# Buchan Offshore Wind

## Chapter 4 Project Description

## QMS Review

| Name | Company | Date | Reviewed | Approved |
|---|---|---|---|---|
| RML/CMO | BOW | 11/07/2025 | CMO | ISS |

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## 4.1 INTRODUCTION

### 4.1.1 Purpose of this Chapter

4-1. This chapter of the Offshore Environmental Impact Assessment Report (EIAR) provides a description of the offshore components (the Proposed Offshore Development) of the Buchan Offshore Wind Farm (the Project) and details on how the Proposed Offshore Development will be constructed, operated, maintained and decommissioned. The details within this chapter form the basis on which the assessments have been undertaken for each technical chapter within this Offshore EIAR.

4-2. For the purpose of this Offshore EIAR, the Proposed Offshore Development is defined as the offshore elements of the Buchan Offshore Wind Farm only, up to Mean High Water Springs (MHWS). Under the Town and Country Planning (Scotland) Act 1997 a separate onshore planning application and EIAR is being progressed, covering details of the Project landward of MLWS.

4-3. The Proposed Offshore Development comprises both the Offshore Generation Infrastructure (OGI) and the Offshore Transmission Infrastructure (OTI). The components of both the OGI and the OTI are detailed in this Chapter.

4-4. As presented in **Volume 1, Chapter 1: Introduction,** the Project is being developed by Buchan Offshore Wind Ltd (the Applicant), a partnership of three leading energy businesses: BW Ideol, Elicio and BayWa r.e. The Applicant was awarded the development rights for the ScotWind NE8 Plan Option (PO) in January 2022.

4-5. The Project aims to generate an anticipated capacity of 1 GW of renewable power using up to 70 floating Wind Turbine Generators (WTGs), harnessing average wind speeds[1] of 10.5 $ms^{-1}$ and supporting the Scottish Government's target of net-zero emissions of all greenhouse gases by 2045. It is anticipated that the Project will have a design lifespan of 35 years. Buchan Offshore Wind is committed to working with the Scottish manufacturing sector to secure investment, remove bottlenecks and enhance the amount of Scottish content within the Project.

4-6. The Proposed Offshore Development includes the Array Area of up to 330 $km^2$ (reflecting the Option Area awarded by Crown Estate Scotland (CES)). The Array Area is located within the ScotWind PO NE8, as defined by the Sectoral Marine Plan (SMP) (Scottish Government, 2020) (**Volume 1, Chapter 3: Site Selection and Consideration of Alternatives**).

4-7. The Array Area will contain the OGI including floating WTGs, floating foundations, moorings, anchors, and inter-array cables between turbines. The Array Area will also contain up to three Offshore Substation Platforms (OSPs) and associated interconnector cabling between them, which form part of the OTI. The remainder of the OTI comprises up to three export cables, which will transmit electricity from the OSPs, potentially through an Intermediate Reactive Compensation (IRC) platform to landfall, where the export cables will transition from offshore to onshore cables. From there, the onshore export cables will connect to the

[1] Measured wind speed at 150m height (29th November 2022 – 31st October 2023)

grid connection point which forms part of the National Electricity Transmission System (NETS).

4-8. **Figure 4.1** presents an indicative Project overview.

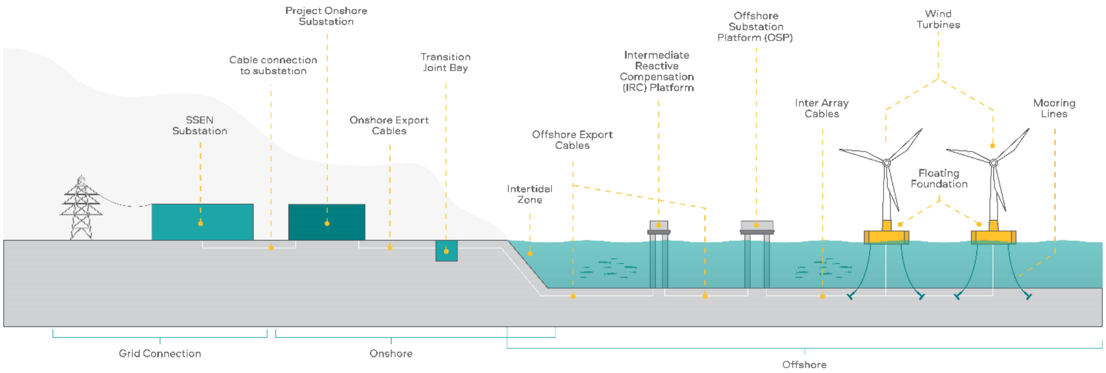



**Figure 4.1 Indicative Project Overview**

4-9. As discussed in **Volume 1, Chapter 3**: **Site Selection and Consideration of Alternatives,** the final design of the Project will continue to be refined post consent until a greater understanding of the site conditions and technology is reached, this will allow the Applicant to take maximum advantage of emerging technology. The description of the Project identifies and describes a Project Design Envelope (PDE) which defines the minimum and maximum limits within which the Proposed Offshore Development will be assessed, with reasonably foreseeable technology options.

### 4.1.2 Project Design Envelope

4-10. The PDE approach provides a degree of flexibility to the Proposed Offshore Development whilst ensuring all potential likely significant effects are assessed within the EIA process. The Proposed Offshore Development parameters presented in this chapter include a range of potential values up to and including the maximum and minimum Proposed Offshore Development design parameters.

4-11. The PDE approach is in accordance with the guidance prepared by Marine Scotland and the Energy Consents Unit in June 2022 for applicants using the design envelope approach for applications under section 36 of the Electricity Act 1989 (Scottish Government (2022)). This guidance notes that: *"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."*

4-12. The PDE approach is also in line with the Scottish Government (2013) guidance, which states that "*by applying the principles of an approach commonly known as the 'Rochdale Envelope' it is possible to undertake an environmental assessment which takes account of the need for flexibility in the future evolution of the detailed Project proposal, within clearly defined parameters. In such cases, the level of detail of the proposals must be sufficient to enable a proper assessment of the likely significant environmental effects, and any resultant mitigation measures - if necessary, considering a range of possibilities*.".

4-13. In accordance with these sets of guidance the Proposed Offshore Development's PDE is therefore designed to allow sufficient flexibility to accommodate further refinement during the final Project design phase, whilst being sufficiently detailed to allow proper assessment as required by the EIA process. The information presented in this chapter outlines the options required and the range of potential design and activity parameters upon which the subsequent impact assessment chapters are based. Where appropriate, each impact assessment chapter contains a section detailing the realistic 'worst-case' scenario for specific receptors and impacts.

## 4.2 SITE DESCRIPTION

### 4.2.1 Site Location

4-14. The Proposed Offshore Development is located within the Array Area and the Export Cable Corridor (ECC) seaward of MHWS. Together, the area locating the Proposed Offshore Development is referred to as the Proposed Offshore Development Area within this EIAR.

4-15. The Array Area covers an area of up to 330 $km^2$ and is located within PO NE8, approximately 75 km at its closest point off the Aberdeenshire coast, northeast of Fraserburgh in the outer Moray Firth.

4-16. The Export Cable Corridor (ECC) runs south from the Array Area, and makes landfall within Rattray Bay, Aberdeenshire, located immediately north of the St Fergus Gas Terminal and associated offshore pipelines. The maximum length of the export cable is 86.5 km and total area of the ECC is 86 $km^2$.

4-17. The Proposed Offshore Development Area is presented in **Figure 4.2.**

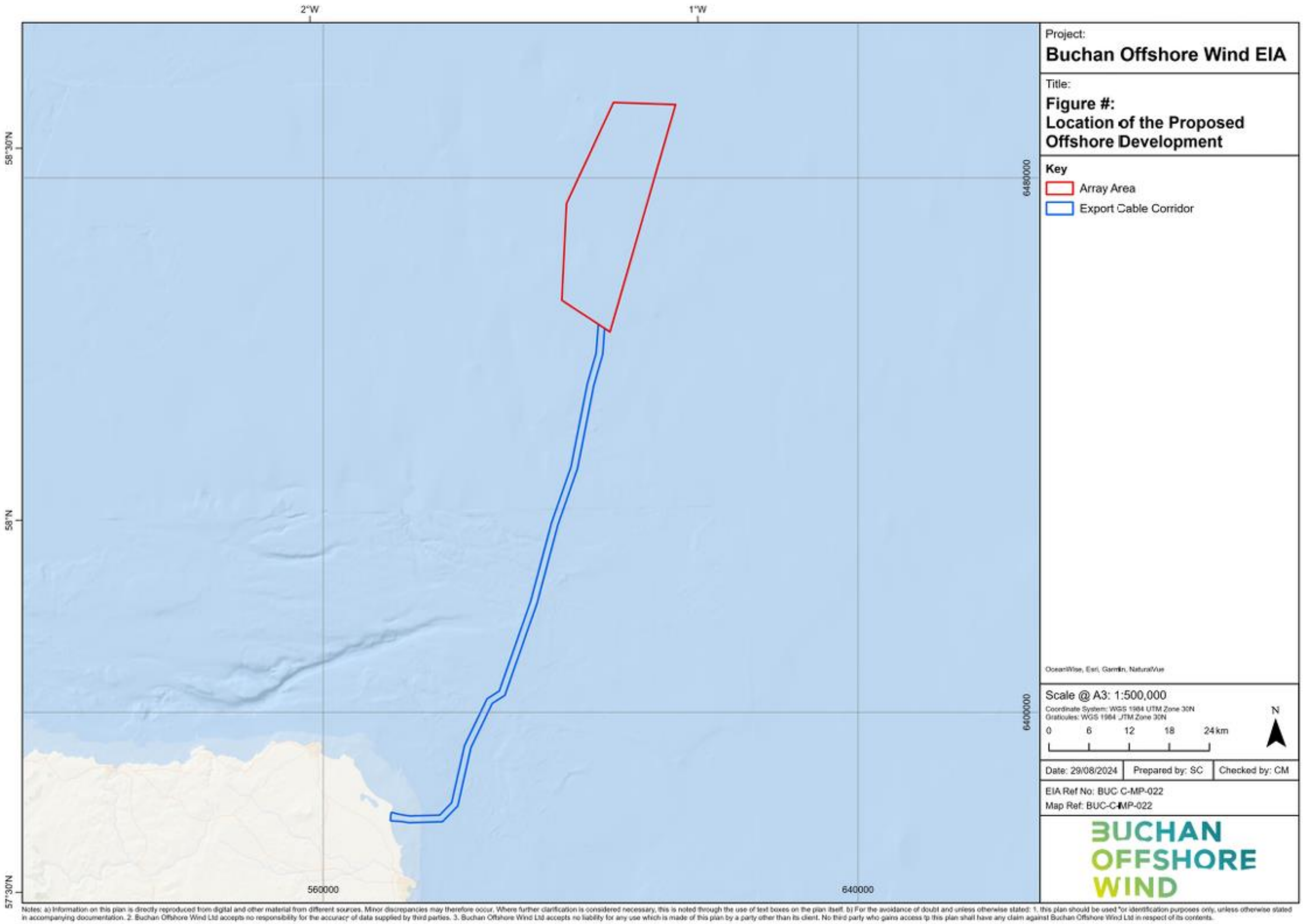



**Figure 4.2 Location of the Proposed Offshore Development**

### 4.2.2 General Site Characteristics

4-18. In the Proposed Offshore Development Area, the water depths range between 0.5 m LAT and 123.2 m LAT with the greatest depths located in a depression along the ECC. The seafloor gradients are generally gentle (<5°) with numerous localised steeper values (20°) observed. Seabed features across the Array Area and ECC include sand ripples, megaripples and sandwaves, localised seabed depressions, boulders, wrecks and possible unexploded ordnance (UXOs). Boulders are mainly found in the northwest and south of the Array Area. Water depths within the Array Area range from approximately 73 m to 110 m.

4-19. The Little Halibut Bank feature lies to the south of the Array Area and primarily comprises gravelly and silty sand and gravel. Pockmarks, suggestive of Witch Ground Formation, are located throughout the Array Area, with higher frequency in the south of the Array Area. Proposed Offshore Development infrastructure will seek to avoid pockmarks where reasonably practicable.

4-20. The ECC passes through the Southern Trench Marine Protected Area (MPA). The Southern Trench MPA forms a long, deep trench, which has been carved out by glaciers. It acts as a nursery ground for several fish species and provides habitats for several commercially important crustaceans, including *Nephrops* and crabs.

4-21. The Southern Trench MPA has been designated to protect, amongst others, the following features:

- Minke whale (included in the assessment in **Volume 2, Chapter 11: Marine Mammals and other Megafauna**);
- Burrowed mud (included in the assessment in **Volume 2, Chapter 8: Benthic Ecology**); and
- Geodiversity (quaternary of Scotland and submarine mass movement) (included in the assessment in **Volume 2, Chapter 6: Marine and Coastal Physical Processes**).

4-22. The seabed along the ECC predominantly comprises sand and gravel with areas of bedrock in the closest nearshore and generally silty sand moving further offshore. The Array Area predominantly comprises gravelly silty sand and silty sand in the south and silty sand in the north. Mobile sediments are noted across the ECC in the form of ripples, megaripples and sandwaves.

4-23. There are several offshore oil and gas installations in the vicinity of the ECC, including pipelines, with up to two pipeline crossings anticipated.

4-24. The inferred dominant current direction is variable across the Proposed Offshore Development Area. Within the nearshore area the dominant current is east to west, whilst in much of the area of the ECC the dominant current direction is south-east to north-west. From about 18 km offshore the dominant current direction is south-west to north-east.

4-25. The habitat in the vicinity of the proposed landfall location consists of a shallow barren sandy beach along exposed open coast. This is backed by extensive sand dunes featuring a covering of marram grass, and associated dune slack habitat leading into extensive farmland.

4-26. Further details on the bathymetry and seabed composition within the Array Area and along the ECC are presented within **Volume 2, Chapter 7: Marine Physical and Coastal Processes.**

### 4.2.3 Offshore Constraints

4-27. The Strategic Environmental Assessment (SEA) (Scottish Government (2019)) identified possible constraints with regards to aviation, including oil and gas Helicopter Main Routes (HMRs) which overlap with the Array Area. Further details are presented and assessed within **Volume 2, Chapter 16: Military and Civil Aviation.**

4-28. As presented in **Volume 2, Chapter 17: Marine Archaeology and Volume 2, Cultural Heritage** and **Volume 2, Chapter 15: Major Accidents and Disasters,** two wrecks have been identified within the Array Area and several potential UXOs have been identified within the Array Area and along the ECC.

4-29. The ECC is located within an area associated with the oil and gas industry and there are a number of gas pipelines to the south of the ECC, two of which cross the ECC. The St Fergus outfall pipeline is located just south of the ECC as it approaches landfall. Further details on pipelines and associated crossings are presented in **Volume 2, Chapter 13: Infrastructure and Other Marine Users.**

4-30. The ECC passes through the Southern Trench Marine Protected Area (MPA), designated for its biodiversity (minke whales, burrowed mud, fronts and shelf deeps) and geodiversity (quaternary of Scotland, submarine mass movement). The ECC avoids the Southern Trench itself.

4-31. There are active pelagic fisheries in and close to the Array Area and ECC and some static fishing operations in the nearshore ECC. These are presented, and impacts arising from the Proposed Offshore Development assessed, in **Volume 2, Chapter 12: Commercial Fisheries.**

4-32. The passenger ferry route between Aberdeen and Lerwick passes parallel to the western boundary of the Array Area. This, and other shipping constraints, are presented and assessed in **Volume 2, Chapter 14: Shipping and Navigation.**

## 4.3 PROJECT TIMELINE

4-33. The Project is aiming to provide an anticipated capacity of 1 GW clean energy to the National Grid with a grid connection date of 2033. A high-level overview of the proposed, indicative project timeline is presented in **Figure 4.3**.

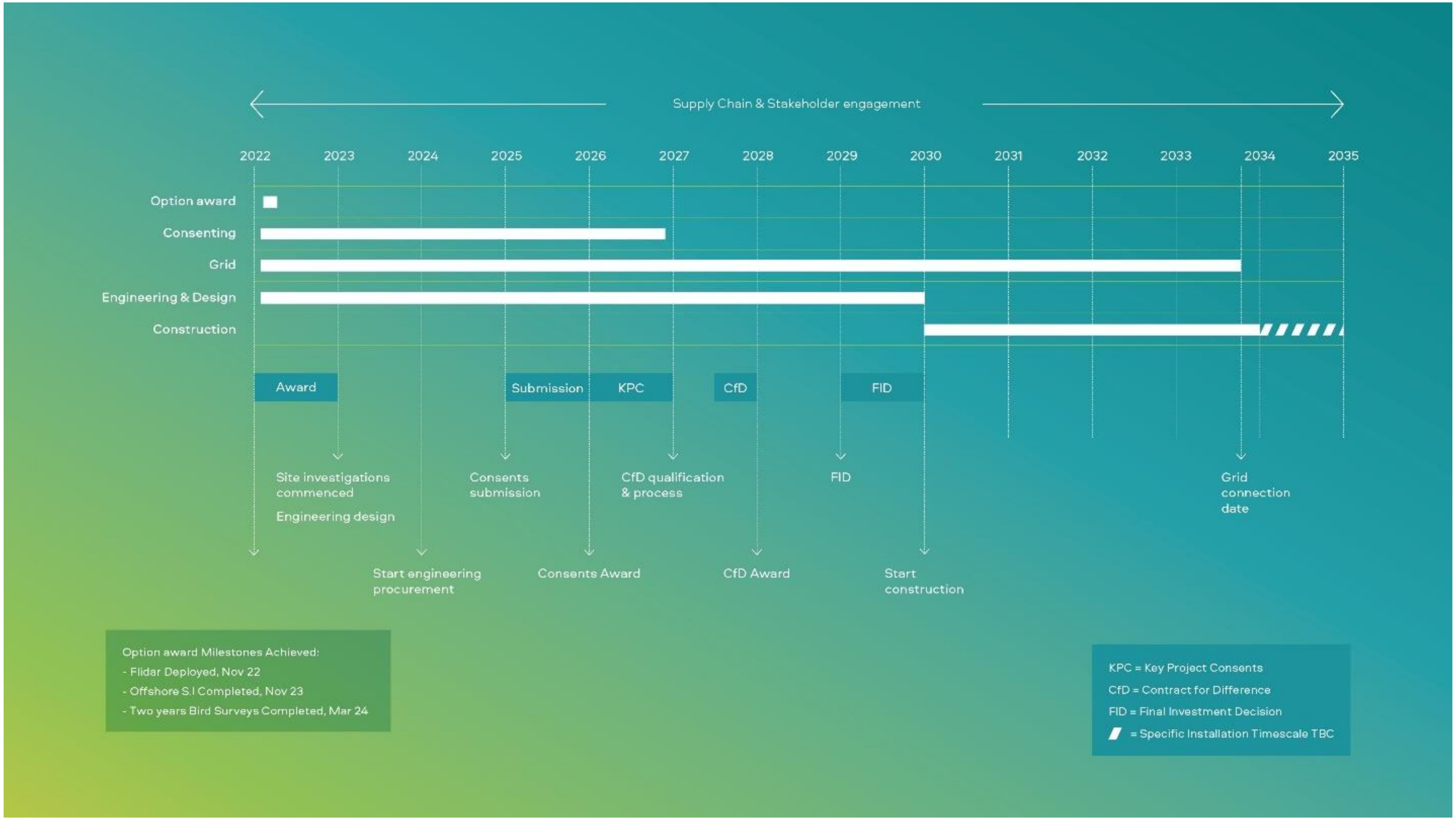



**Figure 4.3 Buchan Offshore Wind Farm Proposed Timeline**

4-34. The Project seeks to support the purpose of ScotWind, to benefit Scottish businesses and communities for decades to come as well as providing a major boost to UK clean energy production. In doing so, it will contribute to Scotland's net zero emissions target of 2045, reflecting Scotland's commitment to combat climate change and transition to a more sustainable future (**Volume 1, Chapter 2: Legislation and Policy**).

4-35. The Scottish Government has also committed to a target of 40 GW of offshore wind by 2030, which includes 11 GW of floating offshore wind.

4-36. The Project is aiming to be eligible to qualify for a CfD in 2027, and as such the Applicant requires the necessary consents to be obtained from Scottish Ministers prior to applying to bid for the CfD in the relevant "Allocation Round". The Applicant aims to begin construction in 2030 and be fully operational in 2035.

## 4.4 OFFSHORE INFRASTRUCTURE

4-37. The key components of the Proposed Offshore Development are presented within two general categories:

4-38. Offshore Generation Infrastructure (OGI):

- up to 70 WTGs (each comprising a tower section, nacelle and three rotor blades);
- associated supporting structures, including floating foundations; and
- mooring systems and anchors; and
- a network of inter-array cables (IACs) connecting an array of WTGs to an OSP, which forms part of the Offshore Transmission Infrastructure (OTI).

4-39. Offshore Transmission Infrastructure (OTI):

- up to three OSPs and associated support structures, foundations and scour protection;
- up to three offshore export cables, forming the ECC and connecting the OSPs to landfall location;
- one IRC platform located within the ECC; and
- cable protection and/or utility crossings where required.

4-40. If the final design comprises more than one OSP (which form part of the OTI), these will be connected by interconnector cables and associated and scour and cable protection.

4-41. A data acquisition, transmission and storage system will cover all offshore assets. The Supervisory Control and Data Acquisition (SCADA) system enables individual WTGs, the OSPs and IRC to communicate operational status including faults. This will allow the remote diagnosis of faults and issue commands to stop, start and reset WTGs and other equipment. The SCADA system keeps a full operating history of the offshore assets.

4-42. Infrastructure-specific details are provided in the proceeding sections.

### 4.4.1 Generation Infrastructure

#### 4.4.1.1 Wind Turbine Generators (WTGs)

4-43. The Array Area will comprise of up to 70 floating WTGs, with the final number dependent on the capacity of the individual turbines used, as well as detailed design informed by further environmental and engineering studies to be undertaken post-consent. There is the potential for a reduced number of WTGs to be used if an increased rated output of turbine model is chosen or as part of the wider site optimisation process.

4-44. A range of WTGs have been considered as part of this EIAR, which includes a consideration of minimum and maximum design parameters of aspects such as rotor diameters, hub heights and maximum tip heights. Consent is sought to enable the delivery of a range of potential scenarios included within the assessed envelope. A labelled diagram of an indicative schematic floating WTG is presented in **Figure 4.4.**

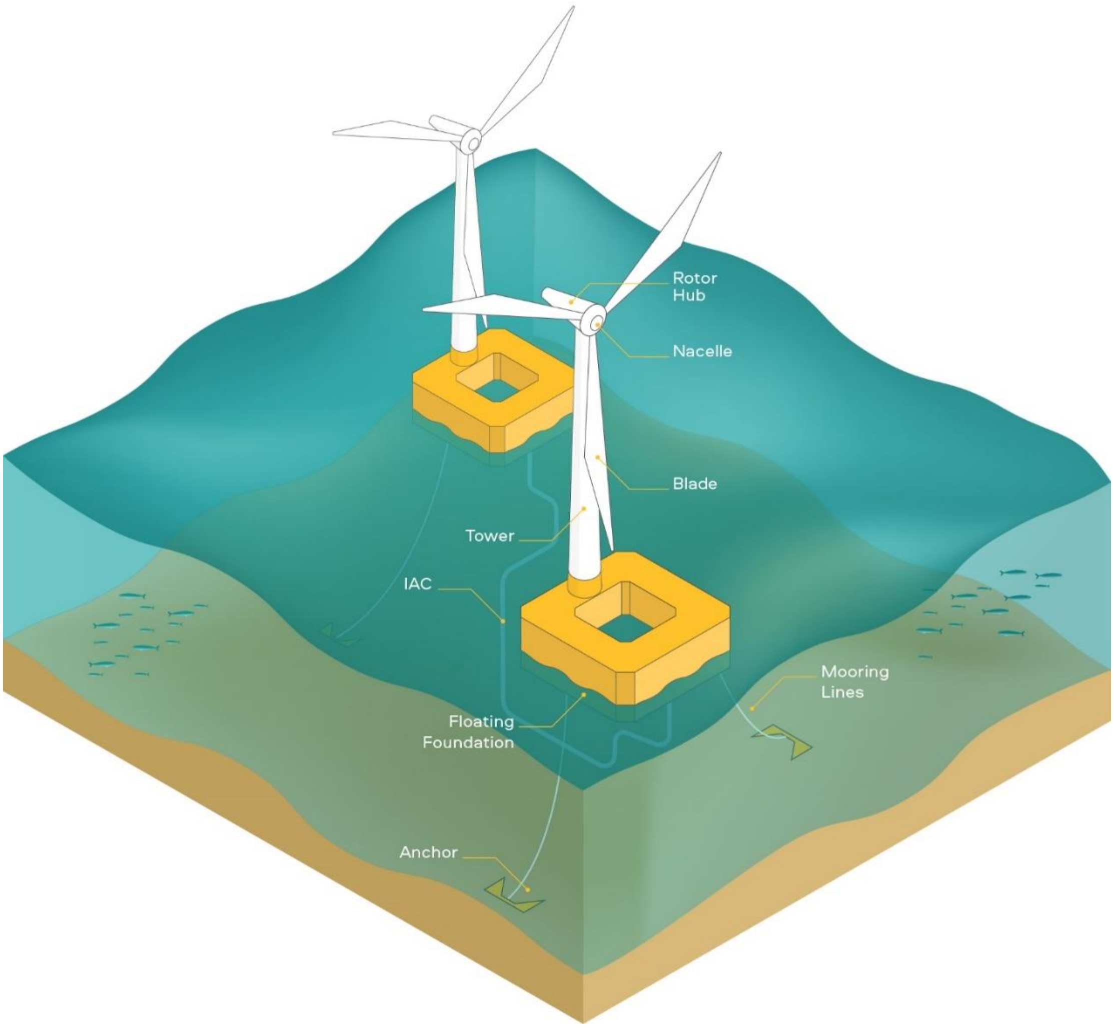



**Figure 4.4 A Floating Wind Turbine Generator**

4-45. The maximum height of the WTG will be 340 m above MHWS to the blade tip in a vertical position and the minimum air draft above MHWS will be 30 m. The rotor diameter will be circa double the rotor radius, comprising of the individual blade length plus the diameter of the rotor hub. The WTG rotor diameter will be between 236 m and 310 m. The rotor hub height will be determined by the rotor radius plus the blade tip clearance. For the aforementioned rotor diameters, this will equate to a rotor hub height of between circa 148 m to 185 m above MHWS.

4-46. The layout of the WTGs will be developed to optimise both the available wind resource and suitability of seabed conditions, along with spatial environmental constraints and sensitivities. The minimum spacing between WTGs will be circa 1.42 km (centre to centre). Indicative layouts have been used to inform assessments included in this EIAR, with the final layout to be confirmed at the final design stage (post-application) and detailed within a specific Design Specification and Layout Plan (DSLP).

4-47. The WTGs will comprise a horizontal axis rotor with three blades connected via the rotor hub to the nacelle, which will be mounted on top of the WTG tower. The WTG tower is a tubular steel column with a base diameter of between 7.5 m and 12.5 m. The power generation equipment will be housed within the nacelle and each WTG will have the ability to control its own yaw to ensure the rotor can be positioned to respond to dynamic wind conditions, and ramp down in high wind speeds as a protection method. The WTG monitoring and SCADA control system will also be located in the nacelle.

4-48. The wind speeds within which all WTGs being considered can typically safely operate range from 3 $m/s^{-1}$ to 25 $m/s^{-1}$, above which the rotor is stopped to prevent damage to the WTG.

4-49. The PDE parameters of the WTGs are presented in **Table 4-1** PDE Parameters of the WTGs.

**Table 4-1 PDE Parameters of the WTGs**

| Description | Design Parameter | |
|---|---|---|
| | Min | Max |
| Number of WTGs within the array | 40 | 70 |
| Number of blades | 3 | |
| Axis | Horizontal | |
| WTG rotor diameter (m) | 236 | 310 |
| Rotor hub height above MHWS (m) | 148 | 185 |
| Maximum WTG tip height above MHWS (m) | 340 | |
| Minimum blade clearance above MWHS (m) | 30 | |
| Maximum rotor swept area per turbine ($km^2$) | 0.04 | |
| Maximum spacing between WTGs (m) | ≤10 rotor diameters | |
| Colour | Matt light grey/off white, yellow floating foundation | |
| Navigation Lighting | As required by CAA, MCA etc. | |

### 4.4.1.2 Floating Foundations

4-50. The WTGs located within the Array Area will be mounted upon floating foundations which are moored to the seabed. While a preferred WTG floating foundation option has been provisionally identified at this stage, in order to retain flexibility a second design option is included in the PDE.

4-51. The floating sub-structure components are illustrated in **Figure 4.5** and include:

- A floating hull;
- A WTG transition piece; and
- The mooring system (which enables the floating foundation to remain in position in all conditions) will be comprised of:
    - a mooring interface structure bolted on the hull structure;
    - mooring lines (composed of chain or wire and synthetic rope);
    - connectors and mooring jewellery (potentially including clump weights, tensioners, buoyancy elements); and
    - anchors (fixing the mooring system to the seabed).

4-52. A yellow coating will be applied to the floating foundation and marine warning lights installed on the floating structure. Other navigation aids, such as Automatic Identification System (AIS), corner lights, Aid to Navigation light, ID-sign light, and helihoist lights are anticipated to be installed. It is anticipated that the specific marking and lights will be agreed with relevant authorities through a consent condition prior to the installation of the WTGs.

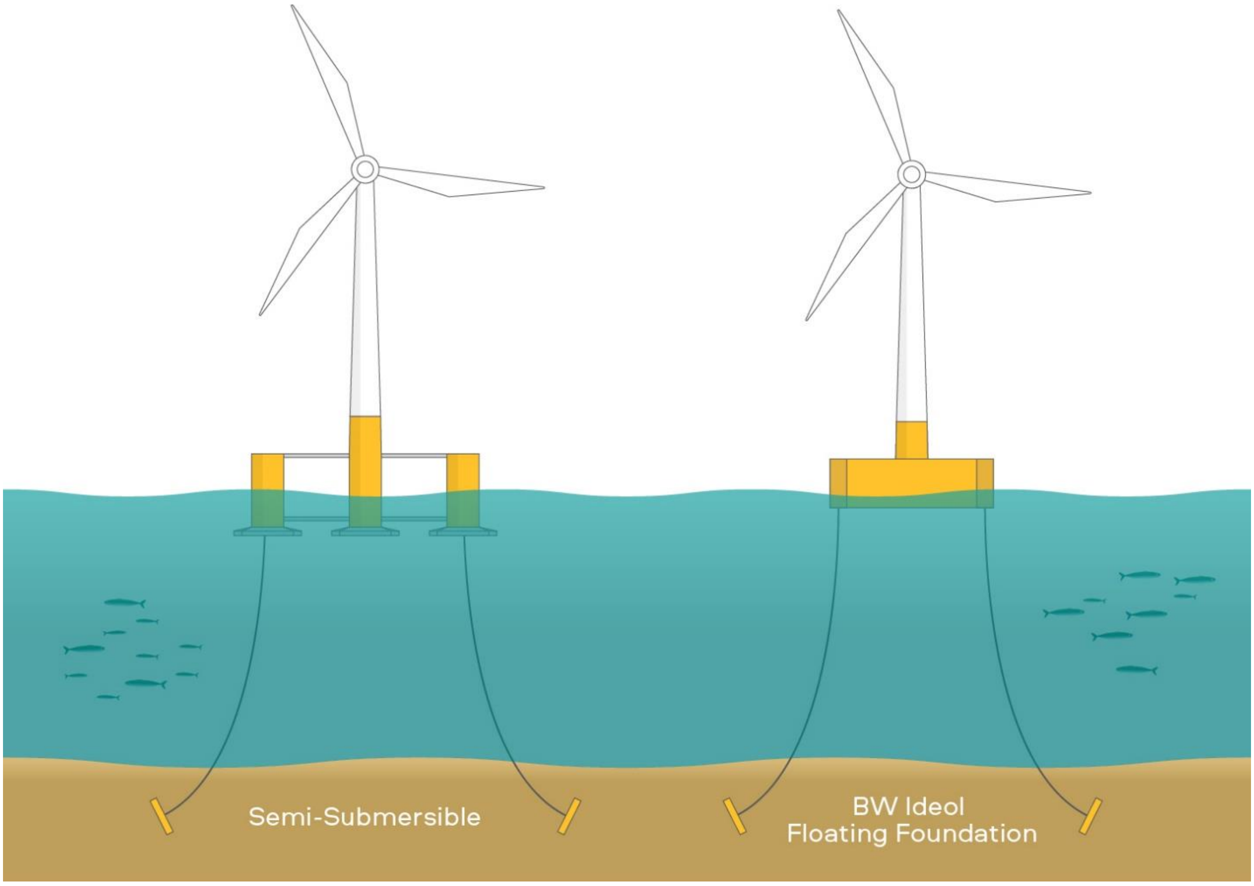



**Figure 4.5 Illustration Floating Foundation Design Options**

4-53. **Table** 4-2 presents the design parameters within the envelope of the floating foundation design for which consent is being sought.

**Table 4-2 Minimum and Maximum Design Parameters of the Floating Foundation**

| Description | Design Parameter |
|---|---|
| Length of hull (m) | 100.8 - 122.3 |
| Hull breadth (m) | 114.5 - 139.0 |
| Hull draft (m) | 17.0 - 20.0 |
| Hull depth (m) | 30.0 - 35.0 |
| Hull displacement (tonnes) | 26,570.0 - 36,049.0 |
| Hull displacement ($m^3$) | 25,985.3 - 35,255.8 |
| Minimum air gap to MHWS (m) | 30 |
| Markings and lighting requirements | As required by post consent agreement |

#### 4.4.1.2.1 BW Ideol Floating Foundation

4-54. The BW Ideol floating foundation (DampingPool®) technology is a patented design developed by BW Ideol, who are a partner in the Applicant's joint venture consortium. It is a polygonal ring-shaped hull fitted with a large moonpool, termed the 'Damping Pool' (**Figure 4.6**) optimising the stability and performance of the floating wind turbine, even in extreme conditions. The technology allows for a compact, shallow draft without compromising stability. A horizontal skirt may be added to reduce hull motion. The foundation features secondary structures including boat landings, external working platforms, deck space, walkways, railings and associated equipment, including J or I tubes and bend restrictors for IAC access. This technology has been successfully deployed in Japan and France, supporting operating WTGs since 2018.

4-55. The hull can be constructed from either concrete or steel, and its simple design allows for flexible construction methods, as well as improved industrialised construction methods, allowing for efficiencies.

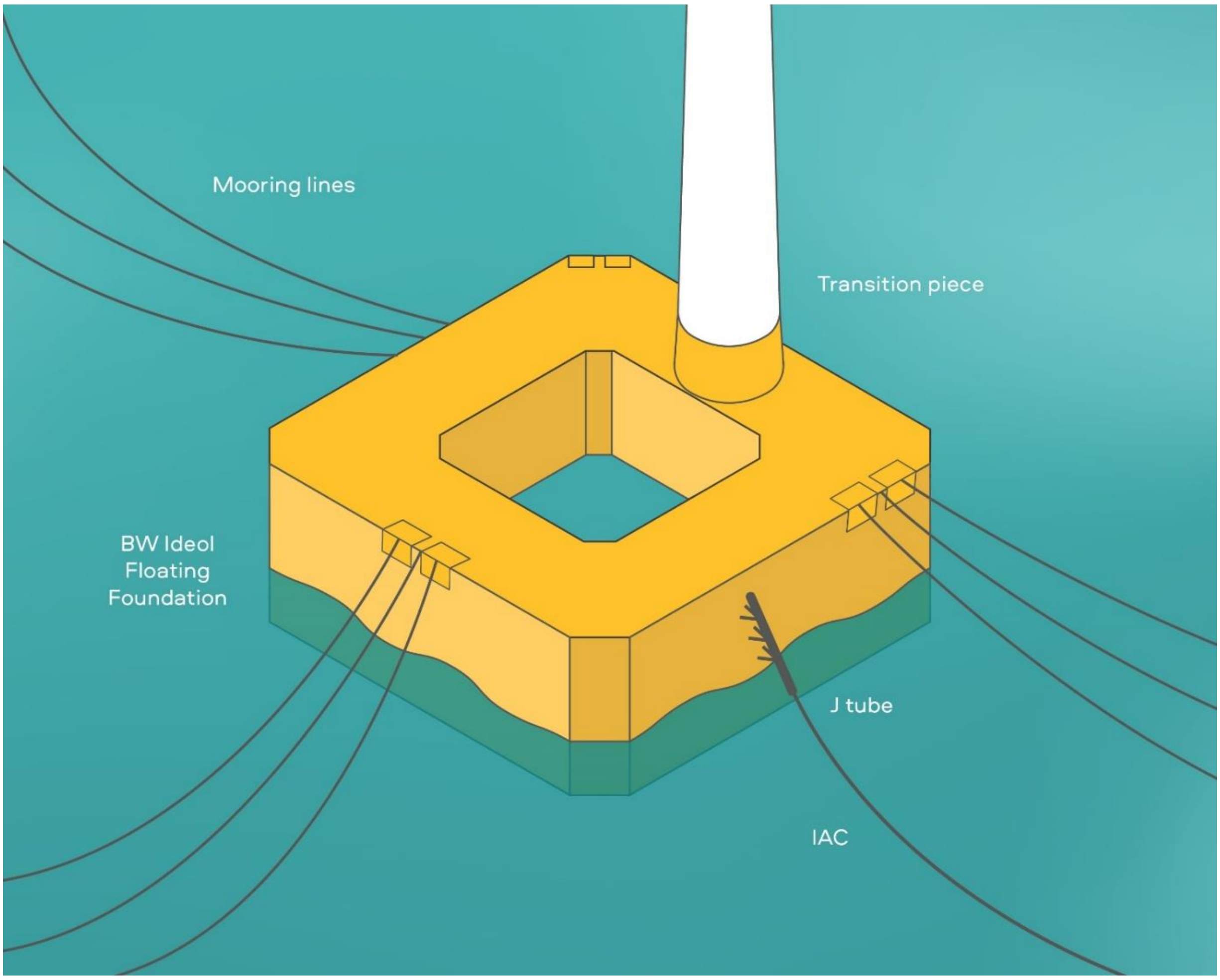



**Figure 4.6 BW Ideol Barge Design (Indicative)**

#### 4.4.1.2.2 Floating Semi-Submersible Foundation

4-56. The floating semi-submersible design comprises a partially submerged, buoyant platform attached to the seabed via moorings and anchors.

4-57. The semi-submersible floating foundation comprises three or four vertical columns interconnected by horizontal structural elements. The foundation features secondary structures including boat landings, external working platforms, deck space, walkways, railings and associated equipment, including J or I tubes and bend restrictors for IAC access.

### 4.4.1.3 Inter-Array Cables

4-58. The network of up to 210 km IACs will carry the electricity generated by the WTGs to an offshore substation platform (OSP) where the combined generated power can be converted to a higher voltage for transmission to the National Grid onshore.

4-59. Each IAC will consist of a three-core dynamic HVAC cable rated between 66 kV and 132 kV.

4-60. IACs are designed to accommodate the range of movement associated with the floating foundation technology. Dynamic IACs are supported by the WTG floating foundation and buoyancy which is located along the length of the cable to create a “lazy S” shape, which reduces hull motion induced stresses upon the cable (**Figure 4.7**).

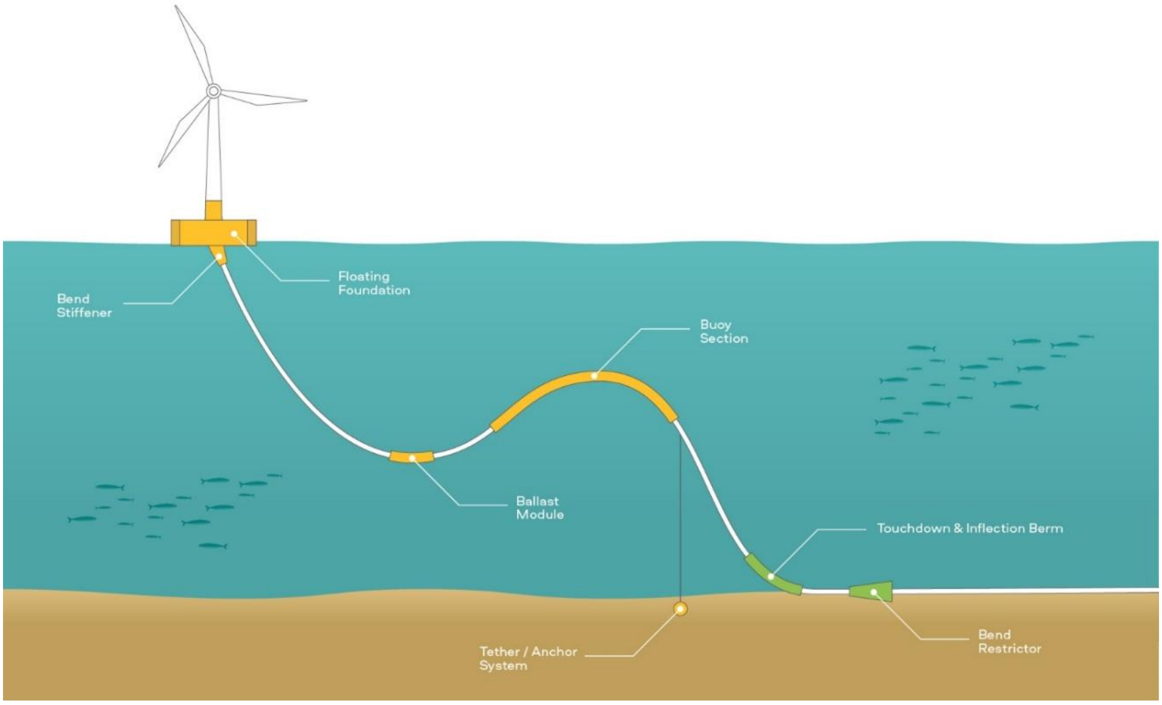



**Figure 4.7 Dynamic Inter-Array Cable**


**Figure 4.8 Example Potential WTG, IAC and OSP Layout[2]**

[2] WTGs, IACs and OSPs are shown for illustrative purposes only to provide an indication of how the layout in the Array Area may appear should the full Array Area be utilised.

4-61. Final design and layout of the IACs will be considered in parallel with final WTG designs and the Array layout. This will be informed by a range of factors including electrical systems design, metocean conditions, floating foundation technology, cable grounding technology, seabed conditions, wind resource analysis, and environmental constraints. An example of layout is presented in **Figure 4.8.**

4-62. IACs will be fixed to the seabed at the point where contact is made. Lengths of cable in contact with the seabed may be surface laid, or will be buried up to a depth of 1.4 m. Where cables cannot be buried, they may be protected using a range of cable protection methods, including the use of rock, rock/grout bags, concrete mattresses and protective cable shells.

##### 4.4.1.3.1 Inflection Berm

4-63. The inflection berm (shown in **Figure 4.7**) may be required for the transition between the static and dynamic sections of the IACs. It is a small berm that is expected to stabilise the cable where it first touches down onto the seabed and as it transitions to burial depth or the static cable system. The detailed design of the inflection berm is highly dependent on the specific dynamic IAC design, the cable configuration and anchoring system.

4-64. A summary of the estimated dimensions of the inflection berm are shown in **Table** 4-3**.** Rock bags may also provide a suitable solution for the inflection berm, but these will fall within the envelope of the inflection berm dimensions.

**Table 4-3 Inflection Berm Dimensions**

| Berm height (m) | Berm width (m) | Berm cross sectional area ($m^2$) | Berm material |
|---|---|---|---|
| 1.50 | 11.00 | 9.75 | Filter grade rock |

#### 4.4.1.4 Moorings and Anchors

##### 4.4.1.4.1 Mooring Design Options

4-65. The floating foundations will be anchored to the seabed by a spread of mooring lines and anchors. The anticipated mooring system could be a semi-taut mooring system or catenary mooring options.

4-66. The mooring lines will use a combination of steel chains, steel wire, synthetic ropes, buoyancy modules, and connectors to attach to the foundation and anchor points. The mooring design options under consideration are illustrated in **Figure 4.9** and **Figure 4.11.**

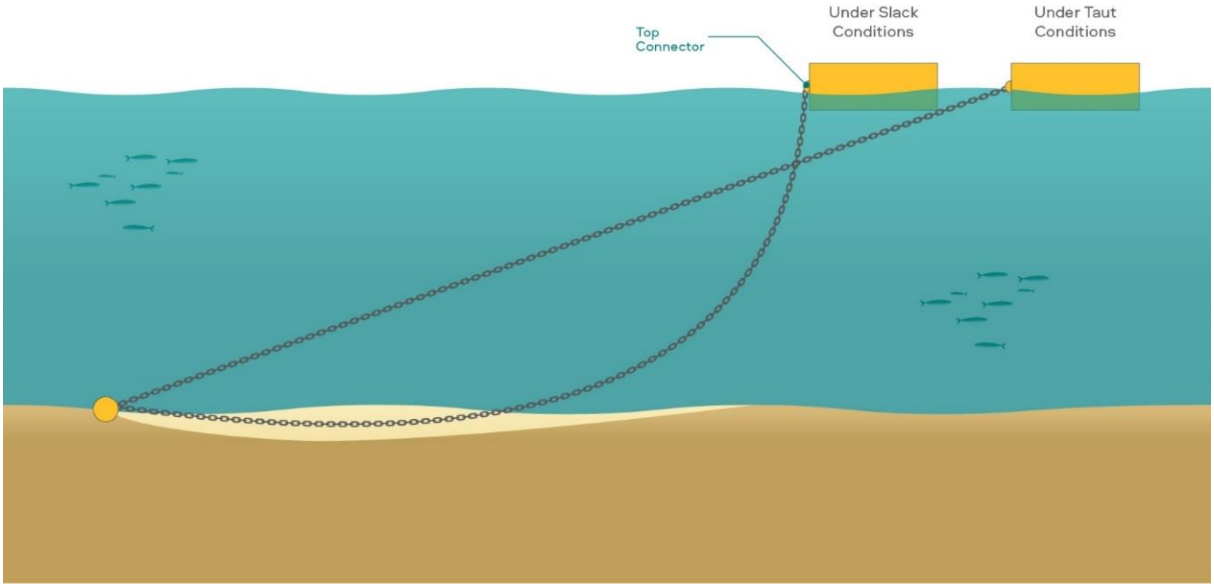



**Figure 4.9 Catenary Mooring Design**

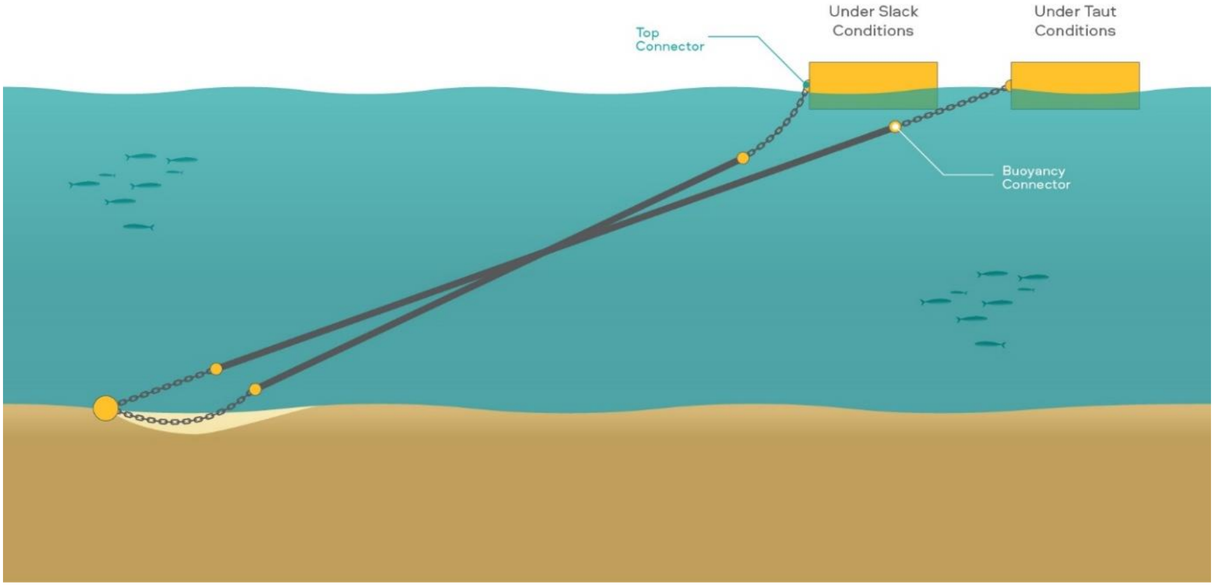



**Figure 4.10 Semi-Taut Mooring Design**

4-67. A summary of the maximum design parameters of the mooring systems considered within the design envelope are presented in **Table 4-4.**

**Table 4-4 Mooring Design Descriptions**

| Description | Maximum Design Parameter |
|---|---|
| Number of mooring lines | 9 lines per structure |
| Mooring line composition (mm) | 188 mm chain and 300 mm synthetic |

| Description | Maximum Design Parameter |
|---|---|
| Length of mooring line left on the seabed attached to the anchor prior to WTG unit installation | • Corresponding to chain catenary system, 9 lines per structure<br>• Line lengths on seabed up to 850 m per line, 161 mm diameter chain, laid on seabed prior to install.<br>• Once installed, the chain will be intermittently in contact with the seabed as it picks-up and sets-down. depending on position of WTG, there will be between 100 m and 800 m of each mooring line on the seabed at any one time. |
| Length of mooring line/point of contact information left on the seabed prior to WTG unit installation | In-place point of contact with seabed constantly moving due to motions of floating WTGs, as highlighted by the mooring line/seabed interactions shown in **Figure 4.9 and Figure 4.10**.<br>Will be moving 100 m-800 m from platform centre, depending on line load at any one time. |
| Maximum mooring radius (m) | 1,750 m |

4-68. An indicative mooring configuration is illustrated in **Figure 4.11**; at the current stage of design, it is anticipated that a maximum of up to nine mooring lines may be required for each floating foundation with a maximum mooring length of 1,750 m from a the centre of the floating foundation to the anchor. The final number and mooring design will be dependent on the size of the floating structures, metocean conditions and water depths, and will be informed by detailed design work.

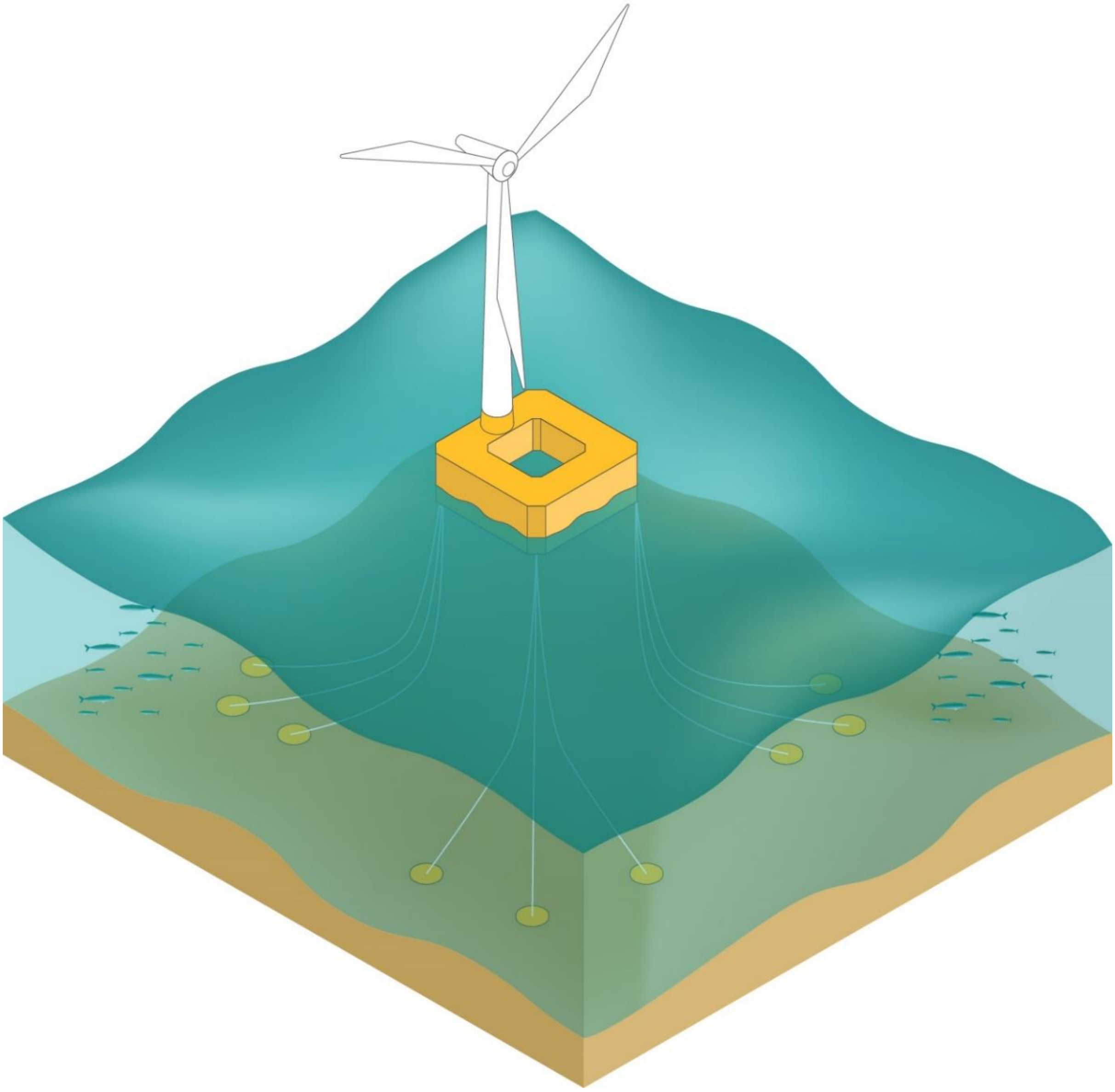


**Figure 4.11 Example of Mooring Configuration for Floating Foundations**

### 4.4.1.4.2 Anchor Design Options

4-69. Anchors will be installed to fix the mooring lines in position at the seabed. A range of anchor options are included in the PDE to provide flexibility prior to more detailed design work. A maximum of nine anchors are required per WTG floating foundation, corresponding to the maximum potential number of mooring lines, with one anchor per mooring line being the maximum number of anchors.

4-70. It may be possible to reduce the number of anchors installed from one per mooring line through the use of shared anchors, where a single anchor could secure multiple mooring lines from adjacent turbines. A schematic diagram of the shared anchor design is presented in **Figure 4.12.** The rotor diameter is the parameter that governs the minimum distance between WTGs.

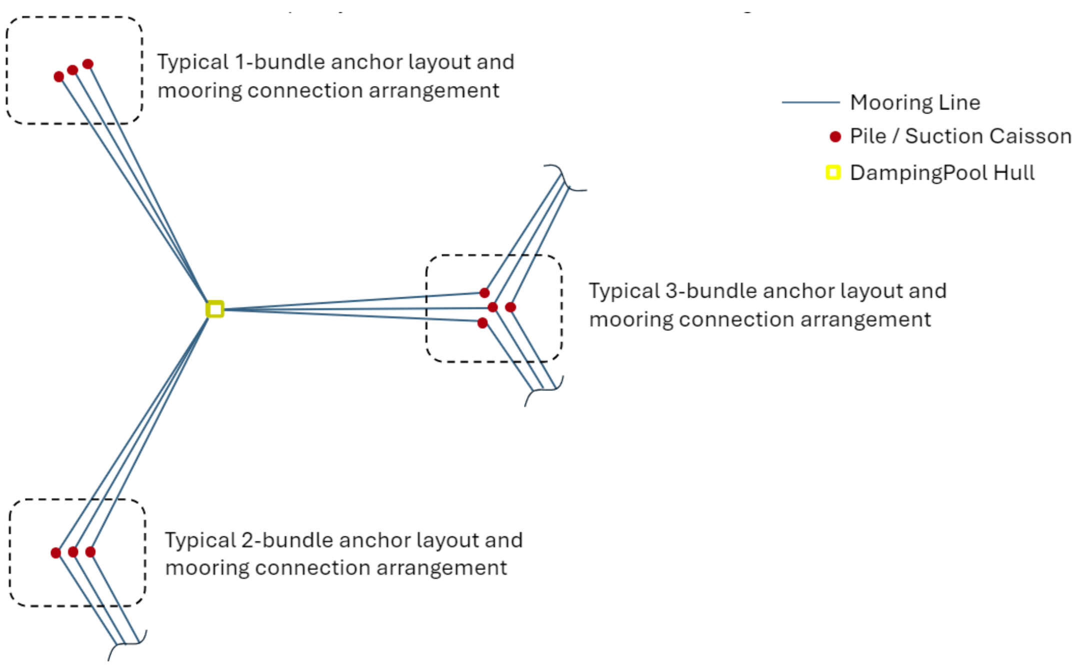



**Figure 4.12 Schematic Shared Anchor Scenario**

4-71. Anchor design options are presented in **Table 4-5** and **Figure 4.13.** The final anchor design option will be informed by detailed design work, supported by ground model data and metocean conditions, details of final WTG and foundation design. At this stage, up to four anchor types are included within the PDE. These are Suction Piles, Driven Piles, Drag Embedment and Plate Anchors, which are described in **Table 4-5**.

**Table 4-5 Anchor Design Descriptions**

| Anchor Type | Suction pile | Driven Pile | Drag embedment | Plate |
|---|---|---|---|---|
| Description | Installed by pumping water out of a closed end steel cylinder, which creates a pressure difference with the external sea. This pressure differential effectively "sucks" the pile into the seabed. | Steel tubular piles are driven into the seabed using an impact pile driving hammer or may include vibro-driven piles. | Anchors are pulled into the seabed by a vessel pulling on the anchor cable. The shape of the anchor encourages the anchor penetrate the seabed until the target founding soil strata is reached. | Anchors are installed by penetration using suction caisson. The plate anchor is held in place on the end of a suction caisson, fluid is pumped out of the internal volume creating a differential pressure to "suck" the pile (and therefore plate) into the seabed. Once in place the suction caisson is removed, leaving behind the plate anchor. |
| Number of anchors | Up to 630 | | | |
| Permanent footprint of each anchor ($m^2$) | 51 | 16 | Installed seabed footprint is effectively zero as anchor is installed entirely below the seabed surface with protruding chain. However, during installation the anchor is "dragged" into the seabed, covering a distance of 75m as it ploughs subsurface. This embedment impact could be doubled if installation using a reaction anchor. | |
| Total anchor footprint including scour protection ($m^2$) | 760 | 284 | | |
| Maximum depth seabed penetration (m) | 14 | 45 | 14 | 23 |
| Maximum pile/anchor diameter (m) | 8 | 4.5 | N/A | Width 5 m, length 10 m |

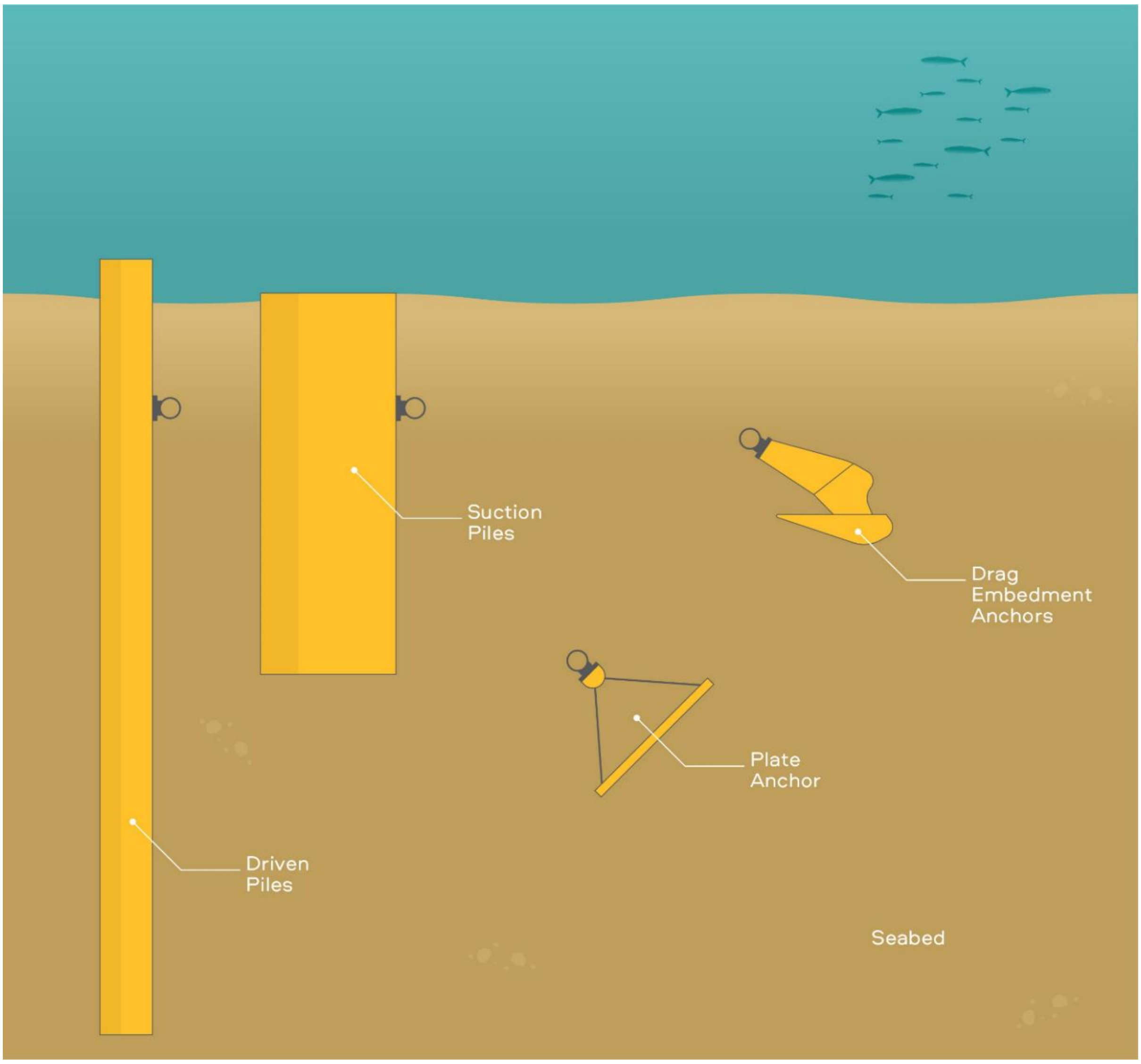



**Figure 4.13 Profile View of Anchor Design Options**

### 4.4.1.4.3 Scour Protection

4-72. Some designs of anchors for WTGs and platforms are at risk of seabed erosion and scour from natural hydrodynamic and sedimentary processes, which can compromise the stability or integrity of the anchor and moorings. Scour protection can be installed to mitigate the effects of erosion.

4-73. Scour protection has been considered for driven pile and suction pile anchors, however, as the other anchor types within the design envelope will be completely embedded beneath the seabed (acknowledging that in certain situations mooring line dynamics can cause a trench to form) and situated far apart from other anchor moorings, scour protection is not considered necessary.

4-74. It is envisaged that local scour would be limited due to the anchor's profile (~1.0 m) above seabed., where the larger the object obstructing flow, the greater the scour.

4-75. There are a number of scour protection types available, including frond mats, concrete mattresses or integrated aprons. However, a rock placement solution (including a falling apron design to account for seabed lowering) is the most likely choice due to its extensive successful use in industry and adaptability to the Proposed Offshore Development.

4-76. Using the precautionary PDE approach, an area of up to 705 $m^2$ and 325 $m^2$ rock protection may be required at each suction pile and driven pile respectively. The final choice of scour protection type and amount of rock protection will be made after final selection and design of the anchor, taking into account most recent geotechnical data, meteorological and oceanographic data, water depth, foundation type, maintenance strategy and cost.

4-77. The scour protection parameters presented in **Table 4-6** and

4-78. **Table** 4-7 have been selected conservatively to cover the most extreme wave, current and wind conditions with assumed values for profile and general scour. These are precautionary considered a reasonable worst case scenario, based on professional judgement and experience.

**Table 4-6 Maximum Scour Protection Parameters – WTG anchors**

| Parameter | Maximum Design Parameters | |
|---|---|---|
| | Suction pile (WTG) | Driven pile (WTG) |
| Type | Rock placement | |
| Height (m) | 0.6 | 0.6 |
| Diameter of scour protection (m) | 31 | 19 |
| Area ($m^2$) | 709 | 267.6 |
| Volume ($m^3$) | 426 | 160.6 |
| Total volume per WTG ($m^3$) | 3,834 | 1,440 |
| Total volume for wind farm ($m^3$) | 268,380 | 100,800 |

**Table 4-7 Maximum Scour Protection Parameters - OSPs and IRC anchors**

| Parameter | Maximum PDE | | | |
|---|---|---|---|---|
| | Suction pile (OSP) | Driven pile (OSP) | Suction pile (IRC) | Driven pile (IRC) |
| Preferred type | Rock placement* | | | |
| Height (m) | 2.5 | 2.5 | 2.5 | 2.5 |
| Diameter of scour protection (m) | 35 *(from edge of suction bucket, which has a maximum diameter of 24m)* | 30 | 38.5 *(from edge of suction bucket, which has a maximum diameter of 27m)* | 30 |
| Area ($m^2$) | 27,800 | 20,600 | 34,000 | 20,600 |
| Total volume per platform ($m^3$) | 64,900 | 960MW= 51,500<br>640MW= 50,500<br>320MW= 47,250[3] | 79,200 | 51,500 |
| Total volume for wind farm ($m^3$) | 194,700 | 141,750 *(based on worst case configuration of 3 x 320MW OSPs)* | 79,200 | 51,500 |

[3] The combination of OSPs to achieve the export 1 GW could be 1 x 960 MW OSP, 1 x 640 MW plus 2 x 320 MW or 3 x 320 MW OSPs

* Flexibility to be maintained in the type of scour protection, to account for new technologies that may be available at the time of construction, as these will be evaluated for the final design nearer to the time of construction.

### 4.4.2 Offshore Transmission Infrastructure

#### 4.4.2.1 Offshore Substation Platform (OSP) and Interconnector Cables

4-79. Up to three OSPs will be required and will be located within the Array Area. The Project is assuming a high voltage alternating current (HVAC) transmission option, and the maximum design parameters for each OSP (including helideck) required to support this transmission are presented in **Table 4-8.** An example OSP is shown in **Figure 4.14**.


*Source: Galloper Wind Farm Ltd*

**Figure 4.14 Example Offshore Substation Platform**

4-80. Each OSP will sit on a substructure, the final design of which depends on detailed design work supported by metocean conditions and ground model. The Proposed Offshore Development is assuming a four-legged jacket design, such as the one presented in **Figure 4.14**.

4-81. The options to fix the OSP substructures to the seabed include:

- driven piles; and
- suction piles.

4-82. The piles to secure the substructure to the seabed will have a maximum diameter of 3.4 m and be driven down into the seabed to a maximum depth penetration of 63 m. The maximum hammer energy in the case of the driven pile would be 4,400 kJ. The maximum design parameters of the OSPs are presented in **Table 4-8.**

**Table 4-8 Offshore Substation Platform Parameters**

| | |
|---|---|
| Maximum number of OSPs | 3 |
| Structure type | 4-legged jacket |
| Transmission type | HVAC |
| Maximum water depth (LAT) (m) | 110 |
| Maximum height of OSP (LAT) (m) | 64 |
| Maximum topside length (m) | 109 |
| Maximum topside width (m) | 64 |
| Maximum footprint area per OSP foundation without scour protection ($m^2$) | 6,622 |
| Maximum footprint area per OSP foundation with scour protection ($m^2$) | 27,800 |
| Maximum hammer energy for driven piles (kJ) | 4,400 |
| Maximum number of piles per foundation | 16 |
| Maximum total continuous pile installation time per OSP (minutes) | 1,920 |

4-83. Equipment and associated infrastructure within the OSPs may include:

- high-voltage power transformers;
- high-voltage switchgear and busbars;
- substation auxiliary systems and low voltage distribution;
- shunt reactor(s);
- instrumentation, metering equipment and control systems;
- standby generators;
- auxiliary and uninterruptible power-supply systems;
- navigation, aviation & safety marking and lighting;
- helideck;
- systems for vessel access and/or retrieval;
- platform cranes;
- potable water supply;
- black water separation;
- storage (including stores, fuel and spares);
- fire-fighting rooms;
- emergency accommodation;
- welfare facilities, lockers and first aid room;
- workshop; and

- communication systems and control hub facilities.

**Interconnector Cables**

4-84. Interconnector cables will link individual OSPs together, passing generated power into the export system. Depending on the further detailed design stages of the Project, interconnector cables may be required to link together up to three OSPs. The following lengths are precautionary at this early design stage, and actual distances will depend on the final electrical design and project layout:

- Substation 1 to Substation 2 - approx. 10 km
- Substation 2 to Substation 3 - approx. 10 km
- Substation 3 to Substation 1 - approx. 20 km

### 4.4.2.2 Intermediate Reactive Compensation (IRC) Platform

4-85. When power is transmitted over long distances in an HVAC system the balance between the two components of electrical power, real power and reactive power, become increasingly imbalanced. If this imbalance becomes too large the power cannot be transferred into the national power grid. A reactive compensation platform manages the voltage stability and power quality to mitigate this imbalance. Given the distance the array is from landfall combined with the proposed use of an HVAC transmission system an IRC platform will likely be required to rebalance the power quality.

4-86. **Figure 4.15** presents an example IRC of a similar design to the one proposed.


*Source: Ørsted*[4]

**Figure 4.15 Example Intermediate Reactive Compensation Platform**

4-87. The IRC platform will be located approximately midway between the OSP(s) and the onshore grid connection point (

4-88. **Figure** 4.16). The final location of the IRC platform will be informed by environmental and technical parameters including ground conditions, ongoing electrical design studies, marine traffic survey results, consultation with commercial fishing and ferry operating sectors, along with wider navigational stakeholders and other environmental factors and sensitivities.

[4] Hornsea Project One Welcomes World's First Offshore RCS | Offshore Wind

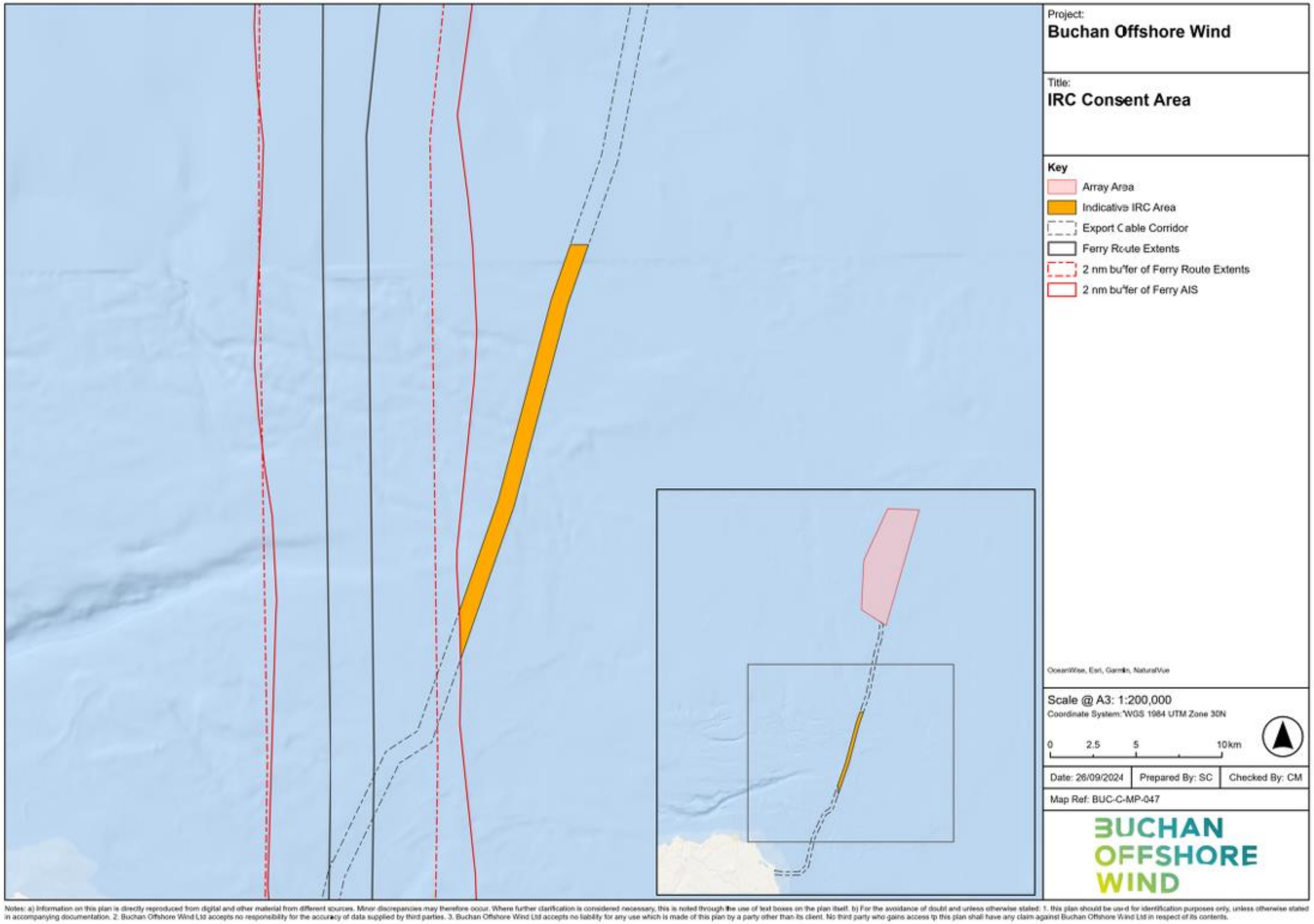



**Figure 4.16 Proposed Location of IRC**

4-89. The maximum dimensions of the IRC topside (including a helideck) will be 60 m x 80 m x 62.5 m. The foundation type being considered is a jacket with up to four legs, and this will be installed using either drilled, driven, or suction piles based on the existing knowledge of ground conditions. Key parameters are presented in **Table 4-9.**

**Table 4-9 Intermediate Reactive Compensation Platform Parameters**

| | |
|---|---|
| Maximum number of IRCs | 1 |
| Transmission type | HVAC |
| Maximum water depth (LAT) (m) | 90 |
| Maximum height of IRC above LAT (m) | 60 |
| Maximum topside length (m) | 80 |
| Maximum topside width (m) | 62.5 |
| Maximum footprint area per foundation without scour protection ($m^2$) | 6,798 |
| Maximum footprint area per foundation with scour protection ($m^2$) | 20,600 |
| Maximum hammer energy for driven piles (kJ) | 4,400 |
| Maximum total continuous pile driving time (minutes) | 250 |

### 4.4.2.3 Export Cables

4-90. Offshore export cables enable the transfer of electricity generated at the Array Area to the onshore transmission infrastructure. Following a feasibility assessment, the PDE has been refined to include up to three HVAC export cables of between 220 kV and 275 kV, which will be installed between the OSP(s) and landfall, connecting to the onshore transmission infrastructure. Further details on the alternatives considered are presented in **Volume 1, Chapter 3: Site Selection and Consideration of Alternatives**.

4-91. It is strongly preferred that the offshore export cables are buried, however the ability to do this is determined by sediment types and ground conditions. Cable burial depths have been informed by a Cable Protection Assessment (CPA) and are expected to be up to 2.4 m, with a target depth of 1.5 m. Installation techniques being considered include trenching, ploughing, jetting, and mechanical cutting. The temporary working trench width (i.e. width over which sediment may be disturbed) is 10 m, with a target width of 1.95 m. An overview of the maximum design parameters of the export cables are presented in **Table 4-10.**

4-92. Where a target burial depth cannot be achieved or the cables need to be surface laid, cables may be protected with rock berms or concrete mattresses. Protection will also be needed at cable and pipeline crossings.

**Table 4-10 Offshore Export Cables Design Parameters**

| Description | Maximum Design Parameter |
|---|---|
| Maximum number of export cables | 3 |
| Transmission type | HVAC |
| Indicative cable voltage (kV) | 220-275 kV |
| Cable burial depths (m) | Target depth 1.5 m<br>Exceptional maximum burial depth - 2.4 m expected along the cable corridor (where vessel traffic is more prominent, and subject to findings of the CPA)<br>Pre-sweeping for sandwave maximum burial depth – 5.73 m |
| Cable burial trench width (m) | 1.95 m (with a maximum temporary working width of 10 m) |
| Number of export cable crossings | 2 |
| Length | 86.5 km per cable |

#### 4.4.2.3.1 Joint Pits

4-93. Subsea joint pits are expected to be required where the maximum spool length on the vessel has a lower capacity than the maximum cable range. All joints are potential weak points on the cable route and should be appropriately protected. The cable joint area will preferably be placed in an area with the following conditions:

- a relatively flat area free from slopes or hummocky ground;
- away from any geological and geomorphological hazards that could compromise the jointing operation or joints' long-term stability;
- away from any environmentally sensitive areas; and
- in granular soils with low thermal resistivity.

The subsea joint will be laid down in a joint pit as presented in **Figure 4.17** and **Figure 4.18**. The joint pit will be constructed by dredging, with 1:3 slopes to provide a naturally stable slope.

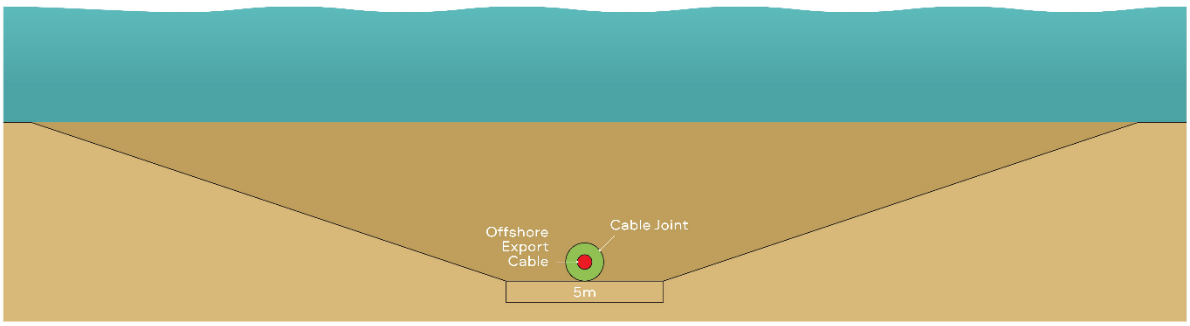



**Figure 4.17 Cable Joint Pit**

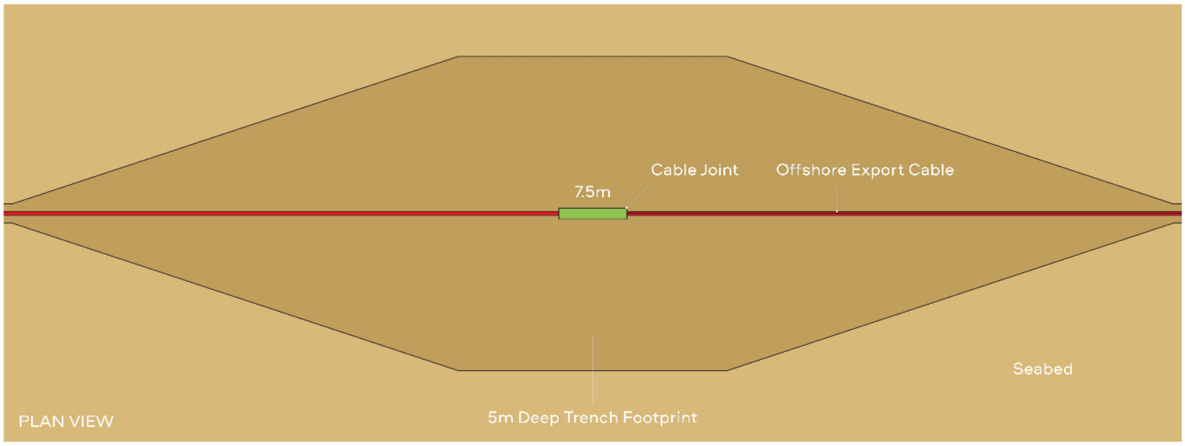



**Figure 4.18 Export Cable Joint – Plan View**

4-94. A summary of the maximum dimensions and volume for the joint pit are presented in **Table 4-11.**

**Table 4-11 Summary of Dredging Requirements for Joint Pit**

| Max number of joint pits | Max depth (m) | Max width (m) | Max area ($m^2$) | Length (m) | Total volume ($m^3$) |
|---|---|---|---|---|---|
| 3 | 5 | 35 | 100 | 130 | 6,800 |

### 4.4.2.4 Cable Crossings

4-95. Cable crossings are required where the export cable needs to cross any existing seabed infrastructure such as pipelines or other cables. Crossings will be required at two known locations along the export cable corridor to cross the third-party assets presented in **Table 4-12**.

**Table 4-12 Cable Crossings**

| Asset name | Diameter (inch) | Fluid | Status | Operator |
|---|---|---|---|---|
| Ross Gas Export Line | 6 | Gas | Active | Repsol Sinopec |
| Captain Gas Export Line | 8 | Gas | Active | Ithaca |

4-96. Crossings will be designed both to preserve a target one metre separation between the export cable and third-party assets whilst ensuring the integrity of the existing infrastructure and the crossing cables. It is assumed that the existing third-party infrastructure has been buried to a target depth of 1.5 m below the surface, or otherwise suitable protected. Crossings will be made as close to perpendicular as possible. Due to the assumed shallow burial depth of the existing pipelines, the export cable may need to be laid over a separation layer. An example of the proposed crossing layout is shown in **Figure 4.19** and **Figure 4.20**.

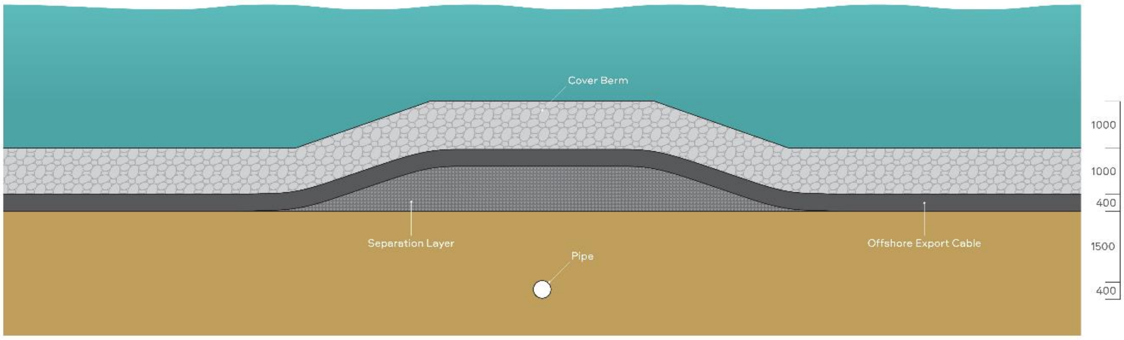



**Figure 4.19 Cross Sectional View of Proposed Crossing Layout**

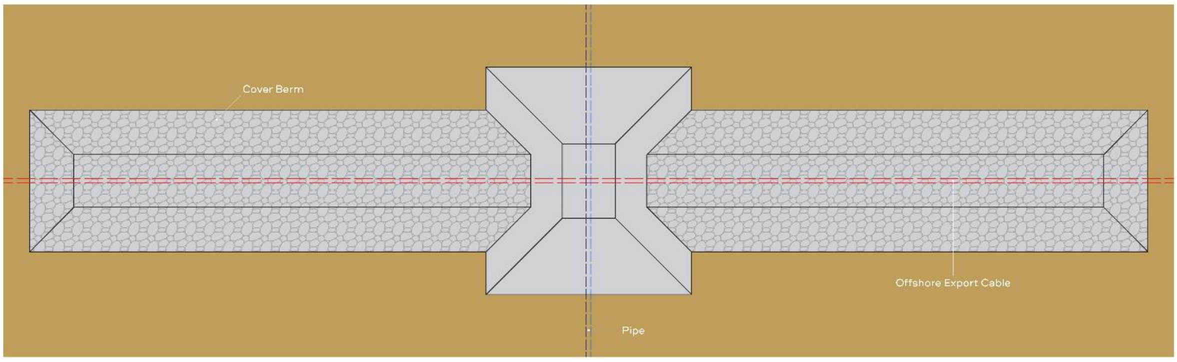



**Figure 4.20 Plan View of Proposed Cable Crossing Layout**

4-97. A separation layer will be placed between the seabed and the export cable. This is done for two reasons. The first is to spread the load induced by the mass of the rock cover berm evenly into the seabed and avoid overstressing the pipe buried below. The second reason is to preserve the soil on which the cable is laid, ensuring a physical separation of the two assets.

4-98. The separation layer is expected to be filter grade rock, to be installed by a flexible fall-pipe vessel (FFPV) prior to cable lay. A cable crossing assessment has been undertaken which has assumed the following, conservative assumptions:

- the separation layer has been assumed in a maximum design scenario to be circa 1 m in height; and
- a cover berm of circa 1 m thickness has been assumed to be acceptable for the crossing location. This is less than the target depth of 1.5 m where the cable is buried but is considered to provide appropriate protection to the cable and third party assets, and other users of the sea where crossings occur.

4-99. Detailed design of the cable crossing will consider the maximum allowable stress the crossed third-party asset can safely handle. This could require a further reduction in rock berm and filter layer height.

4-100. A summary of the estimated dimensions of the crossing berm are shown in **Table 4-13.** Should any additional crossings be required in the time between consent application and construction, it is anticipated that they will not exceed the design parameters presented and assessed in this EIAR.

**Table 4-13 Crossing Berm Dimensions**

| Berm height (m) | Berm width (m) | Berm cross sectional area ($m^2$) | Berm material |
|---|---|---|---|
| 2.4 | 21.4 | 34.1 | Filter grade rock<br>Armour grade rock |

### 4.4.2.5 Landfall Infrastructure

4-101. To bring power generated at the Array Area onshore, the offshore export cables need to land at the coast, pass through the intertidal area, and reach above MHWS to a Transition Joint Bay (TJB). The TJB is the location where the offshore and onshore transmission cables meet.

4-102. All infrastructure and associated activities located above MHWS are outside of the scope of the Proposed Offshore Development EIA and will be detailed within the Proposed Onshore Development EIA submitted as part of the planning application for the onshore elements (see **Section 4.1.1**). The likely significant effects from the proposed onshore infrastructure will be considered from the cumulative perspective as part of the Proposed Offshore Development Cumulative Effects Assessment presented in this EIAR.

4-103. Activities associated with the Project in the intertidal zone will be assessed as part of both the Proposed Onshore Development EIA and Proposed Offshore Development EIA.

4-104. Extensive engagement with National Grid Electricity System Operator (NGESO) and Scottish and Southern Electricity Networks Transmission (SSEN-T), as part of the Holistic Network Design Follow-up Exercise (HNDFUE) resulted in the Project's grid connection location to be identified as Peterhead, Aberdeenshire. Understanding the likely grid connection location has allowed the Applicant to undertake an assessment of the landfall and associated routing options within an area between Rosehearty and Cruden Bay in Aberdeenshire.

4-105. As presented in **Figure 4.21** the preferred Export Cable Corridor (ECC) runs south from the Array Area, and makes landfall within Rattray Bay, Aberdeenshire, located immediately north of the St Fergus Gas Terminal and associated offshore pipelines. The nearshore section of the ECC is presented in **Figure 4.21**.

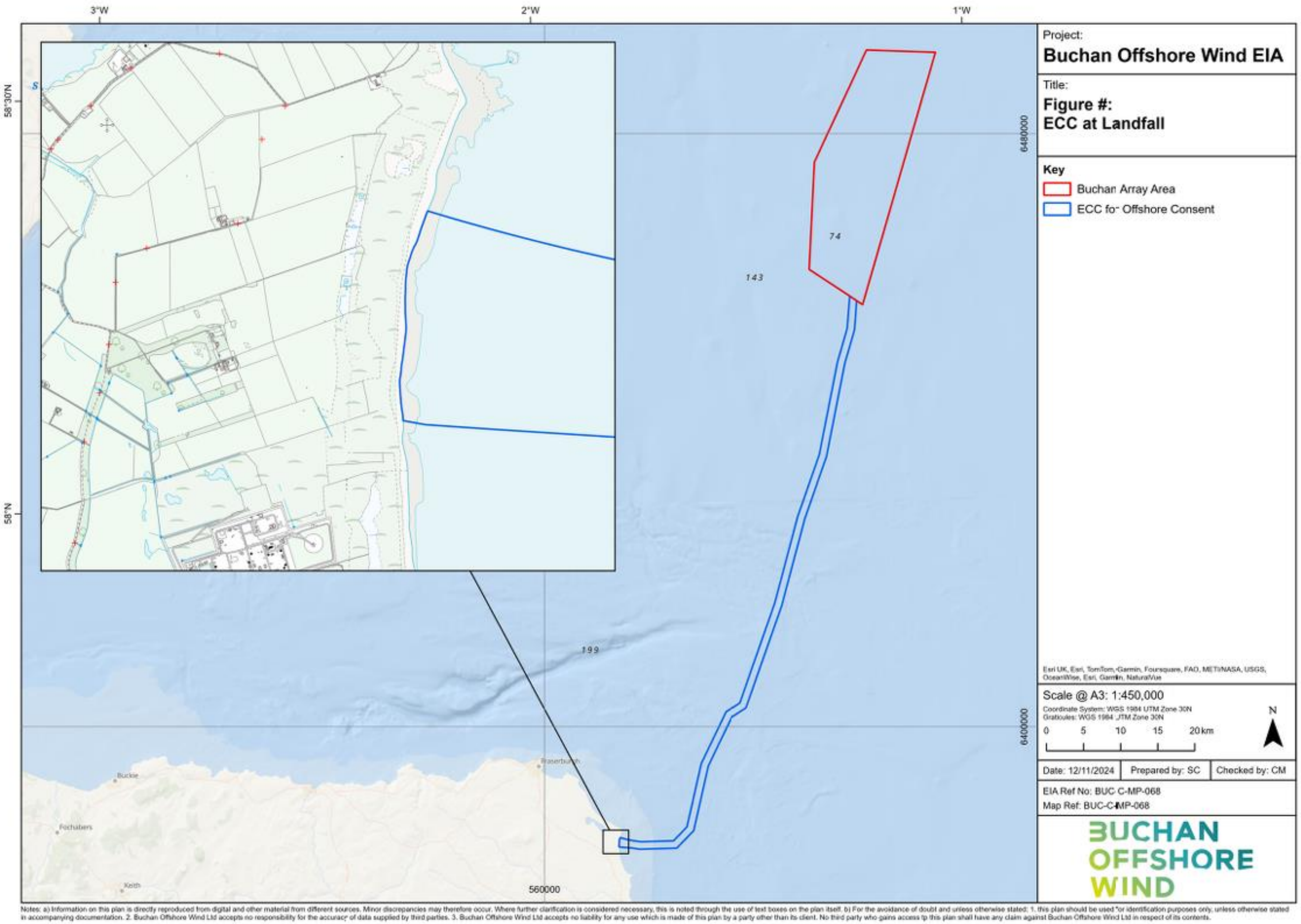



**Figure 4.21 Location of the Proposed Landfall**

4-106. In the Offshore Scoping Report (Buchan Offshore Wind Limited, 2023), both trenched and trenchless landfall options were considered. A Landfall Feasibility Assessment was undertaken which considered several different methods for forming the landfall route, including trenched options (cut & cover, plough) and trenchless options (pipe jacking, direct pipe and Horizontal Directional Drilling (HDD)). Of these, the trenchless method of HDD was recommended as the most feasible solution. This process is discussed further in **Volume 1, Chapter 3: Site Selection and Consideration of Alternatives.**

4-107. Following these findings, a further landfall HDD study has been undertaken to define the worst-case credible HDD solution, which has been included as part of the consent envelope. No open-cut trenching will be required at landfall.

## 4.5 SITE PREPARATION

4-108. A range of site preparation activities are required at the Array Area and ECC. The proceeding sections provide detail on these activities.

### 4.5.1 Pre-Construction Surveys

4-109. Pre-construction surveys will be undertaken to determine in detail the seabed characteristics and morphology, presence of potential obstructions and hazards and potential risk of UXO, within the Array Area and ECC. Should any hazards be identified, micro-siting or installation of cable protection may be required.

4-110. The pre-construction surveys are expected to take place in 2030 and will inform detailed design work and are presented below.

4-111. Geophysical surveys include:

- Multibeam Echosounder (MBES)
- Dual Frequency Side Scan Sonar (SSS)
- Magnetometer (MAG)
- Sub-bottom Profiler (SBP)
- Ultra High Resolution Seismic (UHRS)

4-112. Pre-construction surveys will also include geotechnical surveys, which may include boreholes and wider sediment sampling to characterise the subsea conditions and profile.

4-113. In addition to pre-construction surveys, a pre-lay grapnel run (PLGR) may be required to clear debris from the cable route. Should a PLGR be required, it is anticipated that this will be completed within a circa four-month period.

4-114. The pre-construction surveys will be undertaken across the Array Area, ECC and landfall and are expected to take approximately 10 months.

### 4.5.2 Unexploded Ordnance (UXO) Avoidance/Clearance

4-115. A desk-based study undertaken by 6-Alpha (2023) and site-specific geophysical surveys undertaken in 2023 (Ocean Infinity, 2023) have identified several potential UXOs within the area of the Proposed Offshore Development. Where a UXO is identified, and infrastructure cannot be micro-sited to avoid them, it represents a health and safety risk. Therefore, UXO may need to be cleared or detonated to make the area safe for vessel travel and construction.

4-116. The following methods are being considered for UXO avoidance/clearance:

- avoidance of UXO;
- relocation of UXO, avoiding detonation;
- micro-siting to avoid UXO;
- low order clearance (e.g. deflagration); and
- high order detonation.

4-117. For receptors where there is potential for a likely significant effect, an assessment has been undertaken and presented within the associated technical chapter of this EIAR.

4-118. Should the mitigation activities or clearance or detonation be required they would be subject to separate assessment and licence applications.

### 4.5.3 Boulder Clearance

4-119. Boulder clearance may be required during the preparation of the Array Area and ECC. A boulder is typically defined as a rock fragment which is over 256 mm in diameter.

4-120. Boulder clearance may be required to reduce the possibility of cable burial depth being limited by boulders and to reduce damage to cables during installation.

4-121. Boulder clearance may be required in the vicinity of anchor locations of the WTGs and foundation locations for the OSPs and IRC in order to avoid disruption to installation activities.

4-122. Cable routes may be ploughed to remove boulders, or alternatively, debris can be removed using a boulder grab. Any boulder larger than 15 $m^3$ will likely stay *in situ* and will be avoided during installation.

### 4.5.4 Sandwave Clearance

4-123. Sandwaves have been identified through geophysical surveys of the Array Area and ECC (Ocean Infinity, 2023, also **Volume 3, Appendix 7.1: Buchan Environmental Survey Report**). Sandwaves and similar seabed formations may need to be cleared or trenched to a deeper level during construction to ensure the seabed is flat enough for cable installation as the necessary tools often require a relatively flat surface to work effectively.

4-124. Clearance of sandwaves also prevents cable abrasion and ensures long-term reliability of cable performance. Sandwaves are mobile and increase the chance of an inconsistent burial depth which can change over time, and in some cases the movement can even leave the cable exposed.

4-125. Clearance may be undertaken during the construction phase by pre-sweeping (dredging), where dredged seabed will be moved into the troughs, creating a level surface for cable burial. It is anticipated that the maximum width of pre-sweeping for sandwaves will be 36.2 m. It may also be completed through other methodologies, such as pre-installation ploughing tools and sweeping using jetting tools which level the seabed.

### 4.5.5 Vessels

4-126. A summary of the vessels to be used during site preparation works is presented in **Table 4-14.**

**Table 4-14 Proposed Site Preparation Vessels**

| Operation | Vessel type | Maximum number of vessels on site at any one time | Maximum total movements (return trips)[5] |
|---|---|---|---|
| UXO and Boulder Survey & ID | Multipurpose Survey Vessel | 2 | 40 |
| UXO Removal (Offshore) | Multipurpose Vessel with Remotely Operated Vehicle (ROV) | 2 | 30 |
| UXO Removal (Nearshore) | Multicat | 1 | 10 |
| Boulder Clearance | Multipurpose Vessel with ROV | 2 | 69 |
| Guard Vessels | Guard Vessel | 2 | 80 |
| Rock Placement | Rock Dump Vessel | 1 | 20 |
| General Support, Pre-Construction Survey | Multipurpose Vessel | 1 | 13 |

Note PLGR vessels are captured as part of the IAC installation vessel numbers in **Section 4.7.8.**

## 4.6 SAFETY ZONES

4-127. Safety zones around renewable energy installations can be declared under s.95 of the Energy Act 2004 to secure the safety of other users of the marine environment during the construction, operation and maintenance, extension or decommissioning periods. The standard safety zone is 500 metres for construction and 50 metres for operation, but this may be restricted or affected by constraints including navigable routes.

4-128. The Project expects to apply for safety zones during construction and major maintenance activities. Safety zones may also be applied for around certain offshore structures (i.e., floating WTGs or the IRC) during the operational phase, subject to engagement with consultees and agreement with relevant authorities. At the appropriate phase a detailed safety zone plan will be prepared to inform the size and location of any safety zones applied for, and how these will be communicated to the relevant stakeholders. The plan will seek to exclude rights of navigation in the proposed radius around each installation during the operational phase, and around a wider area in the construction and maintenance phases. The aim of any navigational restrictions will relate to the safety of users of the marine environment and the protection of both assets of the Proposed Offshore Development and of other users of the marine environment.

[5] Total number of trips will not be known until final design and construction planning is complete, with the numbers presented representing a reasonable worst case estimate at this stage.

## 4.7 CONSTRUCTION METHODOLOGY

4-129. A key advantage to floating wind technology is the ability for elements of the offshore wind substructures to be constructed and integrated on land.

4-130. The Project is expected to be constructed in the following order, although the final details may vary from this and some of these elements may run concurrently:

1. anchor, mooring line and scour protection installation;
2. offshore export cable and cable protection installation;
3. OSP installation and commissioning;
4. IRC platform installation and commissioning;
5. inter-array and interconnector cable installation and cable protection installation and hook-up; and
6. WTG and floating foundation tow-out, installation and commissioning.

### 4.7.1 Construction Programme

4-131. Construction of the onshore elements of the Project is planned to begin in Q1 year one (2030) and run over a period of up to three years. The first offshore activity will be seabed preparation, followed by anchor and mooring line installation, and is anticipated to start from late winter (Q1) of Year 2. **Figure 4.22** presents an overview of the planned construction programme. The Applicant will work with the supply chain, wider project delivery partners and stakeholders with the aim of reducing the total duration of the construction programme, representing a more efficient construction process without compromising on safe delivery.

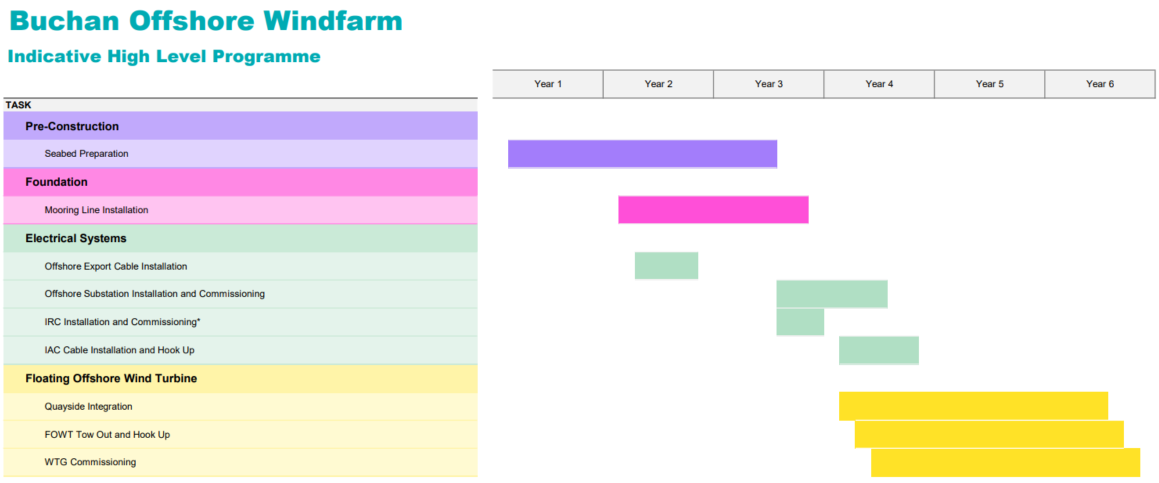



**Figure 4.22 Construction Programme Overview**

### 4.7.2 Anchor, Mooring Line and Scour Protection Installation

4-132. Due to the variety of anchor designs within the design envelope, a variety of installation methods may be deployed, although a general sequence is provided to inform the EIA process. All anchor types will firstly be prepared on a vessel and then dispatched over its stern. Once the anchor is secured in the seabed, the vessel will pay out chain and sail along the mooring line route, attaching a buoy to the end of the chain to keep it afloat.

4-133. For drag anchors, once laid on the seabed, tension will be applied to embed drag anchors below the mudline. Reaction anchors will be used to support the installation of drag anchors, as outlined in **Section 4.7.2.1**.

4-134. For suction pile anchors, installation will involve pumping water out of a closed-end steel cylinder, which creates a pressure difference with the external sea. This pressure differential effectively "sucks" the pile into the seabed.

4-135. For driven pile anchors, the anchors will be hammered into unprepared seabed using a mechanical impact driver. The piles are held in place by friction between the steel pile and seabed material.

4-136. Plate anchors are installed by penetration using suction caisson. The plate anchor is held in place on the end of a suction caisson, fluid is pumped out of the internal volume creating a differential pressure to "suck" the pile (and therefore plate) into the seabed. Once in place the suction caisson is removed, leaving behind the plate anchor.

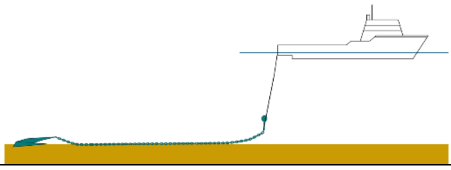
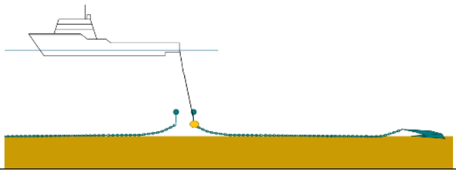
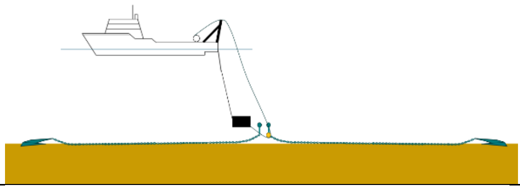
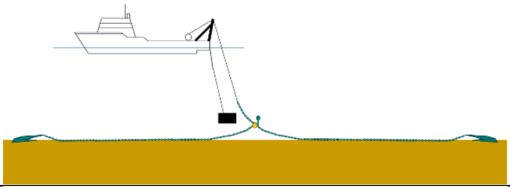
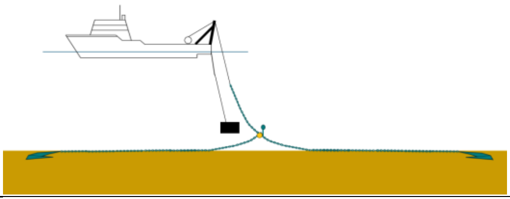
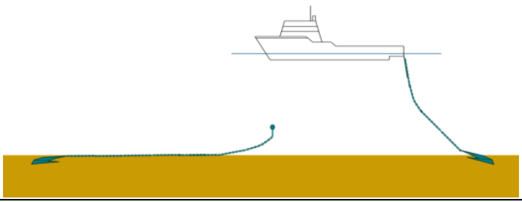
4-137. Scour protection will only be necessary for suction piles and driven piles; both drag anchors and plate anchors are entirely below the seabed and therefore not exposed to the effects of scour.

4-138. One layer of rock protection is proposed at each anchor site for the purposes of scour protection where it is required.

#### 4.7.2.1 Reaction Anchor Installation

4-139. Reaction anchors are used during installation of a drag anchor to facilitate tensioning and burial of the anchor. **Table 4-15** presents the reaction anchor installation steps.

**Table 4-15 Reaction Anchor Installation Process**

| Step | Description | |
|---|---|---|
| 1 | The anchor and mooring line is pre-laid on the seabed. |  |
| 2 | The reaction anchor and temporary line pre-laid in the opposite direction. |  |
| 3 | An ROV then passes a leader line through a subsea tensioner and connects the mooring line with a temporary chain. |  |
| 4 | The main vessel winch is used to pull the temporary chain through the tensioner and draw anchors together, embedding them in the seabed. |  |
| 5 | The temporary line is winched in until the desired embedment depth achieved |  |
| 6 | Temporary lines disconnected and the reaction anchor is removed from seabed, leaving mooring and anchor installed. |  |

## 4.7.3 Offshore Export Cable and Cable Protection Installation

### 4.7.3.1 Landfall Operations

4-140. Trenchless installation of the export cables at landfall using HDD is the preferred installation method. This method involves the use of a directionally drilled pilot tunnel(s), from the land compound along the cable alignment. The drill string and tunnelling machine can be withdrawn back to the land compound, where the pilot bore is subsequently enlarged using a reamer. The tunnel bore is temporarily supported by drilling fluids (typically bentonite) until the tunnel lining is installed. The tunnel lining / duct is typically a flexible High-Density Polyethylene (HDPE) pipe. Break through at the seaward end is planned to limit the loss of drilling fluids into the sea. The cable is then fed through the tunnel(s)/ duct(s).

4-141. Once the cable has exited the HDD tunnel (at approximately the 10 m LAT contour line) it will be buried to a target depth of 1.5 m along the length of the ECC route to reduce the risk of damage, or otherwise protected where suitable burial cannot be achieved. Cable burial will be undertaken using either a non-displacement plough (simultaneous lay and burial method) or a tracked jetting tool (post-lay burial method) as described in the following sections.

#### 4.7.3.2 Simultaneous Lay and Burial Method

4-142. In this method of operation, the cable lay and burial operations are combined into a single operation, with a trenching tool mobilised onboard the cable lay vessel. As the cable is laid onto the seabed, the tool is lowered to the cable touchdown point to facilitate burial of the cable. This allows installation to be completed in a single pass with a single construction vessel, providing immediate protection for the cable.

4-143. The speed of the operation is constrained by the speed of the burial tool, and this technique is substantially slower than other methods. The usual production rate of a cable plough is in the order of 150-200 m per hour, whilst a cable lay vessel can lay at 600 m per hour. This necessitates a longer weather window for the installation, due both to the reduced installation rate and the need to recover the plough in certain sections of the route (i.e. cable crossings). This method can be restrictive if the cable is especially rigid as control of the burial tool reduces with distance from the vessel to the point of seabed touchdown. Whereas a rigid/stiff cable can be difficult to handle over stern rollers and at touchdown, a more flexible cable will fall more easily over the stern rollers and allow the burial tool to land on the seabed closer to the vessel, allowing more control of the burial tool from the vessel.

#### 4.7.3.3 Post Lay Burial Method

4-144. This method involves laying the cable prior to the burial operation and then employing a burial support vessel to conduct burial operations. Multiple passes may be taken if burial was unsuccessful at the first pass. This method can benefit from working in shorter weather windows, as the burial operation can be performed intermittently. This method poses some risks, such as the risk of anchor strike or damage from fishing/trawling to the cable in the interval between the cable lay and burial operations. While the cable is on the seabed unprotected, a guard vessel may also be required.

#### 4.7.3.4 Cable Protection

4-145. Cable protection against external factors is required in locations where it is not practicable to bury the cable. Cable protection will be required in the standoff area, areas with poor ground conditions or geological or geomorphological hazards that prevent burial, and at transition points between dynamic and static cables. Up to 791,102.4 $m^3$ cable protection is anticipated across the Proposed Offshore Development site.

4-146. Cable protection provides protection from external hazards such as anchor strikes and trawling/fishing activity. Additionally, the protection also prevents erosion and scour from around the cable which could cause it to become exposed over time.

4-147. Rock installations are expected to be installed by a FFPV with mattresses and rock bags to be installed from a construction support vessel. Rock is expected to be loaded directly onto the vessel.  Vessels can install rock at a rate of up to 700 $m^3$ per hour; however, operational limitations such as efficiency and water depth will impact installation rates.

#### 4.7.3.4.1 Standard Rock Berm

4-148. The minimum height of the rock berm is dependent on the worst-case depth of penetration into the rock berm that could occur as a result of an anchor strike and/or trawling fishing activity. The standard rock berm will be designed against two potentially destructive events which could damage the rock berm and affect other users of the sea.  The first, seabed lowering, is estimated in a worst case to lower by 0.5 m over the 30-year design life.  The second is an extreme storm event, which could result in displacement of the rock berm and exposure of the cable. Based on industry good practice, the rock berm will be designed to deal with a 1:100 year storm event.  The events caused by the seabed lowering and storm events will cause the rock berm to round and drop in height.

4-149. Studies undertaken as part of engineering design have calculated that a 1.8 m high and 5 m wide rock berm with 1:3 slopes will be sufficient to protect the cable against anticipated worst-case storms and worst-case seabed lowering over the anticipated design life. This will be confirmed during detailed design.  The total volume per metre run of cable in the rock berm is anticipated to be in the range of 19 $m^3$.

4-150. A cross-sectional drawing with the estimated dimensions of the rock berm is shown in

4-151. **Figure** 4.23 An estimation of the rock berm shape and dimensions after rounding in storm events and seabed lowering is shown in **Figure 4.24**.

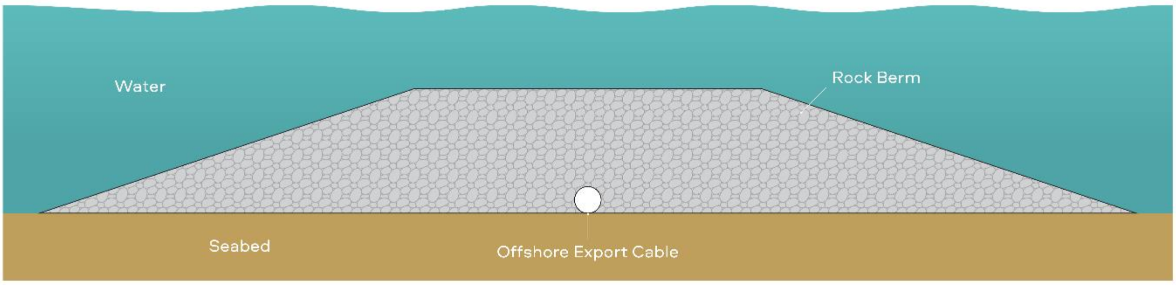



**Figure 4.23 Cable Protection - Rock Berm**

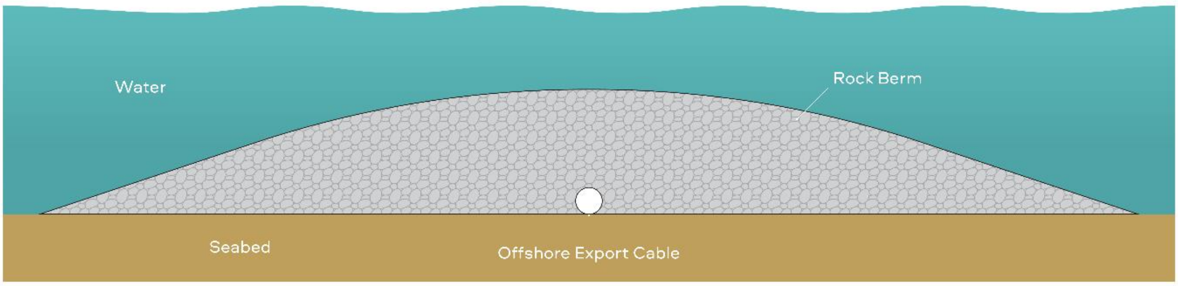



**Figure 4.24 Cable Protection - Rock Berm after Storm Event and Seabed Lowering**

4-152. A summary of the estimated dimensions of the standard rock berm are presented in **Table** 4-16

**Table 4-16 Maximum Standard Rock Berm Dimensions**

| Berm height (m) | Berm width (m) | Berm cross sectional area ($m^3$) | Berm area |
|---|---|---|---|
| 1.8 | 16.0 | 19.0 | Filter and armour grade Norwegian granite |

#### 4.7.3.4.2 Concrete Mattress

4-153. Concrete mattresses are formed from rigid sections of concrete linked together with flexible material, usually steel cables.

4-154. The mattresses provide protection from anchor strikes by latching the anchor and deflecting it over the cable. This may displace the mattress away from the cable and render the struck section unprotected, requiring remediation.

4-155. The mattress is most suited to the nearshore sections as it has a shallow height of 0.3 m, which would be beneficial in shallow sections as not to reduce the navigable depth. An example of the concrete mattress and estimated maximum dimension under consideration for shallow sections is shown in **Figure 4.25.**

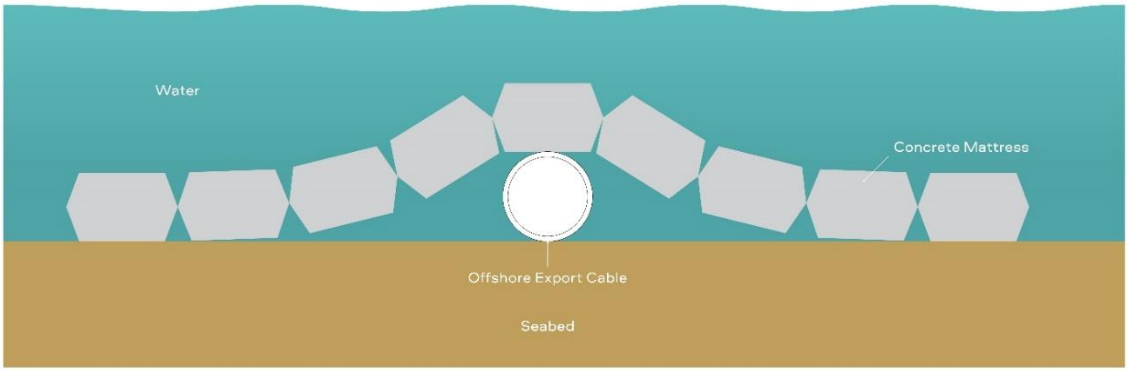



**Figure 4.25 Cable Protection – Concrete Mattress**

4-156. A summary of the maximum design parameters of the mattress are presented in **Table** 4-17

**Table 4-17 Concrete Mattress Maximum Dimensions**

| Height (m) | Width (m) | Cross sectional area ($m^2$) | Material |
|---|---|---|---|
| 0.70 | 4.32 | 1.73 | Concrete blocks/steel cables |

### 4.7.4 OSP Installation and Commissioning

4-157. The OSP topsides will be manufactured onshore, fully fitted with all necessary electrical and mechanical equipment, before being transported offshore for installation mounted on the OSP foundations. They will be securely attached to the foundations using welding, grouting, or bolting.

4-158. As presented in **Section 4.4.2.1**, the jacket foundation will be fixed to the seabed with driven piles or suction piles.

4-159. All necessary cable connecting and commissioning works are expected to be carried out with the assistance of a dynamic positioning vessel and assisting support and supply vessels as required. Crew Transfer Vessels (CTVs) may be used to transfer personnel to and from the installation vessel.

#### 4.7.4.1 Jacket with Driven Piles

4-160. The piles, OSP and jacket will be loaded and transported to site using a heavy lift vessel (HLV) and transportation vessels or barges. Following pre-installation surveys and any necessary seabed preparation the HLV will place the jacket into position on the seabed.

4-161. The piles will be lifted into a vertical position and lowered to the seabed into pile sleeves at the base of the jacket legs. The piles will be installed using a hydraulic hammer.

4-162. A soft-start procedure will be implemented using low-energy hammer blows to initially embed the pile and allow marine mammals the opportunity to leave the area. This would start with 10% hammer energy at 10 blows per minute, ramping up in hammer energy and blow rate over the course of 40 minutes to full power.

4-163. Hammer energies will be ramped up to levels required for pile installation, up to a maximum 4,400 kJ and a hammer blow rate of 40 strikes per minute maintained until target depth is reached. The complete piling operation of each four-legged jacket is expected to take up to 16.7 hours.

4-164. The HLV will then lift and install the OSP topside onto the jacket.

4-165. There is the potential for WTG anchors to be piled simultaneously with the OSP jackets if driven pile anchors are selected.

4-166. Relevant stakeholders will be consulted on the potential for the use of acoustic deterrent devices (ADDs) to repel marine mammals from the area during piling operations, and this will be implemented through the Marine Mammal Mitigation Plan (MMMP) as appropriate.

#### 4.7.4.2 Jacket with Suction Piles

4-167. The jacket and OSP will be loaded and transported to site using a HLV and transportation vessels or barges. Suction piles will be pre-installed to the base of the jacket legs during fabrication.

4-168. Following pre-installation surveys and any necessary seabed preparation the HLV will place the jacket into position on the seabed. Once placed on the seabed and settled under its own weight, water will be pumped out of each of the suction buckets to create negative pressure within the suction buckets compared to the surrounding sea. This will cause the suction buckets to penetrate the seabed due to the resulting force until the desired depth is achieved. Time will be spent adjusting the negative pressures within the suction buckets to balance them out and reach the same depth.

4-169. Once complete, the pump will be turned off and some grout may be injected under the bucket to fill the air gap and ensure contact between the soil and the bucket.

4-170. Suction bucket seabed penetration could take between eight and 12 hours depending on the seabed conditions. Installation of all four suction buckets will occur simultaneously however only one OSP will be installed at any one time and no more than four suction buckets will be installed in 24 hours.

4-171. There may be a requirement to balance the depths of each suction bucket, depending on the seabed, and post-installation levelling work could take between one and two days.

4-172. An initial scour protection filter layer will be placed on the seabed at each foundation location followed by installation of larger rocks around the foundations, above the seabed. The rocks will be placed using a fall pipe vessel or a vessel with a side-tipping system. Alternatively, a grabbing device may be used to place the rock directly.

### 4.7.5 IRC Platform Installation and Commissioning

4-173. The installation and commissioning of the IRC platform will follow the same process as that for the OSP installation, as presented in **Section 4.7.4.**

### 4.7.6 Inter-Array and Interconnector Cable Installation and Cable Protection Installation and Hook-Up

4-174. The IAC and interconnector layout and routing will be informed by desktop studies and site surveys. Prior to IAC and interconnector installation, geophysical and ground-truthing surveys will be undertaken to ensure there are no obstructions (eg UXOs, boulders, sandwaves, wrecks, debris etc) along the planned route. If an obstruction is identified, it will be removed or avoided by re-routing the cable.

4-175. Each WTG will be connected via a 66 - 132 kV dynamic IAC which will be fitted with buoyancy modules (to prevent the cable over-stretching), dynamic bend stiffeners and touchdown protection (**Figure 4.7).**

4-176. IACs where they are on the seabed will be buried where conditions allow (see **Section 4.4.1.3**). Where this is not practicable, cable protection in the form of rock berms will be implemented, and a worst-case allowance of 10% of all IACs protected by rock berms has been assumed within the design envelope.

4-177. As presented in **Section 4.4.2.1**, up to three interconnector cables may be required to link the OSPs.

4-178. Interconnector cables will be installed following the same procedure as the export cables, as detailed in Section **4.7.3.**

### 4.7.7 Wind Turbine Integration, Tow-Out, Installation and Commissioning

#### 4.7.7.1 Integration of WTGs and Floating Foundations

4-179. Specific details on WTG integration and installation will vary depending on the specific floating technology adopted and may change due to evolution in both the technology and supply chain. Components will be manufactured at a location dependent on technology and local supply chain capability. If not fabricated at the assembly location the WTG and floating foundation components will be transported by sea to the assembly port.

4-180. The floating foundations will be assembled at the quayside either onshore, in a dry dock or on a semi-submersible barge, depending on technology-specific installation requirements.

Each WTG will be assembled and installed on the floating foundation at the quayside using a crane. Quayside pre-commissioning will take place to reduce offshore operations.

#### 4.7.7.2 Tow-Out of Integrated WTGs

4-181. WTGs may be partially assembled prior to installation on floating foundations, or will be assembled directly onto floating foundations. The integrated WTG and floating foundations will then be towed to the Array Area using Anchor Handling Tugs (AHTs). Operations will proceed if the weather forecast on the towing route and Array Area allow for safe towing conditions. The WTG and floating foundations will be manoeuvred into their pre-determined position using dynamic positioning. Anchors will only be dropped in an emergency such as adverse weather or mechanical failure.

4-182. A tow-plan will be developed by the AHT operator in advance of any tow-out operations, and will include emergency contingency plans, such as a shelter response plan. The tow-plan will be reviewed and agreed by the Applicant before any tow-out operations.

#### 4.7.7.3 Installation of Integrated WTGs

4-183. Once at site, each WTG and floating foundation is hooked up to the pre-installed mooring system (see **Section 4.7.2**). The inter-array cables are then hooked up to the WTG and floating foundation.

#### 4.7.7.4 Commissioning of WTGs

4-184. Following installation of the integrated WTGs, commissioning activities will be undertaken including mechanical completion, electrical completion, high voltage (HV) commissioning and HV energisation, and final verification tests, commissioned and released for automatic, unattended operation.

4-185. Following energisation, the HV commissioning activities will be completed and the WTGs undergo performance and reliability testing.

### 4.7.8 Installation Vessels

4-186. **Table 4-18** presents an overview of the number of each type of vessels and the associated activities and movements that are expected across construction of the Proposed Offshore Development**.**

**Table 4-18 Vessels Required to Undertake Construction Activities**

| Operation and Vessel Type | Max Number Vessels | Max Total Return Transits |
|---|---|---|
| Seabed preparation (Multipurpose Survey Vessel, Multipurpose Vessel with ROV, Multicat, Guard Vessel, Rock Dump Vessel) | 10 | 249 |
| Mooring Line Pre-Installation (Anchor Handling Vessel) | 4 | 96 |
| Mooring Line Pre-Installation Support (Multipurpose Vessel) | 2 | 65 |
| Floating WTG Tow Out and Hookup (Offshore Tug Vessel, Anchor Handling Vessel, Multipurpose Vessel with ROV, SOV or Accommodation Vessel, CTV/Daughter Craft) | 11 | 748 |
| Pile Transportation (Barge, Offshore Tug) | 4 | 12 |
| Pile Installation (Semisubmersible Crane Vessel or HLV, Multipurpose Vessel) | 2 | 4 |
| Jacket Transportation (Barge, Offshore Tug) | 4 | 12 |
| Jacket Installation (Semisubmersible Crane Vessel or HLV, Multipurpose Vessel with ROV) | 2 | 6 |
| Topsides Installation and Hookup (Semisubmersible Crane Vessel, Barge, Offshore Tug, SOV) | 6 | 12 |
| Topsides Commissioning (SOV / Accommodation Vessel) | 2 | 48 |
| IRC Installation and Hookup (Semisubmersible Crane Vessel, Offshore Tug, SOV) | 6 | 6 |
| IRC Commissioning (SOV or Accommodation Vessel, Jack-Up) | 2 | 18 |
| Export Cable PLGR (Multicat) | 2 | 5 |
| Export Cable Lay | 5 | 132 |
| Export Cable Burial (Cable Burial Vessel) | 1 | 7 |
| Inter-Array Cable PLGR (Multicat) | 2 | 5 |
| IAC Cable Lay (Cable Lay Vessel, Multipurpose Vessel with ROV) | 2 | 22 |
| IAC Cable Burial (Cable Burial Vessel, Rock Dump Vessel) | 2 | 21 |
| IAC Hook-Up (SOV or Accommodation Vessel, CTV/Daughter Craft) | 4 | 323 |
| Transport of WTG Main Components (Transport Vessel) | 4 | 48 |
| Offshore Commissioning (SOV or Accommodation Vessel, CTV/Daughter Craft) | 4 | 323 |
| General Support, Pre-Construction Survey (Multipurpose Vessel) | 1 | 13 |
| General Support, As-Built Survey (Multipurpose Vessel) | 1 | 10 |
| Guard Vessels | 6 | 360 |

4-187. The full number of vessel movements across the project build is likely to be around 2,540. It is unlikely that vessels requiring anchors will be used as vessels with dynamic positioning capability will be used for installation activities.

### 4.7.9 Installation Helicopters

4-188. Helicopters are being considered to facilitate the transportation of personnel involved in the commissioning of the OSPs and IRC. The proposed maximum number of helicopters and respective transits are presented in **Table 4-19.**

**Table 4-19 Maximum Proposed Helicopter use During Construction**

| Operation | Max no. | Expected Max total return transits |
|---|---|---|
| Topsides Commissioning | 2 | 94 |
| IRC Commissioning | 2 | 34 |

### 4.7.10 Construction Ports

4-189. The final location for construction is still to be determined, however, a long-list of ports under consideration includes those listed below and shown on **Figure 4.26**:

- Fraserburgh
- Peterhead
- Wick
- Macduff
- Buckie
- Aberdeen
- Nigg
- Ardersier
- Cromarty Firth
- Montrose
- Inverness
- Methil
- Scapa Flow
- Dundee
- Kishorn

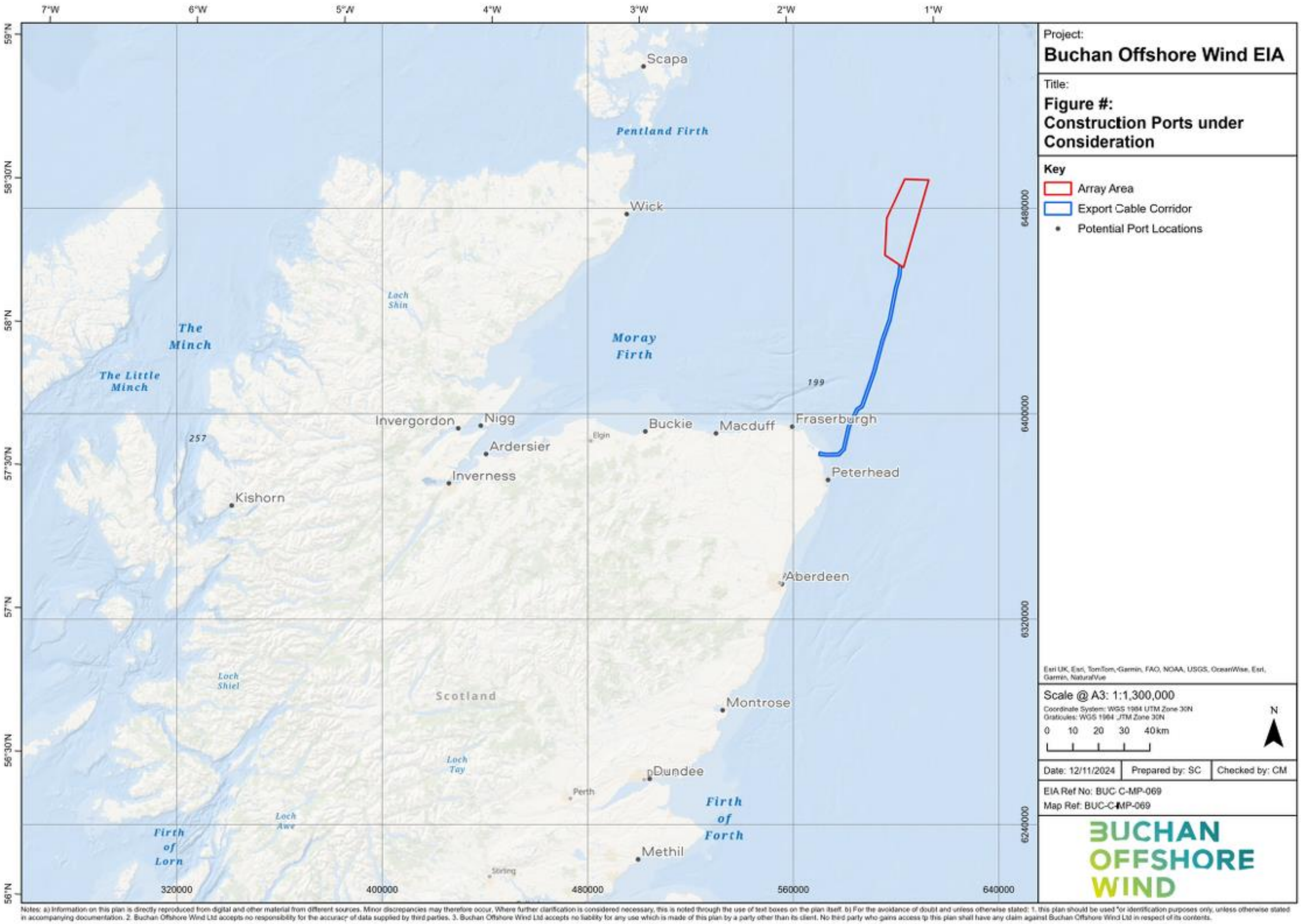



**Figure 4.26 Construction Ports under Consideration**

4-190. During construction it is possible that one port or multiple ports will be used depending on the delivery strategy, with key activities including:

- manufacture – principally of floating foundations, but with the potential for other elements to be manufactured at port such as OSPs;
- assembly of components at port, either onshore or offshore;
- integration of components at port, either onshore or offshore, such as the integration of WTGs onto floating foundations; and
- marshalling of components and vessels at port prior to deployment or use within the construction process.

#### 4.7.10.1.1 Wet Storage

4-191. It is expected that the relevant consents, permits, or licences, for the integration and pre-commissioning of WTGs and the wet storage of floating foundations and fully integrated units will be the responsibility of the relevant port authority or party responsible for the provision of wet storage. Should this position change, a separate licence application and supporting study will be submitted by the Applicant. At this stage of the project there is not sufficient detail known about the location of wet storage to enable a meaningful assessment and application to be made.

4-192. The Project will require facilities to assemble, fabricate, and store the WTGs on floating foundations. The fabrication process will be carried out onshore and the floating foundations will move along a production line before being transferred into the water. Once the floating foundations are in the water they may require a form of storage before the WTG can be integrated, referred to as 'wet storage'. In addition to this, once fully integrated the WTG will likely require wet storage before it can be towed to the array site for installation. Floating WTGs may also require wet storage if quayside repairs are necessary during the operation and maintenance phase.

4-193. Fabrication and integration may take place at the same port facility, or components may be fabricated at one location, and then transported to another port location for integration and/ or storage. The location or combination of locations will be dependent upon the facilities and capacity available at each port, as well as the WTG supplier selected. Preferred suitable quayside areas for wet storage will be located in sheltered, coastal waters which are outside of areas strongly influenced by tidal currents.

4-194. At the time of consent application, the Applicant notes that MD-LOT is considering the permitting and assessment requirements for the assembly, operation, storage and ongoing maintenance of offshore wind turbines in the sea, and is intending to provide guidance on this. If guidance becomes available, the Project will consider this in relation to the storage of WTGs at ports in particular. At this stage, the application and EIAR do not include the storage of integrated WTGs close to port prior to tow-out. This is expected to be covered by permissions for port operators or, should a stand alone Marine Licence be required, though a separate consenting process undertaken by the port operator.

## 4.8 OPERATION AND MAINTENANCE METHODOLOGY

4-195. The overall operation and maintenance methodology and programme will be finalised once technical specifics of the Proposed Offshore Development are determined, including selection of WTGs, OSPs, IRC and export cable(s). The final layout of the infrastructure will also inform operation and maintenance strategy.

4-196. The operation and maintenance (O&M) activities presented here are based on currently available information drawn from operational knowledge, current regulatory requirements and existing industry good practice. These approaches are likely to evolve as technology, regulation and good practice evolve over the life of the Project.

4-197. For floating WTGs, there is the potential opportunity to conduct tow-to-port operations for major O&M activities, such as major component replacement. In this scenario the WTG and floating foundation is decoupled from the mooring and towed to a suitable port facility to perform maintenance. Following completion, the WTG and floating foundation would be towed back to their original location and reconnected to the mooring system and electrical connections. Operation and Maintenance Activities

4-198. Scheduled and unscheduled maintenance and monitoring of the offshore infrastructure will be required during the operation of the Proposed Offshore Development. Floating foundations, WTGs, moorings, anchors, cables and offshore platforms will all require monitoring for repair, refurbishment and replacement needs and will be included in monitoring and maintenance programmes. An outline of these is presented in **Table 4-20**

**Table 4-20 Expected Operation and Maintenance Activities**

| Description | Indicative Expected Frequency |
|---|---|
| Routine exterior inspections of Project offshore infrastructure | Routine maintenance - Depending on asset this is estimated to between every six months to a year (with the exception of topsides). A percentage of IACs, foundations and WTGs will be inspected annually. Topsides will be inspected on a monthly basis. |
| Geophysical survey of seabed and assets, including cable protection | Estimated to be annually |
| Repair and replacement of electrical equipment, consumables and minor components on the OGI and OTI | Reactive maintenance - Estimated once every two years or when required |
| Removal of marine growth and bird guano | Estimated twice over the lifetime of the project |
| Application of paint or other coatings to protect the exposed infrastructure from corrosion (internal/external), including surface preparation. | Carried out during other works, estimated 10% of exposed infrastructure per year |
| Replacement of ancillary structures (eg ladders and boat landings) | Estimated at once every five years plus possible ad hoc requirements |
| Replacement of major components including blades, gearboxes, transformers, generators, transformers, switchgears etc | Reactive maintenance - As required |
| Repair, replacement and re-burial of inter-array cable section/whole inter-array cable. | Ten inter-array cable repair events of up to 3,000 m each, over the lifetime of the project. |
| Repair and replacement of offshore export cable | Four offshore export cable repair events of up to 1,000 m each, over the lifetime of the Project |

4-199. The nature of operation and maintenance activities will be to both prevent and correct any issues occurring associated with the operation of the offshore infrastructure. This will be informed by a logistics strategy, which will detail programme, vessels, personnel and health and safety requirements. The logistics strategy will be developed once detailed design of the Proposed Offshore Development is completed.

#### 4.8.1.1 Operational Onshore Base

4-200. All O&M activities will be managed and controlled from a purpose-built onshore Marine Operations Centre. The location is not confirmed at this stage, however, it will likely be within an east coast harbour in proximity to the Project. Consent for the Marine Operations Centre will be sought from Aberdeenshire Council following onshore site location and design development.

4-201. Identification and surveillance of any vessels which enter any safety zone(s) will be undertaken from the Marine Operations Centre, using AIS, video and radar coverage. Any vessel which is identified within a safety zone is considered a potential danger and will be instructed by a crew member of a Project guard vessel to divert their course away from the relevant safety zone. In the event a vessel ignores this instruction, they will be notified again before the vessel details are reported to the MCA enforcement unit.

4-202. As discussed in **Section 4.4,** each WTG, OSP and IRC will be fitted with a Supervisory Control and Data Acquisition (SCADA) system which will link to a central SCADA system in the Marine Operations Centre to monitor and control individual infrastructure operations on the Proposed Offshore Development.

4-203. Live metocean information will also be fed from the Proposed Offshore Development to the Marine Operations Centre to support operations throughout the lifetime of the Project. Parameters monitored will include wind speed and direction, wave height, tidal flow and direction and water temperature.

#### 4.8.1.2 Operation and Maintenance Vessels

4-204. The maximum estimated number of vessels required during O&M activities are presented in **Table** 4-21.

**Table 4-21 Maximum Vessels Required to Undertake Operation and Maintenance Activities**

| Operation | Vessel Type | Max no. Vessels | Number | Crew Change | Return Transits/Year |
|---|---|---|---|---|---|
| Cable Repair / Replacement | Cable Installation Vessel | 1 | 2 | 1 | 2 |
| | Services Offshore Vessel (SOV) | 1 | 2 | 1 | 2 |
| Inspections and Surveys | Remotely Operated Vehicle (ROV)/ Autonomous Surface Vehicle (ASV) Survey Vessel | 2 | 195 | 14 | 28 |
| Scour / Cable Protection Repair | Rock Placement Vessel | 1 | 14 | 14 | 1 |
| Planned Maintenance Campaigns | SOV | 2 | 210 | 14 | 30 |
| | CTV/Daughter Craft | 2 | 210 | 7 | 60 |
| Major Component Replacement In-Situ | Semisubmersible Crane Vessel | 1 | 2 | 1 | 2 |
| | Transport Vessel (e.g Barge) | 1 | 2 | 1 | 2 |
| | Ocean Going Tugs | 3 | 2 | 1 | 6 |
| Anchor/Mooring Line Repair/Replacement | Anchor Handling Vessels | 1 | 4 | 1 | 4 |

| Operation | Vessel Type | Max no. Vessels | Number | Crew Change | Return Transits/Year |
|---|---|---|---|---|---|
| Quayside Component Replacement | Anchor Handling Vessels | 1 | 1 | 1 | 1 |
| | Ocean Going Tugs | 2 | 1 | 1 | 2 |

#### 4.8.1.3 Helicopters

4-205. Helicopters may be used as part of the planned maintenance campaigns. If utilised, it is expected that up to 210 return transits per year could be undertaken to support operations.

#### 4.8.1.4 Health and Safety

4-206. All activities associated with Project including the Proposed Offshore Development will be compliant with relevant government guidance and regulations with respect to health and safety.

4-207. No diving activities are anticipated to be required during the lifetime of the Project.

4-208. All activities will be supported by risk assessments that will then inform the methods and safety mitigations implemented throughout the lifetime of the Project. The Applicant has a strong commitment to develop a safe system of work for Operation and Maintenance activities by focusing on people and processes aiming to reach ambitious targets on Health and Safety Performance. Focusing on individuals is a priority for the Project, which will ensure the level of competence and experience is assessed and maintained by providing adapted and regular training.

#### 4.8.1.5 Waste Management

4-209. Waste generated as a result of the Proposed Offshore Development will be handled and processed as described in a Site Waste Management Plan (SWMP). The SWMP will describe and quantify the waste types expected from construction, O&M and decommissioning phases of the Project and procedures to manage these (e.g. dispose, reuse, recycle or recover).

4-210. The SWMP will be developed and provided following finalisation of detailed design.

## 4.9 DECOMMISSIONING METHODOLOGY

### 4.9.1 Wind Turbines

4-211. Decommissioning will be done based on the technology available and good practice at the time of decommissioning which is likely to evolve over the life of the Project, particularly given the very limited deployment, and even more limited decommissioning, of floating offshore wind technology to date. The currently accepted decommissioning approaches for fixed-bottom offshore wind farms provide some guidance for the decommissioning of elements of the Proposed Offshore Development. For fixed-bottom offshore wind farms, removal of the WTG has traditionally been the first step in decommissioning and has been completed on-site using a jack-up vessel. Currently, there are not any jack-up vessels which operate in the water depths which are found in the Array Area. As such, three alternative methods of WTG removal are being considered by the Applicant at this stage. These three methods are listed in **Table** 4-22**.**

**Table 4-22 WTG Removal Options Currently Being Considered**

| Removal Options | Description |
|---|---|
| Quayside Removal | Tow of WTG and floating foundations to a port where there is an onshore-based crane for WTG removal at quayside. This could potentially be done at the same port that was used for assembly of the WTG and floating foundation. |
| Near-shore Removal | Tow of WTG and floating foundation to a near-shore based crane. A near-shore site where the WTG and floating foundations could be temporarily moored would be identified. |
| Offshore Removal | WTG would be removed by either a floating foundation or vessel-mounted crane. Floating foundation mounted cranes are not currently available, however may be developed in the lifetime of the Project. |

4-212. For each WTG removal option, an onshore area will be required for storing, dismantling and sorting into waste streams of the removed WTGs. Cranes with suitable hook heights will be required for lifting and moving the WTG components.

4-213. The three options above provide an indication of the decommissioning options at the time of writing. The final decommissioning of WTGs will be dependent on good practice and available technology at the time of decommissioning.

### 4.9.2 Floating Foundations

4-214. The floating foundations will be towed to an appropriate port to decommission, which will likely be selected based on proximity, availability and capability. Depending on the port and methods selected, WTG removal and floating foundation decommissioning may happen at the same location, or the floating foundations may be towed to a different location to be decommissioned.

#### 4.9.2.1 Onshore Demolition of offshore components

4-215. The nature of decommissioning of floating foundations will depend on the material deployed. Anticipated approaches presented are based on experience to date but will be undertaken in accordance with best practice at the time of decommissioning.

4-216. Where steel foundations are used, following removal from the water, inspection and controlled removal of marine growth or other contamination as required, consideration will be given to recycling of the steel.

4-217. Where concrete floating foundations are used, once the floating foundation has been removed from the water, it will require deconstruction and demolition. Prior to this, it will be inspected to determine if there has been any contamination from salt, marine growth, oil or other chemicals which could have affected the concrete whilst offshore, and to assess its structural integrity. Foundations will then be cleaned to remove any salt and marine growth from the concrete surface, using pressure hoses or mechanical scrubbing.

4-218. The concrete hull will then be dismantled and demolished.

### 4.9.3 Material Waste Streams

4-219. The secondary structure components for concrete floating foundations are likely to be steel. Steel is a readily recycled material, and consideration will be given to recycling of the steel, if practicable at the relevant stage.

### 4.9.4 Mooring Lines and Anchors

4-220. The mooring line system recovery is expected to target the removal of mooring lines from the Array Area. The outline mooring line recovery process will be subject to good practice and guidance in place at the relevant time, however is anticipated at this stage to be as follows:

1. Mooring lines are disconnected from the floating foundations and anchors using AHVs.
2. Mooring lines are left on the seabed, until the start of the removal campaign.
3. Buoyancy aids or retrieval lines are attached to the mooring lines.
4. Mooring lines are removed by AHVs.
5. Mooring chain and synthetic lines are cleaned and transported for re-use, recycling, repurposing or disposal.

4-221. The mooring lines will be taken onshore to a port for processing, and the port will be selected to ensure it has the appropriate facilities. If there is no suitable port, additional transportation will be considered to take the mooring lines to a land facility.

4-222. The nature of the chosen anchoring system will determine its decommissioning. Where impact piled anchors are used, it is expected that anchors will be cut to a depth of one metre below the seabed, with the rest of the structure remaining *in situ*, as removal has the potential to be more damaging than this approach. Where drag embedment anchors or plate anchors are used, these may be left in situ or removed depending on the likely disturbance caused by removal and the relevant guidelines and technologies in place at the time. Where suction anchors are used it is expected that removal will be the reverse of the installation process, with air pumped into the anchor to cause it to lift out of the seabed where it can be taken ashore for processing and recycling.

4-223. Whichever anchoring system is used, and regardless of the removal method or extent of removal, the post decommissioning state of the seabed will be the same in terms of leaving a clear surface free from obstruction to other seabed users and equipment, such a fishing gear.

### 4.9.5 Scour Protection

4-224. While there is a presumption in favour of removal, the potential for leaving scour protection *in situ* is being considered by industry and regulators. The methodology for removal will be reviewed throughout the lifetime of the Project and good practice at the time of decommissioning will be followed. If removed, scour protection, including concrete mattresses and rock berms are likely to be removed using a grab vessel with support from divers and ROVs if necessary. The scour protection would then be lifted on to a vessel and taken back to shore for disposal.

### 4.9.6 OSPs and IRC

#### 4.9.6.1 Topsides

4-225. The OSP and IRC topsides will be fully removed from site by reversing the methods used to install them.

#### 4.9.6.2 Jackets

4-226. Jackets will be fully removed from site, with piles cut at the seabed and left in situ. This approach will be reviewed throughout the life of the Project and will follow industry good practice and the most up-to-date guidance at the time of decommissioning.

### 4.9.7 Inter-Array Cables

4-227. Given the dynamic nature of the IACs, it is expected that full removal will be required. The methodology for removal will be reviewed throughout the lifetime of the Project and good practice at the time of decommissioning will be followed.

4-228. Where IACs remain buried, they may be cut and left in situ if this is deemed to result in less damage to the marine environment and does not cause a navigational or safety hazard for other users of the sea, and in accordance with good practice at the time of decommissioning.

### 4.9.8 Export Cable

4-229. Complete removal of export cables may be undertaken as part of decommissioning where this can be done safely and without damaging the marine environment more than leaving in situ. Where the cables are buried they may be cut and left *in situ* if this is deemed to result in less damage to the marine environment and does not cause a navigational or safety hazard for other users of the sea and in accordance with good practice at the time of decommissioning.

## 4.10 REPOWERING

4-230. Repowering offshore wind farms involves upgrading or replacing existing WTGs when the current ones have reached the end of their lifespan. The current period under the lease between the CES and the Applicant is 60 years, and the expected design lifespan of the Project is 35 years.

4-231. There may be additional time for operating the Array under the terms of the agreement between the Applicant and CES, therefore options for repowering could be considered by the Applicant in accordance with the circumstances and regime in place at the relevant time.. Repowering can be done partially or fully. Partial repowering involves upgrading each WTG, whereas full repowering involves the replacement of all WTGs, foundations, and cables.

4-232. Repowering offers a number of benefits, including delivering lower cost renewable electricity on a site with known environmental impact. It could also result in the avoidance of further site investigation work as the site has already been explored extensively, and the existing grid connections can remain in place which significantly streamlines the process of developing an offshore windfarm.

## 4.11 EMBEDDED MITIGATION

4-233. The Offshore Scoping Report (Buchan Offshore Wind Limited, 2023) presented a number of embedded mitigation measures which have been implemented within the Proposed Offshore Development design to reduce the potential for adverse impacts and likely significant effects to the environment. These measures continue to be applicable, with any additional embedded mitigation measures identified and presented throughout the EIAR.

4-234. Embedded mitigation measures and Project commitments are presented in **Volume 3, Appendix 1.1: Commitments, Mitigation and Monitoring Register**.

## 4.12 REFERENCES


6-alpha (2023). Unexploded Ordnance Tool Box Brief for grab sampling and geotechnical investigations, Buchan Offshore Wind Farm.

Ocean Infinity (2023). Environmental Survey Report. Document reference 104244-FEA-OI-SUR-ENVSURRE.

Scottish Government (2013). Planning Advice Note 1/2013: Environmental Impact Assessment. Available online: 4. Integration with Planning Procedure - Planning Advice Note 1/2013: Environmental Impact Assessment - gov.scot (www.gov.scot) (Accessed March 2024).

Scottish Government (2019). SEA of Sectoral Marine Plan for Offshore Wind Energy - Strategic Environmental Assessment Environmental Report. Available online at: https://www.gov.scot/publications/draft-sectoral-marine-plan-offshore-wind-energy-strategic-environmental-assessment/ (Accessed August 2024).

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