Chapter 5 Project Description

5.1 Introduction

1 This chapter describes the indicative design scenarios for the project and the methods likely to be adopted for the construction, operation and maintenance, and ultimately decommissioning of the proposed Neart na Gaoithe offshore wind farm development.

2 The fabrication of individual project components is not the focus of this Environmental Statement (ES) and is not considered in this document. Delivery and transport of component parts are also not assessed, as these are considered to be the responsibility of the supplier, but are described as necessary.

3 The procurement process and appointment of contractors had not concluded at the time of submission of this application and therefore construction techniques and infrastructure design are based on current understanding of existing projects and information provided by potential market suppliers. The actual method of construction may deviate from what is described; however, any deviation from that described will be within the parameters of the Rochdale Envelope for the development (refer to Section 5.4 for a description of the Rochdale Envelope approach).

4 The onshore infrastructure comprising onshore buried cables and electrical substation development will be consented under the Town and Country Planning (Scotland) Act 1997 and is described in the forthcoming onshore application and supporting ES. While details of the onshore works are not included within this document, consideration of works at, and adjacent to, the landfall are considered as part of the cumulative assessment where appropriate.

5.2 Project Location

5 Neart na Gaoithe is located approximately 15.5 km from Fife Ness and 16 km from the Isle of May. The development site lies in the outer Firth of Forth and covers an area of 105 km^2. Water depths across the site range from approximately 40 to 60 m below Lowest Astronomical Tide (LAT). The export cables are planned to run southwest from the site making landfall at Thorntonloch beach to the south of Torness Power Station. Figure 5.1 shows the location of the site. The boundary co-ordinates of the offshore site are given in Table 5.1.

Easting UTM30N	Northing UTM30N	Longitude (degrees decimal minutes)	Latitude (degrees decimal minutes)
551736	6234720	002° 9.898' W	056° 15.271' N
552458	6229999	002° 9.255' W	056° 12.721' N
547554	6229998	002° 13.998' W	056° 12.752' N
545182	6229999	002° 16.293' W	056° 12.766' N
541685	6234997	002° 19.628' W	056° 15.479' N
541238	6235637	002° 20.055' W	056° 15.827' N
541026	6238611	002° 20.232' W	056° 17.430' N
543465	6242941	002° 17.826' W	056° 19.752' N
544801	6243993	002° 16.518' W	056° 20.312' N
546461	6243751	002° 14.910' W	056° 20.171' N

Table 5.1: Site co-ordinates

6 The exact route of the export cables has not been confirmed but co-ordinates for the centre line of the cable corridor, in which the dual export cables are proposed to be located, are detailed in Table 5.2.

Easting UTM30N	Northing UTM30N	Longitude (degrees decimal minutes)	Latitude (degrees decimal minutes)
543003	6233007	002° 18.370' W	056° 14.400' N
538912	6202174	002° 22.600' W	055° 57.800' N
538783	6202143	002° 22.724' W	055° 57.784' N
538522	6202080	002° 22.975' W	055° 57.751' N
537831	6201914	002° 23.641' W	055° 57.665' N

Table 5.2: Co-ordinates for centre line of cable corridor

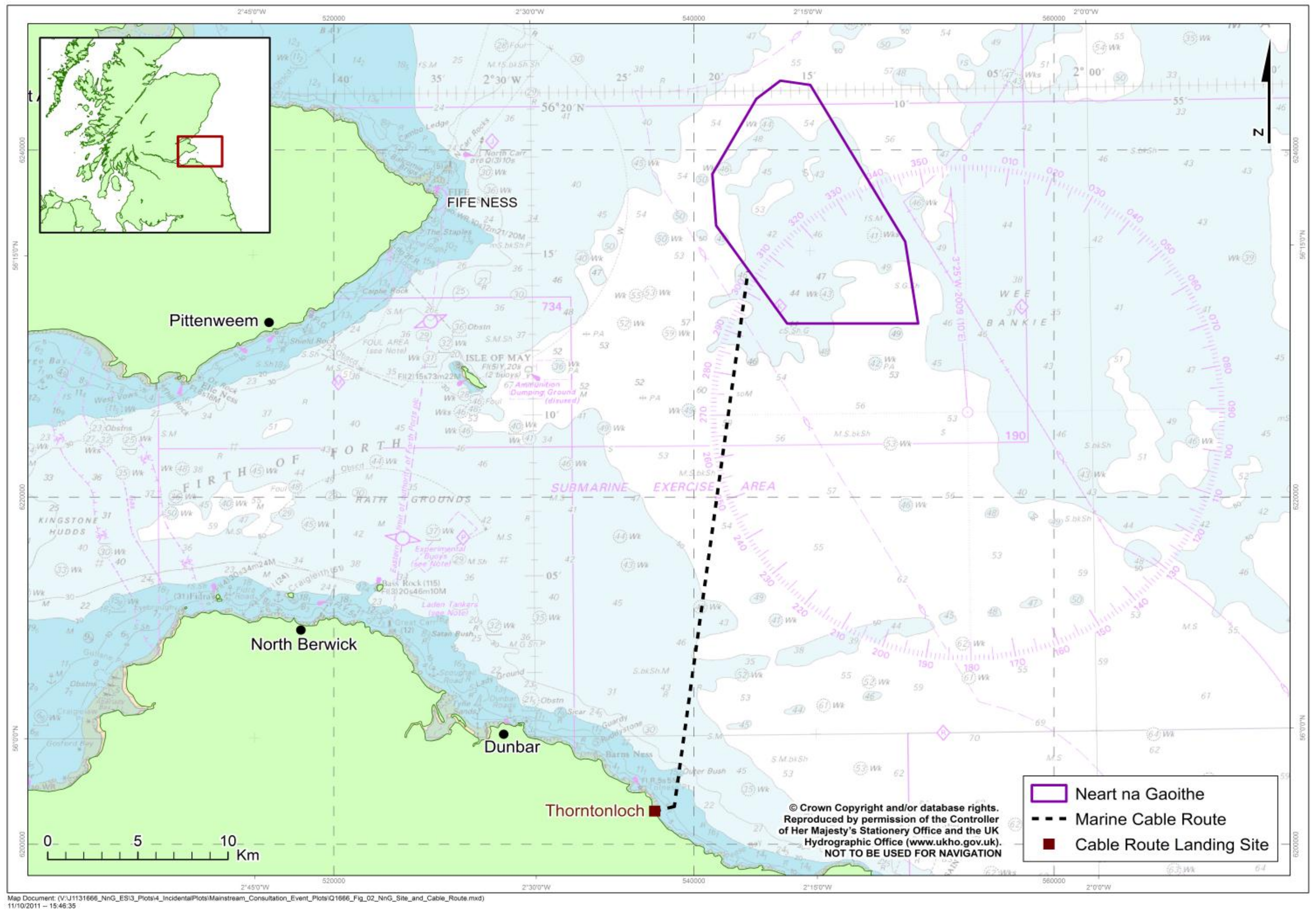

Figure 5.1: Location of Neart na Gaoithe offshore wind farm

5.3 General Project Programme

7 The precise details of the construction programme and sequence are not yet confirmed. An indicative project installation schedule is shown in Table 5.3. This is based on project consent being achieved in the first quarter (Q1) of 2013 which will then permit funding commitment for detailed investigations to be completed in summer 2013. This in turn will allow the necessary follow-on design and fabrication activities to be programmed in advance of installation dates shown. If the geotechnical investigation is not completed in 2013, these dates are likely to slip by about one year. In addition, it is important to note that the indicative durations detailed in Table 5.3 assume no weather or other unforeseen delays. Should it be necessary to suspend works for any reason the final completion dates cannot be guaranteed.

Component installation	Start date	Duration	Completion
Foundations	March 2015	16 months	July 2016
Export cable	March 2015	9 months	December 2015
Substation (s)	March 2015	9 months	December 2015
Turbines	September 2015	12 months	September 2016
Inter-array cabling	September 2015	12 months	September 2016

Table 5.3: Indicative offshore construction schedule

8 The main construction phases and likely sequence (with significant overlaps between phases) are as follows:

- Site preparation for foundations, including levelling or pre-piling operations;
- Installation of foundations;
- Concurrent site preparation for inter-array cabling;
- Site preparation for offshore substation;
- Installation of substation;
- Installation of export cables (concurrent trenching and installation);
- Installation of inter-array cables;
- Installation of wind turbines; and
- Commissioning and energy export.

9 Offshore works are planned to be carried out all year round with the majority of works likely to be performed in the spring and summer months to take advantage of more benign offshore conditions. The overall construction period of the wind farm is likely to be approximately two years.

10 The offshore construction strategy is likely to make use of the following vessel types:

- Dynamic positioning (DP) floating vessels;
- Jack-up barges; and
- Support vessels.

5.3.1 Safety Zones

11 Neart na Gaoithe Offshore Wind Farm Limited (NnGOWL), hereafter known as 'the developer' will apply for a notice declaring safety zones around the wind turbines, foundations and offshore substation platform(s) during construction and thereafter for maintenance works. The safety zone notice will be applied for under Section 95 of the Energy Act 2004 in accordance with Schedule 16 of the Energy Act 2004 and the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007. The safety zone will have a radius of 500 m from the outer edge of the proposed wind turbine. The safety zones will limit all non-project vessels from entering the safety zones, as discussed in 5.10.1.

12 From time to time during the construction programme and in consultation with the regulators, the developer may issue Notices to Mariners (NtM) suggesting advisory safety zones in addition to that covered by the safety zone notice to accommodate installation vessels with larger anchor spreads. NtM will also be issued suggesting advisory safety zones in respect of the cable installation works. This is to protect both the construction vessels and other vessels using the surrounding area.

5.4 The Rochdale Envelope Approach

13 Due to ongoing uncertainties as to the precise nature of the ground conditions and the commercial sensitivities associated with the procurement process, it is not possible to finalise the exact layout, location and design of the offshore infrastructure prior to applying for consent.

14 Marine Scotland recognises the difficulty in defining the project in sufficient detail and has made provision to accept a more flexible approach whereby the development details are described within the bounds of the 'Rochdale Envelope', which describes the minimum and maximum parameters of the development to allow an evaluation to be carried out. A description of the Rochdale Envelope Approach is presented in Chapter 6: The Approach to Environmental Impact Assessment.

15 In the October 2011 edition of the Marine Strategy Forum Quarterly Update[1] it is stated that:

"Work is underway in consultation with the offshore wind industry and Scottish Natural Heritage (SNH) to produce a Scottish Government policy/guidance document on the Rochdale Envelope for developers in Scotland. The 'Rochdale Envelope' is an approach which tries to address some of the issues associated with large scale offshore wind projects where, due to the scale, type, timescales, or other factors, there remain limitations in the amount of detail that is available on the project at the time at which consent is being sought. This has been identified as being of particular importance to offshore wind applications in Scottish Waters where a number of factors remain to be resolved. This document is due for completion in the near future."

16 The final design description will not be confirmed until consent has been granted and the procurement process has concluded. Further details on the Rochdale Envelope approach are detailed in Chapter 6: The Approach to Environmental Impact Assessment.

[1] http://www.scotland.gov.uk/Resource/Doc/295194/0122748.doc

17 The range of options considered for the Neart na Gaoithe offshore wind farm development is described in detail in this chapter, but in summary comprise:

- Up to 125 wind turbine foundations, of either jacket or gravity base structure plus ancillary equipment such as J-tubes and access facilities. There is the possibility that scour protection may be required particularly if gravity based foundations are used (refer to Section 5.5.2);
- Up to 125 wind turbines[2] between 3.6 MW and 7 MW capacity (refer to Section 5.6.1);
- Up to two offshore substations (including foundations) housing electrical infrastructure and potentially facilities for operation and maintenance (refer to Section 5.7.1);
- Between 85 km and 140 km of inter-array cables (refer to Section 5.7.2);
- Scour protection on certain areas of the subsea cabling as required (refer to Section 5.7.2);
- Two export cables (refer to Section 5.7.3); and
- Ancillary equipment as necessary, including access facilities and J-tubes (refer to Section 5.8).

18 The chapter is structured in the above order with the infrastructure being described first, then the installation techniques, likely maintenance requirements and finally, decommissioning options. The project design parameters, the Rochdale Envelope, are presented in an overview table in Section 5.15: Neart na Gaoithe Rochdale Envelope.

19 Terrestrial infrastructure will be consented separately and will include:

- Transition pit beyond the high water mark;
- Transmission cabling from the transition pits to the electrical substation; and
- Electrical substation.

20 Meteorological or anemometry masts (met masts) are installed on site to measure wind speed and direction over a given period of time.

21 It is currently planned for an offshore meteorological mast to be installed in 2013 with potential for an additional two masts to be installed at a later date. The design parameters of the meteorological mast are detailed in this chapter but are subject to a separate consent application which will be submitted prior to any construction works commencing.

22 The met masts are estimated to be between 103 m and 115 m high (with respect to LAT). There will be an anemometer to measure wind speed and direction mounted on the top of each mast. Additional instrumentation will include sensors to measure wave height and direction, sea temperature and salinity, and structural response data. An example met mast is shown in Figure 5.2.

23 The foundation option for the met masts is not yet confirmed. Detailed site investigations are planned for 2012 and 2013 which will provide additional information on the localised area which will influence the foundation type selection. All available information will be included in the met mast application documents in support of the consent application.

24 Another option being considered for the project to supplement data obtained from a met mast is the Light Detection and Ranging (LiDAR) technology, which can be used to measure wind speed and direction without the need to erect a met mast. LiDAR units comprise a floating buoy on which meteorological instruments are mounted to obtain wind speed and directional data. These instruments use infrared light beams to measure the wind speed and direction at a determined height using the Doppler shift in the reflected signal. An illustration of a typical floating LiDAR structure is given below in Figure 5.3.

[2] The term 'wind turbine' as used in this document is defined to mean the complete tower, nacelle, hub and blades

Figure 5.2: Example met mast at Hornsea offshore wind farm (Source: SMart Wind)

Figure 5.3: Typical floating LiDAR structure with mounted meteorological recording instruments (Source: Subsea World News 2011)

5.5 Foundation Options

25 Gravity base foundations and steel jacket foundations are considered to be the most appropriate foundation designs for both the wind turbines and the substation(s) in the prevailing site conditions. Chapter 4: Site Selection, Project Alternatives and Design Evolution describes other foundation concepts that were discounted.

5.5.1 Foundation Installation

26 The general sequence of foundation installation is broadly similar for both gravity base and jacket foundations. The installation sequence is shown in the flow chart in Figure 5.4. Ballast will not be necessary for jacket foundations.

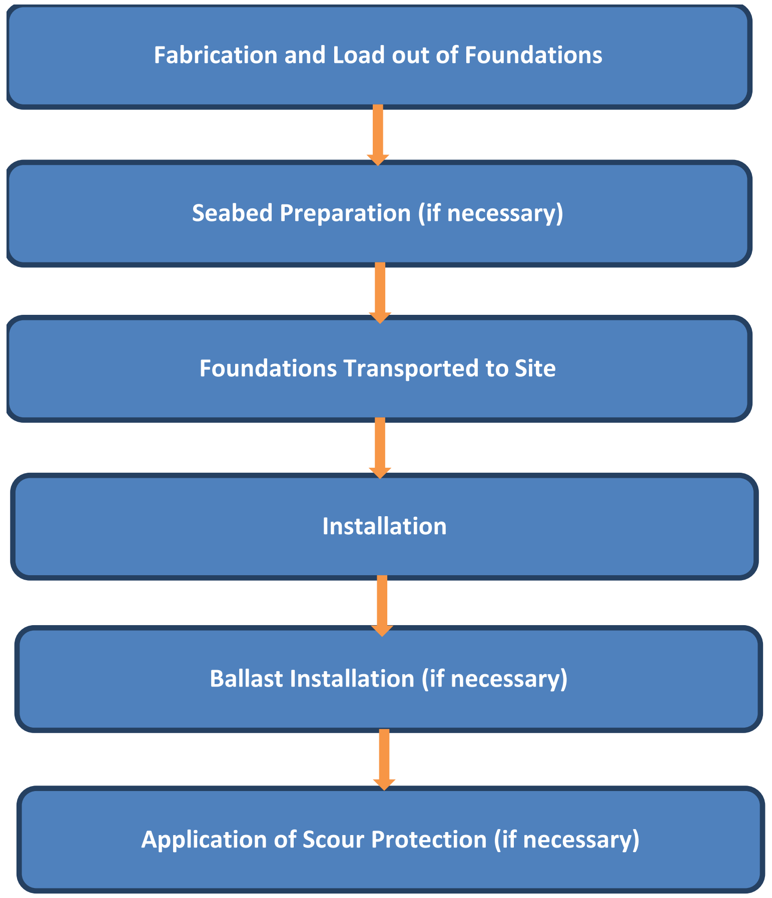

Figure 5.4: Flow chart illustrating generic foundation installation sequence

5.5.2 Gravity Base Foundations

27 Gravity base foundations are constructed from reinforced concrete and are generally conical in shape. The foundation is held in place by both the weight distribution of the structure and by the downward force of gravity and as a result requires no drilling or piling to hold the foundation in place.

28 The concept can have various designs, including solid concrete, and hollow concrete caisson with a circular (refer to Figure 5.5 and Figure 5.7) or cruciform (cross) shaped base (refer to Figure 5.6). The perimeter of the base may include "skirts" i.e., a perimeter wall which is designed to enhance the embedment of the gravity base foundation by penetrating the seabed. Where the design includes a skirt, there may be less seabed preparation required, however internal grouting of the gap between the seabed and the underside of the base may be necessary.

29 Preliminary site investigations indicate that gravity base foundations are widely applicable throughout the site. Future geotechnical investigations conducted within the project area will help refine structural design parameters and may indicate some areas where small location changes (micrositing) are necessary.

30 Numerous examples of the use of gravity base foundations in deep waters are to be found in the oil and gas sector. Examples of gravity base foundation being used in the offshore wind sector include Thornton Bank Offshore Wind Farm in Belgium and Vindeby Offshore Wind Farm in Denmark.

Figure 5.5: Circular hollow concrete gravity base (Source: Gravitas Offshore Ltd)

5.5.2.1 *Dimensions of the Gravity Base Foundations*

31 The dimensions of the gravity base foundation are dependent on the size of turbine which is to be installed and the specific site conditions of the final location. It is likely that the dimensions of the gravity base foundations will vary throughout the project because of the variations in water depth and ground conditions at turbine locations. Table 5.4 details the likely dimensions of a gravity base foundation on Neart na Gaoithe. Dimensions are provided for both gravity base foundation with a circular footprint and a cruciform footprint. The dredging volumes shown assume that no skirt is used. The use of a skirt will be evaluated in detailed design and dredging volumes are likely to reduce if adopted.

	3.6 MW turbine	4.1 MW turbine	6 MW turbine	7 MW turbine
Foundation footprint diameter (m)	20 - 30 m	20 - 30 m	25 - 45 m	25 - 45 m
Foundation footprint cross dimensions (cruciform option) (m)	20 - 30 by 5 - 7 m	20 - 30 by 5 - 7 m	30 - 40 by 5 - 7 m	30 - 40 by 5 - 7 m
Area of foundation footprint (m^2)	300 - 700 m^2	300 - 700 m^2	490 - 1600 m^2	490 - 1600 m^2
Seabed preparation	Dredging in areas where loose sand or soft clay present at seabed plus gravel placement in area of dredging to provide a stable platform for foundation.			
Quantity of material dredged	Average of 1,500 m^3 dredged per foundation. Approximately 190,000 m^3 of material dredged over entire site.		Average of 4,000 m^3 dredged per foundation. Approximately 320,000 m^3 of material dredged over entire site.	
Disposal of dredged material	Dredged material will be disposed of at a licensed disposal area.			
Gravel bed	Minimum 530 m^3 per foundation, Maximum 1850 m^3 per foundation			
Depth of gravel bed	The gravel beds will be an average of 1.5 m deep. In areas of very soft sediment gravel bed could be up to 4 m deep, this is expected to be the case in less than 5% of turbine locations.			
Extension of gravel bed beyond foundation perimeter	2 – 4 m	2 – 4 m	2 – 4 m	2 – 4 m
Foundation material	The gravity base structure will be reinforced concrete. This will be filled with a ballast of sand which has been dredged from the turbine location in seabed preparation and sand/gravel which has been sourced from a licensed dredging area.			
Foundation installation duration	Dredging 4 - 7 days, gravel bed placement 4 - 7 days, foundation placement and filling 4 - 7 days scour protection placement 7 - 14 days.			
Scour protection and footprint size (m)	Scour protection extends 5 - 8 m outside foundation perimeter.			

Table 5.4: Gravity base foundation parameters

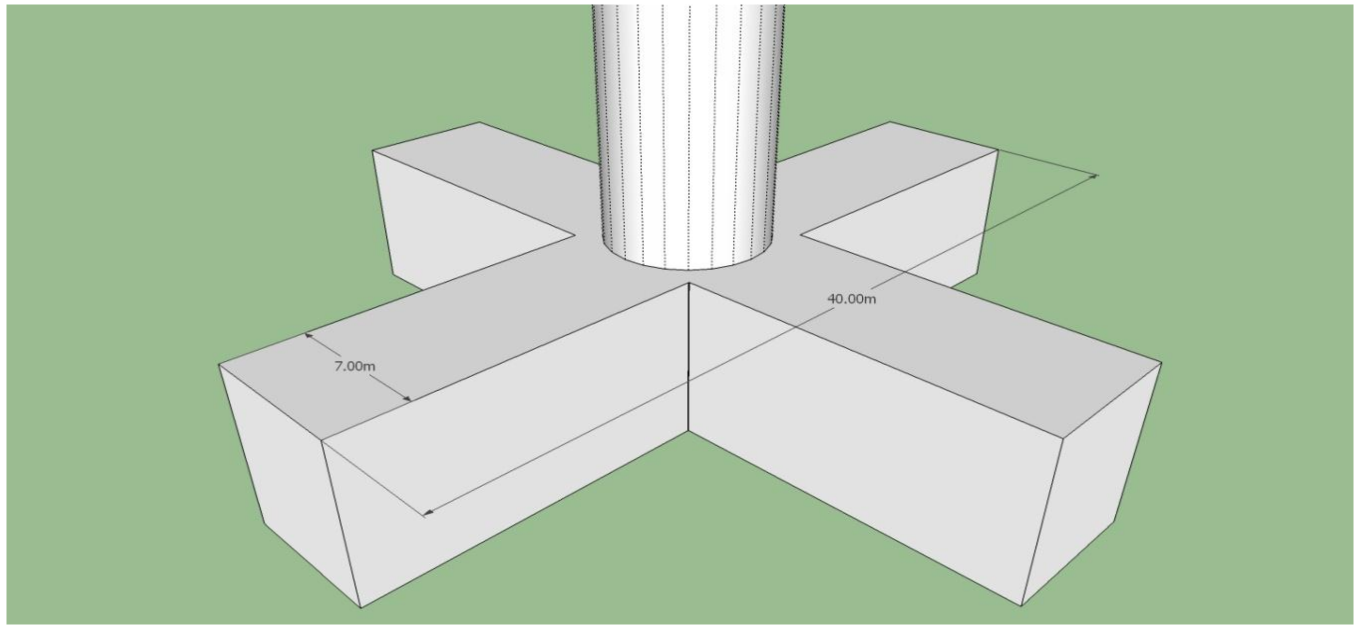

Figure 5.6: Cruciform foundation with dimensions of 40 m by 7 m

32 The approximate amount of material required for a concrete gravity base foundation is:

- Concrete: 2,000 to 5,000 m^3;
- Ballast (dense gravel/sand): 5,500 to 12,500 m^3; and
- Scour protection: 730 – 1,590 m^3.

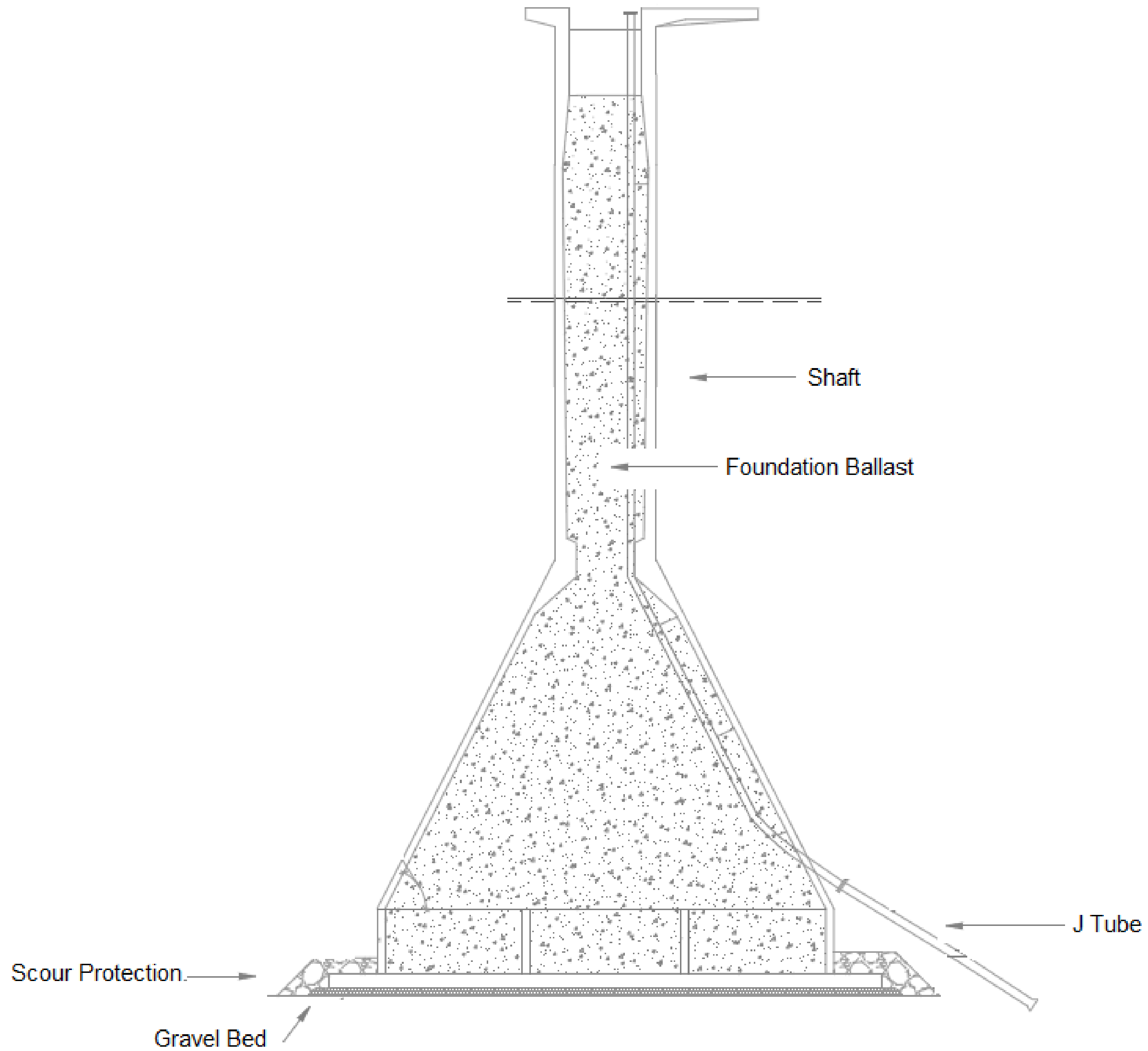

Figure 5.7: Components of a circular base gravity base foundation

5.5.2.2 *Installation of Gravity Base Foundation*

33 Depending on weather and physical site conditions, the complete installation process could take between 19 and 35 days to install each gravity base foundation (refer to Table 5.5). A breakdown of the maximum anticipated durations at each stage of the process is shown below. It should be noted that these stages utilise different vessels as described below, and when one operation is completed at a given foundation location, the vessel will move to the next location for commencement of the same operation there.

Phase	Anticipated duration
Dredging and gravel base placement	8 -14 days
Foundation placement and filling	4 -7 days
Scour protection placement	7 - 14 days

Table 5.5: Maximum anticipated durations of each stage

Step 1: Fabrication and Load Out

34 The gravity base foundations will be fabricated and constructed onshore, with temporary storage located onshore or offshore depending upon logistical considerations. At the time of submission, the fabrication and load out areas have not been confirmed. Onshore impacts associated with fabrication of the bases are not considered within this ES.

Step 2: Seabed Preparation

35 Gravity base foundations generally require some degree of seabed preparation. The extent of works is dependent on seabed conditions at each location and the design of the gravity base foundation; those foundations with skirts will require less seabed preparation. As a result, there will be varying degrees of seabed preparation across the site. The following sequence is broadly that which may be necessary for each foundation position.

36 Depending on the design adopted, the seabed may need to be levelled if the seabed slope is in excess of approximately 1 degree. Any loose, soft or otherwise compressible sediment present at the surface may need to be removed by dredging. Dredging of loose sand/soft clay can be achieved using industry standard suction dredgers (similar to that shown in Figure 5.8). More dense or stiff soils can be removed using grab excavation (refer to figure 5.9). Dredging vessels typically have a capacity to extract 20,000 to 30,000 tonnes per sailing. The dredged material will be recovered to the surface, and stored on the dredging vessel or on a holding barge before transfer to a licensed disposal area.

Figure 5.8: Dredging vessel – suction dredger (Source: DEME Group)

37 All dredged material will be disposed of at a licensed disposal site(s).

38 The process of dredging using a suction dredger is expected to involve the following procedure:

- When arriving at the turbine foundation location, the speed of the suction dredger is reduced, the draghead(s) is/are lowered to the sea bottom and dredging commences;
- The suction dredger takes up a mixture of water and sediments through the draghead(s) and suction pipe and pumps the mixture into the hopper well. The hopper well is an onboard chamber or reservoir which holds the dredged material;
- The dredged sediment will then settle in the hopper, naturally separating from the water. The decanted water is discharged through the adjustable overflow system. It should be noted that the water decanted via the overflow may contain a fraction of fine material;
- When the draught of the vessel reaches the dredging loading mark (by instrumentation onboard) or when circumstances do not allow for further loading (i.e., depth limitations), dredging will stop and the suction pipe hoisted on deck. Once the vessel is secured it transits to the discharge site;
- Upon arrival at the licensed disposal site, the suction dredger is able to maintain a fixed position if required using its onboard DP system;
- When the hopper is in position for discharge, the bottom valves/doors are opened. This technique allows for immediate discharge of the dredged sediment; and
- Upon completion of discharge, the hopper is cleaned and the bottom doors closed for departure to continue the cycle.

39 It may prove more efficient for the dredger to remain on site and transfer dredged material to a barge which will be used to transport it to the disposal site. A typical dredging and gravel bed laying operation will require up to six vessels; a primary dredging vessel plus up to two supporting vessels (one safety vessel and one support/survey vessel), and a primary gravel bed vessel plus up to two supporting vessels. It is likely that dredging and gravel bed laying operations will be undertaken concurrently at different foundation locations leading to a maximum of 12 vessels to be on site in total during these activities.

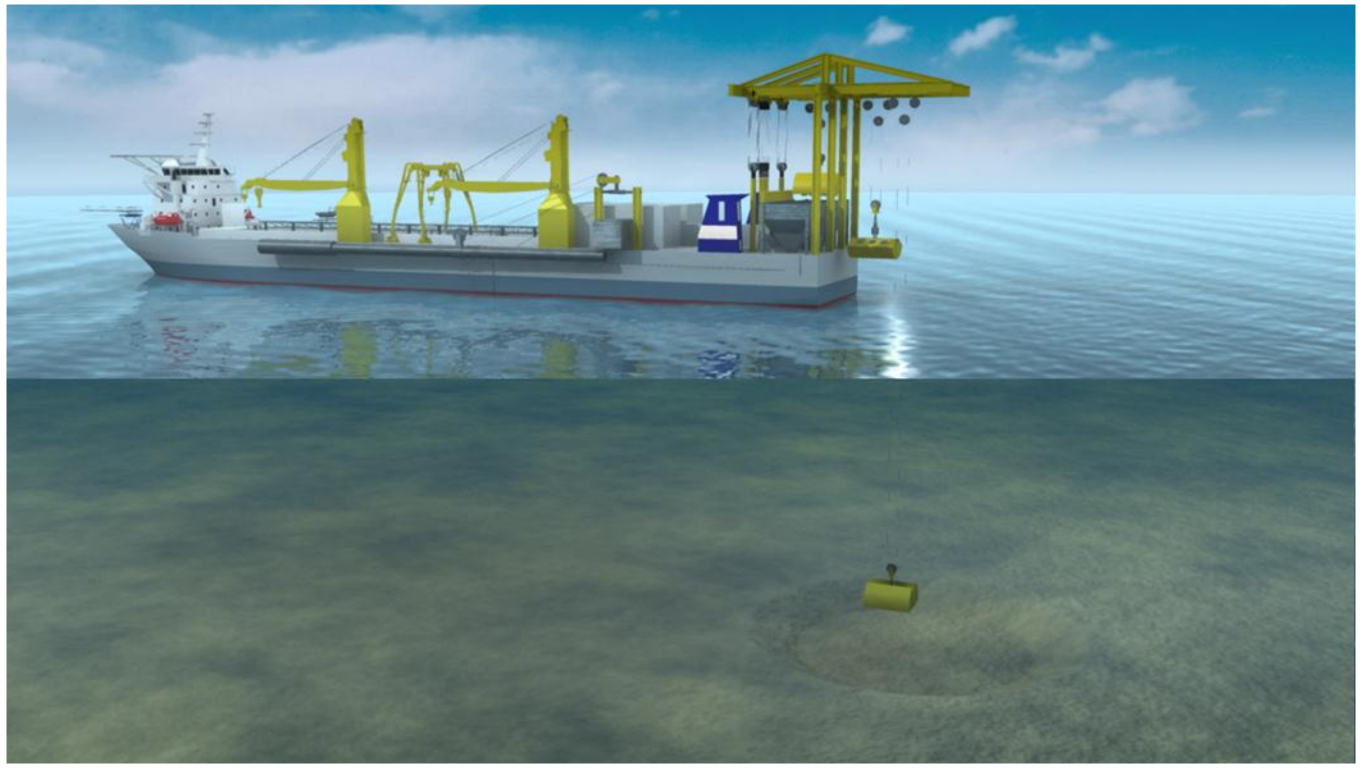

Figure 5.9: Seabed dredging by grab excavation for gravity base foundation (Source: Strabag Offshore Wind GmbH)

40 Site preparation is concluded by installing a suitable load bearing base which typically is made up of graded gravels. This base layer could extend up to 4 m beyond the perimeter of the gravity base foundation to aid stability and placement. Indications suggest that between 1,100 and 2,200 m^3 of gravel will be necessary per foundation to create this base layer. Specialist rock placement vessels similar to that shown in Figure 5.12 for scour protection placement will be used for gravel bed placement. In this phase of the operations, the gravel bed placement vessel will be accompanied by up to two support vessels.

41 To prevent back fill of soft sediments prior to the placement of the graded base it is likely that dredging and base layer placement activities will take place in immediate sequence.

Step 3: Transportation of Foundation to Site

42 The foundations will be transported individually to the installation site by a barge or transport vessel either directly or via a staging port. Alternatively if the design allows, the foundations may be floated to their final site location.

43 A typical foundation transportation operation will require four vessels; a primary vessel plus three supporting vessels/barges/tugs. It is likely that transportation barges will be operating concurrently on site along with dredging and container vessels.

Step 4: Foundation Installation

44 Installation of individual gravity base foundations commences with the controlled sinking of the foundation to settle on the pre-prepared base layer. A Remotely Operated Vehicle (ROV) is used for surveillance to ensure proper placement. Lifting and lowering will be required if a sheerleg barge is used. A sheerleg barge is one which uses a fixed crane, generally at the stern of the vessel. The sheerleg generally allows heavier lifts due to a simplified crane mechanism (i.e., no rotation), in comparison to standard cranes. A typical sheerleg barge (in this case lifting a substation topside) is shown in Figure 5.10. The sheerleg barge would be supported by up to three additional vessels including tugs.

45 If the gravity base foundation is floated to site it will be filled with water when arriving at the installation location to effect a controlled sinking onto the prepared bed. If installed from floating mode up to three vessels will be used to maintain the gravity base positioning.

46 The gravity base placement process is expected to take up to 12 hours per foundation.

47 If the design includes a perimeter skirt, internal grouting of any gap between the seabed and the base may be carried out as the final installation operation. A calcium silicate water mix will be used as the grout material and the volume used in this operation will depend on the seating on the seabed. The grout will be introduced via pipes into an area completely sealed by the gravity base skirts and there is therefore no risk of release of grout into the marine environment. This operation, if required, is expected to take up to 12 hours.

Figure 5.10: Sheerleg barge Taklift transporting substation topside (Picture courtesy of CG. Copyright ®vanoordbv-mennomulder.com)

Step 5: Ballast Installation

48 The ballast, sand or gravel, to be used in the foundation will usually be mixed with water so that it is suitable for hydraulic pumping. It will be pumped into the foundation using a vessel equipped with a filling tower for this purpose; Figure 5.11 illustrates a vessel with this capability. The ballast installation vessel will be supported by up to two support vessels.

Figure 5.11: Schematic of vessel used for filling gravity base foundation (Source: DEME Group)

Step 6: Scour Protection

49 Depending on local conditions, gravity base foundations may require some scour protection. A layer of scour protection between 1 to 1.5 m thick will be laid where necessary around the gravity base. This layer is likely to extend from 5 to 8 m from the outer edge of the base plate perimeter. The scour protection will be placed as soon as possible after placement of the gravity base foundation.

50 There are several material types used to provide scour protection to foundations and cables which include:

- Durable crushed or original rock of defined size range;
- Artificial fronds or seaweed;
- Concrete 'mattresses'; and
- Bags (high strength nylon fibre) of gravel, hardened sand-cement grout or concrete (grout/concrete pre-filled and hardened onshore). The bag option may include a technique where the grout is introduced to the nylon fibre bag offshore through proprietary pipes (the bags being permeable to water but not to grout).

51 The amount of scour protection to be confirmed in the final design is dependent on the mobility of the seabed. Preliminary calculations have indicated that if unbound rock is used, the rock particle size is expected to have a median diameter of 100 mm. The expected volume of scour protection is between 730 – 1,590 m^3 per foundation.

52 If unbound rock is used, placing of the scour protection can be performed by a fall pipe, wire crane with grab or by rock-dumping. Figure 5.12 illustrates a fall pipe installing scour protection around a gravity base foundation. Alternatively, a crane may be used to lower scour protection into position where bags of gravel, grout or concrete are deployed and where a fall pipe is not suitable.

53 Scour protection installation is expected to take 7 - 14 days per location. The scour protection installation vessel will be accompanied by up to two support vessels.

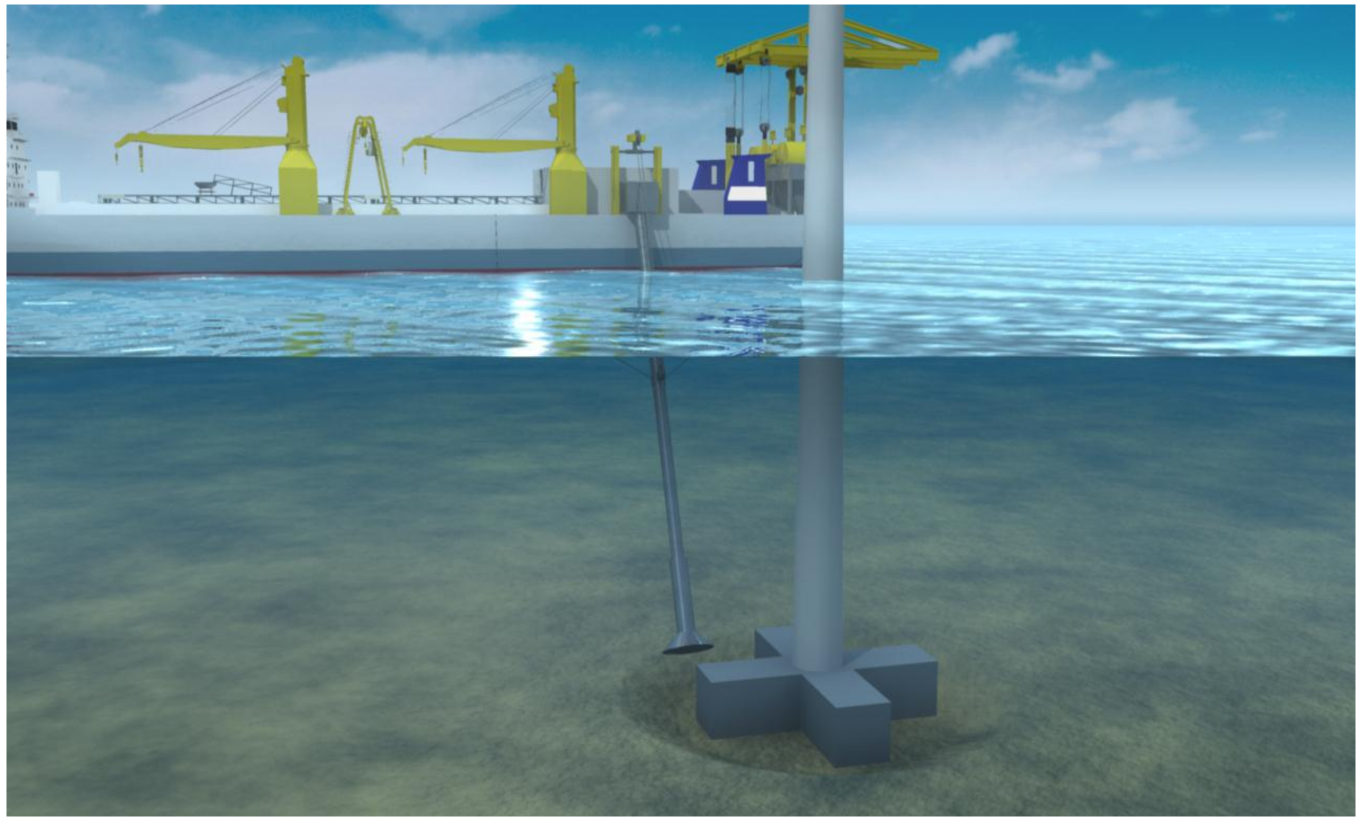

Fig 5.12: Installation of scour protection around cruciform shaped gravity base foundation (Source: Strabag Offshore Wind GmbH)

5.5.2.3 Noise Emissions during Gravity Base Foundation Installation

54 The effects of noise impacts on biological receptors are discussed in Chapter 12: Ornithology, Chapter 13: Marine Mammals, Chapter 14: Benthic Ecology and Chapter 15: Fish and Shellfish Ecology. Installation of gravity base foundations generates very little noise as no piling is required and the foundation sinks to the seabed under its own weight.

5.5.3 Steel Jacket Foundations

55 Steel jacket foundations are formed of a steel lattice construction comprising tubular steel members and welded joints and are fixed to the seabed using piles below each leg of the jacket (refer to Figure 5.13). Typically piles are of hollow steel and are drilled or driven up to 50 m into the seabed sub-strata, relying on the frictional and end bearing properties of the seabed for support. Examples of steel jackets being used in the offshore wind sector include Beatrice Wind Farm Demonstrator Project, Ormonde Wind Farm in the Irish Sea and Alpha Ventus in the German sector of the North Sea.

56 In addition, jacket foundation structures may also have working and intermediate platforms, boat landing facilities and external J-tubes in which the export cables will be housed. Jacket style foundations are considered to encompass both three and four legged conventional jackets and twisted jackets.

5.5.3.1 *Dimensions of Steel Jacket Foundations*

57 The dimensions for the key design elements of the jacket foundations are presented in Table 5.6.

	3.6 MW turbine	4.1 MW turbine	6 MW turbine	7 MW turbine
Jacket leg spacing at seabed level (m x m)	15x15 - 25x25	15x15 - 25x25	20x20 - 30x30	25x25 - 35x35
Details of seabed preparation	A seabed template with up to 4 legs (max leg spacing 35 m by 35 m) will sit temporarily on the seabed during pile installation.			
Foundation diameter (m) (piles)	2.5-3.5	2.5-3.5	2.5-3.5	2.5-3.5
Number of piles per foundation	3 or 4	3 or 4	3 or 4	3 or 4
Foundation bed penetration depth (m) (piling)	15 - 40	15 - 40	20 - 50	20 - 50
Foundation installation method	Approximately 3% of piles will be driven only, 7% of piles will be drilled only. 90% of piles will be driven-drilled. Of these an average of 30% of the pile will be driven and 70% drilled.			
Foundation installation duration (per foundation) (hours)	Piling (62-180 hours for 4 piles), jacket installation (12-24 hours). This includes time for setting up and changing equipment between piling locations.			
Total seabed occupied by jacket (piles, legs and scour protection) (m^2)	Approximately 225 m^2			

Table 5.6: Dimensions for the key design elements of the jacket foundations supporting turbines

58 The typical amounts of material per jacket foundation are:

- Jacket: 200 to 1,000 tonnes (steel);
- Piles (3 or 4): 300 to 700 tonnes per pile (steel);
- High strength grout for fixing jacket to piles: 10 to 30 m^3 per foundation; and
- Cementitious grout in annulus of drilled piles: 20 to 115 m^3 per pile.

59 The grout used in the annulus of drilled piles and for fixing the jacket to the piles is expected to be high strength anti-washout grout, such as GW80. This is a blend of ingredients including Ordinary Portland Cement, selected pulverised fuel ash and a polymeric additive. The setting time of the grout is approximately 5 hours.

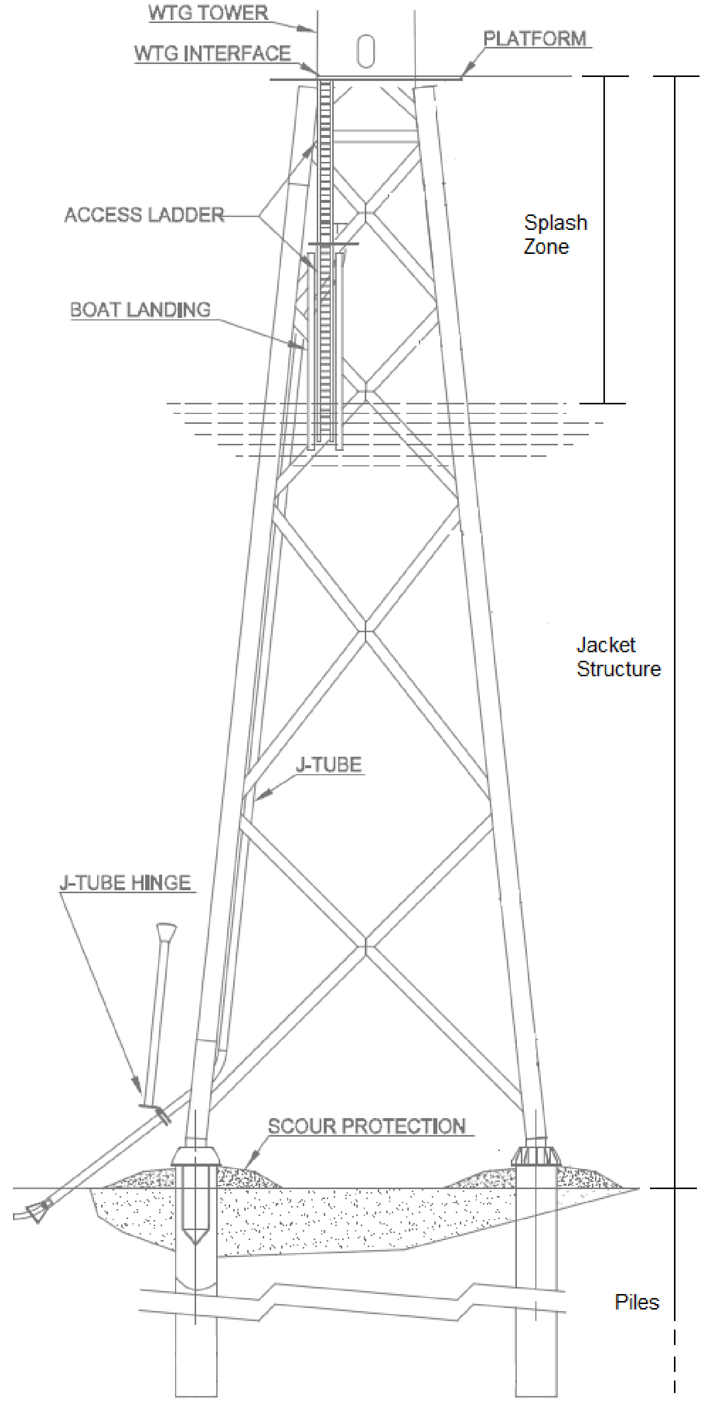

Figure 5.13: Typical jacket foundation[3]

[3] In this diagram, WTG refers to wind turbine generators

5.5.3.2 Steel Jacket Foundation Coating and Protection

60 It is likely that the jacket foundations will require cathodic protection to prevent corrosion.

61 Usually this takes the form of galvanic anodes; these are usually affixed during the fabrication process to parts of the jacket that will be submerged when installed in the final location. A typical arrangement is shown on Figure 5.14 below:

Figure 5.14: Anodes affixed to jacket members (source: Keystone)

62 In addition to this protection, the area of the foundation between the splash zone and the wind turbine tower may also be protected with the following coatings during fabrication:

- Zinc primer applied preferably as a thermal spray;
- A silicon epoxy resin sealant;
- A coating of two-part liquid epoxy coating; and
- A final coat consisting of polyurethane, is applied by brush or spray, and is normally moisture curing and drying if solvent free.

63 All coatings/paints used will be suitable for the marine environment and will conform to the provisions of ISO 20340 and Norsok M-501 standards.

5.5.3.3 Installation of Jacket Foundations

Step 1: Fabrication and Load Out

64 The jacket foundations will be fabricated at an as yet unidentified onshore base. Once fabricated the jackets with transition pieces (refer to Section 5.8.3) attached will be transported to the project site aboard either a transport barge or vessel, or on the installation vessel.

Step 2: Seabed Preparation

65 Seabed preparation necessary for piling and jacket placement is minimal and at worst will comprise removal of problem debris or levelling by dredging.

Step 3: Transportation to Site

66 As discussed above, the fabricated jacket foundations will be transported from the onshore base to the wind farm site. This may be carried out by means of a transport barge, in which case additional installation vessels will be required for installation. Alternatively, this may potentially be carried out using a suitably equipped single vessel capable of both transport and installation. In this case, it may be possible to transport multiple jacket foundations using a single vessel. An illustration of such a vessel is provided in Figure 5.15 below. The precise method of transportation to site has not been confirmed at the time of writing.

Figure 5.15: Transportation and installation vessel concept (Source: W3G Marine 2012)

Step 4: Foundation Installation

67 Once at site the jackets will be lifted by crane barge, appropriately orientated and placed either on pre-installed piles in the seabed or directly on to a prepared seabed in the case where piles are not pre-installed. A jack-up platform or floating vessel will be used to install the piles and jacket. Jack-ups require a footing on the seabed. To increase the footing area, and hence reduce bearing pressure on the seabed surface, the jack-up may use spud cans. Spud cans are essentially conical shaped plates fixed to the bottom of the jack-up legs. The diameter of the spud cans will vary depending on the jack-up barge and soil conditions, although a typical spud can diameter is approximately 8 m. Depending on the pile spacing the jack-up may need to be relocated more than once to complete the full foundation (piles + jacket) structure. Table 5.7 provides indicative details of such activity. The installation barge will require up to three support vessels. If a jack-up barge is used it is likely that anchors will be used to maintain position; the maximum expected anchor spread of a jack-up is 1 km. It is possible that up to four jack-ups will operate on site at any one time.

Component	Minimum	Maximum
Jack-up moves per foundation installation	1 (pile installation) 1 (jacket installation)	3 (pile installation) 1 (jacket installation)
Leg spacing of jack-up (m)	50x50	100x100
Number of spud cans	4	8
Spud can footing area (m^2) (per spud can)	1 (leg area without spud can)	106
Number of anchors	0 (position on DP only)	8
Anchor mooring length	200 m	1,200 m

Table 5.7: Jack-up platform details

Figure 5.16: Jack-up barge installing seabed template (source: Fugro Seacore)

5.5.3.4 Piling

68 The jacket can be pinned to the seabed in one of two ways:

- Using pre-installed piles installed with the use of a seabed template (as shown in Figure 5.16); and
- Installation of piles after the jacket foundation placement by either:
  - Installing piles through special footplates on each leg of the jacket; or
  - Installing the piles through the legs of the jacket.

69 Owing to the nature of the seabed sediments at the site and the presence of shallow bedrock, there are three main installation methods that could be used for the piles at Neart na Gaoithe:

- Driven only pile - driving with a hydraulic hammer;
- Driven and drilled pile - the 'drive–drill-drive' method (as shown on Figure 5.18 below) where successive driving and drilling phases are used; and
- Drill only pile - drilling out the entire hole for the pile and subsequently grouting the pile in (as shown on Figure 5.19).

70 The ground conditions at each location will dictate the method that will be used for each foundation. Preliminary geotechnical investigations of the seabed suggest that:

- Approximately 3% of piles will be driven only (where bedrock depth below seabed is more than the designed pile length);
- 7% of piles will be drilled only (where bedrock depth is very shallow); and
- 90% will be driven - drilled (where bedrock is at an intermediate depth and/or the bedrock is highly fractured), of these an average of 30% of the pile will be driven and 70% drilled.

71 Future geotechnical investigations will refine these estimates.

72 The 'driven only' piles will be installed without generating any arisings or rock fragments. The 'driven-drilled' piles will generate rock fragments during the drilling element of this process. As these rock fragments are generated, they will be mixed with seawater and drawn into the inlet of a hydraulic chute at the drillhead. This will then be discharged from deck level on the supporting vessel and dispersed over the sea surface, as depicted in Figure 5.17 below (Fugro Seacore 2012). It is anticipated that guar gum will be used in drilling. Guar gum is used in drilling due to its ability to suspend solids; it regulates the viscosity of mud solution, and stabilises and regulates the flow properties of the drilling muds. Guar gum is a natural product[4] that is biodegradable, has no bioaccumulation potential and is not a persistent, bioaccumulative, toxic (PBT) substance. Guar gum has little or no environmental impact. As is normal practice, the suspension of guar gum, water and fine rock particles will be discharged into the adjacent sea and the fine rock particles will settle out on the seabed.

[4]Guar gum is an extract of the guar bean ground into a powder which forms a paste when mixed with water.

Figure 5.17: Rock fragment dispersal process (Source: Fugro Seacore 2012)

73 The drill only piles will be installed by first drilling a socket (hole) into the bedrock that is of a slightly larger diameter than the steel pile to be installed. As with the driven and drilled piles, the suspended material will be discharged into the adjacent sea, as described above. The volume of material to be discharged will be equal to the internal volume of the each pile below sea floor level. This will depend on the final choice of pile diameter and the required embedment depth of each pile. Based on the figures in Table 5.6, the volume of discharged material will be between 130 m^3 and 360 m^3 per drilled pile. After drilling, the pile section is installed by inserting the pile into the socket and grouting the structure in place (refer to Figure 5.19). This process entails the filling of the annulus between the pile and the socket wall with a cementitious grout. This grout is injected through pipes that pass through to the pile base and emerge into the annulus through holes in the pile wall (estimated volume indicated above).

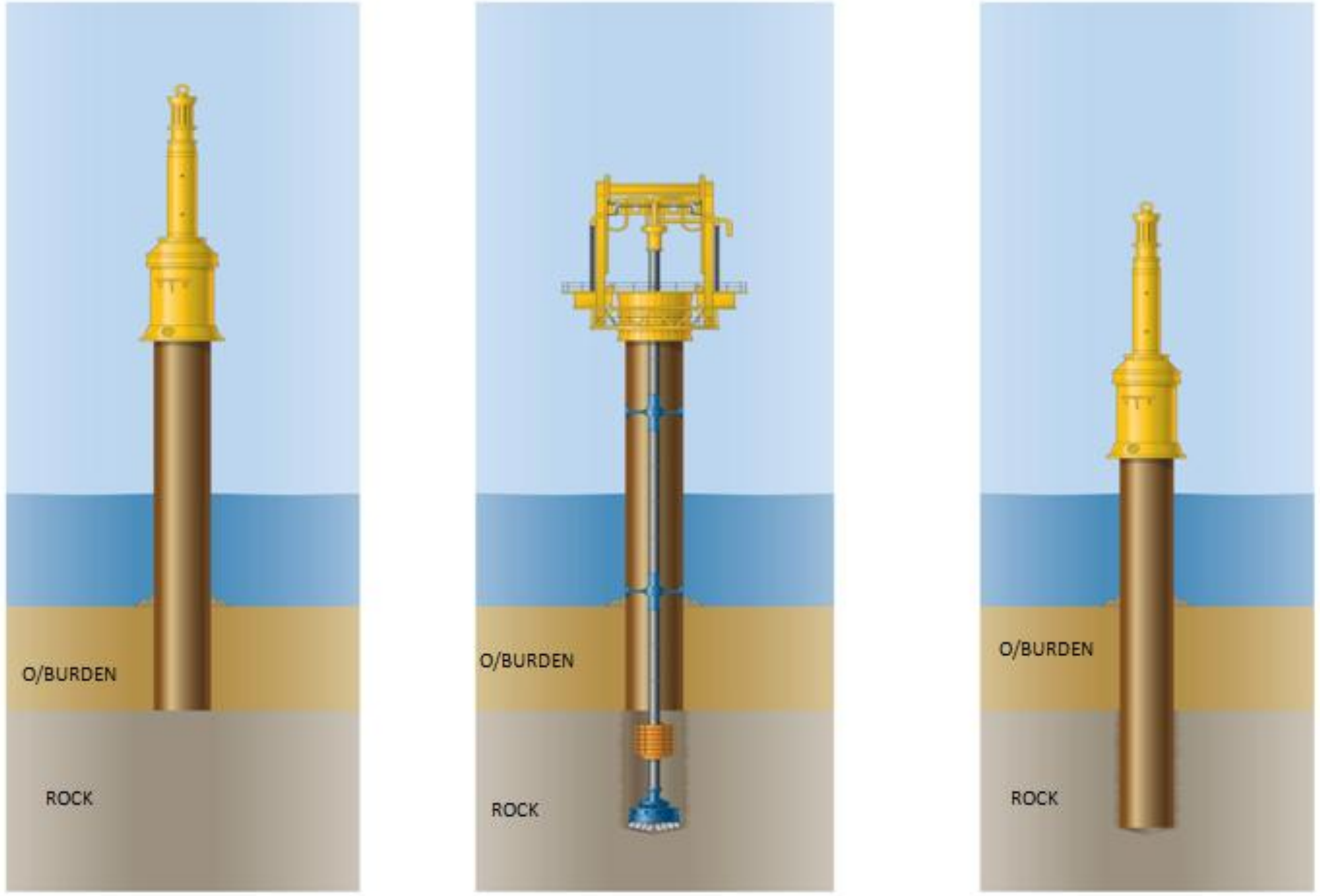

Figure 5.18: Drive-drill-drive installation sequence for each pile (Source: Fugro Seacore 2012)

5.5.3.5 *Noise Emissions*

74 Noise is generated during pile driving operations. The level of noise generated is dependent on the hammer size (expressed in maximum blow energy) needed to drive the piles to the design embedment depth, and on the blow regime adopted.

75 For driven only and the drill and driven pile installations, preliminary estimations have been made of the pile size, hammer size and on the blow regime that will be required to install the piles. Drill and drive and drive only estimates that have been used in the noise modelling for the project (refer to Chapter 12: Ornithology, Chapter 13: Marine Mammals, Chapter 14: Benthic Ecology, Chapter 15: Fish and Shellfish Ecology and Appendix 13.1 Noise Model Technical Report) are included in Table 5.8 below.

76 The drill and drive parameters are based on an average soil profile for the site that assumes an 8 m thickness of soil above the bedrock. The drive details show how the hammer energy level is increased in stages and driving continued for the durations shown until the target penetration below sea floor is reached. The driving is interrupted by the operation of changing the hammer with the drill, and after drilling completion, the final drive to the embedment depth is completed.

77 The drive only parameters are based on the limited parts of the site where bedrock is very deep below seabed and piles can be installed by driving methods without the need for drilling.

Neart na Gaoithe most likely case – drill and drive (bedrock profile)		
Pile diameter (mm)	2500	
Wall thickness (mm)	100	
Target penetration (m below sea floor (BSF))	27.5	
Max hammer energy transferred (kJ)	1200	
Soft start duration (min)	20	
Total drive duration (estimate)	120 min (virgin pile drive) + 100 min (drive after drill)	
Drive details	**Duration (min)**	**Energy (kJ)**
	20	240
	100	995
	26.5 (hours)	Change out hammer and drilling time
	20	240
	80	995
Strike rate – soft start (blow count per second (bc/s))	0.5	
Strike rate – soft start (bc/s)	0.5	
Neart na Gaoithe worst (realistic) case – drive only (channel profile)		
Pile diameter (mm)	3500	
Wall thickness (mm)	100	
Target penetration (m BSF)	38.5	
Max hammer energy transferred (kJ)	1635	
Soft start duration (min)	114	
Total drive duration (estimate)	216	
Drive details	**Time (min)**	**Energy (kJ)**
	114	318
	85	925
	17	1383
Strike rate – soft start (bc/s)	0.5	
Strike rate – soft start (bc/s)	0.5	

Table 5.8: Drill Drive and Drive only scenarios for piling driving noise assessments

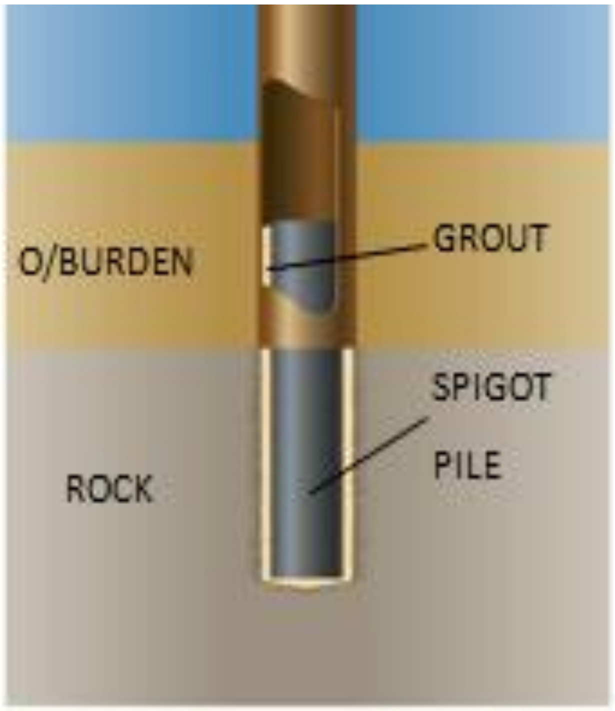

Figure 5.19: Grouted pile arrangement (Source: Fugro Seacore 2012)

Step 5: Scour Protection

78 In detailed design the need for scour protection around jacket piles will be defined. Should scour protection be required, the area of seabed protected will be in the range of 100 to 250 m^2. The volume of material to be placed on the seabed for the purpose of scour protection will be in the range of 100 to 375 m^3 per jacket, and therefore significantly less than the area/volume needed for a gravity base. The final determination as to the need or otherwise for scour protection measures requires the completion of the detailed design process. This in turn requires the completion of further planned geotechnical investigations which have not taken place at the time of writing.

5.6 Turbine Options

79 The wind turbines to be installed at Neart na Gaoithe will be chosen on the basis of efficiency, reliability, commercial availability and economics. Whilst it is likely that the wind farm will utilise a single design to take advantage of bulk purchase arrangements and standardisation it is possible that more than one design option will be used if circumstances dictate.

80 Each turbine will have the same three bladed design overall incorporating the following internal mechanics (refer to Figure 5.20).

- The blades or rotor convert wind energy to low speed rotational energy. The blades are attached to the nacelle;
- The nacelle (Figure 5.20 below) houses the electrical generator, the control electronics, and most likely a gearbox for converting the low speed incoming rotation to electricity;
- The tower supports the nacelle; and
- The turbine transformer is located within the wind turbine tower, usually at platform level above the foundation. The transformer is housed in a hermetically sealed unit and serves to step up the generator voltage to the inter-array voltage.

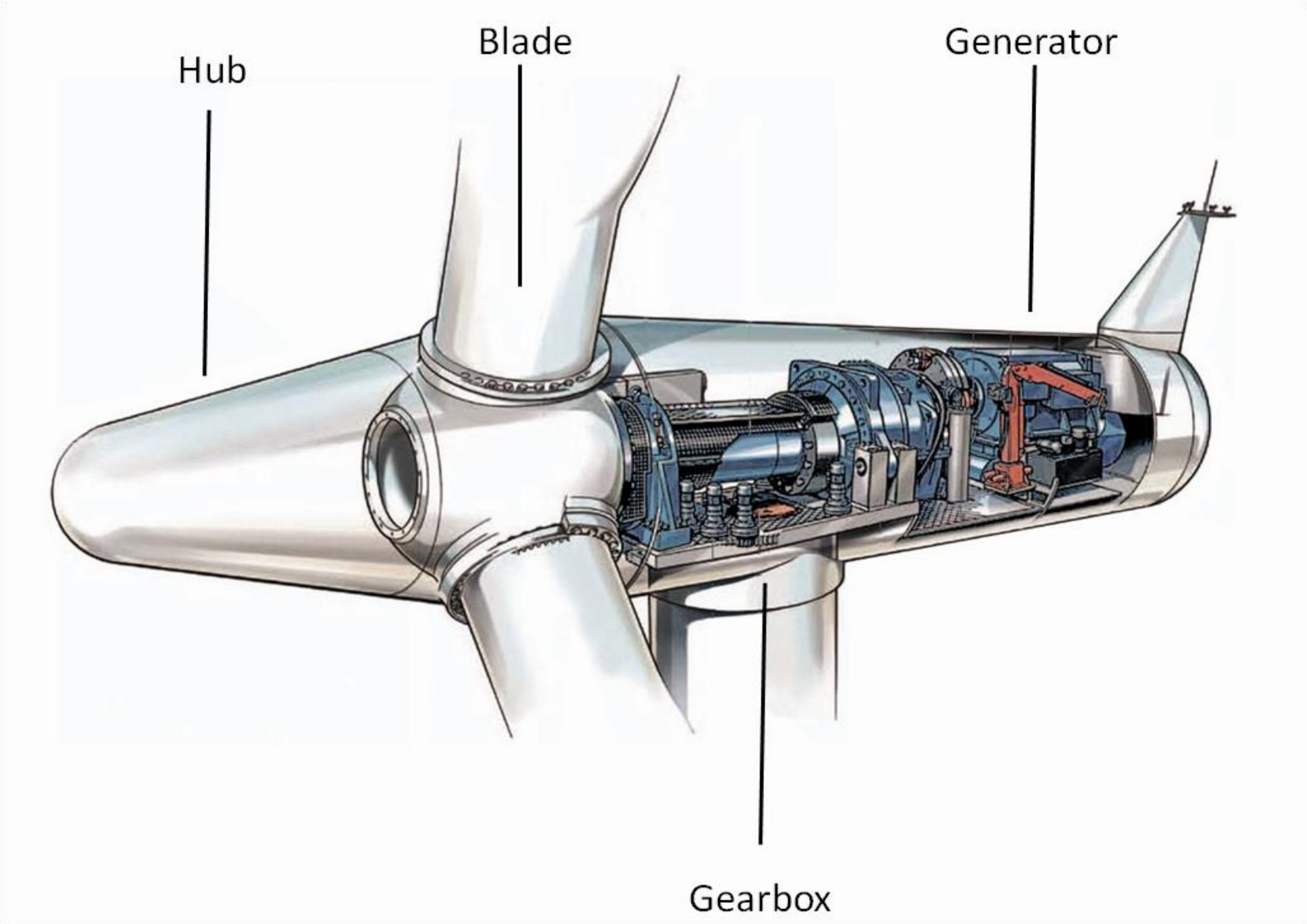

Figure 5.20: Components of a typical offshore wind turbine (Source: Siemens Wind Power)

81 The turbine options being considered range in power output size from 3.6 MW to 7 MW. The turbine options outlined in Table 5.9 are considered to represent the full range of upper and lower limits in each parameter. Figure 5.21 defines the terminology used to describe the dimensions of the wind turbine.

82 The 3.6 MW turbine under consideration will generally start to produce electricity when the wind speed at hub height is 3 to 4 m/s. Wind speeds in the order of 14 to 15 m/s will produce the maximum capacity of 3.6 MW. Turbines are designed with a 'fail-safe' which operates in the event of malfunction and excessive wind speeds. Wind speeds greater than 25 m/s for an extended period will cause the turbines to shut down by feathering the rotor blades. All turbines rotate in a clockwise direction when viewed from the windward direction.

83 The tallest turbine with the largest rotor diameter is the 7 MW design. A layout that uses the 3.6 MW has the largest number of turbines at the highest density. The 4.1 MW and 6 MW turbine designs – both of which meet the technical specifications within the bounds outlined by the 3.6 MW and the 7 MW - were included as potential alternative options. It should be noted that the 4.1 MW design has a smaller rotor diameter than the 3.6 MW model and therefore could have the smallest distance between turbines within the array.

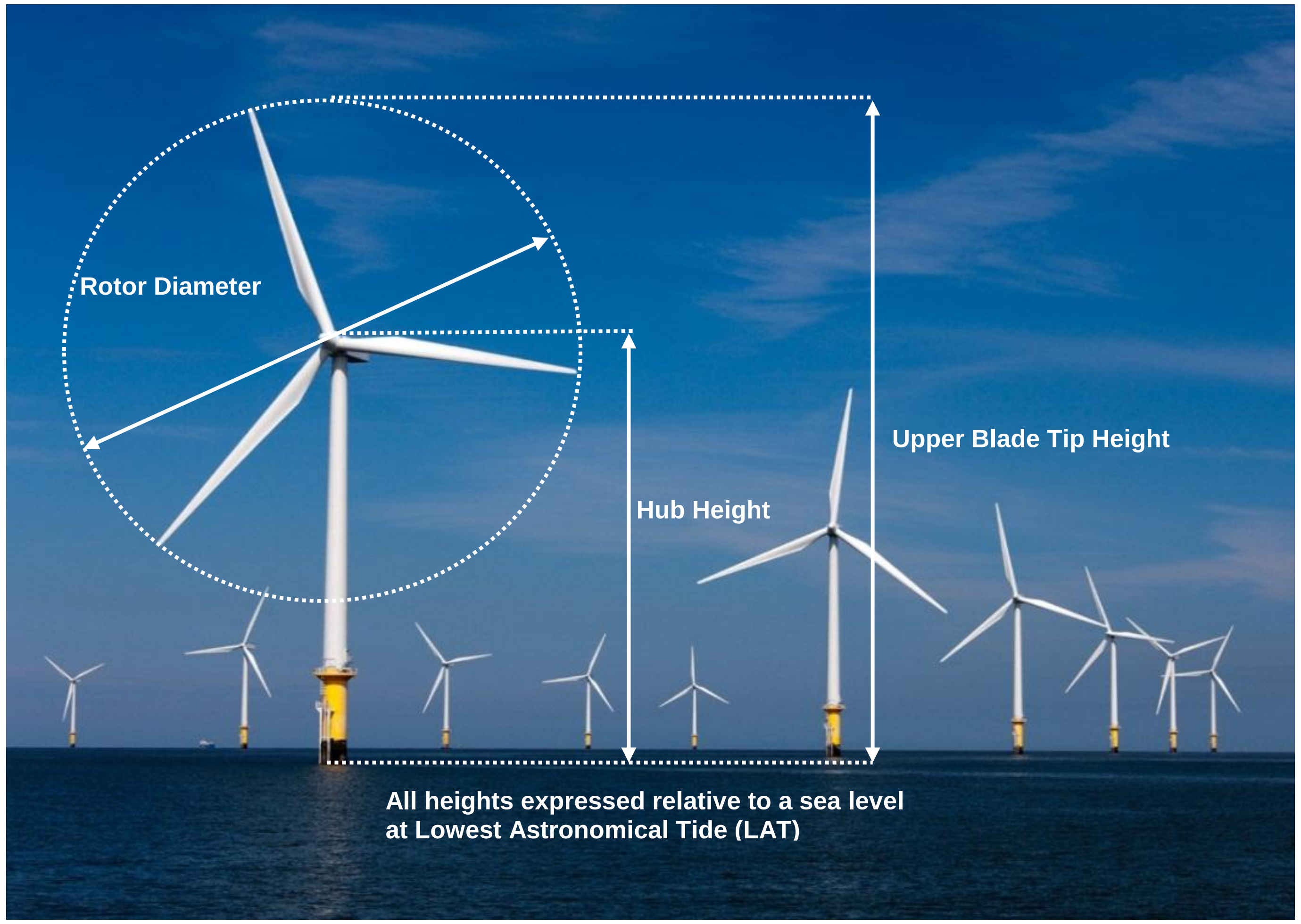

Figure 5.21: Wind turbine dimensions, adapted from Renew (2011)

Parameter	Turbine rated output			
	3.6 MW turbine	4.1 MW turbine	6 MW turbine	7 MW turbine
Number at 450 MW capacity	125	109	75	64
Maximum rotor tip height (m) (LAT)	175	171.25	175.5	197
Rotor diameter (m)	120	112.5	121	164
Minimum / maximum hub height (m) (LAT)	84 / 115	80.25 / 115	84.5 / 115	106 / 115
Air gap (m) clearance to blade tip (minimum of) from LAT	26	26	26	26
Revolutions per minute (rpm)	5 – 13	8 - 18	5 - 13	4.8 - 12.1
Speed at blade tip (m/s)	31.4 - 81.64	50.24 - 113.04	31 - 83	41-104
Height of platform (m) LAT	18	18	18	18
Max turbine spacing (m) (approximately)	1320	1240	1330	1805
Min turbine spacing (m) (approximately)	480	450	484	656
Position of turbines	Indicative Layout A		Indicative Layout B	

Table 5.9: Turbine specifications

5.6.1 Project Layout

84 Neart na Gaoithe has the potential to generate up to 450 MW. The exact number of turbines required to generate this output will depend on the rated capacity of the turbines used. At the time of submission it is not possible to confirm the type or the final number of turbines which will be installed on site. This is due to both the variety of turbines currently available on the open market and also the degree of uncertainty with regard to detailed site conditions. The final selection of turbine type will not progress until after consent has been granted and detailed site investigations have been undertaken.

85 To enable the assessment process to continue, two indicative layouts have been developed, each with a maximum number of the different turbine models. Indicative layout A (Figure 5.22) uses the 3.6 MW and 4.1 MW turbines and indicative layout B (Figure 5.23) uses the 6 MW and 7 MW turbines. This is considered to provide a realistic range of parameters within which the final development layout will lie. The indicative layouts allow for flexibility in turbine choice provided that in any layout the energy output does not exceed 450 MW. Table 5.10 details the maximum number of turbines within each indicative layout.

	3.6 MW turbine	4.1 MW turbine	6 MW turbine	7 MW turbine
Maximum number	125	109	75	64
Indicative layout scenarios	Indicative layout A 128 turbines		Indicative layout B 80 turbines	

Table 5.10: Turbine rating against site capacity

86 Should a 3.6 MW turbine prove to be the most appropriate choice this will result in the highest density of turbine and associated foundation placements. Figure 5.22 shows an indicative layout of 128 turbines and Figure 5.23 contains an indicative layout showing 80 turbines. The extra turbine positions are included above the site capacity to allow a degree of flexibility in the final placement.

87 The exact locations of each turbine will depend on both the size of the turbine (larger turbines will require greater inter-turbine spacing) and the ground conditions at each location. Micrositing of up to 500 m per turbine is proposed to allow greatest layout flexibility.

5.6.2 Oils and Fluids

88 Each wind turbine will contain components which require lubricants and hydraulic oils in order to operate. The turbine transformer may be oil filled or 'dry type'. The volume of oil is dependent on the size of the turbine and typical maximum figures are shown in Table 5.11 below. The table presents the typical quantities of lubricating and hydraulic oils likely to be present in the turbine. The nacelle, tower and rotor are designed and constructed to retain any leaks from the outset reducing the risk of leakages to the wider environment.

Element	Maximum
Grease	129 l
Hydraulic oil	460 l
Gear oil	825 l
Transformer silicon / ester oil	2200 kg

Table 5.11: Maximum estimated turbine oils and fluids volumes

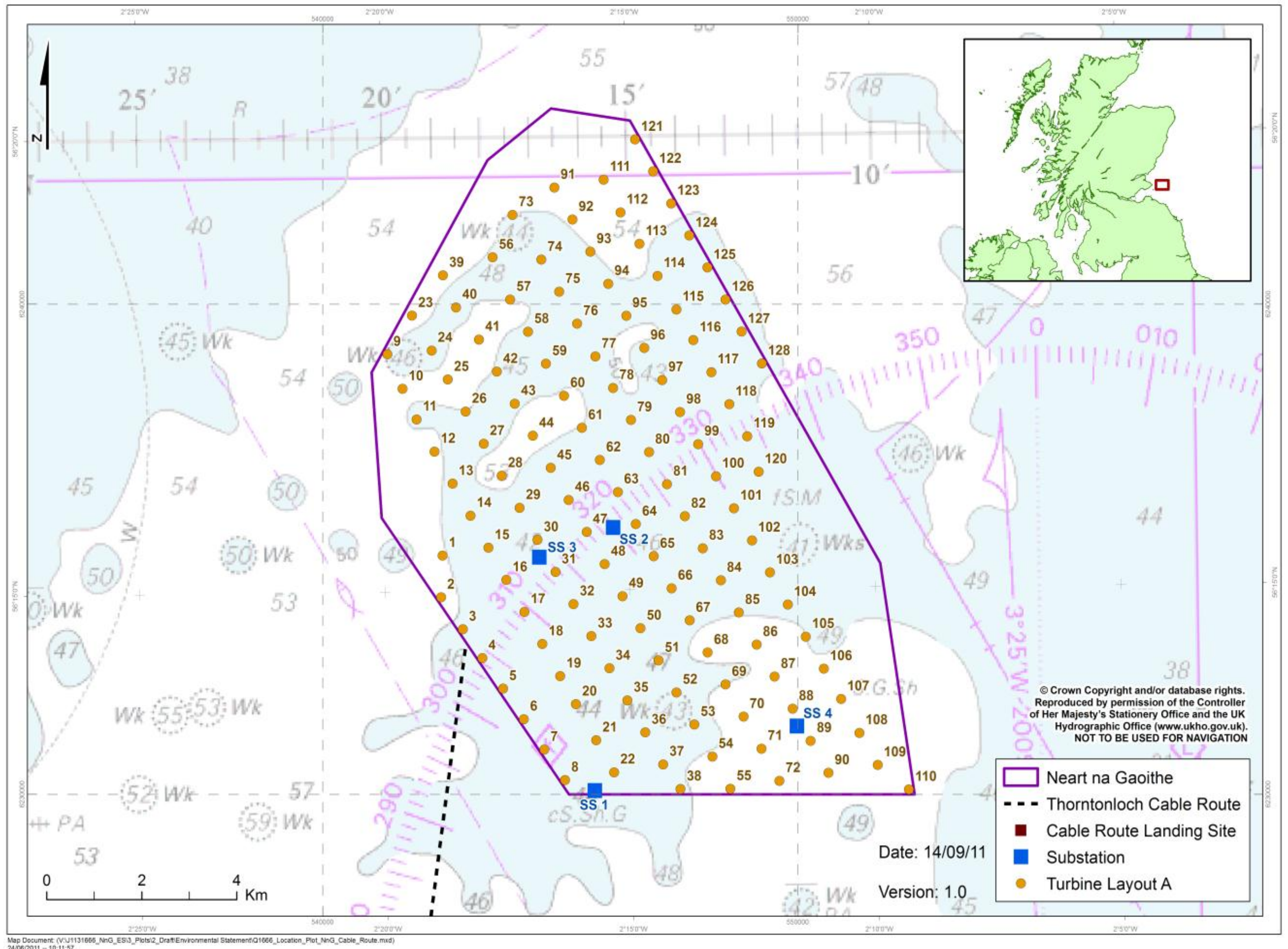

Figure 5.22: Indicative layout A which considers 3.6 MW and 4.1 MW turbines and 4 indicative substation locations (max of 2 will be used)

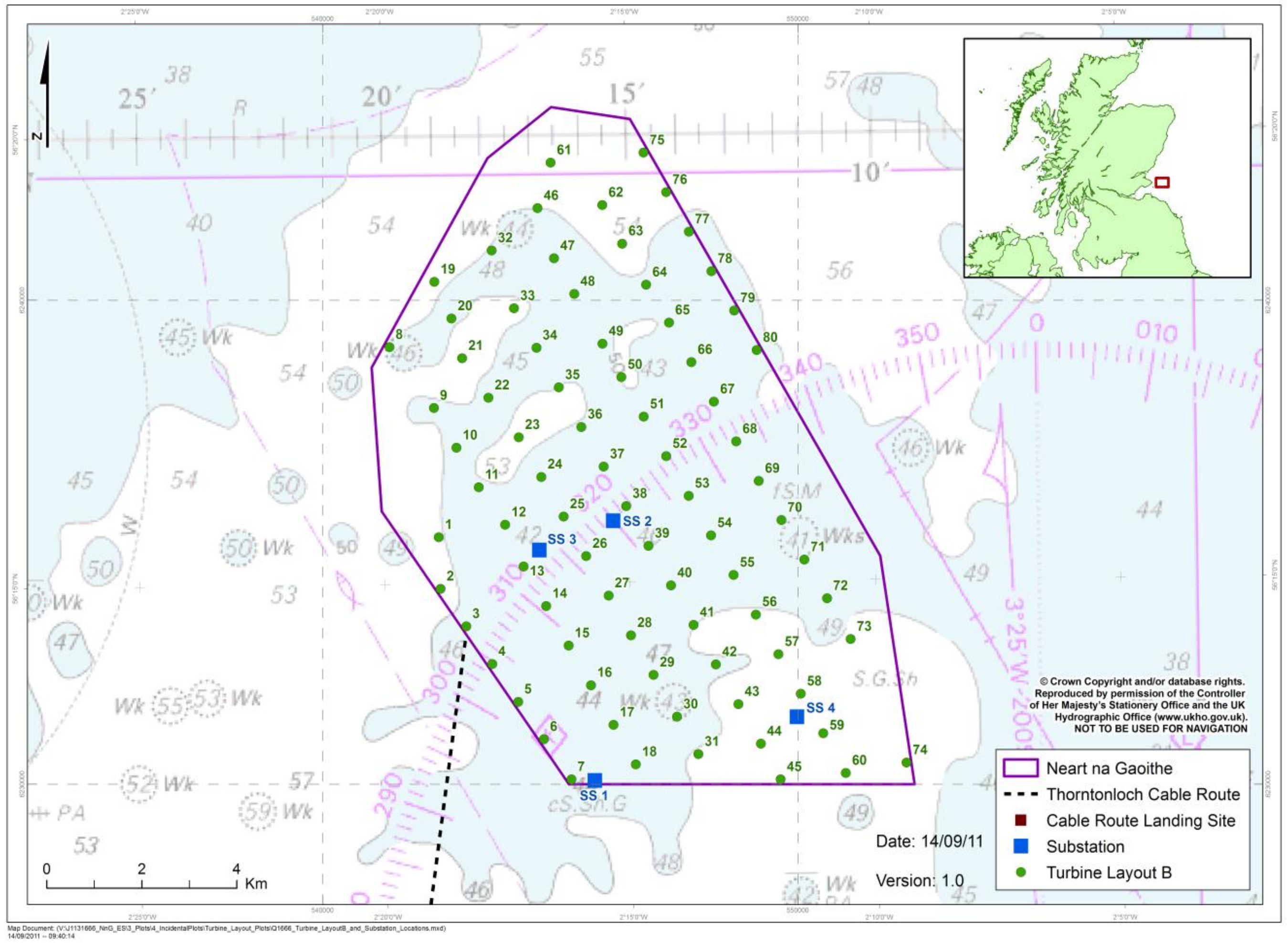

Figure 5.23: Indicative layout B which considers 6 MW and 7 MW turbines and 4 indicative substation locations (max of 2 will be used)

5.6.3 Installation of Turbines

89 Turbine installation will follow on from the installation of the chosen foundation and transition solution and will preferably take place after commissioning of the associated inter-array cable. The choice of either gravity base or steel jacket foundations will not materially affect turbine installation practices.

5.6.3.1 General Sequence of Turbine Installation

90 The general sequence of wind turbine installation is shown in Figure 5.24.

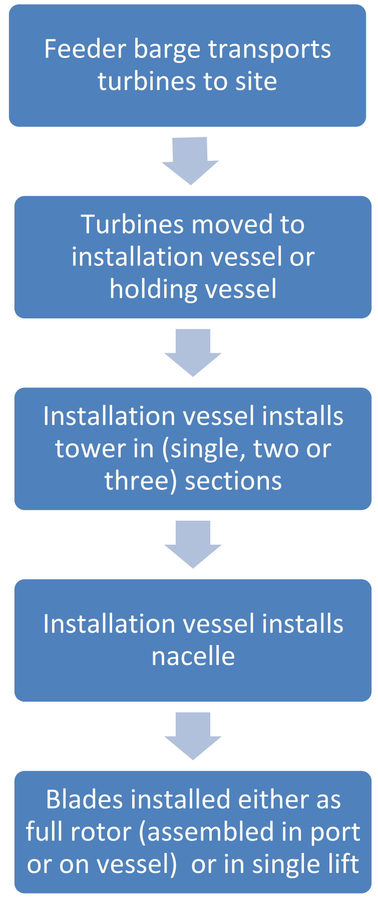

Figure 5.24: General sequence of wind turbine installation

91 A typical installation process detailing the base case wind turbine installation scenario is outlined below and in Figure 5.24; however, this may be subject to change following the selection of the turbine supplier.

- Turbine sub-assemblies (nacelle, rotor blades and towers) will be loaded on to either the installation vessel or on to a feeder vessel(s) and shipped to the installation site. Depending upon which vessel is used it is likely that between 3 and 10 complete turbine sub-assemblies will be loaded at a time;
- At the installation location, the tower will be erected first, followed by the nacelle and blades. The blades may be installed one at a time (single blade installation or pre-assembled as shown in Figure 5.25).

92 Regarding the vessels to be employed for this installation, this will be largely determined by the final choice of turbine model and the availability of suitable vessels at the time of installation. In general terms, the installation sequence depicted above is expected to be followed, whereby separate vessels are used for the transport and installation of each turbine. This may, however, potentially be carried out using a single larger floating vessel, should such be commercially available at the time of construction.

Figure 5.25: Turbine installation (Source: Repower)

5.6.3.2 Commissioning and Testing

93 Turbine erection will preferably not commence until a power supply from the onshore grid connection is available. Once each turbine has been installed and the cabling connected, a process of testing and commissioning will be carried out prior to the turbine being put into service. Testing and commissioning of each turbine is estimated to take approximately eight days. The turbine testing process consists of checking all of the control systems on the turbine, generator, switchgear, transformer gearbox, yaw control and meteorological measurement functions, before running up the turbine through its normal design sequences. All interlocks and safety systems are checked for functionality in both the static and running modes. Ancillary systems such as the hydraulics also go through a pre-testing regime before the turbine is rotated. A standard checklist will be prepared before the turbine is put into service. The last phase of the commissioning is energising the turbine via the inter-array cables. In the event that the grid connection is not completed at the time of turbine installation, a back-up plan involving a temporary power supply will be implemented.

5.7 Offshore Electrical Infrastructure

94 Electricity generated by wind turbines offshore requires the following components to transmit power to the National Grid:

- Two export cables from the offshore substation to the landing point at Thorntonloch;
- Between 85 km and 140 km of inter-array cables from turbines to offshore substation(s); and
- Maximum of two offshore substations;

95 A range of different design options for the electrical system are being considered and the final decisions will be reliant on the final turbine and array choice.

5.7.1 Offshore Substation

96 The purpose of an offshore substation platform is to transform the electricity generated offshore from a medium voltage) (up to 70 kV) to a higher voltage (220 kV). This increase in voltage allows the power to be transmitted from the offshore to the onshore substation efficiently and with lower transmission losses. There will be a maximum of two high voltage alternating current (HVAC) offshore substations installed at Neart na Gaoithe. Four potential locations have been identified, as shown on Figures 5.22 and 5.23.

97 The following potential locations (refer to Table 5.12) have been identified. These should be considered as indicative only: following detailed site investigations one or two positions will be selected.

Location	Easting UTM30N	Northing UTM30N	Longitude (degrees decimal minutes)	Latitude (degrees decimal minutes)	Geographic location
Sub Station 1	545725	6230074	002° 15.766'W	056° 12.803'N	Site periphery
Sub Station 2	546111	6235442	002° 15.337'W	056° 15.695'N	Centre
Sub Station 3	544559	6234836	002° 16.846'W	056° 15.377'N	Western valley
Sub Station 4	549981	6231390	002° 11.635'W	056° 13.487'N	Southern valley

Table 5.12: Indicative substation locations

98 Each substation will consist of a foundation, substructure and topside facilities. The foundation design will be primarily determined by the weight of the topside, depth of water and seabed conditions. The foundation types being considered for the substations are either a jacket or gravity base foundation.

99 The topside size and weight are determined by the equipment that is to be accommodated at the substation. Due to the offshore conditions, the substations will be built to withstand corrosion and prevent equipment damage, hence all electrical equipment is enclosed to protect it from the environment.

5.7.1.1 Substation Design: Topside

100 The topside structure will accommodate the substation electrical equipment and provide access and temporary accommodation for personnel as well as areas for cable marshalling and other services. The substation(s) will incorporate several decks. Each deck will contain different modules, enclosures or systems including, for example:

- Transformers;
- Transformer cooling system;
- Transformer dump tank;
- 220 kV gas insulated switchgear room;
- Medium voltage switchgear;
- Heating, ventilation and air conditioning;
- Fire suppression systems;
- Emergency diesel generation system;
- Batteries, battery chargers and Uninterruptable Power System (UPS);
- Control and protection room; and
- People facilities (possibly including temporary or emergency accommodation and lifeboats).

101 The main dimensions of the topside of the offshore substation are shown in Table 5.13.

Parameter	Unit
Level of topside (LAT)	Approximately 18 m
Height to top of crane / helicopter pad (LAT)	Approximately 60 m
Length x width of topside (m)	Approximately 30x30 m
Total area of topside	Approximately 2,500 m^2
Total weight of topside (tonnes)	2,000 to 2,500

Table 5.13: Offshore substation parameters

102 If only one substation is used there could be up to three transformers and associated equipment in the substation. If two substations are used, two transformers will be accommodated within each.

103 The major plant items likely to be present on an offshore substation are detailed in table 5.14.

Plant Item	No.	Notes
Transformer	Up to 3	Oil filled transformer complete with oil bunding designed to capture any leakages. The bund capacity will be 110% of the volume of oil contained in the transformer. Each transformer will contain of the order of 150,000 litres of oil. Consideration will be given in detailed design to a gas insulated transformer that contains SF_6 gas instead of oil
Transformer cooler	Up to 3	Contained within ventilated (louvres on external wall), perimeter enclosure
MV switchgear	Approximately 20 per platform	Modular, gas insulated switchgear (33 kV to 77 kV)
220 kV breakers	Up to 8	Modular, gas insulated unit. Number depending on final design of protection system

Table 5.14: Summary of major plant items on offshore substation

104 Each offshore substation(s) will be supported by a jacket or gravity base foundation. The characteristics of the foundations will be similar to those already described in Section 5.5 and where necessary, similar seabed preparation will be undertaken.

105 Scour protection, if required, will be similar to the scour protection outlined in Section 5.5 and the quantity will depend on the foundation type. If a gravity base foundation is used, the quantity of scour protection is expected to be between 730 – 1,590 m^3; this would extend between 5 and 8 m outside the foundation perimeter. If a jacket foundation is used and scour protection is required, the area of seabed protected will be approximately 225m^2, with a placed material volume of approximately 340m^2 per jacket.

106 Table 5.15 presents the dimensions of the key design elements for the substation foundation for jackets, which is the most likely candidate type.

Element	Dimension
Piles per jacket	4 - 8
Diameter of piles	Up to 3.5 m
Pile penetration depth	20 – 60 m
Weight of jacket (tonnes)	1,000 to 1,500
Diameter of main jacket tubulars	0.75 – 3 m
Jacket leg spacing at seabed level	Up to 60 m
Total seabed occupied by substation (piles, legs and scour protection) (m^2)	Approximately 450m^2

Table 5.15: Offshore substation foundation parameters

5.7.1.2 *Hazardous Substances Contained in the Offshore Substation*

Transformer Oil

107 Oil is used primarily as a cooling medium for power transformers. Each transformer(s) will be filled with approximately 150,000 litres of oil (Midel or equivalent) at the docks in advance of transportation offshore.

108 An oil collection (bunding) system will be installed underneath the power transformers. This will consist of collection pans which cover areas at risk from spillage, including the transformers. Oil-resistant and fire resistant plastic or rubber liners may be installed on the floor or underneath/around catchment pans for added protection. The collection pans will feed into an oil sump collection tank that will have a capacity of at least 110% of the stored volume of oil.

Sulphur Hexafluoride

109 Sulphur hexafluoride (SF_6) is used in gas insulated switchgear as an arc quenching agent. It facilitates the design of compact and highly reliable switchgear. SF_6 is likely to be used in the MV and 220 kV switchgear and may be considered for use in the HVAC transformers. SF_6 switchgear is long established and is a proven product used both onshore and offshore.

110 Under operational conditions, including fault conditions, SF_6 remains completely inert and is totally contained within the switchgear. Normal risk mitigating measures include switchgear SF_6 pressure monitoring. The SF_6 components of gas insulated switchgear are designed to be maintenance free for their life, which exceeds 25 years.

Batteries

111 A direct current (DC) system consisting of dry type valve regulated lead acid (VRLA) batteries, battery chargers and a distribution board will all be housed in standalone floor mounted cabinets to cater for the substation 48 V DC supplies. The batteries will be mounted on terraced shelves covered with an acid resistant sheet behind secure front opening doors. Telecommunications equipment may have dedicated batteries such as nickel cadmium. These battery cells typically have a design life of 10 to 12 years and will be recycled and properly disposed of at the end of their useable life.

Diesel Fuel

112 There will be a diesel generator, with integral fuel tank included at the offshore substation(s), which will be used to provide emergency electrical supplies for a period of time in the event of loss of connection to shore. The amount of fuel needed will be based on the auxiliary load of the substation and the suggested runtime fuel needed for emergencies. Based on existing wind farm experience, a diesel fuel volume of the order of 10,000 litres (l)is anticipated. Standard offshore practice, using containerised bunded gensets, or gensets enclosed within a purpose built enclosure will be used. The generator will run for test purposes, typically at 1 year intervals. Fuel top-ups to replace volumes of fuel used in testing, will take place using a flexible retractable hose from a licensed diesel supply vessel.

Fire Extinguishing Agents

113 A fire detection and suppression system complying with relevant regulations will be installed during the manufacturing of the substation. As a minimum this will comprise mains powered smoke detectors with rechargeable battery back-up. These detectors will be wired through to the site remote telecommunications supervisory control and data acquisition (SCADA) system and transmitted offsite to alert control operators of a fire at the substation. Suitable fire extinguishers shall be installed in all substation rooms. The fire suppression system and manual fire extinguishers in the substation will be equipped with appropriate extinguishing agents.

Anti-Corrosion Coatings

114 The steelwork and other materials vulnerable to corrosion used in the construction of the topside will be either hot dip galvanised or coated with other corrosion protection coating during fabrication. Electrical equipment such as cooling radiators can be coated to provide resistance to scratches and impacts. Minor volumes of touch up corrosion protection coating (anticipated less than 50 l) will be housed on the substation to deal with any areas that require maintenance.

5.7.1.3 Installation of the Substation

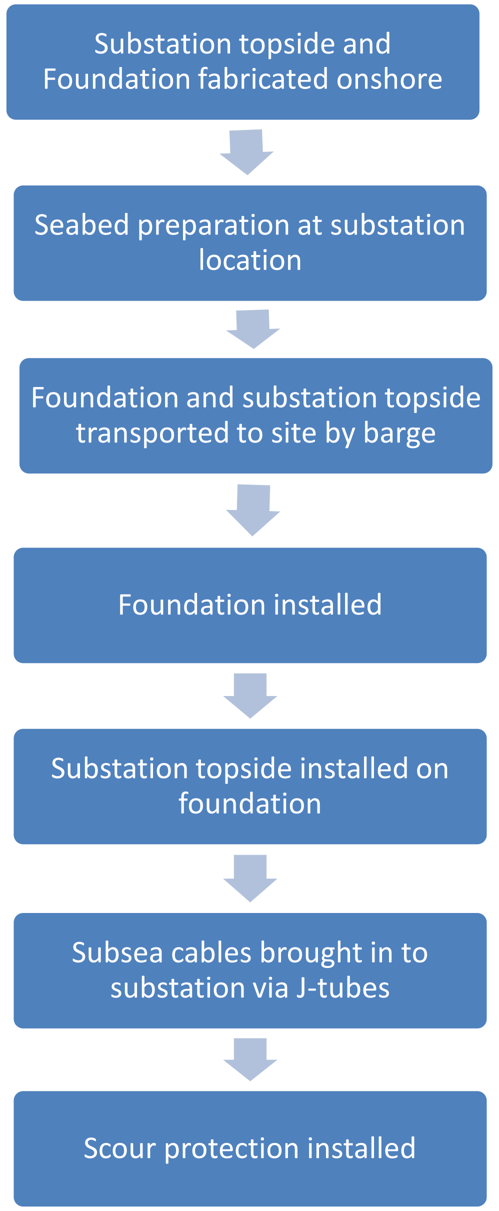

Figure 5.26: General sequence of substation installation

115 Installation of the substation(s) is expected to follow the general sequence shown on Figure 5.26 above. The complete topside will be manufactured onshore and all electrical and mechanical equipment will be installed and pre-commissioned onshore before being transported offshore. Similarly, and independently, the foundation will be fabricated onshore and transported offshore.

116 Seabed preparation and installation of the foundation will occur as in the method described for turbine foundations in Section 5.5.2: Gravity Base Foundations, and Section 5.5.3: Steel Jacket Foundations. The topside will be transported offshore on a barge or a heavy lift vessel. A heavy lift vessel will be used for lifting the topside structure onto the foundation; it is likely the heavy lift vessel will be supported by up to four vessels including tugs and fast response vessels. As the design of the substation has not been finalised it is not known whether the installation of the topside will be done by a jack-up or floating vessel. If a jack-up is used, it is likely that it will be supported on four legs.

117 For transportation of the structure it is possible that four journeys will be required. The vessels will be selected in accordance with transportation requirements. Once the substation is in place, the subsea cables are brought into the topside and final commissioning work is undertaken. Total installation is expected to take approximately 30 days exclusive of weather downtime. Figure 5.27 shows a fully installed substation. For clarity, this image depicts a monopile foundation; this project is considering only jacket foundation or gravity base foundation.

Figure 5.27: Installed substation (Pictures courtesy of CG. Copyright ®vanoordbv-mennomulder.com)

118 In the event that two substations are used both will be connected to shore via independent 220 kV cables. If one of these cables goes out of service, a level of redundancy will be provided by a 220 kV cable connecting the substations. Such interconnection improves export power flexibility and will be made using 220 kV cables similar to that used for the export of power to shore. The installation and burial of this cable will be the same as that described in Section 5.7.3: Export Cables.

5.7.2 Offshore Inter-array Cables

119 Cabling used to connect turbines within turbine arrays may be rated at up to 70 kV (medium voltage). The cables will be steel wire armoured and will have three electrical conductor cores varying in size up to 500 mm^2. The cables will have cross-linked polyethylene (XLPE) insulation. Optical data cables for SCADA, control and protection will be included within the cable bundle.

120 The inter-array cabling layout will be optimised to minimise losses and capital expenditure costs. There will be up to 16 collector circuits, connecting up to ten turbines each, dependent on the turbine model; these will directly link to the substation. This connection will be made after the turbine foundation installation but before the turbine installation. Details of the cable design and cable burial parameters are given in Table 5.16.

Parameter	Turbine rated output			
	3.6 MW turbine	4.1 MW turbine	6 MW turbine	7 MW turbine
Number of cables	Up to 16 circuits with a total of 85 to 140 km of cable.			
Design of array	Max 10 turbines per collector circuit	Max 9 turbines per collector circuit	Max 6 turbines per collector circuit	Max 6 turbines per collector circuit
Specification of cables	XLPE AC cable up to 70 kV Size ranges from 50 mm^2 to 500 mm^2			
Burial method / scour protection	Likely ploughing/cutting/jetting or rock cover. Exact options finalised when layout is confirmed.			
Width of seabed affected (per cable)	2 m direct impact width, up to 8 m width of zone of minor disturbance (10 m in total).			
Width of cable corridor	30 to 100 m			
Burial depth (m)	Likely to vary across site up to 1.5 m.			

Table 5.16: Inter-array cable burial and design parameters

121 The total length of inter-array cabling will be between 85 and 140 km depending upon final turbine layout choice, ground conditions encountered and certain potential mechanical risks arising from fishing and shipping activity.

122 Inter-array cables will be buried where practicable and protected by other means where burial is not possible. There are several materials used to provide scour protection to cables which include:

- Durable crushed or original rock of defined size range;
- Artificial fronds or seaweed;
- Concrete 'mattresses'; and
- Bags (high strength nylon fibre) of gravel, hardened sand-cement grout, or concrete (grout/concrete pre-filled and hardened onshore). The bag option may include a technique where the grout is introduced to the nylon fibre bag offshore through proprietary pipes (the bags being permeable to water but not to grout).

123 The amount of scour protection is dependent on the mobility of the seabed in the vicinity of the cables. Preliminary calculations have indicated that the scour protection grain size is expected to have a median diameter of 100 mm. The width of scour protection above the cable where necessary is expected to be about 2 m and thickness of the scour protection is expected to be of the order of 0.5 m.

124 Placing scour protection can be performed by a fall pipe, wire crane with grab or by rock-dumping.

5.7.2.1 Inter-array Cable Installation

125 Inter-array cables will be buried and protected as appropriate in order to:

- Prevent movement or exposure of cables over the lifetime of the wind farm due to seabed movement;
- Protect the cables from other activities such as fishing or anchor placement;
- Protect against the small risk of dropped objects; and
- Limit the potential effects on environmental receptors from the effects of heat and or induced magnetic fields caused by the cables.

126 Due to the relatively small diameter, greater inherent flexibility and shorter route lengths involved in inter-array cable installation different approaches can be adopted:

- Cables can be cut to length prior to the offshore installation phase;
- Uncut cable can be loaded into a vessel cable tank or carousel (with capacity up to 80 km of cable); or
- Shorter lengths can be spooled on to an installation reel or reels, which can then be lifted onto the installation vessel.

Method of Burial of Inter-array Cables

127 It is expected that the inter-array cables will be buried to depths up to 1.5 m using cable ploughs - refer to Figure 5.28 - and/or mechanical cutters as necessary. The cable plough uses a remotely operated adjustable steel cutting tool to achieve the required trench depth. In harder soils a mechanical cutter can be used that adopts a hydraulically operated chain cutter. A trenching plan that will identify specific areas for plough and mechanical cutter will be prepared following the detailed geotechnical investigation. This installation is likely to achieve an installation rate of 2 to 3 km per day depending on weather conditions. The use of water jetting is considered unlikely to be viable, due to the hard soils anticipated and the potential for very shallow rock outcropping, however it may be used in some areas of the site. It is likely that scour protection will be required over approximately 20% of the inter-array cable length where desired burial depths are difficult to achieve; such instances would occur where bedrock outcrops at seabed level or in zones where thin sediment exists over the bedrock. The installation may be done by either a single vessel or twin vessels as detailed below.

128 Cable layout designs will seek to ensure that cable crossing is avoided; however, should this prove impractical protection measures will be necessary. No non-project related cabling or pipelines have been identified within the site boundary. However, should a cable or pipeline crossing be required the protection would consist of one or more of the scour protection materials identified in Section 5.7.2.

Figure 5.28: Cable plough (Source: Prysmian Group)

Single Vessel Installation Process

129 The most typical installation method is using a single vessel to both lay and bury the cable simultaneously. Support vessels will be used to manage the safety zone (refer to Section 5.10.1). The process is as follows:

- The cable laying vessel approaches the first structure and the cable end is over-boarded, transited to the structure probably by ROV, carefully pulled into the first J-tube and hung off;
- The installation vessel then over-boards the plough or trenching unit, and cable loading takes place either on the vessel back deck or subsea;
- There is simultaneous lay and burial of the cable using the cable burial equipment;
- At the end of the cable where the next turbine is approached, the plough or trenching unit cutting action would be stopped and the vessel would transit past the turbine foundation leaving a length of cable exposed on the seabed;
- Following recovery of the plough, an ROV would be used to recover the cable end which is ultimately pulled up through the J-tube; and
- The length of cable - approximately 100 m - left unburied at the approach to each turbine has to be protected. This can be done by any of the scour protection measures identified above or alternatively an ROV can mechanically cut a trench to accomplish burial of the cable in this area.

Twin Vessel Installation Process

130 This method involves two vessels, one to lay the cable and the other to bury it. In this scenario, the lay and bury activities occur in much the same way as described above but cable burial takes place from a separate trenching vessel either simultaneously or immediately after installation and cable hang off. Post-lay trenching is likely to be less well suited for ploughing operations and better suited to a mechanical trencher. It is possible that multiple vessels may install the cables simultaneously.

Post Burial

131 Following the completion of burial activities, a further scour protection phase may be required to protect the cable transitions and any areas of cable exposure around the J-tubes. This burial protection will be installed using one of the processes outlined for foundation scour protection (see Section 5.5). The final decision concerning optimal burial methodologies will be made at a later date when further geotechnical investigations have been carried out and market availability of particular cable laying technologies tested.

132 Contingency plans will be developed to ensure that appropriate actions are taken should any of the cables become exposed.

5.7.3 Export Cables

5.7.3.1 Cable Characteristics

133 Cable characteristics vary depending upon cable manufacturer. Typical 220 kV HVAC 3-core cable characteristics fall within the ranges conveyed within Table 5.17. Currently, it is assumed that Neart na Gaoithe will use subsea cables with 500 mm^2 copper conductors and galvanized steel wire armouring to protect the cables. The total length of installed export cable is estimated to be approximately 66 km (two cables at 33 km each).

Three-core 220 kV export cable		
Conductor (mm^2)	**Cable diameter (mm)**	**Mass in air (kg/m)**
500	219	81
630	224	87
800	234	95

Table 5.17: Physical specifications of 3-core 220 kV export cable

134 An example of a typical 220 kV 3-core HVAC cable cross section is shown in Figure 5.29. The cable typically comprises three copper conductors insulated by cross linked polyethylene and an integral optical fibre cable (24 single mode fibres). Individual cables have an insulation screen, a lead alloy sheath and a polyethylene over sheath. The three core assembly is encased with a single layer steel wire armour covering and a final outer polypropylene sheath.

Figure 5.29: Typical 220 kV 3-core subsea cable (Source: Prysmian Group)

135 The final design of the subsea export cable system will be determined by a combination of results from geophysical and geotechnical surveys and electrical losses considerations. Consideration will be given to minimising the number of cable joints, of both factory and offshore types. The general export cable specification is shown in Table 5.18.

Export cables	
Number of cables	2
Length (m)	33 km
Specification of cables	220 kV (Um 245 kV) 3-phase AC XLPE insulated
Spacing between cables (m)	Minimum 70 m/maximum 500 m (3x water depth but no less than 70 m)
Cable corridor width (m)	300 m (i.e., 150 m either side of cable route centre line)
Burial depth (m)	Up to 3 m

Table 5.18: Export cable specification

5.7.3.2 Installation of Offshore Export Cable

136 Two export cables will be used to transmit power back to the shore from the offshore substation. Each will consist of XLPE 3-core cables (three conductors per cable) with a maximum continuous rated voltage of 245 kV. The operating voltage will be 220 kV. Fibre optic data cables will be included within the cable bundle SCADA.

137 The cable route will be a balance of the shortest route possible between the offshore substation and the onshore landing point, suitable seabed conditions, and environmental considerations. A cable corridor has been determined and surveyed, but the exact location of the cable will be microsited based on a pre-cable lay survey.

138 Subsea export cables are thicker and heavier than inter-array cables and land cables, commonly in the region of 100 kg per metre length. Larger vessels are, therefore, required for installation. Figure 5.30 shows a photograph of such a vessel which could be used for the installation of subsea export cables. The vessel has a mechanised cable turntable on deck which is used to wind the cable onboard and to wind it off again. This vessel uses dynamic positioning and other navigational aids to maintain accurate cable laying. All operations need to be strictly controlled to respect design requirements for cable bending radii, stresses and strains.

Figure 5.30: Cable lay vessel Giulio Verne (Source: Prysmian Group)

139 The extent to which the cables will be buried will be dependent on the result of a detailed seabed survey of the final cable route and associated burial risk assessment process.

140 The intention is to bury the cable as far as is practicable along the entire cable route (refer to Table 5.18 and Table 5.19). In suitable seabed conditions cables could be buried to 3 m. Export cables will be separated by a minimum spacing at sea of 70 m extending to 300 m in some areas.

Element	Maximum	Comments
Burial depth	Up to 3 m	Dependent on risk assessment, including ground conditions.
Width of seabed affected (per cable)	Up to 10 m	2 m direct impact width in the centre of an up to 10 m wide zone of minor disturbance from the plough skids.
Max cable spacing	300 m	Dependent on ground conditions and will be finalised after detailed survey.

Table 5.19: Offshore HVAC cable installation dimensions

5.7.3.3 Export Cable Installation Process

141 It is likely there will be one primary vessel and up to three support vessels in use per cable installation. Cable lay vessels can typically install between 2 km/day and 20 km/day depending on ground conditions and the need for supplementary cable protection. The cable installation methods to be adopted will be dependent on the ground conditions along the route. Final decisions will be made following detailed geotechnical investigations. Installation methods under consideration for the installation of the export cables include:

- Use of high pressure pump/jets to cut trenches where sandy conditions exist. Having laid the cable, the trenches will close naturally without backfilling;
- Use of mechanical cutters or cable ploughs as described above for the inter-array cables; and
- Laying of cable on the seabed and covering with scour protection, either with a rock mattress or by overplacement with unbound graded rock (where bedrock outcrops at seabed level or thin sediment layer is present over the bedrock).

142 Given the length of the proposed cable route corridor a combination of methodologies may be required to bury the cable in different sections of the route. Seabed conditions or protection issues may require the cable to be protected by scour protection instead of, or in addition to, burying. It is estimated that 15% of the export cable route will require scour protection.

143 There are three common vessel arrangements used to install long distance cables:

- Lay and protect the cable from a single cable installation vessel (2 to 3 km/day);
- Lay the cable using a cable installation vessel and protect the cable using a separate vessel, but with both vessels travelling together and working as a single unit to achieve an expected installation rate of 2 to 3 km per day; and
- Lay the cable using a cable installation vessel with a separate ship protecting the cable and both ships travelling independently. The cable installation ship could in this case travel much faster (15 to 20 km/day).

144 The export cable will require installation in varying water depths from the offshore substation to the beach landing point or to the intertidal zone. Based upon the water depths and nature of the seabed along the route, a dynamically positioned vessel is likely to offer the optimal operational flexibility across the range of operations necessary. Based upon the length and assumed weight of the cable, it is likely that each export cable would be laid in a single length without the requirement for a midline joint.

5.7.3.4 Intertidal Zone

145 At the time of writing the ES, a detailed intertidal geotechnical survey has not yet been undertaken. For this reason, details as to exact locations of cable laying and associated infrastructure have not yet been confirmed and the following text is indicative of the possible process.

146 Cable landfall will be at Thorntonloch beach, to the south of Torness Power Station. At landfall, the two offshore export cables will be brought from the offshore cable laying vessel, up the intertidal zone, to two adjacent transition pits located above the high water mark – where the onshore and offshore cables will be connected.

147 The exact, final location of the cable landfall will depend on the final offshore cable route. Figure 5.31 shows the proposed envelope of potential intertidal cable routes.

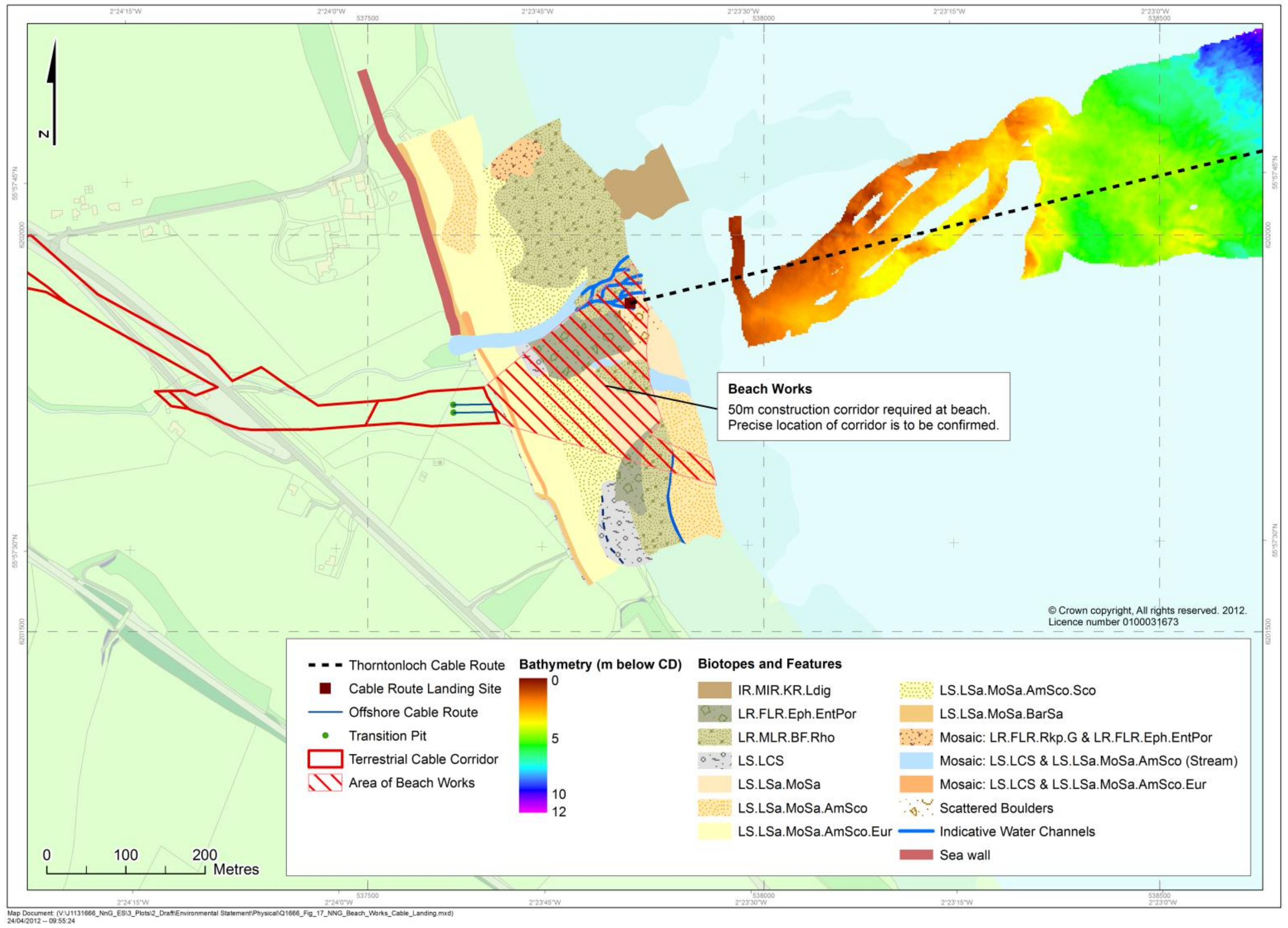

Figure 5.31: Proposed beach landfall location

148 The two subsea cables will be separated by a minimum spacing of approximately 50 m offshore, at the location where the cable laying vessel is positioned. The cable separation will be reduced to a minimum of 10 m as the cables approach the landfall and the connection with the onshore cables. The 10 m spacing is required for cable thermal rating purposes where depths of approximately 8 m are required, however the spacing will reduce as the cable depth reduces and as the cable approaches the joint transition pits. The landfall cables will be housed in high density polyethylene ducts installed under the beach and under any onshore constraints.

149 The method of installation for intertidal works will be dependent on the ground and seabed conditions along the cable route. Two potential options are being considered for installation, both are described below.

Horizontal Directional Drilling

150 Horizontal Directional Drilling (HDD) is a method of underground cable installation being considered at the land-sea interface for the project. The principle of HDD is to drill a channel underground between two points, into which an electrical cable can be installed, without needing to excavate an open trench along the channel route (refer to Figure 5.32). To achieve this, an onshore drill rig commences drilling at the start of the underground channel (known as the Rig Site), toward the end point of the channel (known as the Pipe Site). Using this methodology it estimated that the entire duration of cable installation works between the rig site and the pipe site will be approximately 4 months.

151 For this project, the rig site will be located above the high water mark of Thorntonloch beach and will contain a receiving pit for the electrical cable. This will be similar to a conventional manhole and approximately 2.5 m long by 1 m wide by 1 m deep. The pipe site is likely to be located at a point seaward of mean low water springs (MLWS) on Thorntonloch beach. Confirmation of the precise location of the pipe site requires the completion of a planned geotechnical survey of the intertidal area. Thus, the pipe site location will be confirmed prior to the commencement of works.

152 The rig site will comprise a construction area of approximately 30 m long by 40 m wide and will contain a drill rig, an electrical generator, a water tanker, a mud recycling unit and a temporary site office. Drilling mud containing bentonite will be used to aid the drilling process and will use the output from the mud recycling unit mixed with water for this purpose.

153 The pipe site will comprise an area of approximately 20 m long by 20 m wide. A jack-up platform equipped with an excavator will be used to carry out the works at this location. A circular/rectangular steel casing will be installed into the seabed to facilitate the excavation of a dry area within which a second receiving pit will be constructed. Here, the cable will emerge from the channel and be joined with the export cable. The cable will then be buried, the disturbed area reinstated and the casing removed.

154 In simple terms, the drilling/installation process will comprise four stages:

- A small diameter pilot hole will be drilled from the rig site to the pipe site, for the purpose of defining the path of the channel into which the cable is to be installed;
- A steel reamer will then be pulled back through the pilot hole from the pipe site to the rig site, enlarging the diameter of the hole as it progresses. This may need to be repeated a number of times, depending on the nature of the soil through which it passes, in order to enlarge the channel diameter sufficiently as to accommodate the electrical cable;
- The electrical cable and the ducting within which it rests will then be attached to the reamer and pulled through the channel from the pipe site to the rig site, at which point it will be secured in place by means of precast concrete thrust blocks within the transition pit; and
- At the pipe site, the jack-up platform will then be removed. The cable end will then be connected to the remainder of the offshore cable and buried into the seabed.

155 At the pipe site, the cable will be supplied by a cable installation vessel such that it can be drawn through the channel behind the reamer. This vessel will be required to remain a minimum distance from shore to ensure adequate water depth for operation. This distance is estimated as 1 km approximately, however this will be confirmed following the completion of the above mentioned geotechnical survey.

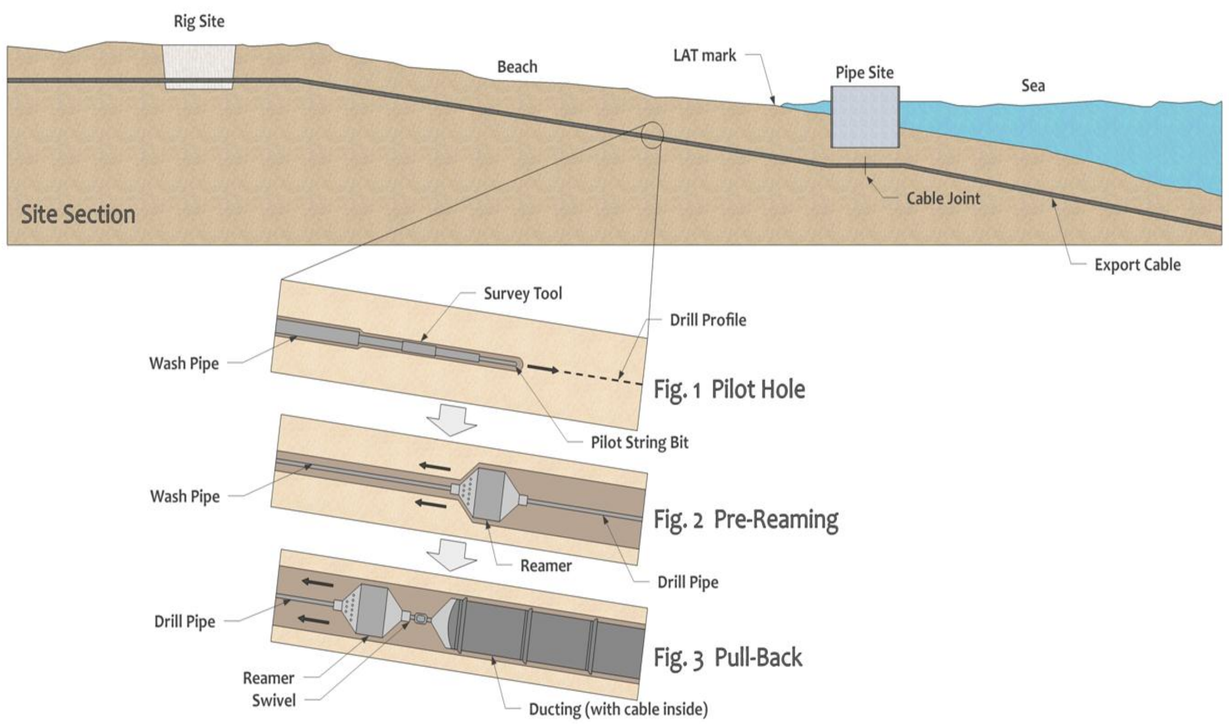

Figure 5.32: Illustration of directional drilling process

Open Cut Trenching

156 Open cut trenching may be used as an alternative to HDD to route the subsea cables through the intertidal zone. The cables will be laid in PVC ducts (a tube which facilitates the passage of the cable and offers some protection). The required burial depth will be determined in detailed design and is anticipated to be in the order of 1 m. Figure 5.33 depicts a typical open trenching scenario.

157 Preparatory works along the intertidal zone will depend on the underlying geology. Excavators will be used to dig the necessary trenches. Should the sediment depth be insufficient, rock breakers or other mechanical cutting methods may be required to achieve the designed burial depth. Cable ducts will be installed in the trenches from the transition pit and a temporary winch will be installed above high water mark for cable pull in.

158 Once the preparatory works are complete, the cable will be winched to shore from the cable laying vessel.

159 For installing cable ducts, navigational safety areas around the works could be required for up to 3 months depending on the extent of clay/bedrock excavation required with an additional minor exclusion period (estimated at 1 day) during the cable pull in.

160 Excavation will be achieved using an excavator mounted on a barge or jack-up platform in water depths up to approximately 5 m below LAT. In the deeper water beyond this point, cable burial into the bedrock can be handled by rock cutting or trenching using an ROV.

Figure 5.33: Beach excavations – tracked excavators and barge mounted excavators (Source ETA Ltd)

Construction of Transition Pits

161 The transition pits will consist of an underground structure and will house the joints that link the multi-core offshore cables with the single core onshore export cables. Each circuit may have its own transition pit; located adjacent to each other with approximately 5 m separation. Alternatively, both circuits could be accommodated in a single pit.

162 The transition pit(s) will be located behind any sea defences at the approximate location as detailed in Table 5.20.

Parameter	Easting UTM30N	Northing UTM30N	Longitude (degrees decimal minutes)	Latitude (degrees decimal minutes)
Transition pit(s)	537608	6201786	02°23.857 W	55° 57.597 N

Table 5.20: Co-ordinates of transition pits location

163 Each transition pit will be within a below ground excavated trench with reinforced concrete sides and base. The dimensions are likely to be approximately 10 m length by 4 m width by 3 m depth. A concrete cover will be placed over the top of the pit for protection and land above will be reinstated to its previous condition.

164 The transition pits will be excavated by a mechanical excavator after which a concrete chamber will be installed. The concrete chamber will either be constructed on site or will be brought in prefabricated. A small container will be temporarily placed on top of the transition pit to allow a clean, secure and weatherproof working environment during cable jointing. A generator will be required to provide power supplies during jointing operations. A temporary security fence and lighting will be constructed to enclose and secure the transition pits during construction.

165 An access track will need to be made to the transition pit location during construction. It is anticipated that access will be made via the onshore cable corridor haul road, requiring the use of a temporary bridge across Thornton Burn.

166 Once the transition pit has been established, the offshore cables will be winched into place as part of the offshore cable installation process. A joint is then made at this point to join the subsea cables to the terrestrial cables.

167 On completion of the transition joint the excavation will be reinstated to the original ground level with excess material removed from site.

5.8 Ancillary Equipment

5.8.1 J-Tubes

168 A J-tube is the conduit for cables to travel from the seabed to the work platform on the wind turbines and at the substation(s). J-tubes will be attached to the jacket or gravity base foundation as part of the overall onshore fabrication works. The inter-array cables within the J-tubes have to be protected where they emerge at the base of the foundation structure. Where necessary, scour protection in the form of durable mattresses pre-filled with stone will be used to protect the cable between the base of the foundation and the point of burial. Further details are provided on such protective measures later in this section.

5.8.2 Access Facilities

169 A boat landing, ladders, hoists and fenders will be located on the foundation structures to allow safe access to the turbine/substation(s) for maintenance and operation. These facilities will be constructed and installed on the structure during the fabrication of the foundation in the fabrication yard.

5.8.3 Transition Piece

170 Dependent upon the nature of the foundation, a means of connecting turbine towers to the foundation is required. The aim is to enable the use of towers which are to a large extent standardised by individual manufacturers. Hence a transition piece which has standard tower attachments, typically bolted flanges on one end and a foundation specific arrangement on the other, is used.

5.8.4 Colour Scheme and Navigational Markings

171 The turbines and associated support structures will be marked according to the requirements of the Northern Lighthouse Board (NLB) and Civil Aviation Authority (CAA). Consultation is ongoing but the colour of the turbine tower, nacelle and blades is likely to be light grey RAL 7035. The transition piece and tower will be yellow above LAT to an agreed height above highest astronomical tide (HAT).

172 As with the turbines the offshore collector substations will be marked according to the requirements of the NLB and CAA. Navigation markings may be allocated solely to a number of wind turbines in the field.

5.8.5 Lighting

173 Three types of lighting are mandatory on wind turbines: medium intensity red lights, low intensity green lights, and low intensity red lights. In addition, low intensity infrared (i.e., invisible to the eye) lighting may be requested.

174 The legal requirement for offshore wind turbine lighting is stipulated in Article 220 of the Air Navigation Order 2009 (reproduced in CAP393 *Air Navigation: The Order and the Regulations*), with other documents providing further policy information and guidance.

175 It is noted that the Air Navigation Order only requires lighting to be fitted to turbines on the periphery of a group of turbines (refer to Appendix 18.2: Aviation Lighting and Marking Requirements); it is implicit that situating a light on the periphery every 3 to 4 km should be adequate as a *maximum* separation.

176 A lighting scheme is proposed and included in Appendix 18.2: Aviation Lighting and Marking Requirements.

5.9 Commissioning Process

177 Commissioning of individual turbines will typically take up to 8 days. The process will involve mechanical completion followed by all internal electrical connections. Following this, turbines will be electrically energised and a series of tests will be undertaken to ensure that all connections are made correctly - e.g., phase rotation for wiring. Once this is complete, safety checks and operational checks of all subsystems will be undertaken. Following completion of all these tests the turbine will be put into service.

178 Duration of commissioning will be dependent on how much of the commissioning can be carried out onshore; this is dependent on turbine and foundation selection.

5.10 Operation and Maintenance

5.10.1 Safety Zones

179 The developer's safety zone application will include safety zones around the wind turbines, foundations and offshore substation platform(s) during major maintenance works. In addition, the developer may issue NtM suggesting advisory safety zones to accommodate vessels with larger anchor spreads and major maintenance works to cables. Details of the safety zones typically expected at each phase are presented in Table 5.21.

Vessel type	Offshore project – turbines, collector station/collector stations, inter-array cables			Export cable route		
	Build phase	O&M phase (no works underway)	O&M phase (works underway)	Build phase	O&M phase (no works underway)	O&M phase (works underway)
Fishing (mobile gear)	Phased safety zones	No formal safety zone but avoidance of areas with cabling with certain fishing gear encouraged.	Roaming safety zone of 500 m around maintenance vessels. NtM to be issued in advance of works.	Safety zone within 500 m buffer either side of cable route.	Safety zone within 500 m buffer either side of cable route.	Safety zone with 500 m buffer either side of cable route.
Fishing (static gear), commercial, leisure	Phased safety zones	No formal safety zone but avoidance of areas with cabling with certain fishing gear encouraged.	Roaming safety zone of 500 m around maintenance vessels. NtM to be issued in advance of works.	Safety zone within 500 m buffer either side of cable route.	N/A	Rolling safety zone of 500 m around maintenance vessels. NtM to be issued in advance of works.

Table 5.21: Safety zones

5.10.1.1 Noise and Vibration of Operating Turbines

180 Noise from wind turbines can be divided into two categories; aerodynamic and mechanical. Aerodynamic noise is created by the wind passing around the blades and mechanical noise arises from the normal operation of the engineering components of the turbine such as the gear box, if present, and generator.

181 Aerodynamic noise is strongly influenced by incident conditions, i.e., wind speed and turbulence intensity. As a result aerodynamic noise is wind speed dependent, and the sound power output from a turbine must be measured and quoted relative to wind speed.

182 Unlike aerodynamic noise, mechanical noise tends to be tonal in nature, i.e., it is concentrated at a few discrete frequencies. This form of noise can be more intrusive than broader band noise. Mechanical noise can be successfully controlled at the design stage of the turbine, using advanced gearbox design and anti-vibration techniques. The present generation turbines considered for the proposed development incorporate design features which ensure that such tonal noise emissions are not considered significant.

5.10.2 Operational Summary

183 Neart na Gaoithe will be designed to operate with minimum day to day local intervention over the life of the wind farm. Individual turbines will be monitored and controlled in the first instance using onboard microprocessor controls. Turbine faults will be diagnosed at each turbine and a turbine will shut down automatically as is necessary. The SCADA system will transmit signals and commands to and from the field to an onshore control room, to provide oversight and control.

184 Each turbine and the offshore substation control system will be linked to the onshore monitoring facilities via optical cables contained within the inter-array and export cabling.

185 Provision will be made to control the wind farm from a number of locations, which will be determined as part of the final project design, but are likely to include:

- Onshore operations base - possibly staffed 24/7;
- Operation and maintenance (O&M) offshore facility – e.g., Service Operations Vessel (SOV); and
- All turbines and the offshore substation will have an internal emergency shutdown capability, which would automatically be triggered in the event of certain key component or system malfunctions.

5.10.3 Wind Farm Maintenance Requirements

5.10.3.1 Maintenance of Wind Turbine Foundations

186 Each foundation will be subject to routine inspections that will check the structural integrity of the foundation, ancillary equipment such as access ways and J-tubes, and the effectiveness of anti-corrosion measures in place. Marine growth may be removed in certain circumstances particularly if in the vicinity of access points, or if its loading effect on the foundation is considered to be excessive. Current indications suggest that two such inspection visits will be necessary per year per foundation. Alternative approaches to prevention and removal of marine growth are also being considered at present, including using semi-submersible scrubbers, powered by waves (refer to Figure 5.34). In the event that marine growth is necessary to be removed, conventional power washing using a high speed water spray will be used. Subsea investigations and remedial works will be carried out by ROV or by divers as is necessary.

Figure 5.34: Marine growth prevention solutions (Source: FoundOcean Ltd)

5.10.3.2 Maintenance of Turbines

187 Maintenance can be categorised into different levels. 'Local resets' are frequent events where a maintenance crew does a local visual inspection. It is estimated that these will require 5 to 10 visits per turbine per year.

188 The 'First Line' routine scheduled maintenance visits include changing out consumables and worn parts as part of a preventative maintenance regime. It is anticipated that two visits per year per turbine will be required. Lubricants, hydraulic oils and any other hazardous liquids and materials will be disposed of through licensed recycling contractors onshore.

189 'Second Line' maintenance is to replace parts that have failed, where access is achieved using conventional workboats.

190 'Third Line' maintenance is to replace major components, requiring the use of a jack-up on site. These major visits are infrequent and have a likelihood of occurrence of between 1 and 3 times per annum across the full wind farm. The main activities would involve disassembly and replacement of components, such as blades, gearboxes etc.

5.10.3.3 Maintenance of Offshore Substation(s)

191 The substation(s) will be subject to regular inspections and planned maintenance regimes. Emergency systems, circuit breakers and transformers will be checked regularly. Dissolved gas analysis and protection testing will be carried out on the transformers

192 Control and protection equipment tends to have an operational life of between 15 and 20 years and may therefore require replacement within the lifetime of the wind farm. Transformers typically have useful life spans in excess of 20 to 25 years.

193 The foundation structure will be maintained in accordance with the procedures outlined in the previous section on wind turbines.

5.10.3.4 Maintenance of Subsea Cables

194 The inter-array and export cables will be inspected regularly by use of ROV. The frequency of such inspections will be determined on a risk basis. Such operations will seek to check the integrity of the cable, cable burial and cable protection around J-tubes.

195 Such inspections will probably be carried out in summer months.

196 Should remedial action become necessary, a variety of measures may be viable; including additional rock dumping, mattressing, or the use of cable laying vessels with remote cable burial ROV to rebury the cable. Any works additional to those described in detail within this ES will require consent from Marine Scotland.

5.10.4 Resourcing the Maintenance Requirements

197 Careful consideration is being given to the nature of operations and maintenance for the project. There are two options currently being considered: an onshore operational base and an offshore operations hub.

198 The onshore operations base would ideally be situated within 30 to 40 km of the Neart na Gaoithe offshore site. This is feasible, but selection of this approach would result in a slower response time to address equipment failures.

199 A preferred solution has not been selected at this time. Both solutions and the vessel movements associated with each are therefore described in Section 5.10.4.1.

5.10.4.1 Offshore Operations Hub

200 This hub would be used to provide:

- Operations control centre;
- Accommodation quarters;
- Storage facility for spare parts;
- Workshop facilities;
- Medical centre; and
- Work boats to convey maintenance crews within the wind farm site.

201 A number of options both fixed and floating have been considered:

- The use of purpose built jack-up platforms;
- Fixed platform options;
- Floating ship based accommodation (Flotel); and
- SOV.

202 A flotel vessel may hold station at given positions within the field and would require dedicated anchorage points within the field for prolonged periods. An SOV would move around the site to transfer personnel. It would have specialised transfer systems and position keeping systems. A number of vessel designs are being promoted for such applications - Figure 5.35 shows an example of an SOV.

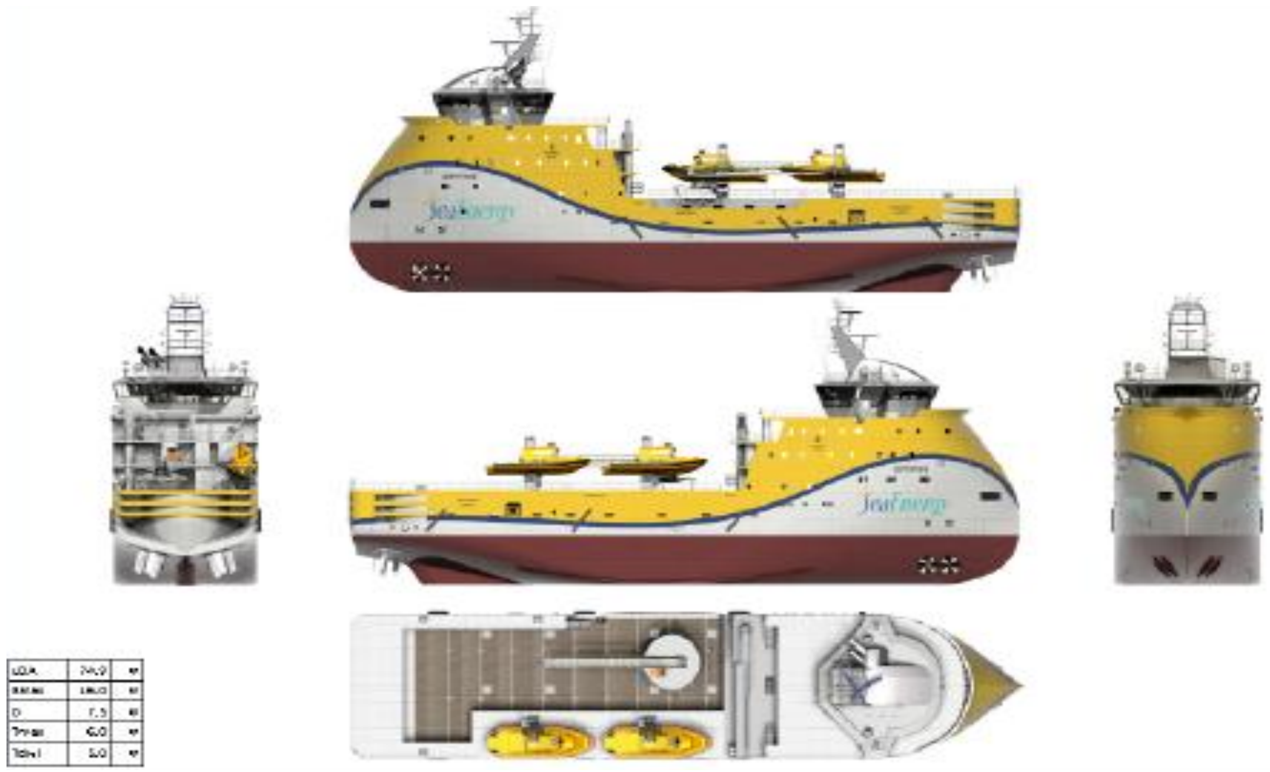

Figure 5.35: Zephyrus – offshore support vessel (Source: SeaEnergy Plc)

203 Maintenance crews would either be deployed directly from the operations vessel or by smaller purpose work boats which can be recovered to the operations vessel using onboard cranes/davits.

204 A typical operational crew roster would probably contain the following disciplines:

- Turbine maintenance technicians;
- Marine traffic and works controllers;
- HVAC engineers and technicians;
- Offshore supervisory staff;
- Offshore technical staff; and
- Ship and work boat crew.

205 Workboats associated with the SOV vessel would probably be 18 to 20 m catamaran type vessels. The davit arrangements proposed would be capable of launching or recovering vessels and crew from the water on the lee side of the SOV even during relatively severe weather, due to the shelter afforded by the SOV.

206 The intention, however, would be for the majority of turbine transfers to take place directly from SOV to turbine. Additionally, crew transfers and provisioning, and spare parts replenishment would take place on a fortnightly basis at port, further minimising risk to personnel during the transfer process.

207 Regular maintenance up to second line maintenance level can be facilitated using such a vessel. Third line maintenance, carried out from a jack-up vessel is common to both strategies, and is discussed later.

5.10.4.2 Shore Based Vessel Approach

208 The alternative to an offshore based operations and maintenance approach is the use of a local port or harbour.

209 In this scenario, a number of catamaran type vessels would be dispatched from a harbour to transport personnel to carry out local resets and first line maintenance. A proportion of second line maintenance would also be possible, using smaller vessels with the foredeck space and handling capabilities to transfer components to turbines requiring component replacement.

210 A harbour facility, with capability for mooring up to five catamarans would be necessary. Local offices, together with storage facilities for spare parts and portside light duty craneage would also be necessary. In addition, it would be advantageous if the location had facilities for craft maintenance.

211 Methods for transfer of personnel from such vessels to wind turbines offshore are continually being developed. It is likely that by the date of operation, effective systems will be commercially available. This factor may also have a significant impact on the O&M strategy selected by the developer.

212 The workboats will be capable of making the transit to shore as and when necessary in all but the most extreme conditions. Workboats will be dual hull for added stability and have purpose built access platforms to assist transits to and from offshore structures (refer to Figure 5.36 for a typical example). The Det Norske Veritas certified vessels will be around 22 m in length with an operational speed of 20 to 27 knots and be licensed to carry up to 14 persons (12 technicians, plus crew).

Figure 5.36: Example of offshore workboat (Source: Windcat Workboats)

5.10.4.3 Summary of Vessel

213 A summary of the type of vessel activities on site is given in Table 5.22 for each of the options described in the preceding sections.

Activity	Annual frequency	Vessel used	Comment
Staff transportation to and from site	20 - 30 transfers (round trip from a local port).	SOV	These trips would probably take place fortnightly.
Balance of plant maintenance	10-20 two week campaigns.	Conventional maintenance vessel	None
Scheduled 1st line maintenance	Built into SOV operations within the site.	Catamaran / trimaran.	Commonly used offshore
2nd line maintenance	Built into SOV operations on site.	Catamaran /Hi Speed	None
3rd line maintenance	Average 2 events per annum.	Jack-up barge	Failures higher initially
Local reset activities[5]	400-600 events.	SOV / catamaran	Where possible, transfers would take place from SOV. Catamaran support as required for peak smoothing.

Table 5.22: Option 1 - Use of an SOV based strategy

[5] 'Local resets' are frequent events where a maintenance crew does a local visual inspection.

214 The following information in Table 5.23 is based onshore based vessel approach:

Activity	Annual frequency	Vessel used	Comment
Staff transportation	3 vessel departures per day, average, 320 days per year.	Circa 20 metre catamarans	Fuel Usage 0.25 t per hour
Balance of plant (BOP) maintenance	10-20 two week campaigns.	Conventional maintenance vessel	
Scheduled maintenance	Included above	Catamaran / trimaran	Commonly used offshore .
2nd line maintenance	Included abov.	Catamaran / other larger vessel	
3rd line maintenance	Average 2 events	Jack-up barge	Failures higher initially
Local resets	400-600 events – included above.	Catamaran	

Table 5.23: Shore based operations

215 Under this scenario, each catamaran round trip would probably be for 12 hours. Fuel usage would therefore likely be circa 3,000 tonnes per annum. Fuel usage for jack-up barges will be entirely dependent on where they are dispatched from.

216 In respect of the above arrangements, helicopter transfers have not been considered. However, if helicopters are used, there would be up to 80 round trips for a small helicopter per annum to site. Such an approach may prove feasible in the event that a number of projects are located in the area.

5.11 Decommissioning

5.11.1 Decommissioning and Removal of Foundations

5.11.1.1 Gravity Base Foundations

217 The decommissioning process will adhere to all necessary requirements and regulations in force at the time. At present it is anticipated that gravity base foundation decommissioning will be the reverse of installation as follows:

- An initial inspection to establish gravity base structural integrity will be carried out using ROV;
- Suction dredging vessels will remove ballast from within the foundation structure. Removed material will be transported to and disposed of in suitable licensed disposal sites either onshore but ideally offshore;
- ROV will be used to repair lifting attachments (if necessary) and carry out a pre lift inspection; and
- A heavy lift vessel will lift the foundations from the seabed and land them onboard a suitable transportation vessel or barge for onward transportation to a suitable onshore recycling site. Alternatively, if the foundations were floated to site they may be floated back to shore.

5.11.1.2 Jacket Foundations

218 Best practice will be followed at the time of decommissioning. Current practice for offshore jacket installations is to cut piled foundations below seabed level using either an abrasive water jet or diamond wire cutter. The jacket superstructure is then raised to the surface and removed to a suitable onshore site for recycling. Removal of the entire embedded pile is considered impractical and is likely to lead to unnecessary environmental impacts.

219 The following sequence of operations is likely to be followed during decommissioning:

- Underwater inspection using ROV;
- Heavy lift anchoring points will be established and made good;
- Removal of any marine growth and or debris with the potential to impact later cutting activities;
- Establish lifting points for decommissioning vessel ;

- Cut piles at required depth;
- Raise jacket to the surface for removal from site; and
- Seabed inspection and final clearance.

220 It should be noted that as the decommissioning procedures are not fully known at this time, decommissioning is not assessed in detail in this ES. A decommissioning plan will be submitted to the Department of Energy and Climate Change (DECC) prior to construction commencing.

5.11.2 Decommissioning and Removal of Turbines

221 Removal of turbines, either for replacement or final decommissioning, is likely to be the reverse of the installation procedure. The sequence of activity is expected to be:

- Conduct inspection to identify any safety or operational hazards;
- Disconnect turbine from electrical and control networks;
- Removal and appropriate disposal of any hazardous liquids or materials;
- Mobilise decommissioning vessel or barge to site;
- Remove rotor blades, nacelle and tower section in that order; and
- Transport components to designated recycling site onshore.

5.11.3 Decommissioning of Electrical Infrastructure

5.11.3.1 Offshore Substation

222 The offshore substation(s) will be removed and processed for decommissioning after the operational lifetime of the wind farm. The following steps will be taken:

- De-energise and isolate the wind farm from the grid system;
- Marshal the appropriate lift vessels to the wind farm location;
- Cut or disconnect and remove cables from the substation;
- Removal and proper processing of all hazardous substances and fluids such as oil from reservoirs;
- Transport the substation to shore, intact if possible. Otherwise, it may be necessary to deconstruct the substation into smaller modules to be transported; and
- Once onshore, the substation will be deconstructed. All components will be taken to the appropriate facility for processing for either reuse, recycling, or disposal.

223 Where possible, components will be removed from the offshore site intact and disassembly will take place onshore at an appropriate facility to minimise risks of spillage and to optimise safety.

224 Foundations will be removed in keeping with the procedures outlined in Section 5.11.1 covering wind turbine foundation removal and decommissioning

5.11.3.2 Inter-array Cables

225 Inter-array cables will normally be left *in situ* as is the current industry standard. Similar to turbine foundations, best practice will be followed at the time of decommissioning. Current practice for cables is to cut to below seabed level and remove the cut ends.

226 If cable removal is required this will be done using a water jetting or grapnel tool. The cable will be lifted at both ends and spooled onto a cable drum. Typically the cable can be recycled after recovery.

227 Any cables that are cut during removal of the wind turbines will be removed and reused, recycled and/or disposed of appropriately.

5.11.3.3 Export Cable

228 Export cables will be removed if necessary in a similar manner to that described for the inter-array cabling (refer to section 5.11.3.2).

5.11.3.4 Transition Pit(s)

229 Similar to the remainder of the onshore cable system, it is likely that the transition pit(s) will be left *in situ* as removal will result in significant disturbance to the local environment. Contingency plans will be developed to ensure that appropriate actions are taken should the transition pit be disturbed or exposed.

5.12 Repowering

230 Although The Crown Estate (TCE) lease is for 50 years, the turbines have a design lifetime of up to 25 years. Any application for repowering will be the subject of a separate environmental impact assessment.

5.13 Additional Projects Included for Specific Assessments

231 As discussed in Chapter 1: Introduction, TCE granted lease agreements to nine other offshore wind farm developers operating within Scottish territorial waters (STW) . Collaboration with offshore wind farms in the immediate and wider region is necessary to fully assess the potential impacts on a given receptor.

232 The Forth and Tay Offshore Wind Developers Group (FTOWDG) was formed to facilitate collaboration between the neighbouring developments of Inch Cape and Firth of Forth Round 3 Zone 2 developments and is discussed in more detail in Chapter 1: Introduction. The extent of the collaboration is discussed in Chapter 7: Engagement and Commitments. Figure 5.37 provides a map of the area and shows the sites, both in relation to each other and the Scottish coastline.

233 In addition to the group collaboration, FTOWDG is collaborating with the developers in the Moray Firth region (Moray Firth Offshore Wind Farm Developers – MFOWDG) to develop a series of common mitigation strategies which can be presented to the fishing industry for discussion. A consistent approach to industry wide mitigation will mean greater transparency and fairness for all involved. FTOWDG is also collaborating with the MFOWDG in joint consultation initiatives, again with the fishing industry to reduce the demands on industry wide representatives.

234 In some cases it has been necessary to include additional wind farm sites when a potential interaction was highlighted during the course of the impact assessment process. Additional sites for consideration are detailed in the individual chapters.

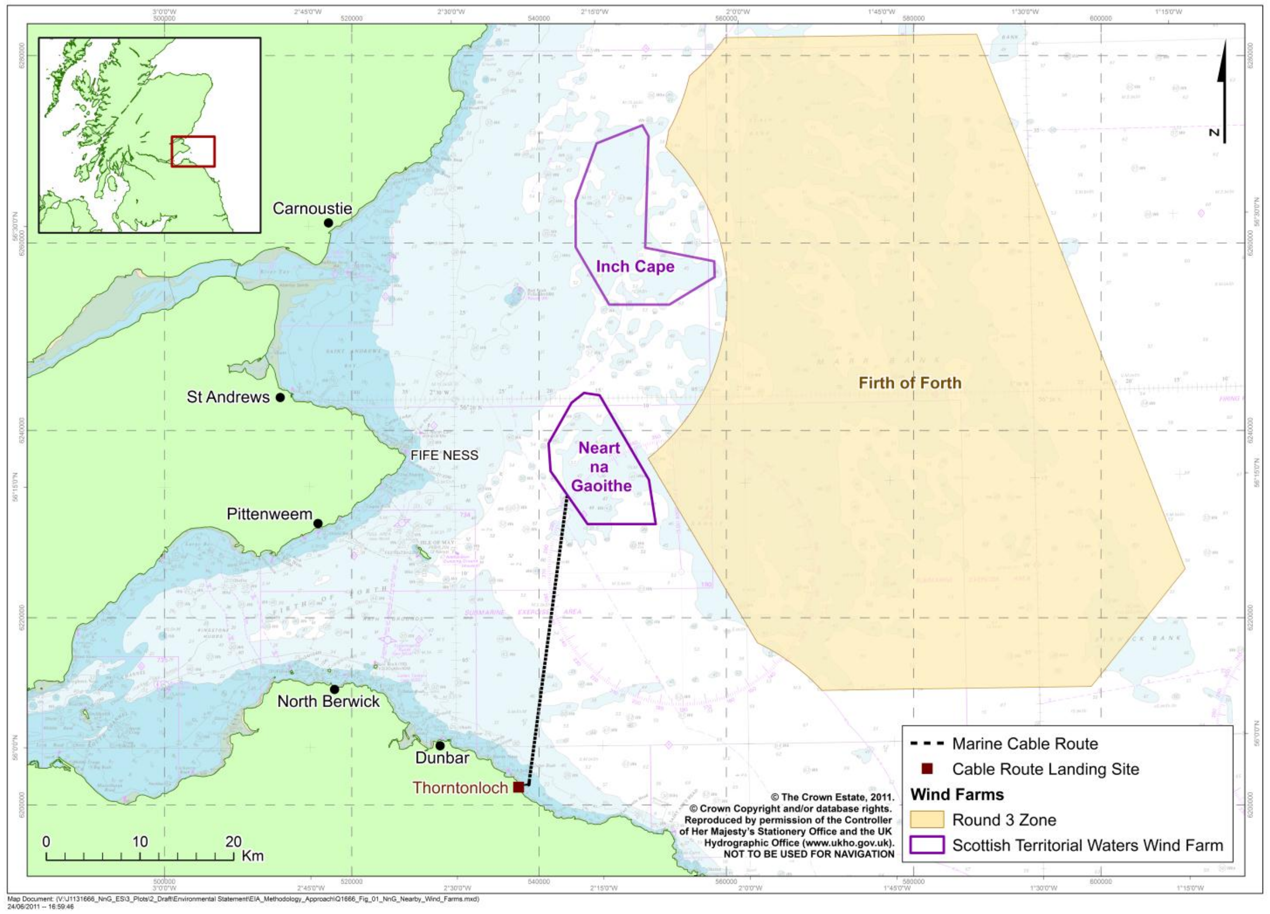

Figure 5.37: FTOWDG sites

5.13.1 The Approach to Assessment

235 In order to assess the potential cumulative impacts arising from multiple projects in close proximity it is necessary to have clarity on the parameters of the potential developments. Due to differing project timelines the given Rochdale Envelopes are indicative outer limits of what is currently considered to be feasible at the time of the assessment. As time progresses, developments will have increased certainty over project details and the Rochdale Envelope for a particular project is likely to increase in certainty and therefore reduce the scope for assessment.

236 It is likely that when the Inch Cape and Firth of Forth Round 3 Zone 2 developments reach the consent application stage the Rochdale Envelope for their projects will have been significantly refined compared to that which has been used as a basis for the impact assessment in this ES. As such, the cumulative assessment can be considered conservative.

5.13.2 Inch Cape

237 Inch Cape Offshore Wind Farm site is approximately 150 km^2 in area and lies approximately 15-22 km east of the Angus coast (refer to Figure 5.37 and Figure 5.38). The site capacity is approximately 1,000 MW which is currently anticipated to be achieved through the installation of up to 213 turbines. It is important to note that since the assessment was completed the values for the Inch Cape offshore wind farm Rochdale Envelope were refined, the revised values are presented in Table 5.24. As the Rochdale Envelope details were refined following the completion of the assessment process, the original values are presented in individual ES chapters.

The export cable will be either high voltage direct current (HVDC) or HVAC. The export cable route and landing point are currently not confirmed. The assessment corridor indicates a landing point between Cockenzie and Seton Sands. Additional offshore infrastructure is expected to include 1 to 5 substation platforms, 1 to 3 met masts, approximately 353 km of inter-array cable and up to four export cables. The Rochdale Envelope provided by Inch Cape is detailed in Table 5.24.

Parameter	Value	
Number of wind turbine generators	213	
Rotor diameter range	172 m	
Blade tip height range	152 – 215 m	
Hub height range	92 – 129 m	
Turbine separation (downwind x crosswind)	Minimum: 7 rotor diameter (D) x 5 D Maximum: 10 D x 10 D	
Rotor clearance	22 m (above Mean High Water Springs (MHWS))	
Operating rotor speed range	5 - 13 rpm	
Substructure type	Gravity base structure	
	Jacket (including tripod)	
Foundation type	Driven piles	1.8 m - 3.0 m diameter
	Suction piles	17 m diameter
	Drilled piles	1.8 m - 3.0 m diameter
	Gravity base foundation	44 m - 72 m diameter
Footprint (area of the foundation component which is in direct contact with the seabed)	Driven piles	up to 28 m^2
	Suction piles	up to 910 m^2
	Drilled piles	up to 28 m^2
	Gravity base foundation	up to 4,295 m^2
Scour protection	Driven piles	not required
	Suction piles	up to 6,000 m^2
	Drilled piles	not required
	Gravity base foundation	up to 7,300 m^2
Maximum hammer blow energy (piling)	1200 kilojoules (kJ) - 2300 kJ	
Number of simultaneous piling events on site	2	
Number of permanent met masts	1	
Met mast height	129 m - 215 m	
Met mast foundation and substructure type	Same as wind turbine foundations	
Number of offshore substation platforms	1 - 5	
Offshore substation platform dimensions	HVAC OSP - 40 m L x 40 m W x 30 m H HVDC OSP - 115 m L x 55 m W x 42 m H Combined HVAC/HVDC OSP - 115 m L- 72 m W - 42 m H	
Offshore substation platform dimensions footprint	Jacket - 14 m^2 (AC OSP) to 65 m^2 (DC OSP) gravity base - 1,963 m^2 (AC OSP) to 10,100 m^2 (DC OSP)	
Scour protection	up to 45,000 m^2	
Inter-array cabling voltage	33 kV - 66 kV	
Maximum Inter-array cable trench (WxD)	3 m x 1.5 m	
Total export cable length	50 km-75 km	

Table 5.24: Inch Cape Rochdale Envelope (information provided by Inch Cape)

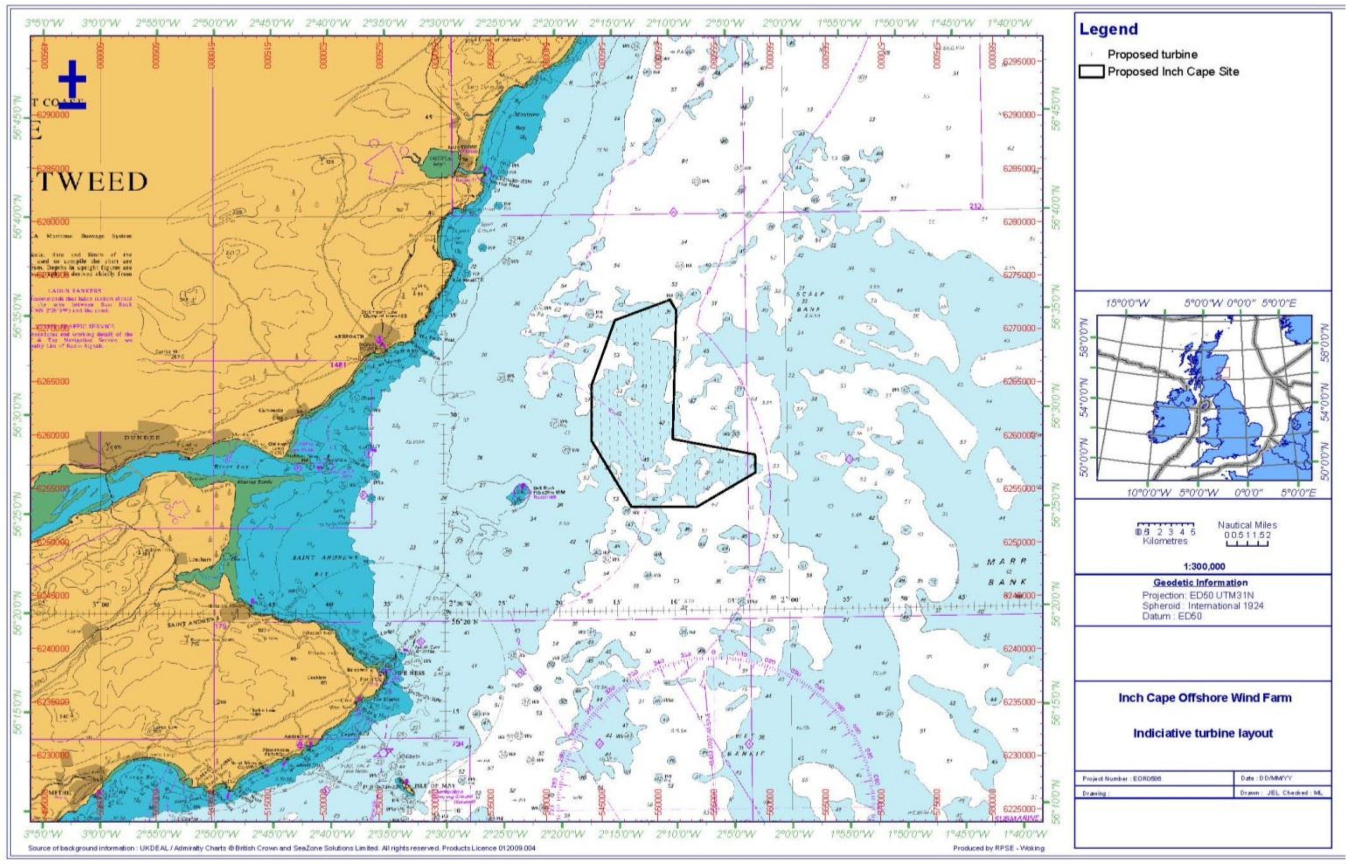

Figure 5.38: Inch Cape Indicative layout map

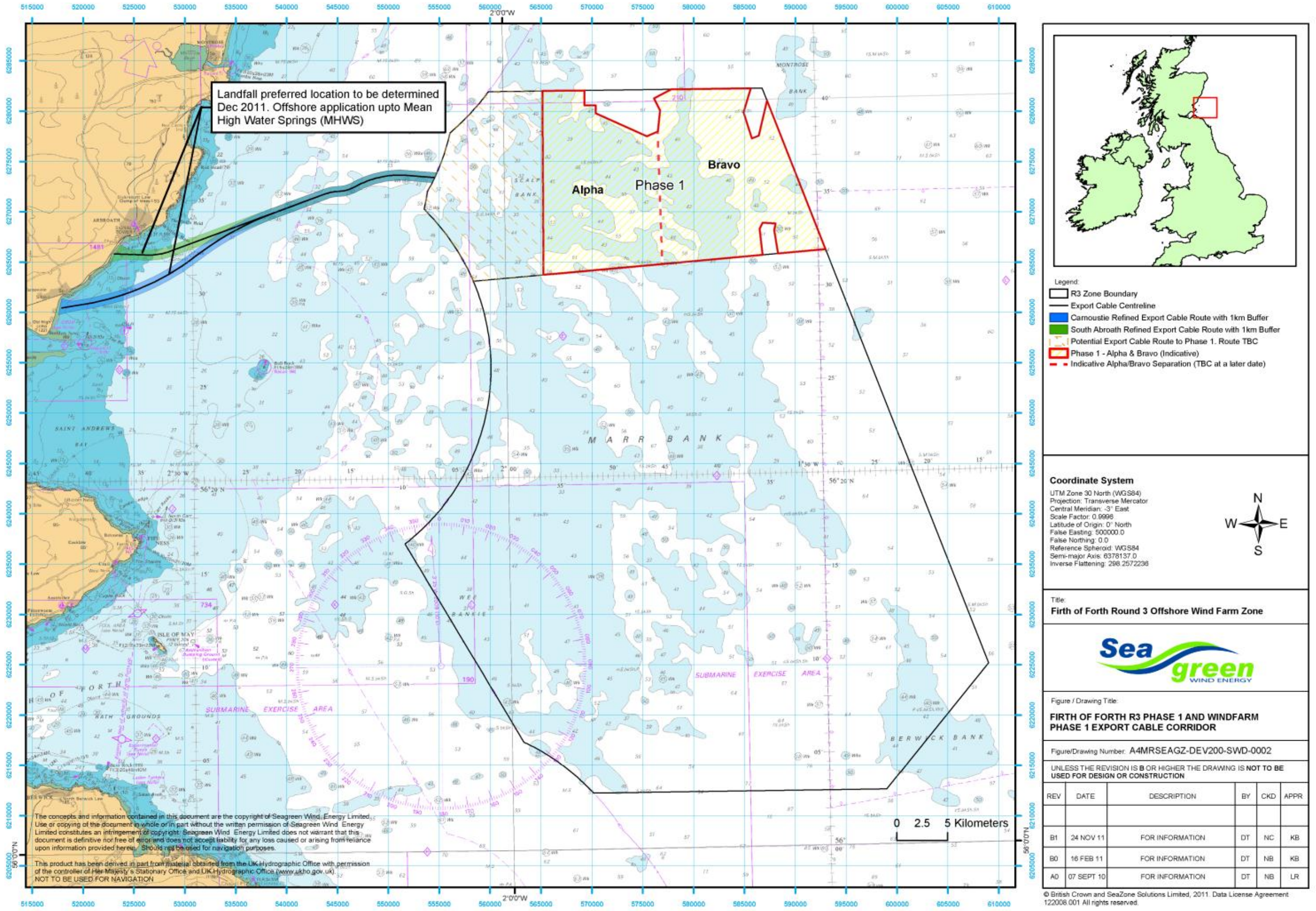

Figure 5.39: Firth of Forth Round 3 Zone 2

5.13.3 Firth of Forth Round 3 Zone 2

239 The Firth of Forth Round 3 Zone 2 development is located outside of the STW limit, approximately 25 km east of Fife and covers an area of 2,852 km^2 in the outer Firth of Forth (see Figure 5.37 and Figure 5.39). The Zone has a potential installed capacity of circa 3.5 GW. The Firth of Forth Round 3 Zone 2 development is currently separated into three phases which are scheduled for submission of consent applications as follows: Phase 1 Summer 2012, Phase 2 Autumn 2014, and Phase 3 Winter 2016.

240 The export cables will be either HVDC or HVAC. The export cable route and landing point for Phase 1 of the Zone's development is currently not confirmed and Seagreen has examined two potential landfall locations (at Carnoustie and Arbroath). It is Seagreen's intention to select a preferred location prior to submission of their consent application. The two assessment corridors share a common route from the wind farm until they split close to the landing points, as seen in Figure 5.39. For Phases 2 and 3 only an indicative export cable route corridor has been identified along the East Lothian coast. Additional offshore infrastructure for the Zone is expected to include 1 to 5 substation platforms, 1 to 9 met masts, inter-array cabling and a minimum of 2 export cables.

241 The Rochdale Envelope information detailed in Table 5.25 was provided by Seagreen on 5 December 2011. It contains full information on parameters for Phase 1. In addition, it provides likely numbers of turbines and met masts for Phases 2 and 3.

242 Depending on the receptor and specific potential areas of interaction, different aspects of the Rochdale Envelope were used. The cumulative Rochdale is defined on an individual receptor basis in each chapter as appropriate.

Aspect	Wind farm design parameter	Phase 1 Rochdale Envelope	Most likely scenario phases 1,2 and 3
Site characteristics	Phase 1 maximum area	390 km^2	390 km^2
	Water depth	40 m - 60 m (LAT)	40 m - 60 m (LAT)
Wind turbine generators	Turbine specification	3.5 MW - 7.0 MW	6 MW
	Number of turbines	154 - 299	Phase 1 = 180, Phase 2 = 304 and Phase 3 132
	Turbine maximum separation (8 rotor diameter x 6 rotor diameter)	Downwind - 96 m - 1,360 m Crosswind - 720 m - 990 m	Downwind - 1,008 m Crosswind – 726 m
	Rotor diameter	120 m - 165 m	126 m (LAT)
	Blade maximum tip height	154 m - 199 m (LAT)	160 m (LAT)
	Maximum hub height	94 m - 116.5 m (LAT)	97 m (LAT)
	Minimum rotor clearance	25.4 m (LAT)	25.4 m
	Operating rotor speed	4.8 rpm - 13 rpm	4.8 rpm - 13 rpm
Foundations and substructures	Substructure type	Jacket Gravity base	Jacket Gravity base
	Foundation	Jacket - pile diameter 2.1 m - 3.0 m	Jacket pile diameter 2.1 m gravity base footing -

Aspect	Wind farm design parameter	Phase 1 Rochdale Envelope	Most likely scenario phases 1,2 and 3
		Jacket suction cassion diameter 7 m Gravity base footing - concrete slab diameter 44 m - 72 m	concrete slab diameter 37 m
	Footprint (area of the foundation component which is in direct contact with the seabed)	jacket piled - 14 m2 - 28 m^2 Jacket suction cassion -616 m^2 Octagonal gravity base – 1604 m^2 - 4295 m^2	jacket piled - 14 m^2 Octagonal gravity base - 4,295 m^2
	Scour protection	Jacket - not required Suction cassion - 3,949 m^2 - 6,223 m^2 gravity base - 6,030 m^2 - 7,281 m^2	Jacket - not required gravity base - 10,923 m^2
Met masts	Number of permanent met masts	1 to 3	3 in each phase
	Met mast height	154 m to 199 m (LAT)	160 m
	Met mast foundation/substructure type	Jacket/gravity base as per turbines	Jacket/gravity base as per turbines
	Transmission asset design parameter	Phase 1 Rochdale Envelope range	Most likely scenario Phase 1
Offshore substation	Number of offshore platforms	HVAC offshore platforms – 2 HVDC offshore platforms - 2 to 3	2
	Maximum offshore platform size	HVAC OSP 40 m L x 40 m W x 30 m H HVDC OSP 115 m L x 55 m W x 42 m H Combined HVAC and HVDC OSP - 115 m L x 72 m W , 42 m H	2 no. HVAC OSP - 40 m L x 40 m W x 30 m H 1 no. HVDC OSP - 115 m L x 55 m W x 42 m H
	Offshore substation foundation footprint	Jacket 14 m2 (AC OSP) to 65 m2 (DC OSP) gravity base - 1,963 m^2 (AC OSP) to 10,100 m^2 (DC OSP)	Currently unknown
	Scour protection	Jacket - not required gravity base - 12,115 m^2 to 45,100 m^2	tbc
Cables	Inter-array cabling voltage	33 kV AC	33 kV AC
	Maximum inter-array cable trench	3 m W x 1.5 m D	3 m W x 1.5 m D
	Export cable route landfall	Arbroath or Carnoustie	Phase 1; Arbroath or Carnoustie Phases 2/3: Corridor along East Lothian coast
	Total export cable length	75 km to 208 km	104 km
	Interconnecting cable between areas Alpha and Bravo	16 km	16 km

Table 5.25: Seagreen Rochdale Envelope (information provided by Seagreen)

5.14 Benefits to the Collaborative Approach

243 Agreeing survey methodologies and committing to sharing survey data ensure that a greater understanding of the baseline environment is gained and the potential resulting impacts can be more accurately assessed. The conclusions of the cumulative assessment are strengthened by this collaboration, both in terms of data input but also by way of information and experience sharing.

5.15 Neart na Gaoithe Rochdale Envelope

Project design element	Parameter	3.6 MW	4.1 MW	6 MW	7 MW
Turbines					
Turbines	Number at 450 MW capacity	125	109	75	64
	Maximum rotor tip height (m) (LAT)	175	171.25	175.5	197
	Rotor diameter (m)	120	112.5	121	164
	Minimum hub height (m) (LAT)	84	80.25	84.5	106
	Maximum hub height (m) (LAT)	115	115	115	115
	Air gap (m) clearance to blade tip (minimum of) from LAT	26	26	26	26
	Rev. per min. (rpm)	5 - 13 rpm	8-18 rpm	5-13 rpm	4.8-12.1 rpm
	Speed at blade tip (m/s)	31.4 - 81.64 m/s	50.24 - 113.04 m/s	31 - 83 m/s	41-104 m/s
	Height of platform (m) LAT	18	18	18	18
	Max turbine spacing (m) (approximately)	1320	1240	1330	1805
	Min turbine spacing (m) (approximately)	480	450	484	656
	Position of turbines	**Indicative layout A (Figure 5.22)**		**Indicative layout B (Figure 5.23)**	
	Colour scheme / lighting	Light Grey RAL 7035	Light Grey RAL 7035	Light Grey RAL 7035	Light Grey RAL 7035
	No. of concurrent turbine installations	Maximum 2 at a time	Maximum 2 at a time	Maximum 2 at a time	Maximum 2 at a time
Other infrastructure					
Offshore Substation	Number of offshore substations	1 or 2	1 or 2	1 or 2	1 or 2
	Position of collector stations	On layout diagram (Figure 5.22 and 5.23)			
	Height of structures (m) LAT	Platform height estimated 18 m above LAT Highest structure estimated 60 m above LAT			
	Foundation of substation	4-8 piles per jacket at up to 3.5 m diameter (each). Pre-install piles in template and fit jacket onto piles / or post pile through jacket sleeves after placing jacket. If piles in valley piles will be embedded up to 60 m below seabed, if in bedrock up to 20 m embedment below rockhead level. Bedrock - drilled piles.			
	Chemicals and oils	Sulphur hexaflouride usually inside gas insulated switchgear. Oil as cooling medium for transformers, back-up generator - with diesel tanks.			
	Size of structures (m)	Deck area approximately 30 x 30. Jacket leg spacing at seabed up to 60 x 60.			
	Design details	Substation likely to include transformer rooms (and coolers), switchgear rooms (220 kV and 33 kV), stores, working areas, WC and shower, emergency accommodation, control and protection room and space for cable marshaling and transformer oil sump. Potential to have offshore mother ship or daily transits from local ports.			
	Colour scheme / lighting	Yellow up to underside of platform then grey.			

Project design element	Parameter	3.6 MW	4.1 MW	6 MW	7 MW
jacket foundations					
Turbine Foundations	Jacket leg spacing at seabed level (m x m)	15x15 - 25x25	15x15 - 25x25	20x20 - 30x30	25x25 - 35x35
	Details of seabed preparation	A seabed template with up to 4 legs (max leg spacing 30 m x 30 m) will sit temporarily on the seabed during pile installation.		A seabed template with up to 4 legs (max leg spacing 35 m x 35 m) will sit temporarily on the seabed during pile installation.	A seabed template with up to 4 legs (max leg spacing 40 m x 40 m) will sit temporarily on the seabed during pile installation.
	Foundation diameter (m) (piles)	2.5-3.5	2.5-3.5	2.5-3.5	2.5-3.5
	Number of piles per foundation	3 or 4	3 or 4	3 or 4	3 or 4
	Foundation material	Steel	Steel	Steel	Steel
	Foundation bed penetration depth (m) (piling)	15-40	15-40	20-50	20-50
	Foundation installation method	Approximately 3% of piles will be driven only, 7% of piles will be drilled only. 90% of piles will be driven-drilled. Of these an average of 30% of the pile will be driven and 70% drilled.			
	Foundation installation duration (per foundation) (Hours)	Piling (62-180 hours for 4 piles), Jacket installation (12-24 hours). This includes time for setting up and changing equipment between piling locations.			
	Foundation installation frequency (No. of days per foundation) if using one vessel	5-12			
	Jack-up number of moves per foundation installation	1-3	1-3	1-3	1-3
	Foot print from jack-up (leg spacing)	50x50 – 100x100	50x50 – 100x100	50x50 – 100x100	50x50 – 100x100
	Number of spud cans	4-8	4-8	4-8	4-8
	Spud can footing area (m^2) (per spud can)	1 m^2 (leg area without spud can) to 106 m^2			
	Turbine foundation scour protection and footprint size (m^2)	100 – 250 m^2			
	Collector station foundation	Likely to be jacket on piles	Likely to be jacket on piles	Likely to be jacket on piles	Likely to be jacket on piles
Gravity base foundations					
Turbine Foundations	Area of foundation footprint (m^2)	300-700	300-700	490-1600	490-1600
	Foundation footprint diameter (m)	20 - 30 m	20 - 30 m	25 - 45 m	25 - 45 m
	Foundation footprint cross dimensions (cruciform option) (m)	20 - 30 by 5 - 7 m	20 - 30 by 5 - 7 m	30 - 40 by 5 - 7 m	30 - 40 by 5 - 7 m
	Seabed preparation	Dredging in areas where loose sand or soft clay present at seabed plus gravel placement in area of dredging to provide a stable platform for foundation.			
	Quantity of material dredged	Average of 1500 m^3 dredged per foundation. Approximately 190,000 m^3 of material dredged over entire site.		Average of 4,000 m^3 dredged per foundation. Approximately 320,000 m^3 of material dredged over entire site.	
	Disposal of dredged material	Dredged material will be disposed of at a licensed disposal area.			
	Gravel bed	Minimum 530 m^3 per foundation, Maximum 1850 m^3 per foundation foundation			
	Depth of gravel bed	The gravel beds will be an average of 1.5 m deep. In areas of very soft sediment gravel bed could be up to 4 m deep, this is expected to be the case in less than 5% of turbine locations.			

Project design element	Parameter	3.6 MW	4.1 MW	6 MW	7 MW
	Extension of gravel bed beyond foundation perimeter	2 – 4 m	2 – 4 m	2 – 4 m	2 – 4 m
	Foundation material	The gravity base structure will be reinforced concrete. This will be filled with a ballast of sand which has been dredged from the turbine location in seabed preparation and sand/gravel which has been sourced from a licenced dredging area.			
	Foundation installation duration (hours)	Dredging 4-7 days, foundation placement and filling 4 - 7 days , scour protection placement 7 - 14 days.			
	Scour protection and footprint size (m)	Scour protection extends 5 - 8 m outside foundation perimeter.			
Cables					
Inter-array cables	Number of cables	Up to 16 circuits with a total of 85 to 140 km of cable.			
	Design of array	Max 10 Turbines per collector circuit	Max 9 turbines per collector circuit	Max 6 turbines per collector circuit	Max 6 turbines per collector circuit
	Specification of cables	XLPE AC Cable Up to 70 kV Size ranges from 50 mm2 to 500 mm2			
	Burial method / scour protection	Currently unconfirmed, but likely plough/cutting/jetting or rock cover.			
	Width of seabed affected (per cable)	2 m direct impact width, up to 8 m width of zone of minor disturbance (10 m in total).			
	Burial depth (m)	Currently unconfirmed, varies across the site likely to be 1-1.5 m.			
	Width of cable corridor	30 to 100 m			
Export cables	Number of cables (No.)	2			
	Route / length (m)	33 km			
	Specification of cables	220 kV (Um 245 kV) 3-phase AC XLPE insulated			
	Spacing between cables (m)	Minimum 70 m/ max 300 m. 3x water depth but no less than 70 m.			
	Width of cable corridor (m)	300 m (150 m on either side of cable route centre line)			
	Burial depth (m)	1-3 m			
	Burial method / scour protection	Currently unconfirmed, but likely plough/cutting/jetting or rock cover.			
	Landing point	Thorntonloch			

5.16 References

Subsea World News, 2011. *FLIDAR Completes Successful Tests off Belgian Coast*. Available online from: http://subseaworldnews.com/2011/11/28/flidar-completes-successfull-tests-off-belgian-coast/ [Accessed Apr 2012].

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