumps and filter units;
- winches;
- cable reel trailers;
- duct fabrication equipment;
- large concrete mixers;
- concrete trucks and equipment;
- rollers and compaction equipment;
- telescopic handlers;
- generators; and
- tower lights.

Construction traffic

4.8.2.59 Construction of the onshore infrastructure will generate traffic on the local road network. This will include HGVs and LGVs. Cables would be delivered in drums, with the cable lengths on the drums being specified during design and procurement phases. For significant cable lengths, for instance in excess of 1,000m, specialist hauliers may be required. Indicative construction traffic movements and potential resulting effects based are assessed in **Chapter 26: Traffic and Transport**.

4.8.2.60 An CTMP has also been prepared and submitted as part of the planning application, see **Volume 4: Outline Construction Traffic Management Plan**. A full CTMP will be developed prior to construction. The CTMP will include details of delivery timings for plant and equipment, vehicle access routes and temporary road closures diversions and / or other local traffic management that will be necessary, restrictions to timing of vehicle movements, construction signage and car parking arrangements as well as any other key requirements.

Workforce

4.8.2.61 The total number of construction employees required has been estimated at an average of approximately 50 to 100 construction personnel per day.

4.8.3 Onshore substations

4.8.3.1 Three onshore substations will be co-located within the onshore substation site, one for each Project phase. The three onshore substations will accommodate a total combined capacity of 3GW. The purpose of the new onshore substations is to transform / convert the onshore export cable voltage to the 400kV required to connect to the proposed SSEN Netherton Hub and to house the HVDC and HVAC electrical components required to ensure the offshore wind farm export power is compliant with UK Grid Code (NESO, 2023) at the time of connection. The onshore export cables will be routed to each of the onshore substations and from the onshore substations to the point of connection at SSEN Netherton Hub.

4.8.3.2 **Volume 2, Figure 4.1** identifies the location of the onshore substation site and the indicative location of the three onshore substations which is based on maximum permanent footprint and two site access roads to enable access to each of three onshore substations. The three onshore substations will be built sequentially to align with the phased energisation of the WTGs. Further information on the indicative construction programme for the construction of the onshore substations is provided in **Section 4.9**.

4.8.3.3 The maximum permanent footprint of the proposed onshore substations will be, collectively, up to 15 hectares (ha) within the onshore substation site boundary. The remaining site area includes permanent access roads and a combination of landscape and ecological mitigation and drainage works, as shown for the onshore substations in **Volume 4: Outline Landscape and Architectural Strategy**.

4.8.3.4 At this stage, a decision has not been made on whether the electrical components and equipment necessary to connect the electricity generated by the Project to the national electricity transmission network will be fully housed in buildings or whether this equipment will be partially placed outdoors, incorporating sufficient mitigation to meet the necessary noise limits. The onshore substations include the following buildings, electrical components and equipment:

- STATCOM Hall;
- STATCOM Compensation Transformer;

- Super Grid Transformer (400 / 275kV);
- 275kV Shunt Reactor (SHR);
- 275 & 400kV GIS Hall;
- 275kV GIS Hall;
- 400kV GIS Hall;
- Control Room;
- 275kV Harmonic Filter (HF) Building;
- 400kV HF;
- 400kV SHR;
- HVDC Converter Hall;
- Power line carrier Filter, AC Switchgear and HF Building;
- Spare Parts Building; and
- Car parking.

4.8.3.5 Whether the onshore substations electrical components and equipment are fully housed in buildings, or this equipment is partially placed outdoors, the three onshore substations will be subject to the maximum design parameters presented in **Table 4.25**.

Table 4.25 Indicative onshore substation parameters

Parameters	Indicative design envelope – fully enclosed onshore substations	Indicative design envelope – partially enclosed onshore substations
Permanent combined onshore substation site footprint	Up to 15ha.	
Typical onshore substation foundation depth	600mm	
Permanent access roads	Approximately 700m in length and 6m wide.	
Temporary construction compound	Up to 3.06ha.	
Maximum building height for HVAC electrical infrastructure	Up to 17.5m.	
Maximum building height for HVDC electrical infrastructure	Up to 30m.	
Maximum number of buildings	Up to 35.	Up to 12.
Maximum building length	Up to 104m.	Up to 91m.
Maximum building width	Up to 88m.	Up to 88m.

Parameters	Indicative design envelope – fully enclosed onshore substations	Indicative design envelope – partially enclosed onshore substations
Maximum height of external electrical infrastructure for HVAC	N/A	Up to 12m.
Maximum height of external electrical infrastructure for HVDC	N/A	Up to 16.6m.
Lightning protection mast height	Up to 32m.	
Duration of construction	Onshore substation 1 – up to 3 years. Onshore substation 2 – up to 3 years. Onshore substation 3 – up to 3 years.	

Onshore substation site construction

4.8.3.6 Construction activities for the onshore substations will include enabling works and construction works. Enabling works will prepare the site ahead of construction and include vegetation clearance, access road construction, installation of drainage systems, stone fill, installation of a temporary construction compound, temporary site offices, fencing, delivery of materials, plant, machinery and fuel and any early landscape planting.

4.8.3.7 The onshore substation site is a relatively level site and low levels of soil excavation are expected to be required. Any soil excavated will be reused where possible. Site access works will involve stripping topsoil. The topsoil will be protected and stored nearby for the duration of the onshore substation site construction works.

4.8.3.8 The onshore substations will be constructed utilising a combination of concrete foundations and piled or screwed foundations with concrete foundations typically used for buildings and piled or screwed foundations for electrical equipment such as busbars.

4.8.3.9 Generally, the construction of the onshore substations will take place during daylight hours with a requirement only for local task lighting. Construction works will involve:

- installation of perimeter fencing;
- ground preparation works;
- installation of underground services and onshore substation site foundations;
- construction of the control and switchgear buildings and plant buildings;
- construction of cable trenches;
- construction of ducts and pits;
- construction of the oil containment bund;
- provision of utility supplies; and
- ecology mitigation, landscaping and drainage works.

4.8.3.10 Access to the onshore substations will be required during construction and subsequently during O&M. There are two construction access points to the site, one from the A950 to the north of the site and one from the minor road to the east of the site, as illustrated in **Volume 2, Figure 4.1**, with further detail on construction access provided in **Volume 4:**

Outline Construction Traffic Management Plan. The construction access points will be used for the duration of the onshore substation site construction works and will remain as permanent accesses during the operation of the onshore substation site.

4.8.3.11 A temporary construction compound will be required. This will be located adjacent to the construction access road from the east of the site and will be up to 3.06ha in area (see **Volume 2, Figure 4.1**. This compound will occupy the same location for the duration of the construction of the onshore substations.

4.8.3.12 Once all construction activities have been carried out at each onshore substation, the electrical equipment will be installed, commissioned and tested for the performance of the connection between the offshore wind farm, the onshore substation and the point of connection at SSEN Netherton Hub. Finally, each onshore substation will be secured, and following completion of the final onshore substations, the temporary construction area returned to its original use and condition.

Construction equipment

4.8.3.13 Typical construction equipment utilised in the construction of the onshore substations includes:

- 20 tonne dump trucks (tipping fill); bulldozers;
- wheeled backhoe loaders; tracked / backhoe excavators; wheeled loaders; water pumps; large concrete mixers;
- truck mounted concrete pump and boom arm;
- drum vibratory compacters;
- piling rig and associated equipment;
- powerfloats;
- road rollers;
- graders;
- mobile telescopic cranes;
- telescopic handlers;
- generators; and
- tower lights.

Construction Traffic

4.8.3.14 HGVs and LGVs will be required during the enabling and construction stage of the onshore substations. Abnormal indivisible load movements are required during the construction stage to transport permanent plant, such as transformers and SHRs to the site. The construction access point from the A950 will be utilised for the delivery of abnormal loads such as transformers. Indicative construction traffic movements are assessed in **Chapter 26: Traffic and Transport**. Further details on the delivery of abnormal loads are detailed in **Volume 3, Appendix 26.2: Abnormal Load Assessment**.

4.8.3.15 An Outline CTMP has also been prepared and submitted as part of the planning application, see **Volume 4: Outline Construction Traffic Management Plan**. A full CTMP will be developed prior to construction. The CTMP will include details of delivery timings for plant and equipment, vehicle access routes and temporary road closures diversions and / or other local traffic management that will be necessary, restrictions to timing of vehicle movements, construction signage and car parking arrangements as well as any other key requirements.

Workforce

4.8.3.16 The total number of construction employees required has been estimated at an average of approximately 50 to 200 construction personnel per day.

4.8.4 Onshore grid connection export cables

4.8.4.1 An onshore export cable corridor is required from the proposed onshore substations to the grid connection point at SSEN Netherton Hub (see **Volume 2, Figure 4.1**). The construction methodology for the grid connection cables will be the same as described for the onshore export cables from the landfall(s) to the onshore substations.

4.9 Project construction programme and construction timings

4.9.1 Construction programme

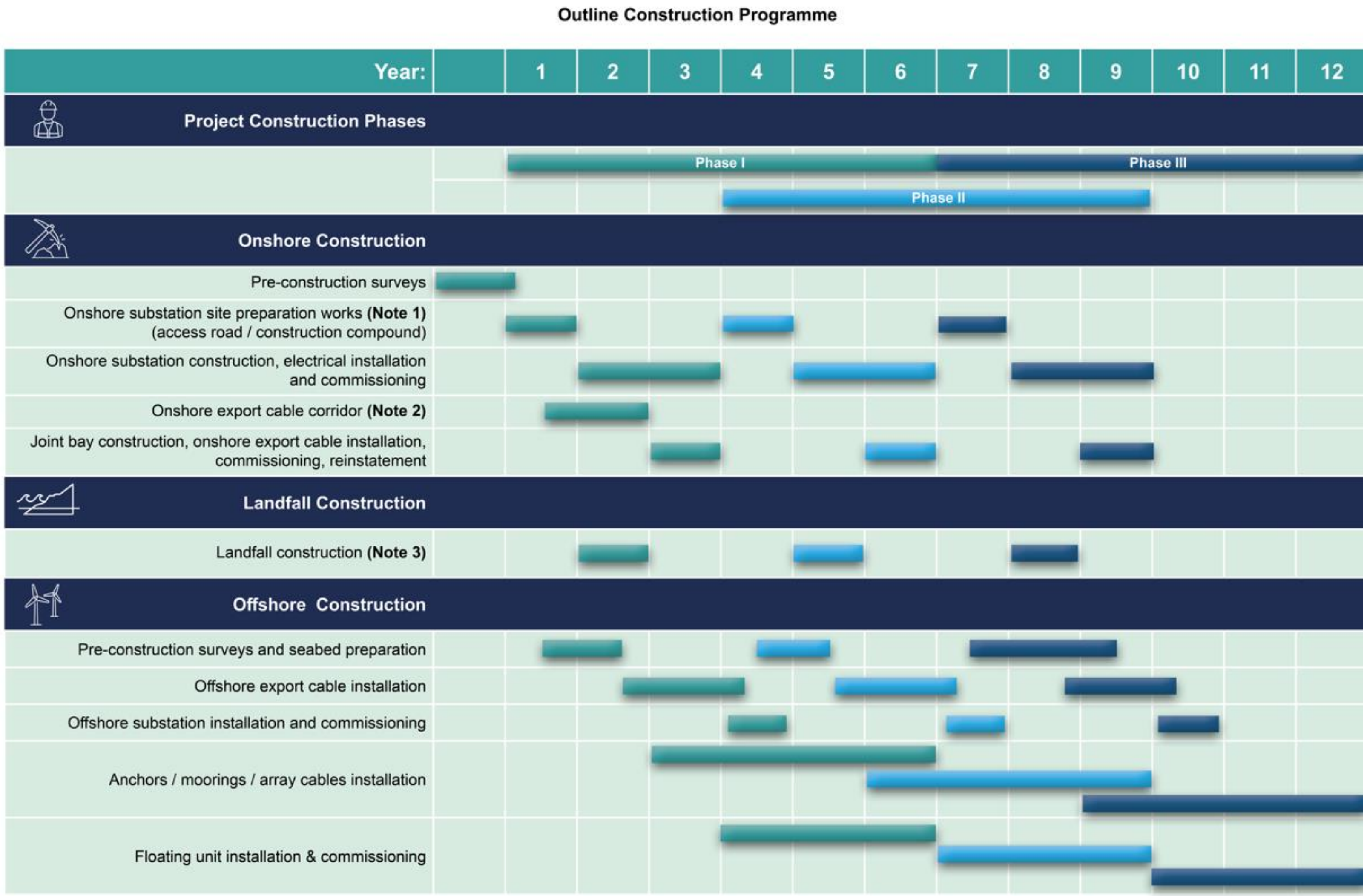
4.9.1.1 An indicative construction programme for the Project is presented in **Plate 4.16**. The programme illustrates the anticipated duration of the main construction / installation activities by infrastructure component.

4.9.1.2 The overall duration of construction of the offshore infrastructure is anticipated to be up to 12 years. This will be subject to the final grid connection date, supply chain discussions and further site surveys (pre-consent).

4.9.1.3 A shorter period within the twelve years is expected for construction of the onshore infrastructure; in the range of up to nine years.

4.9.1.4 The Project will be delivered in phases, which are reflected in the indicative construction programme. It is anticipated that construction of the Project would commence in 2030.

Plate 4.16 Indicative construction programme



Note 1: Permanent roads built as part of first phase onshore substation build. No further permanent roads required as part of second & third phases.

Note 2: Includes site preparation works (access / haul roads, construction compounds), cable trenching, horizontal directional drilling works and duct installation for all Project phases.

Note 3: Includes site preparation works (access road / construction compound), transition joint bay construction, horizontal directional drilling works and associated duct installation.

4.9.2 Construction timing

4.9.2.1 As secured in **Volume 4: Outline Environmental Management Plan** the worst-case expected working hours offshore would be 24 hours a day subject to relevant marine law and watch keeping.

4.9.2.2 As secured in **Volume 4: Outline Construction Environmental Management Plan**, core working hours for onshore construction works for the Project are as follows:

- 08:00 to 18:00 hours Monday to Friday; and
- 08:00 to 13:00 hours on Saturday.

4.9.2.3 Prior to and following the core working hours Monday to Friday, a ‘shoulder hour’ for mobilisation and shut down will be applied (07:00 to 08:00 and 18:00 to 19:00) for which restrictions are described further in **Volume 4: Outline Construction Environmental Management Plan**. No activity outside of these hours, including Sundays, public holidays or bank holidays will take place apart from under the following circumstances:

- where continuous periods (up to 24-hours, seven days per week) of construction work are required for HDD (or similar trenchless technique);
- for other works requiring extended working hours such as concrete pouring which will require the relevant planning authority to be notified at least 72 hours in advance; and
- for the delivery of abnormal loads to the connection works, which may cause congestion on the local road network, where the relevant highway authority has been notified prior to such works 72 hours in advance; or as otherwise agreed in writing with the relevant planning authority.

4.10 General construction practices

4.10.1 Offshore safety zones

4.10.1.1 During construction, safety zones of up to 500m radius will be sought around each WTG and their associated floating units, and offshore substations whilst construction operations are ongoing. Safety zones will be clearly indicated by the buoyage and the presence of installation vessels. Several installation activities may take place simultaneously and consequently; safety zones will be sought around each of these activities as they take place within the offshore wind farm site. Prior to commissioning, a 50m radius safety zone will be sought around each constructed WTG and floating unit, and each offshore substation and their associated foundations structures. Further information is set out within the **Safety Zone Statement**.

4.10.2 Environmental management

4.10.2.1 In relation to the construction of the offshore infrastructure, an Outline EMP has been prepared (see **Volume 4: Outline Environmental Management Plan**). This Outline EMP sets out the environmental management approach and controls that will be put in place and adopted by the Applicant, in addition to contractors and sub-contractors as appropriate. The purpose of these measures is to protect the environment during the construction and operation of the Project. It includes defined roles and responsibilities relating to environmental management, reporting procedures put in place to manage specific environmental issues (e.g. waste management and pollution prevention) as well as management measures to prevent adverse environmental impacts (e.g. introduction of invasive non-native species.

4.10.2.2 The Outline EMP will form the basis of the Final EMP, which will be finalised and approved post-consent and approved as part of condition discharge prior to construction, O&M and decommissioning by Scottish Ministers in accordance with s.36 and associated marine licences.

4.10.2.3 In relation to the construction of the onshore infrastructure, an Outline Construction Environmental Management Plan (CEMP) has been prepared (see **Volume 4: Outline Construction Environmental Management Plan**). The Outline CEMP sets out the environmental management and control measures essential for ensuring effective environmental management throughout the Project's construction period, including the landfall(s) works. The Outline CEMP has been developed in accordance with the relevant environmental legislation and mitigation measures outlined in the EIA Report and industry best practice, ensuring full compliance throughout the construction process. The measures include control and monitoring procedures to manage construction activities, ensuring environmental impacts are avoided, prevented, or minimised.

4.10.2.4 The Outline CEMP will form the basis of the Final CEMP. The Final CEMP will be finalised and approved post-consent and approved as part of condition discharge prior to construction by Aberdeenshire Council, in advance of starting works on-site.

4.10.3 Waste management

4.10.3.1 Waste will be generated as a result of the Project, with most waste expected to be generated during the construction and decommissioning phases. The Applicant will adopt good construction and management practices and will apply the waste hierarchy. This will ensure that waste arising during the construction, O&M, and decommissioning phases of the Project is minimised as far as possible and that the storage, transport and eventual disposal of waste have no significant environmental effects. The volume of waste produced in all phases of the Project is anticipated to be low and that it can be accommodated by local facilities.

4.10.3.2 For onshore specific waste, an Outline Site Waste Management Plan is provided in **Volume 4: Outline Construction Environmental Management Plan**.

4.10.3.3 For offshore specific waste, **Volume 4: Outline Environmental Management Plan** commits to producing a Waste Management Plan (WMP). The WMP will be developed to manage all waste generated during the construction and operation stages of the Project.

4.11 O&M stage

4.11.1 Introduction

4.11.1.1 It is anticipated that the first phase of the Project would become fully operational in 2037 following commissioning of the WTGs for phase 1. It is anticipated the second phase of the Project would become fully operational in 2040 and the third phase in 2043. The operational lifetime of the Project for each phase is expected to be around 35 years.

4.11.1.2 It is the Applicant's intention to have fully operational phases in the dates outlined in **paragraph 4.11.1.1** subject to the reasons outline in **Section 4.2.2**.

4.11.1.3 O&M activities can be divided into two main categories:

- scheduled maintenance; and

- unscheduled maintenance.

4.11.2 The Applicant's O&M strategy

4.11.2.1 The developer is responsible for the O&M activities associated with the generating assets. However, as per the Electricity Act 1989, a generator may not own the transmission system. As such the offshore substations and offshore export cables will be sold to an Offshore Transmission Operator (OFTO), who will be accountable for O&M of the Offshore Transmission assets.

4.11.2.2 After commissioning, and in line with the Electricity Act 1989, the ownership of the offshore substation, RCPs and associated infrastructure to shore, including the onshore substation, will be transferred to a separate third party OFTO. As such it is necessary to keep the flexibility open for different O&M requirements.

4.11.2.3 The overall O&M strategy will be finalised once the O&M base location and technical specifications of the offshore elements are known. A monitoring, inspection and maintenance plan will be put in place to ensure the integrity of all offshore infrastructure associated with the Project. Maintenance requirements will depend on the infrastructure used, depending on the type of wind turbine, floating platforms, electrical transmission infrastructure and final layout of the wind farm. Maintenance and repair operations will typically be undertaken via SOV. Where necessary, helicopters or other specialised vessels may also be used. Twenty-four-hour operations within the OAA and along the offshore export cable corridor is normal but will be assessed for safety considerations if transfer of personnel is required outwith daylight hours.

Key O&M requirements

- **Remote monitoring**: The wind farm will be equipped with advanced monitoring systems that will provide real-time data on its performance and condition. This data will be analysed to identify trends, predict potential failures, and optimise maintenance schedules.
- **Preventive maintenance**: A proactive maintenance program will be established to prevent failures and minimise downtime. This will involve scheduled replacement of components, cleaning, lubrication, and calibration of equipment.
- **Corrective maintenance**: In the event of unexpected failures or malfunctions, prompt corrective maintenance will be performed to restore functionality. This may involve repairs, component replacements, or system adjustments.
- Where scour protection had been employed during the initial construction stage, this may be replenished during operation via the addition of fresh material on top of existing scour protection areas should it be required.

Frequency of O&M activities

4.11.2.4 The frequency of O&M activities will vary depending on the specific component or system. Some tasks may be performed daily (for example remote monitoring), while others may be scheduled annually or less frequently (for example component replacements). The O&M plan will outline the specific frequency for each activity based on manufacturer recommendations, industry best practices, and operational experience, but will not be finalised for the transmission assets until the OFTO transfer is complete.

Offshore surveys

4.11.2.5 Offshore surveys will be undertaken on an ongoing basis throughout the O&M phase, which may include geophysical surveys to monitor the condition of the seabed and subsea infrastructure, depth of burial surveys using acoustic or electromagnetic survey techniques to monitor the condition of buried cables, and visual inspections via ROV.

4.11.2.6 Seabed surveys of the OAA will also typically be performed. The timing of the inspection or monitoring of the infrastructure will be subject to further assessment during detailed design phase. However, as there is a up to 12 year construction stage, vessels will be in the vicinity to complete spot checks where necessary.

4.11.2.7 The survey schedule for the remaining lifetime of the wind farm will be determined after the first surveys. This schedule should include, as a minimum, two further surveys over the remaining lifetime of the wind farm. Depending on site conditions, additional or rescheduled monitoring following a major storm event. Depending on site conditions, additional or rescheduled monitoring following a major storm event may be carried out.

O&M commitments

4.11.2.8 The Project is committed to ensuring the long-term reliability and performance of the wind farm through a comprehensive and well-planned O&M strategy. This strategy will be designed to minimise environmental impact while maintaining operational efficiency.

4.11.2.9 A rigorous Health and Safety Management Plan will be developed to ensure the well-being of personnel during O&M activities. This plan will be created in accordance with industry best practices and guidelines, including the Offshore Wind and Marine Energy Health and Safety Guidelines and Work Health and Safety on Offshore Wind Farms - Special Report 310 and will also take account of best practices and guidelines from other relevant industries.

4.11.2.10 O&M activities will be conducted in a manner that minimises environmental impact. This includes the development of a Waste Management and Disposal Plan, EMP and Emergency Response Plans amongst others.

4.11.2.11 The Project will engage with stakeholders as necessary to ensure transparency and address any concerns related to O&M activities. Regular updates and open communication channels will be maintained to foster good relationships and community support.

4.11.2.12 Continuous improvement will be a key focus, with regular reviews and updates to the O&M strategy based on operational experience and technological advancements. This adaptive approach will help ensure the wind farm remains efficient, safe, and environmentally responsible throughout its operational life.

O&M ports

4.11.2.13 The Applicant will endeavour to use Scottish and UK ports, with an indicative shortlist of O&M ports considered for the Project identified in **Table 4.26**. These are based on the main O&M activities that are envisaged to be required under the current Project requirements and port capabilities.

Table 4.26 Potential O&M ports

O&M activity	Potential ports
General O&M for supply SOV / crew changes	Aberdeen Fraserburgh Peterhead Montrose, Angus Nigg, Highland Cromarty Ardersier
Major component replacement (MCR) O&M that requires floating unit / WTG to be towed to port	Inverness and Cromarty Firth Green Freeport, for example Nigg, Invergordon or Ardersier. Forth Green Freeport, for example Burntisland & Leith. Aberdeen.

4.11.3 O&M activities for WTGs

Overview

4.11.3.1 The following O&M activities are expected to occur in relation to the floating WTGs:

- replacement of consumable items (for example lubricants);
- routine inspections;
- blade repairs and / or replacements;
- gear box replacements;
- other minor repairs;
- painting or other protective coatings; and
- visual inspections.

4.11.3.2 Regular maintenance activities will primarily be carried out offshore with the WTG in situ. For MCR, it may be necessary to tow the WTG / floating unit assembly to port, particularly in the early years of floating wind farm operation. Emerging technologies are being considered and developed that would remove the need for tow to port and allow MCR to be undertaken offshore. ROVs, tow vessels, cable vessels and anchor handler vessels may be used in the case of MCR, which is anticipated to occur on an unscheduled basis (i.e. as required).

4.11.3.3 It is assumed that the majority of the activities will be carried out using SOVs and associated daughter craft.

4.11.3.4 It is currently anticipated that any large O&M activities, including MCR will take place at a local O&M port or harbour facility. The process would follow a reverse of the installation approach. It is anticipated that the following indicative steps will be followed to undertake any major O&M works:

- disconnect and unhook the array cable(s) and wet store these on or buoyed above the seabed;
- ballasting of the floating foundation (if required);

- disconnect the mooring lines from the floating foundation and wet store on or buoyed above the seabed; and
- tow the turbine to a suitable O&M facility using anchor handling tugs, or similar. It is expected that a quayside mounted crane, or a suitable alternative, will be used to undertake any MCRs. Ballasting and de-ballasting at the quayside may also be required.

4.11.3.5 Following completion of O&M works, the WTG will be towed back to the WTG location within the OAA. Mooring lines would be reconnected; the turbine foundation would be ballasted (as required) and the array cable will be pulled into the WTG and reconnected.

4.11.3.6 Other O&M strategies would be considered including solutions that do not require towing to port.

Floating units

4.11.3.7 The following O&M activities are expected to occur in relation to the floating units:

- routine inspections;
- repairs or replacements of navigational equipment and other ancillary equipment including condition monitoring equipment;
- removal of marine debris (for example lost fishing gear);
- application of paint or other protective coatings and corrosion protection measures;
- modification or replacement of ancillary structures such as access ladders and boat landings;
- replacement or repair of mooring line components and hardware such as rope, links, chain buoyancy aids and / or clump weights where necessary; and
- replacement or repair of array cables.

4.11.3.8 It is assumed that the majority of these activities will be carried out using, SOVs and ROVs, which may include uncrewed surface vessels (USVs), and tug vessels, with appropriate equipment for the activity to be undertaken.

4.11.3.9 The Project’s design basis is to avoid the use of divers, but it may be necessary in special cases. These will then use diving support vessels (DSVs) to support operations.

4.11.3.10 It is assumed that the majority of these O&M activities will be routinely scheduled throughout the lifetime of the OAA. The frequency of O&M activities will be dependent on the findings of routine inspections.

Array cables

4.11.3.11 The following O&M activities are expected to occur in relation to the array cables:

- routine inspections;
- geophysical surveys;
- cable repair by recovering the cable from its trench or water column and making the necessary repairs.
- reburial of sections of cable that have become exposed;
- ancillary equipment repair or replacement; and

- replacement of cable protection over sections of the cable identified as in need of protection.

4.11.3.12 During the O&M stage of the Project, the offshore array cables and any buoyancy or other fittings will be periodically inspected for any maintenance and repair needs. O&M activities will be conducted using a variety of vessels commonly employed in the offshore industry, including USVs, SOVs, ROVs and cable-laying vessels. Divers and DSVs may utilise when necessary for specialised tasks. The majority of these activities are expected to be routinely scheduled throughout the operational lifespan of the Project.

4.11.3.13 Regular inspections using ROVs will be conducted to assess the condition of the array cables, including its burial depth and any protective measures in place. Periodic surveys utilising sonar and other geophysical techniques will be performed to monitor the seabed conditions along the array cable route, ensuring the array cable remains adequately buried and protected. If any exposure of the array cable is detected, prompt action will be taken to rebury the cable or install additional protective measures.

4.11.3.14 Where a fault is detected, the damaged section of cable will be recovered and repaired by splicing in a new section or replaced in its entirety. For buried cables, it will be necessary to expose the cable prior to recovery where testing will be conducted to establish the extent and type of repair required.

4.11.3.15 The cable will be recovered onto the deck of a vessel, the damaged section removed, and a new cable section connected in with two joints. When cables are replaced on the seabed, the new cable section forms a repair ‘bight’, which gives the underwater cable an omega-shape (Ω) relative to the original cable position. This is because the new section of the cable will be longer than the original, meaning that it cannot be placed back in exactly the same place. The cable will be replaced within the licenced boundary for the Project.

4.11.3.16 After repairs are complete, the cable will again be buried below the seabed using on the same techniques as used for the initial construction. New cable protection material may need to be installed over the repaired section. Where cable protection was in place, this would need to have been displaced to allow recovery of the cable and then replaced.

Moorings and anchors

4.11.3.17 A monitoring, inspection and maintenance plan will be put in place to ensure the integrity of the mooring system.

4.11.3.18 The mooring lines may need to be periodically re-tensioned during the lifetime of the wind farm due to creep / stretching. Depending on which floating units and mooring systems are selected, re-tensioning would require either a single anchor handling vessel or an offshore construction vessel and support vessels to provide access.

4.11.3.19 Where anchors or mooring lines need to be replaced, the existing mooring line will be disconnected from the floating unit and a new line installed and hooked up to the floating substructure using the same process as used during construction.

4.11.3.20 Debris, including lost fishing gear will also be monitored via ROV, with debris and excessive growth or colonisation of marine biota removed intermittently. As with the floating substructures, some of the mooring system ancillaries (ancillaries may include permanent and temporary buoyancy or clump weights) may be painted in a low-toxicity anti-fouling paint to reduce the build-up of marine growth.

Subsea distribution centres and subsea substations

4.11.3.21 The following O&M activities are expected to occur in relation to SDC and subsea substations:

- routine inspection by ROV;
- geophysical surveys;
- removal of marine growth;
- replacement of corrosion protection anodes;
- replacement of equipment / connections;
- cable repair or replacement; and
- replacement of scour protection (if fitted).

4.11.3.22 As subsea substations will be sold to an OFTO after commissioning, the associated O&M activities will be confirmed by the OFTO that takes ownership of the assets.

4.11.4 O&M activities for offshore platforms

4.11.4.1 As the offshore platforms will be sold to an OFTO after commissioning, the following O&M activities may be reasonably anticipated but will be confirmed by the OFTO that takes ownership of these assets.

Offshore platform topsides

4.11.4.2 The following O&M activities are expected to occur in relation to the offshore substation topsides:

- routine inspections;
- removal of avian guano;
- replacement of consumables and electrical transmission components; and
- painting and other coatings.

O&M activities for offshore substations and RCPs

4.11.4.3 The following O&M activities are expected to occur in relation to the offshore substation and RCP jacket foundations:

- routine inspections;
- geophysical surveys;
- repairs and replacements of navigational equipment and other ancillary equipment including condition monitoring equipment;
- removal of marine growth;
- replacement of corrosion protection anodes;
- application of painting or other protective coatings;
- replacement of access ladders and boat landings;
- modifications to or replacement of J and I-tubes; and

- replacement of scour protection.

4.11.5 O&M activities for offshore export cables

4.11.5.1 As the offshore export cables will be sold to an OFTO after commissioning, the following O&M activities may be reasonably anticipated but will be confirmed by the OFTO that takes ownership of these assets.

4.11.5.2 The following O&M activities are expected to occur in relation to the offshore export cables:

- routine inspections;
- geophysical surveys;
- cable repair by recovering the cable from its trench / water column and making the necessary repairs;
- reburial of sections of cable that have become exposed;
- ancillary equipment repair; and
- replacement of cable protection over sections of the cable identified as in need of protection.

Offshore export cable corridor repairs and maintenance

4.11.5.3 During the O&M stage of the Project, the offshore export cables will be periodically inspected for any maintenance and repair needs. O&M activities will be conducted using a variety of vessels commonly employed in the offshore wind industry, including USVs, SOVs, crew transfer vessels, ROVs, and cable-laying vessels. Divers and DSVs may be utilised when necessary for specialised tasks. The majority of these activities are expected to be routinely scheduled throughout the operational lifespan of the wind farm.

4.11.5.4 Regular inspections using ROVs will be conducted to assess the condition of the offshore export cable, including its burial depth and any protective measures in place. Periodic surveys utilising sonar and other geophysical techniques will be performed to monitor the seabed conditions along the offshore cable corridor, ensuring the cable remains adequately buried and protected. If any exposure of the offshore export cable is detected, prompt action will be taken to rebury the cable or install additional protective measures.

4.11.5.5 Where a fault is detected, the damaged section of cable will be recovered and repaired by splicing in a new section or replaced in its entirety. For buried cable, it will be necessary to expose the cable prior to recovery where testing will be conducted to establish the extent and type of repair required.

4.11.5.6 The cable will be recovered onto the deck of a vessel, the damaged section removed, and a new cable section connected in with two joints. When cables are replaced on the seabed, the new cable section forms a repair ‘bight’, which gives the underwater cable an Ω-shape relative to the original cable position. This is because the new section of cable will be longer than the original, meaning that it cannot be placed back in exactly the same place. The cable will be replaced within the licenced boundary for the Project.

4.11.5.7 After repairs are complete, the cable will again be buried below the seabed using one of the same techniques as used for the initial construction. New cable protection material may need to be installed over the repaired section. Where cable protection was in place, this would need to have been displaced to allow recovery of the cable and then replaced.

4.11.5.8 Upon completion of re-burial, a post-burial survey will be carried out to assess whether the cable is at the correct position and required depth of lowering.

4.11.5.9 Seabed surveys will also be required to ensure that cables remain buried and that the cable protection around cable crossings remains intact. Should any areas of exposed or insufficiently buried cables be identified, jetting equipment (for instance mass flow excavator or similar) will be used to achieve the required burial depth or alternative protective measures such as rock placement in accordance with over trawlable design. Once complete, a seabed survey will be conducted to confirm the success of the operation and if not, actions listed above will be repeated until successful burial or protection is achieved.

4.11.6 Offshore access and logistics for O&M activities

Access and logistics strategy

4.11.6.1 The general offshore O&M strategy may rely on an onshore O&M base, SOVs, jack-up vessels, offshore accommodation vessels, supply vessels, cable and remedial protection vessels and helicopters for the O&M services that will be performed for the Project. The final O&M strategy chosen may be a combination of the above solutions. Each vessel movement represents a return trip to and from the OAA.

4.11.6.2 The vessel movements in **Table 4.27** represent annual averages across the lifetime of the Project, and due to the nature of unplanned maintenance, specific years may require more activity than others.

4.11.6.3 **Table 4.27** provides the worst-case design scenario for vessel movements during O&M.

Table 4.27 Worst-case design scenario offshore O&M – vessel movements

Component	Design envelope
Average annual SOV movements	Two-week rotation x two vessels when full 3GW built out.
Average annual jack-up vessel movements (in-field maintenance)	Jack-up or offshore accommodation vessels would only be for major maintenance, assumed once every ten years. It would seldom move during this time, remaining in position or significant operations, then moving to the next offshore substation for example, as opposed to coming to shore. It would be ‘fed’ by supply vessels / personnel transfer by helicopter for the period it is there. Time in-situ is assumed to be four weeks per offshore substation.
Average annual towing spread movements (tow-to-port maintenance)	Unknown currently, but a conservative assumption is that every floating unit moves once every five years in first instance. This may reduce over time.
Average annual anchor handling vessel movements	Only relevant if drag embedment anchors are used, with a conservative assumption being the relaying of 12 drag embedment anchors per year.
Average annual helicopter transfers	On an ad hoc basis, daily trips four weeks of the year are assumed.
Average annual cable laying vessels movements	Up to five array cable changes are assumed per year at full 3GW scale.
Average annual diving support vessels movements	The Project is designed for ROV replacement, with diving support a back-up option only. A conservative assumption is

Component	Design envelope
	that diving would be used on an ad hoc basis two weeks a year with two transits to shore.
Guard vessels	Two dedicated guard vessels will operate year-round on a two-week rotation to maintain site safety and enforce exclusion zones in accordance with MCA Marine Guidance Note (MGN) 654 and COLREGs. Their primary role is to monitor marine traffic and support navigational risk mitigation during O&M activities. Under the worst-case scenario, this results in approximately 104 round trips and 208 transits per year, ensuring continuous coverage of the offshore array and associated infrastructure.

4.11.6.4 Peak of up to seven O&M vessels offshore with up to 364 round trips to port per year.

4.11.6.5 MCR number of vessels and trips are not included and will be assessed post-consent subject to further design decisions taken by the Project.

O&M access and vehicle / vessel types for offshore platforms

4.11.6.6 The offshore substations and RCPs will normally be unmanned during the operational phase of the Project. However, maintenance will be required throughout the Project lifetime.

4.11.6.7 Maintenance types would include:

- Planned shutdown maintenance: work undertaken using either a walk to work vessel or a jack-up. More people would be required to get the work done efficiently. This is likely when major equipment needs replaced and would align with onshore outages.
- Ad hoc preventative / corrective maintenance: would involve a small number of personnel who will be transferred to the facility, either via SOV or helicopter.

4.11.6.8 Vessel types used for accessing and maintaining the offshore substations and RCPs are:

- helicopters: used for routine inspections, minor maintenance tasks, and personnel transfers;
- SOVs: equipped with workshops, cranes, ROVs, and accommodation facilities, allowing for extended maintenance campaigns;
- jack-up vessels: used for offshore substation extended maintenance campaigns that require a stable platform and heavy lifting capabilities.
- guard vessels: vessels tasked with protecting specific areas, worksites, or assets, by monitoring marine traffic and ensuring the safety of the area; and
- dedicated accommodation vessels for offshore crew, referred to as ‘flotels’.

Helicopter and crew movements

4.11.6.9 The offshore crew for the O&M of the wind farm will be transferred from port via dedicated vessels and / or helicopters as required. The frequency of these movements is yet to be determined and may constitute a regular pattern, with additional movements, when necessary, in response to maintenance needs offshore.

4.11.7 Offshore safety zones

4.11.7.1 As stated in **Section 4.10.1** a **Safety Zone Statement** has been submitted with this Application. There will be no permanent operational safety zone, only temporary / major maintenance (if required) of up to 500m. Where appropriate, guard vessels will also be used to ensure adherence with safety zones or advisory passing distances, as defined by risk assessment, to mitigate any impact that poses a risk to surface navigation during construction, maintenance and decommissioning phases. Such impacts may include partially installed structures or cables, extinguished navigation lights or other unmarked hazards.

4.11.8 Landfall(s) O&M

4.11.8.1 Scheduled and unscheduled maintenance in relation to the transition joint bays and the associated landfall(s) section of the onshore export cables is covered in **Section 4.11.9**.

4.11.8.2 Where a repair is required to a section of offshore export cable inside a landfall duct the following process would take place:

- A new section of offshore cable would be installed across the landfall, either using the original duct (if the faulty cable inside can be successfully removed) or using a duct installed as spare during the original landfall(s) construction stage. Either way, the faulty cable section would need to be disconnected at the transition joint bay and cut at the offshore end at a suitable distance from the end of the duct and in water deep enough to allow repair vessel access. The cut end would be sealed and buoyed for later recovery and laid down (‘streamed’) on the seabed.
- As with the original export cable installation campaign, the replacement section would be pulled through the empty duct from a cable repair vessel stationed at the offshore duct end to the onshore transition joint bay. This would require mobilisation of a winch and associated equipment at the onshore end as with the original installation of cables at the landfall.
- At the offshore end, the replacement cable would then need to be jointed to the streamed end of the offshore export cable. The repair vessel would lay away from the duct end until it reached the position of the streamed end. The end would be recovered to deck, and both ends would be cut, tested and prepared for jointing. An offshore joint would then be completed.
- The repaired cable would be re-laid back on the seabed as close to the original cable position as possible, noting that the cable route will now be characterised by an Ω-shape loop laid down approximately perpendicular to the direction of the cable route. Once in position, the cable will be inspected and reburied using jetting or covered by external cable protection where burial cannot be achieved.
- The replacement landfall cable would be jointed to the onward onshore export cable at the relevant transition joint bay (the faulty cable connection having been removed).

4.11.9 Onshore infrastructure O&M

4.11.9.1 Maintenance of the onshore export cable between the landfalls and the onshore substations is expected to be minimal. During O&M, periodic testing of the cable is likely to be required (every two to five years). This will require access to the link boxes at defined inspection points along the onshore export cable corridor. Unscheduled maintenance or emergency repair visits will typically involve attendance by up to three light vehicles, such as vans, in a day at any one location. The vehicles will gain access using existing field or site access points to reach the relevant sections of the onshore export cable.

4.11.9.2 Infrequently, the onshore export cable may need to be repaired. In these circumstances the use of an occasional HGV may be utilised, depending on the nature of the repair. Subject to the location of the repair, the replacement of a cable will involve building a temporary access track from a suitable access point, excavating to confirm the cable fault location using excavation equipment and excavating the required length of cable to enable a double joint repair. The length of cable replacement will be subject to the failure location and will be several meters in length. The length of faulty or damaged cable will be removed, a double joint repair made, and an equivalent length replacement spare cable installed. Once complete, the ground and the access will be re-instated.

4.11.9.3 Monitoring of the onshore substations will be undertaken remotely using closed-circuit television technology and other remote monitoring equipment. The security fencing installed during construction will remain in place. Certain areas of the onshore substations will have permanent light fittings. However, these lights will only be used when required for maintenance or emergency repair purposes.

4.11.9.4 At the onshore substations, unscheduled maintenance or emergency repair visits will typically involve a very small number of vehicles, typically light vans. Infrequently, equipment may need to be replaced, where this is required the use of an occasional HGV may be utilised, depending on the nature of the repair.

4.11.9.5 Inspection and minor servicing may be required for the electrical plant, but it is anticipated that the onshore substations will require minimal scheduled maintenance and operation activities.

4.11.9.6 It is anticipated that a monthly inspection of the electrical infrastructure will be required. Maintenance of the buildings is anticipated to be carried out annually, with maintenance of electrical infrastructure being carried out during onshore substation outage periods, typically every few years. Access to the onshore substations will be via the permanent access road/s, up to 6m in width, as identified in **Volume 2, Figure 4.1**.

4.11.9.7 Lighting during O&M activities is expected to be minimal. External lighting will be directional and limited to essential security and safety requirements. External works will usually be scheduled during daylight hours. If night working is required, then portable directional task lighting will be deployed.

4.11.9.8 Foul drainage at the onshore substations would be collected in either of the following ways:

- mains connection discharging to the Scottish Water sewer system, if available; or
- septic tank located within the onshore substation site boundary.

4.11.9.9 The preferred method for controlling foul waste would be determined during detailed design and will depend upon the availability and cost of a mains connection and the number of visiting hours staff would attend site.

4.11.9.10 For the onshore export cable between the onshore substations and the point of connection at SSEN Netherton Hub, scheduled and unscheduled maintenance or emergency repair visits will follow the same process as for the onshore export cable between the landfall(s) and the onshore substations described above.

4.12 Decommissioning stage

4.12.1 Offshore decommissioning

Overview

4.12.1.1 The approach to decommissioning of the offshore infrastructure will be completed in line with any relevant guidance and legislation at the time of decommissioning. It is however expected that all infrastructure above the seabed will be removed. Any infrastructure below the seabed will be assessed to determine if less impactful (from an environmental perspective) to remove or leave in position. This is particularly relevant where new habitats have developed during the O&M stage of the Project.

4.12.1.2 A Decommissioning Programme will be developed post consent but prior to construction. It will be updated during the operational phase of the Project to account for any changes to industry best practice, relevant legislation, guidance and policy, or developments in technology.

4.12.1.3 Once decommissioned, all components will be reused or recycled where possible.

WTGs

4.12.1.4 The dismantling of turbine components, such as blades, nacelle, and tower, will primarily follow the reverse order of the installation process (see **Section 4.6**). These operations are expected to take place at the quayside, where they can be managed under controlled conditions.

4.12.1.5 The general methodology for carrying out wind turbine decommissioning is anticipated to involve the following steps:

- assessment of potential hazards during the decommissioning work and pollutants to the environment that may result from decommissioning work;
- de-energisation of the WTGs and isolation from the grid;
- mobilise suitable vessel(s) to site to carry out the disconnection and tow to port operation;
- reposition the WTGs to a port or sheltered nearshore location;
- remove / dismantle turbine blades, nacelle and tower components; and
- transport all components to an onshore facility where they will be processed for reuse / recycling / disposal.

Floating units

4.12.1.6 The removal and dismantling of the floating units will largely be the reversal of the installation process (**Section 4.6**). Decommissioning will be undertaken in the same controlled manner as the installation process and in accordance with a risk management plan to ensure the same level of safety and pollution measures.

4.12.1.7 The floating unit will be towed to port (expected to be combined with the WTG (see **paragraph 4.12.1.5**). After the WTG is removed the floating unit may be repurposed or taken to an alternative site or port suited to decommissioning larger structures. In this instance the floating units will be dismantled and recycled. It is expected that a high percentage of recycling will be possible due to experience of decommissioning other similar structures. This will be confirmed in detail prior to decommissioning.

4.12.1.8 Mooring lines will be fully removed from site. Anchors will be removed where feasible, practicable and less environmentally impactful to do so than leaving in position. In cases where anchors are to be left in situ, best practice shall be adopted to ensure environmental and other marine users are considered. This approach will be reviewed throughout the lifetime of the OAA, ensuring adherence to the most up-to-date and good practice guidance at the time of decommissioning.

Array cables

4.12.1.9 The approach for decommissioning the array cables on the seabed is yet to be determined. This will be reviewed throughout the lifetime of the Project, and good practice guidance at time of decommissioning will be followed.

4.12.1.10 The dynamic portion of the array cables within the water column will be fully removed. If there are no issues with stakeholders / regulators and the risk of the cables becoming exposed is minimal, then the static buried cables (and relevant cable protection) may be cut and left in situ to avoid disturbing the seabed unnecessarily.

4.12.1.11 The ends of the cables will be cut as close to the seabed and weighted down for burial to ensure there is no interference with trawling and other users of the sea. A decision to decommission infrastructure in situ will be supported by a comparative assessment process (in line with the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) (2025) and Scottish Government guidance (Scottish Government, 2022)).

4.12.1.12 The sequence for removal of the cables is anticipated to be:

- To retrieve the cable, a grapnel or similar will be used to locate and lift it from either the water column or the seabed. If needed, a ROV may be deployed to cut the cable or attach a lifting device to enable safe retrieval to the vessel.
- If necessary, seabed material will be cleared to access static cables on the seabed, typically using a water jetting tool.
- For dynamic cable removal, the buoyancy modules will be detached as the cable is brought up onto the deck.
- The recovery vessel will then move along the cable route while winching the cable onto a carousel or reel.

4.12.1.13 Where possible, array cable materials will be processed for reuse / recycling / disposal.

4.12.1.14 Leaving the cable protection in situ may be beneficial to preserve the marine habitat that has developed during the Project’s lifespan. Engagement with relevant stakeholders and regulatory bodies will help determine the most suitable approach.

4.12.1.15 If deemed required a decommissioning methodology for the cable protection is anticipated to include:

- for rock armour, individual boulders would likely be retrieved using a grab vessel, then loaded onto a barge for transport to an approved onshore location for either reuse or proper disposal; and
- the filter layer would likely be dredged and transported for reuse or disposed of at a licensed site, which may be either offshore or onshore.

Subsea distribution centres and subsea substations

4.12.1.16 The decommissioning methodology is anticipated to involve the removal of all offshore infrastructure above the seabed. An offshore construction vessel would remove cable connections prior to removal of the foundation.

4.12.1.17 Driven piles, if used, would be cut at seabed level to enable removal of the SDCs and subsea substations first. The SDCs and subsea substations would likely be a single or multiple lift operation from a similar vessel as the construction vessel. Upon removal of the SDCs and subsea substation, remaining driven or suction piles would be addressed in the same manner as the anchors for the floating units (outlined in **paragraph 4.12.1.8**).

Offshore substations and RCPs

4.12.1.18 The decommissioning methodology is anticipated to involve the removal of all offshore infrastructure above the seabed. A heavy lift vessel would then remove the topside before work to decommission and remove the foundation could commence.

4.12.1.19 Driven piles if used would be cut at seabed level to enable removal of the foundation. The offshore substation foundation would likely be a single lift operation by a heavy lift vessel. Upon removal of the foundation remaining driven or suction pile would be addressed in the same manner as the anchors for the floating units (outline in **paragraph 4.12.1.8**).

Offshore export cables

4.12.1.20 Offshore export cables may be left in-situ or removed from the seabed. Relevant stakeholders and regulators will be consulted prior to decommissioning to establish which sections of the offshore export cables will require removal. If it is not required by stakeholders / regulators and the risk of the cables becoming exposed is minimal, then the cables (and relevant cable protection) may be cut and left in situ to avoid disturbing the seabed unnecessarily.

4.12.1.21 The ends of the cables will be cut as close to the seabed and weighted down for burial to ensure there is no interference with commercial fishing activities and other users of the sea. A decision to decommission infrastructure in situ will be supported by a comparative assessment process (in line with the OPRED, 2025 and Scottish Government, 2022).

4.12.1.22 Where cables are required to be removed, the sequence of activities is anticipated to be:

- Locate the cable section for removal by a cable recovery vessel. If necessary, seabed material will be cleared to access static cables on the seabed, typically using water jetting tool.
- The cable recovery vessel will then move along the cable route while winching the cable onto a carousel or reel.

4.12.1.23 Export cable materials will be processed for reuse / recycling / disposal.

4.12.1.24 Where cable protection has been used, leaving it in situ may be beneficial to preserve the marine habitat that has developed during the Project’s lifespan. Engagement with relevant stakeholders and regulatory bodies will help determine the most suitable approach.

4.12.1.25 If deemed required, the decommissioning methodology for cable protection is anticipated to include:

- for rock armour, individual boulders would likely be retrieved using a grab vessel, then loaded onto a barge for transport to an approved onshore location for either reuse or proper disposal; and

- the filter layer would likely be dredged and transported for reuse or disposed of at a licensed site, which may be either offshore or onshore.

Decommissioning ports

4.12.1.26 The Applicant will endeavour to use Scottish and UK ports with an indicative shortlist of ports considered for the decommissioning of the Project, identified in **Table 4.28**.

4.12.1.27 These are based on the main decommissioning activities and envisaged to be required under the current project requirements and port capabilities.

Table 4.28 Potential decommissioning ports

Decommissioning activity	Potential ports
Decommissioning	Kishorn Scapa Teeside Nigg Ardersier Invergordon Methil

4.12.2 Onshore decommissioning

Overview

4.12.2.1 The decommissioning stage will commence at the end of the operational lifetime of the Project. The decommissioning duration of the onshore infrastructure may take the same amount of time as construction of the Project, up to nine years, although this indicative timing may reduce. Materials would be reused or recycled, where possible, with the remainder of any material to be disposed with a licensed waste disposal site.

4.12.2.2 Prior to decommissioning taking place, an onshore decommissioning plan will be submitted and agreed Aberdeenshire Council before decommissioning works commence, following cessation of commercial operation.

Onshore export cables

4.12.2.3 It is anticipated that the onshore electrical cables will be left in-situ with ends cut, sealed and buried to minimise environmental effects associated with removal. The underground structures of the joint bays, fibre optic cable junction boxes and link boxes will be removed only if it is feasible with minimal environmental disturbance or if their removal is required to return the land to its current agricultural use. It should be noted that, whilst this is the current assumption, the regulations and practice applicable at the time of planning for decommissioning will be reviewed and followed. Further detail will be provided in an onshore decommissioning plan, prepared prior to the start of any decommissioning activities.

Onshore substations

4.12.2.4 The onshore substations and associated access roads will be removed and the site reinstated. The decommissioning works are likely to be undertaken in reverse to the sequence of construction works and involve similar types and levels of equipment and vehicles. The onshore substation site will be restored to its original state or made suitable for an alternative use. Further detail will be provided in an onshore decommissioning plan, prepared prior to the start of any decommissioning activities.

4.13 References

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4.14 Glossary of terms and abbreviations

4.14.1 Abbreviations

Acronym	Definition
AC	Alternating Current
AHTS	Anchor Handling Tug Supply
AOD	Above Ordnance Datum
CAA	Civil Aviation Authority
CBS	Cement Bound Sand
CEMP	Construction Environmental Management Plan
CfD	Contract for Difference
CSV	Construction Support Vessel
CTMP	Construction Traffic Management Plan
DSV	Diving Support Vessel
EIA	Environmental Impact Assessment
EMF	Electromagnetic Fields
EMP	Environmental Management Plan
FOC	Fibre Optic Cable
GIS	Gas Insulated Switchgear
GW	Gigawatt
ha	hectare
HAT	Highest Astronomical Tide
HDD	Horizontal Directional Drilling
HF	Harmonic Filter
HGV	Heavy Goods Vehicle
HND	Holistic Network Design
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
kJ	kilojoules

Acronym	Definition
kV	kilovolt
LAT	Lowest Astronomical Tide
LGV	Light Goods Vehicle
m	metre
MCA	Maritime and Coastguard Agency
MCR	Major Component Replacement
MD–LOT	Marine Directorate – Licensing Operations Team
MHWS	Mean High Water Springs
MLWS	Mean Low Water Springs
MSL	Mean Sea Level
MW	Megawatt
NE7	Northeast 7
NESO	National Electricity System Operator
nm	Nautical mile
O&M	Operation and maintenance
OAA	Option Agreement Area
OFTO	Offshore Transmission Operator
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
RCP	Reactive Compensation Platform
ROV	Remotely Operated Vehicle
RPM	Revolutions per minute
SHR	Shunt Reactor
SOV	Service Operation Vessel
SSEN	Scottish and Southern Electricity Networks
UK	United Kingdom
USV	Uncrewed Surface Vessel
UXO	Unexploded Ordnance
WMP	Waste Management Plan
WTG	Wind Turbine Generators

4.14.2 Glossary of terms

Term	Definition
Array cables	Array cables will be used to connect the WTGs to the offshore substation. This will be via other WTGs if in a string or loop arrangement, or to a subsea distribution centre, and then onto the offshore substation if in a star configuration. The cables will have a requirement to withstand both dynamic conditions at the floating units as well as static lay and burial in or on the seabed.
Construction Environmental Management Plan	A plan that sets out the standards and procedures to which developers and contractors must adhere when undertaking construction of major projects. This will assist with managing the environmental impacts and will identify the main responsibilities and requirements of developers and contractors.
Decommissioning	The period during which a development and its associated processes are removed from active operation.
Environmental measures	Measures that are proposed to prevent, reduce and where possible offset any significant adverse effects (or to avoid, reduce and if possible, remedy identified effects).
Environmental Impact Assessment	The process of evaluating the likely significant environmental effects of a proposed project or development over and above the existing circumstances (or ‘baseline’).
Environmental Impact Assessment Report	The outcome of the Environmental Impact Assessment (EIA) process is reported within a document called an EIA Report.
Export Cable Corridor	The broad linear area through seabed (seaward of Mean High Water Springs (MHWS)) and land (landward of MHWS) connecting the Project OAA offshore to the proposed point of connection onshore, and within which electrical export cables will be located.
Gigawatt	A unit of electrical power equivalent to one billion Watts.
Grid connection cables	These are the underground cables that connect from the proposed onshore substations to the grid connection point at SSEN Netherton Hub.
Intertidal	The area of a seashore that is covered by water at high tide and exposed to the air at low tide.
Horizontal Directional Drill	An engineering technique for laying cables that avoids open trenches by drilling between two locations beneath the ground's surface.
Landfall(s)	The generic term applied to the entire coastal area between the limit of MLWS and the position of the transition joint bays located above the limit of MHWS, inclusive of all construction works, including the offshore and onshore export cable corridor, intertidal working area and landfall(s) temporary construction compound.
Marine Directorate – Licencing Operations Team	The regulator for determining marine licence applications on behalf of the Scottish Ministers in the Scottish inshore region (between 0 and 12 nautical miles) under the Marine (Scotland) Act 2010, and in the Scottish offshore region (between 12 and 200 nautical miles) under the Marine and Coastal Access Act 2009.

Term	Definition
Maximum Design Scenario	The maximum design scenario represents the worst-case scenario for each aspect whilst allowing the flexibility to make improvements in the future in ways that cannot be predicted at the time of submission of the planning, s.36 consent and marine licence applications.
Mean High Water Springs	The average throughout a year of the heights of two successive high waters during those periods of 24 hours (approximately once a fortnight) when the tidal range is greatest.
Mean Low Water Springs	The average throughout a year of the heights of two successive low waters during those periods of 24-hours (approximately once a fortnight) when the tidal range is greatest.
Megawatts	Unit of electrical power equal to one million Watts.
Metre	Unit of lateral measurement equivalent to 100 centimetres.
Offshore	The offshore elements of the Project refer to works seaward of Mean High Water Springs (MHWS).
Onshore export cable	These are underground cables that connect from the landfall(s) transition joint bays to the onshore substations. As with the offshore export cables, the type and number of cables will depend on the transmission technology used. Cables are typically installed in ducts in a standard buried trench arrangement where possible. HDD (or similar trenchless technique) or other tunnelling methods may be necessary to cross sensitive features such as watercourses, roads and pipelines.
Offshore substation	Offshore substations are installed to collect the energy generated by the WTGs and house transmission equipment. The latter is required to convert the wind farm electricity to higher voltages necessary for long distance transmission through subsea cables to the onshore grid. Offshore substations can be above the sea surface on a platform and/or subsea. Several platforms may be required for the Project.
Onshore	The onshore elements of the Project refer to works landward of Mean Low Water Springs (MLWS).
Offshore export cable	Subsea export cables connect the offshore substations to the landfall(s)where a transition joint bay links the offshore subsea cables to the onshore underground cables. This cable system is necessary to export power from the offshore wind farm through the onshore substation to the existing grid network.
Onshore substations	Three new onshore substations are required to transform / convert the onshore export cable voltage to the 400kV required to connect to SSEN Netherton Hub.
Option Area Agreement	Term for the wind farm site upon the seabed at a location specified in the Option Agreement between the Crown Estate Scotland and a developer. It is the agreement that allows the developer the rights to undertake such tests, survey and site investigations that do not entail the temporary or permanent installation of any works or structures on the seabed.
Reactive Compensation Platform	For HVAC transmission, there is an upper limit of offshore export cable route length, beyond which the electrical losses incurred during

Term	Definition
	transmission become prohibitive. This limit can be increased using reactive power compensation equipment connected through a separate substation(s) along the offshore export cable corridor, typically close to the mid-point between the offshore substation and onshore substations.
Red Line Boundary	The Red Line Boundary is a geographical area within which the offshore wind farm; associated onshore and offshore infrastructure will be located. It represents the boundary identified for the relevant planning and consent applications.
Scour	A localised sediment erosion feature caused by local enhancement of flow speed and turbulence due to interaction with an obstacle.
Subsea distribution centres	Subsea distribution centres comprise a foundation support structure and protection structure. The subsea distribution centres allow cables from multiple WTGs to connect, with a single array cable then going from the subsea distribution centre to the offshore substation.
Subsea substations	Subsea substations comprise of a foundation support structure and protection structure, which is secured subsea to support associated distribution equipment. Given the access restrictions from being subsea they will be designed for ease of access and consider the need for O&M activities through life.
The Project	The MarramWind Offshore Wind Farm that is the subject of this EIA Report, as described in **Chapter 4: Project Description.**
Transition joint bay	Transition joint bays are permanent, below ground infrastructure, where the offshore and onshore export cables are jointed together.
Unexploded Ordnance	Explosive weapons (for example bombs, shells, grenades, land mines, naval mines) that did not explode when they were employed or discarded and still pose a risk of detonation, potentially many decades later.
Wind Turbine Generators	WTGs convert wind energy to electricity. Each floating WTG will comprise a tower (potentially assembled in sections), a rotor with three blades attached to a nacelle. The nacelle typically houses a gearbox, generator, converter, transformer, and control equipment.
WTG floating unit	Each WTG is supported by a floating unit that is positively buoyant and moored in position on the seabed. A number of floating unit concepts are currently under consideration.
WTG station keeping system	Each WTG on its floating unit will be secured in place using a station keeping or mooring system, involving anchors and mooring lines. Typically, multiple mooring lines will spread out radially from the floating structure, each ending in an anchor point on the seabed.

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